ENVIRONMENTAL PROTECTION AGENCY

40 CFR Parts 60 and 63

[EPA–HQ–OAR–2010–0505; FRL–9448–6]

RIN 2060–AP76

Oil and Natural Gas Sector: New Source Performance Standards and National Emission Standards for Hazardous Air Pollutants Reviews

AGENCY: Environmental Protection Agency (EPA).

ACTION: Proposed rule.

SUMMARY: This action announces how the EPA proposes to address the reviews of the new source performance standards for volatile organic compound and sulfur dioxide emissions from natural gas processing plants. We are proposing to add to the source category list any oil and gas operation not covered by the current listing. This action also includes proposed amendments to the existing new source performance standards for volatile organic compounds from natural gas processing plants and proposed standards for operations that are not covered by the existing new source performance standards. In addition, this action proposes how the EPA will address the residual risk and technology review conducted for the oil and natural gas production and natural gas transmission and storage national emission standards for hazardous air pollutants. This action further proposes standards for emission sources within these two source categories that are not currently addressed, as well as amendments to improve aspects of these national emission standards for hazardous air pollutants related to applicability and implementation. Finally, this action addresses provisions in these new source performance standards and national emission standards for hazardous air pollutants related to emissions during periods of startup, shutdown and malfunction.

DATES: Comments must be received on or before October 24, 2011.

Public Hearing. Three public hearings will be held to provide the public an opportunity to provide comments on this proposed rulemaking. One will be held in the Dallas, Texas area, one in Pittsburgh, Pennsylvania, and one in Denver, Colorado, on dates to be announced in a separate document. Each hearing will convene at 10 a.m. local time. For additional information on the public hearings and requesting to speak, see the **SUPPLEMENTARY INFORMATION** section of this preamble.

ADDRESSES: Submit your comments, identified by Docket ID Number EPA–HQ–OAR–2010–0505, by one of the following methods:

- *Federal eRulemaking Portal: http://www.regulations.gov:* Follow the instructions for submitting comments.
- *Agency Web site: http://www.epa.gov/oar/docket.html.* Follow the instructions for submitting comments on the Air and Radiation Docket Web site.
- *E-mail: a-and-r-docket@epa.gov.* Include Docket ID Number EPA–HQ–OAR–2010–0505 in the subject line of the message.
- *Facsimile:* (202) 566–9744.
- *Mail:* Attention Docket ID Number EPA–HQ–OAR–2010–0505, 1200 Pennsylvania Ave., NW., Washington, DC 20460. Please include a total of two copies. In addition, please mail a copy of your comments on the information collection provisions to the Office of Information and Regulatory Affairs, Office of Management and Budget (OMB), Attn: Desk Officer for the EPA, 725 17th Street, NW., Washington, DC 20503.
- *Hand Delivery:* United States Environmental Protection Agency, EPA West (Air Docket), Room 3334, 1301 Constitution Ave., NW., Washington, DC 20004, Attention Docket ID Number EPA–HQ–OAR–2010–0505. Such deliveries are only accepted during the Docket's normal hours of operation, and special arrangements should be made for deliveries of boxed information.

Instructions: Direct your comments to Docket ID Number EPA–HQ–OAR–2010–0505. The EPA's policy is that all comments received will be included in the public docket without change and may be made available online at *http://www.regulations.gov,* including any personal information provided, unless the comment includes information claimed to be confidential business information (CBI) or other information whose disclosure is restricted by statute. Do not submit information that you consider to be CBI or otherwise protected through *http://www.regulations.gov* or e-mail. The *http://www.regulations.gov* Web site is an ''anonymous access'' system, which means the EPA will not know your identity or contact information unless you provide it in the body of your comment. If you send an e-mail comment directly to the EPA without going through *http://www.regulations.gov,* your e-mail address will be automatically captured and included as part of the comment that is placed in the public docket and made available on the Internet. If you submit an electronic comment, the EPA recommends that you include your name and other contact information in the body of your comment and with any disk or CD–ROM you submit. If the EPA cannot read your comment due to technical difficulties and cannot contact you for clarification, the EPA may not be able to consider your comment. Electronic files should avoid the use of special characters, any form of encryption, and be free of any defects or viruses. For additional information about the EPA's public docket, visit the EPA Docket Center homepage at *http://www.epa.gov/epahome/dockets.htm.* For additional instructions on submitting comments, go to section II.C of the **SUPPLEMENTARY INFORMATION** section of this preamble.

Docket: All documents in the docket are listed in the *http://www.regulations.gov* index. Although listed in the index, some information is not publicly available, *e.g.,* CBI or other information whose disclosure is restricted by statute. Certain other material, such as copyrighted material, is not placed on the Internet and will be publicly available only in hard copy. Publicly available docket materials are available either electronically through *http://www.regulations.gov* or in hard copy at the U.S. Environmental Protection Agency, EPA West (Air Docket), Room 3334, 1301 Constitution Ave., NW., Washington, DC 20004. The Public Reading Room is open from 8:30 a.m. to 4:30 p.m., Monday through Friday, excluding legal holidays. The telephone number for the Public Reading Room is (202) 566–1744, and the telephone number for the Air Docket is (202) 566–1742.

FOR FURTHER INFORMATION CONTACT: Bruce Moore, Sector Policies and Programs Division, Office of Air Quality Planning and Standards (E143–01), Environmental Protection Agency, Research Triangle Park, North Carolina 27711, telephone number: (919) 541–5460; facsimile number: (919) 685–3200; e-mail address: *moore.bruce@epa.gov*.

SUPPLEMENTARY INFORMATION:

Organization of This Document. The following outline is provided to aid in locating information in this preamble.

I. Preamble Acronyms and Abbreviations

Several acronyms and terms used to describe industrial processes, data inventories and risk modeling are included in this preamble. While this may not be an exhaustive list, to ease the reading of this preamble and for reference purposes, the following terms and acronyms are defined here:

ACGIH American Conference of Governmental Industrial Hygienists
ADAF Age-Dependent Adjustment Factors
AEGL Acute Exposure Guideline Levels
AERMOD The air dispersion model used by the HEM–3 model
API American Petroleum Institute
BACT Best Available Control Technology
BID Background Information Document
BPD Barrels Per Day
BSER Best System of Emission Reduction
BTEX Benzene, Ethylbenzene, Toluene and Xylene
CAA Clean Air Act
CalEPA California Environmental Protection Agency
CBI Confidential Business Information
CEM Continuous Emissions Monitoring
CEMS Continuous Emissions Monitoring System
CFR Code of Federal Regulations
CIIT Chemical Industry Institute of Toxicology
CO Carbon Monoxide
CO_2 Carbon Dioxide
CO_2e Carbon Dioxide Equivalent
DOE Department of Energy
ECHO Enforcement and Compliance History Online
e-GGRT Electronic Greenhouse Gas Reporting Tool
EJ Environmental Justice
EPA Environmental Protection Agency
ERPG Emergency Response Planning Guidelines
ERT Electronic Reporting Tool
GCG Gas Condensate Glycol
GHG Greenhouse Gas
GOR Gas to Oil Ratio
GWP Global Warming Potential
HAP Hazardous Air Pollutants
HEM–3 Human Exposure Model, version 3
HI Hazard Index
HP Horsepower
HQ Hazard Quotient
H_2S Hydrogen Sulfide
ICR Information Collection Request
IPCC Intergovernmental Panel on Climate Change
IRIS Integrated Risk Information System
km Kilometer
kW Kilowatts
LAER Lowest Achievable Emission Rate
lb Pounds
LDAR Leak Detection and Repair
MACT Maximum Achievable Control Technology
MACT Code Code within the NEI used to identify processes included in a source category
Mcf Thousand Cubic Feet
Mg/yr Megagrams per year
MIR Maximum Individual Risk
MIRR Monitoring, Inspection, Recordkeeping and Reporting
$MMtCO_2e$ Million Metric Tons of Carbon Dioxide Equivalents
NAAQS National Ambient Air Quality Standards
NAC/AEGL National Advisory Committee for Acute Exposure Guideline Levels for Hazardous Substances
NAICS North American Industry Classification System
NAS National Academy of Sciences
NATA National Air Toxics Assessment
NEI National Emissions Inventory
NEMS National Energy Modeling System
NESHAP National Emissions Standards for Hazardous Air Pollutants
NGL Natural Gas Liquids
NIOSH National Institutes for Occupational Safety and Health
NO_X Oxides of Nitrogen
NRC National Research Council
NSPS New Source Performance Standards
NSR New Source Review
NTTAA National Technology Transfer and Advancement Act
OAQPS Office of Air Quality Planning and Standards
OMB Office of Management and Budget
PB–HAP Hazardous air pollutants known to be persistent and bio-accumulative in the environment
PFE Potential for Flash Emissions
PM Particulate Matter
$PM_{2.5}$ Particulate Matter (2.5 microns and less)
POM Polycyclic Organic Matter
PPM Parts Per Million
PPMV Parts Per Million by Volume
PSIG Pounds per square inch gauge
PTE Potential to Emit
QA Quality Assurance
RACT Reasonably Available Control Technology
RBLC RACT/BACT/LAER Clearinghouse
REC Reduced Emissions Completions
REL CalEPA Reference Exposure Level
RFA Regulatory Flexibility Act
RfC Reference Concentration
RfD Reference Dose
RIA Regulatory Impact Analysis
RICE Reciprocating Internal Combustion Engines
RTR Residual Risk and Technology Review
SAB Science Advisory Board
SBREFA Small Business Regulatory Enforcement Fairness Act
SCC Source Classification Codes
SCFH Standard Cubic Feet Per Hour
SCFM Standard Cubic Feet Per Minute
SCM Standard Cubic Meters
SCMD Standard Cubic Meters Per Day
SCOT Shell Claus Offgas Treatment
SIP State Implementation Plan
SISNOSE Significant Economic Impact on a Substantial Number of Small Entities
S/L/T State and Local and Tribal Agencies
SO_2 Sulfur Dioxide
SSM Startup, Shutdown and Malfunction
STEL Short-term Exposure Limit
TLV Threshold Limit Value
TOSHI Target Organ-Specific Hazard Index
TPY Tons per Year
TRIM Total Risk Integrated Modeling System
TRIM.FaTE A spatially explicit, compartmental mass balance model that

describes the movement and transformation of pollutants over time, through a user-defined, bounded system that includes both biotic and abiotic compartments
TSD Technical Support Document
UF Uncertainty Factor
UMRA Unfunded Mandates Reform Act
URE Unit Risk Estimate
VCS Voluntary Consensus Standards
VOC Volatile Organic Compounds
VRU Vapor Recovery Unit

II. General Information

A. Does this action apply to me?

The regulated industrial source categories that are the subject of this proposal are listed in Table 1 of this preamble. These standards and any changes considered in this rulemaking would be directly applicable to sources as a Federal program. Thus, Federal, state, local and tribal government entities are not affected by this proposed action.

TABLE 1—INDUSTRIAL SOURCE CATEGORIES AFFECTED BY THIS PROPOSED ACTION

Category	NAICS code [1]	Examples of regulated entities
Industry	211111	Crude Petroleum and Natural Gas Extraction.
	211112	Natural Gas Liquid Extraction.
	221210	Natural Gas Distribution.
	486110	Pipeline Distribution of Crude Oil.
	486210	Pipeline Transportation of Natural Gas.
Federal government	.....	Not affected.
State/local/tribal government	.....	Not affected.

[1] North American Industry Classification System.

This table is not intended to be exhaustive, but rather provides a guide for readers regarding entities likely to be affected by this action. To determine whether your facility would be regulated by this action, you should examine the applicability criteria in the regulations. If you have any questions regarding the applicability of this action to a particular entity, contact the person listed in the preceding **FOR FURTHER INFORMATION CONTACT** section.

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

In addition to being available in the docket, an electronic copy of this proposal will also be available on the EPA's Web site. Following signature by the EPA Administrator, a copy of this proposed action will be posted on the EPA's Web site at the following address: *http://www.epa.gov/airquality/oilandgas.*

Additional information is available on the EPA's Residual Risk and Technology Review (RTR) Web site at *http://www.epa.gov/ttn/atw/rrisk/oarpg.html.* This information includes the most recent version of the rule, source category descriptions, detailed emissions and other data that were used as inputs to the risk assessments.

C. What should I consider as I prepare my comments for the EPA?

Submitting CBI. Do not submit information containing CBI to the EPA through *http://www.regulations.gov* or e-mail. Clearly mark the part or all of the information that you claim to be CBI. For CBI information on a disk or CD ROM that you mail to the EPA, mark the outside of the disk or CD ROM as CBI and then identify electronically within the disk or CD ROM the specific information that is claimed as CBI. In addition to one complete version of the comment that includes information claimed as CBI, a copy of the comment that does not contain the information claimed as CBI must be submitted for inclusion in the public docket. If you submit a CD ROM or disk that does not contain CBI, mark the outside of the disk or CD ROM clearly that it does not contain CBI. Information not marked as CBI will be included in the public docket and the EPA's electronic public docket without prior notice. Information marked as CBI will not be disclosed except in accordance with procedures set forth in 40 CFR part 2. Send or deliver information identified as CBI only to the following address: Roberto Morales, OAQPS Document Control Officer (C404–02), Environmental Protection Agency, Office of Air Quality Planning and Standards, Research Triangle Park, North Carolina 27711, Attention Docket ID Number EPA–HQ–OAR–2010–0505.

D. When will a public hearing occur?

We will hold three public hearings, one in the Dallas, Texas area, one in Pittsburgh, Pennsylvania, and one in Denver, Colorado. If you are interested in attending or speaking at one of the public hearings, contact Ms. Joan Rogers at (919) 541–4487 by September 6, 2011. Details on the public hearings will be provided in a separate notice and we will specify the time and date of the public hearings on *http://www.epa.gov/airquality/oilandgas.* If no one requests to speak at one of the public hearings by September 6, 2011, then that public hearing will be cancelled without further notice.

III. Background Information

A. What are standards of performance and NSPS?

1. What is the statutory authority for standards of performance and NSPS?

Section 111 of the Clean Air Act (CAA) requires the EPA Administrator to list categories of stationary sources, if such sources cause or contribute significantly to air pollution, which may reasonably be anticipated to endanger public health or welfare. The EPA must then issue performance standards for such source categories. A performance standard reflects the degree of emission limitation achievable through the application of the ''best system of emission reduction'' (BSER) which the EPA determines has been adequately demonstrated. The EPA may consider certain costs and nonair quality health and environmental impact and energy requirements when establishing performance standards. Whereas CAA section 112 standards are issued for existing and new stationary sources, standards of performance are issued for new and modified stationary sources. These standards are referred to as new source performance standards (NSPS). The EPA has the authority to define the source categories, determine the pollutants for which standards should be developed, identify the facilities within each source category to be covered and set the emission level of the standards.

CAA section 111(b)(1)(B) requires the EPA to ''at least every 8 years review and, if appropriate, revise'' performance standards unless the ''Administrator determines that such review is not appropriate in light of readily available information on the efficacy'' of the

standard. When conducting a review of an existing performance standard, the EPA has discretion to revise that standard to add emission limits for pollutants or emission sources not currently regulated for that source category.

In setting or revising a performance standard, CAA section 111(a)(1) provides that performance standards are to ''reflect the degree of emission limitation achievable through the application of the best system of emission reduction which (taking into account the cost of achieving such reduction and any nonair quality health and environmental impact and energy requirements) the Administrator determines has been adequately demonstrated.'' In this notice, we refer to this level of control as the BSER. In determining BSER, we typically conduct a technology review that identifies what emission reduction systems exist and how much they reduce air pollution in practice. Next, for each control system identified, we evaluate its costs, secondary air benefits (or disbenefits) resulting from energy requirements and nonair quality impacts such as solid waste generation. Based on our evaluation, we would determine BSER. The resultant standard is usually a numerical emissions limit, expressed as a performance level (*i.e.,* a rate-based standard or percent control), that reflects the BSER. Although such standards are based on the BSER, the EPA may not prescribe a particular technology that must be used to comply with a performance standard, except in instances where the Administrator determines it is not feasible to prescribe or enforce a standard of performance. Typically, sources remain free to elect whatever control measures that they choose to meet the emission limits. Upon promulgation, an NSPS becomes a national standard to which all new, modified or reconstructed sources must comply.

2. What is the regulatory history regarding performance standards for the oil and natural gas sector?

In 1979, the EPA listed crude oil and natural gas production on its priority list of source categories for promulgation of NSPS (44 FR 49222, August 21, 1979). On June 24, 1985 (50 FR 26122), the EPA promulgated an NSPS for the source category that addressed volatile organic compound (VOC) emissions from leaking components at onshore natural gas processing plants (40 CFR part 60, subpart KKK). On October 1, 1985 (50 FR 40158), a second NSPS was promulgated for the source category that regulates sulfur dioxide (SO_2) emissions from natural gas processing plants (40 CFR part 60, subpart LLL). Other than natural gas processing plants, EPA has not previously set NSPS for a variety of oil and natural gas operations.

B. What are NESHAP?

1. What is the statutory authority for NESHAP?

Section 112 of the CAA establishes a two-stage regulatory process to address emissions of hazardous air pollutants (HAP) from stationary sources. In the first stage, after the EPA has identified categories of sources emitting one or more of the HAP listed in section 112(b) of the CAA, section 112(d) of the CAA calls for us to promulgate national emission standards for hazardous air pollutants (NESHAP) for those sources. ''Major sources'' are those that emit or have the potential to emit (PTE) 10 tons per year (tpy) or more of a single HAP or 25 tpy or more of any combination of HAP. For major sources, these technology-based standards must reflect the maximum degree of emission reductions of HAP achievable (after considering cost, energy requirements and nonair quality health and environmental impacts) and are commonly referred to as maximum achievable control technology (MACT) standards.

MACT standards are to reflect application of measures, processes, methods, systems or techniques, including, but not limited to, measures which, (1) reduce the volume of or eliminate pollutants through process changes, substitution of materials or other modifications, (2) enclose systems or processes to eliminate emissions, (3) capture or treat pollutants when released from a process, stack, storage or fugitive emissions point, (4) are design, equipment, work practice or operational standards (including requirements for operator training or certification) or (5) are a combination of the above. CAA section 112(d)(2)(A)–(E). The MACT standard may take the form of a design, equipment, work practice or operational standard where the EPA first determines either that, (1) a pollutant cannot be emitted through a conveyance designed and constructed to emit or capture the pollutant or that any requirement for or use of such a conveyance would be inconsistent with law or (2) the application of measurement methodology to a particular class of sources is not practicable due to technological and economic limitations. CAA sections 112(h)(1)–(2).

The MACT ''floor'' is the minimum control level allowed for MACT standards promulgated under CAA section 112(d)(3), and may not be based on cost considerations. For new sources, the MACT floor cannot be less stringent than the emission control that is achieved in practice by the best-controlled similar source. The MACT floors for existing sources can be less stringent than floors for new sources, but they cannot be less stringent than the average emission limitation achieved by the best-performing 12 percent of existing sources in the category or subcategory (or the best-performing five sources for categories or subcategories with fewer than 30 sources). In developing MACT standards, we must also consider control options that are more stringent than the floor. We may establish standards more stringent than the floor based on the consideration of the cost of achieving the emissions reductions, any nonair quality health and environmental impacts and energy requirements.

The EPA is then required to review these technology-based standards and to revise them ''as necessary (taking into account developments in practices, processes, and control technologies)'' no less frequently than every 8 years, under CAA section 112(d)(6). In conducting this review, the EPA is not obliged to completely recalculate the prior MACT determination. *NRDC* v. *EPA,* 529 F.3d 1077, 1084 (D.C. Cir. 2008).

The second stage in standard-setting focuses on reducing any remaining ''residual'' risk according to CAA section 112(f). This provision requires, first, that the EPA prepare a *Report to Congress* discussing (among other things) methods of calculating risk posed (or potentially posed) by sources after implementation of the MACT standards, the public health significance of those risks, and the EPA's recommendations as to legislation regarding such remaining risk. The EPA prepared and submitted this report (*Residual Risk Report to Congress,* EPA–453/R–99–001) in March 1999. Congress did not act in response to the report, thereby triggering the EPA's obligation under CAA section 112(f)(2) to analyze and address residual risk.

CAA section 112(f)(2) requires us to determine for source categories subject to MACT standards, whether the emissions standards provide an ample margin of safety to protect public health. If the MACT standards for HAP ''classified as a known, probable, or possible human carcinogen do not reduce lifetime excess cancer risks to the individual most exposed to emissions from a source in the category or subcategory to less than 1-in-1 million,'' the EPA must promulgate

residual risk standards for the source category (or subcategory), as necessary, to provide an ample margin of safety to protect public health. In doing so, the EPA may adopt standards equal to existing MACT standards if the EPA determines that the existing standards are sufficiently protective. *NRDC* v. *EPA,* 529 F.3d 1077, 1083 (D.C. Cir. 2008). (''If EPA determines that the existing technology-based standards provide an ''ample margin of safety,'' then the Agency is free to readopt those standards during the residual risk rulemaking.'') The EPA must also adopt more stringent standards, if necessary, to prevent an adverse environmental effect,[1] but must consider cost, energy, safety and other relevant factors in doing so.

Section 112(f)(2) of the CAA expressly preserves our use of a two-step process for developing standards to address any residual risk and our interpretation of ''ample margin of safety'' developed in the *National Emission Standards for Hazardous Air Pollutants: Benzene Emissions from Maleic Anhydride Plants, Ethylbenzene/Styrene Plants, Benzene Storage Vessels, Benzene Equipment Leaks, and Coke By-Product Recovery Plants (Benzene NESHAP)* (54 FR 38044, September 14, 1989). The first step in this process is the determination of acceptable risk. The second step provides for an ample margin of safety to protect public health, which is the level at which the standards are set (unless a more stringent standard is required to prevent, taking into consideration costs, energy, safety, and other relevant factors, an adverse environmental effect).

The terms ''individual most exposed,'' ''acceptable level,'' and ''ample margin of safety'' are not specifically defined in the CAA. However, CAA section 112(f)(2)(B) preserves the interpretation set out in the Benzene NESHAP, and the United States Court of Appeals for the District of Columbia Circuit in *NRDC* v. *EPA,* 529 F.3d 1077, concluded that the EPA's interpretation of subsection 112(f)(2) is a reasonable one. See *NRDC* v. *EPA,* 529 F.3d at 1083 (D.C. Cir., ''[S]ubsection 112(f)(2)(B) expressly incorporates EPA's interpretation of the Clean Air Act from the Benzene standard, complete with a citation to the **Federal Register**''). (D.C. Cir. 2008). See also, *A Legislative History of the Clean Air Act Amendments of 1990,* volume 1, p. 877 (Senate debate on Conference Report). We notified Congress in the *Residual Risk Report to Congress* that we intended to use the Benzene NESHAP approach in making CAA section 112(f) residual risk determinations (EPA–453/R–99–001, p. ES–11).

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

> * * * in protecting public health with an ample margin of safety, we strive to provide maximum feasible protection against risks to health from hazardous air pollutants by, (1) protecting the greatest number of persons possible to an individual lifetime risk level no higher than approximately 1-in-1 million; and (2) limiting to no higher than approximately 1-in-10 thousand [*i.e.,* 100-in-1 million] the estimated risk that a person living near a facility would have if he or she were exposed to the maximum pollutant concentrations for 70 years.

The Agency also stated that, ''The EPA also considers incidence (the number of persons estimated to suffer cancer or other serious health effects as a result of exposure to a pollutant) to be an important measure of the health risk to the exposed population. Incidence measures the extent of health risk to the exposed population as a whole, by providing an estimate of the occurrence of cancer or other serious health effects in the exposed population.'' The Agency went on to conclude that ''estimated incidence would be weighed along with other health risk information in judging acceptability.'' As explained more fully in our *Residual Risk Report to Congress,* the EPA does not define ''rigid line[s] of acceptability,'' but considers rather broad objectives to be weighed with a series of other health measures and factors (EPA–453/R–99–001, p. ES–11). The determination of what represents an ''acceptable'' risk is based on a judgment of ''what risks are acceptable in the world in which we live'' (*Residual Risk Report to Congress,* p. 178, quoting the Vinyl Chloride decision at 824 F.2d 1165) recognizing that our world is not risk-free.

In the Benzene NESHAP, we stated that ''EPA will generally presume that if the risk to [the maximum exposed] individual is no higher than approximately 1-in-10 thousand, that risk level is considered acceptable.'' 54 FR 38045. We discussed the maximum individual lifetime cancer risk (or maximum individual risk (MIR)) as being ''the estimated risk that a person living near a plant would have if he or she were exposed to the maximum pollutant concentrations for 70 years.'' *Id.* We explained that this measure of risk ''is an estimate of the upper bound of risk based on conservative assumptions, such as continuous exposure for 24 hours per day for 70 years.'' *Id.* We acknowledge that maximum individual lifetime cancer risk ''does not necessarily reflect the true risk, but displays a conservative risk level which is an upper-bound that is unlikely to be exceeded.'' *Id.*

Understanding that there are both benefits and limitations to using maximum individual lifetime cancer risk as a metric for determining acceptability, we acknowledged in the 1989 Benzene NESHAP that ''consideration of maximum individual risk * * * must take into account the strengths and weaknesses of this measure of risk.'' *Id.* Consequently, the presumptive risk level of 100-in-1 million (1-in-10 thousand) provides a benchmark for judging the acceptability of maximum individual lifetime cancer risk, but does not constitute a rigid line for making that determination.

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

In some cases, these health measures and factors taken together may provide a more realistic description of the magnitude of risk in the exposed population than that provided by maximum individual lifetime cancer risk alone. As explained in the Benzene NESHAP, ''[e]ven though the risks judged ''acceptable'' by the EPA in the first step of the Vinyl Chloride inquiry are already low, the second step of the inquiry, determining an ''ample margin of safety,'' again includes consideration of all of the health factors, and whether to reduce the risks even further.'' In the ample margin of safety decision process, the Agency again considers all of the health risks and other health information considered in the first step. Beyond that information, additional factors relating to the appropriate level

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

of control will also be considered, including costs and economic impacts of controls, technological feasibility, uncertainties and any other relevant factors. Considering all of these factors, the Agency will establish the standard at a level that provides an ample margin of safety to protect the public health, as required by CAA section 112(f). 54 FR 38046.

2. How do we consider the risk results in making decisions?

As discussed in the previous section of this preamble, we apply a two-step process for developing standards to address residual risk. In the first step, the EPA determines if risks are acceptable. This determination ''considers all health information, including risk estimation uncertainty, and includes a presumptive limit on maximum individual lifetime [cancer] risk (MIR) [2] of approximately 1-in-10 thousand [*i.e.,* 100-in-1 million].'' 54 FR 38045. In the second step of the process, the EPA sets the standard at a level that provides an ample margin of safety ''in consideration of all health information, including the number of persons at risk levels higher than approximately 1-in-1 million, as well as other relevant factors, including costs and economic impacts, technological feasibility, and other factors relevant to each particular decision.'' *Id.*

In past residual risk determinations, the EPA presented a number of human health risk metrics associated with emissions from the category under review, including: The MIR; the numbers of persons in various risk ranges; cancer incidence; the maximum noncancer hazard index (HI); and the maximum acute noncancer hazard. In estimating risks, the EPA considered source categories under review that are located near each other and that affect the same population. The EPA provided estimates of the expected difference in actual emissions from the source category under review and emissions allowed pursuant to the source category MACT standard. The EPA also discussed and considered risk estimation uncertainties. The EPA is providing this same type of information in support of these actions.

The Agency acknowledges that the Benzene NESHAP provides flexibility regarding what factors the EPA might consider in making our determinations and how they might be weighed for each source category. In responding to comment on our policy under the Benzene NESHAP, the EPA explained that: ''The policy chosen by the Administrator permits consideration of multiple measures of health risk. Not only can the MIR figure be considered, but also incidence, the presence of noncancer health effects, and the uncertainties of the risk estimates. In this way, the effect on the most exposed individuals can be reviewed as well as the impact on the general public. These factors can then be weighed in each individual case. This approach complies with the Vinyl Chloride mandate that the Administrator ascertain an acceptable level of risk to the public by employing [her] expertise to assess available data. It also complies with the Congressional intent behind the CAA, which did not exclude the use of any particular measure of public health risk from the EPA's consideration with respect to CAA section 112 regulations, and, thereby, implicitly permits consideration of any and all measures of health risk which the Administrator, in [her] judgment, believes are appropriate to determining what will 'protect the public health.' ''

For example, the level of the MIR is only one factor to be weighed in determining acceptability of risks. The Benzene NESHAP explains ''an MIR of approximately 1-in-10 thousand should ordinarily be the upper end of the range of acceptability. As risks increase above this benchmark, they become presumptively less acceptable under CAA section 112, and would be weighed with the other health risk measures and information in making an overall judgment on acceptability. Or, 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.'' Similarly, with regard to the ample margin of safety analysis, the Benzene NESHAP states that: ''EPA believes the relative weight of the many factors that can be considered in selecting an ample margin of safety can only be determined for each specific source category. This occurs mainly because technological and economic factors (along with the health-related factors) vary from source category to source category.''

3. What is the regulatory history regarding NESHAP for the oil and natural gas sector?

On July 16, 1992 (57 FR 31576), the EPA published a list of major and area sources for which NESHAP are to be published (*i.e.,* the source category list). Oil and natural gas production facilities were listed as a category of major sources. On February 12, 1998 (63 FR 7155), the EPA amended the source category list to add Natural Gas Transmission and Storage as a major source category.

On June 17, 1999 (64 FR 32610), the EPA promulgated MACT standards for the Oil and Natural Gas Production and Natural Gas Transmission and Storage major source categories. The Oil and Natural Gas Production NESHAP (40 CFR part 63, subpart HH) contains standards for HAP emissions from glycol dehydration process vents, storage vessels and natural gas processing plant equipment leaks. The Natural Gas Transmission and Storage NESHAP (40 CFR part 63, subpart HHH) contains standards for glycol dehydration process vents.

In addition to these NESHAP for major sources, the EPA also promulgated NESHAP for the Oil and Natural Gas Production area source category on January 3, 2007 (72 FR 26). These area source standards, which are based on generally available control technology, are also contained in 40 CFR part 63, subpart HH. This proposed action does not impact these area source standards.

C. What litigation is related to this proposed action?

On January 14, 2009, pursuant to section 304(a)(2) of the CAA, WildEarth Guardians and the San Juan Citizens Alliance filed a Complaint alleging that the EPA failed to meet its obligations under CAA sections 111(b)(1)(B), 112(d)(6) and 112(f)(2) to take actions relative to the review/revision of the NSPS and the NESHAP with respect to the Oil and Natural Gas Production source category. On February 4, 2010, the Court entered a consent decree requiring the EPA to sign by July 28, 2011,[3] proposed standards and/or determinations not to issue standards pursuant to CAA sections 111(b)(1)(B), 112(d)(6) and 112(f)(2) and to take final action by February 28, 2012.

D. What is a sector-based approach?

Sector-based approaches are based on integrated assessments that consider multiple pollutants in a comprehensive and coordinated manner to manage emissions and CAA requirements. One of the many ways we can address sector-based approaches is by reviewing multiple regulatory programs together whenever possible, consistent with all

[2] Although defined as ''maximum individual risk,'' MIR refers only to cancer risk. MIR, one metric for assessing cancer risk, is the estimated risk were an individual exposed to the maximum level of a pollutant for a lifetime.

[3] On April 27, 2011, pursuant to paragraph 10(a) of the Consent Decree, the parties filed with the Court a written stipulation that changes the proposal date from January 31, 2011, to July 28, 2011, and the final action date from November 30, 2011, to February 28, 2012.

applicable legal requirements. This approach essentially expands the technical analyses on costs and benefits of particular technologies, to consider the interactions of rules that regulate sources. The benefit of multi-pollutant and sector-based analyses and approaches includes the ability to identify optimum strategies, considering feasibility, cost impacts and benefits across the different pollutant types while streamlining administrative and compliance complexities and reducing conflicting and redundant requirements, resulting in added certainty and easier implementation of control strategies for the sector under consideration. In order to benefit from a sector-based approach for the oil and gas industry, the EPA analyzed how the NSPS and NESHAP under consideration relate to each other and other regulatory requirements currently under review for oil and gas facilities. In this analysis, we looked at how the different control requirements that result from these requirements interact, including the different regulatory deadlines and control equipment requirements that result, the different reporting and recordkeeping requirements and opportunities for states to account for reductions resulting from this rulemaking in their State Implementation Plans (SIP). The requirements analyzed affect criteria pollutant, HAP and methane emissions from oil and natural gas processes and cover the NSPS and NESHAP reviews. As a result of the sector-based approach, this rulemaking will reduce conflicting and redundant requirements. Also, the sector-based approach facilitated the streamlining of monitoring, recordkeeping and reporting requirements, thus, reducing administrative and compliance complexities associated with complying with multiple regulations. In addition, the sector-based approach promotes a comprehensive control strategy that maximizes the co-control of multiple regulated pollutants while obtaining emission reductions as co-benefits.

IV. Oil and Natural Gas Sector

The oil and natural gas sector includes operations involved in the extraction and production of oil and natural gas, as well as the processing, transmission and distribution of natural gas. Specifically for oil, the sector includes all operations from the well to the point of custody transfer at a petroleum refinery. For natural gas, the sector includes all operations from the well to the customer. The oil and natural gas operations can generally be separated into four segments: (1) Oil and natural gas production, (2) natural gas processing, (3) natural gas transmission and (4) natural gas distribution. Each of these segments is briefly discussed below.

Oil and natural gas production includes both onshore and offshore operations. Production operations include the wells and all related processes used in the extraction, production, recovery, lifting, stabilization, separation or treating of oil and/or natural gas (including condensate). Production components may include, but are not limited to, wells and related casing head, tubing head and ''Christmas tree'' piping, as well as pumps, compressors, heater treaters, separators, storage vessels, pneumatic devices and dehydrators. Production operations also include the well drilling, completion and workover processes and includes all the portable non-self-propelled apparatus associated with those operations. Production sites include not only the ''pads'' where the wells are located, but also include stand-alone sites where oil, condensate, produced water and gas from several wells may be separated, stored and treated. The production sector also includes the low pressure, small diameter, gathering pipelines and related components that collect and transport the oil, gas and other materials and wastes from the wells to the refineries or natural gas processing plants. None of the operations upstream of the natural gas processing plant are covered by the existing NSPS. Offshore oil and natural gas production occurs on platform structures that house equipment to extract oil and gas from the ocean or lake floor and that process and/or transfer the oil and gas to storage, transport vessels or onshore. Offshore production can also include secondary platform structures connected to the platform structure, storage tanks associated with the platform structure and floating production and offloading equipment.

There are three basic types of wells: Oil wells, gas wells and associated gas wells. Oil wells can have ''associated'' natural gas that is separated and processed or the crude oil can be the only product processed. Once the crude oil is separated from the water and other impurities, it is essentially ready to be transported to the refinery via truck, railcar or pipeline. We consider the oil refinery sector separately from the oil and natural gas sector. Therefore, at the point of custody transfer at the refinery, the oil leaves the oil and natural gas sector and enters the petroleum refining sector.

Natural gas is primarily made up of methane. However, whether natural gas is associated gas from oil wells or non-associated gas from gas or condensate wells, it commonly exists in mixtures with other hydrocarbons. These hydrocarbons are often referred to as natural gas liquids (NGL). They are sold separately and have a variety of different uses. The raw natural gas often contains water vapor, hydrogen sulfide (H_2S), carbon dioxide (CO_2), helium, nitrogen and other compounds. Natural gas processing consists of separating certain hydrocarbons and fluids from the natural gas to produced ''pipeline quality'' dry natural gas. While some of the processing can be accomplished in the production segment, the complete processing of natural gas takes place in the natural gas processing segment. Natural gas processing operations separate and recover NGL or other non-methane gases and liquids from a stream of produced natural gas through components performing one or more of the following processes: Oil and condensate separation, water removal, separation of NGL, sulfur and CO_2 removal, fractionation of natural gas liquid and other processes, such as the capture of CO_2 separated from natural gas streams for delivery outside the facility. Natural gas processing plants are the only operations covered by the existing NSPS.

The pipeline quality natural gas leaves the processing segment and enters the transmission segment. Pipelines in the natural gas transmission segment can be interstate pipelines that carry natural gas across state boundaries or intrastate pipelines, which transport the gas within a single state. While interstate pipelines may be of a larger diameter and operated at a higher pressure, the basic components are the same. To ensure that the natural gas flowing through any pipeline remains pressurized, compression of the gas is required periodically along the pipeline. This is accomplished by compressor stations usually placed between 40 and 100 mile intervals along the pipeline. At a compressor station, the natural gas enters the station, where it is compressed by reciprocating or centrifugal compressors.

In addition to the pipelines and compressor stations, the natural gas transmission segment includes underground storage facilities. Underground natural gas storage includes subsurface storage, which typically consists of depleted gas or oil reservoirs and salt dome caverns used for storing natural gas. One purpose of this storage is for load balancing (equalizing the receipt and delivery of natural gas). At an underground storage site, there are typically other processes,

including compression, dehydration and flow measurement.

The distribution segment is the final step in delivering natural gas to customers. The natural gas enters the distribution segment from delivery points located on interstate and intrastate transmission pipelines to business and household customers. The delivery point where the natural gas leaves the transmission segment and enters the distribution segment is often called the ''citygate.'' Typically, utilities take ownership of the gas at the citygate. Natural gas distribution systems consist of thousands of miles of piping, including mains and service pipelines to the customers. Distribution systems sometimes have compressor stations, although they are considerably smaller than transmission compressor stations. Distribution systems include metering stations, which allow distribution companies to monitor the natural gas in the system. Essentially, these metering stations measure the flow of gas and allow distribution companies to track natural gas as it flows through the system.

Emissions can occur from a variety of processes and points throughout the oil and natural gas sector. Primarily, these emissions are organic compounds such as methane, ethane, VOC and organic HAP. The most common organic HAP are n-hexane and BTEX compounds (benzene, toluene, ethylbenzene and xylenes). Hydrogen sulfide (H_2S) and sulfur dioxide (SO_2) are emitted from production and processing operations that handle and treat ''sour gas.'' Sour gas is defined as natural gas with a maximum H_2S content of 0.25 gr/100 scf (4ppmv) along with the presence of CO_2.

In addition, there are significant emissions associated with the reciprocating internal combustion engines and combustion turbines that power compressors throughout the oil and natural gas sector. However, emissions from internal combustion engines and combustion turbines are covered by regulations specific to engines and turbines and, thus, are not addressed in this action.

V. Summary of Proposed Decisions and Actions

Pursuant to CAA sections 111(b), 112(d)(2), 112(d)(6) and 112(f), we are proposing to revise the NSPS and NESHAP relative to oil and gas to include the standards and requirements summarized in this section. More details of the rationale for these proposed standards and requirements are provided in sections VI and VII of this preamble. In addition, as part of these rationale discussions, we solicit public comment and data relevant to several issues. The comments we receive during the public comment period will help inform the rule development process as we work toward promulgating a final action.

A. What are the proposed revisions to the NSPS?

We reviewed the two NSPS that apply to the oil and natural gas industry. Based on our review, we believe that the requirements at 40 CFR part 60, subpart KKK, should be updated to reflect requirements in 40 CFR part 60, subpart VVa for controlling VOC equipment leaks at processing plants. We also believe that the requirements at 40 CFR part 60, subpart LLL, for controlling SO_2 emissions from natural gas processing plants should be strengthened for facilities with the highest sulfur feed rates and the highest H_2S concentrations. For a more detailed discussion, please see section VI.B.1 of this preamble.

In addition, there are significant VOC emissions from oil and natural gas operations that are not covered by the two existing NSPS, including other emissions at processing plants and emissions from upstream production, as well as transmission and storage facilities. In the 1984 notice that listed source categories (including Oil and Natural Gas) for promulgation of NSPS, we noted that there were discrepancies between the source category names on the list and those in the background document, and we clarified our intent to address all sources under an industry heading at the same time. See 44 FR 49222, 49224–49225.[4] We, therefore, believe that the currently listed Oil and Natural Gas source category covers all operations in this industry (*i.e.,* production, processing, transmission, storage and distribution). To the extent there are oil and gas operations not covered by the currently listed Oil and Natural Gas source category, pursuant to CAA section 111(b), we hereby modify the category list to include all operations in the oil and natural gas sector. Section 111(b) of the CAA gives the EPA broad authority and discretion to list and establish NSPS for a category that, in the Administrator's judgment, causes or contributes significantly to air pollution which may reasonably be anticipated to endanger public health or welfare. Pursuant to CAA section 111(b), we are modifying the source category list to include any oil and gas operation not covered by the current listing and evaluating emissions from all oil and gas operations at the same time.

We are also proposing standards for several new oil and natural gas affected facilities. The proposed standards would apply to affected facilities that commence construction, reconstruction or modification after August 23, 2011. These standards, which include requirements for VOC, would be contained in a new subpart, 40 CFR part 60, subpart OOOO. Subpart OOOO would incorporate 40 CFR part 60, subpart KKK and 40 CFR part 60, subpart LLL, thereby having in this one subpart, all standards that are applicable to the new and modified affected facilities described above. We also propose to amend the title of subparts KKK and LLL, accordingly, to apply only to affected facilities already subject to those subparts. Those operations would not become subject to subpart OOOO unless they triggered applicability based on new or modified affected facilities under subpart OOOO.

We are proposing operational standards for completions of hydraulically fractured gas wells. Based on our review, we identified two subcategories of fractured gas wells for which well completions are conducted. For non-exploratory and non-delineation wells, the proposed operational standards would require reduced emission completion (REC), commonly referred to as ''green completion,'' in combination with pit-flaring of gas not suitable for entering the gathering line. For exploratory and delineation wells (these wells generally are not in close proximity to a gathering line), we proposed an operational standard that would require pit flaring. Well completions subject to the standards would be limited to gas well completions following hydraulic fracturing operations. These completions include those conducted at newly drilled and fractured wells, as well as completions conducted following refracturing operations at various times over the life of the well. We have determined that a completion associated with refracturing performed at an existing well (*i.e.,* a well existing prior to August 23, 2011) is considered a modification under CAA section 111(a), because physical change occurs to the existing well resulting in emissions increase during the refracturing and completion operation. A detailed discussion of this determination is presented in the Technical Support Document (TSD) in the docket. Therefore, the proposed standards would apply to completions at new gas wells that are fractured or

[4] The Notice further states that ''The Administrator may also concurrently develop standards for sources which are not on the priority list.'' 44 FR at 49225.

refractured along with completions associated with fracturing or refracturing of existing gas wells. The modification determination and resultant applicability of NSPS to the completion operation following fracturing or refracturing of existing gas wells (*i.e.,* wells existing before August 23, 2011 would be limited strictly to the wellhead, well bore, casing and tubing, and any conveyance through which gas is vented to the atmosphere and not be extended beyond the wellhead to other ancillary components that may be at the well site such as existing storage vessels, process vessels, separators, dehydrators or any other components or apparatus.

We are also proposing VOC standards to reduce emissions from gas-driven pneumatic devices. We are proposing that each pneumatic device is an affected facility. Accordingly, the proposed standards would apply to each newly installed pneumatic device (including replacement of an existing device). At gas processing plants, we are proposing a zero emission limit for each individual pneumatic controller. The proposed emission standards would reflect the emission level achievable from the use of non-gas-driven pneumatic controllers. At other locations, we are proposing a bleed limit of 6 standard cubic feet of gas per hour for an individual pneumatic controller, which would reflect the emission level achievable from the use of low bleed gas-driven pneumatic controllers. In both cases, the standards provide exemptions for certain applications based on functional considerations.

In addition, the proposed rule would require measures to reduce VOC emissions from centrifugal and reciprocating compressors. As explained in more detail below in section VI.B.4, we are proposing equipment standards for centrifugal compressors. The proposed standards would require the use of dry seal systems. However, we are aware that some owners and operators may need to use centrifugal compressors with wet seals, and we are soliciting comment on the suitability of a compliance option allowing the use of wet seals combined with routing of emissions from the seal liquid through a closed vent system to a control device as an acceptable alternative to installing dry seals.

Our review of reciprocating compressors found that piston rod packing wear produces fugitive emissions that cannot be captured and conveyed to a control device. As a result, we are proposing operational standards for reciprocating compressors, such that the proposed rule would require replacement of the rod packing based on hours of usage. The owner or operator of a reciprocating compressor affected facility would be required to monitor the duration (in hours) that the compressor is operated. When the hours of operation reaches 26,000 hours, the owner or operator would be required to change the rod packing immediately. However, to avoid unscheduled shutdowns when 26,000 hours is reached, owners and operators could track hours of operation such that packing replacement could be coordinated with planned maintenance shutdowns before hours of operation reached 26,000. Some operators may prefer to replace the rod packing on a fixed schedule to ensure that the hours of operation would not reach 26,000 hours. We solicit comment on the appropriateness of a fixed replacement frequency and other considerations that would be associated with regular replacement.

We are also proposing VOC standards for new or modified storage vessels. The proposed rule, which would apply to individual vessels, would require that vessels meeting certain specifications achieve at least 95-percent reduction in VOC emissions. Requirements would apply to vessels with a throughput of 1 barrel of condensate per day or 20 barrels of crude oil per day. These thresholds are equivalent to VOC emissions of about 6 tpy.

For gas processing plants, we are updating the requirements for leak detection and repair (LDAR) to reflect procedures and leak thresholds established by 40 CFR 60, subpart VVa. The existing NSPS requires 40 CFR part 60, subpart VV procedures and thresholds.

For 40 CFR part 60, subpart LLL, which regulates SO_2 emissions from natural gas processing plants, we determined that affected facilities with sulfur feed rate of at least 5 long tons per day or H_2S concentration in the acid gas stream of at least 50 percent can achieve up to 99.9-percent SO_2 control, which is greater than the existing standard. Therefore, we are proposing revision to the performance standards in subpart LLL as a result of this review. For a more detailed discussion of this proposed determination, please see section VI.B.1 of this preamble.

We are proposing to address compliance requirements for periods of startup, shutdown and malfunction (SSM) for 40 CFR part 60, subpart OOOO. The SSM changes are discussed in detail in section VI.B.5 below. In addition, we are proposing to incorporate the requirements in 40 CFR part 60, subpart KKK and 40 CFR part 60, subpart LLL into the new subpart OOOO so that all requirements applicable to the new and modified facilities would be in one subpart. This would simplify and streamline compliance efforts on the part of the oil and natural gas industry and could minimize duplication of notification, recordkeeping and reporting.

B. What are the proposed decisions and actions related to the NESHAP?

This section summarizes the results of our RTR for the Oil and Natural Gas Production and the Natural Gas Transmission and Storage source categories and our proposed decisions concerning these two 1999 NESHAP.

1. Addressing Unregulated Emissions Sources

Pursuant to CAA sections 112(d)(2) and (3), we are proposing MACT standards for subcategories of glycol dehydrators for which standards were not previously developed (hereinafter referred to as the ''small dehydrators''). In the Oil and Natural Gas Production source category, the subcategory consists of glycol dehydrators with an actual annual average natural gas flowrate less than 85,000 standard cubic meters per day (scmd) or actual average benzene emissions less than 0.9 megagrams per year (Mg/yr). In the Natural Gas Transmission and Storage source category, the subcategory consists of glycol dehydrators with an actual annual average natural gas flowrate less than 283,000 scmd or actual average benzene emissions less than 0.9 Mg/yr.

The proposed MACT standards for the subcategory of small dehydrators at oil and gas production facilities would require that existing affected sources meet a unit-specific BTEX limit of 1.10×10^{-4} grams BTEX/standard cubic meters (scm)-parts per million by volume (ppmv) and that new affected sources meet a BTEX limit of 4.66×10^{-6} grams BTEX/scm-ppmv. At natural gas transmission and storage affected sources, the proposed MACT standard for the subcategory of small dehydrators would require that existing affected sources meet a unit-specific BTEX emission limit of 6.42×10^{-5} grams BTEX/scm-ppmv and that new affected sources meet a BTEX limit of 1.10×10^{-5} grams BTEX/scm-ppmv.

We are also proposing MACT standards for storage vessels that are currently not regulated under the Oil and Natural Gas Production NESHAP. The current MACT standards apply only to storage vessels with the potential for flash emissions (PFE). As explained in section VII, the original MACT analysis

accounted for all storage vessels. We are, therefore, proposing to apply the current MACT standards of 95-percent emission reduction to every storage vessel at major source oil and natural gas production facilities. In conjunction with this change, we are proposing to amend the definition of associated equipment to exclude all storage vessels, and not just those with the PFE, from being considered ''associated equipment.'' This means that emissions from all storage vessels, and not just those from storage vessels with the PFE, are to be included in the major source determination.

2. What are the proposed decisions and actions related to the risk review?

For both the Oil and Natural Gas Production and the Natural Gas Transmission and Storage source categories, we find that the current levels of emissions allowed by the MACT reflect acceptable levels of risk; however, the level of emissions allowed by the alternative compliance option for glycol dehydrator MACT (*i.e.*, the option of reducing benzene emissions to less than 0.9 Mg/yr in lieu of the MACT standard of 95-percent control) reflects an unacceptable level of risk. We are, therefore, proposing to eliminate the 0.9 Mg/yr alternative compliance option.

In addition, we are proposing that the MACT for these two oil and gas source categories, as revised per above, provide an ample margin of safety to protect public health and prevent adverse environmental effects.

3. What are the proposed decisions and actions related to the technology reviews of the existing NESHAP?

For both the Oil and Natural Gas Production and the Natural Gas Transmission and Storage source categories, we are proposing no revisions to the existing NESHAP pursuant to section 112(d)(6) of the CAA.

4. What other actions are we proposing?

We are proposing an alternative performance test for non-flare, combustion control devices. This test is to be conducted by the combustion control device manufacturer to demonstrate the destruction efficiency achieved by a specific model of combustion control device. This would allow a source to purchase a performance tested device for installation at their site without being required to conduct a site-specific performance test. A definition for ''flare'' is being proposed in the NESHAP to clarify which combustion control devices fall under the manufacturers' performance testing alternative, and to clarify which devices must be performance tested.

We are also proposing to: Revise the parametric monitoring calibration provisions; require periodic performance testing where applicable; remove the allowance of a design analysis for all control devices other than condensers; remove the requirement for a minimum residence time for an enclosed combustion device; and add recordkeeping and reporting requirements to document carbon replacement intervals. These changes are being proposed to bring the NESHAP up-to-date based on what we have learned regarding control devices and compliance since the original promulgation date.

In addition, we are proposing the elimination of the SSM exemption in the Oil and Natural Gas Production and the Natural Gas Transmission and Storage NESHAP. As discussed in more detail below in section VII, consistent with *Sierra Club* v. *EPA,* 551 F.3d 1019 (D.C. Cir. 2010), the EPA is proposing that the established standards in these two NESHAP apply at all times. We are proposing to revise Table 2 to both 40 CFR part 63, subpart HH and 40 CFR part 63, subpart HHH to indicate that certain 40 CFR part 63 general provisions relative to SSM do not apply, including: 40 CFR 63.6 (e)(1)(i) [5] and (ii), 40 CFR 63.6(e)(3) (SSM plan requirement), 40 CFR 63.6(f)(1); 40 CFR 63.7(e)(1), 40 CFR 63.8(c)(1)(i) and (iii), and the last sentence of 40 CFR 63.8(d)(3); 40 CFR 63.10(b)(2)(i),(ii), (iv) and (v); 40 CFR 63.10(c)(10), (11) and (15); and 40 CFR 63.10(d)(5). We are also proposing to: (1) Revise 40 CFR 63.771(d)(4)(i) and 40 CFR 63.1281(d)(4)(i) regarding operation of the control device to be consistent with the SSM compliance requirements; and (2) revise the SSM-associated reporting and recordkeeping requirements in 40 CFR 63.774, 40 CFR 63.775, 40 CFR 63.1284 and 40 CFR 63.1285 to require reporting and recordkeeping for periods of malfunction. In addition, as explained below, we are proposing to add an affirmative defense to civil penalties for exceedances of emission limits caused by malfunctions, as well as criteria for establishing the affirmative defense.

The EPA has attempted to ensure that we have neither overlooked nor failed to propose to remove from the existing text any provisions that are inappropriate, unnecessary or redundant in the absence of the SSM exemption, nor included any such provisions in the proposed new regulatory language. We are specifically seeking comment on whether there are any such provisions that we have inadvertently overlooked or incorporated.

We are also revising the applicability provisions of 40 CFR part 63, subpart HH to clarify requirements regarding PTE determination and the scope of a facility subject to subpart HH. Lastly, we are proposing several editorial corrections and plain language revisions to improve these rules.

C. What are the proposed notification, recordkeeping and reporting requirements for this proposed action?

1. What are the proposed notification, recordkeeping and reporting requirements for the proposed NSPS?

The proposed 40 CFR part 60, subpart OOOO includes new requirements for several operations for which there are no existing Federal standards. Most notably, as discussed in sections V.A and VI.B of this preamble, the proposed NSPS will cover completions and recompletions of hydraulically fractured gas wells. We estimate that over 20,000 completions and recompletions annually will be subject to the proposed requirements. Given the number of these operations, we believe that notification and reporting must be streamlined to the extent possible to minimize undue burden on owners and operators, as well as state, local and tribal agencies. In section V.D of this preamble, we discuss some innovative implementation approaches being considered and seek comment on these and other potential methods of streamlining notification and reporting for well completions covered by the proposed rule.

Owners or operators are required to submit initial notifications and annual reports, and to retain records to assist in documenting that they are complying with the provisions of the NSPS. These notification, recordkeeping and reporting activities include both requirements of the 40 CFR part 60 General Provisions, as well as requirements specific to 40 CFR part 60, subpart OOOO.

Owners or operators of affected facilities (except for pneumatic controller and gas wellhead affected

[5] 40 CFR 63.6(e)(1)(i) requires owners or operators to act according to the general duty to ''operate and maintain any affected source, including associated air pollution control equipment and monitoring equipment, in a manner consistent with safety and good air pollution control practices for minimizing emissions.'' This general duty to minimize is included in our proposed standard at 40 CFR 63.783(b)(1).

sources) must submit an initial notification within 1 year after becoming subject to 40 CFR part 60, subpart OOOO or by 1 year after the publication of the final rule in the **Federal Register**, whichever is later. For pneumatic controllers, owners and operators are not required to submit an initial notification, but instead are required to report the installation of these affected facilities in their facility's annual report. Owners or operators of wellhead affected facilities (well completions) would also be required to submit a 30-day advance notification of each well completion subject to the NSPS. In addition, annual reports are due 1 year after initial startup date for your affected facility or 1 year after the date of publication of the final rule in the **Federal Register**, whichever is later. The notification and annual reports must include information on all affected facilities owned or operated that were new, modified or reconstructed sources during the reporting period. A single report may be submitted covering multiple affected facilities, provided that the report contains all the information required by 40 CFR 60.5420(b). This information includes general information on the facility (*i.e.*, company name and address, etc.), as well as information specific to individual affected facilities.

For wellhead affected facilities, this information includes details of each well completion during the period, including duration of periods of gas recovery, flaring and venting. For centrifugal compressor affected facilities, information includes documentation that the compressor is fitted with dry seals. For reciprocating compressors, information includes the cumulative hours of operation of each compressor and records of rod packing replacement.

Information for pneumatic device affected facilities includes location and manufacturer specifications of each pneumatic controller installed during the period and documentation that supports any exemption claimed allowing use of high bleed controllers. For controllers installed at gas processing plants, the owner or operator would document the use of non-gas driven devices. For controllers installed in locations other than at gas processing plants, owners or operators would provide manufacturer's specifications that document bleed rate not exceeding 6 cubic feet per hour.

For storage vessel affected facilities, required report information includes information that documents control device compliance, if applicable. For vessels with throughputs below 1 barrel of condensate per day and 21 barrels of crude oil per day, required information also includes calculations or other documentation of the throughput. For onshore gas processing plants, semi-annual reports are required, and include information on number of pressure relief devices, number of pressure relief devices for which leaks were detected and pressure relief devices for which leaks were not repaired, as required in 40 CFR 60.5396 of subpart OOOO.

Records must be retained for 5 years and generally consist of the same information required in the initial notification and annual and semiannual reports.

2. What are the proposed amendments to notification, recordkeeping and reporting requirements for the NESHAP?

We are proposing to revise certain recordkeeping requirements of 40 CFR part 63, subpart HH and 40 CFR part 63, subpart HHH. Specifically, we are proposing that facilities using carbon adsorbers as a control device keep records of their carbon replacement schedule and records for each carbon replacement. In addition, owners and operators are required to keep records of the occurrence and duration of each malfunction or operation of the air pollution control equipment and monitoring equipment.

In addition, in conjunction with the proposed MACT standards for small glycol dehydration units and storage vessels that do not have the PFE in the proposed amendment to 40 CFR part 63, subpart HH, we are proposing that owners and operators of affected small glycol dehydration units and storage vessels submit an initial notification within 1 year after becoming subject to subpart HH or by 1 year after the publication of the final rule in the **Federal Register**, whichever is later.

Similarly, in conjunction with the proposed MACT standards for small glycol dehydration units in the proposed 40 CFR part 63, subpart HHH amendments, we are proposing that owners and operators of small glycol dehydration units submit an initial notification within 1 year after becoming subject to subpart HHH or by 1 year after the publication of the final rule in the **Federal Register**, whichever is later. Affected sources under either 40 CFR part 63, subpart HH or subpart HHH that plan to be area sources by the compliance dates will be required to submit a notification describing their schedule for the actions planned to achieve area source status.

The proposed amendments to the NESHAP also include additional requirements for the contents of the periodic reports. For both 40 CFR part 63, subpart HH and 40 CFR part 63, subpart HHH, we are proposing that the periodic reports also include periodic test results and information regarding any carbon replacement events that occurred during the reporting period.

3. *How is information submitted using the Electronic Reporting Tool (ERT)?*

Performance test data are an important source of information that the EPA uses in compliance determinations, developing and reviewing standards, emission factor development, annual emission rate determinations and other purposes. In these activities, the EPA has found it ineffective and time consuming, not only for owners and operators, but also for regulatory agencies, to locate, collect and submit performance test data because of varied locations for data storage and varied data storage methods. In recent years, though, stack testing firms have typically collected performance test data in electronic format, making it possible to move to an electronic data submittal system that would increase the ease and efficiency of data submittal and improve data accessibility.

Through this proposal, the EPA is taking a step to increase the ease and efficiency of data submittal and improve data accessibility. Specifically, the EPA is proposing that owners and operators of oil and natural gas sector facilities submit electronic copies of required performance test reports to the EPA's WebFIRE database. The WebFIRE database was constructed to store performance test data for use in developing emission factors. A description of the WebFIRE database is available at *http://cfpub.epa.gov/oarweb/index.cfm?action=fire.main.*

As proposed above, data entry would be through an electronic emissions test report structure called the *Electronic Reporting Tool* (ERT). The ERT will be able to transmit the electronic report through the EPA's Central Data Exchange network for storage in the WebFIRE database making submittal of data very straightforward and easy. A description of the ERT can be found at *http://www.epa.gov/ttn/chief/ert/ert_tool.html.*

The proposal to submit performance test data electronically to the EPA would apply only to those performance tests conducted using test methods that will be supported by the ERT. The ERT contains a specific electronic data entry form for most of the commonly used EPA reference methods. A listing of the pollutants and test methods supported by the ERT is available at *http://*

www.epa.gov/ttn/chief/ert/ert_tool.html. We believe that industry would benefit from this proposed approach to electronic data submittal. Having these data, the EPA would be able to develop improved emission factors, make fewer information requests, and promulgate better regulations.

One major advantage of the proposed submittal of performance test data through the ERT is a standardized method to compile and store much of the documentation required to be reported by this rule. Another advantage is that the ERT clearly states testing information that would be required. Another important benefit of submitting these data to the EPA at the time the source test is conducted is that it should substantially reduce the effort involved in data collection activities in the future. When the EPA has performance test data in hand, there will likely be fewer or less substantial data collection requests in conjunction with prospective required residual risk assessments or technology reviews. This would result in a reduced burden on both affected facilities (in terms of reduced manpower to respond to data collection requests) and the EPA (in terms of preparing and distributing data collection requests and assessing the results).

State, local and tribal agencies could also benefit from more streamlined and accurate review of electronic data submitted to them. The ERT would allow for an electronic review process rather than a manual data assessment making review and evaluation of the source provided data and calculations easier and more efficient. Finally, another benefit of the proposed data submittal to WebFIRE electronically is that these data would greatly improve the overall quality of existing and new emissions factors by supplementing the pool of emissions test data for establishing emissions factors and by ensuring that the factors are more representative of current industry operational procedures. A common complaint heard from industry and regulators is that emission factors are outdated or not representative of a particular source category. With timely receipt and incorporation of data from most performance tests, the EPA would be able to ensure that emission factors, when updated, represent the most current range of operational practices. In summary, in addition to supporting regulation development, control strategy development and other air pollution control activities having an electronic database populated with performance test data would save industry, state, local, tribal agencies and the EPA significant time, money and effort while also improving the quality of emission inventories and, as a result, air quality regulations.

D. What are the innovative compliance approaches being considered?

Given the potential number and diversity of sources affected by this action, we are exploring optional approaches to provide the regulated community, the regulators and the public a more effective mechanism that maximizes compliance and transparency while minimizing burden.

Under a traditional approach, owners or operators would provide notifications and keep records of information required by the NSPS. In addition, they would certify compliance with the NSPS as part of a required annual report that would include compliance-related information, such as details of each well completion event and information documenting compliance with other requirements of the NSPS. The EPA, state or local agency would then physically inspect the affected facilities and/or audit the records retained by the owner or operator. As an alternative to the traditional approach, we are seeking an innovative way to provide for more transparency to the public and less burden on the regulatory agencies and owners and operators, especially as it relates to modification of existing sources through recompletions of hydraulically fractured gas wells. These innovative approaches would provide compliance assurance in light of the absence of requirements for CAA title V permitting of non-major sources.

Section V.E of this preamble discusses permitting implications associated with the NSPS and presents a proposed rationale for exempting non-major sources subject to the NSPS from title V permitting requirements. As discussed in sections V.A, V.C and VI.B of this preamble, the proposed NSPS will cover completions and recompletions of hydraulically fractured gas wells. We estimate that over 20,000 completions and recompletions annually will be subject to the proposed requirements. As a result, we believe that notification and reporting associated with well completions must be streamlined to the extent possible to minimize undue burden on owners and operators, as well as state, local and tribal agencies. Though the requirements being proposed here are based on the traditional approach to compliance and do not include specific regulatory provisions for innovative compliance tools, we have included discussions below that describe how some of these optional tools could work, and we will consider providing for such options in the final action. Further, we request comments and suggestions on all aspects of the innovative compliance approaches discussed below and how they may be implemented appropriately. We are seeking comment regarding the scope of application of one or more of these approaches, *i.e.,* which provisions of the standards being proposed here would be suitable for specific compliance approaches, and whether the approaches should be alternatives to the requirements in the regulations.

The guiding principles we are following in considering these approaches to compliance are: (1) Simplicity and ease of understanding and implementation; (2) transparency and public accessibility; (3) electronic implementation where appropriate; and (4) encouragement of compliance by making compliance easier than noncompliance. Below are some tools that, when used in tandem with emissions limits and operational standards, the Agency believes could both assure compliance and transparency, while minimizing burden on affected sources and regulatory agencies.

1. Registration of Wells and Advance Notification of Planned Completions

Although the proposed NSPS will not require approval to drill or complete wells, it is important that regulatory agencies know when completions of hydraulically fractured wells are to be performed. Notification should occur sufficiently in advance to allow for inspections or audits to certify or verify that the operator will have in place and use the appropriate controls during the completion. To that end, the proposed NSPS requires a 30-day advance notification of each completion or recompletion of a hydraulically fractured gas well. The advance notification would require that owners or operators provide the anticipated date of the completion, the geographic coordinates of the well and identifying information concerning the owner or operator and responsible company official. We believe this notification requirement serves as the registration requirement and could be streamlined through optional electronic reporting with web-based public access or other methods. We seek comment on potential methodologies that would minimize burden on operators, while providing timely and useful information for regulators and the public. We also solicit comment on provisions for a follow-up notification one or two days before an impending completion via

telephone or by electronic means, since it is difficult to predict exactly when a well will be ready for completion a month in advance. However, we would expect an owner or operator to provide the follow-up notification only in cases where the completion date was expected to deviate from the original date provided. We ask for suggestions regarding how much advance notification is needed and the most effective method of providing sufficient and accurate advance notification of well completions.

2. Third Party Verification

To complement the annual compliance certification required under the proposed NSPS, we are considering and seeking comment on the potential use of third party verification to assure compliance. Since the emission sources in the oil and natural gas sector, especially well completions, are widely geographically dispersed (often in very remote locations), compliance assurance can be very difficult and burdensome for state, local and tribal agencies and EPA permitting staff, inspectors and compliance officers. Additionally, we believe that verification of the data collection, compilation and calculations by an independent and impartial third party could facilitate the demonstration of compliance for the public. Verification of emissions data can also be beneficial to owners and operators by providing certainty of compliance status.

As mentioned above, notification and reporting requirements associated with well completions are likely applications for third party verification used in tandem with the required annual compliance certification. The third party verification program could be used in a variety of ways to ease regulatory burden on the owners and operators and to leverage compliance assurance efforts of the EPA and state, local and tribal agencies. The third party agent could serve as a clearinghouse for notifications, records and annual compliance certifications submitted by owners and operators. This would provide online access to completion information by regulatory agencies and the public. Having notifications submitted to the clearinghouse would relieve state, local and tribal agencies of the burden of receiving thousands of paper or e-mail well completion notifications each year, yet still provide them quick access to the information. Using a third party agent, it is possible that notifications of well completions could be submitted with an advance period much less than 30 days that could make a 2 day follow-up notification unnecessary. The clearinghouse could also house information on past completions and copies of compliance certifications. We seek comment on whether annual reports for well completions would be needed if a suitable third party verification program was in place and already housed that same information. We also solicit comment on the range of potential activities the third party verification program could handle with regard to well completions.

In this proposed action, there are also provisions for applying third party verification to the required electronic reporting using the ERT (see section V.C.3 above for a discussion of the ERT). As stated above, all sources must use the ERT to submit all performance test reports (required in 40 CFR parts 60, 61 and 63) to the EPA. There is an option in the ERT for state, local and tribal agencies to review and verify that the information submitted to the EPA is truthful, accurate and complete. Third party verifiers could be contractors or other personnel familiar with oil and natural gas exploration and production. We are seeking comment on appropriate third party reviewers and qualifications and registration requirements under such a program. We want to state clearly here that third party verification would not supersede or substitute for inspections or audit of data and information by state, local and tribal agencies and the EPA.

Potential issues with third party verification include costs incurred by industry and approval of third party verifiers. The cost of third party verification would be borne by the affected industries. We are seeking comment on whether third party verification paid for by industry would result in impartial, accurate and complete data information. The EPA, working with state, local and tribal agencies and industry, would expect to develop guidance for third party verifiers. We are seeking comment on whether or not the EPA should approve third party verifiers.

3. Electronic Reporting Using Existing Mechanisms

The proposed 40 CFR part 60, subpart OOOO and final Greenhouse Gas (GHG) Mandatory Reporting Rule, 40 CFR part 98, subpart W, provide details on flare and vented emission sources and how to estimate their emissions. We solicit comment on requiring sources to electronically submit their emissions data for the oil and gas rules proposed here. The EPA's *Electronic Greenhouse Gas Reporting Tool* (e-GGRT) for 40 CFR part 98, subpart W, while used to report emissions at the emissions source level (*e.g.,* well completions, well unloading, compressors, gas plant leaks, etc.), will aggregate emissions at the basin level for e-reporting purposes. As a result, it may be difficult to merge reporting under NSPS subpart OOOO with GHG Reporting Rule subpart W methane reporting, especially if manual reporting is used. However, since the operator would have these emissions details at the individual well level (because that will be how they would develop their basin-wide estimates), we do not believe it would be a significant burden to require owners or operators to report the data they already have for subpart W in an ERT for NSPS and NESHAP compliance purposes. However, if the e-GGRT is not structured to provide for reporting of other pollutants besides GHG (*e.g.,* VOC and HAP), then there may be some modification of the database required to accommodate the other pollutants.

4. Provisions for Encouraging Innovative Technology

The oil and natural gas industry has a long history of innovation in developing new exploration and production methods, along with techniques to minimize product losses and reduce adverse environmental impacts. These efforts are often undertaken with tremendous amounts of research, including pilot applications at operating facilities in the field. Absent regulation, these developmental activities, some of which ultimately are not successful, can proceed without risk of violation of any standards. However, as more emission sources in this source category are covered by regulation, as in the case of the action being proposed here, there likely will be situations where innovation and development of new control techniques potentially could be stifled by risk of violation.

We believe it is important to facilitate, not hinder, innovation and continued development of new technology that can result in enhanced environmental performance of facilities and sources affected by the EPA's regulations. However, any approaches to accommodate technology development must be designed and implemented in accordance with the CAA and other statutes. We seek comment on approaches that may be suitable for allowing temporary field testing of technology in development. These approaches could include not only established procedures under the CAA and its implementing regulations, but new ways to apply or interpret these provisions to avoid impeding

innovation while remaining environmentally responsible and legal.

E. How does the NSPS relate to permitting of sources?

1. How does this action affect permitting requirements?

The proposed rules do not change the Federal requirements for determining whether oil and gas sources are major sources for purposes of nonattainment major New Source Review (NSR), prevention of significant deterioration, CAA title V, or HAP major sources pursuant to CAA section 112. Specifically, if an owner or operator is not currently required to get a major NSR or title V permit for oil and gas sources, including well completions, it would not be required to get a major NSR or title V permit as a result of these proposed standards. EPA-approved state and local major source permitting programs would not be affected. That is, state and local agencies with EPA-approved programs will still make case-by-case major source determinations for purposes of major NSR and title V, relying on the regulatory criteria, as explained in the McCarthy Memo.[6] Consistent with the McCarthy Memo, whether or not a permitting authority should aggregate two or more pollutant-emitting activities into a single major stationary source for purposes of NSR and title V remains a case-by-case decision in which permitting authorities retain the discretion to consider the factors relevant to the specific circumstances of the permitted activities.

In addition, the proposed standards would not change the requirements for determining whether oil and gas sources are subject to minor NSR. Nor would the proposed standards affect existing EPA-approved state and local minor NSR rules, as well as policies and practices implementing those rules. Many state and local agencies have already adopted minor NSR permitting programs that provide for control of emissions from relatively small emission sources, including various pieces of equipment used in oil and gas fields. State and local agencies would be able to continue to use any EPA-approved General Permits, Permits by Rule, and other similar streamlining mechanisms to permit oil and gas sources such as wells. We recently promulgated the final Tribal Minor NSR rules for use in issuing minor issue permits on tribal lands, where many oil and gas sources are located.

The proposed standards will lead to better control of and reduced emissions from oil and gas production, gas processing and transmission and storage, including wells. In some instances, we anticipate that complying with the NSPS would reduce emissions from these smaller sources to below the minor source applicability thresholds. In those cases, sources that would otherwise have been subject to minor NSR would not need to get minor NSR permits as a result of being subject to the NSPS. Accordingly, the number of minor NSR permits, as well as the Agency resources needed to issue them, would be reduced.

We expect the emission reductions achieved from the proposed standards to significantly improve ozone nonattainment problems in areas where oil and gas production occurs. Strategies for attaining and maintaining the national ambient air quality standards (NAAQS) are a function of SIP (or, in some instances, Federal Implementation Plans and Tribal Implementation Plans) pursuant to CAA section 110. In developing plans to attain and maintain the NAAQS, EPA works with state, local or Tribal agencies to account for growth and develop overall control strategies that address existing and expected emissions. The reductions achieved by the standards will make it easier for state and local agencies to plan for and to attain and maintain the ozone NAAQS.

2. How does this action affect applicability of CAA title V?

Under section 502(a) of the CAA, the EPA may exempt one or more non-major sources[7] subject to CAA section 111 (NSPS) standards from the requirements of title V if the EPA finds that compliance with such requirements is ''impracticable, infeasible, or unnecessarily burdensome'' on such sources. The EPA determine whether to exempt a non-major source from title V at the time we issue the relevant CAA section 111 standards (40 CFR 70.3(b)(2)). We are proposing in this action to exempt from the requirements of title V non-major sources that would be subject to the proposed NSPS for well completions, pneumatic devices, compressors, and/or storage vessels. These non-major sources (hereinafter referred to as the ''oil and gas NSPS non-major sources'') would not be required to obtain title V permits solely as a result of being subject to one or more of the proposed NSPS identified above (hereinafter referred to as the ''proposed NSPS''); however, if they were otherwise required to obtain title V permits, such requirement(s) would not be affected by the proposed exemption.

Consistent with the statute, the EPA believes that compliance with title V permitting is ''unnecessarily burdensome'' for the oil and gas NSPS non-major sources. The EPA's inquiry into whether this criterion was satisfied is based primarily upon consideration of the following four factors: (1) Whether title V would result in significant improvements to the compliance requirements that we are proposing for the oil and gas NSPS affected non-major sources; (2) whether title V permitting would impose a significant burden on these non-major sources and whether that burden would be aggravated by any difficulty these sources may have in obtaining assistance from permitting agencies; (3) whether the costs of title V permitting for these non-major sources would be justified, taking into consideration any potential gains in compliance likely to occur for such sources; and (4) whether there are implementation and enforcement programs in place that are sufficient to assure compliance with the proposed Oil and Natural Gas NSPS without relying on title V permits. Not all of the four factors must weigh in favor of an exemption. See 70 FR 75320, 75323 (Title V Exemption Rule). Instead, the factors are to be considered in combination and the EPA determines whether the factors, taken together, support an exemption from title V for the oil and gas non-major sources. Additionally, consistent with the guidance provided by the legislative history of CAA section 502(a),[8] we considered whether exempting the Oil and Natural Gas NSPS non-major sources would adversely affect public health, welfare or the environment. The first factor is whether title V would result in significant improvements to the compliance requirements in the proposed NSPS. A finding that title V would not result in significant improvements to the compliance requirements in the proposed NSPS would support a conclusion that title V permitting is ''unnecessary'' for non-

[6] *Withdrawal of Source Determinations for Oil and Gas Industries,* September 22, 2009. This memo continues to articulate the Agency's interpretation for major NSR and title V permitting of oil and gas sources.

[7] CAA section 502(a) prohibits title V exemption for any major source, which is defined in CAA section 501(2) and 40 CFR 70.2.

[8] The legislative history of section 502(a) suggests that EPA should not grant title V exemptions where doing so would adversely affect public health, welfare or the environment. (See Chafee-Baucus Statement of Senate Managers, Environment and Natural Resources Policy Division 1990 CAA Leg. Hist. 905, Compiled November 1993.)

major sources subject to the Oil and Natural Gas Production NSPS.

One way that title V may improve compliance is by requiring monitoring (including recordkeeping designed to serve as monitoring) to assure compliance with permit terms and conditions reflecting the emission limitations and control technology requirements imposed in the standard. See 40 CFR 70.6(c)(1) and 40 CFR 71.6(c)(1). The ''periodic monitoring'' provisions of 40 CFR 70.6(a)(3)(i)(B) and 40 CFR 71.6(a)(3)(i)(B) require new monitoring to be added to the permit when the underlying standard does not already require ''periodic testing or instrumental or noninstrumental monitoring (which may consist of recordkeeping designed to serve as monitoring).'' In addition, title V imposes a number of recordkeeping and reporting requirements that may be important for assuring compliance. These include requirements for a monitoring report at least every 6 months, prompt reports of deviations, and an annual compliance certification. See 40 CFR 70.6(a)(3) and 40 CFR 71.6(a)(3), 40 CFR 70.6(c)(1) and 40 CFR 71.6(c)(1), and 40 CFR 70.6(c)(5) and 40 CFR 71.6(c)(5). To determine whether title V permits would add significant compliance requirements to the proposed NSPS, we compared the title V monitoring, recordkeeping and reporting requirements mentioned above to those requirements proposed for the Oil and Natural Gas NSPS affected facilities.

For wellhead affected facilities (well completions), the proposed NSPS would require (1) 30-day advance notification of each well completion to be performed; (2) noninstrumental monitoring, which is achieved through documentation and recordkeeping of procedures followed during each completion, including total duration of the completion event, amount of time gas is recovered using reduced emission completion techniques, amount of time gas is combusted, amount of time gas is vented to the atmosphere and justification for periods when gas is combusted or vented rather than being recovered; (3) reports of cases where well completions were not performed in compliance with the NSPS; (4) annual reports that document all completions performed during the reporting period (a single report may be used to document multiple completions conducted by a single owner or operator during the reporting period); and (5) annual compliance certifications submitted with the annual report.

These monitoring, recordkeeping and reporting requirements in the proposed NSPS for well completions are sufficient to ensure that the Administrator, the state, local and tribal agencies and the public are aware of completion events before they are performed to provide opportunity for inspection. Sufficient documentation would also be required to be retained and reported to the Administrator to assure compliance with the NSPS for well completions. In light of the above, we have determined that additional monitoring through title V is not needed and that the monitoring, recordkeeping and reporting requirements described above are sufficient to assure compliance with the proposed requirements for well completions.

With respect to storage vessels, the proposed NSPS would require 95-percent control of VOC emissions. The proposed standard could be met by a vapor recovery unit, a flare control device or other control device. The proposed NSPS would require an initial performance test followed by continuous monitoring of the control device used to meet the 95-percent control. We believe that the monitoring requirements described above are sufficient to assure compliance with the proposed NSPS for storage vessels and, therefore, additional monitoring through title V is not needed. In addition to monitoring, as part of the first factor, we have considered the extent to which title V could potentially enhance compliance through recordkeeping or reporting requirements. The proposed NSPS would require (1) construction, startup and modification notifications, as required by 40 CFR 60.7(a); and (2) annual reports that identify all storage vessel affected facilities of the owner or operator and documentation of periods of non-compliance. The proposed NSPS would also require records documenting liquid throughput of condensate or crude oil (to determine applicability), as provided for in the proposed rule. Recordkeeping would also include records of the initial performance test and other information that document compliance with applicable emission limit. These requirements are similar to those under title V. In light of the above, we believe that the monitoring, recordkeeping and reporting requirements described above are sufficient to assure compliance with the proposed NSPS for storage vessels.

For pneumatic controllers, centrifugal compressors and reciprocating compressors, the proposed NSPS are in the form of operational, work practice or equipment standards.[9] For each of these affected facilities, the proposed NSPS would require: (1) Construction, startup and modification notifications, as required by 40 CFR 60.7(a); (2) annual reports; (3) for each pneumatic controller installed or modified (including replacement of an existing controller), records of location and date of installation and documentation that each controller emits no more than the applicable emission limit or is exempt (with rationale for the exemption); (4) for each centrifugal compressor, records that document that each new or modified compressor is equipped with dry seals; and (5) for each new or modified reciprocating compressor, records of rod packing replacement, including elapsed operating hours since the previous rod packing installation.

For these other affected sources described above, the proposed NSPS provide monitoring in the form of recordkeeping (as described above) that would assure compliance with the proposed operational, work practice or equipment standards. Monitoring by means other than recordkeeping would not be practical or appropriate for these standards. Records are required to ensure that these standards and practices are followed. We believe that the monitoring, recordkeeping and reporting requirements described above are sufficient to assure compliance with the proposed NSPS for pneumatic controllers and compressors.

We acknowledge that title V might provide for additional compliance requirements for these non-major sources, but we have determined, as explained above, that the monitoring, recordkeeping and reporting requirements in this proposed NSPS are sufficient to assure compliance with the proposed standards for well completions, storage vessels, pneumatic controllers and compressors. Further, given the nature of some of the operations and the types of the requirements at issue, the additional compliance requirements under title V would not significantly improve the compliance requirements in this proposed NSPS. For instance, well completions occur over a very short period (generally 3 to 10 days), and the proposed NSPS for pneumatic controllers and centrifugal compressors can be met by simply installing the equipment that meet the proposed emission limit; therefore, the semi-annual reporting requirement under title V would not improve compliance with

[9] The proposed numeric standards for pneumatic controllers reflect the use of specific equipment (either non-gas driven device or low-bleed device).

these proposed NSPS and, in fact, may seem inappropriate for such short term operations.

For the reasons stated above, we believe that title V would not result in significant improvements to the compliance requirements that are provided in this proposed NSPS. Therefore, the first factor supports a conclusion that title V permitting is ''unnecessary'' for non-major sources subject to the Oil and Natural Gas NSPS.

The second factor we considered is whether title V permitting would impose significant burdens on the oil and natural gas NSPS non-major sources and whether that burden would be aggravated by any difficulty these sources may have in obtaining assistance from permitting agencies. Subjecting any source to title V permitting imposes certain burdens and costs that do not exist outside of the title V program. EPA estimated that the average cost of obtaining and complying with a title V permit was $65,700 per source for a 5-year permit period, including fees. See Information Collection Request (ICR) for Part 70 Operating Permit Regulations, January 2007, EPA ICR Number 1587.07. EPA does not have specific estimates for the burdens and costs of permitting the oil and gas NSPS non-major sources; however, there are certain activities associated with the 40 CFR part 70 and 40 CFR part 71 rules. These activities are mandatory and impose burdens on any facility subject to title V. They include reading and understanding permit program regulations; obtaining and understanding permit application forms; answering follow-up questions from permitting authorities after the application is submitted; reviewing and understanding the permit; collecting records; preparing and submitting monitoring reports; preparing and submitting prompt deviation reports, as defined by the state, which may include a combination of written, verbal and other communication methods; collecting information, preparing and submitting the annual compliance certification; preparing applications for permit revisions every 5 years; and, as needed, preparing and submitting applications for permit revisions. In addition, although not required by the permit rules, many sources obtain the contractual services of consultants to help them understand and meet the permitting program's requirements. The ICR for 40 CFR part 70 provides additional information on the overall burdens and costs, as well as the relative burdens of each activity described here. Also, for a more comprehensive list of requirements imposed on 40 CFR part 70 sources (hence, burden on sources), see the requirements of 40 CFR 70.3, 40 CFR 70.5, 40 CFR 70.6, and 40 CFR 70.7. The activities described above, which are quite extensive and time consuming, would be a significant burden on the non-major sources that would be subject to the proposed NSPS, in particular for well completion and/or pneumatic devices, considering the short duration of a well completion and the one time equipment installation of a pneumatic controller for meeting the proposed NSPS. Furthermore, some of the non-major sources that would be subject to the proposed NSPS may be small entities that may lack the technical resources and, therefore, need assistance from the permitting authorities to comply with the title V permitting requirements. Based on our projections, over 20,000 well completions (for both new hydraulically fractured gas wells and for existing gas wells that are subsequently fractured or re-fractured) will be performed each year. For pneumatic controller affected facilities, we estimate that approximately 14,000 new controllers would be subject to the NSPS each year. Our estimated numbers of affected facilities that would be subject to the proposed NSPS for storage vessels and compressors are smaller (around 500 compressors and 300 storage vessels). Although we do not know the total number of non-major sources that would be subject to the proposed NSPS, based on the estimated numbers of affected facilities, we anticipate a significant increase in the number of permit applications that permitting authorities would have to process each year. This significant burden on the permitting authorities raises a concern with the potential difficulty or delay that the small entities may face in obtaining sufficient assistance from the permitting authorities.

The third factor we considered is whether the costs of title V permitting for these area sources would be justified, taking into consideration any potential gains in compliance likely to occur for such sources. We concluded, in considering the first factor, that the monitoring, recordkeeping and reporting requirements in this proposed NSPS assure compliance with the proposed standards, that title V would not result in significant improvement to these compliance requirements and, that, in some instances, certain title V compliance requirements may not be appropriate. In addition, as discussed above in our consideration of the second factor, we have concerns with the potential burdens that title V may impose on these sources. In addition, below in our consideration of the fourth factor, we find that there are adequate implementation and enforcement programs in place to assure compliance with the proposed NSPS. In light of the above, we find that the costs of title V permitting are not justified for the sources we propose to exempt. Accordingly, the third factor supports title V exemption for the oil and gas NSPS non-major sources.

The fourth factor we considered is whether there are implementation and enforcement programs in place that are sufficient to assure compliance with the proposed NSPS for oil and gas sources without relying on title V permits. The CAA provides States the opportunity to take delegation of NSPS. Before the EPA will delegate the program, the EPA will evaluate the state programs to ensure that states have adequate capability to enforce the CAA section 111 regulations and provide assurances that they will enforce the NSPS. In addition, EPA retains authority to enforce this NSPS anytime under CAA sections 111, 113 and 114. Accordingly, we can enforce the monitoring, recordkeeping and reporting requirements, which, as discussed under the first factor, are adequate to assure compliance with this NSPS. Also, states and the EPA often conduct voluntary compliance assistance, outreach and education programs (compliance assistance programs), which are not required by statute. We determined that these additional programs will supplement and enhance the success of compliance with these proposed standards. We believe that the statutory requirements for implementation and enforcement of this NSPS by the delegated states, the EPA and the additional assistance programs described above together are sufficient to assure compliance with these proposed standards without relying on title V permitting.

Our balance of the four factors strongly supports a finding that title V is unnecessarily burdensome for the oil and gas non-major sources. While title V might add additional compliance requirements if imposed, we believe that there would not be significant improvements to the compliance requirements in this proposed rule because the proposed rule requirements are specifically designed to assure compliance with the proposed NSPS and, as explained above, some of the title V requirements may not be appropriate for certain operations and/or proposed standards. We are also concerned with the potential burden that title V may impose on some of these

sources. In light of little or no potential gain in compliance if title V were required, we do not believe that the costs of title V permitting is justified in this case. Finally, there are adequate implementation and enforcement programs in place to assure compliance with these proposed standards. Thus, we propose that title V permitting is ''unnecessarily burdensome'' for the oil and gas non-major sources.

In addition to evaluating whether compliance with title V requirements is ''unnecessarily burdensome,'' EPA also considered, consistent with guidance provided by the legislative history of section 502(a), whether exempting oil and gas NSPS non-major sources from title V requirements would adversely affect public health, welfare or the environment. The title V permit program does not impose new substantive air quality control requirements on sources, but instead requires that certain procedural measures be followed, particularly with respect to determining compliance with applicable requirements. As stated in our consideration of factor one, title V would not lead to significant improvements in the compliance requirements for the proposed NSPS. For the reason stated above, we believe that exempting these non-major sources from title V permitting requirements would not adversely affect public health, welfare or the environment.

On the contrary, we are concerned that requiring title V in this case could potentially adversely affect public health, welfare or the environment. As mentioned above, we anticipate a significant increase in the number of permit applications that permitting authorities would have to process each year. Depending on the number of non-major sources that would be subject to this rule, requiring permits for those sources, at least in the first few years of implementation, could potentially adversely affect public health, welfare or the environment by shifting state agencies resources away from assuring compliance for major sources (which cannot be exempt from title V) to issuing new permits for these non-major sources, potentially reducing overall air program effectiveness.

Based on the above analysis, we conclude that title V permitting would be ''unnecessarily burdensome'' for oil and gas NSPS non-major sources. We are, therefore, proposing that these non-major sources be exempt from title V permitting requirements.

VI. Rationale for Proposed Action for NSPS

A. What did we evaluate relative to NSPS?

As noted above, there are two existing NSPS that address emissions from the Oil and Natural Gas source category. These NSPS are relatively narrow in scope, as they address emissions only at natural gas processing plants. Specifically, 40 CFR part 60, subpart KKK addresses VOC emissions from leaking equipment at onshore natural gas processing plants and 40 CFR part 60, subpart LLL addresses SO_2 emissions from natural gas processing plants.

CAA section 111(b)(1)(B) requires the EPA to review and revise, if appropriate, NSPS standards. Accordingly, we evaluated whether the existing NSPS reflect the BSER for the emission sources that they address. This review was conducted by examining currently used, new and emerging control systems and assessing whether they represent advances in emission reduction techniques from those upon which the existing NSPS are based, including advances in LDAR approaches and SO_2 control at natural gas processing plants. For each new or emerging control option identified, we then evaluated emission reductions, costs, energy requirements and non-air quality impacts, such as solid waste generation.

In this package, we have also evaluated whether there were additional pollutants emitted by facilities in the Oil and Natural Gas source category that warrant regulation and for which we have adequate information to promulgate standards of performance. Finally, we have identified additional processes in the Oil and Natural Gas source category for which it may be appropriate to develop performance standards. This would include processes that emit the currently regulated pollutants, VOC and SO_2, as well as any additional pollutants for which we determined regulation to be appropriate.

B. What are the results of our evaluations and proposed actions relative to NSPS?

1. Do the existing NSPS reflect the BSER for sources covered?

Consistent with our obligations under CAA section 111(b), we evaluated whether the control options reflected in the current NSPS for the Oil and Natural Gas source category still represent BSER. To evaluate the BSER options for equipment leaks, we reviewed EPA's current LDAR programs, the Reasonably Available Control Technology (RACT)/Best Available Control Technology (BACT)/Lowest Achievable Emission Rate (LAER) Clearinghouse (RBLC) database, and emerging technologies that have been identified by partners in the Natural Gas STAR program.

The current NSPS for equipment leaks of VOC at natural gas processing plants (40 CFR part 60, subpart KKK) requires compliance with specific provisions of 40 CFR part 60, subpart VV, which is a LDAR program, based on the use of EPA Method 21 to identify equipment leaks. In addition to the subpart VV requirements, we reviewed the LDAR requirements in 40 CFR part 60, subpart VVa. This LDAR program is considered to be more stringent than the subpart VV requirements, because it has lower component leak threshold definitions and more frequent monitoring, in comparison to the subpart VV program. Furthermore, subpart VVa requires monitoring of connectors, while subpart VV does not. We also reviewed options based on optical gas imaging.

As mentioned above, the currently required LDAR program for natural gas processing plants (40 CFR part 60, subpart KKK) is based on EPA Method 21, which requires the use of an organic vapor analyzer to monitor components and to measure the concentration of the emissions in identifying leaks. We recognize that there have been advancements in the use of optical gas imaging to detect leaks from these same types of components. These instruments do not yet provide a direct measure of leak concentrations. The instruments instead provide a measure of a leak relative to an instrument specific calibration point. Since the promulgation of 40 CFR part 60, subpart KKK (which requires Method 21 leak measurement monthly), the EPA has updated the 40 CFR part 60 General Provisions to allow the use of advanced leak detection tools, such as optical gas imaging and ultrasound equipment as an alternative to the LDAR protocol based on Method 21 leak measurements (see 40 CFR 60.18(g)). The alternative work practice allowing use of these advanced technologies includes a provision for conducting a Method 21-based LDAR check of the regulated equipment annually to verify good performance.

In our review, we evaluated 4 options in considering BSER for VOC equipment leaks at natural gas processing plants. One option we evaluated consists of changing from a 40 CFR part 60, subpart VV-level program, which is what 40 CFR part 60, subpart KKK currently requires, to a 40 CFR part 60, subpart VVa program, which applies to new

synthetic organic chemical plants after 2006. Subpart VVa lowers the leak definition for valves from 10,000 parts per million (ppm) to 500 ppm, and requires the monitoring of connectors. In our analysis of these impacts, we estimated that, for a typical natural gas processing plant, the incremental cost effectiveness of changing from the current subpart VV-level program to a subpart VVa-level program using Method 21 is $3,352 per ton of VOC reduction.

In evaluating 40 CFR part 60, subpart VVa-level LDAR at processing plants, we also analyzed separately the individual types of components (valves, connectors, pressure relief devices and open-ended lines) to determine cost effectiveness for individual components. Detailed discussions of these component-by-component analyses are included in the TSD in the docket. Cost effectiveness ranged from $144 per ton of VOC (for valves) to $4,360 per ton of VOC (for connectors), with no change in requirements for pressure relief devices and open-ended lines.

Another option we evaluated for gas processing plants was the use of optical gas imaging combined with an annual EPA Method 21 check (*i.e.,* the alternative work practice for monitoring equipment for leaks at 40 CFR 60.18(g)). We had previously determined that the VOC reduction achieved by this combination of optical gas imaging and Method 21 would be equivalent to reductions achieved by the 40 CFR part 60, subpart VVa-level program. Based on that emission reduction level, we determined the cost effectiveness of this option to be $6,462 per ton of VOC reduction. This analysis is based on the facility purchasing an optical gas imaging system costing $85,000. However, we identified at least one manufacturer who rents the optical gas imaging systems. That manufacturer rents the optical gas imaging system for $3,950 per week. Using this rental cost in place of the purchase cost, the VOC cost effectiveness of the monthly optical gas imaging combined with annual Method 21 checks is $4,638 per ton of VOC reduction.[10] A third option we evaluated consisted of monthly optical gas imaging without an annual Method 21 check. We estimated the annual cost of the monthly optical gas imaging LDAR program to be $76,581, based on camera purchase, or $51,999, based on camera rental. However, because we were unable to estimate the VOC emissions achieved by an optical imaging program alone, we were unable to estimate the cost effectiveness of this option.

Finally, we evaluated a fourth option similar to the third option, except that the optical gas imaging would be performed annually rather than monthly. For this option, we estimated the annual cost to be $43,851, based on camera purchase, or $18,479, based on camera rental.

We request comment on the applicability of an LDAR program based solely on the use of optical gas imaging. Of most use to us would be information on the effectiveness of this and, potentially, other advanced measurement technologies, to detect and repair small leaks on the same order or smaller than specified in the 40 CFR part 60, subpart VVa equipment leak requirements and the effects of increased frequency of and associated leak detection, recording and repair practices.

Because we could not estimate the cost effectiveness of options 3 and 4, we could not identify either of these two options as BSER for reducing VOC leaks at gas processing plants. Because options 1 and 2 have achieved equivalent VOC reduction and are both cost effective, we believe that both options 1 and 2 reflect BSER for LDAR for natural gas processing plants. As mentioned above, option 1 is the LDAR in 40 CFR part 60, subpart VVa and option 2 is the alternative work practice at 40 CFR 60.18(g) and is already available to use as an alternative to subpart VVa LDAR. Therefore, we propose that the NSPS for equipment leaks of VOC at gas processing plants be revised to require compliance with the subpart VVa equipment leak requirements.

For 40 CFR part 60, subpart LLL, we reviewed control systems for SO_2 emissions from sweetening units located at natural gas processing plants, including those followed by a sulfur recovery unit. Subpart LLL provides specific standards for SO_2 emission reduction efficiency, on the basis of sulfur feed rate and the sulfur content of the natural gas.

According to available literature, the most widely used process for converting H_2S in acid gases (*i.e.,* H_2S and CO_2) separated from natural gas by a sweetening process (such as amine treating) into elemental sulfur is the Claus process. Sulfur recovery efficiencies are higher with higher concentrations of H_2S in the feed stream due to the thermodynamic equilibrium limitation of the Claus process. The Claus sulfur recovery unit produces elemental sulfur from H_2S in a series of catalytic stages, recovering up to 97-percent recovery of the sulfur from the acid gas from the sweetening process. Further, sulfur recovery is accomplished by making process modifications or by employing a tail gas treatment process to convert the unconverted sulfur compounds from the Claus unit.

We evaluated process modifications and tail gas treatment options when we proposed 40 CFR part 60, subpart LLL. 49 FR 2656, 2659–2660 (1984). As we explained in the preamble to the proposed subpart LLL, control through sulfur recovery with tail gas treatment may not always be cost effective, depending on sulfur feed rate and inlet H_2S concentrations. Therefore, other methods of increasing sulfur recovery via process modifications were evaluated. As shown in the original evaluation, the performance capabilities and costs of each of these technologies are highly dependent on the ratio of H_2S and CO_2 in the gas stream and the total quantity of sulfur in the gas stream being treated. The most effective means of control was selected as BSER for the different stream characteristics. As a result, separate emissions limitations were developed in the form of equations that calculate the required initial and continuous emission reduction efficiency for each plant. The equations were based on the design performance capabilities of the technologies selected as BSER relative to the gas stream characteristics. 49 FR 2656, 2663–2664 (1984). The emission limit for sulfur feed rates at or below 5 long tons per day, regardless of H_2S content, was 79 percent. For facilities with sulfur feed rates above 5 long tons per day, the emission limits ranged from 79 percent at an H_2S content below 10 percent to 99.8 percent for H_2S contents at or above 50 percent.

To review these emission limitations, we performed a search of the RBLC database and state regulations. No state regulations identified had emission limitations more stringent than 40 CFR part 60, subpart LLL. However, the RBLC database search identified two entries with SO_2 emission reductions of 99.9 percent. One entry is for a facility in Bakersfield, California, with a 90 long ton per day sulfur recovery unit followed by an amine-based tail-gas treating unit. The second entry is for a facility in Coden, Alabama, with a sulfur recovery unit with a sulfur feed rate of 280 long tons per day, followed by selective catalytic reduction and a tail gas incinerator. However, neither of these entries contained information regarding the H_2S contents of the feed

[10] Because optical gas imaging is used to view several pieces of equipment at a facility at once to survey for leaks, options involving imaging are not amenable to a component by component analysis.

stream. Because the sulfur recovery efficiency of these large sized plants was greater than 99.8 percent, we reevaluated the original data. Based on the available cost information, it appears that a 99.9-percent efficiency is cost effective for facilities with a sulfur feed rate greater than 5 long tons per day and H_2S content equal to or greater than 50 percent. Based on our review, we are proposing that the maximum initial and continuous efficiency for facilities with a sulfur feed rate greater than 5 long tons per day and an H_2S content equal to or greater than 50 percent be raised to 99.9 percent. We are not proposing to make changes to the equations.

Our search of the RBLC database did not uncover information regarding costs and achievable emission reductions to suggest that the emission limitations for facilities with a sulfur feed rate less than 5 long tons per day or H_2S content less than 50 percent should be modified. Therefore, we are not proposing any changes to the emissions limitations for facilities with sulfur feed rate and H_2S content less than 5 long tons per day and 50 percent, respectively.

2. What pollutants are being evaluated in this Oil and Natural Gas NSPS package?

The two current NSPS for the Oil and Natural Gas source category address emissions of VOC and SO_2. In addition to these pollutants, sources in this source category also emit a variety of other pollutants, most notably, air toxics. As discussed elsewhere in this notice, there are NESHAP that address air toxics from the oil and natural gas sector.

In addition, processes in the Oil and Natural Gas source category emit significant amounts of methane. The 1990–2009 U.S. GHG Inventory estimates 2009 methane emissions from Petroleum and Natural Gas Systems (not including petroleum refineries) to be 251.55 $MMtCO_2e$ (million metric tons of CO_2-equivalents (CO_2e)).[11] The emissions estimated from well completions and recompletions exclude a significant number of wells completed in tight sand plays, such as the Marcellus, due to availability of data when the 2009 Inventory was developed. The estimate in this proposal includes an adjustment for tight sand plays (being considered as a planned improvement in development of the 2010 Inventory). This adjustment would increase the 2009 Inventory estimate by 76.74 $MMtCO_2e$. The total methane emissions from Petroleum and Natural Gas Systems, based on the 2009 Inventory, adjusted for tight sand plays and the Marcellus, is 328.29 $MMtCO_2e$. Although this proposed rule does not include standards for regulating the GHG emissions discussed above, we continue to assess these significant emissions and evaluate appropriate actions for addressing these concerns. Because many of the proposed requirements for control of VOC emissions also control methane emissions as a co-benefit, the proposed VOC standards would also achieve significant reduction of methane emissions.

Significant emissions of oxides of nitrogen (NO_X) also occur at oil and natural gas sites due to the combustion of natural gas in reciprocating engines and combustion turbines used to drive the compressors that move natural gas through the system, and from combustion of natural gas in heaters and boilers. While these engines, turbines, heaters and boilers are co-located with processes in the oil and natural gas sector, they are not in the Oil and Natural Gas source category and are not being addressed in this action. The NO_X emissions from engines and turbines are covered by the Standards of Performance for Stationary Spark Internal Combustion Engines (40 CFR part 60, subpart JJJJ) and Standards of Performance for Stationary Combustion Turbines (40 CFR part 60, subpart KKKK), respectively.

An additional source of NO_X emissions would be pit flaring of VOC emissions from well completions during periods where REC is not feasible, as would be required under our proposed operational standards for wellhead affected facilities. As discussed below in section VI.B.4 (well completion), pit flaring is the only way we identified of controlling VOC emissions during these periods. Because there is no way of directly measuring the NO_X produced, nor is there any way of applying controls other than minimizing flaring, we propose to allow flaring only when REC is not feasible. We have included our estimates of NO_X formation from pit flaring in our discussion of secondary impacts in section VI.B.4.

3. What emission sources are being evaluated in this Oil and Natural Gas NSPS package?

The current NSPS only cover emissions of VOC and SO_2 from one type of facility in the oil and natural gas sector, which is the natural gas processing plant. This is the only type of facility in the Oil and Natural Gas source category where we would expect SO_2 to be emitted directly, although H_2S contained in sour gas, when oxidized in the atmosphere or combusted in boilers and heaters in the field, forms SO_2 as a product of oxidation. These field boilers and heaters are not part of the Oil and Natural Gas source category and are generally too small to be regulated by the NSPS covering boilers (*i.e.,* they have a heat input of less than 10 million British Thermal Units per hour). However, we may consider addressing them as part of a future sector-based strategy for the oil and natural gas sector.

In addition to VOC emissions from gas processing plants, there are numerous sources of VOC throughout the oil and natural gas sector that are not addressed by the current NSPS. As explained above in section V.A, pursuant to CAA section 111(b), to the extent necessary, we are modifying the listed category to include all segments of the oil and natural gas industry for regulation. We are also proposing VOC standards to cover additional processes at oil and natural gas operations. These include NSPS for VOC from gas well completions, pneumatic controllers, compressors and storage vessels.

We believe that produced water ponds are also a potentially significant source of emissions, but we have only limited information. We, therefore, solicit comments on produced water ponds, particularly in the following subject areas:

(a) We are requesting comments pertaining to methods for calculating emissions. The State of Colorado currently uses a mass balance that assumes 100 percent of the VOC content is emitted to the atmosphere. Water9, an air emissions model, is another option that has some limitations, including poor methanol estimation.

(b) We are requesting additional information on typical VOC content in produced water and any available chemical analyses, including data that could help clarify seasonal variations or differences among gas fields. Additionally, we request data that increase our understanding of how changing process variables or age of wells affect produced water output and VOC content.

(c) We solicit information on the size and throughput capacity of typical evaporation pond facilities and request suggestions on parameters that could be used to define affected facilities or affected sources. We also seek information on impacts of smaller evaporation pits that are co-located with drilling operations, whether those

[11] U.S. EPA. *Inventory of U.S. Greenhouse Gas Inventory and Sinks.* 1990–2009. *http://www.epa.gov/climatechange/emissions/downloads10/US-GHG-Inventory-2010_ExecutiveSummary.pdf.*

warrant control and, if so, how controls should be developed.

(d) An important factor is cost of emission reduction technologies, including recovery credits or cost savings realized from recovered salable product. We are seeking information on these considerations as well.

(e) We are also seeking information on any limitations for emission reduction technologies such as availability of electricity, waste generation and disposal and throughput and concentration constraints.

(f) Finally, we solicit information on separator technologies that are able to improve the oil-water separation efficiency.

4. What are the rationales for the proposed NSPS?

We have provided below our rationales for the proposed BSER determinations and performance standards for a number of VOC emission sources in the Oil and Natural Gas source category that are not covered by the existing NSPS. Our general process for evaluating systems of emission reduction for the emission sources discussed below included: (1) Identification of available control measures; (2) evaluation of these measures to determine emission reductions achieved, associated costs, nonair environmental impacts, energy impacts and any limitations to their application; and (3) selection of the control techniques that represent BSER based on the information we considered.

We identified the control options discussed in this package through our review of relevant state and local requirements and mitigation measures developed and reported by the EPA's Natural Gas STAR program. The EPA's Natural Gas STAR program has worked with industry partners since 1993 to identify cost effective measures to reduce emissions of methane and other pollutants from natural gas operations. We relied heavily on this wealth of information in conducting this review. We also identified state regulations, primarily in Colorado and Wyoming, which require mitigation measures for some emission sources in the Oil and Natural Gas source category.

a. NSPS for Well Completions

Well completion activities are a significant source of VOC emissions, which occur when natural gas and non-methane hydrocarbons are vented to the atmosphere during flowback of a hydraulically fractured gas well. Flowback emissions are short-term in nature and occur over a period of several days following fracturing of a new well or refracturing of an existing well. Well completions include multiple steps after the well bore hole has reached the target depth. These steps include inserting and cementing-in well casing, perforating the casing at one or more producing horizons, and often hydraulically fracturing one or more zones in the reservoir to stimulate production. Well recompletions may also include hydraulic fracturing. Hydraulic fracturing is one technique for improving gas production where the reservoir rock is fractured with very high pressure fluid, typically water emulsion with a proppant (generally sand) that ''props open'' the fractures after fluid pressure is reduced. Emissions are a result of the backflow of the fracture fluids and reservoir gas at high volume and velocity necessary to lift excess proppant and fluids to the surface. This multi-phase mixture is often directed to a surface impoundment where natural gas and VOC vapors escape to the atmosphere during the collection of water, sand and hydrocarbon liquids. As the fracture fluids are depleted, the backflow eventually contains more volume of natural gas from the formation. Wells that are fractured generally have great amounts of emissions because of the extended length of the flowback period required to purge the well of the fluids and sand that are associated with the fracturing operation. Along with the fluids and sand from the fracturing operation, the 3- to 10-day flowback period also results in emissions of natural gas and VOC that would not occur in large quantities at oil wells or at natural gas wells that are not fractured. Thus, we estimate that gas well completions involving hydraulic fracturing vent substantially more VOC, approximately 200 times more, than completions not involving hydraulic fracturing. Specifically, we estimate that uncontrolled well completion emissions for a hydraulically fractured gas well are approximately 23 tons of VOC, where emissions for a conventional gas well completion are around 0.12 tons VOC. These estimates are explained in detail in the TSD available in the docket. Based on our review, we believe that emissions from recompletions of previously completed wells that are fractured or refractured to stimulate production or to begin production from a new production horizon are of similar magnitude and composition as emissions from completions of new wells that have been hydraulically fractured.

EPA has based the NSPS impacts analysis on best available emission data. However, we recognize that there is uncertainty associated with our estimates. For both new completions and recompletions, there are a variety of factors that will determine the length of the flowback period and actual volume of emissions such as the number of zones, depth, pressure of the reservoir, gas composition, etc. This variability means there will be some wells which emit more than the estimated emission factor and some wells that emit less.

During our review, we examined information from the Natural Gas STAR program and the Colorado and Wyoming state rules covering well completions. We identified two subcategories of fractured gas wells: (1) Non-exploratory and non-delineation wells; and (2) exploratory and delineation wells. An exploratory well is the first well drilled to determine the presence of a producing reservoir and the well's commercial viability. A delineation well is a well drilled to determine the boundary of a field or producing reservoir. Because exploratory and delineation wells are generally isolated from existing producing wells, there are no gathering lines available for collection of gas recovered during completion operations. In contrast, non-exploratory and non-delineation wells are located where existing, producing wells are connected to gathering lines and are, therefore, able to be connected to a gathering line to collect recovered salable natural gas product that would otherwise be vented to the atmosphere or combusted.

For subcategory 1, we identified ''green'' completion, which we refer to as REC, as an option for reducing VOC emissions during well completions. REC are performed by separating the flowback water, sand, hydrocarbon condensate and natural gas to reduce the portion of natural gas and VOC vented to the atmosphere, while maximizing recovery of salable natural gas and VOC condensate. In some cases, for a portion of the completion operation, such as when CO_2 or nitrogen is injected with the fracture water, initial gas produced is not of suitable quality to introduce into the gathering line due to CO_2 or nitrogen content or other undesirable characteristic. In such cases, for a portion of the flowback period, gas cannot be recovered, but must be either vented or combusted. In practice, REC are often combined with combustion to minimize the amount of gas and condensate being vented. This combustion process is rather crude, consisting of a horizontal pipe

downstream of the REC equipment, fitted with a continuous ignition source and discharging over a pit near the wellhead. Because of the nature of the flowback (*i.e.,* with periods of water, condensate, and gas in slug flow), conveying the entire portion of this stream to a traditional flare control device or other control device, such as a vapor recovery unit, is not feasible. These control devices are not designed to accommodate the multiphase flow consisting of water, sand and hydrocarbon liquids, along with the gas and vapor being controlled. Although ''pit flaring'' does not employ a traditional flare control device, and is not capable of being tested or monitored for efficiency due to the multiphase slug flow and intermittent nature of the discharge of gas, water and sand over the pit, it does provide a means of minimizing vented gas and is preferable to venting. Because of the rather large exposed flame, open pit flaring can present a fire hazard or other undesirable impacts in some situations (*e.g.,* dry, windy conditions, proximity to residences, etc.). As a result, we are aware that owners and operators may not be able to pit flare unrecoverable gas safely in every case. In some cases, pit flaring may be prohibited by local ordinance.

Equipment required to conduct REC may include tankage, special gas-liquid-sand separator traps and gas dehydration. Equipment costs associated with REC will vary from well to well. Typical well completions last between 3 and 10 days and costs of performing REC are projected to be between $700 and $6,500 per day, including a cost of approximately $3,523 per completion event for the pit flaring equipment. However, there are savings associated with the use of REC because the gas recovered can be incorporated into the production stream and sold. In fact, we estimate that REC will result in an overall net cost savings in many cases.

The emission reductions for a hydraulically fractured well are estimated to be around 22 tons of VOC. Based on an average incremental cost of $33,237 per completion, the cost effectiveness of REC, without considering any cost savings, is around $1,516 per ton of VOC (which we have previously found to be cost effective on average). When the value of the gas recovered (approximately 150 tons of methane per completion) is considered, the cost effectiveness is estimated as an average net savings of $99 per ton VOC reduced, using standard discount rates. We believe that these costs are very reasonable, given the emission reduction that would be achieved. Aside from the potential hazards associated with pit flaring, in some cases, we did not identify any nonair environmental impacts, health or energy impacts associated with REC combined with combustion. However, pit flaring would produce NO_X emissions. Because we believe that these emissions cannot be controlled or measured directly due to the open combustion process characteristic of pit flaring, we used published emission factors (EPA Emission Guidelines AP–42) to estimate the NO_X emissions for purposes of assessing secondary impacts. For category 1 well completions, we estimated that 0.02 tons of NO_X are produced per event. This is based on the assumption that 5 percent of the flowback gas is combusted by the combustion device. The 1.2 tons of VOC controlled during the pit flaring portion of category 1 well completions is approximately 57 times greater than the NO_X produced by pit flaring. Thus, we believe that the benefit of the VOC reduction far outweighs the secondary impact of NO_X formation during pit flaring.

We believe that, based on the analysis above, REC in combination with combustion is BSER for subcategory 1 wells. We considered setting a numerical performance standard for subcategory 1 wells. However, it is not practicable to measure the emissions during pit flaring or venting because the gas is discharged over the pit along with water and sand in multiphase slug flow. Therefore, we believe it is not feasible to set a numerical performance standard. Pursuant to section 111(h)(2) of the CAA, we are proposing an operational standard for subcategory 1 wells that would require a combination of REC and pit flaring to minimize venting of gas and condensate vapors to the atmosphere, with provisions for venting in lieu of pit flaring for situations in which pit flaring would present safety hazards or for periods when the flowback gas is noncombustible due to high concentrations of nitrogen or CO_2. The proposed operational standard would be accompanied by requirements for documentation of the overall duration of the completion event, duration of recovery using REC, duration of combustion, duration of venting, and specific reasons for venting in lieu of combustion.

We recognize that there is heterogeneity in well operations and costs, and that while RECs may be cost-effective on average, they may not be for all operators. Nonetheless, EPA is proposing to require an operational standard rather than a performance-based standard (*e.g.,* requiring that some percentage of emissions be flared or captured), because we believe there are no feasible ways for operators to measure emissions with enough certainty to demonstrate compliance with a performance-based standard for REC in combination with pit flaring. The EPA requests comment on this and seeks input on whether alternative approaches to requiring REC for all operators with access to pipelines may exist that would allow operators to meet a performance-based standard if they can demonstrate that an REC is not cost effective.

We have discussed above certain situations where unrecoverable gas would be vented because pit flaring would present a fire hazard or is infeasible because gas is noncombustible due to high concentrations of nitrogen or CO_2. We solicit comment on whether there are other such situations where flaring would be unsafe or infeasible, and potential criteria that would support venting in lieu of pit flaring. In addition, we learned that coalbed methane reservoirs may have low pressure, which would present a technical barrier for performing a REC because the well pressure may not be substantial enough to overcome gathering line pressure. In addition, we identified that coalbed methane wells often have low to almost no VOC emissions, even following the hydraulic fracturing process. We solicit comment on criteria and thresholds that could be used to exempt some well completion operations occurring in coalbed methane reservoirs from the requirements for subcategory 1 wells.

Of the 25,000 new and modified fractured gas wells completed each year, we estimate that approximately 3,000 to 4,000 currently employ reduced emission completion. We expect this number to increase to over 21,000 REC annually as operators comply with the proposed NSPS. We estimate that approximately 9,300 new wells and 12,000 existing wells will be fractured or refractured annually that would be subject to subcategory 1 requirements under the NSPS. We believe that there will be a sufficient supply of REC equipment available by the time the NSPS becomes effective. However, energy availability could be affected if a shortage of REC equipment was allowed to cause delays in well completions. We request comment on whether sufficient supply of this equipment and personnel to operate it will be available to accommodate the increased number of REC by the effective date of the NSPS. We also request specific estimates of

how much time would be required to get enough equipment in operation to accommodate the full number of REC performed annually.

In the event that public comments indicate that available equipment would likely be insufficient to accommodate the increase in number of REC performed, we are considering phasing in requirements for well completions that would achieve an overall comparable level of environmental benefit. For example, operators performing completions of fractured or refractured existing wells (*i.e.,* modified wells) could be allowed to control emissions through pit flaring instead of REC for some period of time. After some date certain, all modified wells would be subject to REC. We solicit comment on the phasing of requirements for REC along with suggestions for other ways to address a potential short-term REC equipment shortage that may hinder operators' compliance with the proposed NSPS, while also achieving a comparable level of reduced emissions to the air.

Although we have determined that, on average, reduced emission completions are cost effective, well and reservoir characteristics could vary, such that some REC are more cost effective than others. Unlike most stationary source controls, REC equipment is used only for a 3 to 10 day period. Our review found that most operators contract with service companies to perform REC rather than purchase the equipment themselves, which was reflected in our economic analysis. It is also possible that the contracting costs of supplying and operating REC equipment may rise in the short term with the increased demand for those services. We request comment and any available technical information to judge whether our assumption of $33,237 per well completion for this service given the projected number of wells in 2015 subject to this requirement is accurate.

We believe that the proposed rule regulates only significant emission sources for which controls are cost-effective. Nevertheless, we solicit comment and supporting data on appropriate thresholds (*e.g.,* pressure, flowrate) that we should consider in specifying which well completions are subject to the REC requirements for subcategory 1 wells. Comments specifying thresholds should include an analysis of why sources below these thresholds are not cost effective to control.

In addition, there may be economic, technical or other opportunities or barriers associated with performing cost effective REC that we have not identified in our review. For example, some small regulated entities may have an increased source of revenue due to the captured product. On the other hand, some small regulated entities may have less access to REC than larger regulated entities might have. We request information on such opportunities and barriers that we should consider and suggestions for how we may take them into account in structuring the NSPS.

The second subcategory of fractured gas wells includes exploratory wells or delineation wells. Because these types of wells generally are not in proximity to existing gathering lines, REC is not an option, since there is no infrastructure in place to get the recovered gas to market or further processing. For these wells, the only potential control option we were able to identify is pit flaring, described above. As explained above, because of the slug flow nature of the flowback gas, water and sand, control by a traditional flare control device or other control devices, such as vapor recovery units, is infeasible, which leaves pit flaring as the only practicable control system for subcategory 2 wells. As also discussed above, open pit flaring can present a fire hazard or other undesirable impacts in some situations. Aside from the potential hazards associated with pit flaring, in some cases, we did not identify any nonair environmental impacts, health or energy impacts associated with pit flaring. However, pit flaring would produce NO_X emissions. As in the case of category 1 wells, we believe that these emissions cannot be controlled or measured directly due to the open combustion process characteristic of pit flaring. We again used published emission factors to estimate the NO_X emissions for purposes of assessing secondary impacts. For category 2 well completions, we estimated that 0.32 tons of NO_X are produced as secondary emissions per completion event. This is based on the assumption that 95 percent of flowback gas is combusted by the combustion device. The 22 tons of VOC reduced during the pit flaring used to control category 2 well completions is approximately 69 times greater than the NO_X produced. Thus, we believe that the benefit of the VOC reduction far outweighs the secondary impact of NO_X formation during pit flaring.

In light of the above, we propose to determine that BSER for subcategory 2 wells would be pit flaring. As we explained above, it is not practicable to measure the emissions during pit flaring or venting because the gas is discharged during flowback mixed with water and sand in multiphase slug flow. It is, therefore, not feasible to set a numerical performance standard.

Pursuant to CAA section 111(h)(2), we are proposing an operational standard for subcategory 2 wells that requires minimization of venting of gas and hydrocarbon vapors during the completion operation through the use of pit flaring, with provisions for venting in lieu of pit flaring for situations in which flaring would present safety hazards or for periods when the flowback gas is noncombustible due to high concentrations of nitrogen or carbon dioxide.

Consistent with requirements for subcategory 1 wells, owners or operators of subcategory 2 wells would be required to document completions and provide justification for periods when gas was vented in lieu of combustion. We solicit comment on whether there are other such situations where flaring would be unsafe or infeasible and potential criteria that would support venting in lieu of pit flaring.

For controlling completion emissions at oil wells and conventional (non-fractured) gas wells, we have identified and evaluated the following control options: REC in conjunction with pit flaring and pit flaring alone. Due to the low uncontrolled VOC emissions of approximately 0.007 ton per completion and, therefore, low potential emission reductions from these events, the cost per ton of reduction based on REC would be extremely high (over $700,000 per ton of VOC reduced). We evaluated the use of pit flaring alone as a system for controlling emissions from oil wells and conventional gas wells and determined that the cost cost-effectiveness would be approximately $520,000 per ton for oil wells and approximately $32,000 per ton for conventional gas wells. In light of the high cost per ton of VOC reduction, we do not consider either of these control options to be BSER for oil wells and conventional wells.

We propose that fracturing (or refracturing) and completion of an existing well (*i.e.,* a well existing prior to August 23, 2011) is considered a modification under CAA section 111(a), because physical change occurs to the existing well, which includes the wellbore, casing and tubing, resulting in an emissions increase during the completion operation. The physical change, in this case, would be caused by the reperforation of the casing and tubing, along with the refracturing of the wellbore. The increased VOC emissions would occur during the flowback period following the fracturing or refracturing operation. Therefore, the proposed

standards for category 1 and category 2 wells would apply to completions at existing fractured or refractured wells.

EPA seeks comment on the 10 percent per year rate of refracturing for natural gas wells assumed in the impacts analysis found in the TSD. EPA has received anecdotal information suggesting that refracturing could be occurring much less frequently, while others suggest that the percent of wells refractured in a given year could be greater. We seek comment and comprehensive data and information on the rate of refracturing and key factors that influence or determine refracturing frequency.

In addition to well completions, we considered VOC emissions occurring at the wellhead affected facility during subsequent day-to-day operations during well production. As discussed below in section VI.B.1.e, VOC emissions from wellheads are very small during production and account for about 2.6 tons VOC per year. We are not aware of any cost effective controls that can be used to address these relatively small emissions.

b. NSPS for Pneumatic Controllers

Pneumatic controllers are automated instruments used for maintaining a process condition, such as liquid level, pressure, pressure differential and temperature. Pneumatic controllers are widely used in the oil and natural gas sector. In many situations across all segments of the oil and gas industry, pneumatic controllers make use of the available high-pressure natural gas to operate. In these ''gas-driven'' pneumatic controllers, natural gas may be released with every valve movement or continuously from the valve control pilot. The rate at which this release occurs is referred to as the device bleed rate. Bleed rates are dependent on the design of the device. Similar designs will have similar steady-state rates when operated under similar conditions. Gas-driven pneumatic controllers are typically characterized as ''high-bleed'' or ''low-bleed,'' where a high-bleed device releases more than 6 standard cubic feet per hour (scfh) of gas, with 18 scfh bleed rate being what we used in our analyses below. There are three basic designs: (1) Continuous bleed devices (high or low-bleed) are used to modulate flow, liquid level or pressure and gas is vented at a steady-state rate; (2) actuating/intermittent devices (high or low-bleed) perform quick control movements and only release gas when they open or close a valve or as they throttle the gas flow; and (3) self-contained devices release gas to a downstream pipeline instead of to the atmosphere. We are not aware of any add-on controls that are or can be used to reduce VOC emissions from gas-driven pneumatic devices.

For an average high-bleed pneumatic controller located in production (where the content of VOC in the raw product stream is relatively high), the difference in VOC emissions between a high-bleed controller and a low-bleed controller is around 1.8 tpy. For the transmission and storage segment (where the content of VOC in the pipeline quality gas is relatively low), the difference in VOC emissions between a high-bleed controller and a low-bleed controller is around 0.89 tpy. We have developed projections that estimate that approximately 13,600 new gas-driven units in the production segment and 67 new gas-driven units in the transmission and storage segment will be installed each year, including replacement of old units. Not all pneumatic controllers are gas driven. These ''non-gas driven'' pneumatic controllers use sources of power other than pressurized natural gas, such as compressed ''instrument air.'' Because these devices are not gas driven, they do not release natural gas or VOC emissions, but they do have energy impacts because electrical power is required to drive the instrument air compressor system. Electrical service of at least 13.3 kilowatts (kW) is required to power a 10 horsepower (hp) instrument air compressor, which is a relatively small capacity compressor. At sites without available electrical service sufficient to power an instrument air compressor, only gas driven pneumatic devices can be used. During our review, we determined that gas processing plants are the only facilities in the oil and natural gas sector highly likely to have electrical service sufficient to power an instrument air system, and that approximately half of existing gas processing plants are using non-gas driven devices.

For devices at gas processing plants, we evaluated the use of non-gas driven controllers and low-bleed controllers as options for reducing VOC emissions, with high-bleed controllers being the baseline. As mentioned above, non-gas driven devices themselves have zero emissions, but they do have energy impacts because electrical power is required to drive the instrument air compressor system. In our cost analysis, we determined that the annualized cost of installing and operating a fully redundant 10 hp (13.3 kW) instrument air system (systems generally are designed with redundancy to allow for system maintenance and failure without loss of air pressure), including duplicate compressors, air tanks and dryers, would be $11,090. A system of this size is capable of serving 15 control loops and reducing VOC emissions by 4.2 tpy, for a cost effectiveness of $2,659 per ton of VOC reduced. If the savings of the salable natural gas that would have been emitted is considered, the value of the gas not emitted would help offset the cost for this control, bringing the cost per ton of VOC down to $1,824.

We also evaluated the use of low-bleed controllers in place of high-bleed controllers at processing plants. We evaluated the impact of bleeding 6 standard cubic feet of natural gas per hour, which is the maximum bleed rate from low-bleed controllers, according to manufacturers of these devices. We chose natural gas as a surrogate for VOC, because manufacturers' technical specifications for pneumatic controllers are stated in terms of natural gas bleed rate rather than VOC. The capital cost difference between a new high-bleed controller and a new low-bleed controller is estimated to be $165. Without taking into account the savings due to the natural gas losses avoided, the annual costs are estimated to be around $23 per year, which is a cost of $13 per ton of VOC reduced for the production segment. If the savings of the salable natural gas that would have been emitted is considered, there is a net savings of $1,519 per ton of VOC reduced.

Although the non-gas-driven controller system is more expensive than the low-bleed controller system, it is still reasonably cost-effective. Furthermore, the non-gas-driven controller system achieves a 100-percent VOC reduction in contrast to a 66-percent reduction achieved by a low-bleed controller. Moreover, we believe the collateral emissions from electrical power generation needed to run the compressor are very low. Finally, non-gas-driven pneumatic controllers avoid potentially explosive concentrations of natural gas which can occur as a result of normal bleeding from groups of gas-driven pneumatic controllers located in close proximity, as they often are at gas processing plants. Based on our review described above, we believe that a non-gas-driven controller is BSER for reducing VOC emissions from pneumatic devices at gas processing plants. Accordingly, the proposed standard for pneumatic devices at gas processing plants is a zero VOC emission limit.

For the production (other than processing plants) and transmission and storage segments, where electrical service sufficient to power an instrument air system is likely

unavailable and, therefore, only gas-driven devices can be used, we evaluated the use of low-bleed controllers in place of high-bleed controllers. Just as in our analysis of low-bleed controllers as an option for gas processing plants, we evaluated the impact of bleeding 6 standard cubic feet per minute (scfm) of natural gas per hour contrasted with 18 scfm from a high-bleed unit. Again, the capital cost difference between a new high-bleed controller and a new low-bleed controller is estimated to be $165. Without taking into account the savings due to the natural gas losses avoided, the annual costs are estimated to be around $23 per year, which is a cost of $13 per ton of VOC reduced for the production segment. If the savings of the salable natural gas that would have been emitted is considered, there is a net savings for this control. In the transmission and storage segment, where the VOC content of the vented gas is much lower than in the production segment, the cost effectiveness of a low-bleed pneumatic device is estimated to be around $262 per ton of VOC reduced. However, there are no potential offsetting savings to be realized in the transmission and storage segment, since the operators of transmission and storage stations typically do not own the gas they are handling. Based on our evaluation of the emissions and costs, we believe that low-bleed controllers represent BSER for pneumatic controllers in the production (other than processing plants) and transmission and storage segments. Therefore, for pneumatic devices at these locations, we propose a natural gas bleed rate limit of 6.0 scfh to reflect the VOC limit with the use of a low-bleed controller.

There may be situations where high-bleed controllers and the attendant gas bleed rate greater than 6 cubic feet per hour, are necessary due to functional requirements, such as positive actuation or rapid actuation. An example would be controllers used on large emergency shutdown valves on pipelines entering or exiting compression stations. For such situations, we have provided in the proposed rule an exemption where pneumatic controllers meeting the emission standards discussed above would pose a functional limitation due to their actuation response time or other operating characteristics. We are requesting comments on whether there are other situations that should be considered for this exemption. If you provide such comment, please specify the criteria for such situations that would help assure that only appropriate exemptions are claimed.

The proposed standards would apply to installation of a new pneumatic device (including replacing an existing device with a new device). We consider that a pneumatic device, an apparatus, is an affected facility and each installation is construction subject to the proposed NSPS. See definitions of ''affected facility'' and ''construction'' at 40 CFR 60.2.

c. NSPS for Compressors

There are many locations throughout the oil and natural gas sector where compression of natural gas is required to move it along the pipeline. This is accomplished by compressors powered by combustion turbines, reciprocating internal combustion engines or electric motors. Turbine-powered compressors use a small portion of the natural gas that they compress to fuel the turbine. The turbine operates a centrifugal compressor, which compresses the natural gas for transit through the pipeline. Sometimes an electric motor is used to turn a centrifugal compressor. This type of compressor does not require the use of any of the natural gas from the pipeline, but it does require a substantial source of electricity. Reciprocating spark ignition engines are also used to power many compressors, referred to as reciprocating compressors, since they compress gas using pistons that are driven by the engine. Like combustion turbines, these engines are fueled by natural gas from the pipeline. Both centrifugal and reciprocating compressors are sources of VOC emissions and were evaluated for coverage under the NSPS.

Centrifugal Compressors. Centrifugal compressors require seals around the rotating shaft to minimize gas leakage and fugitive VOC emissions from where the shaft exits the compressor casing. There are two types of seal systems: Wet seal systems and mechanical dry seal systems.

Wet seal systems use oil, which is circulated under high pressure between three or more rings around the compressor shaft, forming a barrier to minimize compressed gas leakage. Very little gas escapes through the oil barrier, but considerable gas is absorbed by the oil. The amount of gas absorbed and entrained by the oil barrier is affected by the operating pressure of the gas being handled; higher operating pressures result in higher absorption of gas into the oil. Seal oil is purged of the absorbed and entrained gas (using heaters, flash tanks and degassing techniques) and recirculated to the seal area for reuse. Gas that is purged from the seal oil is commonly vented to the atmosphere. Degassing of the seal oil emits an average of 47.7 scfm of gas, depending on the operating pressure of the compressor. An uncontrolled wet seal system can emit, on average, approximately 20.5 tpy of VOC during the venting process (production segment) or about 3.5 tpy (transmission and storage segment). We identified two potential control techniques for reducing emissions from degassing of wet seal systems: (1) Routing the gas back to a low pressure fuel stream to be combusted as fuel gas and (2) routing the gas to a flare. We know only of anecdotal, undocumented information on routing of the gas back to a fuel stream and, therefore, were unable to assess costs and cost effectiveness of the first option. Although we do not have specific examples of routing emissions from wet seal degassing to a flare, we were able to estimate the cost, emission reductions and cost effectiveness of the second option using uncontrolled wet seals as a baseline.

Based on the average uncontrolled emissions of wet seal systems discussed above and a flare efficiency of 95 percent, we determined that VOC emission reductions from a wet seal system would be an average of 19.5 tpy (production segment) or 3.3 tpy (transmission and storage segment). Using an annualized cost of flare installation and operation of $103,373, we estimated the incremental cost effectiveness of this option (from uncontrolled wet seals to controlled wet seals using a flare) to be approximately $5,300/ton and $31,000/ton for the production segment and transmission and storage segment, respectively. With this option, there would be secondary air impacts from combustion. However we did not identify any nonair quality or energy impacts associated with this control technique.

Dry seal systems do not use any circulating seal oil. Dry seals operate mechanically under the opposing force created by hydrodynamic grooves and springs. Fugitive emissions occur from dry seals around the compressor shaft. Based on manufacturer studies and engineering design estimates, fugitive emissions from dry seal systems are approximately 6 scfm of gas, depending on the operating pressure of the compressor. A dry seal system can have fugitive emissions of, on average, approximately 2.6 tpy of VOC (production segment) or about 0.4 tpy (transmission and storage segment). We did not identify any control device suitable to capture and control the fugitive emissions from dry seals around the compressor shaft.

Using uncontrolled wet seals as a baseline, we evaluated the reductions and incremental cost effectiveness of dry seal systems. Based on the average fugitive emissions, we determined that VOC emission reductions achieved by dry seal systems compared to uncontrolled wet seal systems would be 18 tpy (production segment) and 3.1 tpy (transmission and storage segment). Combined with an annualized cost of dry seal systems of $10,678, the incremental cost effectiveness compared to uncontrolled wet seal systems would be $595/ton and $3,495/ton for the production segment and transmission and storage segment, respectively. We identified neither nonair quality nor any energy impacts associated with this option.

In performing our analysis, we estimated the incremental cost of a dry seal compressor over that of an equivalent wet seal compressor to be $75,000. This value was obtained from a vendor who represents a large share of the market for centrifugal compressors. However, this number likely represents a conservatively high value because wet seal units have a significant amount of ancillary equipment, namely the seal oil system and, thus, additional capital expenses. Dry seal systems have some ancillary equipment (the seal gas filtration system), but the costs are less than the wet seal oil system. We were not able to directly confirm this assumption with the vendor, however, a search of product literature showed that seal oil systems and seal gas filtration systems are typically listed separate from the basic compressor package. Using available data on the cost of this equipment, it is very likely that the cost of purchasing a dry seal compressor may actually be lower that a wet seal compressor. We seek comment on available cost data of a dry seal versus wet seal compressor, including all ancillary equipment costs.

In light of the above analyses, we propose to determine that dry seal systems are BSER for reducing VOC emissions from centrifugal compressors. We evaluated the possibility of setting a performance standard that reflects the emission limitation achievable through the use of a dry seal system. However, as mentioned above, VOC from centrifugal compressors with dry seals are fugitive emissions from around the compressor shafts. There is no device to capture and control these fugitive emissions, nor can reliable measurement of these emissions be conducted due to difficulty in accessing the leakage area and danger of contacting the shaft rotating at approximately 30,000 revolutions per minute. This not only poses a likely hazard that would destroy test equipment on contact, it poses a safety hazard to personnel, as well. Therefore, pursuant to section 111(h)(2) of the CAA, we are proposing an equipment standard that would require the use of dry seals to limit the VOC emissions from new centrifugal compressors. We consider that a centrifugal compressor, an apparatus, is an affected facility and each installation is construction subject to the proposed NSPS. See definitions of ''affected facility'' and ''construction'' at 40 CFR 60.2. Accordingly, the proposed standard would apply to installation of new centrifugal compressors at new locations, as well as replacement of old compressors.

Although we are proposing to determine dry seal systems to be BSER for centrifugal compressors, we are soliciting comments on the emission reduction potential, cost and any limitations for the option of routing the gas back to a low pressure fuel stream to be combusted as fuel gas. In addition, we solicit comments on whether there are situations or applications where wet seal is the only option, because a dry seal system is infeasible or otherwise inappropriate.

Reciprocating Compressors. Reciprocating compressors in the natural gas industry leak natural gas fugitive VOC during normal operation. The highest volumes of gas loss and fugitive VOC emissions are associated with piston rod packing systems. Packing systems are used to maintain a tight seal around the piston rod, preventing the high pressure gas in the compressor cylinder from leaking, while allowing the rod to move freely. This leakage rate is dependent on a variety of factors, including physical size of the compressor piston rod, operating speed and operating pressure. Under the best conditions, new packing systems properly installed on a smooth, well-aligned shaft can be expected to leak a minimum of 11.5 scfh. Higher leak rates are a consequence of fit, alignment of the packing parts and wear.

We evaluated the possibility of reducing VOC emissions from reciprocal compressors through a control device. However, VOC from reciprocating compressors are fugitive emissions from around the compressor shafts. Although it is possible to construct an enclosure around the rod packing area and vent the emissions outside for safety purposes, connection to a closed vent system and control device would create back pressure on the leaking gas. This back pressure would cause the leaked gas instead to be forced inside the crankcase of the engine, which would dilute lubricating oil, causing premature failure of engine bearings, pose an explosion hazard and eventually be vented from the crankcase breather, defeating the purpose of a control device.

As mentioned above, as packing wears and deteriorates, leak rates can increase. We, therefore, evaluate replacement of compressor rod packing systems as an option for reducing VOC emissions. Conventional bronze-metallic packing rings wear out and need to be replaced every 3 to 5 years, depending on the compressor's rate of usage (*i.e.,* the percentage of time that a compressor is in pressurized mode).

Based on industry experience in the Natural Gas STAR program and other sources, we evaluated the rod packing replacement costs for reciprocating compressors at different segments of this industry. Usage rates vary by segment. Usage rates for compressors at wellheads, gathering/boosting stations, processing plants, transmission stations and storage facilities are 100, 79, 90, 79 and 68 percent, respectively. Reciprocating compressors at wellheads are small and operate at lower pressures, which limit VOC emissions from these sources. Due to the low VOC emissions from these compressors, about 0.044 tpy, combined with an annual cost of approximately $3,700, the cost per ton of VOC reduction is rather high. We estimated that the cost effectiveness of controlling wellhead compressors is over $84,000 per ton of VOC reduced, which we believe to be too high and, therefore, not reasonable. Because the cost effectiveness of replacing packing wellhead compressor rod systems is not reasonable, and absent other emission reduction measures, we did not find a BSER for reducing VOC emissions from reciprocal compressors at wellheads.

For reciprocating compressors located at other oil and gas operations, we estimated that the cost effectiveness of controlling compressor VOC emissions by rod packing replacement would be $870 per ton of VOC for reciprocating compressors at gathering and boosting stations, $270 per ton of VOC for reciprocating compressors at processing stations, $2,800 per ton of VOC for reciprocating compressors at transmission stations and $3,700 per ton of VOC for reciprocating compressors at underground storage facilities. We consider these costs to be reasonable. We did not identify any nonair quality health or environmental impacts or energy impacts associated with rod packing replacement. In light of the above, we propose to determine that such control is the BSER for reducing

VOC emission from compressors at these other oil and gas operations.

Because VOC emitted from reciprocal compressors are fugitive emissions, there is no device to capture and control the emissions. Therefore, pursuant to section 111(h) of the CAA, we are proposing an operational standard. Based on industry experience reported to the Natural Gas STAR program, we determined that packing rods should be replaced every 3 years of operation. However, to account for segments of the industry in which reciprocating compressors operate in pressurized mode a fraction of the calendar year (ranging from approximately 68 percent up to approximately 90 percent), the proposed rule expresses the replacement requirement in terms of hours of operation rather than on a calendar year basis. One year of continuous operation would be 8,760 hours. Three years of continuous operation would be 26,280 hours, or rounded to the nearest thousand, 26,000 hours. Accordingly, the proposed rule would require the replacement of the rod packing every 26,000 hours of operation. The owner or operator would be required to monitor the hours of operation beginning with the installation of the reciprocating compressor affected facility. Cumulative hours of operation would be reported each year in the facility's annual report. Once the hours of operation reached 26,000 hours, the owner or operator would be required to change the rod packing immediately, although unexpected shutdowns could be avoided by tracking hours of operation and planning for packing replacement at scheduled maintenance shutdowns before the hours of operation reached 26,000.

Some industry partners of the Natural Gas STAR program currently conduct periodic testing to determine the leakage rates that would identify economically beneficial replacement of rod packing based on natural gas savings. Therefore, we are soliciting comments on incorporating a method similar to that in the Natural Gas STAR's Lessons Learned document entitled, *Reducing Methane Emissions from Compressor Rod Packing Systems* (*http://www.epa.gov/gasstar/documents/ll_rodpack.pdf*), to be incorporated in the NSPS. We are soliciting comments on how to determine a suitable leak threshold above which rod packing replacement would be cost effective for VOC emission reduction. We are also soliciting comment on the appropriate replacement frequency and other considerations that would be associated with regular replacement periods.

d. NSPS for Storage Vessels

Crude oil, condensate and produced water are typically stored in fixed-roof storage vessels. Some vessels used for storing produced water may be open-top tanks. These vessels, which are operated at or near atmospheric pressure conditions, are typically located as part of a tank battery. A tank battery refers to the collection of process equipment used to separate, treat and store crude oil, condensate, natural gas and produced water. The extracted products from productions wells enter the tank battery through the production header, which may collect product from many wells.

Emissions from storage vessels are a result of working, breathing and flash losses. Working losses occur due to the emptying and filling of storage tanks. Breathing losses are the release of gas associated with daily temperature fluctuations and other equilibrium effects. Flash losses occur when a liquid with dissolved gases is transferred from a vessel with higher pressure to a vessel with lower pressure, thus, allowing dissolved gases and a portion of the liquid to vaporize or flash. In the oil and natural gas production segment, flashing losses occur when live crude oils or condensates flow into a storage tank from a processing vessel operated at a higher pressure. Typically, the larger the pressure drop, the more flash emissions will occur in the storage stage. Temperature of the liquid also influences the amount of flash emissions. The amount of liquid entering the tank during a given time, commonly known as throughput, also affects the emission rate, with higher throughput tanks having higher annual emissions, given that other parameters are the same.

In analyzing controls for storage vessels, we reviewed control techniques identified in the Natural Gas STAR program and state regulations. We identified two ways of controlling storage vessel emissions, both of which can reduce VOC emissions by 95 percent. One option would be to install a vapor recovery unit (VRU) and recover all the vapors from the tanks. The other option would be to route the emissions from the tanks to a flare control device. These devices could be ''candlestick'' flares that are found at gas processing plants or other larger facilities or enclosed combustors which are commonly found at smaller field facilities. We estimated the total annual cost for a VRU to be approximately $18,900/yr and for a flare to be approximately $8,900/yr. Cost effectiveness of these control options depend on the amount of vapor produced by the storage vessels being controlled. A VRU has a potential advantage over flaring, in that it recovers hydrocarbon vapors that potentially can be used as supplemental burner fuel, or the vapors can be condensed and collected as condensate that can be sold. If natural gas is recovered, it can be sold, as well, as long as a gathering line is available to convey the recovered salable gas product to market or to further processing. A VRU also does not have secondary air impacts that flaring does, as described below. However, a VRU cannot be used in all instances. Some conditions that affect the feasibility of VRU are: Availability of electrical service sufficient to power the VRU; fluctuations in vapor loading caused by surges in throughput and flash emissions from the tank; potential for drawing air into condensate tanks causing an explosion hazard; and lack of appropriate destination or use for the vapor recovered.

Like a VRU, a flare control device can also achieve a control efficiency of 95 percent. There are no technical limitations on the use of flares to control vapors from condensate and crude oil tanks. However, flaring has a secondary impact from emissions of NO_X and other pollutants. In light of the technical limitations with the use of a VRU, we are unable to conclude that a VRU is better than flaring. We, therefore, propose to determine that both a VRU and flare are BSER for reducing VOC emission from storage vessels. We propose an NSPS of 95-percent reduction for storage vessels to reflect the level of emission reduction achievable by VRU and flares.

VOC emissions from storage vessels vary significantly, depending on the rate of liquid entering and passing through the vessel (*i.e.,* its throughput), the pressure of the liquid as it enters the atmospheric pressure storage vessel, the liquid's volatility and temperature of the liquid. Some storage vessels have negligible emissions, such as those with very little throughput and/or handling heavy liquids entering at atmospheric pressure. We do not believe that it is cost effective to control these vessels. We believe it is important to control tanks with significant VOC emissions under the proposed NSPS.

In our analysis, we evaluated storage tanks with varying condensate or crude oil throughput. We used emission factors developed for the Texas Environmental Research Consortium in a study that evaluated VOC emissions from crude oil and condensate storage tanks by performing direct

measurements. The study found that the average VOC emission factor for crude oil storage tanks was 1.6 pounds (lb) VOC per barrel of crude oil throughput. The average VOC emission factor for condensate tanks was determined to be 33.3 lb VOC per barrel of condensate throughput. Applying these emission factors and evaluating condensate throughput rates of 0.5, 1, 2 and 5 barrels per day (bpd), we determined that VOC emissions at these condensate throughput rates would be approximately 3, 6, 12 and 30 tpy, respectively. Similarly, we evaluated crude oil throughput rates of 1, 5, 20 and 50 bpd. Based on the Texas study, these crude oil throughput rates would result in VOC emissions of 0.3, 1.5, 5.8 and 14.6 tpy, respectively. We believe that it is important to control tanks with significant VOC emissions. Furthermore, we believe it would be easier and less costly for owners and operators to determine applicability by using a throughput threshold instead of an emissions threshold. As a result of the above analyses, we believe that storage vessels with at least 1 bpd of condensate or 20 bpd of crude oil should be controlled. These throughput rates are equivalent to VOC emissions of approximately 6 tpy. Based on an estimated annual cost of $18,900 for the control device, controlling storage vessels with these condensate or crude oil throughputs would result in a cost effectiveness of $3,150 per ton of VOC reduced.

Based on our evaluation, we propose to determine that both a VRU and flare are BSER for reducing VOC emission from storage vessels with throughput of at least 1 barrel of condensate per day or 20 barrels of crude oil per day. We propose an NSPS of 95-percent reduction for these storage vessels to reflect the level of emission reduction achievable by VRU and flare control devices.

For storage vessels below the throughput levels described above (''small throughput tanks''), for which we do not consider flares or VRU to be cost effective controls, we evaluated other measures to reduce VOC emissions. Standard practices for such tanks include requiring a cover that is well designed, maintained in good condition and kept closed. Crude oil and condensate storage tanks in the oil and natural gas sector are designed to operate at or just slightly above or below atmospheric pressure. Accordingly, they are provided with vents to prevent tank destruction under rapid pressure increases due to flash emissions conditions. Studies by the Natural Gas STAR program and by others have shown that working losses (*i.e.,* those emissions absent flash emission conditions) are very low, approaching zero. During times of flash emissions, tanks are designed such that the flash emissions are released through a vent on the fixed roof of the tank when pressure reaches just a few ounces to prevent pressure buildup and resulting tank damage. At those times, vapor readily escapes through the vent to protect the tank. Tests have shown that open hatches or leaking hatch gaskets have little effect on emissions from uncontrolled tanks due to the functioning roof vent. However, in the case of controlled tanks, the control requirements include provisions for maintaining integrity of the closed vent system that conveys emissions to the control device, including hatches and other tank openings. As a result, hatches are required to be kept closed and gaskets kept in good repair to meet control requirements of controlled storage vessels. Because the measures we evaluated, including maintenance of hatch integrity, do not provide appreciable emission reductions for storage vessels with throughputs under 1 barrel of condensate per day and 21 barrels of crude oil per day, we believe that the control options we evaluated do not reflect BSER for the small throughput tanks and we are not proposing standards for these tanks.

As discussed in section VII of this preamble, we are proposing to amend the NESHAP for oil and natural gas production facilities at 40 CFR part 63, subpart HH to require that all storage vessels at production facilities reduce HAP emissions by 95 percent. Because the controls used to achieve the 95-percent HAP reduction are the same as the proposed BSER for VOC reduction for storage vessels (*i.e.,* VRU and flare), sources that are achieving the 95-percent HAP reduction would also be meeting the proposed NSPS of 95-percent VOC reduction. In light of the above, and to avoid duplicate monitoring, recordkeeping and reporting, we propose that storage vessels subject to the requirements of subpart HH are exempt from the proposed NSPS for storage vessel in 40 CFR part 60, subpart OOOO.

e. NSPS for VOC Equipment Leaks

Equipment leaks are fugitive emissions emanating from valves, pump seals, flanges, compressor seals, pressure relief valves, open-ended lines and other process and operation components. There are several potential reasons for equipment leak emissions. Components such as pumps, valves, pressure relief valves, flanges, agitators and compressors are potential sources that can leak due to seal failure. Other sources, such as open-ended lines and sampling connections may leak for reasons other than faulty seals. In addition, corrosion of welded connections, flanges, and valves may also be a cause of equipment leak emissions. Because of the large number of valves, pumps and other components within an oil and gas production, processing and transmission facility, equipment leak volatile emissions from these components can be significant. Natural gas processing plants, especially those using refrigerated absorption and transmission stations tend to have a large number of components. Equipment leaks from processing plants are addressed in our review of 40 CFR part 60, subpart KKK, which is discussed above in section VI.B.1.

In addition to gas processing plants, these types of equipment also exist at oil and gas production sites and gas transmission and storage facilities. While the number of components at individual transmission and storage facilities is relatively smaller than at processing plants, collectively, there are many components that can result in significant emissions.

Therefore, we evaluated applying NSPS for equipment leaks to facilities in the production segment of the industry, which includes everything from the wellhead to the point that the gas enters the processing plant, transmission pipeline or distribution pipeline. Production facilities can vary significantly in the operations performed and the processes, all of which impact the number of components and potential emissions from leaking equipment and, thus, impact the annual costs related to implementing a LDAR program. We used data collected by the Gas Research Institute to develop model production facilities. Baseline emissions, along with emission reductions and costs of regulatory alternatives, were estimated using these model production facilities. We considered production facilities where separation, storage, compression and other processes occur. These facilities may not have a wellhead on-site, but would be associated with a wellhead. We also evaluated gathering and boosting facilities, where gas and/or oil are collected from a number of wells, then processed and transported downstream to processing plants or transmission stations. We evaluated the impacts at these production facilities with varying number of operations and equipment. We also developed a model plant for the transmission and storage segment using data from the Gas

Research Institute. Details of these evaluations may be found in the TSD in the docket.

For an average production site at or associated with a wellhead, we estimated annual VOC emissions from equipment leaks of around 2.6 tpy. For an average gathering/boosting facility, we estimated the annual VOC emissions from equipment leaks to be around 9.8 tpy. The average transmission and storage facility emits 2.7 tpy of VOC.

For facilities in each non-gas processing plant segment, we evaluated the same four options as we did for gas processing plants in section VI.B.1 above. These four options are as follows: (1) 40 CFR part 60, subpart VVa-level LDAR (which is based on conducting Method 21 monthly, defining ''leak'' at 500 ppm threshold, and adding connectors to the VV list of components to be monitored); (2) monthly optical gas imaging with annual Method 21 check (the alternative work practice for monitoring equipment for leaks at 40 CFR 60.18(g)); (3) monthly optical gas imaging alone; and (4) annual optical gas imaging alone.

For option 1, we evaluated subpart VVa-LDAR as a whole. We also analyzed separately the individual types of components (valves, connectors, pressure relief devices and open-ended lines). Detailed discussions of these component by component analyses are included in the TSD in the docket.

Based on our evaluation, subpart VVa-level LDAR (Option 1) results in more VOC reduction than the subpart VV-level LDAR currently required for gas processing plants, because more leaks are found based on the lower definition of ''leak'' under subpart VVa (10,000 ppm for subpart VV and 500 ppm for subpart VVa). In addition, our evaluation shows that the cost per ton of VOC reduced for subpart VVa level controls is less than the cost per ton of VOC reduced for the less stringent subpart VV level of control. Although the cost of repairing more leaks is higher, the increased VOC control afforded by subpart VVa level controls more than offsets the increased costs.

For the subpart VVa level of control at the average production site associated with a wellhead, average facility-wide cost-effectiveness would be $16,084 per ton of VOC. Component-specific cost-effectiveness ranged from $15,063 per ton of VOC (for valves) to $211,992 per ton of VOC (for pressure relief devices), with connectors and open-ended lines being $74,283 and $180,537 per ton of VOC, respectively. We also looked at component costs for a modified subpart VVa level of control with less frequent monitoring for valves and connectors at production sites associated with a wellhead.[12] The cost-effectiveness for valves was calculated to be $17,828 per ton of VOC by reducing the monitoring frequency from monthly to annually. The cost-effectiveness for connectors was calculated to be $87,277 per ton of VOC by reducing the monitoring frequency from every 4 years to every 8 years after the initial compliance period.

We performed a similar facility-wide and component-specific analysis of option 1 LDAR for gathering and boosting stations. For the subpart VVa level of control at the average gathering and boosting station, facility-wide cost-effectiveness was estimated to be $9,344 per ton of VOC. Component-specific cost-effectiveness ranged from $6,079 per ton of VOC (for valves) to $77,310 per ton of VOC (for open-ended lines), with connectors and pressure relief devices being $23,603 and $72,523 per ton, respectively. For the modified subpart VVa level of control at gathering and boosting stations, cost-effectiveness ranged from $5,221 per ton of VOC (for valves) to $77,310 per ton of VOC (for open-ended lines), with connectors and pressure relief devices being $27,274 and $72,523 per ton, respectively. The modified subpart VVa level controls were more cost-effective than the subpart VVa level controls for valves, but not for connectors. This is due to the low cost of monitoring connectors and the low VOC emissions from leaking connectors.

We also performed a similar analysis of option 1 subpart VVa-level LDAR for gas transmission and storage facilities. For the subpart VVa level of control at the average transmission and storage facility, facility-wide cost-effectiveness was $20,215. Component-specific cost-effectiveness ranged from $24,762 per ton of VOC (for open-ended lines) to $243,525 per ton of VOC (for pressure relief devices), with connectors and valves being $36,527 and $43,111 per ton of VOC, respectively. For the modified subpart VVa level of control at transmission and storage facilities, cost-effectiveness ranged from $24,762 per ton of VOC (for open-ended lines) to $243,525 per ton of VOC (for pressure relief devices), with connectors and valves being $42,140 and $40,593 per ton of VOC, respectively. Again, the modified subpart VVa level controls were more cost-effective for valves and less cost effective for connectors than the subpart VVa level controls. This is due to the low cost of monitoring connectors and the low VOC emissions from leaking connectors.

For each of the non-gas processing segments, we also evaluated monthly optical gas imaging with annual Method 21 check (Option 2). As discussed in secton VI.B.1, we had previously determined that the VOC reductions achieved under this option would be the same as for option 1 subpart VVa-level LDAR. In our evaluation of Option 2, we estimated that a single optical imaging instrument could be used for 160 well sites and 13 gathering and boosting stations, which means that the cost of the purchase or rental of the camera would be spread across 173 facilities.

For production sites, gathering and boosting stations, and transmission and storage facilities, we estimated that option 2 monthly optical gas imaging with annual Method 21 check would have cost-effectiveness of $16,123, $10,095, and $19,715 per ton of VOC, respectively.[13]

The annual costs for option 1 and option 2 leak detection and repair programs for production sites associated with a wellhead, gathering and boosting stations and transmission and storage facilities were higher than those estimated for natural gas processing plants because natural gas processing plant annual costs are based on the incremental cost of implementing subpart VVa-level standards, whereas the other facilities are not currently regulated under an LDAR program. The currently unregulated sites would be required to set up a new LDAR program; perform initial monitoring, tagging, logging and repairing of components; as well as planning and training personnel to implement the new LDAR program.

In addition to options 1 and 2, we evaluated a third option that consisted of monthly optical gas imaging without an annual Method 21 check. Because we were unable to estimate the VOC emissions achieved by an optical imaging program alone, we were unable to estimate the cost-effectiveness of this option. However, we estimated the annual cost of the monthly optical gas imaging LDAR program at production sites, gathering and boosting stations, and transmission and storage facilities to be $37,049, $86,135, and $45,080, respectively, based on camera purchase, or $32,693, $81,780, and $40,629, respectively, based on camera rental.

Finally, we evaluated a fourth option similar to the third option except that the optical gas imaging would be performed annually rather than monthly. For this option, we estimated the annual cost for production sites, gathering and boosting stations, and transmission and storage facilities to be

[13] Because optical gas imaging is used to view several pieces of equipment at a facility at once to survey for leaks, options involving imaging are not amenable to a component by component analysis.

$30,740, $64,416, and $24,031, respectively, based on camera purchase, or $26,341, $60,017, and $19,493, respectively, based on camera rental.

We request comment on the applicability of a leak detection and repair program based solely on the use of optical imaging or other technologies. Of most use to us would be information on the effectiveness of advanced measurement technologies to detect and repair small leaks on the same order or smaller as specified in the VVa equipment leak requirements and the effects of increased frequency of and associated leak detection, recording, and repair practices.

Based on the evaluation described above, we believe that neither option 1 nor option 2 is cost effective for reducing fugitive VOC emissions from equipment leaks at sites, gathering and boosting stations, and transmission and storage facilities. For options 3 and 4, we were unable to estimate their cost effectiveness and, therefore, could not identify either of these two options as BSER for addressing equipment leak of VOC at production facilities associated with wellheads, at gathering and boosting stations or at gas transmission and storage facilities. We are, therefore, not proposing NSPS for addressing VOC emissions from equipment leaks at these facilities.

5. What are the SSM provisions?

The EPA is proposing standards in this rule that apply at all times, including during periods of startup or shutdown, and periods of malfunction. In proposing the standards in this rule, the EPA has taken into account startup and shutdown periods.

The General Provisions in 40 CFR part 60 require facilities to keep records of the occurrence and duration of any startup, shutdown or malfunction (40 CFR 60.7(b)) and either report to the EPA any period of excess emissions that occurs during periods of SSM (40 CFR 60.7(c)(2)) or report that no excess emissions occurred (40 CFR 60.7(c)(4)). Thus, any comments that contend that sources cannot meet the proposed standard during startup and shutdown periods should provide data and other specifics supporting their claim.

Periods of startup, normal operations and shutdown are all predictable and routine aspects of a source's operations. However, by contrast, malfunction is defined as a ''sudden, infrequent, and not reasonably preventable failure of air pollution control and monitoring equipment, process equipment or a process to operate in a normal or usual manner * * *'' (40 CFR 60.2.) The EPA has determined that malfunctions should not be viewed as a distinct operating mode and, therefore, any emissions that occur at such times do not need to be factored into development of CAA section 111 standards. Further, nothing in CAA section 111 or in case law requires that the EPA anticipate and account for the innumerable types of potential malfunction events in setting emission standards. See, *Weyerhaeuser* v *Costle,* 590 F.2d 1011, 1058 (D.C. Cir. 1978) (''In the nature of things, no general limit, individual permit, or even any upset provision can anticipate all upset situations. After a certain point, the transgression of regulatory limits caused by 'uncontrollable acts of third parties,' such as strikes, sabotage, operator intoxication or insanity, and a variety of other eventualities, must be a matter for the administrative exercise of case-by-case enforcement discretion, not for specification in advance by regulation.''), and, therefore, any emissions that occur at such times do not need to be factored into development of CAA section 111 standards.

Further, it is reasonable to interpret CAA section 111 as not requiring the EPA to account for malfunctions in setting emissions standards. For example, we note that CAA section 111 provides that the EPA set standards of performance which reflect the degree of emission limitation achievable through ''the application of the best system of emission reduction'' that the EPA determines is adequately demonstrated. Applying the concept of ''the application of the best system of emission reduction'' to periods during which a source is malfunctioning presents difficulties. The ''application of the best system of emission reduction'' is more appropriately understood to include operating units in such a way as to avoid malfunctions.

Moreover, even if malfunctions were considered a distinct operating mode, we believe it would be impracticable to take malfunctions into account in setting CAA section 111 standards for affected facilities under 40 CFR part 60, subpart OOOO. As noted above, by definition, malfunctions are sudden and unexpected events and it would be difficult to set a standard that takes into account the myriad different types of malfunctions that can occur across all sources in the category. Moreover, malfunctions can vary in frequency, degree and duration, further complicating standard setting.

In the event that a source fails to comply with the applicable CAA section 111 standards as a result of a malfunction event, the EPA would determine an appropriate response 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. The EPA would also consider whether the source's failure to comply with the CAA section 111 standard was, in fact, ''sudden, infrequent, not reasonably preventable'' and was not instead ''caused in part by poor maintenance or careless operation.'' 40 CFR 60.2 (definition of malfunction).

Finally, the EPA recognizes that even equipment that is properly designed and maintained can sometimes fail. Such failure can sometimes cause an exceedance of the relevant emission standard (See, *e.g.,* State Implementation Plans: Policy Regarding Excessive Emissions During Malfunctions, Startup, and Shutdown (September 20, 1999); Policy on Excess Emissions During Startup, Shutdown, Maintenance, and Malfunctions (February 15, 1983)). The EPA is, therefore, proposing to add an affirmative defense to civil penalties for exceedances of emission limits that are caused by malfunctions. See 40 CFR 60.41Da (defining ''affirmative defense'' to mean, in the context of an enforcement proceeding, a response or defense put forward by a defendant, regarding which the defendant has the burden of proof and the merits of which are independently and objectively evaluated in a judicial or administrative proceeding). We also are proposing other regulatory provisions to specify the elements that are necessary to establish this affirmative defense; the source must prove by a preponderance of the evidence that it has met all of the elements set forth in 40 CFR 60.46Da. (See 40 CFR 22.24). These criteria ensure that the affirmative defense is available only where the event that causes an exceedance of the emission limit meets the narrow definition of malfunction in 40 CFR 60.2 (sudden, infrequent, not reasonably preventable and not caused by poor maintenance and or careless operation). For example, to successfully assert the affirmative defense, the source must prove by a preponderance of the evidence that excess emissions ''[w]ere caused by a sudden, infrequent, and unavoidable failure of air pollution control and monitoring equipment, process equipment, or a process to operate in a normal or usual manner * * *'' The criteria also are designed to ensure that steps are taken to correct the

malfunction, to minimize emissions in accordance with 40 CFR 60.40Da and to prevent future malfunctions. For example, the source would have to prove by a preponderance of the evidence that ''[r]epairs were made as expeditiously as possible when the applicable emission limitations were being exceeded * * *'' and that ''[a]ll possible steps were taken to minimize the impact of the excess emissions on ambient air quality, the environment and human health * * *'' In any judicial or administrative proceeding, the Administrator may challenge the assertion of the affirmative defense and, if the respondent has not met the burden of proving all of the requirements in the affirmative defense, appropriate penalties may be assessed in accordance with CAA section 113 (see also 40 CFR part 22.77).

VII. Rationale for Proposed Action for NESHAP

A. What data were used for the NESHAP analyses?

To perform the technology review and residual risk analysis for the two NESHAP, we created a comprehensive dataset (*i.e.,* the MACT dataset). This dataset was based on the EPA's 2005 National Emissions Inventory (NEI). The NEI database contains information about sources that emit criteria air pollutants and their precursors and HAP. The database includes estimates of annual air pollutant emissions from point, nonpoint and mobile sources in the 50 states, the District of Columbia, Puerto Rico and the Virgin Islands. The EPA collects information about sources and releases an updated version of the NEI database every 3 years.

The NEI database is compiled from these primary sources:

- Emissions inventories compiled by state and local environmental agencies
- Databases related to the EPA's MACT programs
- Toxics Release Inventory data
- For electric generating units, the EPA's Emission Tracking System/ CEM data and United States Department of Energy (DOE) fuel use data
- For onroad sources, the United States Federal Highway Administration's estimate of vehicle miles traveled and emission factors from the EPA's MOBILE computer model
- For nonroad sources, the EPA's NONROAD computer model
- Emissions inventories from previous years, if states do not submit current data

To concentrate on only records pertaining to the oil and natural gas industry sector, data were extracted using two criteria. First, we specified that all facilities containing codes identifying the Oil and Natural Gas Production and the Natural Gas Transmission and Storage MACT source categories (MACT codes 0501 and 0504, respectively). Second, we extracted facilities identified with the following NAICS codes: 211 * * * (Oil and Gas Extraction), 221210 (Natural Gas Distribution), 4861 * * * (Pipeline Transportation of Crude Oil), and 4862 * * * (Pipeline Transportation of Natural Gas). Once the data were extracted, we reviewed the Source Classification Codes (SCC) to assess whether there were any records included in the dataset that were clearly not a part of the oil and natural gas sector. Our review of the SCC also included assigning each SCC to an ''Emission Process Group'' that represents emission point types within the oil and natural gas sector.

Since these MACT standards only apply to major sources, only facilities designated as major sources in the NEI were extracted. In the NEI, sources are identified as major if the facility-wide emissions are greater than 10 tpy for any single HAP or 25 tpy for any combination of HAP. We believe that this may overestimate the number of major sources in the oil and natural gas sector because it does not take into account the limitations set forth in the CAA regarding aggregation of emissions from wells and associated equipment in determining major source status.

The final dataset contained a total of 1,311 major sources in the oil and natural gas sector; 990 in Oil and Natural Gas Production, and 321 in Natural Gas Transmission and Storage. To assess how representative this number of facilities was, we obtained information on the number of subject facilities for both MACT standards from the Enforcement and Compliance History Online (ECHO) database. The ECHO database is a web-based tool (*http://www.epa-echo.gov/echo/index.html*) that provides public access to compliance and enforcement information for approximately 800,000 EPA-regulated facilities. The ECHO database allows users to find permit, inspection, violation, enforcement action and penalty information covering the past 3 years. The site includes facilities regulated as CAA stationary sources, as well as Clean Water Act direct dischargers, and Resource Conservation and Recovery Act hazardous waste generators/handlers. The data in the ECHO database are updated monthly.

We performed a query on the ECHO database requesting records for major sources, with NAICS codes 211*, 221210, 4861* and 4862*, with information for MACT. The ECHO database query identified records for a total of 555 facilities, 269 in the Oil and Natural Gas Production source category (NAICS 211* and 221210) and 286 in the Natural Gas Transmission and Storage source category (NAICS 4861* and 4862*). This comparison leads us to conclude that, for the Natural Gas Transmission and Storage segment, the NEI database is representative of the number of sources subject to the rule. For the Oil and Natural Gas Production source category, it confirms our assumption that the NEI dataset contains more facilities than are subject to the rule. However, this provides a conservative overestimate of the number of sources, which we believe is appropriate for our risk analyses.

We are requesting that the public provide a detailed review of the information in this dataset and provide comments and updated information where appropriate. Section X of this preamble provides an explanation of how to provide updated information for these datasets.

B. What are the proposed decisions regarding certain unregulated emissions sources?

In addition to actions relative to the technology review and risk reviews discussed below, we are proposing, pursuant to CAA sections 112(d)(2) and (3), MACT standards for glycol dehydrators and storage vessels for which standards were not previously developed. We are also proposing changes that affect the definition of ''associated equipment'' which could apply these MACT standards to previously unregulated sources.

1. Glycol Dehydrators

Once natural gas has been separated from any liquid materials or products (*e.g.,* crude oil, condensate or produced water), residual entrained water is removed from the natural gas by dehydration. Dehydration is necessary because water vapor may form hydrates, which are ice-like structures, and can cause corrosion in or plug equipment lines. The most widely used natural gas dehydration processes are glycol dehydration and solid desiccant dehydration. Solid desiccant dehydration, which is typically only used for lower throughputs, uses adsorption to remove water and is not a source of HAP emissions.

Glycol dehydration is an absorption process in which a liquid absorbent, glycol, directly contacts the natural gas stream and absorbs any entrained water vapor in a contact tower or absorption column. The majority of glycol dehydration units use triethylene glycol as the absorbent, but ethylene glycol and diethylene glycol are also used. The rich glycol, which has absorbed water vapor from the natural gas stream, leaves the bottom of the absorption column and is directed either to (1) a gas condensate glycol (GCG) separator (flash tank) and then a reboiler or (2) directly to a reboiler where the water is boiled off of the rich glycol. The regenerated glycol (lean glycol) is circulated, by pump, into the absorption tower. The vapor generated in the reboiler is directed to the reboiler vent.

The reboiler vent is a source of HAP emissions. In the glycol contact tower, glycol not only absorbs water, but also absorbs selected hydrocarbons, including BTEX and n-hexane. The hydrocarbons are boiled off along with the water in the reboiler and vented to the atmosphere or to a control device. The most commonly used control device is a condenser. Condensers not only reduce emissions, but also recover condensable hydrocarbon vapors that can be recovered and sold. In addition, the dry non-condensable off-gas from the condenser may be used as fuel or recycled into the production process or directed to a flare, incinerator or other combustion device.

If present, the GCG separator (flash tank) is also a potential source of HAP emissions. Some glycol dehydration units use flash tanks prior to the reboiler to separate entrained gases, primarily methane and ethane from the glycol. The flash tank off-gases are typically recovered as fuel or recycled to the natural gas production header. However, the flash tank may also be vented directly to the atmosphere. Flash tanks typically enhance the reboiler condenser's emission reduction efficiency by reducing the concentration of non-condensable gases present in the stream prior to being introduced into the condenser.

In the development of the MACT standards for the two oil and natural gas source categories, the EPA created two subcategories of glycol dehydrators based on actual annual average natural gas flowrate and actual average benzene emissions. Under 40 CFR part 63, subpart HH, (the Oil and Natural Gas Production NESHAP), the EPA established MACT standards for glycol dehydration units with an actual annual average natural gas flowrate greater than or equal to 85,000 scmd and actual average benzene emissions greater than or equal to 0.90 Mg/yr (40 CFR 63.765(a)). The EPA did not establish standards for the other subcategory, which consists of glycol dehydration units that are below the flowrate and emission thresholds specified in subpart HH. Similarly, under 40 CFR part 63, subpart HHH (the Natural Gas Transmission and Storage NESHAP), the EPA established MACT standards for the subcategory of glycol dehydration units with an actual annual average natural gas flowrate greater than or equal to 283,000 scmd and actual average benzene emissions greater than or equal to 0.90 Mg/yr, but did not establish standards for the other subcategory, which consists of glycol dehydration units that are below the flowrate and emission thresholds specified in subpart HHH. As mentioned above, we refer to these unregulated dehydration units in both subparts HH and HHH as ''small dehydrators'' in this proposed rule.

The EPA is proposing emission standards for these subcategories of small dehydrators (*i.e.,* those dehydrators with an actual annual average natural gas flowrate less than 85,000 scmd at production sites or 283,000 scmd at natural gas transmission and storage sites, or actual average benzene emissions less than 0.9 Mg/yr). Because we do not have any new emissions data concerning these emission points, we evaluated the dataset collected from industry during the development of the original MACT standards (legacy docket A–94–04, item II–B–01, disk 1 for oil and natural gas production facilities; and items IV–G–24, 26, 27, 30 and 31 for natural gas transmission and storage facilities). We believe this dataset is representative of currently operating glycol dehydrators because it contains information for a varied group of sources (*i.e.,* units owned by different companies, located in different states, representing a range of gas compositions and emission controls) and that the processes have not changed significantly since the data were collected.

In the Oil and Natural Gas Production source category, there were 91 glycol dehydration units with throughput and emissions data identified that would be classified as small glycol dehydration units. We evaluated the possibility of establishing a MACT floor as a Mg/yr limit. However, due to variability of gas throughput and inlet gas composition, we could not properly identify the best performing units by only considering emissions. To allow us to normalize the emissions for a more accurate determination of the best performing sources, we created an emission factor in terms of grams BTEX/scm-ppmv for each facility. The emission factor reflects the facility's emission level, taking into consideration its natural gas throughput and inlet natural gas BTEX concentration. To determine the MACT floor for the existing dehydrators, we ranked each unit from lowest to highest, based on their emission factor, to determine the facilities in the top 12 percent of the dataset. The MACT floor was an emission factor of 1.10×10^{-4} grams BTEX/scm-ppmv. To meet this level of emissions, we anticipate that sources will use a variety of options, including, but not limited to, routing emissions to a condenser or to a combustion device.

We also considered beyond-the-floor options for the existing sources, as required by section 112(d)(2) of the CAA. To achieve further reductions beyond the MACT floor level of control, sources would have to install an additional add-on control device, most likely a combustion device. Assuming the MACT floor control device is a combustion device, which generally achieves at least a 95-percent HAP reduction, then less than 5 percent of the initial HAP emissions remain. Installing a second device would involve the same costs as the first control, but would only achieve 1/20 of the reduction (*i.e.,* reducing the remaining 5 percent by another 95 percent represents a 4.49-percent reduction of the initial, uncontrolled emissions, which is 1/20 of the 95-percent reduction achieved with the first control). Based on the $8,360/Mg cost effectiveness of the floor level of control, we estimate that the incremental cost effectiveness of the second control to be $167,200/Mg. We do not believe this cost to be reasonable given the level of emission reduction. We are, therefore, proposing an emission standard for existing small dehydrators that reflects the MACT floor.

For new small glycol dehydrators in the Oil and Natural Gas Production source category, based on our performance ranking, the best performing source has an emission factor of 4.66×10^{-6} grams BTEX/scm-ppmv. To meet this level of emissions, we anticipate that sources will use a variety of options, including, but not limited to, routing emissions to a condenser or to a combustion device. The consideration of beyond-the-floor options for new small dehydrators would be the same as for existing small dehydrators, and, as stated above, we do not believe a cost of $167,200/Mg to be reasonable given the level of emission

reduction. We are, therefore, proposing a MACT standard for new small dehydrators that reflects the MACT floor level of control.

Under our proposal, a small dehydrator's actual MACT emission limit would be determined by multiplying the MACT floor emission factor in g BTEX/scm-ppmv by its unit-specific incoming natural gas throughput and BTEX concentration for the dehydrator. A formula is provided in 40 CFR 63.765(b)(1)(iii) to calculate the MACT limit as an annual value.

In the Natural Gas Transmission and Storage source category, there were 16 facilities for which throughput and emissions data were available that would be classified as small glycol dehydration units. Since the number of units was less than 30, the MACT floor for existing sources was based on the top five performing units. Using the same emission factor concept, we determined that the MACT floor for existing sources is an emission factor equal to 6.42×10^{-5} grams BTEX/scm-ppmv. To meet this level of emissions, we anticipate that sources will use a variety of options, including, but not limited to, routing emissions to a condenser or to a combustion device.

We also considered beyond-the-floor options for the existing small dehydrators as required by section 112(d)(2) of the CAA. To achieve further reductions beyond the MACT floor level of control, sources would have to install an additional add-on control device, most likely a combustion device. Assuming the MACT floor control device is a combustion device, which generally achieves at least a 95-percent HAP reduction, then less than 5 percent of the initial HAP emissions remain. Installing a second device would involve the same costs as the first control device, but would only achieve 1/20 of the reduction (*i.e.,* reducing the remaining 5 percent by another 95 percent represents a 4.49-percent reduction of the initial, uncontrolled emissions, which is 1/20 of the 95-percent reduction achieved with the first control). Based on the $1,650/Mg cost effectiveness of the floor level of control, we estimate that the incremental cost effectiveness of the second control to be $33,000/Mg. We do not believe this cost to be reasonable given the level of emission reduction. We are, therefore, proposing an emission standard for existing small dehydrators that reflects the MACT floor.

For new small glycol dehydrators, based on our performance ranking, the best performing source has an emission factor of 1.10×10^{-5} grams BTEX/scm-ppmv. To meet this level of emissions, we anticipate that sources will use a variety of options, including, but not limited to, routing emissions to a condenser or to a combustion device. The consideration of beyond-the-floor options for new small dehydrators would be the same as for existing small dehydrators, and, as stated above, we do not believe a cost of $33,000/Mg to be reasonable given the level of emission reduction. We are, therefore, proposing an emission standard for new sources that reflects the MACT floor level of control.

Under our proposal, a source's actual MACT emissions limit would be determined by multiplying this emission factor by their unit-specific incoming natural gas throughput and BTEX concentration for the dehydrator. A formula is provided in 40 CFR 63.1275(b)(1)(iii) to calculate the limit as an annual value.

As discussed below, we are proposing that, with the removal of the 1-ton alternative compliance option from the existing standards for glycol dehydrators, the MACT for these two source categories would provide an ample margin of safety to protect public health. We, therefore, maintain that, after the implementation of the small dehydrator standards discussed above, these MACT will continue to provide an ample margin of safety to protect public health. Consequently, we do not believe it will be necessary to conduct another residual risk review under CAA section 112(f) for these two source categories 8 years following promulgation of the small dehydrator standards merely due to the addition of these new MACT requirements.

2. Storage Vessels

Crude oil, condensate and produced water are typically stored in fixed-roof storage vessels. Some vessels used for storing produced water may be open-top tanks. These vessels, which are operated at or near atmospheric pressure conditions, are typically located at tank batteries. A tank battery refers to the collection of process components used to separate, treat and store crude oil, condensate, natural gas and produced water. The extracted products from productions wells enter the tank battery through the production header, which may collect product from many wells.

Emissions from storage vessels are a result of working, breathing and flash losses. Working losses occur due to the emptying and filling of storage tanks. Breathing losses are the release of gas associated with daily temperature fluctuations and other equilibrium effects. Flash losses occur when a liquid with entrained gases is transferred from a vessel with higher pressure to a vessel with lower pressure, thus, allowing entrained gases or a portion of the liquid to vaporize or flash. In the oil and natural gas production segment, flashing losses occur when live crude oils or condensates flow into a storage tank from a processing vessel operated at a higher pressure. Typically, the larger the pressure drop, the more flashing emission will occur in the storage stage. Temperature of the liquid may also influence the amount of flash emissions.

In the Oil and Natural Gas Production NESHAP (40 CFR part 63, subpart HH), the MACT standards for storage vessels apply only to those with the PFE. Storage vessels with the PFE are defined as storage vessels that contain hydrocarbon liquids that meet the following criteria:

- A stock tank gas to oil ratio (GOR) greater than or equal to 0.31 cubic meters per liter (m^3/liter); and
- An American Petroleum Institute (API) gravity greater than or equal to 40 degrees; and
- An actual annual average hydrocarbon liquid throughput greater than or equal to 79,500 liters per day (liter/day).

Accordingly, there is no emission limit in the existing MACT for storage vessels without the PFE. However, the MACT analysis performed at the time indicates that the MACT floor was based on all storage vessels, not just those vessels with flash emissions. See, *Recommendation of MACT Floor Levels for HAP Emission Points at Major Sources in the Oil and Natural Gas Production Source Category,* (September 23, 1997, Docket A–94–04, Item II–A–07). We, therefore, propose to apply the existing MACT for storage vessels with PFE to all storage vessels (*i.e.,* storage vessels with the PFE, as well as those without the PFE).

3. Definition of Associated Equipment

CAA section 112(n)(4)(A) provides:

> Notwithstanding the provisions of subsection (a), emissions from any oil or gas exploration or production well (with its associated equipment) and emission from any pipeline compressor or pump station shall not be aggregated with emissions from other similar units, whether or not such units are in contiguous area or under common control, to determine whether such units or stations are major sources.

As stated above, the CAA prevents aggregation of HAP emissions from wells and associated equipment in making major source determinations. In the absence of clear guidance in the statute on what constitutes ''associated equipment,'' the EPA sought to define

''associated equipment'' in a way that recognizes the need to implement relief for this industry as Congress intended and that also allow for the appropriate regulation of significant emission points. 64 FR at 32619. Accordingly, in the existing Oil and Natural Gas Production NESHAP (1998 and 1999 NESHAP), the EPA defined ''associated equipment'' to exclude glycol dehydration units and storage vessels with PFE (thus allowing their emissions to be included in determining major source status) because EPA identified these sources as substantial contributors to HAP emissions. *Id.* EPA explained in that NESHAP that, because a single storage vessel with flash emissions may emit several Mg of HAP per year and individual glycol dehydrators may emit above the major source level, storage vessels with PFE and glycol dehydrators are large individual sources of HAP, 63 FR 6288, 6301 (1998). The EPA therefore considered these emission sources substantial contributors to HAP emissions and excluded them from the definition of ''associated equipment.'' 64 FR at 32619. We have recently examined HAP emissions from storage vessels without flash emissions and found that these emissions are significant and comparable to those vessels with flash emissions. For example, one storage vessel with an API gravity of 30 degrees and a GOR of 2.09 $\times 10^{-3}$ m^3/liter with a throughput of 79,500 liter/day had HAP emissions of 9.91 Mg/yr, including 9.45 Mg/yr of n-hexane.

Because storage vessels without the PFE can have significant emissions at levels that are comparable to emissions from storage vessels with the PFE, there is no appreciable difference between storage vessels with the PFE and those without the PFE for purposes of defining ''associated equipment.'' We are, therefore, proposing to amend the associated equipment definition to exclude all storage vessels and not just storage vessels with the PFE.

C. How did we perform the risk assessment and what are the results and proposed decisions?

1. How did we estimate risks posed by the source categories?

The EPA conducted risk assessments that provided estimates for each source in a category of the MIR posed by the HAP emissions, the HI for chronic exposures to HAP with the potential to cause noncancer health effects, and the hazard quotient (HQ) for acute exposures to HAP with the potential to cause noncancer health effects. The assessments also provided estimates of the distribution of cancer risks within the exposed populations, cancer incidence and an evaluation of the potential for adverse environmental effects for each source category. The risk assessments consisted of seven primary steps, as discussed below. The docket for this rulemaking contains the following document which provides more information on the risk assessment inputs and models: *Draft Residual Risk Assessment for the Oil and Gas Production and Natural Gas Transmission and Storage Source Categories.* The methods used to assess risks (as described in the seven primary steps below) are consistent with those peer-reviewed by a panel of the EPA's Science Advisory Board (SAB) in 2009 and described in their peer review report issued in 2010 [14]; they are also consistent with the key recommendations contained in that report.

a. Establishing the Nature and Magnitude of Actual Emissions and Identifying the Emissions Release Characteristics

As discussed in section VII.A of this preamble, we used a dataset based on the 2005 NEI as the basis for the risk assessment. In addition to the quality assurance (QA) of the facilities contained in the dataset, we also checked the coordinates of every facility in the dataset through visual observations using tools such as GoogleEarth and ArcView. Where coordinates were found to be incorrect, we identified and corrected them to the extent possible. We also performed QA of the emissions data and release characteristics to ensure there were no outliers.

b. Establishing the Relationship Between Actual Emissions and MACT-Allowable Emissions Levels

The available emissions data in the MACT dataset represent the estimates of mass of emissions actually emitted during the specified annual time period. These ''actual'' emission levels are often lower than the emission levels that a facility might be allowed to emit and still comply with the MACT standards. The emissions level allowed to be emitted by the MACT standards is referred to as the ''MACT-allowable'' emissions level. This represents the highest emissions level that could be emitted by the facility without violating the MACT standards.

We discussed the use of both MACT-allowable and actual emissions in the final Coke Oven Batteries residual risk rule (70 FR 19998–19999, April 15, 2005) and in the proposed and final Hazardous Organic NESHAP residual risk rules (71 FR 34428, June 14, 2006, and 71 FR 76609, December 21, 2006, respectively). In those previous actions, we noted that assessing the risks at the MACT-allowable level is inherently reasonable since these risks reflect the maximum level sources could emit and still comply with national emission standards. But we also explained that it is reasonable to consider actual emissions, where such data are available, in both steps of the risk analysis, in accordance with the Benzene NESHAP. (54 FR 38044, September 14, 1989.)

To estimate emissions at the MACT-allowable level, we developed a ratio of MACT-allowable to actual emissions for each emissions source type in each source category, based on the level of control required by the MACT standards compared to the level of reported actual emissions and available information on the level of control achieved by the emissions controls in use.

c. Conducting Dispersion Modeling, Determining Inhalation Exposures and Estimating Individual and Population Inhalation Risks

Both long-term and short-term inhalation exposure concentrations and health risks from each source in the source categories addressed in this proposal were estimated using the Human Exposure Model (HEM) (Community and Sector HEM–3 version 1.1.0). The HEM–3 performs three primary risk assessment activities: (1) Conducting dispersion modeling to estimate the concentrations of HAP in ambient air, (2) estimating long-term and short-term inhalation exposures to individuals residing within 50 km of the modeled sources and (3) estimating individual and population-level inhalation risks using the exposure estimates and quantitative dose-response information.

The dispersion model used by HEM–3 is AERMOD, which is one of the EPA's preferred models for assessing pollutant concentrations from industrial facilities.[15] To perform the dispersion modeling and to develop the preliminary risk estimates, HEM–3 draws on three data libraries. The first is a library of meteorological data,

[14] U.S. EPA SAB. *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,* May 2010.

[15] U.S. EPA. Revision to the *Guideline on Air Quality Models: Adoption of a Preferred General Purpose (Flat and Complex Terrain) Dispersion Model and Other Revisions* (70 FR 68218, November 9, 2005).

which is used for dispersion calculations. This library includes 1 year of hourly surface and upper air observations for more than 158 meteorological stations, selected to provide coverage of the United States and Puerto Rico. A second library of United States Census Bureau census block[16] internal point locations and populations provides the basis of human exposure calculations (Census, 2000). In addition, for each census block, the census library includes the elevation and controlling hill height, which are also used in dispersion calculations. A third library of pollutant unit risk factors and other health benchmarks is used to estimate health risks. These risk factors and health benchmarks are the latest values recommended by the EPA for HAP and other toxic air pollutants. These values are available at *http://www.epa.gov/ttn/atw/toxsource/summary.html* and are discussed in more detail later in this section.

In developing the risk assessment for chronic exposures, we used the estimated annual average ambient air concentration of each of the HAP emitted by each source for which we have emissions data in the source category. The air concentrations at each nearby census block centroid were used as a surrogate for the chronic inhalation exposure concentration for all the people who reside in that census block. We calculated the MIR for each facility as the cancer risk associated with a continuous lifetime (24 hours per day, 7 days per week, and 52 weeks per year for a 70-year period) exposure to the maximum concentration at the centroid of an inhabited census block. Individual cancer risks were calculated by multiplying the estimated lifetime exposure to the ambient concentration of each of the HAP (in micrograms per cubic meter) by its unit risk estimate (URE), which is an upper bound estimate of an individual's probability of contracting cancer over a lifetime of exposure to a concentration of 1 microgram of the pollutant per cubic meter of air. For residual risk assessments, we generally use URE values from the EPA's Integrated Risk Information System (IRIS). For carcinogenic pollutants without the EPA IRIS values, we look to other reputable sources of cancer dose-response values, often using California EPA (CalEPA) URE values, where available. In cases where new, scientifically credible dose-response values have been developed in a manner consistent with the EPA guidelines and have undergone a peer review process similar to that used by the EPA, we may use such dose-response values in place of or in addition to other values, if appropriate.

Formaldehyde is a unique case. In 2004, the EPA determined that the Chemical Industry Institute of Toxicology (CIIT) cancer dose-response value for formaldehyde (5.5×10^{-9} per $\mu g/m^3$) was based on better science than the IRIS cancer dose-response value (1.3×10^{-5} per $\mu g/m^3$) and we switched from using the IRIS value to the CIIT value in risk assessments supporting regulatory actions. However, subsequent research published by the EPA suggests that the CIIT model was not appropriate and in 2010 the EPA returned to using the 1991 IRIS value, which is more health protective.[17] The EPA has been working on revising the formaldehyde IRIS assessment and the National Academy of Sciences (NAS) completed its review of the EPA's draft in May of 2011. EPA is reviewing the public comments and the NAS independent scientific peer review, and the draft IRIS assessment will be revised and the final assessment will be posted on the IRIS database. In the interim, we will present findings using the 1991 IRIS value as a primary estimate, and may also consider other information as the science evolves.

In the case of benzene, the high end of the reported cancer URE range 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 higher than use of the equally-plausible low end value. We also evaluated the impact of using the low end of the URE range on our risk results.

We also note that polycyclic organic matter (POM), a carcinogenic HAP with a mutagenic mode of action, is emitted by some of the facilities in these two categories.[18] For this compound group,[19] the age-dependent adjustment factors (ADAF) described in the EPA's *Supplemental Guidance for Assessing Susceptibility from Early-Life Exposure to Carcinogens*[20] were applied. This adjustment has the effect of increasing the estimated lifetime risks for POM by a factor of 1.6. In addition, although only a small fraction of the total POM emissions were not reported as individual compounds, the EPA expresses carcinogenic potency for compounds in this group in terms of benzo[a]pyrene equivalence, based on evidence that carcinogenic POM has the same mutagenic mechanism of action as benzo[a]pyrene. For this reason, the EPA's Science Policy Council[21] recommends applying the *Supplemental Guidance* to all carcinogenic polycyclic aromatic hydrocarbons for which risk estimates are based on relative potency. Accordingly, we have applied the ADAF to the benzo[a]pyrene equivalent portion of all POM mixtures.

Incremental individual lifetime cancer risks associated with emissions from the source category were estimated as the sum of the risks for each of the carcinogenic HAP (including those classified as carcinogenic to humans, likely to be carcinogenic to humans and suggestive evidence of carcinogenic potential[22]) emitted by the modeled source. Cancer incidence and the distribution of individual cancer risks for the population within 50 km of any source were also estimated for the source category as part of these assessments by summing individual risks. A distance of 50 km is consistent with both the analysis supporting the 1989 Benzene NESHAP (54 FR 38044) and the limitations of Gaussian dispersion models, including AERMOD.

To assess risk of noncancer health effects from chronic exposures, we summed the HQ for each of the HAP that affects a common target organ system to obtain the HI for that target organ system (or target organ-specific HI, TOSHI). The HQ for chronic exposures is the estimated chronic

[16] A census block is generally the smallest geographic area for which census statistics are tabulated.

[17] For details on the justification for this decision, see the memorandum in the docket from Peter Preuss to Steve Page entitled, *Recommendation for Formaldehyde Inhalation Cancer Risk Values,* January 22, 2010.

[18] U.S. EPA. Performing risk assessments that include carcinogens described in the *Supplemental Guidance* as having a mutagenic mode of action. *Science Policy Council Cancer Guidelines Implementation Work Group Communication II:* Memo from W.H. Farland, dated October 4, 2005.

[19] See the *Risk Assessment for Source Categories* document available in the docket for a list of HAP with a mutagenic mode of action.

[20] U.S. EPA. *Supplemental Guidance for Assessing Early-Life Exposure to Carcinogens.* EPA/630/R–03/003F, 2005. *http://www.epa.gov/ttn/atw/childrens_supplement_final.pdf.*

[21] U.S. EPA. *Science Policy Council Cancer Guidelines Implementation Workgroup Communication II:* Memo from W.H. Farland, dated June 14, 2006.

[22] These classifications also coincide with the terms ''known carcinogen, probable carcinogen and possible carcinogen,'' respectively, which are the terms advocated in the EPA's previous *Guidelines for Carcinogen Risk Assessment,* published in 1986 (51 FR 33992, September 24, 1986). Summing the risks of these individual compounds to obtain the cumulative cancer risks is an approach that was recommended by the EPA's SAB in their 2002 peer review of EPA's NATA entitled, *NATA—Evaluating the National-scale Air Toxics Assessment 1996 Data—an SAB Advisory,* available at: *http://yosemite.epa.gov/sab/sabproduct.nsf/214C6E915BB04E14852570CA007A682C/$File/ecadv02001.pdf.*

exposure divided by the chronic reference level, which is either the EPA reference concentration (RfC), defined as ''an estimate (with uncertainty spanning perhaps an order of magnitude) of a continuous inhalation exposure to the human population (including sensitive subgroups) that is likely to be without an appreciable risk of deleterious effects during a lifetime,'' or, in cases where an RfC from the EPA's IRIS database is not available, the EPA will utilize the following prioritized sources for our chronic dose-response values: (1) The Agency for Toxic Substances and Disease Registry Minimum Risk Level, which is defined as ''an estimate of daily human exposure to a substance that is likely to be without an appreciable risk of adverse effects (other than cancer) over a specified duration of exposure''; (2) the CalEPA Chronic Reference Exposure Level (REL), which is defined as ''the concentration level at or below which no adverse health effects are anticipated for a specified exposure duration''; and (3), as noted above, in cases where scientifically credible dose-response values have been developed in a manner consistent with the EPA guidelines and have undergone a peer review process similar to that used by the EPA, we may use those dose-response values in place of or in concert with other values.

Screening estimates of acute exposures and risks were also evaluated for each of the HAP at the point of highest off-site exposure for each facility (*i.e.,* not just the census block centroids), assuming that a person is located at this spot at a time when both the peak (hourly) emission rate and worst-case dispersion conditions (1991 calendar year data) occur. The acute HQ is the estimated acute exposure divided by the acute dose-response value. In each case, acute HQ values were calculated using best available, short-term dose-response values. These acute dose-response values, which are described below, include the acute REL, acute exposure guideline levels (AEGL) and emergency response planning guidelines (ERPG) for 1-hour exposure durations. As discussed below, we used conservative assumptions for emission rates, meteorology and exposure location for our acute analysis.

As described in the CalEPA's *Air Toxics Hot Spots Program Risk Assessment Guidelines, Part I, The Determination of Acute Reference Exposure Levels for Airborne Toxicants,* an acute REL value (*http://www.oehha.ca.gov/air/pdf/acuterel.pdf*) is defined as ''the concentration level at or below which no adverse health effects are anticipated for a specified exposure duration.'' Acute REL values are based on the most sensitive, relevant, adverse health effect reported in the medical and toxicological literature. Acute REL values are designed to protect the most sensitive individuals in the population by the inclusion of margins of safety. Since margins of safety are incorporated to address data gaps and uncertainties, exceeding the acute REL does not automatically indicate an adverse health impact.

AEGL values were derived in response to recommendations from the National Research Council (NRC). As described in *Standing Operating Procedures (SOP) of the National Advisory Committee on Acute Exposure Guideline Levels for Hazardous Substances (http://www.epa.gov/opptintr/aegl/pubs/sop.pdf),*[23] ''the NRC's previous name for acute exposure levels—community emergency exposure levels—was replaced by the term AEGL to reflect the broad application of these values to planning, response, and prevention in the community, the workplace, transportation, the military, and the remediation of Superfund sites.'' This document also states that AEGL values ''represent threshold exposure limits for the general public and are applicable to emergency exposures ranging from 10 minutes to eight hours.'' The document lays out the purpose and objectives of AEGL by stating (page 21) that ''the primary purpose of the AEGL program and the National Advisory Committee for Acute Exposure Guideline Levels for Hazardous Substances is to develop guideline levels for once-in-a-lifetime, short-term exposures to airborne concentrations of acutely toxic, high-priority chemicals.'' In detailing the intended application of AEGL values, the document states (page 31) that ''[i]t is anticipated that the AEGL values will be used for regulatory and nonregulatory purposes by U.S. Federal and state agencies and possibly the international community in conjunction with chemical emergency response, planning, and prevention programs. More specifically, the AEGL values will be used for conducting various risk assessments to aid in the development of emergency preparedness and prevention plans, as well as real-time emergency response actions, for accidental chemical releases at fixed facilities and from transport carriers.''

The AEGL–1 value is then specifically defined as ''the airborne concentration of a substance above which it is predicted that the general population, including susceptible individuals, could experience notable discomfort, irritation, or certain asymptomatic nonsensory effects. However, the effects are not disabling and are transient and reversible upon cessation of exposure.'' The document also notes (page 3) that, ''Airborne concentrations below AEGL–1 represent exposure levels that can produce mild and progressively increasing but transient and nondisabling odor, taste, and sensory irritation or certain asymptomatic, nonsensory effects.'' Similarly, the document defines AEGL–2 values as ''the airborne concentration (expressed as ppm or mg/m^3) of a substance above which it is predicted that the general population, including susceptible individuals, could experience irreversible or other serious, long-lasting adverse health effects or an impaired ability to escape.''

ERPG values are derived for use in emergency response, as described in the American Industrial Hygiene Association's document entitled, *Emergency Response Planning Guidelines (ERPG) Procedures and Responsibilities* (*http://www.aiha.org/1documents/committees/ERPSOPs2006.pdf*) which states that, ''Emergency Response Planning Guidelines were developed for emergency planning and are intended as health based guideline concentrations for single exposures to chemicals.'' [24] The ERPG–1 value is defined as ''the maximum airborne concentration below which it is believed that nearly all individuals could be exposed for up to 1 hour without experiencing other than mild transient adverse health effects or without perceiving a clearly defined, objectionable odor.'' Similarly, the ERPG–2 value is defined as ''the maximum airborne concentration below which it is believed that nearly all individuals could be exposed for up to 1 hour without experiencing or developing irreversible or other serious health effects or symptoms which could impair an individual's ability to take protective action.''

As can be seen from the definitions above, the AEGL and ERPG values include the similarly-defined severity levels 1 and 2. For many chemicals, a severity level 1 value AEGL or ERPG has not been developed; in these instances, higher severity level AEGL–2 or ERPG–2 values are compared to our modeled

[23] NAS, 2001. *Standing Operating Procedures for Developing Acute Exposure Levels for Hazardous Chemicals,* page 2.

[24] *ERP Committee Procedures and Responsibilities.* November 1, 2006. American Industrial Hygiene Association.

exposure levels to screen for potential acute concerns.

Acute REL values for 1-hour exposure durations are typically lower than their corresponding AEGL–1 and ERPG–1 values. Even though their definitions are slightly different, AEGL–1 values are often the same as the corresponding ERPG–1 values, and AEGL–2 values are often equal to ERPG–2 values. Maximum HQ values from our acute screening risk assessments typically result when basing them on the acute REL value for a particular pollutant. In cases where our maximum acute HQ value exceeds 1, we also report the HQ value based on the next highest acute dose-response value (usually the AEGL–1 and/or the ERPG–1 value).

To develop screening estimates of acute exposures, we developed estimates of maximum hourly emission rates by multiplying the average actual annual hourly emission rates by a factor to cover routinely variable emissions. We chose the factor based on process knowledge and engineering judgment and with awareness of a Texas study of short-term emissions variability, which showed that most peak emission events, in a heavily-industrialized 4-county area (Harris, Galveston, Chambers and Brazoria Counties, Texas) were less than twice the annual average hourly emission rate. The highest peak emission event was 74 times the annual average hourly emission rate, and the 99th percentile ratio of peak hourly emission rate to the annual average hourly emission rate was 9.[25] This analysis is provided in Appendix 4 of the *Draft Residual Risk Assessment for the Oil and Gas Production and Natural Gas Transmission and Storage Source Categories,* which is available in the docket for this action. Considering this analysis, unless specific process knowledge or data are available to provide an alternate value, to account for more than 99 percent of the peak hourly emissions, we apply a conservative screening multiplication factor of 10 to the average annual hourly emission rate in these acute exposure screening assessments. The factor of 10 was used for both the Oil and Natural Gas Production and the Natural Gas Transmission and Storage source categories.

In cases where acute HQ values from the screening step were less than or equal to 1, acute impacts were deemed negligible and no further analysis was performed. In cases where an acute HQ from the screening step was greater than 1, additional site-specific data were considered to develop a more refined estimate of the potential for acute impacts of concern. The data refinements employed for these source categories consisted of using the site-specific facility layout to distinguish facility property from an area where the public could be exposed. These refinements are discussed in the draft risk assessment document, which is available in the docket for each of these source categories. Ideally, we would prefer to have continuous measurements over time to see how the emissions vary by each hour over an entire year. Having a frequency distribution of hourly emission rates over a year would allow us to perform a probabilistic analysis to estimate potential threshold exceedances and their frequency of occurrence. Such an evaluation could include a more complete statistical treatment of the key parameters and elements adopted in this screening analysis. However, we recognize that having this level of data is rare, hence our use of the multiplier approach.

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,[26] we generally examine a wider range of available acute health metrics 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. Comparisons of the estimated maximum off-site 1-hour exposure levels are not typically made to occupational levels for the purpose of characterizing public health risks in RTR assessments. This is because they are developed for working age adults and are not generally considered protective for the general public. We note that occupational ceiling values are, for most chemicals, set at levels higher than a 1-hour AEGL–1.

As discussed in section VII.C.2 of this preamble, the maximum estimated worst-case 1-hour exposure to benzene outside the facility fence line for a facility in either source category is 12 mg/m^3. This estimated exposure exceeds the 6-hour REL by a factor of 9 (HQ_{REL} = 9), but is significantly below the 1-hour AEGL–1 (HQ_{AEGL-1} = 0.07). Although this worst-case exposure estimate does not exceed the AEGL–1, we note here that it slightly exceeds workplace ceiling level guidelines designed to protect the worker population for short duration (<15 minute) increases in exposure to benzene, as discussed below. The occupational short-term exposure limit (STEL) standard for benzene developed by the Occupational Safety and Health Administration is 16 mg/m^3, ''as averaged over any 15-minute period.'' [27] Occupational guideline STEL for exposures to benzene have also been developed by the American Conference of Governmental Industrial Hygienists (ACGIH) [28] for less than 15 minutes [29] (ACGIH threshold limit value (TLV)-STEL value of 8.0 mg/m^3), and by the National Institute for Occupational Safety and Health (NIOSH) [30] ''for any 15 minute period in a work day'' (NIOSH REL–STEL of 3.2 mg/m^3). These shorter duration occupational values indicate potential concerns regarding health effects at exposure levels below the 1-hour AEGL–1 value. We solicit comment on the use of the occupational values described above in the interpretation of these worst-case acute screening exposure estimates.

d. Conducting Multi-Pathway Exposure and Risk Modeling

The potential for significant human health risks due to exposures via routes other than inhalation (*i.e.,* multi-pathway exposures) and the potential for adverse environmental impacts were evaluated in a three-step process. In the first step, we determined whether any facilities emitted any HAP known to be PB–HAP (HAP known to be persistent and bio-accumulative) in the environment. There are 14 PB–HAP compounds or compound classes identified for this screening in the EPA's *Air Toxics Risk Assessment Library* (available at *http://www.epa.gov/ttn/fera/risk_atra_vol1.html*). They are cadmium compounds, chlordane, chlorinated dibenzodioxins and furans,

[25] See *http://www.tceq.state.tx.us/compliance/field_ops/eer/index.html* or docket to access the source of these data.

[26] 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.*

[27] 29 CFR 1910.1028, Benzene. Available online at *http://www.osha.gov/pls/oshaweb/owadisp.show_document?p_table=STANDARDS&p_id=10042.*

[28] ACGIH (2001) Benzene. In *Documentation of the TLVs® and BEIs® with Other Worldwide Occupational Exposure Values.* ACGIH, 1300 Kemper Meadow Drive, Cincinnati, OH 45240 (ISBN: 978–1–882417–74–2) and available online at *http://www.acgih.org.*

[29] The ACGIH definition of a TLV–STEL states that ''Exposures above the TLV–TWA up to the TLV–STEL should be less than 15 minutes, should occur no more than four times per day, and there should be at least 60 minutes between successive exposures in this range.''

[30] NIOSH. *Occupational Safety and Health Guideline for Benzene; http://www.cdc.gov/niosh/74-137.html.*

dichlorodiphenyldichloroethylene, heptachlor, hexachlorobenzene, hexachlorocyclohexane, lead compounds, mercury compounds, methoxychlor, polychlorinated biphenyls, POM, toxaphene and trifluralin.

Since one or more of these PB–HAP are emitted by at least one facility in both source categories, we proceeded to the second step of the evaluation. In this step, we determined whether the facility-specific emission rates of each of the emitted PB–HAP were large enough to create the potential for significant non-inhalation human or environmental risks under reasonable worst-case conditions. To facilitate this step, we have developed emission rate thresholds for each PB–HAP using a hypothetical worst-case screening exposure scenario developed for use in conjunction with the EPA's TRIM.FaTE model. The hypothetical screening scenario was subjected to a sensitivity analysis to ensure that its key design parameters were established such that environmental media concentrations were not underestimated (*i.e.,* to minimize the occurrence of false negatives or results that suggest that risks might be acceptable when, in fact, actual risks are high) and to also minimize the occurrence of false positives for human health endpoints. We call this application of the TRIM.FaTE model TRIM–Screen. The facility-specific emission rates of each of the PB–HAP in each source category were compared to the TRIM–Screen emission threshold values for each of the PB–HAP identified in the source category datasets to assess the potential for significant human health risks or environmental risks via non-inhalation pathways.

There was only one facility in the Natural Gas Transmission and Storage source category with reported emissions of PB–HAP, and the emission rates were less than the emission threshold values. There were 29 facilities in the Oil and Natural Gas Production source category with reported emissions of PB–HAP, and one of these had emission rates greater than the emission threshold values. In this case, the emission threshold value for POM was exceeded by a factor of 6. For POM, dairy, vegetables and fruits were the three most dominant exposure pathways driving human exposures in the hypothetical screening exposure scenario. The single facility with emissions exceeding the emission threshold value for POM is located in a highly industrialized area. Therefore, since the exposure pathways which would drive high human exposure are not locally available, multi-pathway exposures and environmental risks were deemed negligible, and no further analysis was performed. For further information on the multi-pathway analysis approach, see the residual risk documentation.

e. Assessing Risks Considering Emissions Control Options

In addition to assessing baseline inhalation risks and screening for potential multi-pathway risks, where appropriate, we also estimated risks considering the potential emission reductions that would be achieved by the particular control options under consideration. In these cases, the expected emissions reductions were applied to the specific HAP and emissions sources in the source category dataset to develop corresponding estimates of risk reductions.

f. Conducting Other Risk-Related Analyses: Facility-Wide Assessments

To put the source category risks in context, we also examined the risks from the entire ''facility,'' where the facility includes all HAP-emitting operations within a contiguous area and under common control. In other words, for each facility that includes one or more sources from one of the source categories under review, we examined the HAP emissions not only from the source category of interest, but also from all other emission sources at the facility. The emissions data for generating these ''facility-wide'' risks were also obtained from the 2005 NEI. For every facility included in the MACT database, we also retrieved emissions data and release characteristics for all other emission sources at the same facility. We estimated the risks due to the inhalation of HAP that are emitted ''facility-wide'' for the populations residing within 50 km of each facility, consistent with the methods used for the source category analysis described above. For these facility-wide risk analyses, the modeled source category risks were compared to the facility-wide risks to determine the portion of facility-wide risks that could be attributed to the source categories addressed in this proposal. We specifically examined the facilities associated with the highest estimates of risk and determined the percentage of that risk attributable to the source category of interest. The risk documentation available through the docket for this action provides the methodology and the results of the facility-wide analyses for each source category.

g. Conducting Other Analyses: Demographic Analysis

To examine the potential for any environmental justice (EJ) issues that might be associated with each source category, we performed a demographic analysis of population risk. In this analysis, we evaluated the distributions of HAP-related cancer and noncancer risks across different social, demographic and economic groups within the populations living near the facilities where these source categories are located. The development of demographic analyses to inform the consideration of EJ issues in the EPA rulemakings is an evolving science. The EPA offers the demographic analyses in this rulemaking to inform the consideration of potential EJ issues and invites public comment on the approaches used and the interpretations made from the results, with the hope that this will support the refinement and improve the utility of such analyses for future rulemakings.

For the demographic analyses, we focus on the populations within 50 km of any facility estimated to have exposures to HAP which result in cancer risks of 1-in-1 million or greater, or noncancer HI of 1 or greater (based on the emissions of the source category or the facility, respectively). We examine the distributions of those risks across various demographic groups, comparing the percentages of particular demographic groups to the total number of people in those demographic groups nationwide. The results, including other risk metrics, such as average risks for the exposed populations, are documented in source-category-specific technical reports in the docket for both source categories covered in this proposal.

The basis for the risk values used in these analyses were the modeling results based on actual emissions levels obtained from the HEM–3 model described above. The risk values for each census block were linked to a database of information from the 2000 Decennial census that includes data on race and ethnicity, age distributions, poverty status, household incomes and education level. The Census Department Landview® database was the source of the data on race and ethnicity and the data on age distributions, poverty status, household incomes and education level were obtained from the 2000 Census of Population and Housing Summary File 3 Long Form. While race and ethnicity census data are available at the census block level, the age and income census data are only available at the census block group level (which includes an

average of 26 blocks or an average of 1,350 people). Where census data are available at the block group level, but not the block level, we assumed that all census blocks within the block group have the same distribution of ages and incomes as the block group.

For each source category, we focused on those census blocks where source category risk results show estimated lifetime inhalation cancer risks above 1-in-1 million or chronic noncancer indices above 1 and determined the relative percentage of different racial and ethnic groups, different age groups, adults with and without a high school diploma, people living in households below the national median income and for people living below the poverty line within those census blocks. The specific census population categories studied include:

- Total population
- White
- African American (or Black)
- Native Americans
- Other races and multiracial
- Hispanic or Latino
- Children 18 years of age and under
- Adults 19 to 64 years of age
- Adults 65 years of age and over
- Adults without a high school diploma
- Households earning under the national median income
- People living below the poverty line

It should be noted that these categories overlap in some instances, resulting in some populations being counted in more than one category (*e.g.,* other races and multiracial and Hispanic). In addition, while not a specific census population category, we also examined risks to ''Minorities,'' a classification which is defined for these purposes as all race population categories except white.

For further information about risks to the populations located near the facilities in these source categories, we also evaluated the estimated distribution of inhalation cancer and chronic noncancer risks associated with the HAP emissions from all the emissions sources at the facility (*i.e.,* facility-wide). This analysis used the facility-wide RTR modeling results and the census data described above.

The methodology and the results of the demographic analyses for each source category are included in a source-category-specific technical report for each of the categories, which are available in the docket for this action.

h. Considering Uncertainties in Risk Assessment

Uncertainty and the potential for bias are inherent in all risk assessments, including those performed for the source categories addressed in this proposal. Although uncertainty exists, we believe that our approach, which used conservative tools and assumptions, ensures that our decisions are health-protective. A brief discussion of the uncertainties in the emissions datasets, dispersion modeling, inhalation exposure estimates and dose-response relationships follows below. A more thorough discussion of these uncertainties is included in the risk assessment documentation (referenced earlier) available in the docket for this action.

i. Uncertainties in the Emissions Datasets

Although the development of the MACT dataset involved QA/quality control processes, the accuracy of emissions values will vary depending on the source of the data, the degree to which data are incomplete or missing, the degree to which assumptions made to complete the datasets are inaccurate, errors in estimating emissions values and other factors. The emission estimates considered in this analysis generally are annual totals for certain years that do not reflect short-term fluctuations during the course of a year or variations from year to year.

The estimates of peak hourly emission rates for the acute effects screening assessment were based on a multiplication factor of 10 applied to the average annual hourly emission rate, which is intended to account for emission fluctuations due to normal facility operations. Additionally, although we believe that we have data for most facilities in these two source categories in our RTR dataset, our dataset may not include data for all existing facilities. Moreover, there are uncertainties with regard to the identification of sources as major or area in the NEI for these source categories.

ii. Uncertainties in Dispersion Modeling

While the analysis employed the EPA's recommended regulatory dispersion model, AERMOD, we recognize that there is uncertainty in ambient concentration estimates associated with any model, including AERMOD. In circumstances where we had to choose between various model options, where possible, model options (*e.g.,* rural/urban, plume depletion, chemistry) were selected to provide an overestimate of ambient air concentrations of the HAP rather than underestimates. However, because of practicality and data limitation reasons, some factors (*e.g.,* meteorology, building downwash) have the potential in some situations to overestimate or underestimate ambient impacts. For example, meteorological data were taken from a single year (1991) and facility locations can be a significant distance from the site where these data were taken. Despite these uncertainties, we believe that at off-site locations and census block centroids, the approach considered in the dispersion modeling analysis should generally yield overestimates of ambient HAP concentrations.

iii. Uncertainties in Inhalation Exposure

The effects of human mobility on exposures were not included in the assessment. Specifically, short-term mobility and long-term mobility between census blocks in the modeling domain were not considered.[31] The assumption of not considering short or long-term population mobility does not bias the estimate of the theoretical MIR, nor does it affect the estimate of cancer incidence since the total population number remains the same. It does, however, affect the shape of the distribution of individual risks across the affected population, shifting it toward higher estimated individual risks at the upper end and reducing the number of people estimated to be at lower risks, thereby increasing the estimated number of people at specific risk levels.

In addition, the assessment predicted the chronic exposures at the centroid of each populated census block as surrogates for the exposure concentrations for all people living in that block. Using the census block centroid to predict chronic exposures tends to over-predict exposures for people in the census block who live further from the facility, and under-predict exposures for people in the census block who live closer to the facility. Thus, using the census block centroid to predict chronic exposures may lead to a potential understatement or overstatement of the true maximum impact, but is an unbiased estimate of average risk and incidence.

The assessments evaluate the cancer inhalation risks associated with continuous pollutant exposures over a 70-year period, which is the assumed lifetime of an individual. In reality, both the length of time that modeled emissions sources at facilities actually operate (*i.e.,* more or less than 70 years), and the domestic growth or decline of the modeled industry (*i.e.,* the increase

[31] Short-term mobility is movement from one micro-environment to another over the course of hours or days. Long-term mobility is movement from one residence to another over the course of a lifetime.

or decrease in the number or size of United States facilities), will influence the risks posed by a given source category. Depending on the characteristics of the industry, these factors will, in most cases, result in an overestimate both in individual risk levels and in the total estimated number of cancer cases. However, in rare cases, where a facility maintains or increases its emission levels beyond 70 years, residents live beyond 70 years at the same location, and the residents spend most of their days at that location, then the risks could potentially be underestimated. Annual cancer incidence estimates from exposures to emissions from these sources would not be affected by uncertainty in the length of time emissions sources operate.

The exposure estimates used in these analyses assume chronic exposures to ambient levels of pollutants. Because most people spend the majority of their time indoors, actual exposures may not be as high, depending on the characteristics of the pollutants modeled. For many of the HAP, indoor levels are roughly equivalent to ambient levels, but for very reactive pollutants or larger particles, these levels are typically lower. This factor has the potential to result in an overstatement of 25 to 30 percent of exposures.[32]

In addition to the uncertainties highlighted above, there are several factors specific to the acute exposure assessment that should be highlighted. The accuracy of an acute inhalation exposure assessment depends on the simultaneous occurrence of independent factors that may vary greatly, such as hourly emissions rates, meteorology, and human activity patterns. In this assessment, we assume that individuals remain for 1 hour at the point of maximum ambient concentration as determined by the co-occurrence of peak emissions and worst-case meteorological conditions. These assumptions would tend to overestimate actual exposures since it is unlikely that a person would be located at the point of maximum exposure during the time of worst-case impact.

iv. Uncertainties in Dose-Response Relationships

There are uncertainties inherent in the development of the dose-response values used in our risk assessments for cancer effects from chronic exposures and noncancer effects from both chronic and acute exposures. Some uncertainties may be considered quantitatively, and others generally are expressed in qualitative terms. We note as a preface to this discussion a point on dose-response uncertainty that is brought out in the *EPA 2005 Cancer Guidelines;* namely, that ''the primary goal of the EPA actions is protection of human health; accordingly, as an Agency policy, risk assessment procedures, including default options that are used in the absence of scientific data to the contrary, should be health protective.'' (*EPA 2005 Cancer Guidelines,* pages 1–7.) This is the approach followed here as summarized in the next several paragraphs. A complete detailed discussion of uncertainties and variability in dose-response relationships is given in the residual risk documentation, which is available in the docket for this action.

Cancer URE values used in our risk assessments are those that have been developed to generally provide an upper bound estimate of risk. That is, they represent a ''plausible upper limit to the true value of a quantity'' (although this is usually not a true statistical confidence limit).[33] In some circumstances, the true risk could be as low as zero; however, in other circumstances, the risk could also be greater.[34] When developing an upper bound estimate of risk and to provide risk values that do not underestimate risk, health-protective default approaches are generally used. To err on the side of ensuring adequate health-protection, the EPA typically uses the upper bound estimates rather than lower bound or central tendency estimates in our risk assessments, an approach that may have limitations for other uses (*e.g.,* priority-setting or expected benefits analysis).

Chronic noncancer reference (RfC and reference dose (RfD)) values represent chronic exposure levels that are intended to be health-protective levels. Specifically, these values provide an estimate (with uncertainty spanning perhaps an order of magnitude) of daily oral exposure (RfD) or of a continuous inhalation exposure (RfC) to the human population (including sensitive subgroups) that is likely to be without an appreciable risk of deleterious effects during a lifetime. To derive values that are intended to be ''without appreciable risk,'' the methodology relies upon an uncertainty factor (UF) approach (U.S. EPA, 1993, 1994) which includes consideration of both uncertainty and variability. When there are gaps in the available information, UF are applied to derive reference values that are intended to protect against appreciable risk of deleterious effects. The UF are commonly default values,[35] *e.g.,* factors of 10 or 3, used in the absence of compound-specific data; where data are available, UF may also be developed using compound-specific information. When data are limited, more assumptions are needed and more UF 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, it is possible that risks may be underestimated. While collectively termed ''uncertainty factor,'' these factors account for a number of different quantitative considerations when using observed animal (usually rodent) or human toxicity data in the development of the RfC. The UF are intended to account for: (1) Variation in susceptibility among the members of the human population (*i.e.,* inter-individual variability); (2) uncertainty in extrapolating from experimental animal data to humans (*i.e.,* interspecies differences); (3) uncertainty in extrapolating from data obtained in a study with less-than-lifetime exposure (*i.e.,* extrapolating from sub-chronic to chronic exposure); (4) uncertainty in extrapolating the observed data to obtain an estimate of the exposure associated with no adverse effects; and (5) uncertainty when the database is incomplete or there are problems with the applicability of available studies. Many of the UF used to account for variability and uncertainty in the development of acute reference values

[32] U.S. EPA. *National-Scale Air Toxics Assessment for 1996.* (EPA 453/R–01–003; January 2001; page 85.)

[33] IRIS glossary (*http://www.epa.gov/NCEA/iris/help_gloss.htm*).

[34] An exception to this is the URE for benzene, which is considered to cover a range of values, each end of which is considered to be equally plausible and which is based on maximum likelihood estimates.

[35] 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, 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.*

are quite similar to those developed for chronic durations, but they more often use individual UF values that may be less than 10. UF are applied based on chemical-specific or health effect-specific information (*e.g.,* simple irritation effects do not vary appreciably between human individuals, hence a value of 3 is typically used), or based on the purpose for the reference value (see the following paragraph). The UF applied in acute reference value derivation include: (1) Heterogeneity among humans; (2) uncertainty in extrapolating from animals to humans; (3) uncertainty in lowest observed adverse effect (exposure) level to no observed adverse effect (exposure) level adjustments; and (4) uncertainty in accounting for an incomplete database on toxic effects of potential concern. Additional adjustments are often applied to account for uncertainty in extrapolation from observations at one exposure duration (*e.g.,* 4 hours) to derive an acute reference value at another exposure duration (*e.g.,* 1 hour).

Not all acute reference values are developed for the same purpose and care must be taken when interpreting the results of an acute assessment of human health effects relative to the reference value or values being exceeded. Where relevant to the estimated exposures, the lack of short-term dose-response values at different levels of severity should be factored into the risk characterization as potential uncertainties.

Although every effort is made to identify peer-reviewed reference values for cancer and noncancer effects for all pollutants emitted by the sources included in this assessment, some HAP continue to have no reference values for cancer or chronic noncancer or acute effects. Since exposures to these pollutants cannot be included in a quantitative risk estimate, an understatement of risk for these pollutants at environmental exposure levels is possible. For a group of compounds that are either unspeciated or do not have reference values for every individual compound (*e.g.,* glycol ethers), we conservatively use the most protective reference value to estimate risk from individual compounds in the group of compounds.

Additionally, chronic reference values for several of the compounds included in this assessment are currently under the EPA IRIS review and revised assessments may determine that these pollutants are more or less potent than the current value. We may re-evaluate residual risks for the final rulemaking if these reviews are completed prior to our taking final action for these source categories and a dose-response metric changes enough to indicate that the risk assessment supporting this notice may significantly understate human health risk.

v. Uncertainties in the Multi-Pathway and Environmental Effects Assessment

We generally assume that when exposure levels are not anticipated to adversely affect human health, they also are not anticipated to adversely affect the environment. For each source category, we generally rely on the site-specific levels of PB–HAP emissions to determine whether a full assessment of the multi-pathway and environmental effects is necessary. As discussed above, we conclude that the potential for these types of impacts is low for these source categories.

vi. Uncertainties in the Facility-Wide Risk Assessment

Given that the same general analytical approach and the same models were used to generate facility-wide risk results as were used to generate the source category risk results, the same types of uncertainties discussed above for our source category risk assessments apply to the facility-wide risk assessments. Additionally, the degree of uncertainty associated with facility-wide emissions and risks is likely greater because we generally have not conducted a thorough engineering review of emissions data for source categories not currently undergoing an RTR review.

vii. Uncertainties in the Demographic Analysis

Our analysis of the distribution of risks across various demographic groups is subject to the typical uncertainties associated with census data (*e.g.,* errors in filling out and transcribing census forms), as well as the additional uncertainties associated with the extrapolation of census-block group data (*e.g.,* income level and education level) down to the census block level.

2. What are the results and proposed decisions from the risk review for the Oil and Natural Gas Production source category?

a. Results of the Risk Assessments and Analyses

We conducted an inhalation risk assessment for the Oil and Natural Gas Production source category. We also conducted an assessment of facility-wide risk. Details of the risk assessments and analyses can be found in the residual risk documentation, which is available in the docket for this action. For informational purposes and to examine the potential for any EJ issues that might be associated with each source category, we performed a demographic analysis of population risks.

i. Inhalation Risk Assessment Results

Table 2 provides an overall summary of the results of the inhalation risk assessment.

TABLE 2—OIL AND NATURAL GAS PRODUCTION INHALATION RISK ASSESSMENT RESULTS

Number of facilities [1]	Maximum individual cancer risk (in 1 million) [2]		Estimated population at risk ≥ 1-in-1 million	Estimated annual cancer incidence (cases per year)	Maximum chronic noncancer TOSHI [4]		Maximum off-site acute noncancer HQ [5]
	Actual emissions level	Allowable emissions level			Actual emissions level	Allowable emissions level	
990	40	100–400 [3]	160,000 [3]	0.007–0.02 [3]	0.1	0.7	HQ_{REL} = 9 (benzene) HQ_{AEGL-1} = 0.07 (benzene)

[1] Number of facilities evaluated in the risk analysis.

[2] Estimated maximum individual excess lifetime cancer risk.

[3] The EPA IRIS assessment for benzene provides a range of equally-plausible URE (2.2E–06 to 7.8E–06 per ug/m3), giving rise to ranges for the estimates of cancer MIR and cancer incidence. Estimated population values are not scalable with benzene URE range, but would be lower using the lower end of the URE range.

[4] Maximum TOSHI. The target organ with the highest TOSHI for the Oil and Natural Gas Production source category is the respiratory system.

[5] The maximum estimated acute exposure concentration was divided by available short-term dose-response values to develop an array of HQ values.

As shown in Table 2, the results of the inhalation risk assessment performed using actual emissions data indicate the maximum lifetime individual cancer risk could be as high as 40-in-1 million, with POM driving the highest risk, and benzene driving risks overall. The total estimated cancer incidence from this source category is 0.02 excess cancer cases per year (0.007 excess cancer cases per year based on the lower end of the benzene URE range), or one case in every 50 years. Approximately 160,000 people are estimated to have cancer risks at or above 1-in-1 million as a result of the emissions from 89 facilities (use of the lower end of the benzene URE range would further reduce this population estimate). The maximum chronic non-cancer TOSHI value for the source category could be up to 0.1 from emissions of naphthalene, indicating no significant potential for chronic noncancer impacts.

As explained above, our analysis of potential differences between actual emission levels and emissions allowable under the oil and natural gas production MACT standard indicate that MACT-allowable emission levels may be up to 50 times greater than actual emission levels. Considering this difference, the risk results from the inhalation risk assessment indicate the maximum lifetime individual cancer risk could be as high as 400-in-1 million (100-in-1 million based on the lower end of the benzene URE range) and the maximum chronic noncancer TOSHI value could be as high as 0.7 at the MACT-allowable emissions level.

ii. Facility-Wide Risk Assessment Results

A facility-wide risk analysis was also conducted based on actual emissions levels. Table 3 displays the results of the facility-wide risk assessment. For detailed facility-specific results, see Table 2 of Appendix 6 of the risk document in the docket for this rulemaking.

TABLE 3—OIL AND NATURAL GAS PRODUCTION FACILITY-WIDE RISK ASSESSMENT RESULTS

Number of facilities analyzed	990
Cancer Risk:	
Estimated maximum facility-wide individual cancer risk (in 1 million)	100
Number of facilities with estimated facility-wide individual cancer risk of 100-in-1 million or more	1
Number of facilities at which the Oil and Natural Gas Production source category contributes 50 percent or more to the facility-wide individual cancer risks of 100-in-1 million or more	0
Number of facilities with facility-wide individual cancer risk of 1-in-1 million or more	140
Number of facilities at which the Oil and Natural Gas Production source category contributes 50 percent or more to the facility-wide individual cancer risk of 1-in-1 million or more	85
Chronic Noncancer Risk:	
Maximum facility-wide chronic noncancer TOSHI	9
Number of facilities with facility-wide maximum noncancer TOSHI greater than 1	10
Number of facilities at which the Oil and Natural Gas Production source category contributes 50 percent or more to the facility-wide maximum noncancer TOSHI of 1 or more	0

The facility-wide MIR from all HAP emissions at a facility that contains sources subject to the oil and natural gas production MACT standards is estimated to be 100-in-1 million, based on actual emissions. Of the 990 facilities included in this analysis, only one has a facility-wide MIR of 100-in-1 million. At this facility, oil and natural gas production accounts for less than 2 percent of the total facility-wide risk. Nickel emissions from oil-fired boilers and formaldehyde emissions from reciprocating internal combustion engines (RICE) contribute essentially all the facility-wide risks at this facility, with over 80 percent of the risk attributed to the nickel emissions.[36] There are 140 facilities with facility-wide MIR of 1-in-1 million or greater. Of these facilities, 85 have oil and natural gas production operations that contribute greater than 50 percent to the facility-wide risks. As discussed above, we are proposing MACT standards for BTEX emissions from small glycol dehydrators in this action. These standards would reduce the risk from benzene emissions at facilities with oil and gas production. Formaldehyde emissions will be assessed under future RTR for RICE.

The facility-wide maximum individual chronic noncancer TOSHI is estimated to be 9 based on actual emissions. Of the 990 facilities included in this analysis, 10 have facility-wide maximum chronic noncancer TOSHI values greater than 1. Of these facilities, none had oil and natural gas production operations that contributed greater than 50 percent to these facility-wide risks. The chronic noncancer risks at these 10 facilities are primarily driven by acrolein emissions from RICE.

iii. Demographic Risk Analysis Results

The results of the demographic analyses performed to investigate the distribution of cancer risks at or above 1-in-1 million among the surrounding population are summarized in Table 4 below. These results, for various demographic groups, are based on actual emissions levels for the population living within 50 km of the facilities.

TABLE 4—OIL AND NATURAL GAS PRODUCTION DEMOGRAPHIC RISK ANALYSIS RESULTS

	Nationwide	Population with cancer risk at or above 1-in-1 million due to	
		Source category HAP emissions	Facility-wide HAP emissions
Total Population	285,000,000	160,000	597,000

[36] We note that there is an ongoing IRIS reassessment for formaldehyde, and that future RTR risk assessments will use the cancer potency for formaldehyde that results from that reassessment. As a result, the current results may not match those of future assessments.

TABLE 4—OIL AND NATURAL GAS PRODUCTION DEMOGRAPHIC RISK ANALYSIS RESULTS—Continued

	Nationwide	Population with cancer risk at or above 1-in-1 million due to	
		Source category HAP emissions	Facility-wide HAP emissions
Race by Percent			
White	75	62	61
All Other Races	25	38	39
Race by Percent			
White	75	62	61
African American	12	12	8
Native American	0.9	0.7	1.3
Other and Multiracial	12	25	30
Ethnicity by Percent			
Hispanic	14	22	34
Non-Hispanic	86	78	66
Income by Percent			
Below Poverty Level	13	14	19
Above Poverty Level	87	86	81
Education by Percent			
Over 25 and without High School Diploma	13	10	16
Over 25 and with a High School Diploma	87	90	84

The results of the Oil and Natural Gas Production source category demographic analysis indicate that there are approximately 160,000 people exposed to a cancer risk at or above 1-in-1 million due to emissions from the source category, including an estimated 38 percent that are classified as minority (listed as ''All Other Races'' in the table above). Of the 160,000 people with estimated cancer risks at or above 1-in-1 million from the source category, 25 percent are in the ''Other and Multiracial'' demographic group, 22 percent are in the ''Hispanic or Latino'' demographic group, and 14 percent are in the ''Below Poverty Level'' demographic group, results which are 13, 8 and 1 percentage points higher, respectively, than the respective percentages for these demographic groups across the United States. The percentages for the other demographic groups are lower than their respective nationwide percentages. The table also shows that there are approximately 597,000 people exposed to an estimated cancer risk at or above 1-in-1 million due to facility-wide emissions, including 30 percent in the ''Other and Multiracial'' demographic group, 34 percent in the ''Hispanic or Latino'' demographic group, 1.3 percent in the ''Native American'' demographic group and 16 percent in the ''Over 25 and without High School Diploma'' demographic group, results which are 18, 2, 0.4 and 3 percentage points higher than the percentages for these demographic groups across the United States, respectively. The percentages for the other demographic groups are lower than their respective nationwide percentages.

b. What are the proposed risk decisions for the Oil and Natural Gas Production source category?

i. Risk Acceptability

In the risk analysis we performed for this source category, pursuant to CAA section 112(f)(2), we considered the available health information—the MIR; the numbers of persons in various risk ranges; cancer incidence; the maximum noncancer HI; the maximum acute noncancer hazard; the extent of noncancer risks; the potential for adverse environmental effects; and distribution of risks in the exposed population; and risk estimation uncertainty (54 FR 38044, September 14, 1989).

For the Oil and Natural Gas Production source category, the risk analysis we performed indicates that the cancer risks to the individual most exposed could be as high as 40-in-1 million due to actual emissions and as high as 400-in-1 million due to MACT-allowable emissions (100-in-1 million, based on the lower end of the benzene URE range). While the 40-in-1 million risk due to actual emissions is considerably less than 100-in-1 million, which is the presumptive limit of acceptability, the 400-in-1 million risk due to allowable emissions is considerably higher and is considered unacceptable. We do note, however, that the risk analysis shows low cancer incidence (1 case in every 50 years), low potential for adverse environmental effects or human health multi-pathway effects and that chronic noncancer health impacts are unlikely.

We also conclude that acute noncancer health impacts are unlikely. As discussed above, screening estimates of acute exposures and risks were evaluated for each of the HAP at the point of highest off-site exposure for each facility (*i.e.,* not just the census block centroids) assuming that a person is located at this spot at a time when both the peak emission rate and worst-case dispersion conditions occur. Under these worst-case conditions, we estimate benzene acute HQ values (based on the REL) could be as high as 9. Although the REL (which indicates the level below which adverse effects are not anticipated) is exceeded in this case, we believe the potential for acute effects is low for several reasons. First, the acute modeling scenario is worst-case because of the confluence of peak emission rates and worst-case dispersion conditions.

Second, the benzene REL is based on a 6-hour exposure duration because a 1-hour exposure duration value was unavailable. An REL based on a 6-hour exposure duration is generally lower than an REL based on a 1-hour exposure duration and, consequently, easier to exceed. Also, although there are exceedances of the REL, the highest estimated 1-hour exposure is less than 10 percent of the AEGL–1 value, which is a level at which effects could be experienced. Finally, the generally sparse populations near these facilities make it less likely that a person would be near the plant to be exposed. For example, in the two cases where the acute HQ value is as high as 9, there are only 30 people associated with the census blocks within 2 miles of the two facilities.

While our additional analysis of facility-wide risks showed that there is one facility with maximum facility-wide cancer risk of 100-in-1 million or greater and 10 facilities with a maximum chronic noncancer TOSHI greater than 1, it also showed that oil and natural gas production operations did not drive these risks.

In determining whether risk is acceptable, we considered the available health information, as described above. In this case, although a number of factors we considered indicate relatively low risk concern, we are proposing to determine that the risks are unacceptable, in large part, because the MIR is 400-in-1 million due to MACT-allowable emissions, which greatly exceeds the ''presumptive limit on maximum individual lifetime risk of approximately 1-in-10 thousand [100-in-1 million] recognized in the Benzene NESHAP (54 FR 38045).'' The MIR, based on MACT-allowable emissions, is driven by the allowable emissions of 0.9 Mg/yr benzene under the MACT as a compliance option. We are, therefore, proposing to eliminate the alternative compliance option of 0.9 Mg/yr benzene from the existing glycol dehydrator MACT requirements. With this change, the source category MIR, based on MACT-allowable emissions, would be reduced to 40-in-1 million, which we find acceptable in light of all the other factors considered. Thus, we are proposing that the risks from the Oil and Natural Gas Production source category are acceptable, with the removal of the alternative compliance option of 0.9 Mg/yr benzene limit from the current glycol dehydrator MACT requirements.

Pursuant to CAA section 112(f)(4), we are proposing that this change (*i.e.,* removal of the 0.9 Mg/yr compliance alternative) apply 90 days after its effective date. We are requesting comment on whether or not this is sufficient time for the large dehydrators that have been relying on this compliance alternative to come into compliance with the 95-percent control requirement or if additional time is needed. See CAA section 112(f)(4)(A).

We recognize that our proposal to remove the 0.9 Mg/yr compliance alternative for the 95-percent control glycol dehydrator MACT standard could have negative impacts on some sources that have come to rely on the flexibility this alternative provides. We solicit comment on any such impacts and whether such impacts warrant adding a different compliance alternative that would result in less risk than the 0.9 Mg/yr benzene limit compliance option. If a commenter suggests a different compliance alternative, the commenter should explain, in detail, what that alternative would be, how it would work and how it would reduce risk.

ii. Ample Margin of Safety

We next considered whether this revised standard (existing MACT plus removal of 0.9 Mg/yr benzene compliance option) provides an ample margin of safety. In this analysis, we investigated available emissions control options that might reduce the risk associated with emissions from the source category and considered this information along with all of the health risks and other health information considered in the risk acceptability determination.

For glycol dehydrators, we considered the addition of a second control device in the same manner that was discussed in the floor evaluation in section VII.B.1 above. The cost effectiveness associated with that option would be $167,200/Mg, which we believe is too high to require additional controls on glycol dehydrators.

Similarly, we considered the addition of a second control device to the required MACT floor control device (cost effectiveness of $18,300/Mg). Similar to our discussion of beyond-the-MACT-floor controls for glycol dehydrators in section VII.B.1 of this preamble, the incremental cost to add a second control device for storage vessels would be approximately 20 times higher than the MACT floor cost effectiveness, or $366,000/Mg. We do not believe this cost effectiveness is reasonable.

For leak detection, we considered implementation of LDAR programs that are more stringent than the current standards. An assessment performed for various LDAR options under the NSPS in section VI.B.4.b of this preamble yielded the lowest cost effectiveness of $5,170/Mg ($4,700/ton) for control of VOC for the options evaluated. A LDAR program to control HAP would involve similar costs for equipment, labor, etc., to those considered in the NSPS assessment, but since there is approximately 20 times less HAP than VOC present in material handled in regulated equipment, the cost effectiveness to control HAP would be approximately 20 times greater (*i.e.,* $100,000/Mg) for HAP, which we believe is not reasonable.

In accordance with the approach established in the Benzene NESHAP, the EPA weighed all health risk measures and information considered in the risk acceptability determination, along with the costs and economic impacts of emissions controls, technological feasibility, uncertainties and other relevant factors in making our ample margin of safety determination. Considering the health risk information and the high cost effectiveness of the options identified, we propose that the existing MACT standards, with the removal of the 1 tpy benzene limit compliance option from the glycol dehydrator standards, provide an ample margin of safety to protect public health.

While we are proposing that the oil and natural gas production MACT standards (with the removal of the alternative compliance option of 1 tpy benzene limit) provide an ample margin of safety to protect public health, we are concerned about the estimated facility-wide risks identified through these screening analyses. As described previously, the highest estimated facility-wide cancer risks are mostly due to emissions from oil fired boilers and RICE. Both of these sources are regulated under other source categories and we anticipate that emission reductions from those sources will occur as standards for those source categories are implemented.

3. What are the results and proposed decisions from the risk review for the Natural Gas Transmission and Storage source category?

a. Results of the Risk Assessments and Analyses

We conducted an inhalation risk assessment for the Natural Gas Transmission and Storage source category. We also conducted an assessment of facility-wide risk and performed a demographic analysis of population risks. Details of the risk assessments and analyses can be found in the residual risk documentation, which is available in the docket for this action.

i. Inhalation Risk Assessment Results

Table 5 provides an overall summary of the results of the inhalation risk assessment. For informational purposes and to examine the potential for any EJ issues that might be associated with each source category, we performed a demographic analysis of population risks.

TABLE 5—NATURAL GAS TRANSMISSION AND STORAGE INHALATION RISK ASSESSMENT RESULTS

Number of Facilities [1]	Maximum individual cancer risk (in 1 million) [2]		Estimated population at risk ≥ 1-in-1 million	Estimated annual cancer incidence (cases per year)	Maximum chronic noncancer TOSHI [4]		Maximum off-site acute noncancer HQ [5]
	Actual emissions level	Allowable emissions level			Actual emissions level	Allowable emissions level	
321	[3] 30–90	[3] 30–90	[3] 2,500	[3] 0.0003–0.001	0.4	0.8	HQ_{REL} = 5 (benzene) HQ_{AEGL-1} = 0.2 (chlorobenzene)

[1] Number of facilities evaluated in the risk analysis.
[2] Estimated maximum individual excess lifetime cancer risk.
[3] The EPA IRIS assessment for benzene provides a range of equally-plausible URE (2.2E–06 to 7.8E–06 per ug/m^3), giving rise to ranges for the estimates of cancer MIR and cancer incidence. Estimated population values are not scalable with benzene URE range, but would be lower using the lower end of the URE range.
[4] Maximum TOSHI. The target organ with the highest TOSHI for the Natural Gas Transmission and Storage source category is the immune system.
[5] The maximum estimated acute exposure concentration was divided by available short-term dose-response values to develop an array of HQ values.

As shown in Table 5 above, the results of the inhalation risk assessment performed using actual emissions data indicate the maximum lifetime individual cancer risk could be as high as 90-in-1 million, (30-in-1 million based on the lower end of the benzene URE range), with benzene as the major contributor to the risk. The total estimated cancer incidence from the source category is 0.001 excess cancer cases per year (0.0003 excess cancer cases per year based on the lower end of the benzene URE range), or one case in every polycyclic organic matter 1,000 years. Approximately 2,500 people are estimated to have cancer risks at or above 1-in-1 million as a result of the emissions from 15 facilities (use of the lower end of the benzene URE range would further reduce this population estimate). The maximum chronic noncancer TOSHI value for the source category could be up to 0.4 from emissions of benzene, indicating no significant potential for chronic noncancer impacts.

As explained above in section VII.C.1.b, our analysis of potential differences between actual emission levels and emissions allowable under the natural gas transmission and storage MACT standard indicate that MACT-allowable emission levels may be up to 50 times greater than actual emission levels at some sources. However, because some sources are emitting at the level allowed under the current NESHAP, the risk results from the inhalation risk assessment indicate the maximum lifetime individual cancer risk would still be 90-in-1 million (30-in-1 million based on the lower end of the benzene URE range), based on both actual and allowable emission levels, and the maximum chronic noncancer TOSHI value could be as high as 0.8 at the MACT-allowable emissions level.

ii. Facility-Wide Risk Assessment Results

A facility-wide risk analysis was also conducted based on actual emissions levels. Table 6 below displays the results of the facility-wide risk assessment. For detailed facility-specific results, see Table 2 of Appendix 6 of the risk document in the docket for this rulemaking.

TABLE 6—NATURAL GAS TRANSMISSION AND STORAGE FACILITY-WIDE RISK ASSESSMENT RESULTS

Number of Facilities Analyzed	321
Cancer Risk:	
Estimated maximum facility-wide individual cancer risk (in 1 million)	[1] 200
Number of facilities with estimated facility-wide individual cancer risk of 100-in-1 million or more	3
Number of facilities at which the Natural Gas Transmission and Storage source category contributes 50 percent or more to the facility-wide individual cancer risks of 100-in-1 million or more	1
Number of facilities with facility-wide individual cancer risk of 1-in-1 million or more	74
Number of facilities at which the Natural Gas Transmission and Storage source category contributes 50 percent or more to the facility-wide individual cancer risk of 1-in-1 million or more	10
Chronic Noncancer Risk:	
Maximum facility-wide chronic noncancer TOSHI	80
Number of facilities with facility-wide maximum noncancer TOSHI greater than 1	30
Number of facilities at which the Natural Gas Transmission and Storage source category contributes 50 percent or more to the facility-wide maximum noncancer TOSHI of 1 or more	0

[1] We note that the MIR would be 100-in-1 million if the CIIT URE for formaldehyde were used instead of the IRIS URE.

The facility-wide MIR from all HAP emissions at any facility that contains sources subject to the natural gas transmission and storage MACT standards is estimated to be 200-in-1 million, based on actual emissions. Of the 321 facilities included in this analysis, three have facility-wide MIR of 100-in-1 million or greater. The facility-wide MIR is 200-in-1 million at two of these facilities, driven by formaldehyde

from RICE.[37] Another facility has a facility-wide risk of 100-in-1 million, with 90 percent of the risk attributed to natural gas transmission and storage. There are 74 facilities with facility-wide MIR of 1-in-1 million or greater. Of these facilities, 10 have natural gas transmission and storage operations that contribute greater than 50 percent to the facility-wide risks. As discussed above, we are proposing MACT standards for benzene emissions from small glycol dehydrators in this action. These standards would reduce the risk from benzene emissions at facilities with natural gas transmission and storage operations. The facility-wide cancer risks at the facilities with risks of 1-in-1 million or more are primarily driven by formaldehyde emissions from RICE, which will be assessed in a future RTR for that category.

The facility-wide maximum individual chronic noncancer TOSHI is estimated to be 80, based on actual emissions. Of the 321 facilities included in this analysis, 30 have facility-wide maximum chronic noncancer TOSHI values greater than 1. Of these facilities, none had natural gas transmission and storage operations that contributed greater than 50 percent to these facility-wide risks. The chronic noncancer risks at these facilities are primarily driven by acrolein emissions from RICE.

iii. Demographic Risk Analysis Results

The results of the demographic analyses performed to investigate the distribution of cancer risks at or above 1-in-1 million among the surrounding population are summarized in Table 7 below. These results, for various demographic groups, are based on actual emissions levels for the population living within 50 km of the facilities.

TABLE 7—NATURAL GAS TRANSMISSION AND STORAGE DEMOGRAPHIC RISK ANALYSIS RESULTS

	Nationwide	Population with cancer risk at or above 1-in-1 million due to . . .	
		Source category HAP emissions	Facility-wide HAP emissions
Total Population	285,000,000	2,500	99,000
Race by Percent			
White	75	92	58
All Other Races	25	8	42
Race by Percent			
White	75	92	58
African American	12	6	40
Native American	0.9	0.1	0.2
Other and Multiracial	12	1	2
Ethnicity by Percent			
Hispanic	14	1	2
Non-Hispanic	86	99	98
Income by Percent			
Below Poverty Level	13	17	20
Above poverty level	87	83	80
Education by Percent			
Over 25 and without High School Diploma	13	20	15
Over 25 and with a High School Diploma	87	80	85

The results of the Natural Gas Transmission and Storage source category demographic analysis indicate that there are approximately 2,500 people exposed to a cancer risk at or above 1-in-1 million due to emissions from the source category, including an estimated 8 percent that are classified as minority (listed as ''All Other Races'' in Table 7 above). Of the 2,500 people with estimated cancer risks at or above 1-in-1 million from the source category, 17 percent are in the ''Below Poverty Level'' demographic group, and 20 percent are in the ''Over 25 and without High School Diploma'' demographic group, results which are 4 and 7 percentage points higher, respectively, than the percentages for these demographic groups across the United States. The percentages for the other demographic groups are lower than their respective nationwide percentages. The table also shows that there are approximately 99,000 people exposed to an estimated cancer risk at or above 1-in-1 million due to facility-wide emissions, including an estimated 42 percent that are classified as minority (''All Other Races'' in Table 7 above). Of the 99,000 people with estimated cancer risk at or above 1-in-1 million from facility-wide emissions, 40 percent are in the ''African American'' demographic group, 20 percent are in the ''Below Poverty Level'' demographic group, and 15 percent are in the ''Over 25 and without High School Diploma'' demographic group, results which are 28, 7 and 2 percentage points higher, respectively, than the percentages for these demographic groups across the United States. The percentages for the other demographic groups are equal to

[37] We note that there is an ongoing IRIS reassessment for formaldehyde, and that future RTR risk assessments will use the cancer potency for formaldehyde that results from that reassessment. As a result, the current results may not match those of future assessments.

or lower than their respective nationwide percentages.

b. What are the proposed risk decisions for the Natural Gas Transmission and Storage source category?

i. Risk Acceptability

In the risk analysis we performed for this source category, pursuant to CAA section 112(f)(2), we considered the available health information—the MIR; the numbers of persons in various risk ranges; cancer incidence; the maximum noncancer HI; the maximum acute noncancer hazard; the extent of noncancer risks; the potential for adverse environmental effects; distribution of risks in the exposed population; and risk estimation uncertainty (54 FR 38044, September 14, 1989).

For the Natural Gas Transmission and Storage source category, the risk analysis we performed indicates that the cancer risks to the individual most exposed could be as high as 90-in-1 million due to actual and allowable emissions (30-in-1 million, based on the lower end of the benzene URE range). These risks are near 100-in-1 million, which is the presumptive limit of acceptability. On the other hand, the risk analysis shows low cancer incidence (1 case in every 1,000 years), low potential for adverse environmental effects or human health multi-pathway effects and that chronic and acute noncancer health impacts are unlikely. We conclude that acute noncancer health impacts are unlikely for reasons similar to those described in section VII.C.2.b.i of this preamble.

Our additional analysis of facility-wide risks showed that, among three facilities with maximum facility-wide cancer risk of 100-in-1 million or greater, one facility has a facility-wide cancer risk of 100-in-1 million, with 90 percent of the risk attributed to natural gas and transmission and storage. There are 30 facilities with a maximum chronic noncancer TOSHI greater than 1, but natural gas transmission and storage operations did not drive this risk.

In determining whether risk is acceptable, we considered the available health information, as described above. In this case, because the MIR is approaching, but still less than 100-in-1 million risk, and because a number of other factors indicate relatively low risk concern (*e.g.,* low cancer incidence, low potential for adverse environmental effects or human health multi-pathway effects, chronic and acute noncancer health impacts unlikely), we are proposing to determine that the risks are acceptable.

ii. Ample Margin of Safety

We next considered whether the existing MACT standard provides an ample margin of safety. In this analysis, we investigated available emissions control options that might reduce the risk associated with emissions from the source category and considered this information, along with all of the health risks and other health information considered in the risk acceptability determination. The estimated MIR of 90-in-1 million discussed above is driven by the 0.9 Mg/year benzene limit compliance alternative for the glycol dehydrator MACT standard in the current NESHAP. Removal of this compliance alternative would lower the MIR for the source category to 20-in-1 million. We, therefore, considered removing this compliance alternative as an option for reducing risk and assessed the cost of such alternative. Without the compliance alternative, affected glycol dehydrators (*i.e.,* those units with annual average benzene emissions of 0.9 Mg/yr or greater and an annual average natural gas throughput of 283,000 scmd or greater) must demonstrate compliance with the 95-percent control requirement, which we believe can be shown with their existing control devices in most cases, although, in some instances, installation of a different or an additional control may be necessary.

In section VII.B.1 above, we discuss the costs for requiring controls on currently unregulated ''small glycol dehydrators,'' which are similar, in operation and type of emission controls, to the dehydrators subject to the current MACT (''large dehydrators''). The HAP cost effectiveness determined for small dehydrators at the floor level of control was $1,650/Mg. Although control methodologies are similar for large and small dehydrators, we expect that the costs for controls on large units could be as much as twice as high as for small units because of the large gas flow being processed. However, we also expect that the amount of HAP emission reduction for the large dehydrators, in general, to be as much as, or more than, the amount achieved by small dehydrators. In light of the above, we do not expect the cost effectiveness of the control device needed to meet the 95-percent control requirement for large dehydrators to exceed $3,300/Mg (*i.e.,* twice the cost effectiveness for small dehydrators), which we consider to be reasonable.

In accordance with the approach established in the Benzene NESHAP, the EPA weighed all health risk measures and information considered in the risk acceptability determination, along with the costs and economic impacts of emissions controls, technological feasibility, uncertainties and other relevant factors in making our ample margin of safety determination. Considering the health risk information and the reasonable cost effectiveness of the option identified, we propose that the existing MACT standards, with the removal of the 0.9 Mg benzene limit compliance option from the glycol dehydrator standards, provide an ample margin of safety to protect public health.

Pursuant to CAA section 112(f)(4), we are proposing that this change (*i.e.,* removal of the 0.9 Mg/yr compliance alternative) apply 90 days after its effective date. We are requesting comment on whether or not there is sufficient time for the large dehydrators that have been relying on this compliance alternative to come into compliance with the 95-percent control requirement or if additional time is needed. See CAA section 112(f)(4)(A).

We recognize that our proposal to remove the one-ton compliance alternative for the 95-percent control glycol dehydrator MACT standard could have negative impacts on some sources that have come to rely on the flexibility this alternative provides. We solicit comment on any such impacts and whether such impacts warrant adding a different compliance alternative that would result in less risk than the 0.9 Mg/yr benzene limit compliance option. If a commenter suggests a different compliance alternative, the commenter should explain, in detail, what that alternative would be, how it would work, and how it would reduce risk.

As described above, we are proposing that the natural gas transmission and storage MACT standards (with the removal of the 0.9 Mg/yr benzene limit compliance option) provide an ample margin of safety to protect public health. We recognize that one facility has a facility-wide cancer risk of 100-in-1 million, with 90 percent of the risk attributed to natural gas transmission and storage. This risk is driven by benzene emissions from glycol dehydrators and is being addressed by our proposed revision to the Natural Gas Transmission and Storage NESHAP (removal of the 0.9 Mg/yr benzene limit compliance option). As previously mentioned, two facilities have facility-wide MIR of 200-in-1 million, driven by formaldehyde from RICE. Emissions from RICE are regulated under another source category and will be assessed under a future RTR for that category.

D. How did we perform the technology review and what are the results and proposed decisions?

1. What was the methodology for the technology review?

Our technology review is focused on the identification and evaluation of ''developments in practices, processes, and control technologies'' since the promulgation of the MACT standards for the two oil and gas source categories. If a review of available information identifies such developments, then we conduct an analysis of the technical feasibility of requiring the implementation of these developments, along with the impacts (costs, emission reductions, risk reductions, etc.). We then make a decision on whether it is necessary to amend the regulation to require these developments.

Based on specific knowledge of each source category, we began by identifying known developments in practices, processes and control technologies. For the purpose of this exercise, we considered any of the following to be a ''development'':

- Any add-on control technology or other equipment that was not identified and considered during MACT development;
- Any improvements in add-on control technology or other equipment (that was identified and considered during MACT development) that could result in significant additional emission reduction;
- Any work practice or operational procedure that was not identified and considered during MACT development; and
- Any process change or pollution prevention alternative that could be broadly applied that was not identified and considered during MACT development.

In addition to looking back at practices, processes or control technologies reviewed at the time we developed the MACT standards, we reviewed a variety of sources of data to aid in our evaluation of whether there were additional practices, processes or controls to consider. One of these sources of data was subsequent air toxics rules. Since the promulgation of the MACT standards for the source categories addressed in this proposal, the EPA has developed air toxics regulations for a number of additional source categories. We reviewed the regulatory requirements and/or technical analyses associated with these subsequent regulatory actions to identify any practices, processes and control technologies considered in these efforts that could possibly be applied to emission sources in the source categories under this current RTR review.

We also consulted the EPA's RBLC. The terms ''RACT,'' ''BACT,'' and ''LAER'' are acronyms for different program requirements under the CAA provisions addressing the NAAQS. Control technologies classified as RACT, BACT or LAER apply to stationary sources depending on whether the source exists or is new and on the size, age and location of the facility. The BACT and LAER (and sometimes RACT) are determined on a case-by-case basis, usually by state or local permitting agencies. The EPA established the RBLC to provide a central database of air pollution technology information (including technologies required in source-specific permits) to promote the sharing of information among permitting agencies and to aid in identifying future possible control technology options that might apply broadly to numerous sources within a category or apply only on a source-by-source basis. The RBLC contains over 5,000 air pollution control permit determinations that can help identify appropriate technologies to mitigate many air pollutant emission streams. We searched this database to determine whether any practices, processes or control technologies are included for the types of processes used for emission sources (*e.g.,* spray booths) in the source categories under consideration in this proposal.

We also consulted information from the Natural Gas STAR program. The Natural Gas STAR program is a flexible, voluntary partnership that encourages oil and natural gas companies to adopt cost effective technologies and practices that improve operational efficiency and reduce pollutant emissions. The program provides the oil and gas industry with information on new techniques and developments to reduce pollutant emissions from the various processes.

2. What are the results and proposed decisions from the technology review?

There are three types of emission sources covered by the two oil and gas NESHAP. These sources and the control technologies (including add-on control devices and process modifications) considered during the development of the MACT standards are: Glycol dehydrators (combustion devices, recovery devices, process modifications), storage vessels with the PFE (combustion devices, recovery devices) and equipment leaks (LDAR programs, specific equipment modifications). Dehydrators are addressed by both 40 CFR part 63, subpart HH and 40 CFR part 63, subpart HHH, while equipment leaks and storage vessels with the PFE are only covered by subpart HH.

Since the promulgation of 40 CFR part 63, subpart HH, which established MACT standards to address HAP emissions from equipment leaks at gas processing plants, the EPA has developed LDAR programs that are more stringent than what is required in subpart HH. The most prevalent differences between these more stringent programs and subpart HH relate to the frequency of monitoring and the concentration which constitutes a ''leak.'' We do consider these programs to represent a development in practices and evaluated whether to revise the MACT standards for equipment leaks at natural gas processing plants under subpart HH in light of this development.

An analysis was performed above in section VI.B.1 to assess the VOC reduction, costs and other impacts associated with these more stringent LDAR program options at natural gas processing plants. One option considered was to require compliance with 40 CFR part 60, subpart VVa instead of 40 CFR part 60, subpart VV (the current NSPS requirement for equipment leaks of VOC at natural gas processing plants), which changes the leak definition (based on methane) from 10,000 ppm to 500 ppm and requires monitoring of connectors. Because the current leak definition under NESHAP 40 CFR part 63, subpart HH is the same as that in NSPS subpart VV, and the ratio of VOC to HAP is approximately 20 to 1, we expect that the HAP reduction would be 1/20th of the VOC reduction under subpart VVa. The estimated incremental cost for that option was determined to be $3,340 per ton of VOC. Based on the 20-to-1 ratio, we estimate the incremental cost to control HAP at the subpart VVa level would be approximately $66,800 per ton of HAP ($73,480/Mg). Other options considered in section VI.B.1 of this preamble (and the incremental cost of each option for reducing HAP) are as follows: The use of an optical gas imaging camera monthly with an annual EPA Method 21 check ($129,000 per ton of HAP/$143,600 per Mg, if purchasing the camera; $93,000 per ton of HAP/ $103,300 per Mg, if renting the camera); monthly optical gas imagining alone; and annual optical gas imaging.[38] In

[38] As stated above in section VI.B.1, emissions for the two options using the optical gas imaging camera alone cannot be quantified and, therefore, no cost effectiveness values were determined.

light of the above, we do not believe that the additional costs of these programs are justified.

In addition to the plant-wide evaluations, a component analysis was also evaluated at gas processing plants for the 40 CFR part 60, subpart VVa-level of control (option 1 considered in section VI.B.1).[39] That assessment shows that the subpart VVa-level of control for connectors has an incremental cost effectiveness of $4,360 per ton for VOC for connectors and $144 per ton for VOC for valves. This means the incremental cost to control HAP would be approximately $87,200 per ton ($96,900/Mg) for connectors and $2,880 per ton ($3,200/Mg) for valves. We do not believe the additional cost for the more stringent requirement for connectors is justified, but the additional cost for valves is justified. Therefore, we are proposing to revise the equipment leak requirements in 40 CFR part 63, subpart HH to lower the leak definition for valves to an instrument reading of at least 500 ppm as a result of our technology review.

Some of the practices, processes or control technologies listed by the Natural Gas STAR program applicable to the emission sources in these categories were not identified and evaluated during the original MACT development. While the Natural Gas STAR program does contain information regarding new innovative techniques that are available to reduce HAP emissions, they are not considered to have emission reductions higher than what is set by the original MACT. One control technology identified in the Natural Gas STAR program that would result in no HAP emissions from glycol dehydration units would be the replacement of a glycol dehydration unit with a desiccant dehydrator. This technology cannot be used for natural gas operations with gas streams having high temperature, high volume, and low pressure. Due to the limitations posed by these conditions, we do not consider desiccant dehydrators as MACT.

For storage vessels, the applicable technologies identified by the Gas STAR program, which are evaluated above for proposal under NSPS in section VI.B.4, are similar to the cover and control technologies currently required for storage vessels under the existing MACT. Therefore, these technologies would not result in any further emissions reductions than what is achieved by the original MACT.

[39] Because optical gas imaging is used to view several pieces of equipment at a facility at once to survey for leaks, options involving imaging are not amenable to a component by component analysis.

Our review of the RBLC did not identify any practices, processes and control technologies applicable to the emission sources in these categories that were not identified and evaluated during the original MACT development. In light of the above, we are not proposing any revisions to the existing MACT standards for storage vessels pursuant to section 112(d)(6) of the CAA.

E. What other actions are we proposing?

1. Combustion Control Device Testing

As explained below in section VII.E.2, under our proposal, performance testing would be required initially and every 5 years for non-condenser control devices. However, for certain enclosed combustion control devices, we are proposing to allow, as an alternative to on-site testing, a performance test conducted by a control device manufacturer in accordance with the procedures provided in this proposal. We propose to allow a unit whose model meets the proposed performance criteria to claim a BTEX or HAP destruction efficiency of 98 percent at the facility. This value is lower than the 99.9-percent destruction efficiency required in the manufacturers' test due to variations between the test fuel specified and the gas streams combusted at the actual facility. A source subject to the small dehydrator BTEX limit would use the 98-percent destruction efficiency to calculate their dehydrator's BTEX emissions for the purpose of demonstrating compliance. For the 95-percent control MACT standard, a control device matching the tested model would be considered to meet that requirement. Once a device has been demonstrated to meet the proposed performance criteria (and, therefore, is assigned a 98-percent destruction efficiency), installation of a unit matching the tested model at a facility would require no further performance testing (*i.e.,* periodic tests would not be required every 5 years).

We are proposing this alternative to minimize issues associated with performance testing of certain combustion control devices. We believe that testing units that are not configured with a distinct combustion chamber present several technical issues that are more optimally addressed through manufacturer testing, and once these units are installed at a facility, through periodic inspection and maintenance in accordance with manufacturers' recommendations. One issue is that an extension above certain existing combustion control device enclosures will be necessary to get adequate clearance above the flame zone. Such extensions can more easily be configured by the manufacturer of the control device rather than having to modify an extension in the field to fit devices at every site. Issues related to transporting, installing and supporting the extension in the field are also eliminated through manufacturer testing. Another concern is that the pitot tube used to measure flow can be altered by radiant heat from the flame such that gas flow rates are not accurate. This issue is best overcome by having the manufacturer select and use the pitot tube best suited to their specific unit. For these reasons, we believe the manufacturers' test is appropriate for these control devices with ongoing performance ensured by periodic inspection and maintenance.

This proposed alternative does not apply to flares, as defined in 40 CFR 63.761 and 40 CFR 63.1271, which must demonstrate compliance by meeting the design and operation requirements in 40 CFR 63.11(b), 40 CFR 63.772(e)(2) and 40 CFR 63.1282(d)(2). It also would not apply to thermal oxidizers having a combustion chamber/firebox where combustion temperature and residence time can be measured during an on-site performance test and are valid indicators of performance. These thermal oxidizers do not present the issues described above relative to on-site performance testing and, therefore, do not need an alternative testing option. The proposed alternative would, therefore, apply to enclosed combustion control devices except for these thermal oxidizers.

In conjunction with the proposed manufacturer testing alternative, we are proposing to add a definition for flare to clarify that flares, as referenced in the NESHAP (and to which the proposed testing alternative does not apply), refers to a thermal oxidation system with an open flame (*i.e.,* without enclosure). Accordingly, any thermal oxidation system that does not meet the proposed flare definition would be considered an enclosed combustion control device.

We estimate that there are many existing facilities currently using enclosed combustion control devices that would be required to either conduct an on-site performance test or install and operate a control device tested by the manufacturer under our proposal. Given the estimated number of these combustion control devices in use, the time required for manufacturers to test and manufacture such units, we are proposing that existing sources have up to 3 years from the date of the final rules' publication date to comply with

the initial performance testing requirements.

2. Monitoring, Recordkeeping and Reporting

We are proposing to make changes to the monitoring requirements described below to address issues we have identified through a monitoring sufficiency review performed during the RTR process. First, we are including calibration procedures associated with parametric monitoring requirements in the existing NESHAP. The NESHAP require parametric monitoring of control device parameters (*e.g.,* temperatures or flowrate monitoring), but did not include information on calibration or included inadequate information on calibration of monitoring devices. Therefore, we are specifying the calibration requirements for temperature and flow monitors that the NESHAP currently lacks.

In addition, under the current NESHAP, a design analysis can be used in lieu of performance testing to demonstrate compliance and establish operating parameter limits. We are proposing to allow the use of the design evaluation alternative only when the control device being used is a condenser. The design evaluation option is appropriate for condensers because their emissions can be accurately predicted using readily available physical property information (*e.g.,* vapor pressure data and condensation calculations). In those cases, one would not need to conduct emissions testing to determine actual emissions to demonstrate compliance with the MACT standard. For example, a requirement that ''the temperature at the outlet of the condenser shall be maintained at 50° Fahrenheit below the condensation temperature calculated for the compound of interest using the reference equation'' (*e.g.,* National Institute of Standards and Technology Chemistry WebBook at *http://webbook.nist.gov/chemistry/*) is adequate to assure proper operation of the condenser and, therefore, compliance with the required emission standard.

For other types of control technologies, such as carbon adsorption systems and enclosed combustion devices,[40] the ability to predict emissions depends on data developed by the vendor and such data may not reliably result in an accurate prediction of emissions from a specific facility. There are variables (*e.g.,* air to fuel ratios and waste constituents for combustion; varying organic concentrations, constituents and capacity issues, including break-through for carbon adsorption) that make theoretical predictions less reliable. The effects of these site-specific variables on emissions are not easily predictable and establishing monitoring conditions (*e.g.,* combustion temperature, vacuum regeneration) based on vendor data will likely not account for those variables. Therefore, we propose to eliminate the design evaluation alternative for non-condenser controls.

For non-condenser controls (and condensers not using the design analysis option), in addition to the initial compliance testing, we are proposing that performance tests be conducted at least once every 5 years and whenever sources desire to establish new operating limits. Under the current NESHAP, a performance test is only conducted in two instances: (1) As an alternative to a design analysis for their compliance demonstration and identification of operating parameter ranges and (2) as a requirement to resolve a disagreement between the EPA and the owner or operator regarding the design analysis. The current NESHAP do not require additional performance testing beyond these two cases (*i.e.,* there is no periodic testing requirement). As mentioned above, we are proposing to remove the design evaluation option for non-condenser controls. For non-condenser controls (and condensers not using the design analysis option), the proposed periodic testing would ensure compliance with the emission standards by verifying that the control device is meeting the necessary HAP destruction efficiency determined in the initial performance test. As discussed above in section VII.E.1, we are proposing that combustion control devices tested under the manufacturers' procedure are not required to conduct periodic testing. In addition, we are also proposing that combustion control devices that can demonstrate a uniform combustion zone temperature meeting the required control efficiency during the initial performance test are exempt from periodic testing. The requirement for continuous monitoring of combustion zone temperature is an accurate indicator of control device performance and eliminates the need for future testing.

The current NESHAP (40 CFR 63.771(d) and 40 CFR 63.1281(d)) require operating an enclosed combustion device at a minimum residence time of 0.5 seconds at a minimum temperature of 760 degrees Celsius. We are proposing to remove the residence time requirement. The residence time requirement is not needed because the compliance demonstration made during the performance test is sufficient to ensure that the combustion device has adequate residence time to ensure the needed destruction efficiency. Therefore, we are proposing to remove the residence time requirement.

We are also clarifying at 40 CFR 63.773(d)(3)(i) and 40 CFR 63.1283(d)(3)(i) for thermal vapor incinerators, boilers and process heaters, that the temperature sensor shall be installed at a location representative of the combustion zone temperature. Currently, the regulation requires that the temperature sensor be installed at a location ''downstream of the combustion zone'' because we had thought that the temperature downstream would be representative of combustion zone temperature. We have now learned that may or may not be the case. We are, therefore, proposing to amend this provision to more accurately reflect the intended requirement.

Next, consistent with revisions for SSM, we've revised 40 CFR 63.771(d)(4)(i) and 40 CFR 63.1281(d)(4)(i), except when maintenance or repair on a unit cannot be completed without a shutdown of the control device.

Also, we've updated the criteria for prior performance test results that can be used to demonstrate compliance in lieu of conducting a performance test. These updates ensure that data for determining compliance are accurate, up-to-date, and truly representative of actual operating conditions.

In addition, we are proposing to revise the temperature monitoring device minimum accuracy criteria in 40 CFR 63.773(d)(3)(i) to better reflect the level of performance that is required of the temperature monitoring devices. We believe that temperature monitoring devices currently used to meet the requirements of the NESHAP can meet the proposed revised criteria without modification.

Also, we are proposing to revise the calibration gas concentration for the no detectable emissions procedure applicable to closed vent systems in 40 CFR 63.772(c)(4)(ii) from 10,000 ppmv to 500 ppmv methane to be consistent with the leak threshold of 500 ppmv in 40 CFR part 63, subpart HH. The current calibration level is inconsistent with achieving accurate readings at the level necessary to demonstrate there are no detectable emissions.

[40] The design analysis alternative in the existing MACT does not apply to flares. As previously mentioned, the existing MACT provides separate design and operation requirements for flares.

Also, we are proposing recordkeeping and reporting requirements for carbon adsorption systems. The current NESHAP require the replacement of all carbon in the carbon adsorption system with fresh carbon on a regular, predetermined time interval that is no longer than the carbon service life established for the carbon system, but provide no recordkeeping or reporting requirement to document and assure compliance with this standard. We believe that maintaining some sort of log book is a reasonable alternative combined with a requirement to report instances when specified practices are not followed. Therefore, the proposed rule adds reporting and recordkeeping requirements for establishing a schedule and maintaining logs of carbon replacement.

Finally, as noted above in section VII.B.1, we are proposing a BTEX emissions limit for small glycol dehydration unit process vents. For the compliance demonstration, we propose that parametric monitoring of the control device be performed. We believe that parametric monitoring is adequate for glycol dehydrators in these two source categories because temperature monitoring, whether it be to verify proper condenser or combustion device operation, is a reliable indicator of performance for reducing organic HAP emissions. We also considered the use of a continuous emissions monitoring system (CEMS) to monitor compliance. However, for glycol dehydrators in the oil and natural gas sector, the necessary electricity, weather-protective enclosures and daily staffing are not usually available. We, therefore, question the technical feasibility of operating a CEMS correctly in this sector. We request comment on the practicality of including provisions in the final rule for a CEMS to monitor BTEX emissions for small glycol dehydration units.

3. Startup, Shutdown, Malfunction

The United States Court of Appeals for the District of Columbia Circuit vacated portions of two provisions in the EPA's CAA section 112 regulations governing the emissions of HAP during periods of SSM. *Sierra Club* v. *EPA,* 551 F.3d 1019 (D.C. Cir. 2008), *cert. denied, 130 S. Ct. 1735 (U.S. 2010).* Specifically, the Court vacated the SSM exemption contained in 40 CFR 63.6(f)(1) and 40 CFR 63.6(h)(1), that is part of a regulation, commonly referred to as the *General Provisions Rule,* that the EPA promulgated under section 112 of the CAA. When incorporated into CAA section 112(d) regulations for specific source categories, these two provisions exempt sources from the requirement to comply with the otherwise applicable CAA section 112(d) emission standard during periods of SSM.

We are proposing the elimination of the SSM exemption in the two oil and gas NESHAP. Consistent with *Sierra Club* v. *EPA,* the EPA is proposing to apply the standards in these NESHAP at all times. In addition, we are proposing to revise 40 CFR 63.771(d)(4)(i) and 40 CFR 63.1281(d)(4)(i) to remove the provision allowing shutdown of the control device during maintenance or repair. We are also proposing several revisions to the General Provisions applicability table for the MACT standard. For example, we are proposing to eliminate the incorporation of the General Provisions' requirement that the source develop a SSM plan. We are also proposing to eliminate or revise certain recordkeeping and reporting requirements related to the SSM exemption. The EPA has attempted to ensure that we have not included in the proposed regulatory language any provisions that are inappropriate, unnecessary or redundant in the absence of the SSM exemption. We are specifically seeking comment on whether there are any such provisions that we have inadvertently incorporated or overlooked.

In proposing the MACT standards in these rules, the EPA has taken into account startup and shutdown periods. We believe that operations and emissions do not differ from normal operations during these periods such that it warrants a separate standard. Therefore, we have not proposed different standards for these periods.

Periods of startup, normal operations and shutdown are all predictable and routine aspects of a source's operations. However, by contrast, malfunction is defined as a ''sudden, infrequent and not reasonably preventable failure of air pollution control and monitoring equipment, process equipment or a process to operate in a normal or usual manner * * *'' (40 CFR 63.2). The EPA has determined that malfunctions should not be viewed as a distinct operating mode and, therefore, any emissions that occur at such times do not need to be factored into development of CAA section 112(d) standards, which, once promulgated, apply at all times. In *Mossville Environmental Action Now* v. *EPA,* 370 F.3d 1232, 1242 (D.C. Cir. 2004), the Court upheld as reasonable, standards that had factored in variability of emissions under all operating conditions. However, nothing in CAA section 112(d) or in case law requires that the EPA anticipate and account for the innumerable types of potential malfunction events in setting emission standards. See *Weyerhaeuser* v. *Costle,* 590 F.2d 1011, 1058 (D.C. Cir. 1978), (''In the nature of things, no general limit, individual permit, or even any upset provision can anticipate all upset situations. After a certain point, the transgression of regulatory limits caused by ''uncontrollable acts of third parties,'' such as strikes, sabotage, operator intoxication or insanity, and a variety of other eventualities, must be a matter for the administrative exercise of case-by-case enforcement discretion, not for specification in advance by regulation.'').

Further, it is reasonable to interpret CAA section 112(d) as not requiring the EPA to account for malfunctions in setting emissions standards. For example, we note that CAA section 112 uses the concept of ''best performing'' sources in defining MACT, the level of stringency that major source standards must meet. Applying the concept of ''best performing'' to a source that is malfunctioning presents significant difficulties. The goal of best performing sources is to operate in such a way as to avoid malfunctions of their units.

Moreover, even if malfunctions were considered a distinct operating mode, we believe it would be impracticable to take malfunctions into account in setting CAA section 112(d) standards for oil and natural gas production facility and natural gas transmission and storage operations. As noted above, by definition, malfunctions are sudden and unexpected events, and it would be difficult to set a standard that takes into account the myriad different types of malfunctions that can occur across all sources in each source category. Moreover, malfunctions can also vary in frequency, degree and duration, further complicating standard setting.

In the event that a source fails to comply with the applicable CAA section 112(d) standards as a result of a malfunction event, the EPA would determine an appropriate response 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. The EPA would also consider whether the source's failure to comply with the CAA section 112(d) standard was, in fact, ''sudden, infrequent, not reasonably preventable'' and was not instead ''caused in part by poor maintenance or careless operation.'' 40 CFR 63.2 (definition of malfunction).

Finally, the EPA recognizes that even equipment that is properly designed and maintained can sometimes fail and that such failure can sometimes cause or contribute to an exceedance of the relevant emission standard. (See, *e.g., State Implementation Plans: Policy Regarding Excessive Emissions During Malfunctions, Startup, and Shutdown* (September 20, 1999); *Policy on Excess Emissions During Startup, Shutdown, Maintenance, and Malfunctions* (February 15, 1983)). The EPA is, therefore, proposing to add to the final rule an affirmative defense to civil penalties for exceedances of emission limits that are caused by malfunctions in both of the MACT standards addressed in this proposal. See 40 CFR 63.761 for sources subject to the oil and natural gas production MACT standards, or 40 CFR 63.1271 for sources subject to the natural gas transmission and storage MACT standards (defining ''affirmative defense'' to mean, in the context of an enforcement proceeding, a response or defense put forward by a defendant, regarding which the defendant has the burden of proof and the merits of which are independently and objectively evaluated in a judicial or administrative proceeding). We also are proposing other regulatory provisions to specify the elements that are necessary to establish this affirmative defense; a source subject to the oil and natural gas production facilities or natural gas transmission MACT standards must prove by a preponderance of the evidence that it has met all of the elements set forth in 40 CFR 63.762 and a source subject to the natural gas transmission and storage facilities MACT standards must prove by a preponderance of the evidence that it has met all of the elements set forth in 40 CFR 63.1272. (See 40 CFR 22.24.) The criteria ensure that the affirmative defense is available only where the event that causes an exceedance of the emission limit meets the narrow definition of malfunction in 40 CFR 63.2 (sudden, infrequent, not reasonably preventable and not caused by poor maintenance and or careless operation). For example, to successfully assert the affirmative defense, the source must prove by a preponderance of evidence that excess emissions ''[w]ere caused by a sudden, infrequent, and unavoidable failure of air pollution control and monitoring equipment, process equipment, or a process to operate in a normal or usual manner * * *.'' The criteria also are designed to ensure that steps are taken to correct the malfunction, to minimize emissions in accordance with 40 CFR 63.762 for sources subject to the oil and natural gas production facilities MACT standards or 40 CFR 63.1272 for sources subject to the natural gas transmission and storage facilities MACT standards and to prevent future malfunctions. For example, the source must prove by a preponderance of evidence that ''[r]epairs were made as expeditiously as possible when the applicable emission limitations were being exceeded * * *'' and that ''[a]ll possible steps were taken to minimize the impact of the excess emissions on ambient air quality, the environment and human health * * *.'' In any judicial or administrative proceeding, the Administrator may challenge the assertion of the affirmative defense and, if the respondent has not met its burden of proving all of the requirements in the affirmative defense, appropriate penalties may be assessed in accordance with section 113 of the CAA (see also 40 CFR 22.77).

4. Applicability and Compliance

a. Calculating Potential To Emit (PTE)

We are proposing to amend section 40 CFR 63.760(a)(1)(iii) to clarify that sources must use a glycol circulation rate consistent with the definition of PTE in 40 CFR 63.2 in calculating emissions for purposes of determining PTE. Affected parties have misinterpreted the current language concerning measured values or annual average to apply to a broader range of parameters than was intended. Those qualifiers were meant to apply to gas characteristics that are measured, such as inlet gas composition, pressure and temperature rather than process equipment settings. That means that the circulation rate used in PTE determinations shall be the maximum under its physical and operational design.

In addition to the proposed changes described above, we are seeking comment on several PTE related issues. According to the data available to the Administrator, when 40 CFR part 63, subpart HH was promulgated, the level of HAP emissions was predominantly driven by natural gas throughput (*i.e.,* HAP emissions went up or down in concert with natural gas throughput). Since promulgation, we have learned that there is not always a direct correlation between HAP emissions and natural gas throughput. We have received information suggesting that, in some cases, HAP emissions can increase despite decreasing natural gas throughput due to changes in gas composition. We are asking for comment regarding the likelihood of this occurrence and data demonstrating the circumstances where it occurs. In light of the potential issue, we are asking for comment regarding the addition of provisions in the NESHAP to require area sources to recalculate their PTE to confirm that they are indeed area sources and whether that calculation should be performed on an annual or biannual basis to verify that changes in gas composition have not increased their emissions.

b. Definition of Facility and Applicability Criteria

Subpart HH of 40 CFR part 63 (section 63.760(a)(2)) currently defines facilities as those where hydrocarbon liquids are processed, upgraded or stored prior to the point of custody transfer or where natural gas is processed, upgraded or stored prior to entering the Natural Gas Transmission and Storage source category. We are proposing to remove the references to ''point of custody transfer'' and ''transmission and storage source categories'' from the definition because the operations performed at a site sufficiently define a facility and the scope of the subpart is specified already under 40 CFR 63.760. In addition, we are removing the custody transfer reference from the applicability criteria in 40 CFR 63.760(a)(2). Since hydrocarbon liquids can pass through several custody transfer points between the well and the final destination, the custody transfer criteria is not clear enough. We are, therefore, proposing to replace the reference to ''point of custody transfer'' with a more specific description of the point up to which the subpart applies (*i.e.,* the point where hydrocarbon liquids enter either the organic liquids distribution or petroleum refineries source categories) and exclude custody transfer from that criteria. We believe this change eliminates ambiguity and is consistent with the oil and natural gas production-specific provisions in the organic liquids distribution MACT.

5. Other Proposed Changes To Clarify These Rules

The following lists additional changes to the NESHAP we are proposing. This list includes proposed rule changes that address editorial corrections and plain language revisions:

- Revise 40 CFR 63.769(b) to clarify that the equipment leak provisions in 40 CFR part 63, subpart HH do not apply to a source if that source is required to control equipment leaks under either 40 CFR part 63, subpart H or 40 CFR part 60, subpart KKK. The current 40 CFR 63.769(b), which states that subpart HH does not apply if a source meets the

requirements in either of the subparts mentioned above, does not clearly express our intent that such source must be implementing the LDAR provisions in the other 40 CFR part 60 or 40 CFR part 63 subparts to qualify for the exemption.

- Revise 40 CFR 63.760(a)(1) to clarify that an existing area source that increases its emissions to major source levels has up to the first substantive compliance date to either reduce its emissions below major source levels by obtaining a practically enforceable permit or comply with the applicable major source provisions of 40 CFR part 63, subpart HH. We have revised the second to last sentence in 40 CFR 63.760(a)(1) by removing the parenthetical statement because it simply reiterates the last sentence of this section and is, therefore, unnecessary.
- Revise 40 CFR 63.771(d)(1)(ii) and 40 CFR 63.1281(d)(1)(ii) to clarify that the vapor recovery device and ''other control device'' described in those provisions refer to non-destructive control devices only.
- Revise the last sentence of 40 CFR 63.764(i) and 40 CFR 63.1274(g) to clarify the requirements following an unsuccessful attempt to repair a leak.
- Updated the e-mail and physical address for area source reporting in 40 CFR 63.775(c)(1).

VIII. What are the cost, environmental, energy and economic impacts of the proposed 40 CFR part 60, subpart OOOO and amendments to subparts HH and HHH of 40 CFR part 63?

We are presenting a combined discussion of the estimates of the impacts for the proposed 40 CFR part 60, subpart OOOO and proposed amendments to 40 CFR part 63, subpart HH and 40 CFR part 63, subpart HHH. The cost, environmental and economic impacts presented in this section are expressed as incremental differences between the impacts of an oil and natural gas facility complying with the amendments to subparts HH and HHH and new standards under 40 CFR 60, subpart OOOO and the baseline, *i.e.,* the standards before these amendments. The impacts are presented for the year 2015, which will be the year that all existing oil and natural gas facilities will have to be in compliance, and also the year that will represent approximately 5 years of construction of new oil and natural gas facilities subject to the NSPS emissions limits. The analyses and the documents referenced below can be found in Docket ID Numbers EPA–HQ–OAR–2007–0877 and EPA–HQ–OAR–2002–0051.

A. What are the affected sources?

We expect that by 2015, the year when all existing sources will be required to come into compliance in the United States, there will be 97 oil and natural gas production facilities and 15 natural gas transmission and storage facilities with one or more existing glycol dehydration units. We also estimate that there will be an additional 329 (there are 47 facilities that already have an affected glycol dehydration unit) existing oil and natural gas production facilities with existing storage vessels that we expect to be affected by these final amendments. These facilities operate approximately 134 glycol dehydration units (115 in production and 19 in transmission and storage) and 1,970 storage vessels. Approximately 10 oil and natural gas production and two transmission and storage facilities would have new glycol dehydration units and 38 production facilities would have new dehydration units. We expect new production facilities would operate approximately 12 production glycol dehydration units and 197 storage vessels and new transmission and storage would operate approximately two glycol dehydration units.

Based on data provided by the United States Energy Information Administration, we anticipate that by 2015 there will be approximately 21,800 gas wellhead facilities, 790 reciprocating compressors, 30 centrifugal compressors, 14,000 pneumatic devices and 300 storage vessels subject to the new NSPS for VOC. Some of these affected facilities will be built at existing facilities and some at new greenfield facilities. Based on data limitations, we assume impacts are equal regardless of location.

There are about 21 glycol dehydration units with high enough HAP emissions that we believe cannot meet the emissions limit without using more than one control technique. In developing the cost impacts, we assume that they would require multiple controls. The controls for which we have detailed cost data are condensers and VRU, so we developed costs for both controls to develop what we consider to be a reasonable cost estimate for these facilities. This does not imply that we believe these facilities will specifically use a combination of a condenser and vapor recovery limit, but we do believe the combination of these control results is a reasonable estimate of cost.

B. How are the impacts for this proposal evaluated?

For these proposed Oil and Natural Gas Production and Natural Gas Transmission and Storage NESHAP amendments and NSPS, the EPA used two models to evaluate the impacts of the regulation on the industry and the economy. Typically, in a regulatory analysis, the EPA determines the regulatory options suitable to meet statutory obligations under the CAA. Based on the stringency of those options, the EPA then determines the control technologies and monitoring requirements that sources might rationally select to comply with the regulation. This analysis is documented in an engineering analysis. The selected control technologies and monitoring requirements are then evaluated in a cost model to determine the total annualized control costs. The annualized control costs serve as inputs to an Economic Impact Analysis model that evaluates the impacts of those costs on the industry and society as a whole.

The Economic Impact Analysis used the National Energy Modeling System (NEMS) to estimate the impacts of the proposed NSPS on the United States energy system. The NEMS is a publically-available model of the United States energy economy developed and maintained by the Energy Information Administration of the United States DOE and is used to produce the *Annual Energy Outlook,* a reference publication that provides detailed forecasts of the energy economy from the current year to 2035. The impacts we estimated included changes in drilling activity, price and quantity changes in the production and consumption of crude oil and natural gas and changes in international trade of crude oil and natural gas. We evaluated whether and to what extent the increased production costs imposed by the NSPS might alter the mix of fuels consumed at a national level. Additionally, we combined estimated emissions co-reductions of methane from the engineering analysis with NEMS analysis to estimate the net change in CO_2e GHG from energy-related sources.

C. What are the air quality impacts?

For the oil and natural gas sector NESHAP and NSPS, we estimated the emission reductions that will occur due to the implementation of the final emission limits. The EPA estimated emission reductions based on the control technologies selected by the engineering analysis. These emission reductions associated with the proposed amendments to 40 CFR part 63, subpart

HH and 40 CFR part 63, subpart HHH are based on the estimated population in 2008. Under the proposed limits for glycol dehydration units and storage vessels, we have estimated that the HAP emissions reductions will be 1,400 tpy for existing units subject to the proposed emissions limits.

For the NSPS, we estimated the emission reductions that will occur due to the implementation of the final emission limits. The EPA estimated emission reductions based on the control technologies selected by the engineering analysis. These emission reductions are based on the estimated population in 2015. Under the proposed NSPS, we have estimated that the emissions reductions will be 540,000 tpy VOC for affected facilities subject to the NSPS.

The control strategies likely adopted to meet the proposed NESHAP amendments and the proposed NSPS will result in concurrent control of HAP, methane and VOC emissions. We estimate that direct reductions in HAP, methane and VOC for the proposed rules combined total about 38,000 tpy, 3.4 million tpy and 540,000 tpy, respectively.

Under the final standards, new monitoring requirements are being added.

D. What are the water quality and solid waste impacts?

We estimated minimal water quality impacts for the proposed amendments and proposed NSPS. For the proposed amendments to the NESHAP, we anticipate that the water impacts associated with the installation of a condenser system for the glycol dehydration unit process vent would be minimal. This is because the condensed water collected with the hydrocarbon condensate can be directed back into the system for reprocessing with the hydrocarbon condensate or, if separated, combined with produced water for disposal, usually by reinjection.

Similarly, the water impacts associated with installation of a vapor control system either on a glycol dehydration unit or a storage vessel would be minimal. This is because the water vapor collected along with the hydrocarbon vapors in the vapor collection and redirect system can be directed back into the system for reprocessing with the hydrocarbon condensate or, if separated, combined with the produced water for disposal for reinjection.

There would be no water impacts expected for facilities subject to the proposed NSPS. Further, we do not anticipate any adverse solid waste impacts from the implementation of the proposed NESHAP amendments and the proposed NSPS.

E. What are the secondary impacts?

Indirect or secondary air quality impacts include impacts that will result from the increased electricity usage associated with the operation of control devices, as well as water quality and solid waste impacts (which were just discussed) that might occur as a result of these proposed actions. We estimate the proposed amendments to 40 CFR part 63, subpart HH and 40 CFR part 63, subpart HHH will increase emissions of criteria pollutants due to the potential use of flares for the control of storage vessels. We do not estimate an increased energy demand associated with the installation of condensers, VRU or flares. The increases in criteria pollutant emissions associated with the use of flares to control storage vessels subject to existing source standards are estimated to be 5,500 tpy of CO_2, 16 tpy of carbon monoxide (CO), 3 tpy of NO_X, less than 1 tpy of particulate matter (PM) and 6 tpy total hydrocarbons. For storage vessels subject to new source standards, increases in secondary air pollutants are estimated to be less than 900 tpy of CO_2, 3 tpy of CO, 1 tpy of NO_X, 1 tpy of PM and 1 tpy total hydrocarbons.

In addition, we estimate that the secondary impacts associated with the pneumatic controller requirements to comply with the proposed NSPS would be about 22 tpy of CO_2, 1 tpy of NO_X and 3 tpy PM. For gas wellhead affected facilities, we estimate that the use of flares would result in increases in criteria pollutant emissions of about 990,000 tons of CO_2, 2,800 tpy of CO, 500 tpy of NO_X, 5 tpy of PM and 1,000 tpy total hydrocarbons.

F. What are the energy impacts?

Energy impacts in this section are those energy requirements associated with the operation of emission control devices. Potential impacts on the national energy economy from the rule are discussed in the economic impacts section. There would be little national energy demand increase from the operation of any of the control options analyzed under the proposed NESHAP amendments and proposed NSPS.

The proposed NESHAP amendments and proposed NSPS encourage the use of emission controls that recover hydrocarbon products, such as methane and condensate that can be used on-site as fuel or reprocessed within the production process for sale. We estimated that the proposed standards will result in a net cost savings due to the recovery of salable natural gas and condensate. Thus, the final standards have a positive impact associated with the recovery of non-renewable energy resources.

G. What are the cost impacts?

The estimated total capital cost to comply with the proposed amendments to 40 CFR part 63, subpart HH for major sources in the Oil and Natural Gas Production source category is approximately $51.5 million. The total capital cost for the proposed amendments to 40 CFR part 63, subpart HHH for major sources in the Natural Gas Transmission and Storage source category is estimated to be approximately $370 thousand. All costs are in 2008 dollars.

The total estimated net annual cost to industry to comply with the proposed amendments to 40 CFR part 63, subpart HH for major sources in the Oil and Natural Gas Production source category is approximately $16 million. The total net annual cost for proposed amendments to 40 CFR part 63, subpart HHH for major sources in the Natural Gas Transmission and Storage source category is estimated to be approximately $360,000. These estimated annual costs include: (1) The cost of capital, (2) operating and maintenance costs, (3) the cost of monitoring, inspection, recordkeeping and reporting (MIRR) and (4) any associated product recovery credits. All costs are in 2008 dollars.

The estimated total capital cost to comply with the proposed NSPS is approximately $740 million in 2008 dollars. The total estimated net annual cost to industry to comply with the proposed NSPS is approximately $740 million in 2008 dollars. This annual cost estimate includes: (1) The cost of capital, (2) operating and maintenance costs and (3) the cost of MIRR. This estimated annual cost does not take into account any producer revenues associated with the recovery of salable natural gas and hydrocarbon condensates.

When revenues from additional product recovery are considered, the proposed NSPS is estimated to result in a net annual engineering cost savings overall. When including the additional natural gas recovery in the engineering cost analysis, we assume that producers are paid $4 per thousand cubic feet (Mcf) for the recovered gas at the wellhead. The engineering analysis cost analysis assumes the value of recovered condensate is $70 per barrel. Based on the engineering analysis, about 180,000,000 Mcf (180 billion cubic feet) of natural gas and 730,000 barrels of

condensate are estimated to be recovered by control requirements in 2015. Using the price assumptions, the estimated revenues from natural gas product recovery are approximately $780 million in 2008 dollars. This savings is estimated at $45 million in 2008 dollars.

Using the engineering cost estimates, estimated natural gas product recovery, and natural gas product price assumptions, the net annual engineering cost savings is estimated for the proposed NSPS at about $45 million in 2008 dollars. Totals may not sum due to independent rounding.

As the price assumption is very influential on estimated annualized engineering costs, we performed a simple sensitivity analysis of the influence of the assumed wellhead price paid to natural gas producers on the overall engineering annualized costs estimate of the proposed NSPS. At $4.22/Mcf, the price forecast reported in the 2011 Annual Energy Outlook in 2008 dollars, the annualized costs are estimated at about −$90 million, which would approximately double the estimate of net cost savings of the proposed NSPS. As indicated by this difference, EPA has chosen a relatively conservative assumption (leading to an estimate of few savings and higher net costs) for the engineering costs analysis. The natural gas price at which the proposed NSPS breaks-even from an estimated engineering costs perspective is around $3.77/Mcf. A $1/Mcf change in the wellhead natural gas price leads to about a $180 million change in the annualized engineering costs of the proposed NSPS. Consequently, annualized engineering costs estimates would increase to about $140 million under a $3/Mcf price or decrease to about −$230 million under a $5/Mcf price. For further details on this sensitivity analysis, please refer the regulatory impact analysis (RIA) for this rulemaking located in the docket.

H. What are the economic impacts?

The NEMS analysis of energy system impacts for the proposed NSPS option estimates that domestic natural gas production is likely to increase slightly (about 20 billion cubic feet or 0.1 percent) and average natural gas prices to decrease slightly ($0.04 per Mcf in 2008 dollars or 0.9 percent at the wellhead for onshore producers in the lower 48 states) for 2015, the year of analysis. This increase in production and decrease in wellhead price is largely a result of the increased natural gas and condensate recovery as a result of complying with the NSPS. Domestic crude oil production is not expected to change, while average crude oil prices are estimated to decrease slightly ($0.02/barrel in 2008 dollars or less than 0.1 percent at the wellhead for onshore producers in the lower 48 states) in the year of analysis, 2015. The NEMS-based analysis estimates in the year of analysis, 2015, that net imports of natural gas and crude will not change significantly.

Total CO_2e emissions from energy-related sources are expected to increase about 2.0 million metric tons CO_2e or 0.04 percent under the proposed NSPS, according to the NEMS analysis. This increase is attributable largely to natural gas consumption increases. This estimate does not include CO_2e reductions from the implementation of the controls; these reductions are discussed in more detail in the benefits section that follows.

We did not estimate the energy economy impacts of the proposed NESHAP amendments using NEMS, as the expected costs of the rule are not likely to have estimable impacts on the national energy economy.

I. What are the benefits?

The proposed Oil and Natural Gas NSPS and NESHAP amendments are expected to result in significant reductions in existing emissions and prevent new emissions from expansions of the industry. These proposed rules combined are anticipated to reduce 38,000 tons of HAP, 540,000 tons of VOC and 3.4 million tons of methane. These pollutants are associated with substantial health effects, welfare effects and climate effects. With the data available, we are not able to provide credible health benefit estimates for the reduction in exposure to HAP, ozone and PM (2.5 microns and less) ($PM_{2.5}$) for these rules, due to the differences in the locations of oil and natural gas emission points relative to existing information and the highly localized nature of air quality responses associated with HAP and VOC reductions.

This is not to imply that there are no benefits of the rules; 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. In addition to health improvements, there will be improvements in visibility effects, ecosystem effects and climate effects, as well as additional product recovery.

Although we do not have sufficient information or modeling available to provide quantitative estimates for this rulemaking, we include a qualitative assessment of the health effects associated with exposure to HAP, ozone and $PM_{2.5}$ in the RIA for this rule. These qualitative effects are briefly summarized below, but for more detailed information, please refer to the RIA, which is available in the docket. One of the HAP of concern from the oil and natural gas sector is benzene, which is a known human carcinogen, and formaldehyde, which is a probable human carcinogen. VOC emissions are precursors to both $PM_{2.5}$ and ozone formation. As documented in previous analyses (U.S. EPA, 2006[41] and U.S. EPA, 2010[42]), exposure to $PM_{2.5}$ and ozone is associated with significant public health effects. $PM_{2.5}$ is associated with health effects such as premature mortality for adults and infants, cardiovascular morbidity, such as heart attacks, hospital admissions and respiratory morbidity such as asthma attacks, acute and chronic bronchitis, hospital and emergency room visits, work loss days, restricted activity days and respiratory symptoms, as well as visibility impairment.[43] Ozone is associated with health effects such as respiratory morbidity such as asthma attacks, hospital and emergency department visits, school loss days and premature mortality, as well as injury to vegetation and climate effects.[44]

In addition to the improvements in air quality and resulting benefits to human health and non-climate welfare effects previously discussed, this proposed rule is expected to result in significant climate co-benefits due to anticipated methane reductions. Methane is a potent GHG that, once emitted into the atmosphere, absorbs terrestrial infrared radiation, which contributes to increased global warming and continuing climate change. Methane reacts in the atmosphere to form ozone and ozone also impacts global temperatures. According to the

[41] U.S. EPA. RIA. *National Ambient Air Quality Standards for Particulate Matter,* Chapter 5. Office of Air Quality Planning and Standards, Research Triangle Park, NC. October 2006. Available on the Internet at *http://www.epa.gov/ttn/ecas/regdata/RIAs/Chapter%205-Benefits.pdf.*

[42] U.S. EPA. RIA. *National Ambient Air Quality Standards for Ozone.* Office of Air Quality Planning and Standards, Research Triangle Park, NC. January 2010. Available on the Internet at *http://www.epa.gov/ttn/ecas/regdata/RIAs/s1-supplemental_analysis_full.pdf.*

[43] U.S. EPA. *Integrated Science Assessment for Particulate Matter (Final Report).* EPA–600–R–08–139F. National Center for Environmental Assessment—RTP Division. December 2009. Available at *http://cfpub.epa.gov/ncea/cfm/recordisplay.cfm?deid=216546.*

[44] U.S. EPA. *Air Quality Criteria for Ozone and Related Photochemical Oxidants (Final).* EPA/600/R–05/004aF–cF. Washington, DC: U.S. EPA. February 2006. Available on the Internet at *http://cfpub.epa.gov/ncea/CFM/recordisplay.cfm?deid=149923.*

Intergovernmental Panel on Climate Change (IPCC) 4th Assessment Report (2007), methane is the second leading long-lived climate forcer after CO_2 globally. Total methane emissions from the oil and gas industry represent about 40 percent of the total methane emissions from all sources and account for about 5 percent of all CO_2e emissions in the United States, with natural gas systems being the single largest contributor to United States anthropogenic methane emissions.[45] Methane, in addition to other GHG emissions, contributes to warming of the atmosphere, which, over time, leads to increased air and ocean temperatures, changes in precipitation patterns, melting and thawing of global glaciers and ice, increasingly severe weather events, such as hurricanes of greater intensity and sea level rise, among other impacts.

This rulemaking proposes emission control technologies and regulatory alternatives that will significantly decrease methane emissions from the oil and natural gas sector in the United States. The regulatory alternatives proposed for the NESHAP and the NSPS are expected to reduce methane emissions annually by about 3.4 million short tons or 65 million metric tons CO_2e. After considering the secondary impacts of this proposal previously discussed, such as increased CO_2 emissions from well completion combustion and decreased CO_2e emissions because of fuel-switching by consumers, the methane reductions become about 62 million metric tons CO_2e. These reductions represent about 26 percent of the baseline methane emissions for this sector reported in the EPA's U.S. Greenhouse Gas Inventory Report for 2009 (251.55 million metric tons CO_2e when petroleum refineries and petroleum transportation are excluded because these sources are not examined in this proposal). After considering the secondary impacts of this proposal, such as increased CO_2 emissions from well completion combustion and decreased CO_2 emissions because of fuel-switching by consumers, the CO_2e GHG reductions are reduced to about 62 million metric tons CO_2e. However, it is important to note that the emission reductions are based upon predicted activities in 2015; the EPA did not forecast sector-level emissions in 2015 for this rulemaking. These emission reductions equate to the climate benefits of taking approximately 11 million typical passenger cars off the road or eliminating electricity use from about 7 million typical homes each year.[46]

The EPA recognizes that the methane reductions proposed in this rule will provide for significant economic climate benefits to society just described. However, there is no interagency-accepted methodology to place monetary values on these benefits. A 'global warming potential (GWP) approach' of converting methane to CO_2e using the GWP of methane provides an approximation method for estimating the monetized value of the methane reductions anticipated from this rule. This calculation uses the GWP of the non-CO_2 gas to estimate CO_2 equivalents and then multiplies these CO_2 equivalent emission reductions by the social cost of carbon developed by the Interagency Social Cost of Carbon Work Group to generate monetized estimates of the benefits.

The social cost of carbon is an estimate of the net present value of the flow of monetized damages from a 1-metric ton increase in CO_2 emissions in a given year (or from the alternative perspective, the benefit to society of reducing CO_2 emissions by 1 ton). For more information about the social cost of carbon, see the *Support Document: Social Cost of Carbon for Regulatory Impact Analysis Under Executive Order 12866*[47] and RIA for the Light-Duty Vehicle GHG rule.[48] Applying this approach to the methane reductions estimated for the proposed NESHAP and NSPS of the oil and gas rule, the 2015 climate co-benefits vary by discount rate and range from about $370 million to approximately $4.7 billion; the mean social cost of carbon at the 3-percent discount rate results in an estimate of about $1.6 billion in 2015.

The ratio of domestic to global benefits of emission reductions varies with key parameter assumptions. For example, with a 2.5 or 3 percent discount rate, the U.S. benefit is about 7–10 percent of the global benefit, on average, across the scenarios analyzed. Alternatively, if the fraction of GDP lost due to climate change is assumed to be similar across countries, the domestic benefit would be proportional to the U.S. share of global GDP, which is currently about 23 percent. On the basis of this evidence, values from 7 to 23 percent should be used to adjust the global SCC to calculate domestic effects. It is recognized that these values are approximate, provisional and highly speculative. There is no *a priori* reason why domestic benefits should be a constant fraction of net global damages over time.[49]

These co-benefits equate to a range of approximately $110 to $1,400 per short ton of methane reduced, depending upon the discount rate assumed with a per ton estimate of $480 at the 3-percent discount rate. Methane climate co-benefit estimates for additional regulatory alternatives are included in the RIA for this proposed rule. These social cost of methane benefit estimates are not the same as would be derived from direct computations (using the integrated assessment models employed to develop the Interagency Social Cost of Carbon estimates) for a variety of reasons, including the shorter atmospheric lifetime of methane relative to CO_2 (about 12 years compared to CO_2 whose concentrations in the atmosphere decay on timescales of decades to millennia). The climate impacts also differ between the pollutants for reasons other than the radiative forcing profiles and atmospheric lifetimes of these gases.

Methane is a precursor to ozone and ozone is a short-lived climate forcer that contributes to global warming. The use of the *IPCC Second Assessment Report GWP* to approximate co-benefits may underestimate the direct radiative forcing benefits of reduced ozone levels and does not capture any secondary climate co-benefits involved with ozone-ecosystem interactions. In addition, a recent EPA National Center of Environmental Economics working paper suggests that this quick 'GWP approach' to benefits estimation will likely understate the climate benefits of methane reductions in most cases.[50] This conclusion is reached using the 100-year GWP for methane of 25 as put forth in the *IPCC Fourth Assessment Report (AR 4),* as opposed to the lower

[45] U.S. EPA (2011), *2011 U.S. Greenhouse Gas Inventory Report* Executive Summary available on the internet at *http://www.epa.gov/climateexchange/emissions/downloads11/US-GHG-Inventory-2011-Executive Summary.pdf.*

[46] U.S. EPA. *Greenhouse Gas Equivalency Calculator* available at: *http://www.epa.gov/cleanenergy/energy-resources/calculator.html* accessed 07/19/11.

[47] Interagency Working Group on Social Cost of Carbon (IWGSC). 2010. Technical Support Document: Social Cost of Carbon for Regulatory Impact Analysis Under Executive Order 12866. Docket ID EPA–HQ–OAR–2009–0472–114577. *http://www.epa.gov/otaq/climate/regulations/scc-tsd.pdf;* Accessed March 30, 2011.

[48] U.S. EPA. *Final Rulemaking: Light-Duty Vehicle Greenhouse Gas Emissions Standards and Corporate Average Fuel Economy Standards.* May 2010. Available on the Internet at *http://www.epa.gov/otaq/climate/regulations.htm#finalR.*

[49] Interagency Working Group on Social Cost of Carbon (IWGSC). 2010. *Technical Support Document: Social Cost of Carbon for Regulatory Impact Analysis Under Executive Order 12866.*

[50] Marten and Newbold (2011), Estimating the Social Cost of Non-CO_2 *GHG Emissions: Methane and Nitrous Oxide,* NCEE Working Paper Series #11–01. *http://yosemite.epa.gov/EE/epa/eed.nsf/WPNumber/2011-01?OpenDocument.*

value of 21 used in this analysis. Using the higher GWP estimate of 25 would increase these reported methane climate co-benefit estimates by about 19 percent. Although the *IPCC Assessment Report (AR4)* suggested a GWP of 25 for methane, the EPA has used GWP of 21 to estimate the methane climate co-benefits for this oil and gas proposal in order to provide estimates more consistent with global GHG inventories, which currently use GWP from the *IPCC Second Assessment Report.*

Due to the uncertainties involved with the 'GWP approach' estimates presented and methane climate co-benefits estimates available in the literature, the EPA chooses not to compare these co-benefit estimates to the costs of the rule for this proposal. Rather, the EPA presents the 'GWP approach' climate co-benefit estimates as an interim method to produce these estimates until the Interagency Social Cost of Carbon Work Group develops values for non-CO_2 GHG. The EPA requests comments from interested parties and the public about this interim approach specifically and more broadly about appropriate methods to monetize the climate benefits of methane reductions. In particular, the EPA seeks public comments to this proposed rulemaking regarding social cost of methane estimates that may be used to value the co-benefits of methane emission reductions anticipated for the oil and gas industry from this rule. Comments specific to whether GWP is an acceptable method for generating a placeholder value for the social cost of methane until interagency-modeled estimates become available are welcome. Public comments may be provided in the official docket for this proposed rulemaking in accordance with the process outlined earlier in this notice. These comments will be considered in developing the final rule for this rulemaking.

For the proposed NESHAP amendments, a break-even analysis suggests that HAP emissions would need to be valued at $12,000 per ton for the benefits to exceed the costs if the health, ecosystem and climate benefits from the reductions in VOC and methane emissions are assumed to be zero. Even though emission reductions of VOC and methane are co-benefits for the proposed NESHAP amendments, they are legitimate components of the total benefit-cost comparison. If we assume the health benefits from HAP emission reductions are zero, the VOC emissions would need to be valued at $1,700 per ton or the methane emissions would need to be valued at $3,300 per ton for the co-benefits to exceed the costs. All estimates are in 2008 dollars. For the proposed NSPS, the revenue from additional product recovery exceeds the costs, which renders a break-even analysis unnecessary when these revenues are included in the analysis. Based on the methodology from Fann, Fulcher, and Hubbell (2009),[51] ranges of benefit-per-ton estimates for emissions of VOC indicate that on average in the United States, VOC emissions are valued from $1,200 to $3,000 per ton as a $PM_{2.5}$ precursor, but emission reductions in specific areas are valued from $280 to $7,000 per ton in 2008 dollars. As a result, even if VOC emissions from oil and natural gas operations result in monetized benefits that are substantially below the national average, there is a reasonable chance that the benefits of the rule would exceed the costs, especially if we were able to monetize all of the additional benefits associated with ozone formation, visibility, HAP and methane.

IX. Request for Comments

We are soliciting comments on all aspects of this proposed action. All comments received during the comment period will be considered. In addition to general comments on the proposed actions, we are also interested in any additional data that may help to reduce the uncertainties inherent in the risk assessments. We are specifically interested in receiving corrections to the datasets used for MACT analyses and risk modeling. Such data should include supporting documentation in sufficient detail to allow characterization of the quality and representativeness of the data or information. Please see the following section for more information on submitting data.

X. Submitting Data Corrections

The facility-specific data used in the source category risk analyses, facility-wide analyses and demographic analyses for each source category subject to this action are available for download on the RTR Web page at *http://www.epa.gov/ttn/atw/rrisk/rtrpg.html.* These data files include detailed information for each HAP emissions release point at each facility included in the source category and all other HAP emissions sources at these facilities (facility-wide emissions sources). However, it is important to note that the source category risk analysis included only those emissions tagged with the MACT code associated with the source category subject to the risk analysis.

If you believe the data are not representative or are inaccurate, please identify the data in question, provide your reason for concern and provide any ''improved'' data that you have, if available. When you submit data, we request that you provide documentation of the basis for the revised values to support your suggested changes. To submit comments on the data downloaded from the RTR Web page, complete the following steps:

1. Within this downloaded file, enter suggested revisions to the data fields appropriate for that information. The data fields that may be revised include the following:

Data element	Definition
Control Measure	Are control measures in place? (yes or no).
Control Measure Comment	Select control measure from list provided and briefly describe the control measure.
Delete	Indicate here if the facility or record should be deleted.
Delete Comment	Describes the reason for deletion.
Emission Calculation Method Code for Revised Emissions.	Code description of the method used to derive emissions. For example, CEM, material balance, stack test, etc.
Emission Process Group	Enter the general type of emission process associated with the specified emission point.
Fugitive Angle	Enter release angle (clockwise from true North); orientation of the y-dimension relative to true North, measured positive for clockwise starting at 0 degrees (maximum 89 degrees).
Fugitive Length	Enter dimension of the source in the east-west (x-) direction, commonly referred to as length (ft).

[51] Fann, N., C.M. Fulcher, B.J. Hubbell. *The influence of location, source, and emission type in estimates of the human health benefits of reducing a ton of air pollution.* Air Qual Atmos Health (2009) 2:169–176.

Data element	Definition
Fugitive Width	Enter dimension of the source in the north-south (y-) direction, commonly referred to as width (ft).
Malfunction Emissions	Enter total annual emissions due to malfunctions (TPY).
Malfunction Emissions Max Hourly	Enter maximum hourly malfunction emissions here (lb/hr).
North American Datum	Enter datum for latitude/longitude coordinates (NAD27 or NAD83); if left blank, NAD83 is assumed.
Process Comment	Enter general comments about process sources of emissions.
REVISED Address	Enter revised physical street address for MACT facility here.
REVISED City	Enter revised city name here.
REVISED County Name	Enter revised county name here.
REVISED Emission Release Point Type	Enter revised Emission Release Point Type here.
REVISED End Date	Enter revised End Date here.
REVISED Exit Gas Flow Rate	Enter revised Exit Gas Flowrate here (ft^3/sec).
REVISED Exit Gas Temperature	Enter revised Exit Gas Temperature here (OF).
REVISED Exit Gas Velocity	Enter revised Exit Gas Velocity here (ft/sec).
REVISED Facility Category Code	Enter revised Facility Category Code here, which indicates whether facility is a major or area source.
REVISED Facility Name	Enter revised Facility Name here.
REVISED Facility Registry Identifier	Enter revised Facility Registry Identifier here, which is an ID assigned by the EPA Facility Registry System.
REVISED HAP Emissions Performance Level Code	Enter revised HAP Emissions Performance Level here.
REVISED Latitude	Enter revised Latitude here (decimal degrees).
REVISED Longitude	Enter revised Longitude here (decimal degrees).
REVISED MACT Code	Enter revised MACT Code here.
REVISED Pollutant Code	Enter revised Pollutant Code here.
REVISED Routine Emissions	Enter revised routine emissions value here (TPY).
REVISED SCC Code	Enter revised SCC Code here.
REVISED Stack Diameter	Enter revised Stack Diameter here (ft).
REVISED Stack Height	Enter revised Stack Height here (Ft).
REVISED Start Date	Enter revised Start Date here.
REVISED State	Enter revised state here.
REVISED Tribal Code	Enter revised Tribal Code here.
REVISED Zip Code	Enter revised Zip Code here.
Shutdown Emissions	Enter total annual emissions due to shutdown events (TPY).
Shutdown Emissions Max Hourly	Enter maximum hourly shutdown emissions here (lb/hr).
Stack Comment	Enter general comments about emission release points.
Startup Emissions	Enter total annual emissions due to startup events (TPY).
Startup Emissions Max Hourly	Enter maximum hourly startup emissions here (lb/hr).
Year Closed	Enter date facility stopped operations.

2. Fill in the commenter information fields for each suggested revision (*i.e.,* commenter name, commenter organization, commenter e-mail address, commenter phone number and revision comments).

3. Gather documentation for any suggested emissions revisions (*e.g.,* performance test reports, material balance calculations, etc.).

4. Send the entire downloaded file with suggested revisions in Microsoft® Access format and all accompanying documentation to Docket ID Number EPA–HQ–OAR–2010–0505 (through one of the methods described in the **ADDRESSES** section of this preamble). To expedite review of the revisions, it would also be helpful if you submitted a copy of your revisions to the EPA directly at *RTR@epa.gov* in addition to submitting them to the docket.

5. If you are providing comments on a facility with multiple source categories, you need only submit one file for that facility, which should contain all suggested changes for all source categories at that facility. We request that all data revision comments be submitted in the form of updated Microsoft® Access files, which are provided on the *http://www.epa.gov/ttn/atw/rrisk/rtrpg.html* Web page.

XI. Statutory and Executive Order Reviews

A. Executive Order 12866: Regulatory Planning and Review and Executive Order 13563: Improving Regulation and Regulatory Review

Under Executive Order 12866 (58 FR 51735, October 4, 1993), this action is an ''economically significant regulatory action'' because it is likely to have an annual effect on the economy of $100 million or more. Accordingly, the EPA submitted this action to OMB for review under Executive Order 12866 and Executive Order 13563 (76 FR 3821, January 21, 2011) and any changes made in response to OMB recommendations have been documented in the docket for this action.

In addition, the EPA prepared a RIA of the potential costs and benefits associated with this action. The RIA available in the docket describes in detail the empirical basis for the EPA's assumptions and characterizes the various sources of uncertainties affecting the estimates below. Table 8 shows the results of the cost and benefits analysis for these proposed rules. For more information on the benefit and cost analysis, as well as details on the regulatory options considered, please refer to the RIA for this rulemaking, which is available in the docket.

TABLE 8—SUMMARY OF THE MONETIZED BENEFITS, COSTS AND NET BENEFITS FOR THE PROPOSED OIL AND NATURAL GAS NSPS AND NEHSAP AMENDMENTS IN 2015

[Millions of 2008$] [1]

	Proposed NSPS	Proposed NESHAP amendments	Proposed NSPS and NESHAP amendments combined
Total Monetized Benefits [2]	N/A	N/A	N/A.
Total Costs [3]	−$45 million	$16 million	−$29 million.
Net Benefits	N/A	N/A	N/A.
Non-monetized Benefits [4 5]	37,000 tons of HAP 540,000 tons of VOC 3.4 million tons of methane	1,400 tons of HAP 9,200 tons of VOC 4,900 tons of methane	38,000 tons of HAP. 540,000 tons of VOC. 3.4 million tons of methane.
	Health effects of HAP exposure. Health effects of $PM_{2.5}$ and ozone exposure. Visibility impairment. Vegetation effects. Climate effects.		

[1] All estimates are for the implementation year (2015).

[2] While we expect that these avoided emissions will result in improvements in air quality and reductions in health effects associated with HAP, ozone and PM, as well as climate effects associated with methane, we have determined that quantification of those benefits cannot be accomplished for this rule in a defensible way. This is not to imply that there are no benefits of the rules; 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.

[3] The engineering compliance costs are annualized using a 7-percent discount rate. The negative cost for the proposed NSPS reflects the inclusion of revenues from additional natural gas and hydrocarbon condensate recovery that are estimated as a result of the proposed NSPS.

[4] For the NSPS, reduced exposure to HAP and climate effects are co-benefits. For the NESHAP, reduced VOC emissions, $PM_{2.5}$ and ozone exposure, visibility and vegetation effects and climate effects are co-benefits.

[5] The specific control technologies for these proposed rules are anticipated to have minor secondary disbenefits. The net CO_2-equivalent emission reductions are 93,000 metric tons for the NESHAP and 62 million metric tons for the NSPS.

B. Paperwork Reduction Act

The information collection requirements in this proposed action have been submitted for approval to OMB under the *Paperwork Reduction Act,* 44 U.S.C. 3501, *et seq.* The ICR document prepared by the EPA has been assigned EPA ICR Numbers 1716.07 (40 CFR part 60, subpart OOOO), 1788.10 (40 CFR part 63, subpart HH), 1789.07 (40 CFR part 63, subpart HHH) and 1086.10 (40 CFR part 60, subparts KKK and subpart LLL).

The information to be collected for the proposed NSPS and the proposed NESHAP amendments are based on notification, recordkeeping and reporting requirements in the NESHAP General Provisions (40 CFR part 63, subpart A), which are mandatory for all operators subject to national emission standards. These recordkeeping and reporting requirements are specifically authorized by section 114 of the CAA (42 U.S.C. 7414). All information submitted to the EPA pursuant to the recordkeeping and reporting requirements for which a claim of confidentiality is made is safeguarded according to Agency policies set forth in 40 CFR part 2, subpart B.

These proposed rules would require maintenance inspections of the control devices, but would not require any notifications or reports beyond those required by the General Provisions. The recordkeeping requirements require only the specific information needed to determine compliance.

For sources subject to the proposed NSPS, burden changes associated with these amendments result from the respondents' annual reporting and recordkeeping burden associated with this proposed rule for this collection (averaged over the first 3 years after the effective date of the standards). The burden is estimated to be 560,000 labor hours at a cost of $18 million per year. This includes the burden previously estimated for sources subject to 40 CFR part 60, subpart KKK (which is being incorporated into 40 CFR part 60, subpart OOOO). The average hours and cost per regulated entity subject to the NSPS for oil and natural gas production and natural gas transmissions and distribution facilities would be 110 hours per response and $3,693 per response, based on an average of 1,459 operators responding per year and 16 responses per year.

The estimated recordkeeping and reporting burden after the effective date of the proposed amendments is estimated for all affected major and area sources subject to the Oil and Natural Gas Production NESHAP to be approximately 63,000 labor hours per year at a cost of $2.1 million per year. For the Natural Gas Transmission and Storage NESHAP, the recordkeeping and reporting burden is estimated to be 2,500 labor hours per year at a cost of $86,800 per year. This estimate includes the cost of reporting, including reading instructions and information gathering. Recordkeeping cost estimates include reading instructions, planning activities and conducting compliance monitoring. The average hours and cost per regulated entity subject to the Oil and Natural Gas Production NESHAP would be 72 hours per year and $2,500 per year, based on an average of 846 facilities per year and three responses per facility. For the Natural Gas Transmission and Storage NESHAP, the average hours and cost per regulated entity would be 50 hours per year and $1,600 per year, based on an average of 53 facilities per year and three responses per facility. Burden is defined at 5 CFR 1320.3(b).

An agency may not conduct or sponsor, and a person is not required to respond to, a collection of information unless it displays a currently valid OMB control number. The OMB control numbers for the EPA's regulations in 40 CFR are listed in 40 CFR part 9.

To comment on the Agency's need for this information, the accuracy of the provided burden estimates and any suggested methods for minimizing respondent burden, the EPA has established a public docket for this rule, which includes this ICR, under Docket ID Number EPA–HQ–OAR–2010–0505. Submit any comments related to the ICR to the EPA and OMB. See the **ADDRESSES** section at the beginning of this notice for where to submit comments to the

EPA. Send comments to OMB at the Office of Information and Regulatory Affairs, Office of Management and Budget, 725 17th Street, NW., Washington, DC 20503, Attention: Desk Office for the EPA. Since OMB is required to make a decision concerning the ICR between 30 and 60 days after August 23, 2011, a comment to OMB is best assured of having its full effect if OMB receives it by September 22, 2011. The final rule will respond to any OMB or public comments on the information collection requirements contained in this proposal.

C. Regulatory Flexibility Act

The Regulatory Flexibility Act generally requires an agency to prepare a regulatory flexibility analysis of any rule subject to notice and comment rulemaking requirements under the Administrative Procedure Act or any other statute, unless the agency certifies that the rule will not have a significant economic impact on a substantial number of small entities (SISNOSE). Small entities include small businesses, small organizations, and small governmental jurisdictions. For purposes of assessing the impact of this rule on small entities, a small entity is defined as: (1) A small business whose parent company has no more than 500 employees (or revenues of less than $7 million for firms that transport natural gas via pipeline); (2) a small governmental jurisdiction that is a government of a city, county, town, school district, or special district with a population of less than 50,000; and (3) a small organization that is any not-for-profit enterprise which is independently owned and operated and is not dominant in its field.

Proposed NSPS

After considering the economic impact of the proposed NSPS on small entities, I certify that this action will not have a SISNOSE. The EPA performed a screening analysis for impacts on a sample of expected affected small entities by comparing compliance costs to entity revenues. Based upon the analysis in the RIA, which is in the Docket, EPA concludes the number of impacted small businesses is unlikely to be sufficiently large to declare a SISNOSE. Our judgment in this determination is informed by the fact that many affected firms are expected to receive revenues from the additional natural gas and condensate recovery engendered by the implementation of the controls evaluated in this RIA. As much of the additional natural gas recovery is estimated to arise from completion-related activities, we expect the impact on well-related compliance costs to be significantly mitigated. This conclusion is enhanced because the returns to REC activities occur without a significant time lag between implementing the control and obtaining the recovered product, unlike many control options where the emissions reductions accumulate over long periods of time; the reduced emission completions and recompletions occur over a short span of time, during which the additional product recovery is also accomplished.

Proposed NESHAP Amendments

After considering the economic impact of the proposed NESHAP amendments on small entities, I certify that this action will not have a SISNOSE. Based upon the analysis in the RIA, which is in the Docket, we estimate that 62 of the 118 firms (53 percent) that own potentially affected facilities are small entities. The EPA performed a screening analysis for impacts on all expected affected small entities by comparing compliance costs to entity revenues. Among the small firms, 52 of the 62 (84 percent) are likely to have impacts of less than 1 percent in terms of the ratio of annualized compliance costs to revenues. Meanwhile, *10 firms (16 percent)* are likely to have impacts greater than 1 percent. Four of these *10* firms are likely to have impacts greater than 3 percent. While these *10* firms might receive significant impacts from the proposed NESHAP amendments, they represent a very small slice of the oil and gas industry in its entirety, less than 0.2 percent of the estimated 6,427 small firms in NAICS 211. Although this final rule will not impact a substantial number of small entities, the EPA, nonetheless, has tried to reduce the impact of this rule on small entities by setting the final emissions limits at the MACT floor, the least stringent level allowed by law.

We continue to be interested in the potential impacts of the proposed rule on small entities and welcome comments on issues related to such impacts.

D. Unfunded Mandates Reform Act

This action contains no Federal mandates under the provisions of title II of the *Unfunded Mandates Reform Act of 1995* (UMRA), 2 U.S.C. 1531–1538 for state, local or tribal governments or the private sector. This proposed rule does not contain a Federal mandate that may result in expenditures of $100 million or more for state, local and tribal governments, in the aggregate, or to the private sector in any one year. Thus, this proposed rule is not subject to the requirements of sections 202 or 205 of UMRA. This proposed rule is also not subject to the requirements of section 203 of UMRA because it contains no regulatory requirements that might significantly or uniquely affect small governments. This action contains no requirements that apply to such governments nor does it impose obligations upon them.

E. Executive Order 13132: Federalism

This proposed rule does not have federalism implications. It will not have substantial direct effects on the states, on the relationship between the national government and the states, or on the distribution of power and responsibilities among the various levels of government, as specified in Executive Order 13132. Thus, Executive Order 13132 does not apply to this proposed rule. In the spirit of Executive Order 13132 and consistent with the EPA policy to promote communications between the EPA and state and local governments, the EPA specifically solicits comment on this proposed rule from state and local officials.

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

This action does not have tribal implications, as specified in Executive Order 13175 (65 FR 67249, November 9, 2000). It will not have substantial direct effect on tribal governments, on the relationship between the Federal government and Indian tribes or on the distribution of power and responsibilities between the Federal government and Indian tribes, as specified in Executive Order 13175. Thus, Executive Order 13175 does not apply to this action.

The EPA specifically solicits additional comment on this proposed action from tribal officials.

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

This proposed rule is not subject to Executive Order 13045 (62 FR 19885, April 23, 1997) because the Agency does not believe the environmental health risks or safety risks addressed by this action present a disproportionate risk to children. This actions' health and risk assessments are contained in section VII.C of this preamble.

The public is invited to submit comments or identify peer-reviewed studies and data that assess effects of early life exposure to HAP from oil and natural gas sector activities.

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

Executive Order 13211, (66 FR 28,355, May 22, 2001), provides that agencies shall prepare and submit to the Administrator of the Office of Information and Regulatory Affairs, OMB, a Statement of Energy Effects for certain actions identified as significant energy actions. Section 4(b) of Executive Order 13211 defines ''significant energy actions'' as ''any action by an agency (normally published in the **Federal Register**) that promulgates or is expected to lead to the promulgation of a final rule or regulation, including notices of inquiry, advance notices of proposed rulemaking, and notices of proposed rulemaking: (1)(i) That is a significant regulatory action under Executive Order 12866 or any successor order and (ii) is likely to have a significant adverse effect on the supply, distribution, or use of energy; or (2) that is designated by the Administrator of the Office of Information and Regulatory Affairs as a significant energy action.''

The proposed rules will result in the addition of control equipment and monitoring systems for existing and new sources within the oil and natural gas industry. The proposed NESHAP amendments are unlikely to have a significant adverse effect on the supply, distribution or use of energy. As such, the proposed NESHAP amendments are not ''significant energy actions'' as defined in Executive Order 13211 (66 FR 28355, May 22, 2001).

The proposed NSPS is also unlikely to have a significant effect on the supply, distribution or use of energy. As such, the proposed NSPS is not a ''significant energy action'' as defined in Executive Order 13211 (66 FR 28355, May 22, 2001). The basis for the determination is as follows.

As discussed in the impacts section of the Preamble, we use the NEMS to estimate the impacts of the proposed NSPS on the United States energy system. The NEMS is a publically available model of the United States energy economy developed and maintained by the Energy Information Administration of the United States DOE and is used to produce the *Annual Energy Outlook,* a reference publication that provides detailed forecasts of the United States energy economy.

Proposed emission controls for the NSPS capture VOC emissions that otherwise would be vented to the atmosphere. Since methane is co-emitted with VOC, a large proportion of the averted methane emissions can be directed into natural gas production streams and sold. One pollution control requirement of the proposed NSPS also captures saleable condensates. The revenues from additional natural gas and condensate recovery are expected to offset the costs of implementing the proposed NSPS.

The analysis of energy impacts for the proposed NSPS that includes the additional product recovery shows that domestic natural gas production is estimated to increase (20 billion cubic feet or 0.1 percent) and natural gas prices to decrease ($0.04/Mcf or 0.9 percent at the wellhead for producers in the lower 48 states) in 2015, the year of analysis. Domestic crude oil production is not estimated to change, while crude oil prices are estimated to decrease slightly ($0.02/barrel or less than 0.1 percent at the wellhead for producers in the lower 48 states) in 2015, the year of analysis. All prices are in 2008 dollars.

Additionally, the NSPS establishes several performance standards that give regulated entities flexibility in determining how to best comply with the regulation. In an industry that is geographically and economically heterogeneous, this flexibility is an important factor in reducing regulatory burden.

For more information on the estimated energy effects, please refer to the economic impact analysis for this proposed rule. The analysis is available in the RIA, which is in the public docket.

I. National Technology Transfer and Advancement Act

Section 12(d) of the National Technology Transfer and Advancement Act of 1995 (NTTAA), Public Law No. 104–113 (15 U.S.C. 272 note) directs the EPA to use voluntary consensus standards (VCS) in its regulatory activities unless to do so would be inconsistent with applicable law or otherwise impractical. VCS are technical standards (*e.g.,* materials specifications, test methods, sampling procedures, and business practices) that are developed or adopted by VCS bodies. NTTAA directs the EPA to provide Congress, through OMB, explanations when the Agency decides not to use available and applicable VCS.

The proposed rule involves technical standards. Therefore, the requirements of the NTTAA apply to this action. We are proposing to revise 40 CFR part 63, subpart HH and 40 CFR part 63, subpart HHH to allow ANSI/ASME PTC 19.10–1981, Flue and Exhaust Gas Analyses (Part 10, Instruments and Apparatus) to be used in lieu of EPA Methods 3B, 6 and 16A. This standard is available from the American Society of Mechanical Engineers (ASME), Three Park Avenue, New York, NY 10016–5990. Also, we are proposing to revise subpart HHH to allow ASTM D6420–99 (2004), *Test Method for Determination of Gaseous Organic Compounds by Direct Interface Gas Chromatography/Mass Spectrometry,* to be used in lieu of EPA Method 18. For a detailed discussion of this VCS, and its appropriateness as a substitute for Method 18, see the final Oil and Natural Gas Production NESHAP (Area Sources) (72 FR 36, January 3, 2007).

As a result, the EPA is proposing ASTM D6420–99 (2004) for use in 40 CFR part 63, subpart HHH. The EPA also proposes to allow Method 18 as an option in addition to ASTM D6420–99 (2004). This would allow the continued use of gas chromatography configurations other than gas chromatography/mass spectrometry.

The EPA welcomes comments on this aspect of the proposed rulemaking and, specifically, invites the public to identify potentially-applicable VCS and to explain why such standards should be used in this regulation.

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

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

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

To examine the potential for any EJ issues that might be associated with each source category, we evaluated the distributions of HAP-related cancer and noncancer risks across different social, demographic and economic groups within the populations living near the facilities where these source categories

are located. The methods used to conduct demographic analyses for this rule are described in section VII.C of the preamble for this rule. The development of demographic analyses to inform the consideration of EJ issues in EPA rulemakings is an evolving science. The EPA offers the demographic analyses in this proposed rulemaking as examples of how such analyses might be developed to inform such consideration, and invites public comment on the approaches used and the interpretations made from the results, with the hope that this will support the refinement and improve utility of such analyses for future rulemakings.

For the demographic analyses, we focused on the populations within 50 km of any facility estimated to have exposures to HAP which result in cancer risks of 1-in-1 million or greater, or noncancer HI of 1 or greater (based on the emissions of the source category or the facility, respectively). We examined the distributions of those risks across various demographic groups, comparing the percentages of particular demographic groups to the total number of people in those demographic groups nationwide. The results, including other risk metrics, such as average risks for the exposed populations, are documented in source category-specific technical reports in the docket for both source categories covered in this proposal.

As described in the preamble, our risk assessments demonstrate that the regulations for the oil and natural gas production and natural gas transmission and storage source categories, are associated with an acceptable level of risk and that the proposed additional requirements will provide an ample margin of safety to protect public health. Our analyses also show that, for these source categories, there is no potential for an adverse environmental effect or human health multi-pathway effects, and that acute and chronic noncancer health impacts are unlikely. The EPA has determined that, although there may be an existing disparity in HAP risks from these sources between some demographic groups, no demographic group is exposed to an unacceptable level of risk.

List of Subjects

40 CFR Part 60

Environmental protection, Air pollution control, Reporting and recordkeeping requirements, Volatile organic compounds.

40 CFR Part 63

Environmental protection, Air pollution control, Reporting and recordkeeping requirements, Volatile organic compounds.

Dated: July 28, 2011.

Lisa P. Jackson,

Administrator.

For the reasons set out in the preamble, title 40, chapter I of the Code of Federal Regulations is proposed to be amended as follows:

PART 60—[AMENDED]

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

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

2. Section 60.17 is amended by:

a. Revising paragraph (a)(7); and

b. Revising paragraphs (a)(91) and (a)(92) to read as follows:

§ 60.17 Incorporations by reference.

* * * * *

(a) * * *

(7) ASTM D86–78, 82, 90, 93, 95, 96, Distillation of Petroleum Products, IBR approved for §§ 60.562–2(d), 60.593(d), 60.593a(d), 60.633(h) and 60.5401(h).

* * * * *

(91) ASTM E169–63, 77, 93, General Techniques of Ultraviolet Quantitative Analysis, IBR approved for §§ 60.485a(d)(1), 60.593(b)(2), 60.593a(b)(2), 60.632(f) and 60.5400(f).

(92) ASTM E260–73, 91, 96, General Gas Chromatography Procedures, IBR approved for §§ 60.485a(d)(1), 60.593(b)(2), 60.593a(b)(2), 60.632(f), 60.5400(f) and 60.5406(b).

* * * * *

Subpart KKK—Standards of Performance for Equipment Leaks of VOC From Onshore Natural Gas Processing Plants for Which Construction, Reconstruction, or Modification Commenced After January 20, 1984, and on or Before August 23, 2011

3. The heading for Subpart KKK is revised to read as set out above.

4. Section 60.630 is amended by revising paragraph (b) to read as follows:

§ 60.630 Applicability and designation of affected facility.

* * * * *

(b) Any affected facility under paragraph (a) of this section that commences construction, reconstruction, or modification after January 20, 1984, and on or before August 23, 2011, is subject to the requirements of this subpart.

* * * * *

Subpart LLL—Standards of Performance for SO_2 Emissions From Onshore Natural Gas Processing for Which Construction, Reconstruction, or Modification Commenced After January 20, 1984, and on or Before August 23, 2011

5. The heading for Subpart LLL is revised to read as set out above.

6. Section 60.640 is amended by revising paragraph (d) to read as follows:

§ 60.640 Applicability and designation of affected facilities.

* * * * *

(d) The provisions of this subpart apply to each affected facility identified in paragraph (a) of this section which commences construction or modification after January 20, 1984, and on or before August 23, 2011.

* * * * *

7. Add subpart OOOO to part 60 to read as follows:

Subpart OOOO—Standards of Performance for Crude Oil and Natural Gas Production, Transmission, and Distribution

Sec.

Subpart OOOO—Standards of Performance for Crude Oil and Natural Gas Production, Transmission, and Distribution

§ 60.5360 What is the purpose of this subpart?

This subpart establishes emission standards and compliance schedules for the control of volatile organic compounds (VOC) and sulfur dioxide (SO_2) emissions from affected facilities that commenced construction, modification or reconstruction after August 23, 2011.

§ 60.5365 Am I subject to this subpart?

If you are the owner or operator of one or more of the affected facilities listed in paragraphs (a) through (g) of this section that commenced construction, modification, or reconstruction after August 23, 2011 your affected facility is subject to the applicable provisions of this subpart. For the purposes of this subpart, a well completion operation following hydraulic fracturing or refracturing that occurs at a gas wellhead facility that commenced construction, modification, or reconstruction on or before August 23, 2011 is considered a modification of the gas wellhead facility, but does not affect other equipment, process units, storage vessels, or pneumatic devices located at the well site.

(a) A gas wellhead affected facility, is a single natural gas well.

(b) A centrifugal compressor affected facility, which is defined as a single centrifugal compressor located between the wellhead and the city gate (as defined in § 60.5430), except that a centrifugal compressor located at a well site (as defined in § 60.5430) is not an affected facility under this subpart. For the purposes of this subpart, your centrifugal compressor is considered to have commenced construction on the date the compressor is installed at the facility.

(c) A reciprocating compressor affected facility, which is defined as a single reciprocating compressor located between the wellhead and the city gate (as defined in § 60.5430), except that a reciprocating compressor located at a well site (as defined in § 60.5430) is not an affected facility under this subpart. For the purposes of this subpart, your reciprocating compressor is considered to have commenced construction on the date the compressor is installed at the facility.

(d) A pneumatic controller affected facility, which is defined as a single pneumatic controller.

(e) A storage vessel affected facility, which is defined as a single storage vessel.

(f) Compressors and equipment (as defined in § 60.5430) located at onshore natural gas processing plants.

(1) Each compressor in VOC service or in wet gas service is an affected facility.

(2) The group of all equipment, except compressors, within a process unit is an affected facility.

(3) Addition or replacement of equipment, as defined in § 60.5430, for the purpose of process improvement that is accomplished without a capital expenditure shall not by itself be considered a modification under this subpart.

(4) Equipment (as defined in § 60.5430) associated with a compressor station, dehydration unit, sweetening unit, underground storage tank, field gas gathering system, or liquefied natural gas unit is covered by §§ 60.5400, 60.5401, 60.5402, 60.5421 and 60.5422 of this subpart if it is located at an onshore natural gas processing plant. Equipment (as defined in § 60.5430) not located at the onshore natural gas processing plant site is exempt from the provisions of §§ 60.5400, 60.5401, 60.5402, 60.5421 and 60.5422 of this subpart.

(5) Affected facilities located at onshore natural gas processing plants and described in paragraphs (f)(1) and (f)(2) of this section are exempt from this subpart if they are subject to and controlled according to subparts VVa, GGG or GGGa of this part.

(g) Sweetening units located onshore that process natural gas produced from either onshore or offshore wells.

(1) Each sweetening unit that processes natural gas is an affected facility; and

(2) Each sweetening unit that processes natural gas followed by a sulfur recovery unit is an affected facility.

(3) Facilities that have a design capacity less than 2 long tons per day (LT/D) of hydrogen sulfide (H_2S) in the acid gas (expressed as sulfur) are required to comply with recordkeeping and reporting requirements specified in § 60.5423(c) but are not required to comply with §§ 60.5405 through 60.5407 and paragraphs 60.5410(g) and 60.5415(g) of this subpart.

(4) Sweetening facilities producing acid gas that is completely reinjected into oil-or-gas-bearing geologic strata or that is otherwise not released to the atmosphere are not subject to §§ 60.5405 through 60.5407, and §§ 60.5410(g), 60.5415(g), and § 60.5423 of this subpart.

§ 60.5370 When must I comply with this subpart?

(a) You must be in compliance with the standards of this subpart no later than the date of publication of the final rule in the **Federal Register** or upon startup, whichever is later.

(b) The provisions for exemption from compliance during periods of startup, shutdown, and malfunctions provided for in 40 CFR 60.8(c) do not apply to this subpart.

(c) You are exempt from the obligation to obtain a permit under 40 CFR part 70 or 40 CFR part 71, provided you are not otherwise required by law to obtain a permit under 40 CFR 70.3(a) or 40 CFR 71.3(a). Notwithstanding the previous sentence, you must continue to comply with the provisions of this subpart.

§ 60.5375 What standards apply to gas wellhead affected facilities?

If you are the owner or operator of a gas wellhead affected facility, you must comply with paragraphs (a) through (g) of this section.

(a) Except as provided in paragraph (f) of this section, for each well completion operation with hydraulic fracturing, as defined in § 60.5430, you must control emissions by the operational procedures found in paragraphs (a)(1) through (a)(3) of this section.

(1) You must minimize the emissions associated with venting of hydrocarbon fluids and gas over the duration of flowback by routing the recovered liquids into storage vessels and routing the recovered gas into a gas gathering line or collection system.

(2) You must employ sand traps, surge vessels, separators, and tanks during flowback and cleanout operations to safely maximize resource recovery and minimize releases to the environment. All salable quality gas must be routed to the gas gathering line as soon as practicable.

(3) You must capture and direct flowback emissions that cannot be directed to the gathering line to a completion combustion device, except in conditions that may result in a fire hazard or explosion. Completion combustion devices must be equipped with a reliable continuous ignition source over the duration of flowback.

(b) You must maintain a log for each well completion operation at each gas wellhead affected facility. The log must be completed on a daily basis and must contain the records specified in § 60.5420(c)(1)(iii).

(c) You must demonstrate initial compliance with the standards that apply to gas wellhead affected facilities as required by § 60.5410.

(d) You must demonstrate continuous compliance with the standards that apply to gas wellhead affected facilities as required by § 60.5415.

(e) You must perform the required notification, recordkeeping, and reporting as required by § 60.5420.

(f) For wells meeting the criteria for wildcat or delineation wells, each well completion operation with hydraulic fracturing at a gas wellhead affected facility must reduce emissions by using a completion combustion device meeting the requirements of paragraph (a)(3) of this section. You must also maintain records specified in § 60.5420(c)(1)(iii) for wildcat or delineation wells.

§ 60.5380 What standards apply to centrifugal compressor affected facilities?

You must comply with the standards in paragraphs (a) through (d) of this section, as applicable for each centrifugal compressor affected facility.

(a) You must equip each rotating compressor shaft with a dry seal system upon initial startup.

(b) You must demonstrate initial compliance with the standards that apply to centrifugal compressor affected facilities as required by § 60.5410.

(c) You must demonstrate continuous compliance with the standards that apply to centrifugal compressor affected facilities as required by § 60.5415.

(d) You must perform the required notification, recordkeeping, and reporting as required by § 60.5420.

§ 60.5385 What standards apply to reciprocating compressor affected facilities?

You must comply with the standards in paragraphs (a) through (d) of this section for each reciprocating compressor affected facility.

(a) You must replace the reciprocating compressor rod packing before the compressor has operated for 26,000 hours. The number of hours of operation must be continuously monitored beginning upon initial startup of your reciprocating compressor affected facility, or the date of publication of the final rule in the **Federal Register**, or the date of the previous reciprocating compressor rod packing replacement, whichever is later.

(b) You must demonstrate initial compliance with standards that apply to reciprocating compressor affected facilities as required by § 60.5410.

(c) You must demonstrate continuous compliance with standards that apply to reciprocating compressor affected facilities as required by § 60.5415.

(d) You must perform the required notification, recordkeeping, and reporting as required by § 60.5420.

§ 60.5390 What standards apply to pneumatic controller affected facilities?

For each pneumatic controller affected facility you must comply with the VOC standards, based on natural gas as a surrogate for VOC, in either paragraph (b) or (c) of this section, as applicable. Pneumatic controllers meeting the conditions in paragraph (a) are exempt from this requirement.

(a) The requirements of paragraph (b) or (c) of this section are not required if you demonstrate, to the Administrator's satisfaction, that the use of a high bleed device is predicated. The demonstration may include, but is not limited to, response time, safety and actuation.

(b) Each pneumatic controller affected facility located at a natural gas processing plant (as defined in § 60.5430) must have zero emissions of natural gas.

(c) Each pneumatic controller affected facility not located at a natural gas processing plant (as defined in § 60.5430) must have natural gas emissions no greater than 6 standard cubic feet per hour.

(d) You must demonstrate initial compliance with standards that apply to pneumatic controller affected facilities as required by § 60.5410.

(e) You must demonstrate continuous compliance with standards that apply to pneumatic controller affected facilities as required by § 60.5415.

(f) You must perform the required notification, recordkeeping, and reporting as required by § 60.5420, except that you are not required to submit the notifications specified in § 60.5420(a).

§ 60.5395 What standards apply to storage vessel affected facilities?

You must comply with the standards in paragraphs (a) through (e) of this section for each storage vessel affected facility.

(a) You must comply with the standards for storage vessels specified in § 63.766(b) and (c) of this chapter, except as specified in paragraph (b) of this section. Storage vessels that meet either one or both of the throughput conditions specified in paragraphs (a)(1) or (a)(2) of this section are not subject to the standards of this section.

(1) The annual average condensate throughput is less than 1 barrel per day per storage vessel.

(2) The annual average crude oil throughput is less than 20 barrels per day per storage vessel.

(b) This standard does not apply to storage vessels already subject to and controlled in accordance with the requirements for storage vessels in § 63.766(b)(1) or (2) of this chapter.

(c) You must demonstrate initial compliance with standards that apply to storage vessel affected facilities as required by § 60.5410.

(d) You must demonstrate continuous compliance with standards that apply to storage vessel affected facilities as required by § 60.5415.

(e) You must perform the required notification, recordkeeping, and reporting as required by § 60.5420.

§ 60.5400 What VOC standards apply to affected facilities at an onshore natural gas processing plant?

This section applies to each compressor in VOC service or in wet gas service and the group of all equipment (as defined in § 60.5430), except compressors, within a process unit.

(a) You must comply with the requirements of § 60.482–1a(a), (b), and (d), § 60.482–2a, and § 60.482–4a through 60.482–11a, except as provided in § 60.5401.

(b) You may elect to comply with the requirements of §§ 60.483–1a and 60.483–2a, as an alternative.

(c) You may apply to the Administrator for permission to use an alternative means of emission limitation that achieves a reduction in emissions of VOC at least equivalent to that achieved by the controls required in this subpart according to the requirements of § 60.5402 of this subpart.

(d) You must comply with the provisions of § 60.485a of this part except as provided in paragraph (f) of this section.

(e) You must comply with the provisions of §§ 60.486a and 60.487a of this part except as provided in §§ 60.5401, 60.5421, and 60.5422 of this part.

(f) You must use the following provision instead of § 60.485a(d)(1): Each piece of equipment is presumed to be in VOC service or in wet gas service unless an owner or operator demonstrates that the piece of equipment is not in VOC service or in wet gas service. For a piece of equipment to be considered not in VOC service, it must be determined that the VOC content can be reasonably expected never to exceed 10.0 percent by weight. For a piece of equipment to be considered in wet gas service, it must be determined that it contains or contacts the field gas before the extraction step in the process. For purposes of determining the percent VOC content of the process fluid that is contained in or contacts a piece of equipment, procedures that conform to the methods described in ASTM E169–63, 77, or 93, E168–67, 77, or 92, or E260–73, 91, or 96 (incorporated by reference as specified in § 60.17) must be used.

§ 60.5401 What are the exceptions to the VOC standards for affected facilities at onshore natural gas processing plants?

(a) You may comply with the following exceptions to the provisions of subpart VVa of this part.

(b)(1) Each pressure relief device in gas/vapor service may be monitored quarterly and within 5 days after each pressure release to detect leaks by the methods specified in § 60.485a(b) except as provided in § 60.5400(c) and in paragraph (b)(4) of this section, and § 60.482–4a(a) through (c) of subpart VVa.

(2) If an instrument reading of 5000 ppm or greater is measured, a leak is detected.

(3)(i) When a leak is detected, it must be repaired as soon as practicable, but no later than 15 calendar days after it is detected, except as provided in § 60.482–9a.

(ii) A first attempt at repair must be made no later than 5 calendar days after each leak is detected.

(4)(i) Any pressure relief device that is located in a nonfractionating plant that is monitored only by non-plant personnel may be monitored after a pressure release the next time the monitoring personnel are on-site, instead of within 5 days as specified in paragraph (b)(1) of this section and § 60.482–4a(b)(1) of subpart VVa.

(ii) No pressure relief device described in paragraph (b)(4)(i) of this section must be allowed to operate for more than 30 days after a pressure release without monitoring.

(c) Sampling connection systems are exempt from the requirements of § 60.482–5a.

(d) Pumps in light liquid service, valves in gas/vapor and light liquid service, and pressure relief devices in gas/vapor service that are located at a nonfractionating plant with a design capacity to process 283,200 standard cubic meters per day (scmd) (10 million standard cubic feet per day) or more of field gas are exempt from the routine monitoring requirements of §§ 60.482–2a(a)(1) and 60.482–7a(a), and paragraph (b)(1) of this section.

(e) Pumps in light liquid service, valves in gas/vapor and light liquid service, and pressure relief devices in gas/vapor service within a process unit that is located in the Alaskan North Slope are exempt from the routine monitoring requirements of §§ 60.482–2a(a)(1), 60.482–7a(a), and paragraph (b)(1) of this section.

(f) Flares used to comply with this subpart must comply with the requirements of § 60.18.

(g) An owner or operator may use the following provisions instead of § 60.485a(e):

(1) Equipment is in heavy liquid service if the weight percent evaporated is 10 percent or less at 150 °C (302 °F) as determined by ASTM Method D86–78, 82, 90, 95, or 96 (incorporated by reference as specified in § 60.17).

(2) Equipment is in light liquid service if the weight percent evaporated is greater than 10 percent at 150 °C (302 °F) as determined by ASTM Method D86–78, 82, 90, 95, or 96 (incorporated by reference as specified in § 60.17).

§ 60.5402 What are the alternative emission limitations for equipment leaks from onshore natural gas processing plants?

(a) If, in the Administrator's judgment, an alternative means of emission limitation will achieve a reduction in VOC emissions at least equivalent to the reduction in VOC emissions achieved under any design, equipment, work practice or operational standard, the Administrator will publish, in the **Federal Register**, a notice permitting the use of that alternative means for the purpose of compliance with that standard. The notice may condition permission on requirements related to the operation and maintenance of the alternative means.

(b) Any notice under paragraph (a) of this section must be published only after notice and an opportunity for a public hearing.

(c) The Administrator will consider applications under this section from either owners or operators of affected facilities, or manufacturers of control equipment.

(d) The Administrator will treat applications under this section according to the following criteria, except in cases where the Administrator concludes that other criteria are appropriate:

(1) The applicant must collect, verify and submit test data, covering a period of at least 12 months, necessary to support the finding in paragraph (a) of this section.

(2) If the applicant is an owner or operator of an affected facility, the applicant must commit in writing to operate and maintain the alternative means so as to achieve a reduction in VOC emissions at least equivalent to the reduction in VOC emissions achieved under the design, equipment, work practice or operational standard.

§ 60.5405 What standards apply to sweetening units at onshore natural gas processing plants?

(a) During the initial performance test required by § 60.8(b), you must achieve at a minimum, an SO_2 emission reduction efficiency (Z_i) to be determined from Table 1 of this subpart based on the sulfur feed rate (X) and the sulfur content of the acid gas (Y) of the affected facility.

(b) After demonstrating compliance with the provisions of paragraph (a) of this section, you must achieve at a minimum, an SO_2 emission reduction efficiency (Z_c) to be determined from Table 2 of this subpart based on the sulfur feed rate (X) and the sulfur content of the acid gas (Y) of the affected facility.

60.5406 What test methods and procedures must I use for my sweetening units affected facilities at onshore natural gas processing plants?

(a) In conducting the performance tests required in § 60.8, you must use

the test methods in Appendix A of this part or other methods and procedures as specified in this section, except as provided in paragraph § 60.8(b).

(b) During a performance test required by § 60.8, you must determine the minimum required reduction efficiencies (Z) of SO_2 emissions as required in § 60.5405(a) and (b) as follows:

(1) The average sulfur feed rate (X) must be computed as follows:

$X - KQ_a\gamma$

Where:

X = average sulfur feed rate, Mg/D (LT/D).
Q_a = average volumetric flow rate of acid gas from sweetening unit, dscm/day (dscf/day).
Y = average H_2S concentration in acid gas feed from sweetening unit, percent by volume, expressed as a decimal.
K = (32 kg S/kg-mole) / ((24.04 dscm/kg-mole) (1000 kg S/Mg))
= 1.331×10^{-3} Mg/dscm, for metric units
= (32 lb S/lb-mole) / ((385.36 dscf/lb-mole) (2240 lb S/long ton))
= 3.707×10^{-5} long ton/dscf, for English units.

(2) You must use the continuous readings from the process flowmeter to determine the average volumetric flow rate (Q_a) in dscm/day (dscf/day) of the acid gas from the sweetening unit for each run.

(3) You must use the Tutwiler procedure in § 60.5408 or a chromatographic procedure following ASTM E–260 (incorporated by reference—see § 60.17) to determine the H_2S concentration in the acid gas feed from the sweetening unit (Y). At least one sample per hour (at equally spaced intervals) must be taken during each 4-hour run. The arithmetic mean of all samples must be the average H_2S concentration (Y) on a dry basis for the run. By multiplying the result from the Tutwiler procedure by 1.62×10^{-3}, the units gr/100 scf are converted to volume percent.

(4) Using the information from paragraphs (b)(1) and (b)(3) of this section, Tables 1 and 2 of this subpart must be used to determine the required initial (Z_i) and continuous (Z_c) reduction efficiencies of SO_2 emissions.

(c) You must determine compliance with the SO_2 standards in § 60.5405(a) or (b) as follows:

(1) You must compute the emission reduction efficiency (R) achieved by the sulfur recovery technology for each run using the following equation:

$$R = (100S)\frac{\square}{S + E}$$

(2) You must use the level indicators or manual soundings to measure the liquid sulfur accumulation rate in the product storage tanks. You must use readings taken at the beginning and end of each run, the tank geometry, sulfur density at the storage temperature, and sample duration to determine the sulfur production rate (S) in kg/hr (lb/hr) for each run.

(3) You must compute the emission rate of sulfur for each run as follows:

$$E = \frac{C_e Q_{sd}}{K_1}$$

Where:

E = emission rate of sulfur per run, kg/hr.
C_e = concentration of sulfur equivalent (SO_2 + reduced sulfur), g/dscm (lb/dscf).
Q_{sd} = volumetric flow rate of effluent gas, dscm/hr (dscf/hr).
K_1 = conversion factor, 1000 g/kg (7000 gr/lb).

(4) The concentration (C_e) of sulfur equivalent must be the sum of the SO_2 and TRS concentrations, after being converted to sulfur equivalents. For each run and each of the test methods specified in this paragraph (c) of this section, you must use a sampling time of at least 4 hours. You must use Method 1 of Appendix A to part 60 of this chapter to select the sampling site. The sampling point in the duct must be at the centroid of the cross-section if the area is less than 5 m^2 (54 ft^2) or at a point no closer to the walls than 1 m (39 in) if the cross-sectional area is 5 m^2 or more, and the centroid is more than 1 m (39 in.) from the wall.

(i) You must use Method 6 of Appendix A to part 60 of this chapter to determine the SO_2 concentration. You must take eight samples of 20 minutes each at 30-minute intervals. The arithmetic average must be the concentration for the run. The concentration must be multiplied by 0.5×10^{-3} to convert the results to sulfur equivalent.

(ii) You must use Method 15 of appendix A to part 60 of this chapter to determine the TRS concentration from reduction-type devices or where the oxygen content of the effluent gas is less than 1.0 percent by volume. The sampling rate must be at least 3 liters/min (0.1 ft^3/min) to insure minimum residence time in the sample line. You must take sixteen samples at 15-minute intervals. The arithmetic average of all the samples must be the concentration for the run. The concentration in ppm reduced sulfur as sulfur must be multiplied by 1.333×10^{-3} to convert the results to sulfur equivalent.

(iii) You must use Method 16A or Method 15 of appendix A to part 60 of this chapter to determine the reduced sulfur concentration from oxidation-type devices or where the oxygen content of the effluent gas is greater than 1.0 percent by volume. You must take eight samples of 20 minutes each at 30-minute intervals. The arithmetic average must be the concentration for the run. The concentration in ppm reduced sulfur as sulfur must be multiplied by 1.333×10^{-3} to convert the results to sulfur equivalent.

(iv) You must use Method 2 of appendix A to part 60 of this chapter to determine the volumetric flow rate of the effluent gas. A velocity traverse must be conducted at the beginning and end of each run. The arithmetic average of the two measurements must be used to calculate the volumetric flow rate (Q_{sd}) for the run. For the determination of the effluent gas molecular weight, a single integrated sample over the 4-hour period may be taken and analyzed or grab samples at 1-hour intervals may be taken, analyzed, and averaged. For the moisture content, you must take two samples of at least 0.10 dscm (3.5 dscf) and 10 minutes at the beginning of the 4-hour run and near the end of the time period. The arithmetic average of the two runs must be the moisture content for the run.

§ 60.5407 What are the requirements for monitoring of emissions and operations from my sweetening unit affected facilities at onshore natural gas processing plants?

(a) If your sweetening unit affected facility is located at an onshore natural gas processing plant and is subject to the provisions of § 60.5405(a) or (b) you must install, calibrate, maintain, and operate monitoring devices or perform measurements to determine the following operations information on a daily basis:

(1) *The accumulation of sulfur product over each 24-hour period.* The monitoring method may incorporate the use of an instrument to measure and record the liquid sulfur production rate, or may be a procedure for measuring and recording the sulfur liquid levels in the storage tanks with a level indicator or by manual soundings, with subsequent calculation of the sulfur production rate based on the tank geometry, stored sulfur density, and elapsed time between readings. The method must be designed to be accurate within ± 2 percent of the 24-hour sulfur accumulation.

(2) *The H_2S concentration in the acid gas from the sweetening unit for each 24-hour period.* At least one sample per 24-hour period must be collected and analyzed using the equation specified in § 60.5406(b)(1). The Administrator may require you to demonstrate that the H_2S concentration obtained from one or more samples over a 24-hour period is

within ± 20 percent of the average of 12 samples collected at equally spaced intervals during the 24-hour period. In instances where the H_2S concentration of a single sample is not within ± 20 percent of the average of the 12 equally spaced samples, the Administrator may require a more frequent sampling schedule.

(3) *The average acid gas flow rate from the sweetening unit.* You must install and operate a monitoring device to continuously measure the flow rate of acid gas. The monitoring device reading must be recorded at least once per hour during each 24-hour period. The average acid gas flow rate must be computed from the individual readings.

(4) *The sulfur feed rate (X).* For each 24-hour period, you must compute X using the equation specified in § 60.5406(b)(3).

(5) *The required sulfur dioxide emission reduction efficiency for the 24-hour period.* You must use the sulfur feed rate and the H_2S concentration in the acid gas for the 24-hour period, as applicable, to determine the required reduction efficiency in accordance with the provisions of § 60.5405(b).

(b) Where compliance is achieved through the use of an oxidation control system or a reduction control system followed by a continually operated incineration device, you must install, calibrate, maintain, and operate monitoring devices and continuous emission monitors as follows:

(1) *A continuous monitoring system to measure the total sulfur emission rate (E) of SO_2 in the gases discharged to the atmosphere.* The SO_2 emission rate must be expressed in terms of equivalent sulfur mass flow rates (kg/hr (lb/hr)). The span of this monitoring system must be set so that the equivalent emission limit of § 60.5405(b) will be between 30 percent and 70 percent of the measurement range of the instrument system.

(2) Except as provided in paragraph (b)(3) of this section: A monitoring device to measure the temperature of the gas leaving the combustion zone of the incinerator, if compliance with § 60.5405(a) is achieved through the use of an oxidation control system or a reduction control system followed by a continually operated incineration device. The monitoring device must be certified by the manufacturer to be accurate to within ± 1 percent of the temperature being measured.

(3) When performance tests are conducted under the provision of § 60.8 to demonstrate compliance with the standards under § 60.5405, the temperature of the gas leaving the incinerator combustion zone must be determined using the monitoring device. If the volumetric ratio of sulfur dioxide to sulfur dioxide plus total reduced sulfur (expressed as SO_2) in the gas leaving the incinerator is equal to or less than 0.98, then temperature monitoring may be used to demonstrate that sulfur dioxide emission monitoring is sufficient to determine total sulfur emissions. At all times during the operation of the facility, you must maintain the average temperature of the gas leaving the combustion zone of the incinerator at or above the appropriate level determined during the most recent performance test to ensure the sulfur compound oxidation criteria are met. Operation at lower average temperatures may be considered by the Administrator to be unacceptable operation and maintenance of the affected facility. You may request that the minimum incinerator temperature be reestablished by conducting new performance tests under § 60.8.

(4) Upon promulgation of a performance specification of continuous monitoring systems for total reduced sulfur compounds at sulfur recovery plants, you may, as an alternative to paragraph (b)(2) of this section, install, calibrate, maintain, and operate a continuous emission monitoring system for total reduced sulfur compounds as required in paragraph (d) of this section in addition to a sulfur dioxide emission monitoring system. The sum of the equivalent sulfur mass emission rates from the two monitoring systems must be used to compute the total sulfur emission rate (E).

(c) Where compliance is achieved through the use of a reduction control system not followed by a continually operated incineration device, you must install, calibrate, maintain, and operate a continuous monitoring system to measure the emission rate of reduced sulfur compounds as SO_2 equivalent in the gases discharged to the atmosphere. The SO_2 equivalent compound emission rate must be expressed in terms of equivalent sulfur mass flow rates (kg/hr (lb/hr)). The span of this monitoring system must be set so that the equivalent emission limit of § 60.5405(b) will be between 30 and 70 percent of the measurement range of the system. This requirement becomes effective upon promulgation of a performance specification for continuous monitoring systems for total reduced sulfur compounds at sulfur recovery plants.

(d) For those sources required to comply with paragraph (b) or (c) of this section, you must calculate the average sulfur emission reduction efficiency achieved (R) for each 24-hour clock internal. The 24-hour interval may begin and end at any selected clock time, but must be consistent. You must compute the 24-hour average reduction efficiency (R) based on the 24-hour average sulfur production rate (S) and sulfur emission rate (E), using the equation in § 60.5406(c)(1).

(1) You must use data obtained from the sulfur production rate monitoring device specified in paragraph (a) of this section to determine S.

(2) You must use data obtained from the sulfur emission rate monitoring systems specified in paragraphs (b) or (c) of this section to calculate a 24-hour average for the sulfur emission rate (E). The monitoring system must provide at least one data point in each successive 15-minute interval. You must use at least two data points to calculate each 1-hour average. You must use a minimum of 18 1-hour averages to compute each 24-hour average.

(e) In lieu of complying with paragraphs (b) or (c) of this section, those sources with a design capacity of less than 152 Mg/D (150 LT/D) of H_2S expressed as sulfur may calculate the sulfur emission reduction efficiency achieved for each 24-hour period by:

$$R = \frac{K_2 S}{X}$$

Where:

R = The sulfur dioxide removal efficiency achieved during the 24-hour period, percent.

K_2 = Conversion factor, 0.02400 Mg/D per kg/hr (0.01071 LT/D per lb/hr).

S = The sulfur production rate during the 24-hour period, kg/hr (lb/hr).

X = The sulfur feed rate in the acid gas, Mg/D (LT/D).

(f) The monitoring devices required in paragraphs (b)(1), (b)(3) and (c) of this section must be calibrated at least annually according to the manufacturer's specifications, as required by § 60.13(b).

(g) The continuous emission monitoring systems required in paragraphs (b)(1), (b)(3), and (c) of this section must be subject to the emission monitoring requirements of § 60.13 of the General Provisions. For conducting the continuous emission monitoring system performance evaluation required by § 60.13(c), Performance Specification 2 of appendix B to part 60 of this chapter must apply, and Method 6 must be used for systems required by paragraph (b) of this section.

§ 60.5408 What is an optional procedure for measuring hydrogen sulfide in acid gas—Tutwiler Procedure? [1]

(a) When an instantaneous sample is desired and H_2S concentration is ten grains per 1000 cubic foot or more, a 100 ml Tutwiler burette is used. For concentrations less than ten grains, a 500 ml Tutwiler burette and more dilute solutions are used. In principle, this method consists of titrating hydrogen sulfide in a gas sample directly with a standard solution of iodine.

(b) *Apparatus.* (See Figure 1 of this subpart) A 100 or 500 ml capacity Tutwiler burette, with two-way glass stopcock at bottom and three-way stopcock at top which connect either with inlet tubulature or glass-stoppered cylinder, 10 ml capacity, graduated in 0.1 ml subdivision; rubber tubing connecting burette with leveling bottle.

(c) *Reagents.* (1) Iodine stock solution, 0.1N. Weight 12.7 g iodine, and 20 to 25 g cp potassium iodide for each liter of solution. Dissolve KI in as little water as necessary; dissolve iodine in concentrated KI solution, make up to proper volume, and store in glass-stoppered brown glass bottle.

(2) Standard iodine solution, 1 ml = 0.001771 g I. Transfer 33.7 ml of above 0.1N stock solution into a 250 ml volumetric flask; add water to mark and mix well. Then, for 100 ml sample of gas, 1 ml of standard iodine solution is equivalent to 100 grains H_2S per cubic feet of gas.

(3) Starch solution. Rub into a thin paste about one teaspoonful of wheat starch with a little water; pour into about a pint of boiling water; stir; let cool and decant off clear solution. Make fresh solution every few days.

(d) *Procedure.* Fill leveling bulb with starch solution. Raise (L), open cock (G), open (F) to (A), and close (F) when solutions starts to run out of gas inlet. Close (G). Purge gas sampling line and connect with (A). Lower (L) and open (F) and (G). When liquid level is several ml past the 100 ml mark, close (G) and (F), and disconnect sampling tube. Open (G) and bring starch solution to 100 ml mark by raising (L); then close (G). Open (F) momentarily, to bring gas in burette to atmospheric pressure, and close (F). Open (G), bring liquid level down to 10 ml mark by lowering (L). Close (G), clamp rubber tubing near (E) and disconnect it from burette. Rinse graduated cylinder with a standard iodine solution (0.00171 g I per ml); fill cylinder and record reading. Introduce successive small amounts of iodine thru (F); shake well after each addition; continue until a faint permanent blue color is obtained. Record reading; subtract from previous reading, and call difference D.

(e) With every fresh stock of starch solution perform a blank test as follows: Introduce fresh starch solution into burette up to 100 ml mark. Close (F) and (G). Lower (L) and open (G). When liquid level reaches the 10 ml mark, close (G). With air in burette, titrate as during a test and up to same end point. Call ml of iodine used C. Then,

$$\text{Grains } H_2S \text{ per 100 cubic foot of gas} = 100\,(D - C)$$

(f) Greater sensitivity can be attained if a 500 ml capacity Tutwiler burette is used with a more dilute (0.001N) iodine solution. Concentrations less than 1.0 grains per 100 cubic foot can be determined in this way. Usually, the starch-iodine end point is much less distinct, and a blank determination of end point, with H_2S-free gas or air, is required.

BILLING CODE 6560–50–P

[1] Gas Engineers Handbook, Fuel Gas Engineering practices, The Industrial Press, 93 Worth Street, New York, NY, 1966, First Edition, Second Printing, page 6/25 (Docket A–80–20–A, Entry II–I–67).

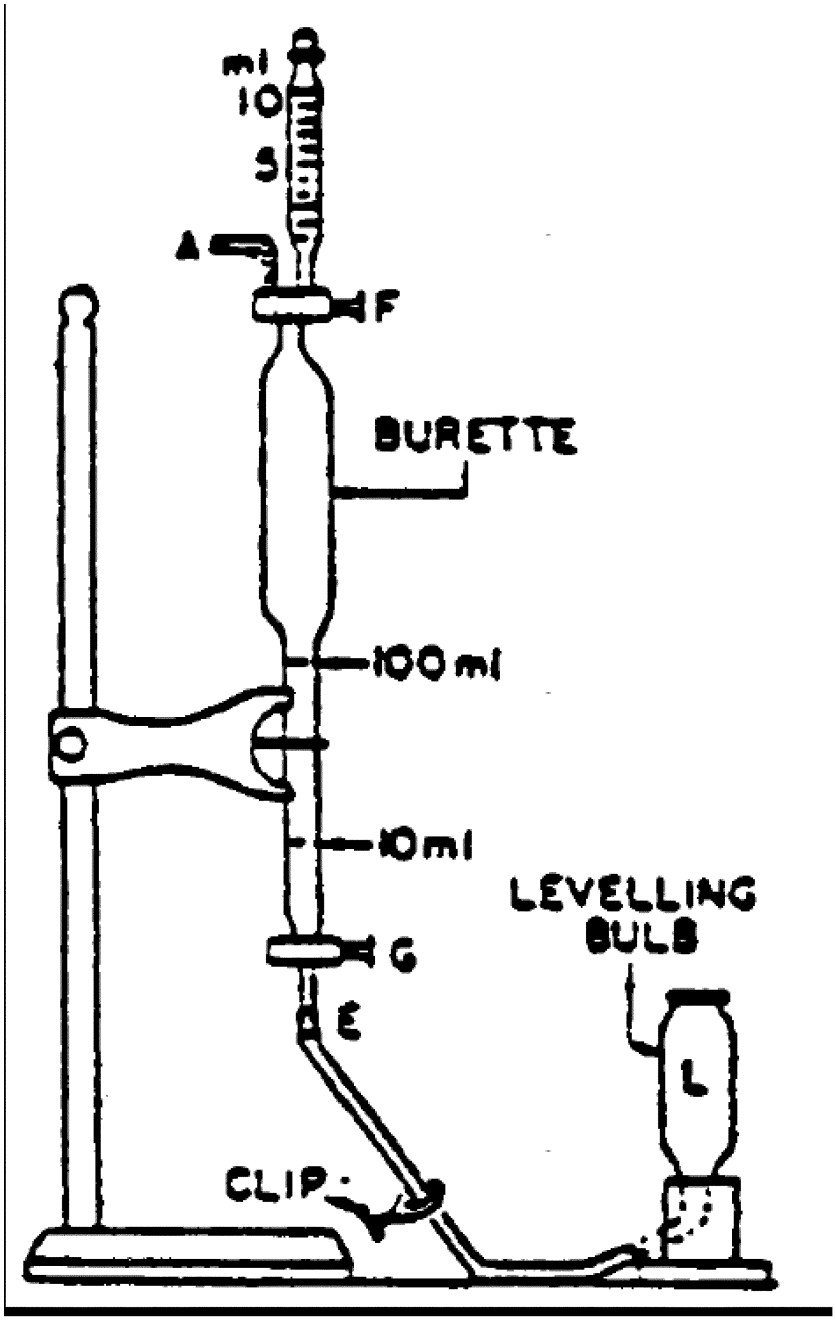

Figure 1. Tutwiler burette (lettered items mentioned in text).

BILLING CODE 6560–50–C

§ 60.5410 How do I demonstrate initial compliance with the standards for my gas wellhead affected facility, my centrifugal compressor affected facility, my reciprocating compressor affected facility, my pneumatic controller affected facility, my storage vessel affected facility, and my affected facilities at onshore natural gas processing plants?

You must determine initial compliance with the standards for each affected facility using the requirements in paragraphs (a) through (g) of this section. The initial compliance period begins on the date of publication of the final rule in the **Federal Register** or upon initial startup, whichever is later, and ends on the date the first annual report is due as specified in § 60.5420(b).

(a) You have achieved initial compliance with standards for each well completion operation conducted at your gas wellhead affected facility if you have complied with paragraphs (a)(1) and (a)(2) of this section.

(1) You have notified the Administrator within 30 days of the commencement of the well completion operation, the date of the commencement of the well completion operation, the latitude and longitude coordinates of the well in decimal degrees to an accuracy and precision of five (5) decimals of a degree using the North American Datum (NAD) of 1983.

(2) You have maintained a log of records as specified in § 60.5375(b) or (f) for each well completion operation conducted during the initial compliance period.

(3) You have submitted the initial annual report for your wellhead affected facility as required in § 60.5420(b).

(b) You have achieved initial compliance with standards for your centrifugal compressor affected facility if the centrifugal compressor is fitted with a dry seal system upon initial startup as required by § 60.5380.

(c) You have achieved initial compliance with standards for each reciprocating compressor affected facility if you have complied with paragraphs (c)(1) and (c)(2) of this section.

(1) During the initial compliance period, you have continuously monitored the number of hours of operation.

(2) You have included the cumulative number of hours of operation for your reciprocating compressor affected facility during the initial compliance period in your initial annual report required in § 60.5420(b).

(d) You have achieved initial compliance with emission standards for your pneumatic controller affected facility if you comply with the requirements specified in paragraphs (d)(1) through (d)(4) of this section.

(1) You have demonstrated, to the Administrator's satisfaction, the use of a high bleed device is predicated as specified in § 60.5490(a).

(2) You own or operate a pneumatic controller affected facility located at a natural gas processing plant and your pneumatic controller is driven other than by use of natural gas and therefore emits zero natural gas.

(3) You own or operate a pneumatic controller affected facility not located at a natural gas processing plant and the manufacturer's design specifications guarantee the controller emits less than or equal to 6.0 standard cubic feet of gas per hour.

(4) You have included the information in paragraphs (d)(1) through (d)(3) of this section in the initial annual report submitted for your pneumatic controller affected facilities according to the requirements of § 60.5420(b).

(e) You have demonstrated initial compliance with emission standards for your storage vessel affected facility if you are complying with paragraphs (e)(1) through (e)(7) of this section.

(1) You have equipped the storage vessel with a closed vent system that meets the requirements of § 63.771(c) of this chapter connected to a control device that meets the conditions specified in § 63.771(d).

(2) You have conducted an initial performance test as required in § 63.772(e) of this chapter within 180 days after initial startup or the date of publication of the final rule in the **Federal Register** and have conducted the compliance demonstration in § 63.772(f).

(3) You have conducted the initial inspections required in § 63.773(c) of this chapter.

(4) You have installed and operated continuous parameter monitoring systems in accordance with § 63.773(d) of this chapter.

(5) If you are exempt from the standards of § 60.5395 according to § 60.5395(a)(1) or (a)(2), you have determined the condensate or crude oil throughput, as applicable, according to paragraphs (e)(5)(i) or (e)(5)(ii) of this section and demonstrated to the Administrator's satisfaction that your annual average condensate throughput is less than 1 barrel per day per tank and your annual average crude oil throughput is less than 20 barrels per day per tank.

(i) You have installed and operated a flow meter to measure condensate or crude oil throughput in accordance with the manufacturer's procedures or specifications.

(ii) You have used any other method approved by the Administrator to determine annual average condensate or crude oil throughput.

(6) You have submitted the information in paragraphs (e)(1) through (e)(5) of this section in the initial annual report for your storage vessel affected facility as required in § 60.5420(b).

(f) For affected facilities at onshore natural gas processing plants, initial compliance with the VOC requirements is demonstrated if you are in compliance with the requirements of § 60.5400.

(g) For sweetening unit affected facilities at onshore natural gas processing plants, initial compliance is demonstrated according to paragraphs (g)(1) through (g)(3) of this section.

(1) To determine compliance with the standards for SO_2 specified in § 60.5405(a), during the initial performance test as required by § 60.8, the minimum required sulfur dioxide emission reduction efficiency (Z_i) is compared to the emission reduction efficiency (R) achieved by the sulfur recovery technology as specified in paragraphs (g)(1)(i) and (g)(1)(ii) of this section.

(i) If $R \geq Z_i$, your affected facility is in compliance.

(ii) If $R < Z_i$, your affected facility is not in compliance.

(2) The emission reduction efficiency (R) achieved by the sulfur reduction technology must be determined using the procedures in § 60.5406(c)(1).

(3) You have submitted the results of paragraphs (g)(1) and (g)(2) of this section in the initial annual report submitted for your sweetening unit affected facilities at onshore natural gas processing plants.

§ 60.5415 How do I demonstrate continuous compliance with the standards for my gas wellhead affected facility, my centrifugal compressor affected facility, my stationary reciprocating compressor affected facility, my pneumatic controller affected facility, my storage vessel affected facility, and my affected facilities at onshore natural gas processing plants?

(a) For each gas wellhead affected facility, you must demonstrate continuous compliance by maintaining the records for each completion operation (as defined in § 60.5430) specified in § 60.5420.

(b) For each centrifugal compressor affected facility, continuous compliance is demonstrated if the rotating compressor shaft is equipped with a dry seal.

(c) For each reciprocating compressor affected facility, you have demonstrated continuous compliance according to paragraphs (c)(1) and (2) of this section

(1) You have continuously monitored the number of hours of operation for each reciprocating compressor affected facility since initial startup, or the date of publication of the final rule in the **Federal Register**, or the date of the previous reciprocating compressor rod packing replacement, whichever is later. The cumulative number of hours of operation must be included in the annual report as required in § 60.5420(b)(4).

(2) You have replaced the reciprocating compressor rod packing before the total number of hours of operation reaches 26,000 hours.

(d) For each pneumatic controller affected facility, continuous compliance is demonstrated by maintaining the records demonstrating that you have installed and operated the pneumatic controllers as required in § 60.5390(a), (b) or (c).

(e) For each storage vessel affected facility, continuous compliance is demonstrated according to § 63.772(f) of this chapter.

(f) For affected facilities at onshore natural gas processing plants, continuous compliance with VOC requirements is demonstrated if you are in compliance with the requirements of § 60.5400.

(g) For each sweetening unit affected facility at onshore natural gas processing plants, you must demonstrate continuous compliance with the standards for SO_2 specified in

§ 60.5405(b) according to paragraphs (g)(1) and (g)(2) of this section.

(1) The minimum required SO_2 emission reduction efficiency (Z_c) is compared to the emission reduction efficiency (R) achieved by the sulfur recovery technology.

(i) If $R \geq Z_c$, your affected facility is in compliance.

(ii) If $R < Z_c$, your affected facility is not in compliance.

(2) The emission reduction efficiency (R) achieved by the sulfur reduction technology must be determined using the procedures in § 60.5406(c)(1).

(h) *Affirmative defense for exceedance of emission limit during malfunction.* In response to an action to enforce the standards set forth in §§ 60.5375, 60.5380, 60.5385, 60.5390, 60.5395, 60.5400, and 60.5405, you may assert an affirmative defense to a claim for civil penalties for exceedances of such standards that are caused by malfunction, as defined at § 60.2. Appropriate penalties may be assessed, however, if you fail to meet your burden of proving all of the requirements in the affirmative defense. The affirmative defense shall not be available for claims for injunctive relief.

(1) To establish the affirmative defense in any action to enforce such a limit, you must timely meet the notification requirements in § 60.5420(a), and must prove by a preponderance of evidence that:

(i) The excess emissions:

(A) Were caused by a sudden, infrequent, and unavoidable failure of air pollution control and monitoring equipment, process equipment, or a process to operate in a normal or usual manner, and

(B) Could not have been prevented through careful planning, proper design or better operation and maintenance practices; and

(C) Did not stem from any activity or event that could have been foreseen and avoided, or planned for; and

(D) Were not part of a recurring pattern indicative of inadequate design, operation, or maintenance; and

(ii) Repairs were made as expeditiously as possible when the applicable emission limitations were being exceeded. Off-shift and overtime labor were used, to the extent practicable to make these repairs; and

(iii) The frequency, amount and duration of the excess emissions (including any bypass) were minimized to the maximum extent practicable during periods of such emissions; and

(iv) If the excess emissions resulted from a bypass of control equipment or a process, then the bypass was unavoidable to prevent loss of life, personal injury, or severe property damage; and

(v) All possible steps were taken to minimize the impact of the excess emissions on ambient air quality, the environment and human health; and

(vi) All emissions monitoring and control systems were kept in operation if at all possible, consistent with safety and good air pollution control practices; and

(vii) All of the actions in response to the excess emissions were documented by properly signed, contemporaneous operating logs; and

(viii) At all times, the facility was operated in a manner consistent with good practices for minimizing emissions; and

(ix) A written root cause analysis has been prepared, the purpose of which is to determine, correct, and eliminate the primary causes of the malfunction and the excess emissions resulting from the malfunction event at issue. The analysis shall also specify, using best monitoring methods and engineering judgment, the amount of excess emissions that were the result of the malfunction.

(2) The owner or operator of the facility experiencing an exceedance of its emission limit(s) during a malfunction shall notify the Administrator by telephone or facsimile (FAX) transmission as soon as possible, but no later than 2 business days after the initial occurrence of the malfunction, if it wishes to avail itself of an affirmative defense to civil penalties for that malfunction. The owner or operator seeking to assert an affirmative defense shall also submit a written report to the Administrator within 45 days of the initial occurrence of the exceedance of the standards in §§ 60.5375, 60.5380, 60.5385, 60.5390, 60.5395, and 60.5400 to demonstrate, with all necessary supporting documentation, that it has met the requirements set forth in paragraph (a) of this section. The owner or operator may seek an extension of this deadline for up to 30 additional days by submitting a written request to the Administrator before the expiration of the 45-day period. Until a request for an extension has been approved by the Administrator, the owner or operator is subject to the requirement to submit such report within 45 days of the initial occurrence of the exceedance.

§ 60.5420 What are my notification, reporting, and recordkeeping requirements?

(a) You must submit the notifications required in § 60.7(a)(1), (a)(3) and (a)(4), and according to paragraphs (a)(1) and (a)(2) of this section, if you own or operate one or more of the affected facilities specified in § 60.5365. For the purposes of this subpart, a workover that occurs after August 23, 2011 at each affected facility for which construction, reconstruction, or modification commenced on or before August 23, 2011 is considered a modification for which a notification must be submitted under § 60.7(a)(4).

(1) If you own or operate a pneumatic controller affected facility you are not required to submit the notifications required in § 60.7(a)(1), (a)(3) and (a)(4).

(2) If you own or operate a gas wellhead affected facility, you must submit a notification to the Administrator within 30 days of the commencement of the well completion operation. The notification must include the date of commencement of the well completion operation, the latitude and longitude coordinates of the well in decimal degrees to an accuracy and precision of five (5) decimals of a degree using the North American Datum of 1983.

(b) *Reporting requirements.* You must submit annual reports containing the information specified in paragraphs (b)(1) through (b)(6) of this section to the Administrator. The initial annual report is due 1 year after the initial startup date for your affected facility or 1 year after the date of publication of the final rule in the **Federal Register,** whichever is later. Subsequent annual reports are due on the same date each year as the initial annual report. If you own or operate more than one affected facility, you may submit one report for multiple affected facilities provided the report contains all of the information required as specified in paragraphs (b)(1) through (b)(6) of this section.

(1) The general information specified in paragraphs (b)(1)(i) through (b)(1)(iii) of this section.

(i) The company name and address of the affected facility.

(ii) An identification of each affected facility being included in the annual report.

(iii) Beginning and ending dates of the reporting period.

(2) For each gas wellhead affected facility, the information in paragraphs (b)(2)(i) through (b)(2)(iii) of this section.

(i) An identification of each well completion operation, as defined in § 60.5430, for each gas wellhead affected facility conducted during the reporting period;

(ii) A record of deviations in cases where well completion operations with hydraulic fracturing were not performed in compliance with the requirements

specified in § 60.5375 for each gas well affected facility.

(iii) Records specified in § 60.5375(b) for each well completion operation that occurred during the reporting period.

(3) For each centrifugal compressor affected facility installed during the reporting period, documentation that the centrifugal compressor is equipped with dry seals.

(4) For each reciprocating compressor affected facility, the information specified in paragraphs (b)(4)(i) and (b)(4)(ii) of this section.

(i) The cumulative number of hours or operation since initial startup, the date of publication of the final rule in the **Federal Register**, or since the previous reciprocating compressor rod packing replacement, whichever is later.

(ii) Documentation that the reciprocating compressor rod packing was replaced before the cumulative number of hours of operation reached 24,000 hours.

(5) For each pneumatic controller affected facility, the information specified in paragraphs (b)(5)(i) through (b)(5)(iv) of this section.

(i) The date, location and manufacturer specifications for each pneumatic controller installed.

(ii) If applicable, documentation that the use of high bleed pneumatic devices is predicated and the reasons why.

(iii) For pneumatic controllers not installed at a natural gas processing plant, the manufacturer's guarantee that the device is designed such that natural gas emissions are less than 6 standard cubic feet per hour.

(iv) For pneumatic controllers installed at a natural gas processing plant, documentation that each controllers has zero natural gas emissions.

(6) For each storage vessel affected facility, the information in paragraphs (b)(6)(i) and (b)(6)(ii) of this section.

(i) If required to reduce emissions by complying with § 60.5395(a)(1), the records specified in § 63.774(b)(2) through (b)(8) of this chapter.

(ii) Documentation that the annual average condensate throughput is less than 1 barrel per day per storage vessel and crude oil throughput is less than 21 barrels per day per storage for meeting the requirements in § 60.5395(a)(1) or (a)(2).

(c) *Recordkeeping requirements.* You must maintain the records identified as specified in § 60.7(f) and in paragraphs (c)(1) through (c)(5) of this section

(1) The records for each gas wellhead affected facility as specified in paragraphs (c)(1)(i) through (c)(1)(iii).

(i) Records identifying each well completion operation for each gas wellhead affected facility conducted during the reporting period;

(ii) Record of deviations in cases where well completion operations with hydraulic fracturing were not performed in compliance with the requirements specified in § 60.5375.

(iii) Records required in § 60.5375(b) or (f) for each well completion operation conducted for each gas wellhead affected facility that occurred during the reporting period. You must maintain the records specified in paragraphs (c)(1)(iii)(A) and (c)(1)(iii)(B) of this section.

(A) For each gas wellheads affected facility required to comply with the requirements of § 60.5375(a), you must record: The location of the well; the duration of flowback; duration of recovery to the sales line; duration of combustion; duration of venting; and specific reasons for venting in lieu of capture or combustion. The duration must be specified in hours of time.

(B) For each gas wellhead affected facility required to comply with the requirements of § 60.5375(f), you must maintain the records specified in paragraph (c)(1)(iii)(A) of this section except that you do not have to record the duration of recovery to the sales line. In addition, you must record the distance, in miles, of the nearest gathering line.

(2) For each centrifugal compressor affected facility, you must maintain records on the type of seal system installed.

(3) For each reciprocating compressors affected facility, you must maintain the records in paragraphs (c)(3)(i) and (c)(3)(ii) of this section.

(i) Records of the cumulative number of hours of operation since initial startup or the date of publication of the final rule in the **Federal Register**, or the previous replacement of the reciprocating compressor rod packing, whichever is later.

(ii) Records of the date and time of each reciprocating compressor rod packing replacement.

(4) For each pneumatic controller affected facility, you must maintain the records identified in paragraphs (c)(4)(i) through (c)(4)(iv) of this section.

(i) Records of the date, location and manufacturer specifications for each pneumatic controller installed.

(ii) Records of the determination that the use of high bleed pneumatic devices is predicated and the reasons why.

(iii) If the pneumatic controller affected facility is not located at a natural gas processing plant, records of the manufacturer's guarantee that the device is designed such that natural gas emissions are less than 6 standard cubic feet per hour.

(iv) If the pneumatic controller affected facility is located at a natural gas processing plant, records of the documentation that only instrument air controllers are used.

(5) For each storage vessel affected facility, you must maintain the records identified in paragraphs (c)(5)(i) and (c)(5)(ii) of this section.

(i) If required to reduce emissions by complying with § 63.766, the records specified in § 63.774(b)(2) through (8) of this chapter.

(ii) Records of the determination that the annual average condensate throughput is less than 1 barrel per day per storage vessel and crude oil throughput is less than 21 barrels per day per storage vessel for the exemption under § 60.5395(a)(1) and (a)(2).

§ 60.5421 What are my additional recordkeeping requirements for my affected facility subject to VOC requirements for onshore natural gas processing plants?

(a) You must comply with the requirements of paragraph (b) of this section in addition to the requirements of § 60.486a.

(b) The following recordkeeping requirements apply to pressure relief devices subject to the requirements of § 60.5401(b)(1) of this subpart.

(1) When each leak is detected as specified in § 60.5401(b)(2), a weatherproof and readily visible identification, marked with the equipment identification number, must be attached to the leaking equipment. The identification on the pressure relief device may be removed after it has been repaired.

(2) When each leak is detected as specified in § 60.5401(b)(2), the following information must be recorded in a log and shall be kept for 2 years in a readily accessible location:

(i) The instrument and operator identification numbers and the equipment identification number.

(ii) The date the leak was detected and the dates of each attempt to repair the leak.

(iii) Repair methods applied in each attempt to repair the leak.

(iv) ''Above 500 ppm'' if the maximum instrument reading measured by the methods specified in paragraph (a) of this section after each repair attempt is 500 ppm or greater.

(v) ''Repair delayed'' and the reason for the delay if a leak is not repaired within 15 calendar days after discovery of the leak.

(vi) The signature of the owner or operator (or designate) whose decision it was that repair could not be effected without a process shutdown.

(vii) The expected date of successful repair of the leak if a leak is not repaired within 15 days.

(viii) Dates of process unit shutdowns that occur while the equipment is unrepaired.

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

(x) A list of identification numbers for equipment that are designated for no detectable emissions under the provisions of § 60.482–4a(a). The designation of equipment subject to the provisions of § 60.482–4a(a) must be signed by the owner or operator.

§ 60.5422 What are my additional reporting requirements for my affected facility subject to VOC requirements for onshore natural gas processing plants?

(a) You must comply with the requirements of paragraphs (b) and (c) of this section in addition to the requirements of § 60.487a(a), (b), (c)(2)(i) through (iv), and (c)(2)(vii) through (viii).

(b) An owner or operator must include the following information in the initial semiannual report in addition to the information required in § 60.487a(b)(1) through (4): Number of pressure relief devices subject to the requirements of § 60.5401(b) except for those pressure relief devices designated for no detectable emissions under the provisions of § 60.482–4a(a) and those pressure relief devices complying with § 60.482–4a(c).

(c) An owner or operator must include the following information in all semiannual reports in addition to the information required in § 60.487a(c)(2)(i) through (vi):

(1) Number of pressure relief devices for which leaks were detected as required in § 60.5401(b)(2); and

(2) Number of pressure relief devices for which leaks were not repaired as required in § 60.5401(b)(3).

§ 60.5423 What additional recordkeeping and reporting requirements apply to my sweetening unit affected facilities at onshore natural gas processing plants?

(a) You must retain records of the calculations and measurements required in § 60.5405(a) and (b) and § 60.5407(a) through (g) for at least 2 years following the date of the measurements. This requirement is included under § 60.7(d) of the General Provisions.

(b) You must submit a written report of excess emissions to the Administrator semiannually. For the purpose of these reports, excess emissions are defined as:

(1) Any 24-hour period (at consistent intervals) during which the average sulfur emission reduction efficiency (R) is less than the minimum required efficiency (Z).

(2) For any affected facility electing to comply with the provisions of § 60.5407(b)(2), any 24-hour period during which the average temperature of the gases leaving the combustion zone of an incinerator is less than the appropriate operating temperature as determined during the most recent performance test in accordance with the provisions of § 60.5407(b)(2). Each 24-hour period must consist of at least 96 temperature measurements equally spaced over the 24 hours.

(c) To certify that a facility is exempt from the control requirements of these standards, for each facility with a design capacity less that 2 LT/D of H_2S in the acid gas (expressed as sulfur) you must keep, for the life of the facility, an analysis demonstrating that the facility's design capacity is less than 2 LT/D of H_2S expressed as sulfur.

(d) If you elect to comply with § 60.5407(e) you must keep, for the life of the facility, a record demonstrating that the facility's design capacity is less than 150 LT/D of H_2S expressed as sulfur.

(e) The requirements of paragraph (b) of this section remain in force until and unless the EPA, in delegating enforcement authority to a state under section 111(c) of the Act, approves reporting requirements or an alternative means of compliance surveillance adopted by such state. In that event, affected sources within the state will be relieved of obligation to comply with paragraph (b) of this section, provided that they comply with the requirements established by the state.

§ 60.5425 What part of the General Provisions apply to me?

Table 3 to this subpart shows which parts of the General Provisions in §§ 60.1 through 60.19 apply to you.

§ 60.5430 What definitions apply to this subpart?

As used in this subpart, all terms not defined herein shall have the meaning given them in the Act, in subpart A or subpart VVa of part 60; and the following terms shall have the specific meanings given them.

Acid gas means a gas stream of hydrogen sulfide (H_2S) and carbon dioxide (CO_2) that has been separated from sour natural gas by a sweetening unit.

Alaskan North Slope means the approximately 69,000 square-mile area extending from the Brooks Range to the Arctic Ocean.

API Gravity means the weight per unit volume of hydrocarbon liquids as measured by a system recommended by the American Petroleum Institute (API) and is expressed in degrees.

Centrifugal compressor means a piece of equipment that compresses a process gas by means of mechanical rotating vanes or impellers.

City gate means the delivery point at which natural gas is transferred from a transmission pipeline to the local gas utility.

Completion combustion device means any ignition device, installed horizontally or vertically, used in exploration and production operations to combust otherwise vented emissions from completions or workovers.

Compressor means a piece of equipment that compresses process gas and is usually a centrifugal compressor or a reciprocating compressor.

Compressor station means any permanent combination of compressors that move natural gas at increased pressure from fields, in transmission pipelines, or into storage.

Condensate means a hydrocarbon liquid separated from natural gas that condenses due to changes in the temperature, pressure, or both, and remains liquid at standard conditions, as specified in § 60.2. For the purposes of this subpart, a hydrocarbon liquid with an API gravity equal to or greater than 40 degrees is considered condensate.

Crude oil means crude petroleum oil or any other hydrocarbon liquid, which are produced at the well in liquid form by ordinary production methods, and which are not the result of condensation of gas before or after it leaves the reservoir. For the purposes of this subpart, a hydrocarbon liquid with an API gravity less than 40 degrees is considered crude oil.

Dehydrator means a device in which an absorbent directly contacts a natural gas stream and absorbs water in a contact tower or absorption column (absorber).

Delineation well means a well drilled in order to determine the boundary of a field or producing reservoir.

Equipment means each pump, pressure relief device, open-ended valve or line, valve, compressor, and flange or other connector that is in VOC service or in wet gas service, and any device or system required by this subpart.

Field gas means feedstock gas entering the natural gas processing plant.

Field gas gathering means the system used to transport field gas from a field to the main pipeline in the area.

Flare means a thermal oxidation system using an open (without enclosure) flame.

Flowback means the process of allowing fluids to flow from the well following a treatment, either in

preparation for a subsequent phase of treatment or in preparation for cleanup and returning the well to production.

Flow line means surface pipe through which oil and/or natural gas travels from the well.

Gas-driven pneumatic controller means a pneumatic controller powered by pressurized natural gas.

Gas processing plant process unit means equipment assembled for the extraction of natural gas liquids from field gas, the fractionation of the liquids into natural gas products, or other operations associated with the processing of natural gas products. A process unit can operate independently if supplied with sufficient feed or raw materials and sufficient storage facilities for the products.

Gas well means a well, the principal production of which at the mouth of the well is gas.

High-bleed pneumatic devices means automated, continuous bleed flow control devices powered by pressurized natural gas and used for maintaining a process condition such as liquid level, pressure, delta-pressure and temperature. Part of the gas power stream which is regulated by the process condition flows to a valve actuator controller where it vents continuously (bleeds) to the atmosphere at a rate in excess of six standard cubic feet per hour.

Hydraulic fracturing means the process of directing pressurized liquids, containing water, proppant, and any added chemicals, to penetrate tight sand, shale, or coal formations that involve high rate, extended back flow to expel fracture fluids and sand during completions and well workovers.

In light liquid service means that the piece of equipment contains a liquid that meets the conditions specified in § 60.485a(e) or § 60.5401(h)(2) of this part.

In wet gas service means that a compressor or piece of equipment contains or contacts the field gas before the extraction step at a gas processing plant process unit.

Liquefied natural gas unit means a unit used to cool natural gas to the point at which it is condensed into a liquid which is colorless, odorless, non-corrosive and non-toxic.

Low-bleed pneumatic controller means automated flow control devices powered by pressurized natural gas and used for maintaining a process condition such as liquid level, pressure, delta-pressure and temperature. Part of the gas power stream which is regulated by the process condition flows to a valve actuator controller where it vents continuously (bleeds) to the atmosphere at a rate equal to or less than six standard cubic feet per hour.

Modification means any physical change in, or change in the method of operation of, an affected facility which increases the amount of VOC or natural gas emitted into the atmosphere by that facility or which results in the emission of VOC or natural gas into the atmosphere not previously emitted. For the purposes of this subpart, each recompletion of a fractured or refractured existing gas well is considered to be a modification.

Natural gas liquids means the hydrocarbons, such as ethane, propane, butane, and pentane that are extracted from field gas.

Natural gas processing plant (gas plant) means any processing site engaged in the extraction of natural gas liquids from field gas, fractionation of mixed natural gas liquids to natural gas products, or both.

Nonfractionating plant means any gas plant that does not fractionate mixed natural gas liquids into natural gas products.

Non gas-driven pneumatic device means an instrument that is actuated using other sources of power than pressurized natural gas; examples include solar, electric, and instrument air.

Onshore means all facilities except those that are located in the territorial seas or on the outer continental shelf.

Plunger lift system means an intermittent gas lift that uses gas pressure buildup in the casing-tubing annulus to push a steel plunger, and the column of fluid ahead of it, up the well tubing to the surface.

Pneumatic controller means an automated instrument used for maintaining a process condition such as liquid level, pressure, delta-pressure and temperature.

Pneumatic pump means a pump that uses pressurized natural gas to move a piston or diaphragm, which pumps liquids on the opposite side of the piston or diaphragm.

Process unit means components assembled for the extraction of natural gas liquids from field gas, the fractionation of the liquids into natural gas products, or other operations associated with the processing of natural gas products. A process unit can operate independently if supplied with sufficient feed or raw materials and sufficient storage facilities for the products.

Reciprocating compressor means a piece of equipment that increases the pressure of a process gas by positive displacement, employing linear movement of the driveshaft.

Reciprocating compressor rod packing means a series of flexible rings in machined metal cups that fit around the reciprocating compressor piston rod to create a seal limiting the amount of compressed natural gas that escapes to the atmosphere.

Reduced emissions completion means a well completion where gas flowback that is otherwise vented is captured, cleaned, and routed to the sales line.

Reduced emissions recompletion means a well completion following refracturing of a gas well where gas flowback that is otherwise vented is captured, cleaned, and routed to the sales line.

Reduced sulfur compounds means H_2S, carbonyl sulfide (COS), and carbon disulfide (CS_2).

Routed to a process or route to a process means the emissions are conveyed to any enclosed portion of a process unit where the emissions are predominantly recycled and/or consumed in the same manner as a material that fulfills the same function in the process and/or transformed by chemical reaction into materials that are not regulated materials and/or incorporated into a product; and/or recovered.

Salable quality gas means natural gas that meets the composition, moisture, or other limits set by the purchaser of the natural gas.

Sales line means pipeline, generally small in diameter, used to transport oil or gas from the well to a processing facility or a mainline pipeline.

Storage vessel means a stationary vessel or series of stationary vessels that are either manifolded together or are located at a single well site and that have potential for VOC emissions equal to or greater than 10 tpy.

Sulfur production rate means the rate of liquid sulfur accumulation from the sulfur recovery unit.

Sulfur recovery unit means a process device that recovers element sulfur from acid gas.

Surface site means any combination of one or more graded pad sites, gravel pad sites, foundations, platforms, or the immediate physical location upon which equipment is physically affixed.

Sweetening unit means a process device that removes hydrogen sulfide and/or carbon dioxide from the natural gas stream.

Total Reduced Sulfur (TRS) means the sum of the sulfur compounds hydrogen sulfide, methyl mercaptan, dimethyl sulfide, and dimethyl disulfide as measured by Method 16 of appendix A to part 60 of this chapter.

Total SO_2 equivalents means the sum of volumetric or mass concentrations of

the sulfur compounds obtained by adding the quantity existing as SO_2 to the quantity of SO_2 that would be obtained if all reduced sulfur compounds were converted to SO_2 (ppmv or kg/dscm (lb/dscf)).

Underground storage tank means a storage tank stored below ground.

Well means an oil or gas well, a hole drilled for the purpose of producing oil or gas, or a well into which fluids are injected.

Well completion means the process that allows for the flow of petroleum or natural gas from newly drilled wells to expel drilling and reservoir fluids and tests the reservoir flow characteristics, steps which may vent produced gas to the atmosphere via an open pit or tank. Well completion also involves connecting the well bore to the reservoir, which may include treating the formation or installing tubing, packer(s), or lifting equipment.

Well completion operation means any well completion or well workover occurring at a gas wellhead affected facility.

Well site means the areas that are directly disturbed during the drilling and subsequent operation of, or affected by, production facilities directly associated with any oil well, gas well, or injection well and its associated well pad.

Wellhead means the piping, casing, tubing and connected valves protruding above the earth's surface for an oil and/or natural gas well. The wellhead ends where the flow line connects to a wellhead valve. The wellhead does not include other equipment at the well site except for any conveyance through which gas is vented to the atmosphere.

Wildcat well means a well outside known fields or the first well drilled in an oil or gas field where no other oil and gas production exists.

TABLE 1 TO SUBPART OOOO OF PART 60—REQUIRED MINIMUM INITIAL SO_2 EMISSION REDUCTION EFFICIENCY (Z_i)

H_2S content of acid gas (Y), %	Sulfur feed rate (X), LT/D			
	$2.0 \le X \le 5.0$	$5.0 < X \le 15.0$	$15.0 < X \le 300.0$	$X > 300.0$
$Y \ge 50$	79.0	$88.51X^{0.0101}Y^{0.0125}$ or 99.9, whichever is smaller		
$20 \le Y < 50$	79.0	$88.5X^{0.0101}Y^{0.0125}$ or 97.9, whichever is smaller		97.9
$10 \le Y < 20$	79.0	$88.5X^{0.0101}Y^{0.0125}$ ... or 97.9, whichever is smaller ...	93.5	93.5
$Y < 10$	79.0	79.0	79.0	79.0

TABLE 2 TO SUBPART OOOO OF PART 60—REQUIRED MINIMUM SO_2 EMISSION REDUCTION EFFICIENCY (Z_c)

H_2S content of acid gas (Y), %	Sulfur feed rate (X), LT/D			
	$2.0 \le X \le 5.0$	$5.0 < X \le 15.0$	$15.0 < X \le 300.0$	$X > 300.0$
$Y \ge 50$	74.0	$85.35X^{0.0144}Y^{0.0128}$ or 99.9, whichever is smaller		
$20 \le Y < 50$	74.0	$85.35X^{0.0144}Y^{0.0128}$ or 97.9, whichever is smaller		97.5
$10 \le Y < 20$	74.0	$85.35X^{0.0144}Y^{0.0128}$ ... or 90.8, whichever is smaller ...	90.8	90.8
$Y < 10$	74.0	74.0	74.0	74.0

E = The sulfur emission rate expressed as elemental sulfur, kilograms per hour (kg/hr) [pounds per hour (lb/hr)], rounded to one decimal place.

R = The sulfur emission reduction efficiency achieved in percent, carried to one decimal place.

S = The sulfur production rate, kilograms per hour (kg/hr) [pounds per hour (lb/hr)], rounded to one decimal place.

X = The sulfur feed rate from the sweetening unit (*i.e.,* the H_2S in the acid gas), expressed as sulfur, Mg/D(LT/D), rounded to one decimal place.

Y = The sulfur content of the acid gas from the sweetening unit, expressed as mole percent H_2S (dry basis) rounded to one decimal place.

Z = The minimum required sulfur dioxide (SO_2) emission reduction efficiency, expressed as percent carried to one decimal place. Z_i refers to the reduction efficiency required at the initial performance test. Z_c refers to the reduction efficiency required on a continuous basis after compliance with Z_i has been demonstrated.

TABLE 3 TO SUBPART OOOO OF PART 60—APPLICABILITY OF GENERAL PROVISIONS TO SUBPART OOOO

[As stated in § 60.5425, you must comply with the following applicable General Provisions]

General provisions citation	Subject of citation	Applies to subpart?	Explanation
§ 60.1	General applicability of the General Provisions	Yes.	
§ 60.2	Definitions	Yes.	Additional terms defined in § 60.5430.
§ 60.3	Units and abbreviations	Yes.	
§ 60.4	Address	Yes.	
§ 60.5	Determination of construction or modification	Yes.	
§ 60.6	Review of plans	Yes.	
§ 60.7	Notification and record keeping	Yes	Except that § 60.7 only applies as specified in § 60.5420(a).

TABLE 3 TO SUBPART OOOO OF PART 60—APPLICABILITY OF GENERAL PROVISIONS TO SUBPART OOOO—Continued

[As stated in § 60.5425, you must comply with the following applicable General Provisions]

General provisions citation	Subject of citation	Applies to subpart?	Explanation
§ 60.8	Performance tests	No	Performance testing is required for storage vessels as specified in 40 CFR part 63, subpart HH.
§ 60.9	Availability of information	Yes.	
§ 60.10	State authority	Yes.	
§ 60.11	Compliance with standards and maintenance requirements.	No	Requirements are specified in subpart OOOO.
§ 60.12	Circumvention	Yes.	
§ 60.13	Monitoring requirements	Yes	Continuous monitors are required for storage vessels.
§ 60.14	Modification	Yes.	
§ 60.15	Reconstruction	Yes.	
§ 60.16	Priority list	Yes.	
§ 60.17	Incorporations by reference	Yes.	
§ 60.18	General control device requirements	Yes.	
§ 60.19	General notification and reporting requirement	Yes.	

PART 63—[AMENDED]

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

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

9. Section 63.14 is amended by:

a. Adding paragraphs (b)(69), (b)(70), (b)(71) and (b)(72); and

b. Revising paragraph (i)(1) to read as follows:

§ 63.14 Incorporations by reference.

* * * * *

(b) * * *

* * * * *

(69) ASTM D1945–03(2010) Standard Test Method for Analysis of Natural Gas by Gas Chromatography, IBR approved for §§ 63.772 and 63.1282.

(70) ASTM D5504–08 Standard Test Method for Determination of Sulfur Compounds in Natural Gas and Gaseous Fuels by Gas Chromatography and Chemiluminescence, IBR approved for §§ 63.772 and 63.1282.

(71) ASTM D3588–98(2003) Standard Practice for Calculating Heat Value, Compressibility Factor, and Relative Density of Gaseous Fuels, IBR approved for §§ 63.772 and 63.1282.

(72) ASTM D4891–89(2006) Standard Test Method for Heating Value of Gases in Natural Gas Range by Stoichiometric Combustion, IBR approved for §§ 63.772 and 63.1282.

* * * * *

(i) * * *

(1) ANSI/ASME PTC 19.10–1981, Flue and Exhaust Gas Analyses [Part 10, Instruments and Apparatus], issued August 31, 1981 IBR approved for §§ 63.309(k)(1)(iii), 63.771(e), 63.865(b), 63.1281(d), 63.3166(a)(3), 63.3360(e)(1)(iii), 63.3545(a)(3), 63.3555(a)(3), 63.4166(a)(3), 63.4362(a)(3), 63.4766(a)(3), 63.4965(a)(3), 63.5160(d)(1)(iii), 63.9307(c)(2), 63.9323(a)(3), 63.11148(e)(3)(iii), 63.11155(e)(3), 63.11162(f)(3)(iii) and (f)(4), 63.11163(g)(1)(iii) and (g)(2), 63.11410(j)(1)(iii), 63.11551(a)(2)(i)(C), 63.11646(a)(1)(iii), table 5 to subpart DDDDD of this part, and table 1 to subpart ZZZZZ of this part.

* * * * *

Subpart HH—[Amended]

10. Section 63.760 is amended by:

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

b. Revising paragraph (a)(1)(iii);

c. Revising paragraph (a)(2);

d. Revising paragraph (b)(1)(ii);

e. Revising paragraph (f) introductory text;

f. Revising paragraph (f)(1);

g. Revising paragraph (f)(2); and

h. Adding paragraphs (f)(7), (f)(8), (f)(9) and (f)(10) to read as follows:

§ 63.760 Applicability and designation of affected source.

(a) * * *

(1) Facilities that are major or area sources of hazardous air pollutants (HAP) as defined in § 63.761. Emissions for major source determination purposes can be estimated using the maximum natural gas or hydrocarbon liquid throughput, as appropriate, calculated in paragraphs (a)(1)(i) through (iii) of this section. As an alternative to calculating the maximum natural gas or hydrocarbon liquid throughput, the owner or operator of a new or existing source may use the facility's design maximum natural gas or hydrocarbon liquid throughput to estimate the maximum potential emissions. Other means to determine the facility's major source status are allowed, provided the information is documented and recorded to the Administrator's satisfaction in accordance with § 63.10(b)(3). A facility that is determined to be an area source, but subsequently increases its emissions or its potential to emit above the major source levels, and becomes a major source, must comply thereafter with all provisions of this subpart applicable to a major source starting on the applicable compliance date specified in paragraph (f) of this section. Nothing in this paragraph is intended to preclude a source from limiting its potential to emit through other appropriate mechanisms that may be available through the permitting authority.

* * * * *

(iii) The owner or operator shall determine the maximum values for other parameters used to calculate emissions as the maximum for the period over which the maximum natural gas or hydrocarbon liquid throughput is determined in accordance with paragraph (a)(1)(i)(A) or (B) of this section. Parameters, other than glycol circulation rate, shall be based on either highest measured values or annual average. For estimating maximum potential emissions from glycol dehydration units, the glycol circulation rate used in the calculation shall be the unit's maximum rate under its physical and operational design consistent with the definition of potential to emit in § 63.2.

(2) Facilities that process, upgrade, or store hydrocarbon liquids prior to the point where hydrocarbon liquids enter either the Organic Liquids Distribution (Non-gasoline) or Petroleum Refineries source categories.

* * * * *

(b) * * *
(1) * * *
(ii) Each storage vessel;
* * * * *

(f) The owner or operator of an affected major source shall achieve compliance with the provisions of this subpart by the dates specified in paragraphs (f)(1), (f)(2), and (f)(7) through (f)(10) of this section. The owner or operator of an affected area source shall achieve compliance with the provisions of this subpart by the dates specified in paragraphs (f)(3) through (f)(6) of this section.

(1) Except as specified in paragraphs (f)(7) through (10) of this section, the owner or operator of an affected major source, the construction or reconstruction of which commenced before February 6, 1998, shall achieve compliance with the applicable provisions of this subpart no later than June 17, 2002, except as provided for in § 63.6(i). The owner or operator of an area source, the construction or reconstruction of which commenced before February 6, 1998, that increases its emissions of (or its potential to emit) HAP such that the source becomes a major source that is subject to this subpart shall comply with this subpart 3 years after becoming a major source.

(2) Except as specified in paragraphs (f)(7) through (10) of this section, the owner or operator of an affected major source, the construction or reconstruction of which commences on or after February 6, 1998, shall achieve compliance with the applicable provisions of this subpart immediately upon initial startup or June 17, 1999, whichever date is later. Area sources, other than production field facilities identified in (f)(9) of this section, the construction or reconstruction of which commences on or after February 6, 1998, that become major sources shall comply with the provisions of this standard immediately upon becoming a major source.

* * * * *

(7) Each affected small glycol dehydration unit and each storage vessel that is not a storage vessel with the potential for flash emissions located at a major source, that commenced construction before August 23, 2011 must achieve compliance no later than 3 years after the date of publication of the final rule in the **Federal Register**, except as provided in § 63.6(i).

(8) Each affected small glycol dehydration unit and each storage vessel that is not a storage vessel with the potential for flash emissions, both as defined in § 63.761, located at a major source, that commenced construction on or after August 23, 2011 must achieve compliance immediately upon initial startup or the date of publication of the final rule in the **Federal Register**, whichever is later.

(9) A production field facility, as defined in § 63.761, constructed before August 23, 2011 that was previously determined to be an area source but becomes a major source (as defined in paragraph 3 of the major source definition in § 63.761) on the date of publication of the final rule in the **Federal Register** must achieve compliance no later than 3 years after the date of publication of the final rule in the **Federal Register**, except as provided in § 63.6(i).

(10) Each large glycol dehydration unit, as defined in § 63.761, that has complied with the provisions of this subpart prior to August 23, 2011 by reducing its benzene emissions to less than 0.9 megagrams per year must achieve compliance no later than 90 days after the date of publication of the final rule in the **Federal Register**, except as provided in § 63.6(i).

* * * * *

11. Section 63.761 is amended by:

a. Adding, in alphabetical order, new definitions for the terms ''affirmative defense,'' ''BTEX,'' ''flare,'' ''large glycol dehydration units'' and ''small glycol dehydration units'';

b. Revising the definitions for ''associated equipment,'' ''facility,'' ''glycol dehydration unit baseline operations,'' and ''temperature monitoring device''; and

c. Revising paragraph (3) of the definition for ''major source'' to read as follows:

§ 63.761 Definitions.

* * * * *

Affirmative defense means, in the context of an enforcement proceeding, a response or defense put forward by a defendant, regarding which the defendant has the burden of proof, and the merits of which are independently and objectively evaluated in a judicial or administrative proceeding.

* * * * *

Associated equipment, as used in this subpart and as referred to in section 112(n)(4) of the Act, means equipment associated with an oil or natural gas exploration or production well, and includes all equipment from the wellbore to the point of custody transfer, except glycol dehydration units and storage vessels.

* * * * *

BTEX means benzene, toluene, ethyl benzene and xylene.

* * * * *

Facility means any grouping of equipment where hydrocarbon liquids are processed, upgraded (*i.e.,* remove impurities or other constituents to meet contract specifications), or stored; or where natural gas is processed, upgraded, or stored. For the purpose of a major source determination, facility (including a building, structure, or installation) means oil and natural gas production and processing equipment that is located within the boundaries of an individual surface site as defined in this section. Equipment that is part of a facility will typically be located within close proximity to other equipment located at the same facility. Pieces of production equipment or groupings of equipment located on different oil and gas leases, mineral fee tracts, lease tracts, subsurface or surface unit areas, surface fee tracts, surface lease tracts, or separate surface sites, whether or not connected by a road, waterway, power line or pipeline, shall not be considered part of the same facility. Examples of facilities in the oil and natural gas production source category include, but are not limited to, well sites, satellite tank batteries, central tank batteries, a compressor station that transports natural gas to a natural gas processing plant, and natural gas processing plants.

* * * * *

Flare means a thermal oxidation system using an open flame (*i.e.,* without enclosure).

* * * * *

Glycol dehydration unit baseline operations means operations representative of the large glycol dehydration unit operations as of June 17, 1999 and the small glycol dehydrator unit operations as of August 23, 2011. For the purposes of this subpart, for determining the percentage of overall HAP emission reduction attributable to process modifications, baseline operations shall be parameter values (including, but not limited to, glycol circulation rate or glycol-HAP absorbency) that represent actual long-term conditions (*i.e.,* at least 1 year). Glycol dehydration units in operation for less than 1 year shall document that the parameter values represent expected long-term operating conditions had process modifications not been made.

* * * * *

Large glycol dehydration unit means a glycol dehydration unit with an actual annual average natural gas flowrate equal to or greater than 85 thousand standard cubic meters per day and actual annual average benzene emissions equal to or greater than 0.90

Mg/yr, determined according to § 63.772(b).

* * * * *

Major source * * *

(3) For facilities that are production field facilities, only HAP emissions from glycol dehydration units and storage vessels shall be aggregated for a major source determination. For facilities that are not production field facilities, HAP emissions from all HAP emission units shall be aggregated for a major source determination.

* * * * *

Small glycol dehydration unit means a glycol dehydration unit, located at a major source, with an actual annual average natural gas flowrate less than 85 thousand standard cubic meters per day or actual annual average benzene emissions less than 0.90 Mg/yr, determined according to § 63.772(b).

* * * * *

Temperature monitoring device means an instrument used to monitor temperature and having a minimum accuracy of ± 1 percent of the temperature being monitored expressed in °C, or ± 2.5 °C, whichever is greater. The temperature monitoring device may measure temperature in degrees Fahrenheit or degrees Celsius, or both.

* * * * *

12. Section 63.762 is revised to read as follows:

§ 63.762 Startups and shutdowns.

(a) The provisions set forth in this subpart shall apply at all times.

(b) The owner or operator shall not shut down items of equipment that are required or utilized for compliance with the provisions of this subpart during times when emissions are being routed to such items of equipment, if the shutdown would contravene requirements of this subpart applicable to such items of equipment. This paragraph does not apply if the owner or operator must shut down the equipment to avoid damage due to a contemporaneous startup or shutdown, of the affected source or a portion thereof.

(c) During startups and shutdowns, the owner or operator shall implement measures to prevent or minimize excess emissions to the maximum extent practical.

(d) In response to an action to enforce the standards set forth in this subpart, you may assert an affirmative defense to a claim for civil penalties for exceedances of such standards that are caused by malfunction, as defined in 40 CFR 63.2. Appropriate penalties may be assessed, however, if you fail to meet your burden of proving all the requirements in the affirmative defense. The affirmative defense shall not be available for claims for injunctive relief.

(1) To establish the affirmative defense in any action to enforce such a limit, you must timely meet the notification requirements in paragraph (d)(2) of this section, and must prove by a preponderance of evidence that:

(i) The excess emissions:

(A) Were caused by a sudden, infrequent, and unavoidable failure of air pollution control and monitoring equipment, process equipment, or a process to operate in a normal or usual manner; and

(B) Could not have been prevented through careful planning, proper design or better operation and maintenance practices; and

(C) Did not stem from any activity or event that could have been foreseen and avoided, or planned for; and

(D) Were not part of a recurring pattern indicative of inadequate design, operation, or maintenance; and

(ii) Repairs were made as expeditiously as possible when the applicable emission limitations were being exceeded. Off-shift and overtime labor were used, to the extent practicable to make these repairs; and

(iii) The frequency, amount and duration of the excess emissions (including any bypass) were minimized to the maximum extent practicable during periods of such emissions; and

(iv) If the excess emissions resulted from a bypass of control equipment or a process, then the bypass was unavoidable to prevent loss of life, personal injury, or severe property damage; and

(v) All possible steps were taken to minimize the impact of the excess emissions on ambient air quality, the environment, and human health; and

(vi) All emissions monitoring and control systems were kept in operation if at all possible, consistent with safety and good air pollution control practices; and

(vii) All of the actions in response to the excess emissions were documented by properly signed, contemporaneous operating logs; and

(viii) At all times, the affected source was operated in a manner consistent with good practices for minimizing emissions; and

(ix) A written root cause analysis has been prepared to determine, correct, and eliminate the primary causes of the malfunction and the excess emissions resulting from the malfunction event at issue. The analysis shall also specify, using best monitoring methods and engineering judgment, the amount of excess emissions that were the result of the malfunction.

(2) *Notification.* The owner or operator of the affected source experiencing exceedance of its emission limit(s) during a malfunction shall notify the Administrator by telephone or facsimile transmission as soon as possible, but no later than two business days after the initial occurrence of the malfunction, if it wishes to avail itself of an affirmative defense to civil penalties for that malfunction. The owner or operator seeking to assert an affirmative defense shall also submit a written report to the Administrator within 45 days of the initial occurrence of the exceedance of the standard in this subpart to demonstrate, with all necessary supporting documentation, that it has met the requirements set forth in paragraph (d)(1) of this section. The owner or operator may seek an extension of this deadline for up to 30 additional days by submitting a written request to the Administrator before the expiration of the 45 day period. Until a request for an extension has been approved by the Administrator, the owner or operator is subject to the requirement to submit such report within 45 days of the initial occurrence of the exceedance.

13. Section 63.764 is amended by:

a. Revising paragraph (c)(2) introductory text;

b. Revising paragraph (e)(1) introductory text;

c. Revising paragraph (i); and

d. Adding paragraph (j) to read as follows:

§ 63.764 General standards.

* * * * *

(c) * * *

(2) For each storage vessel subject to this subpart, the owner or operator shall comply with the requirements specified in paragraphs (c)(2)(i) through (iii) of this section.

* * * * *

(e) *Exemptions.* (1) The owner or operator of an area source is exempt from the requirements of paragraph (d) of this section if the criteria listed in paragraph (e)(1)(i) or (ii) of this section are met, except that the records of the determination of these criteria must be maintained as required in § 63.774(d)(1).

* * * * *

(i) In all cases where the provisions of this subpart require an owner or operator to repair leaks by a specified time after the leak is detected, it is a violation of this standard to fail to take action to repair the leak(s) within the specified time. If action is taken to repair the leak(s) within the specified

time, failure of that action to successfully repair the leak(s) is not a violation of this standard. However, if the repairs are unsuccessful, and a leak is detected, the owner or operator shall take further action as required by the applicable provisions of this subpart.

(j) At all times the owner or operator must operate and maintain any affected source, including associated air pollution control equipment and monitoring equipment, in a manner consistent with safety and good air pollution control practices for minimizing emissions. Determination of whether such operation and maintenance procedures are being used will be based on information available to the Administrator which may include, but is not limited to, monitoring results, review of operation and maintenance procedures, review of operation and maintenance records, and inspection of the source.

14. Section 63.765 is amended by:

a. Revising paragraph (a);

b. Revising paragraph (b)(1);

c. Revising paragraph (c)(2); and

d. Revising paragraph (c)(3) to read as follows:

§ 63.765 Glycol dehydration unit process vent standards.

(a) This section applies to each glycol dehydration unit subject to this subpart that must be controlled for air emissions as specified in either paragraph (c)(1)(i) or paragraph (d)(1)(i) of § 63.764.

(b) * * *

(1) For each glycol dehydration unit process vent, the owner or operator shall control air emissions by either paragraph (b)(1)(i), (ii), or (iii) of this section.

(i) The owner or operator of a large glycol dehydration unit, as defined in § 63.761, shall connect the process vent to a control device or a combination of control devices through a closed-vent system. The closed-vent system shall be designed and operated in accordance with the requirements of § 63.771(c). The control device(s) shall be designed and operated in accordance with the requirements of § 63.771(d).

(A) Connect the process vent to a control device or combination of control devices through a closed-vent system. The closed vent system shall be designed and operated in accordance with the requirements of § 63.771(c). The control device(s) shall be designed and operated in accordance with the requirements of § 63.771(f).

(B) Meet the emissions limit through process modifications in accordance with the requirements specified in § 63.771(e).

(C) Meet the emissions limit for each small glycol dehydration unit using a combination of process modifications and one or more control devices through the requirements specified in paragraphs (b)(1)(iii)(A) and (B) of this section.

(D) Demonstrate that the emissions limit is met through actual uncontrolled operation of the small glycol dehydration unit. Document operational parameters in accordance with the requirements specified in § 63.771(e) and emissions in accordance with the requirements specified in § 63.772(b)(2).

(ii) The owner or operator of a glycol dehydration unit located at an area source, that must be controlled as specified in § 63.764(d)(1)(i), shall connect the process vent to a control device or combination of control devices through a closed-vent system and the outlet benzene emissions from the control device(s) shall be reduced to a level less than 0.90 megagrams per year. The closed-vent system shall be designed and operated in accordance with the requirements of § 63.771(c). The control device(s) shall be designed and operated in accordance with the requirements of § 63.771(d), except that the performance levels specified in § 63.771(d)(1)(i) and (ii) do not apply.

(iii) You must limit BTEX emissions from each small glycol dehydration unit process vent, as defined in § 63.761, to the limit determined in Equation 1 of this section. The limit must be met in accordance with one of the alternatives specified in paragraphs (b)(1)(iii)(A) through (D) of this section.

$$EL_{BTEX} = 1.10x10^{-4} * Throughput * C_{i,BTEX} * 365\ \frac{days}{yr} * \frac{1\ Mg}{1x10^{6}\ grams}$$

Where:

EL_{BTEX} = Unit-specific BTEX emission limit, megagrams per year;

1.10×10^{-4} = BTEX emission limit, grams BTEX/standard cubic meter = ppmv;

Throughput = Annual average daily natural gas throughput, standard cubic meters per day;

$C_{i,BTEX}$ = BTEX concentration of the natural gas at the inlet to the glycol dehydration unit, ppmv.

(iii) For each small glycol dehydration unit, BTEX emissions are reduced to a level less than the limit calculated by paragraph (b)(1)(iii) of this section.

* * * * *

(c) * * *

(2) The owner or operator shall demonstrate, to the Administrator's satisfaction, that the total HAP emissions to the atmosphere from the large glycol dehydration unit process vent are reduced by 95.0 percent through process modifications, or a combination of process modifications and one or more control devices, in accordance with the requirements specified in § 63.771(e).

(3) Control of HAP emissions from a GCG separator (flash tank) vent is not required if the owner or operator demonstrates, to the Administrator's satisfaction, that total emissions to the atmosphere from the glycol dehydration unit process vent are reduced by one of the levels specified in paragraph (c)(3)(i), (ii), or (iii) of this section, through the installation and operation of controls as specified in paragraph (b)(1) of this section.

(i) For any large glycol dehydration unit, HAP emissions are reduced by 95.0 percent or more.

(ii) For area source dehydration units, benzene emissions are reduced to a level less than 0.90 megagrams per year.

15. Section 63.766 is amended by:

a. Revising paragraph (a);

b. Revising paragraph (b) introductory text;

c. Revising paragraph (b)(1); and

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

§ 63.766 Storage vessel standards.

(a) This section applies to each storage vessel (as defined in § 63.761) subject to this subpart.

(b) The owner or operator of a storage vessel (as defined in § 63.761) shall comply with one of the control requirements specified in paragraphs (b)(1) and (2) of this section.

(1) The owner or operator shall equip the affected storage vessel with a cover that is connected, through a closed-vent system that meets the conditions specified in § 63.771(c), to a control device or a combination of control devices that meets any of the conditions specified in § 63.771(d). The cover shall be designed and operated in accordance with the requirements of § 63.771(b).

* * * * *

(d) This section does not apply to storage vessels for which the owner or operator is subject to and controlled under the requirements specified in 40

CFR part 60, subpart Kb; or the requirements specified under 40 CFR part 63 subparts G or CC.

16. Section 63.769 is amended by:

a. Revising paragraph (b);

b. Revising paragraph (c) introductory text; and

b. Revising paragraph (c)(8) to read as follows:

§ 63.769 Equipment leak standards.

* * * * *

(b) This section does not apply to ancillary equipment and compressors for which the owner or operator is subject to and controlled under the requirements specified in subpart H of this part; or the requirements specified in 40 CFR part 60, subpart KKK.

(c) For each piece of ancillary equipment and each compressor subject to this section located at an existing or new source, the owner or operator shall meet the requirements specified in 40 CFR part 61, subpart V, §§ 61.241 through 61.247, except as specified in paragraphs (c)(1) through (8) of this section, except for valves subject to § 61.247–2(b) a leak is detected if an instrument reading of 500 ppm or greater is measured.

* * * * *

(8) Flares, as defined in § 63.761, used to comply with this subpart shall comply with the requirements of § 63.11(b).

17. Section 63.771 is amended by:

a. Revising paragraph (c)(1) introductory text;

b. Revising the heading of paragraph (d);

c. Adding paragraph (d) introductory text;

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

e. Revising paragraph (d)(1)(i)(C);

f. Revising paragraph (d)(1)(ii);

g. Revising paragraph (d)(1)(iii);

h. Revising paragraph (d)(4)(i);

i. Revising paragraph (d)(5)(i);

j. Revising paragraph (e)(2);

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

l. Revising paragraph (e)(3)(ii); and

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

§ 63.771 Control equipment requirements.

* * * * *

(c) *Closed-vent system requirements.* (1) The closed-vent system shall route all gases, vapors, and fumes emitted from the material in an emissions unit to a control device that meets the requirements specified in paragraph (d) of this section.

* * * * *

(d) *Control device requirements for sources except small glycol dehydration units.* Owners and operators of small glycol dehydration units, shall comply with the control device requirements in paragraph (f) of this section.

(1) * * *

(i) An enclosed combustion device (*e.g.,* thermal vapor incinerator, catalytic vapor incinerator, boiler, or process heater) that is designed and operated in accordance with one of the following performance requirements:

* * * * *

(C) For a control device that can demonstrate a uniform combustion zone temperature during the performance test conducted under § 63.772(e), operates at a minimum temperature of 760 degrees C.

* * * * *

(ii) A vapor recovery device (*e.g.,* carbon adsorption system or condenser) or other non-destructive control device that is designed and operated to reduce the mass content of either TOC or total HAP in the gases vented to the device by 95.0 percent by weight or greater as determined in accordance with the requirements of § 63.772(e).

(iii) A flare, as defined in § 63.761, that is designed and operated in accordance with the requirements of § 63.11(b).

* * * * *

(4) * * *

(i) Each control device used to comply with this subpart shall be operating at all times when gases, vapors, and fumes are vented from the HAP emissions unit or units through the closed-vent system to the control device, as required under § 63.765, § 63.766, and § 63.769. An owner or operator may vent more than one unit to a control device used to comply with this subpart.

* * * * *

(5) * * *

(i) Following the initial startup of the control device, all carbon in the control device shall be replaced with fresh carbon on a regular, predetermined time interval that is no longer than the carbon service life established for the carbon adsorption system. Records identifying the schedule for replacement and records of each carbon replacement shall be maintained as required in § 63.774(b)(7)(ix). The schedule for replacement shall be submitted with the Notification of Compliance Status Report as specified in § 63.775(d)(5)(iv). Each carbon replacement must be reported in the Periodic Reports as specified in § 63.772(e)(2)(xii).

* * * * *

(e) * * *

(2) The owner or operator shall document, to the Administrator's satisfaction, the conditions for which glycol dehydration unit baseline operations shall be modified to achieve the 95.0 percent overall HAP emission reduction, or BTEX limit determined in § 63.765(b)(1)(iii), as applicable, either through process modifications or through a combination of process modifications and one or more control devices. If a combination of process modifications and one or more control devices are used, the owner or operator shall also establish the emission reduction to be achieved by the control device to achieve an overall HAP emission reduction of 95.0 percent for the glycol dehydration unit process vent or, if applicable, the BTEX limit determined in § 63.765(b)(1)(iii) for the small glycol dehydration unit process vent. Only modifications in glycol dehydration unit operations directly related to process changes, including but not limited to changes in glycol circulation rate or glycol-HAP absorbency, shall be allowed. Changes in the inlet gas characteristics or natural gas throughput rate shall not be considered in determining the overall emission reduction due to process modifications.

(3) The owner or operator that achieves a 95.0 percent HAP emission reduction or meets the BTEX limit determined in § 63.765(b)(1)(iii), as applicable, using process modifications alone shall comply with paragraph (e)(3)(i) of this section. The owner or operator that achieves a 95.0 percent HAP emission reduction or meets the BTEX limit determined in § 63.765(b)(1)(iii), as applicable, using a combination of process modifications and one or more control devices shall comply with paragraphs (e)(3)(i) and (e)(3)(ii) of this section.

* * * * *

(ii) The owner or operator shall comply with the control device requirements specified in paragraph (d) or (f) of this section, as applicable, except that the emission reduction or limit achieved shall be the emission reduction or limit specified for the control device(s) in paragraph (e)(2) of this section.

(f) *Control device requirements for small glycol dehydration units.* (1) The control device used to meet BTEX the emission limit calculated in § 63.765(b)(1)(iii) shall be one of the control devices specified in paragraphs (f)(1)(i) through (iii) of this section.

(i) An enclosed combustion device (*e.g.,* thermal vapor incinerator, catalytic vapor incinerator, boiler, or process heater) that is designed and operated to reduce the mass content of BTEX in the gases vented to the device as

determined in accordance with the requirements of § 63.772(e). If a boiler or process heater is used as the control device, then the vent stream shall be introduced into the flame zone of the boiler or process heater; or

(ii) A vapor recovery device (*e.g.,* carbon adsorption system or condenser) or other non-destructive control device that is designed and operated to reduce the mass content of BTEX in the gases vented to the device as determined in accordance with the requirements of § 63.772(e); or

(iii) A flare, as defined in § 63.761, that is designed and operated in accordance with the requirements of § 63.11(b).

(2) The owner or operator shall operate each control device in accordance with the requirements specified in paragraphs (f)(2)(i) and (ii) of this section.

(i) Each control device used to comply with this subpart shall be operating at all times. An owner or operator may vent more than one unit to a control device used to comply with this subpart.

(ii) For each control device monitored in accordance with the requirements of § 63.773(d), the owner or operator shall demonstrate compliance according to the requirements of either § 63.772(f) or (h).

(3) For each carbon adsorption system used as a control device to meet the requirements of paragraph (f)(1)(ii) of this section, the owner or operator shall manage the carbon as required under (d)(5)(i) and (ii) of this section.

18. Section 63.772 is amended by:

a. Revising paragraph (b) introductory text;

b. Revising paragraph (b)(1)(ii);

c. Revising paragraph (b)(2);

d. Adding paragraph (d);

e. Revising paragraph (e) introductory text;

f. Revising paragraphs (e)(1)(i) through (v);

g. Revising paragraph (e)(2);

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

i. Revising paragraph (e)(3)(i)(B);

j. Revising paragraph (e)(3)(iv)(C)(*1*);

k. Adding paragraphs (e)(3)(v) and (vi);

l. Revising paragraph (e)(4) introductory text;

m. Revising paragraph (e)(4)(i);

n. Revising paragraph (e)(5);

o. Revising paragraph (f) introductory text;

p. Adding paragraphs (f)(2) through (f)(6);

q. Revising paragraph (g) introductory text;

r. Revising paragraph (g)(1) and paragraph (g)(2) introductory text;

s. Revising paragraph (g)(2)(iii);

t. Revising paragraph (g)(3);

u. Adding paragraph (h); and

v. Adding paragraph (i) to read as follows:

§ 63.772 Test methods, compliance procedures, and compliance demonstrations.

* * * * *

(b) *Determination of glycol dehydration unit flowrate, benzene emissions, or BTEX emissions.* The procedures of this paragraph shall be used by an owner or operator to determine glycol dehydration unit natural gas flowrate, benzene emissions, or BTEX emissions.

(1) * * *

(ii) The owner or operator shall document, to the Administrator's satisfaction, the actual annual average natural gas flowrate to the glycol dehydration unit.

(2) The determination of actual average benzene or BTEX emissions from a glycol dehydration unit shall be made using the procedures of either paragraph (b)(2)(i) or (b)(2)(ii) of this section. Emissions shall be determined either uncontrolled, or with federally enforceable controls in place.

(i) The owner or operator shall determine actual average benzene or BTEX emissions using the model GRI–GLYCalc™, Version 3.0 or higher, and the procedures presented in the associated GRI–GLYCalc™ Technical Reference Manual. Inputs to the model shall be representative of actual operating conditions of the glycol dehydration unit and may be determined using the procedures documented in the Gas Research Institute (GRI) report entitled ''Atmospheric Rich/Lean Method for Determining Glycol Dehydrator Emissions'' (GRI–95/0368.1); or

(ii) The owner or operator shall determine an average mass rate of benzene or BTEX emissions in kilograms per hour through direct measurement using the methods in § 63.772(a)(1)(i) or (ii), or an alternative method according to § 63.7(f). Annual emissions in kilograms per year shall be determined by multiplying the mass rate by the number of hours the unit is operated per year. This result shall be converted to megagrams per year.

* * * * *

(d) *Test procedures and compliance demonstrations for small glycol dehydration units.* This paragraph applies to the test procedures for small dehydration units.

(1) If the owner or operator is using a control device to comply with the emission limit in § 63.765(b)(1)(iii), the requirements of paragraph (e) of this section apply. Compliance is demonstrated using the methods specified in paragraph (f) of this section.

(2) If no control device is used to comply with the emission limit in § 63.765(b)(1)(iii), the owner or operator must determine the glycol dehydration unit BTEX emissions as specified in paragraphs (d)(2)(i) through (iii) of this section. Compliance is demonstrated if the BTEX emissions determined as specified in paragraphs (d)(2)(i) through (iii) are less than the emission limit calculated using the equation in § 63.765(b)(1)(iii).

(i) Method 1 or 1A, 40 CFR part 60, appendix A, as appropriate, shall be used for selection of the sampling sites at the outlet of the glycol dehydration unit process vent. Any references to particulate mentioned in Methods 1 and 1A do not apply to this section.

(ii) The gas volumetric flowrate shall be determined using Method 2, 2A, 2C, or 2D, 40 CFR part 60, appendix A, as appropriate.

(iii) The BTEX emissions from the outlet of the glycol dehydration unit process vent shall be determined using the procedures specified in paragraph (e)(3)(v) of this section. As an alternative, the mass rate of BTEX at the outlet of the glycol dehydration unit process vent may be calculated using the model GRI–GLYCalc™, Version 3.0 or higher, and the procedures presented in the associated GRI–GLYCalc™ Technical Reference Manual. Inputs to the model shall be representative of actual operating conditions of the glycol dehydration unit and shall be determined using the procedures documented in the Gas Research Institute (GRI) report entitled ''Atmospheric Rich/Lean Method for Determining Glycol Dehydrator Emissions'' (GRI–95/0368.1). When the BTEX mass rate is calculated for glycol dehydration units using the model GRI–GLYCalc™, all BTEX measured by Method 18, 40 CFR part 60, appendix A, shall be summed.

(e) *Control device performance test procedures.* This paragraph applies to the performance testing of control devices. The owners or operators shall demonstrate that a control device achieves the performance requirements of § 63.771(d)(1), (e)(3)(ii) or (f)(1) using a performance test as specified in paragraph (e)(3) of this section. Owners or operators using a condenser have the option to use a design analysis as specified in paragraph (e)(4) of this section. The owner or operator may elect to use the alternative procedures in paragraph (e)(5) of this section for performance testing of a condenser used

to control emissions from a glycol dehydration unit process vent. As an alternative to conducting a performance test under this section for combustion control devices, a control device that can be demonstrated to meet the performance requirements of § 63.771(d)(1), (e)(3)(ii) or (f)(1) through a performance test conducted by the manufacturer, as specified in paragraph (h) of this section can be used.

(1) * * *

(i) Except as specified in paragraph (e)(2) of this section, a flare, as defined in § 63.761, that is designed and operated in accordance with § 63.11(b);

(ii) Except for control devices used for small glycol dehydration units, a boiler or process heater with a design heat input capacity of 44 megawatts or greater;

(iii) Except for control devices used for small glycol dehydration units, a boiler or process heater into which the vent stream is introduced with the primary fuel or is used as the primary fuel;

(iv) Except for control devices used for small glycol dehydration units, a boiler or process heater burning hazardous waste for which the owner or operator has either been issued a final permit under 40 CFR part 270 and complies with the requirements of 40 CFR part 266, subpart H; or has certified compliance with the interim status requirements of 40 CFR part 266, subpart H;

(v) Except for control devices used for small glycol dehydration units, a hazardous waste incinerator for which the owner or operator has been issued a final permit under 40 CFR part 270 and complies with the requirements of 40 CFR part 264, subpart O; or has certified compliance with the interim status requirements of 40 CFR part 265, subpart O.

* * * * *

(2) An owner or operator shall design and operate each flare, as defined in § 63.761, in accordance with the requirements specified in § 63.11(b) and the compliance determination shall be conducted using Method 22 of 40 CFR part 60, appendix A, to determine visible emissions.

(3) For a performance test conducted to demonstrate that a control device meets the requirements of § 63.771(d)(1), (e)(3)(ii) or (f)(1), the owner or operator shall use the test methods and procedures specified in paragraphs (e)(3)(i) through (v) of this section. The initial and periodic performance tests shall be conducted according to the schedule specified in paragraph (e)(3)(vi) of this section.

(i) * * *

(B) To determine compliance with the enclosed combustion device total HAP concentration limit specified in § 63.765(b)(1)(iii), or the BTEX emission limit specified in § 63.771(f)(1) the sampling site shall be located at the outlet of the combustion device.

* * * * *

(iv) * * *

(C) * * *

(*1*) The emission rate correction factor for excess air, integrated sampling and analysis procedures of Method 3A or 3B, 40 CFR part 60, appendix A, shall be used to determine the oxygen concentration. The samples shall be taken during the same time that the samples are taken for determining TOC concentration or total HAP concentration.

* * * * *

(v) To determine compliance with the BTEX emission limit specified in § 63.771(f)(1) the owner or operator shall use one of the following methods: Method 18, 40 CFR part 60, appendix A; ASTM D6420–99 (2004), as specified in § 63.772(a)(1)(ii); or any other method or data that have been validated according to the applicable procedures in Method 301, 40 CFR part 63, appendix A. The following procedures shall be used to calculate BTEX emissions:

(A) The minimum sampling time for each run shall be 1 hour in which either an integrated sample or a minimum of four grab samples shall be taken. If grab sampling is used, then the samples shall be taken at approximately equal intervals in time, such as 15-minute intervals during the run.

(B) The mass rate of BTEX (E_o) shall be computed using the equations and procedures specified in paragraphs (e)(3)(v)(B)(*1*) and (*2*) of this section.

(*1*) The following equation shall be used:

$$E_o = K_2\left(\sum_{j=1}^{n} C_{oj} M_{oj}\right) Q_o$$

Where:

E_o= Mass rate of BTEX at the outlet of the control device, dry basis, kilogram per hour.

C_{oj}= Concentration of sample component j of the gas stream at the outlet of the control device, dry basis, parts per million by volume.

M_{oj}= Molecular weight of sample component j of the gas stream at the outlet of the control device, gram/gram-mole.

Q_o= Flowrate of gas stream at the outlet of the control device, dry standard cubic meter per minute.

K_2= Constant, 2.494×10^{-6} (parts per million) (gram-mole per standard cubic meter) (kilogram/gram) (minute/hour), where standard temperature (gram-mole per standard cubic meter) is 20 degrees C.

n = Number of components in sample.

(*2*) When the BTEX mass rate is calculated, only BTEX compounds measured by Method 18, 40 CFR part 60, appendix A, or ASTM D6420–99 (2004) as specified in § 63.772(a)(1)(ii), shall be summed using the equations in paragraph (e)(3)(v)(B)(*1*) of this section.

(vi) The owner or operator shall conduct performance tests according to the schedule specified in paragraphs (e)(3)(vi)(A) and (B) of this section.

(A) An initial performance test shall be conducted within 180 days after the compliance date that is specified for each affected source in § 63.760(f)(7) through (8), except that the initial performance test for existing combustion control devices at existing major sources shall be conducted no later than 3 years after the date of publication of the final rule in the **Federal Register**. If the owner or operator of an existing combustion control device at an existing major source chooses to replace such device with a control device whose model is tested under § 63.772(h), then the newly installed device shall comply with all provisions of this subpart no later than 3 years after the date of publication of the final rule in the **Federal Register**. The performance test results shall be submitted in the Notification of Compliance Status Report as required in § 63.775(d)(1)(ii).

(B) Periodic performance tests shall be conducted for all control devices required to conduct initial performance tests except as specified in paragraphs (e)(3)(vi)(B)(*1*) and (*2*) of this section. The first periodic performance test shall be conducted no later than 60 months after the initial performance test required in paragraph (e)(3)(vi)(A) of this section. Subsequent periodic performance tests shall be conducted at intervals no longer than 60 months following the previous periodic performance test or whenever a source desires to establish a new operating limit. The periodic performance test results must be submitted in the next Periodic Report as specified in § 63.775(e)(2)(xi). Combustion control devices meeting the criteria in either paragraph (e)(3)(vi)(B)(*1*) or (*2*) of this section are not required to conduct periodic performance tests.

(*1*) A control device whose model is tested under, and meets the criteria of, § 63.772(h), or

(*2*) A combustion control device tested under § 63.772(e) that meets the outlet TOC or HAP performance level specified in § 63.771(d)(1)(i)(B) and that

establishes a correlation between firebox or combustion chamber temperature and the TOC or HAP performance level.

(4) For a condenser design analysis conducted to meet the requirements of § 63.771(d)(1), (e)(3)(ii), or (f)(1), the owner or operator shall meet the requirements specified in paragraphs (e)(4)(i) and (e)(4)(ii) of this section. Documentation of the design analysis shall be submitted as a part of the Notification of Compliance Status Report as required in § 63.775(d)(1)(i).

(i) The condenser design analysis shall include an analysis of the vent stream composition, constituent concentrations, flowrate, relative humidity, and temperature, and shall establish the design outlet organic compound concentration level, design average temperature of the condenser exhaust vent stream, and the design average temperatures of the coolant fluid at the condenser inlet and outlet. As an alternative to the condenser design analysis, an owner or operator may elect to use the procedures specified in paragraph (e)(5) of this section.

* * * * *

(5) As an alternative to the procedures in paragraph (e)(4)(i) of this section, an owner or operator may elect to use the procedures documented in the GRI report entitled, ''Atmospheric Rich/Lean Method for Determining Glycol Dehydrator Emissions'' (GRI–95/0368.1) as inputs for the model GRI–GLYCalc™, Version 3.0 or higher, to generate a condenser performance curve.

(f) *Compliance demonstration for control device performance requirements.* This paragraph applies to the demonstration of compliance with the control device performance requirements specified in § 63.771(d)(1)(i), (e)(3) and (f)(1). Compliance shall be demonstrated using the requirements in paragraphs (f)(1) through (3) of this section. As an alternative, an owner or operator that installs a condenser as the control device to achieve the requirements specified in § 63.771(d)(1)(ii), (e)(3) or (f)(1) may demonstrate compliance according to paragraph (g) of this section. An owner or operator may switch between compliance with paragraph (f) of this section and compliance with paragraph (g) of this section only after at least 1 year of operation in compliance with the selected approach. Notification of such a change in the compliance method shall be reported in the next Periodic Report, as required in § 63.775(e), following the change.

* * * * *

(2) The owner or operator shall calculate the daily average of the applicable monitored parameter in accordance with § 63.773(d)(4) except that the inlet gas flow rate to the control device shall not be averaged.

(3) Compliance with the operating parameter limit is achieved when the daily average of the monitoring parameter value calculated under paragraph (f)(2) of this section is either equal to or greater than the minimum or equal to or less than the maximum monitoring value established under paragraph (f)(1) of this section. For inlet gas flow rate, compliance with the operating parameter limit is achieved when the value is equal to or less than the value established under § 63.772(h).

(4) Except for periods of monitoring system malfunctions, repairs associated with monitoring system malfunctions, and required monitoring system quality assurance or quality control activities (including, as applicable, system accuracy audits and required zero and span adjustments), the CMS required in § 63.773(d) must be operated at all times the affected source is operating. A monitoring system malfunction is any 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. Monitoring system repairs are required to be completed in response to monitoring system malfunctions and to return the monitoring system to operation as expeditiously as practicable.

(5) Data recorded during monitoring system malfunctions, repairs associated with monitoring system malfunctions, or required monitoring system quality assurance or control activities may not be used in calculations used to report emissions or operating levels. All the data collected during all other required data collection periods must be used in assessing the operation of the control device and associated control system.

(6) Except for periods of monitoring system malfunctions, repairs associated with monitoring system malfunctions, and required quality monitoring system quality assurance or quality control activities (including, as applicable, system accuracy audits and required zero and span adjustments), failure to collect required data is a deviation of the monitoring requirements.

(g) *Compliance demonstration with percent reduction or emission limit performance requirements—condensers.* This paragraph applies to the demonstration of compliance with the performance requirements specified in § 63.771(d)(1)(ii),(e)(3) or (f)(1) for condensers. Compliance shall be demonstrated using the procedures in paragraphs (g)(1) through (3) of this section.

(1) The owner or operator shall establish a site-specific condenser performance curve according to § 63.773(d)(5)(ii). For sources required to meet the BTEX limit in accordance with § 63.771(e) or (f)(1) the owner or operator shall identify the minimum percent reduction necessary to meet the BTEX limit.

(2) Compliance with the requirements in § 63.771(d)(1)(ii),(e)(3) or (f)(1) shall be demonstrated by the procedures in paragraphs (g)(2)(i) through (iii) of this section.

* * * * *

(iii) Except as provided in paragraphs (g)(2)(iii)(A) and (B) of this section, at the end of each operating day, the owner or operator shall calculate the 365-day average HAP, or BTEX, emission reduction, as appropriate, from the condenser efficiencies as determined in paragraph (g)(2)(ii) of this section for the preceding 365 operating days. If the owner or operator uses a combination of process modifications and a condenser in accordance with the requirements of § 63.771(e), the 365-day average HAP, or BTEX, emission reduction shall be calculated using the emission reduction achieved through process modifications and the condenser efficiency as determined in paragraph (g)(2)(ii) of this section, both for the previous 365 operating days.

(A) After the compliance dates specified in § 63.760(f), an owner or operator with less than 120 days of data for determining average HAP, or BTEX, emission reduction, as appropriate, shall calculate the average HAP, or BTEX emission reduction, as appropriate, for the first 120 days of operation after the compliance dates. For sources required to meet the overall 95.0 percent reduction requirement, compliance is achieved if the 120-day average HAP emission reduction is equal to or greater than 90.0 percent. For sources required to meet the BTEX limit under § 63.765(b)(1)(iii), compliance is achieved if the average BTEX emission reduction is at least 95.0 percent of the required 365-day value identified under paragraph (g)(1) of this section (*i.e.,* at least 76.0 percent if the 365-day design value is 80.0 percent).

(B) After 120 days and no more than 364 days of operation after the

compliance dates specified in § 63.760(f), the owner or operator shall calculate the average HAP emission reduction as the HAP emission reduction averaged over the number of days between the current day and the applicable compliance date. For sources required to meet the overall 95.0-percent reduction requirement, compliance with the performance requirements is achieved if the average HAP emission reduction is equal to or greater than 90.0 percent. For sources required to meet the BTEX limit under § 63.765(b)(1)(iii), compliance is achieved if the average BTEX emission reduction is at least 95.0 percent of the required 365-day value identified under paragraph (g)(1) of this section (*i.e.,* at least 76.0 percent if the 365-day design value is 80.0 percent).

(3) If the owner or operator has data for 365 days or more of operation, compliance is achieved based on the applicable criteria in paragraphs (g)(3)(i) or (ii) of this section.

(i) For sources meeting the HAP emission reduction specified in § 63.771(d)(1)(ii) or (e)(3) the average HAP emission reduction calculated in paragraph (g)(2)(iii) of this section is equal to or greater than 95.0 percent.

(ii) For sources required to meet the BTEX limit under § 63.771(e)(3) or (f)(1), compliance is achieved if the average BTEX emission reduction calculated in paragraph (g)(2)(iii) of this section is equal to or greater than the minimum percent reduction identified in paragraph (g)(1) of this section.

* * * * *

(h) *Performance testing for combustion control devices—manufacturers' performance test.* (1) This paragraph applies to the performance testing of a combustion control device conducted by the device manufacturer. The manufacturer shall demonstrate that a specific model of control device achieves the performance requirements in (h)(7) of this section by conducting a performance test as specified in paragraphs (h)(2) through (6) of this section.

(2) Performance testing shall consist of three one-hour (or longer) test runs for each of the four following firing rate settings making a total of 12 test runs per test. Propene (propylene) gas shall be used for the testing fuel. All fuel analyses shall be performed by an independent third-party laboratory (not affiliated with the control device manufacturer or fuel supplier).

(i) 90–100 percent of maximum design rate (fixed rate).

(ii) 70–100–70 percent (ramp up, ramp down). Begin the test at 70 percent of the maximum design rate. Within the first 5 minutes, ramp the firing rate to 100 percent of the maximum design rate. Hold at 100 percent for 5 minutes. In the 10–15 minute time range, ramp back down to 70 percent of the maximum design rate. Repeat three more times for a total of 60 minutes of sampling.

(iii) 30–70–30 percent (ramp up, ramp down). Begin the test at 30 percent of the maximum design rate. Within the first 5 minutes, ramp the firing rate to 70 percent of the maximum design rate. Hold at 70 percent for 5 minutes. In the 10–15 minute time range, ramp back down to 30 percent of the maximum design rate. Repeat three more times for a total of 60 minutes of sampling.

(iv) 0–30–0 percent (ramp up, ramp down). Begin the test at 0 percent of the maximum design rate. Within the first 5 minutes, ramp the firing rate to 100 percent of the maximum design rate. Hold at 30 percent for 5 minutes. In the 10–15 minute time range, ramp back down to 0 percent of the maximum design rate. Repeat three more times for a total of 60 minutes of sampling.

(3) All models employing multiple enclosures shall be tested simultaneously and with all burners operational. Results shall be reported for the each enclosure individually and for the average of the emissions from all interconnected combustion enclosures/chambers. Control device operating data shall be collected continuously throughout the performance test using an electronic Data Acquisition System and strip chart. Data shall be submitted with the test report in accordance with paragraph (8)(iii) of this section.

(4) Inlet testing shall be conducted as specified in paragraphs (h)(4)(i) through (iii) of this section.

(i) The fuel flow metering system shall be located in accordance with Method 2A, 40 CFR part 60, appendix A–1, (or other approved procedure) to measure fuel flow rate at the control device inlet location. The fitting for filling fuel sample containers shall be located a minimum of 8 pipe diameters upstream of any inlet fuel flow monitoring meter.

(ii) Inlet flow rate shall be determined using Method 2A, 40 CFR part 60, appendix A–1. Record the start and stop reading for each 60-minute THC test. Record the gas pressure and temperature at 5-minute intervals throughout each 60-minute THC test.

(iii) Inlet fuel sampling shall be conducted in accordance with the criteria in paragraphs (h)(4)(iii)(A) and (B) of this section.

(A) At the inlet fuel sampling location, securely connect a Silonite-coated stainless steel evacuated canister fitted with a flow controller sufficient to fill the canister over a 1 hour period. Filling shall be conducted as specified in the following:

(*1*) Open the canister sampling valve at the beginning of the total hydrocarbon (THC) test, and close the canister at the end of the THC test.

(*2*) Fill one canister for each THC test run.

(*3*) Label the canisters individually and record on a chain of custody form.

(B) Each fuel sample shall be analyzed using the following methods. The results shall be included in the test report.

(*1*) Hydrocarbon compounds containing between one and five atoms of carbon plus benzene using ASTM D1945–03.

(*2*) Hydrogen (H_2), carbon monoxide (CO), carbon dioxide (CO_2), nitrogen (N_2), oxygen (O_2) using ASTM D1945–03.

(*3*) Carbonyl sulfide, carbon disulfide plus mercaptans using ASTM D5504.

(*4*) Higher heating value using ASTM D3588–98 or ASTM D4891–89.

(5) Outlet testing shall be conducted in accordance with the criteria in paragraphs (h)(5)(i) through (v) of this section.

(i) Sampling and flowrate measured in accordance with the following:

(A) The outlet sampling location shall be a minimum of 4 equivalent stack diameters downstream from the highest peak flame or any other flow disturbance, and a minimum of one equivalent stack diameter upstream of the exit or any other flow disturbance. A minimum of two sample ports shall be used.

(B) Flow rate shall be measured using Method 1, 40 CFR part 60, Appendix 1, for determining flow measurement traverse point location; and Method 2, 40 CFR part 60, Appendix 1, shall be used to measure duct velocity. If low flow conditions are encountered (*i.e.,* velocity pressure differentials less than 0.05 inches of water) during the performance test, a more sensitive manometer shall be used to obtain an accurate flow profile.

(ii) Molecular weight shall be determined as specified in paragraphs (h)(4)(iii)(B), (h)(5)(ii)(A), and (h)(5)(ii)(B) of this section.

(A) An integrated bag sample shall be collected during the Method 4, 40 CFR part 60, Appendix A, moisture test. Analyze the bag sample using a gas chromatograph-thermal conductivity detector (GC–TCD) analysis meeting the following criteria:

(*1*) Collect the integrated sample throughout the entire test, and collect

representative volumes from each traverse location.

(*2*) The sampling line shall be purged with stack gas before opening the valve and beginning to fill the bag.

(*3*) The bag contents shall be kneaded or otherwise vigorously mixed prior to the GC analysis.

(*4*) The GC–TCD calibration procedure in Method 3C, 40 CFR part 60, Appendix A, shall be modified by using EPAAlt–045 as follows: For the initial calibration, triplicate injections of any single concentration must agree within 5 percent of their mean to be valid. The calibration response factor for a single concentration re-check must be within 10 percent of the original calibration response factor for that concentration. If this criterion is not met, the initial calibration using at least three concentration levels shall be repeated.

(B) Report the molecular weight of: O_2, CO_2, methane (CH4), and N_2 and include in the test report submitted under § 63.775(d)(iii). Moisture shall be determined using Method 4, 40 CFR part 60, Appendix A. Traverse both ports with the Method 4, 40 CFR part 60, Appendix A, sampling train during each test run. Ambient air shall not be introduced into the Method 3C, 40 CFR part 60, Appendix A, integrated bag sample during the port change.

(iii) Carbon monoxide shall be determined using Method 10, 40 CFR part 60, Appendix A. The test shall be run at the same time and with the sample points used for the EPA Method 25A, 40 CFR part 60, Appendix A, testing. An instrument range of 0–10 per million by volume-dry (ppmvd) shall be used.

(iv) Visible emissions shall be determined using Method 22, 40 CFR part 60, Appendix A. The test shall be performed continuously during each test run. A digital color photograph of the exhaust point, taken from the position of the observer and annotated with date and time, will be taken once per test run and the four photos included in the test report.

(6) Total hydrocarbons (THC) shall be determined as specified by the following criteria:

(i) Conduct THC sampling using Method 25A, 40 CFR part 60, Appendix A, except the option for locating the probe in the center 10 percent of the stack shall not be allowed. The THC probe must be traversed to 16.7 percent, 50 percent, and 83.3 percent of the stack diameter during the testing.

(ii) A valid test shall consist of three Method 25A, 40 CFR part 60, Appendix A, tests, each no less than 60 minutes in duration.

(iii) A 0–10 parts per million by volume-wet (ppmvw) (as propane) measurement range is preferred; as an alternative a 0–30 ppmvw (as carbon) measurement range may be used.

(iv) Calibration gases will be propane in air and be certified through EPA Protocol 1—''EPA Traceability Protocol for Assay and Certification of Gaseous Calibration Standards,'' September 1997, as amended August 25, 1999, EPA–600/R–97/121 (or more recent if updated since 1999).

(v) THC measurements shall be reported in terms of ppmvw as propane.

(vi) THC results shall be corrected to 3 percent CO_2, as measured by Method 3C, 40 CFR part 60, Appendix A.

(vii) Subtraction of methane/ethane from the THC data is not allowed in determining results.

(7) Performance test criteria:

(i) The control device model tested must meet the criteria in paragraphs (h)(7)(i)(A) through (C) of this section:

(A) Method 22, 40 CFR part 60, Appendix A, results under paragraph (h)(5)(v) of this section with no indication of visible emissions, and

(B) Average Method 25A, 40 CFR part 60, Appendix A, results under paragraph (h)(6) of this section equal to or less than 10.0 ppmvw THC as propane corrected to 3.0 percent CO_2, and

(C) Average CO emissions determined under paragraph (h)(5)(iv) of this section equal to or less than 10 parts ppmvd, corrected to 3.0 percent CO_2.

(ii) The manufacturer shall determine a maximum inlet gas flow rate which shall not be exceeded for each control device model to achieve the criteria in paragraph (h)(7)(i) of this section.

(iii) A control device meeting the criteria in paragraphs (h)(7)(i)(A) through (C) of this section will have demonstrated a destruction efficiency of 98.0 percent for HAP regulated under this subpart.

(8) The owner or operator of a combustion control device model tested under this section shall submit the information listed in paragraphs (h)(8)(i) through (iii) of this section in the test report required under § 63.775(d)(1)(iii).

(i) Full schematic of the control device and dimensions of the device components.

(ii) Design net heating value (minimum and maximum) of the device.

(iii) Test fuel gas flow range (in both mass and volume). Include the minimum and maximum allowable inlet gas flow rate.

(iv) Air/stream injection/assist ranges, if used.

(v) The test parameter ranges listed in paragraphs (h)(8)(v)(A) through (O) of this section, as applicable for the tested model.

(A) Fuel gas delivery pressure and temperature.

(B) Fuel gas moisture range.

(C) Purge gas usage range.

(D) Condensate (liquid fuel) separation range.

(E) Combustion zone temperature range. This is required for all devices that measure this parameter.

(F) Excess combustion air range.

(G) Flame arrestor(s).

(H) Burner manifold pressure.

(I) Pilot flame sensor.

(J) Pilot flame design fuel and fuel usage.

(K) Tip velocity range.

(L) Momentum flux ratio.

(M) Exit temperature range.

(N) Exit flow rate.

(O) Wind velocity and direction.

(vi) The test report shall include all calibration quality assurance/quality control data, calibration gas values, gas cylinder certification, and strip charts annotated with test times and calibration values.

(i) *Compliance demonstration for combustion control devices—manufacturers' performance test.* This paragraph applies to the demonstration of compliance for a combustion control device tested under the provisions in paragraph (h) of this section. Owners or operators shall demonstrate that a control device achieves the performance requirements of § 63.771(d)(1), (e)(3)(ii) or (f)(1), by installing a device tested under paragraph (h) of this section and complying with the following criteria:

(1) The inlet gas flow rate shall meet the range specified by the manufacturer. Flow rate shall be measured as specified in § 63.773(d)(3)(i)(H)(*1*).

(2) A pilot flame shall be present at all times of operation. The pilot flame shall be monitored in accordance with § 63.773(d)(3)(i)(H)(*2*).

(3) Devices shall be operated with no visible emissions, except for periods not to exceed a total of 5 minutes during any 2 consecutive hours. A visible emissions test using Method 22, 40 CFR part 60, Appendix A, shall be performed monthly. The observation period shall be 2 hours and shall be used according to Method 22.

(4) Compliance with the operating parameter limit is achieved when the following criteria are met:

(i) The inlet gas flow rate monitored under paragraph (i)(1) of this section is equal to or below the maximum established by the manufacturer; and

(ii) The pilot flame is present at all times; and

(iii) During the visible emissions test performed under paragraph (i)(3) of this

section the duration of visible emissions does not exceed a total of 5 minutes during the observation period. Devices failing the visible emissions test shall follow the requirements in paragraphs (i)(4)(iii)(A) and (B) of this section.

(A) Following the first failure, the fuel nozzle(s) and burner tubes shall be replaced.

(B) If, following replacement of the fuel nozzle(s) and burner tubes as specified in paragraph (i)(4)(iii)(A), the visible emissions test is not passed in the next scheduled test, either a performance test shall be performed under paragraph (e) of this section, or the device shall be replaced with another control device whose model was tested, and meets, the requirements in paragraph (h) of this section.

19. Section 63.773 is amended by:

a. Adding paragraph (b);

b. Revising paragraph (d)(1) introductory text;

c. Revising paragraph (d)(1)(ii) and adding paragraphs (d)(1)(iii) and (iv);

d. Revising paragraphs (d)(2)(i) and (d)(2)(ii);

e. Revising paragraphs (d)(3)(i)(A) and (B);

f. Revising paragraphs (d)(3)(i)(D) and (E);

g. Revising paragraphs (d)(3)(i)(F)(*1*) and (*2*);

h. Revising paragraph (d)(3)(i)(G);

i. Adding paragraph (d)(3)(i)(H);

j. Revising paragraph (d)(4);

k. Revising paragraph (d)(5)(i);

l. Revising paragraphs (d)(5)(ii)(A) through (C);

m. Revising paragraphs (d)(6)(ii) and (iii);

n. Adding paragraph (d)(6)(vi);

o. Revising paragraph (d)(8)(i)(A); and

p. Revising paragraph (d)(8)(ii) to read as follows:

§ 63.773 Inspection and monitoring requirements.

* * * * *

(b) The owner or operator of a control device whose model was tested under § 63.772(h) shall develop an inspection and maintenance plan for each control device. At a minimum, the plan shall contain the control device manufacturer's recommendations for ensuring proper operation of the device. Semi-annual inspections shall be conducted for each control device with maintenance and replacement of control device components made in accordance with the plan.

* * * * *

(d) *Control device monitoring requirements.* (1) For each control device, except as provided for in paragraph (d)(2) of this section, the owner or operator shall install and operate a continuous parameter monitoring system in accordance with the requirements of paragraphs (d)(3) through (9) of this section. Owners or operators that install and operate a flare in accordance with § 63.771(d)(1)(iii) or (f)(1)(iii) are exempt from the requirements of paragraphs (d)(4) and (5) of this section. The continuous monitoring system shall be designed and operated so that a determination can be made on whether the control device is achieving the applicable performance requirements of § 63.771(d), (e)(3) or (f)(1). Each continuous parameter monitoring system shall meet the following specifications and requirements:

* * * * *

(ii) A site-specific monitoring plan must be prepared that addresses the monitoring system design, data collection, and the quality assurance and quality control elements outlined in paragraph (d) of this section and in § 63.8(d). Each CPMS must be installed, calibrated, operated, and maintained in accordance with the procedures in your approved site-specific monitoring plan. Using the process described in § 63.8(f)(4), you may request approval of monitoring system quality assurance and quality control procedures alternative to those specified in paragraphs (d)(1)(ii)(A) through (E) of this section in your site-specific monitoring plan.

(A) The performance criteria and design specifications for the monitoring system equipment, including the sample interface, detector signal analyzer, and data acquisition and calculations;

(B) Sampling interface (*e.g.,* thermocouple) location such that the monitoring system will provide representative measurements;

(C) Equipment performance checks, system accuracy audits, or other audit procedures;

(D) Ongoing operation and maintenance procedures in accordance with provisions in § 63.8(c)(1) and (c)(3); and

(E) Ongoing reporting and recordkeeping procedures in accordance with provisions in § 63.10(c), (e)(1), and (e)(2)(i).

(iii) The owner or operator must conduct the CPMS equipment performance checks, system accuracy audits, or other audit procedures specified in the site-specific monitoring plan at least once every 12 months.

(iv) The owner or operator must conduct a performance evaluation of each CPMS in accordance with the site-specific monitoring plan.

(2) * * *

(i) Except for control devices for small glycol dehydration units, a boiler or process heater in which all vent streams are introduced with the primary fuel or is used as the primary fuel; or

(ii) Except for control devices for small glycol dehydration units, a boiler or process heater with a design heat input capacity equal to or greater than 44 megawatts.

(3) * * *

(i) * * *

(A) For a thermal vapor incinerator that demonstrates during the performance test conducted under § 63.772(e) that the combustion zone temperature is an accurate indicator of performance, a temperature monitoring device equipped with a continuous recorder. The monitoring device shall have a minimum accuracy of ± 1 percent of the temperature being monitored in degrees C, or ± 2.5 degrees C, whichever value is greater. The temperature sensor shall be installed at a location representative of the combustion zone temperature.

(B) For a catalytic vapor incinerator, a temperature monitoring device equipped with a continuous recorder. The device shall be capable of monitoring temperature at two locations and have a minimum accuracy of ± 1 percent of the temperature being monitored in degrees C, or ± 2.5 degrees C, whichever value is greater. One temperature sensor shall be installed in the vent stream at the nearest feasible point to the catalyst bed inlet and a second temperature sensor shall be installed in the vent stream at the nearest feasible point to the catalyst bed outlet.

* * * * *

(D) For a boiler or process heater a temperature monitoring device equipped with a continuous recorder. The temperature monitoring device shall have a minimum accuracy of ± 1 percent of the temperature being monitored in degrees C, or ± 2.5 degrees C, whichever value is greater. The temperature sensor shall be installed at a location representative of the combustion zone temperature.

(E) For a condenser, a temperature monitoring device equipped with a continuous recorder. The temperature monitoring device shall have a minimum accuracy of ± 1 percent of the temperature being monitored in degrees C, or ± 2.8 degrees C, whichever value is greater. The temperature sensor shall be installed at a location in the exhaust vent stream from the condenser.

(F) * * *

(*1*) A continuous parameter monitoring system to measure and

record the average total regeneration stream mass flow or volumetric flow during each carbon bed regeneration cycle. The flow sensor must have a measurement sensitivity of 5 percent of the flow rate or 10 cubic feet per minute, whichever is greater. The mechanical connections for leakage must be checked at least every month, and a visual inspection must be performed at least every 3 months of all components of the flow CPMS for physical and operational integrity and all electrical connections for oxidation and galvanic corrosion if your flow CPMS is not equipped with a redundant flow sensor; and

(*2*) A continuous parameter monitoring system to measure and record the average carbon bed temperature for the duration of the carbon bed steaming cycle and to measure the actual carbon bed temperature after regeneration and within 15 minutes of completing the cooling cycle. The temperature monitoring device shall have a minimum accuracy of ± 1 percent of the temperature being monitored in degrees C, or ± 2.5 degrees C, whichever value is greater.

(G) For a nonregenerative-type carbon adsorption system, the owner or operator shall monitor the design carbon replacement interval established using a performance test performed in accordance with § 63.772(e)(3) shall be based on the total carbon working capacity of the control device and source operating schedule.

(H) For a control device model whose model is tested under § 63.772(h):

(*1*) A continuous monitoring system that measures gas flow rate at the inlet to the control device. The monitoring instrument shall have an accuracy of plus or minus 2 percent or better.

(*2*) A heat sensing monitoring device equipped with a continuous recorder that indicates the continuous ignition of the pilot flame.

* * * * *

(4) Using the data recorded by the monitoring system, except for inlet gas flow rate, the owner or operator must calculate the daily average value for each monitored operating parameter for each operating day. If the emissions unit operation is continuous, the operating day is a 24-hour period. If the emissions unit operation is not continuous, the operating day is the total number of hours of control device operation per 24-hour period. Valid data points must be available for 75 percent of the operating hours in an operating day to compute the daily average.

(5) * * *

(i) The owner or operator shall establish a minimum operating parameter value or a maximum operating parameter value, as appropriate for the control device, to define the conditions at which the control device must be operated to continuously achieve the applicable performance requirements of § 63.771(d)(1), (e)(3)(ii) or (f)(1). Each minimum or maximum operating parameter value shall be established as follows:

(A) If the owner or operator conducts performance tests in accordance with the requirements of § 63.772(e)(3) to demonstrate that the control device achieves the applicable performance requirements specified in § 63.771(d)(1), (e)(3)(ii) or (f)(1), then the minimum operating parameter value or the maximum operating parameter value shall be established based on values measured during the performance test and supplemented, as necessary, by a condenser design analysis or control device manufacturer recommendations or a combination of both.

(B) If the owner or operator uses a condenser design analysis in accordance with the requirements of § 63.772(e)(4) to demonstrate that the control device achieves the applicable performance requirements specified in § 63.771(d)(1), (e)(3)(ii) or (f)(1), then the minimum operating parameter value or the maximum operating parameter value shall be established based on the condenser design analysis and may be supplemented by the condenser manufacturer's recommendations.

(C) If the owner or operator operates a control device where the performance test requirement was met under § 63.772(h) to demonstrate that the control device achieves the applicable performance requirements specified in § 63.771(d)(1), (e)(3)(ii) or (f)(1), then the maximum inlet gas flow rate shall be established based on the performance test and supplemented, as necessary, by the manufacturer recommendations.

(ii) * * *

(A) If the owner or operator conducts a performance test in accordance with the requirements of § 63.772(e)(3) to demonstrate that the condenser achieves the applicable performance requirements in § 63.771(d)(1), (e)(3)(ii) or (f)(1), then the condenser performance curve shall be based on values measured during the performance test and supplemented as necessary by control device design analysis, or control device manufacturer's recommendations, or a combination or both.

(B) If the owner or operator uses a control device design analysis in accordance with the requirements of § 63.772(e)(4)(i) to demonstrate that the condenser achieves the applicable performance requirements specified in § 63.771(d)(1), (e)(3)(ii) or (f)(1), then the condenser performance curve shall be based on the condenser design analysis and may be supplemented by the control device manufacturer's recommendations.

(C) As an alternative to paragraph (d)(5)(ii)(B) of this section, the owner or operator may elect to use the procedures documented in the GRI report entitled, ''Atmospheric Rich/Lean Method for Determining Glycol Dehydrator Emissions'' (GRI–95/0368.1) as inputs for the model GRI–GLYCalc™, Version 3.0 or higher, to generate a condenser performance curve.

* * * * *

(6) * * *

(ii) For sources meeting § 63.771(d)(1)(ii), an excursion occurs when the 365-day average condenser efficiency calculated according to the requirements specified in § 63.772(g)(2)(iii) is less than 95.0 percent. For sources meeting § 63.771(f)(1), an excursion occurs when the 365-day average condenser efficiency calculated according to the requirements specified in § 63.772(g)(2)(iii) is less than 95.0 percent of the identified 365-day required percent reduction.

(iii) For sources meeting § 63.771(d)(1)(ii), if an owner or operator has less than 365 days of data, an excursion occurs when the average condenser efficiency calculated according to the procedures specified in § 63.772(g)(2)(iii)(A) or (B) is less than 90.0 percent. For sources meeting § 63.771(d)(1)(ii), an excursion occurs when the 365-day average condenser efficiency calculated according to the requirements specified in § 63.772(g)(2)(iii) is less than the identified 365-day required percent reduction.

* * * * *

(vi) For control device whose model is tested under § 63.772(h) an excursion occurs when:

(A) The inlet gas flow rate exceeds the maximum established during the test conducted under § 63.772(h).

(B) Failure of the monthly visible emissions test conducted under § 63.772(i)(3) occurs.

* * * * *

(8) * * *

(i) * * *

(A) During a malfunction when the affected facility is operated during such

period in accordance with § 63.6(e)(1); or

* * * * *

(ii) For each control device, or combinations of control devices installed on the same emissions unit, one excused excursion is allowed per semiannual period for any reason. The initial semiannual period is the 6-month reporting period addressed by the first Periodic Report submitted by the owner or operator in accordance with § 63.775(e) of this subpart.

* * * * *

20. Section 63.774 is amended by:

a. Revising paragraph (b)(3) introductory text;

b. Removing and reserving paragraph (b)(3)(ii);

c. Revising paragraph (b)(4)(ii) introductory text;

d. Adding paragraph (b)(4)(ii)(C);

e. Adding paragraph (b)(7)(ix); and

f. Adding paragraphs (g) through (i) to read as follows:

§ 63.774 Recordkeeping requirements.

* * * * *

(b) * * *

(3) Records specified in § 63.10(c) for each monitoring system operated by the owner or operator in accordance with the requirements of § 63.773(d). Notwithstanding the requirements of § 63.10(c), monitoring data recorded during periods identified in paragraphs (b)(3)(i) through (b)(3)(iv) of this section shall not be included in any average or percent leak rate computed under this subpart. Records shall be kept of the times and durations of all such periods and any other periods during process or control device operation when monitors are not operating or failed to collect required data.

* * * * *

(ii) [Reserved]

* * * * *

(4) * * *

(ii) Records of the daily average value of each continuously monitored parameter for each operating day determined according to the procedures specified in § 63.773(d)(4) of this subpart, except as specified in paragraphs (b)(4)(ii)(A) through (C) of this section.

* * * * *

(C) For control device whose model is tested under § 63.772(h), the records required in paragraph (h) of this section.

* * * * *

(7) * * *

(ix) Records identifying the carbon replacement schedule under § 63.771(d)(5) and records of each carbon replacement.

* * * * *

(g) The owner or operator of an affected source subject to this subpart shall maintain records of the occurrence and duration of each malfunction of operation (*i.e.,* process equipment) or the air pollution control equipment and monitoring equipment. The owner or operator shall maintain records of actions taken during periods of malfunction to minimize emissions in accordance with § 63.764(a), including corrective actions to restore malfunctioning process and air pollution control and monitoring equipment to its normal or usual manner of operation.

(h) Record the following when using a control device whose model is tested under § 63.772(h) to comply with § 63.771(d), (e)(3)(ii) and (f)(1):

(1) All visible emission readings and flowrate measurements made during the compliance determination required by § 63.772(i); and

(2) All hourly records and other recorded periods when the pilot flame is absent.

(i) The date the semi-annual maintenance inspection required under § 63.773(b) is performed. Include a list of any modifications or repairs made to the control device during the inspection and other maintenance performed such as cleaning of the fuel nozzles.

21. Section 63.775 is amended by:

a. Revising paragraph (b)(1);

b. Revising paragraph (b)(6);

c. Removing and reserving paragraph (b)(7);

d. Revising paragraph (c)(1);

e. Revising paragraph (c)(6);

f. Revising paragraph (c)(7)(i);

g. Revising paragraph (d)(1)(i);

h. Revising paragraph (d)(1)(ii) introductory text;

i. Revising paragraph (d)(5)(ii);

j. Adding paragraph (d)(5)(iv);

k. Revising paragraph (d)(11);

l. Adding paragraphs (d)(13) and (d)(14);

m. Revising paragraphs (e)(2) introductory text, (e)(2)(ii)(B) and (C);

n. Adding paragraphs (e)(2)(ii)(E) and (F);

o. Adding paragraphs (e)(2)(xi) through (xiii); and

p. Adding paragraph (g) to read as follows:

§ 63.775 Reporting requirements.

* * * * *

(b) * * *

(1) The initial notifications required for existing affected sources under § 63.9(b)(2) shall be submitted as provided in paragraphs (b)(1)(i) and (ii) of this section.

(i) Except as otherwise provided in paragraph (ii), the initial notifications shall be submitted by 1 year after an affected source becomes subject to the provisions of this subpart or by June 17, 2000, whichever is later. Affected sources that are major sources on or before June 17, 2000 and plan to be area sources by June 17, 2002 shall include in this notification a brief, nonbinding description of a schedule for the action(s) that are planned to achieve area source status.

(ii) An affected source identified under § 63.760(f)(7) or (9) shall submit an initial notification required for existing affected sources under § 63.9(b)(2) within 1 year after the affected source becomes subject to the provisions of this subpart or by one year after publication of the final rule in the **Federal Register**, whichever is later. An affected source identified under § 63.760(f)(7) or (9) that plans to be an area source by three years after publication of the final rule in the **Federal Register**, shall include in this notification a brief, nonbinding description of a schedule for the action(s) that are planned to achieve area source status.

* * * * *

(6) If there was a malfunction during the reporting period, the Periodic Report specified in paragraph (e) of this section shall include the number, duration, and a brief description for each type of malfunction which occurred during the reporting period and which caused or may have caused any applicable emission limitation to be exceeded. The report must also include a description of actions taken by an owner or operator during a malfunction of an affected source to minimize emissions in accordance with § 63.764(j), including actions taken to correct a malfunction.

(7) [Reserved]

* * * * *

(c) * * *

(1) The initial notifications required under § 63.9(b)(2) not later than January 3, 2008. In addition to submitting your initial notification to the addressees specified under § 63.9(a), you must also submit a copy of the initial notification to the EPA's Office of Air Quality Planning and Standards. Send your notification via e-mail to *Oil and Gas Sector@epa.gov* or via U.S. mail or other mail delivery service to U.S. EPA, Sector Policies and Programs Division/ Fuels and Incineration Group (E143–01), Attn: Oil and Gas Project Leader, Research Triangle Park, NC 27711.

* * * * *

(6) If there was a malfunction during the reporting period, the Periodic Report specified in paragraph (e) of this section shall include the number, duration, and

a brief description for each type of malfunction which occurred during the reporting period and which caused or may have caused any applicable emission limitation to be exceeded. The report must also include a description of actions taken by an owner or operator during a malfunction of an affected source to minimize emissions in accordance with § 63.764(j), including actions taken to correct a malfunction.

(7) * * *

(i) Documentation of the source's location relative to the nearest UA plus offset and UC boundaries. This information shall include the latitude and longitude of the affected source; whether the source is located in an urban cluster with 10,000 people or more; the distance in miles to the nearest urbanized area boundary if the source is not located in an urban cluster with 10,000 people or more; and the name of the nearest urban cluster with 10,000 people or more and nearest urbanized area.

* * * * *

(d) * * *

(1) * * *

(i) The condenser design analysis documentation specified in § 63.772(e)(4) of this subpart, if the owner or operator elects to prepare a design analysis.

(ii) If the owner or operator is required to conduct a performance test, the performance test results including the information specified in paragraphs (d)(1)(ii)(A) and (B) of this section. Results of a performance test conducted prior to the compliance date of this subpart can be used provided that the test was conducted using the methods specified in § 63.772(e)(3) and that the test conditions are representative of current operating conditions. If the owner or operator operates a combustion control device model tested under § 63.772(h), an electronic copy of the performance test results shall be submitted via e-mail to *Oil and Gas PT@EPA.GOV.*

* * * * *

(5) * * *

(ii) An explanation of the rationale for why the owner or operator selected each of the operating parameter values established in § 63.773(d)(5). This explanation shall include any data and calculations used to develop the value and a description of why the chosen value indicates that the control device is operating in accordance with the applicable requirements of § 63.771(d)(1), (e)(3)(ii) or (f)(1).

* * * * *

(iv) For each carbon adsorber, the predetermined carbon replacement schedule as required in § 63.771(d)(5)(i).

* * * * *

(11) The owner or operator shall submit the analysis prepared under § 63.771(e)(2) to demonstrate the conditions by which the facility will be operated to achieve the HAP emission reduction of 95.0 percent, or the BTEX limit in § 63.765(b)(1)(iii), through process modifications or a combination of process modifications and one or more control devices.

* * * * *

(13) If the owner or operator installs a combustion control device model tested under the procedures in § 63.772(h), the data listed under § 63.772(h)(8).

(14) For each combustion control device model tested under § 63.772(h), the information listed in paragraphs (d)(14)(i) through (vi) of this section.

(i) Name, address and telephone number of the control device manufacturer.

(ii) Control device model number.

(iii) Control device serial number.

(iv) Date of control device certification test.

(v) Manufacturer's HAP destruction efficiency rating.

(vi) Control device operating parameters, maximum allowable inlet gas flowrate.

(e) * * *

(2) The owner or operator shall include the information specified in paragraphs (e)(2)(i) through (xiii) of this section, as applicable.

* * * * *

(ii) * * *

(B) For each excursion caused when the 365-day average condenser control efficiency is less than the value specified in § 63.773(d)(6)(ii), the report must include the 365-day average values of the condenser control efficiency, and the date and duration of the period that the excursion occurred.

(C) For each excursion caused when condenser control efficiency is less than the value specified in § 63.773(d)(6)(iii), the report must include the average values of the condenser control efficiency, and the date and duration of the period that the excursion occurred.

* * * * *

(E) For each excursion caused when the maximum inlet gas flow rate identified under § 63.772(h) is exceeded, the report must include the values of the inlet gas identified and the date and duration of the period that the excursion occurred.

(F) For each excursion caused when visible emissions determined under § 63.772(i) exceed the maximum allowable duration, the report must include the date and duration of the period that the excursion occurred.

* * * * *

(xi) The results of any periodic test as required in § 63.772(e)(3) conducted during the reporting period.

(xii) For each carbon adsorber used to meet the control device requirements of § 63.771(d)(1), records of each carbon replacement that occurred during the reporting period.

(xiii) For combustion control device inspections conducted in accordance with § 63.773(b) the records specified in § 63.774(i).

* * * * *

(g) *Electronic reporting.* (1) As of January 1, 2012 and within 60 days after the date of completing each performance test, as defined in § 63.2 and as required in this subpart, you must submit performance test data, except opacity data, electronically to the EPA's Central Data Exchange (CDX) by using the Electronic Reporting Tool (ERT) (see *http://www.epa.gov/ttn/chief/ert/ert tool.html/*). Only data collected using test methods compatible with ERT are subject to this requirement to be submitted electronically into the EPA's WebFIRE database.

(2) All reports required by this subpart not subject to the requirements in paragraphs (g)(1) of this section must be sent to the Administrator at the appropriate address listed in § 63.13. If acceptable to both the Administrator and the owner or operator of a source, these reports may be submitted on electronic media. The Administrator retains the right to require submittal of reports subject to paragraph (g)(1) of this section in paper format.

22. Appendix to subpart HH of part 63 is amended by revising Table 2 to read as follows:

Appendix to Subpart HH of Part 63—Tables

* * * * *

TABLE 2 TO SUBPART HH OF PART 63—APPLICABILITY OF 40 CFR PART 63 GENERAL PROVISIONS TO SUBPART HH

General provisions reference	Applicable to subpart HH	Explanation
§ 63.1(a)(1)	Yes.	
§ 63.1(a)(2)	Yes.	
§ 63.1(a)(3)	Yes.	
§ 63.1(a)(4)	Yes.	
§ 63.1(a)(5)	No	Section reserved.
§ 63.1(a)(6)	Yes.	
§ 63.1(a)(7) through (a)(9)	No	Section reserved.
§ 63.1(a)(10)	Yes.	
§ 63.1(a)(11)	Yes.	
§ 63.1(a)(12)	Yes.	
§ 63.1(b)(1)	No	Subpart HH specifies applicability.
§ 63.1(b)(2)	No	Section reserved.
§ 63.1(b)(3)	Yes.	
§ 63.1(c)(1)	No	Subpart HH specifies applicability.
§ 63.1(c)(2)	Yes	Subpart HH exempts area sources from the requirement to obtain a Title V permit unless otherwise required by law as specified in § 63.760(h).
§ 63.1(c)(3) and (c)(4)	No	Section reserved.
§ 63.1(c)(5)	Yes.	
§ 63.1(d)	No	Section reserved.
§ 63.1(e)	Yes.	
§ 63.2	Yes	Except definition of major source is unique for this source category and there are additional definitions in subpart HH.
§ 63.3(a) through (c)	Yes.	
§ 63.4(a)(1) through (a)(2)	Yes.	
§ 63.4(a)(3) through (a)(5)	No	Section reserved.
§ 63.4(b)	Yes.	
§ 63.4(c)	Yes.	
§ 63.5(a)(1)	Yes.	
§ 63.5(a)(2)	Yes.	
§ 63.5(b)(1)	Yes.	
§ 63.5(b)(2)	No	Section reserved.
§ 63.5(b)(3)	Yes.	
§ 63.5(b)(4)	Yes.	
§ 63.5(b)(5)	No	Section reserved.
§ 63.5(b)(6)	Yes.	
§ 63.5(c)	No	Section reserved.
§ 63.5(d)(1)	Yes.	
§ 63.5(d)(2)	Yes.	
§ 63.5(d)(3)	Yes.	
§ 63.5(d)(4)	Yes.	
§ 63.5(e)	Yes.	
§ 63.5(f)(1)	Yes.	
§ 63.5(f)(2)	Yes.	
§ 63.6(a)	Yes.	
§ 63.6(b)(1)	Yes.	
§ 63.6(b)(2)	Yes.	
§ 63.6(b)(3)	Yes.	
§ 63.6(b)(4)	Yes.	
§ 63.6(b)(5)	Yes.	
§ 63.6(b)(6)	No	Section reserved.
§ 63.6(b)(7)	Yes.	
§ 63.6(c)(1)	Yes.	
§ 63.6(c)(2)	Yes.	
§ 63.6(c)(3) through (c)(4)	No	Section reserved.
§ 63.6(c)(5)	Yes.	
§ 63.6(d)	No	Section reserved.
§ 63.6(e)	Yes.	
§ 63.6(e)(1)(i)	No	See § 63.764(j) for general duty requirement.
§ 63.6(e)(1)(ii)	No.	
§ 63.6(e)(1)(iii)	Yes.	
§ 63.6(e)(2)	No	Section reserved.
§ 63.6(e)(3)	No.	
§ 63.6(f)(1)	No.	
§ 63.6(f)(2)	Yes.	
§ 63.6(f)(3)	Yes.	
§ 63.6(g)	Yes.	
§ 63.6(h)	No	Subpart HH does not contain opacity or visible emission standards.
§ 63.6(i)(1) through (i)(14)	Yes.	
§ 63.6(i)(15)	No	Section reserved.
§ 63.6(i)(16)	Yes.	
§ 63.6(j)	Yes.	

TABLE 2 TO SUBPART HH OF PART 63—APPLICABILITY OF 40 CFR PART 63 GENERAL PROVISIONS TO SUBPART HH—Continued

General provisions reference	Applicable to subpart HH	Explanation
§ 63.7(a)(1)	Yes.	
§ 63.7(a)(2)	Yes	But the performance test results must be submitted within 180 days after the compliance date.
§ 63.7(a)(3)	Yes.	
§ 63.7(b)	Yes.	
§ 63.7(c)	Yes.	
§ 63.7(d)	Yes.	
§ 63.7(e)(1)	No.	
§ 63.7(e)(2)	Yes.	
§ 63.7(e)(3)	Yes.	
§ 63.7(e)(4)	Yes.	
§ 63.7(f)	Yes.	
§ 63.7(g)	Yes.	
§ 63.7(h)	Yes.	
§ 63.8(a)(1)	Yes.	
§ 63.8(a)(2)	Yes.	
§ 63.8(a)(3)	No	Section reserved.
§ 63.8(a)(4)	Yes.	
§ 63.8(b)(1)	Yes.	
§ 63.8(b)(2)	Yes.	
§ 63.8(b)(3)	Yes.	
§ 63.8(c)(1)	No.	
§ 63.8(c)(1)(i)	No.	
§ 63.8(c)(1)(ii)	Yes.	
§ 63.8(c)(1)(iii)	Pending.	
§ 63.8(c)(2)	Yes.	
§ 63.8(c)(3)	Yes.	
§ 63.8(c)(4)	Yes.	
§ 63.8(c)(4)(i)	No	Subpart HH does not require continuous opacity monitors.
§ 63.8(c)(4)(ii)	Yes.	
§ 63.8(c)(5) through (c)(8)	Yes.	
§ 63.8(d)	Yes.	
§ 63.8(d)(3)	Yes	Except for last sentence, which refers to an SSM plan. SSM plans are not required.
§ 63.8(e)	Yes	Subpart HH does not specifically require continuous emissions monitor performance evaluation, however, the Administrator can request that one be conducted.
§ 63.8(f)(1) through (f)(5)	Yes.	
§ 63.8(f)(6)	Yes.	
§ 63.8(g)	No	Subpart HH specifies continuous monitoring system data reduction requirements.
§ 63.9(a)	Yes.	
§ 63.9(b)(1)	Yes.	
§ 63.9(b)(2)	Yes	Existing sources are given 1 year (rather than 120 days) to submit this notification. Major and area sources that meet § 63.764(e) do not have to submit initial notifications.
§ 63.9(b)(3)	No	Section reserved.
§ 63.9(b)(4)	Yes.	
§ 63.9(b)(5)	Yes.	
§ 63.9(c)	Yes.	
§ 63.9(d)	Yes.	
§ 63.9(e)	Yes.	
§ 63.9(f)	No	Subpart HH does not have opacity or visible emission standards.
§ 63.9(g)(1)	Yes.	
§ 63.9(g)(2)	No	Subpart HH does not have opacity or visible emission standards.
§ 63.9(g)(3)	Yes.	
§ 63.9(h)(1) through (h)(3)	Yes	Area sources located outside UA plus offset and UC boundaries are not required to submit notifications of compliance status.
§ 63.9(h)(4)	No	Section reserved.
§ 63.9(h)(5) through (h)(6)	Yes.	
§ 63.9(i)	Yes.	
§ 63.9(j)	Yes.	
§ 63.10(a)	Yes.	
§ 63.10(b)(1)	Yes	§ 63.774(b)(1) requires sources to maintain the most recent 12 months of data onsite and allows offsite storage for the remaining 4 years of data.
§ 63.10(b)(2)	Yes.	
§ 63.10(b)(2)(i)	No	
§ 63.10(b)(2)(ii)	No	See § 63.774(g) for recordkeeping of occurrence, duration, and actions taken during malfunctions.
§ 63.10(b)(2)(iii)	Yes.	
§ 63.10(b)(2)(iv) through (b)(2)(v)	No.	
§ 63.10(b)(2)(vi) through (b)(2)(xiv)	Yes.	

TABLE 2 TO SUBPART HH OF PART 63—APPLICABILITY OF 40 CFR PART 63 GENERAL PROVISIONS TO SUBPART HH—Continued

General provisions reference	Applicable to subpart HH	Explanation
§ 63.10(b)(3)	Yes	§ 63.774(b)(1) requires sources to maintain the most recent 12 months of data on-site and allows offsite storage for the remaining 4 years of data.
§ 63.10(c)(1)	Yes.	
§ 63.10(c)(2) through (c)(4)	No	Sections reserved.
§ 63.10(c)(5) through (8)(c)(8)	Yes.	
§ 63.10(c)(9)	No	Section reserved.
§ 63.10(c)(10) through (11)	No	See § 63.774(g) for recordkeeping of malfunctions.
§ 63.10(c)(12) through (14)	Yes.	
§ 63.10(c)(15)	No.	
§ 63.10(d)(1)	Yes.	
§ 63.10(d)(2)	Yes	Area sources located outside UA plus offset and UC boundaries do not have to submit performance test reports.
§ 63.10(d)(3)	Yes.	
§ 63.10(d)(4)	Yes.	
§ 63.10(d)(5)	No	See § 63.775(b)(6) or (c)(6) for reporting of malfunctions.
§ 63.10(e)(1)	Yes	Area sources located outside UA plus offset and UC boundaries are not required to submit reports.
§ 63.10(e)(2)	Yes	Area sources located outside UA plus offset and UC boundaries are not required to submit reports.
§ 63.10(e)(3)(i)	Yes	Subpart HH requires major sources to submit Periodic Reports semi-annually. Area sources are required to submit Periodic Reports annually. Area sources located outside UA plus offset and UC boundaries are not required to submit reports.
§ 63.10(e)(3)(i)(A)	Yes.	
§ 63.10(e)(3)(i)(B)	Yes.	
§ 63.10(e)(3)(i)(C)	No	Section reserved.
§ 63.10(e)(3)(ii) through (viii)	Yes.	
§ 63.10(f)	Yes.	
§ 63.11(a) and (b)	Yes.	
§ 63.11(c), (d), and (e)	Yes.	
§ 63.12(a) through (c)	Yes.	
§ 63.13(a) through (c)	Yes.	
§ 63.14(a) and (b)	Yes.	
§ 63.15(a) and (b)	Yes.	
§ 63.16	Yes.	

Subpart HHH—[Amended]

23. Section 63.1270 is amended by:

a. Revising paragraph (a) introductory text;

b. Revising paragraph (a)(4);

c. Revising paragraphs (d)(1) and (d)(2); and

d. Adding paragraphs (d)(3), (4) and (5) to read as follows:

§ 63.1270 Applicability and designation of affected source.

(a) This subpart applies to owners and operators of natural gas transmission and storage facilities that transport or store natural gas prior to entering the pipeline to a local distribution company or to a final end user (if there is no local distribution company), and that are major sources of hazardous air pollutants (HAP) emissions as defined in § 63.1271. Emissions for major source determination purposes can be estimated using the maximum natural gas throughput calculated in either paragraph (a)(1) or (2) of this section and paragraphs (a)(3) and (4) of this section. As an alternative to calculating the maximum natural gas throughput, the owner or operator of a new or existing source may use the facility design maximum natural gas throughput to estimate the maximum potential emissions. Other means to determine the facility's major source status are allowed, provided the information is documented and recorded to the Administrator's satisfaction in accordance with § 63.10(b)(3). A compressor station that transports natural gas prior to the point of custody transfer or to a natural gas processing plant (if present) is not considered a part of the natural gas transmission and storage source category. A facility that is determined to be an area source, but subsequently increases its emissions or its potential to emit above the major source levels (without obtaining and complying with other limitations that keep its potential to emit HAP below major source levels), and becomes a major source, must comply thereafter with all applicable provisions of this subpart starting on the applicable compliance date specified in paragraph (d) of this section. Nothing in this paragraph is intended to preclude a source from limiting its potential to emit through other appropriate mechanisms that may be available through the permitting authority.

* * * * *

(4) The owner or operator shall determine the maximum values for other parameters used to calculate potential emissions as the maximum over the same period for which maximum throughput is determined as specified in paragraph (a)(1) or (a)(2) of this section. These parameters shall be based on an annual average or the highest single measured value. For estimating maximum potential emissions from glycol dehydration units, the glycol circulation rate used in the calculation shall be the unit's maximum rate under its physical and operational design consistent with the definition of potential to emit in § 63.2.

* * * * *

(d) * * *

(1) Except as specified in paragraphs (d)(3) through (5) of this section, the owner or operator of an affected source, the construction or reconstruction of which commenced before February 6,

1998, shall achieve compliance with the provisions of this subpart no later than June 17, 2002 except as provided for in § 63.6(i). The owner or operator of an area source, the construction or reconstruction of which commenced before February 6, 1998, that increases its emissions of (or its potential to emit) HAP such that the source becomes a major source that is subject to this subpart shall comply with this subpart 3 years after becoming a major source.

(2) Except as specified in paragraphs (d)(3) through (5) of this section, the owner or operator of an affected source, the construction or reconstruction of which commences on or after February 6, 1998, shall achieve compliance with the provisions of this subpart immediately upon initial startup or June 17, 1999, whichever date is later. Area sources, the construction or reconstruction of which commences on or after February 6, 1998, that become major sources shall comply with the provisions of this standard immediately upon becoming a major source.

(3) Each affected small glycol dehydration unit, as defined in § 63.1271, located at a major source, that commenced construction before August 23, 2011 must achieve compliance no later than 3 years after the date of publication of the final rule in the **Federal Register**, except as provided in § 63.6(i).

(4) Each affected small glycol dehydration unit, as defined in § 63.1271, located at a major source, that commenced construction on or after August 23, 2011 must achieve compliance immediately upon initial startup or the date of publication of the final rule in the **Federal Register**, whichever is later.

(5) Each large glycol dehydration unit, as defined in § 63.1271, that has complied with the provisions of this subpart prior to August 23, 2011 by reducing its benzene emissions to less than 0.9 megagrams per year must achieve compliance no later than 90 days after the date of publication of the final rule in the **Federal Register**, except as provided in § 63.6(i).

* * * * *

24. Section 63.1271 is amended by:

a. Adding, in alphabetical order, new definitions for the terms ''affirmative defense,'' ''BTEX,'' ''flare,'' ''large glycol dehydration units,'' ''small glycol dehydration units''; and

b. Revising the definitions for ''glycol dehydration unit baseline operations'' and ''temperature monitoring device'' to read as follows:

§ 63.1271 Definitions.

* * * * *

Affirmative defense means, in the context of an enforcement proceeding, a response or defense put forward by a defendant, regarding which the defendant has the burden of proof, and the merits of which are independently and objectively evaluated in a judicial or administrative proceeding.

* * * * *

BTEX means benzene, toluene, ethyl benzene and xylene.

* * * * *

Flare means a thermal oxidation system using an open flame (*i.e.,* without enclosure).

* * * * *

Glycol dehydration unit baseline operations means operations representative of the large glycol dehydration unit operations as of June 17, 1999 and the small glycol dehydration unit operations as of August 23, 2011. For the purposes of this subpart, for determining the percentage of overall HAP emission reduction attributable to process modifications, glycol dehydration unit baseline operations shall be parameter values (including, but not limited to, glycol circulation rate or glycol-HAP absorbency) that represent actual long-term conditions (*i.e.,* at least 1 year). Glycol dehydration units in operation for less than 1 year shall document that the parameter values represent expected long-term operating conditions had process modifications not been made.

* * * * *

Large glycol dehydration unit means a glycol dehydration unit with an actual annual average natural gas flowrate equal to or greater than 283.0 thousand standard cubic meters per day and actual annual average benzene emissions equal to or greater than 0.90 Mg/yr, determined according to § 63.1282(a).

* * * * *

Small glycol dehydration unit means a glycol dehydration unit, located at a major source, with an actual annual average natural gas flowrate less than 283.0 thousand standard cubic meters per day or actual annual average benzene emissions less than 0.90 Mg/yr, determined according to § 63.1282(a).

Temperature monitoring device means an instrument used to monitor temperature and having a minimum accuracy of ± 1 percent of the temperature being monitored expressed in °C, or ± 2.5 °C, whichever is greater. The temperature monitoring device may measure temperature in degrees Fahrenheit or degrees Celsius, or both.

* * * * *

25. Section 63.1272 is revised to read as follows:

§ 63.1272 Startups and shutdowns.

(a) The provisions set forth in this subpart shall apply at all times.

(b) The owner or operator shall not shut down items of equipment that are required or utilized for compliance with the provisions of this subpart during times when emissions are being routed to such items of equipment, if the shutdown would contravene requirements of this subpart applicable to such items of equipment. This paragraph does not apply if the owner or operator must shut down the equipment to avoid damage due to a contemporaneous startup or shutdown of the affected source or a portion thereof.

(c) During startups and shutdowns, the owner or operator shall implement measures to prevent or minimize excess emissions to the maximum extent practical.

(d) In response to an action to enforce the standards set forth in this subpart, you may assert an affirmative defense to a claim for civil penalties for exceedances of such standards that are caused by malfunction, as defined in § 63.2. Appropriate penalties may be assessed, however, if you fail to meet your burden of proving all the requirements in the affirmative defense. The affirmative defense shall not be available for claims for injunctive relief.

(1) To establish the affirmative defense in any action to enforce such a limit, the owner or operator must timely meet the notification requirements in paragraph (d)(2) of this section, and must prove by a preponderance of evidence that:

(i) The excess emissions:

(A) Were caused by a sudden, infrequent, and unavoidable failure of air pollution control and monitoring equipment, process equipment, or a process to operate in a normal or usual manner; and

(B) Could not have been prevented through careful planning, proper design or better operation and maintenance practices; and

(C) Did not stem from any activity or event that could have been foreseen and avoided, or planned for; and

(D) Were not part of a recurring pattern indicative of inadequate design, operation, or maintenance; and

(ii) Repairs were made as expeditiously as possible when the applicable emission limitations were being exceeded. Off-shift and overtime labor were used, to the extent practicable to make these repairs; and

(iii) The frequency, amount and duration of the excess emissions (including any bypass) were minimized

to the maximum extent practicable during periods of such emissions; and

(iv) If the excess emissions resulted from a bypass of control equipment or a process, then the bypass was unavoidable to prevent loss of life, personal injury, or severe property damage; and

(v) All possible steps were taken to minimize the impact of the excess emissions on ambient air quality, the environment, and human health; and

(vi) All emissions monitoring and control systems were kept in operation if at all possible, consistent with safety and good air pollution control practices; and

(vii) All of the actions in response to the excess emissions were documented by properly signed, contemporaneous operating logs; and

(viii) At all times, the affected source was operated in a manner consistent with good practices for minimizing emissions; and

(ix) A written root cause analysis has been prepared to determine, correct, and eliminate the primary causes of the malfunction and the excess emissions resulting from the malfunction event at issue. The analysis shall also specify, using best monitoring methods and engineering judgment, the amount of excess emissions that were the result of the malfunction.

(2) *Notification.* The owner or operator of the affected source experiencing an exceedance of its emission limit(s) during a malfunction shall notify the Administrator by telephone or facsimile transmission as soon as possible, but no later than two business days after the initial occurrence of the malfunction, if it wishes to avail itself of an affirmative defense to civil penalties for that malfunction. The owner or operator seeking to assert an affirmative defense shall also submit a written report to the Administrator within 45 days of the initial occurrence of the exceedance of the standard in this subpart to demonstrate, with all necessary supporting documentation, that it has met the requirements set forth in paragraph (d)(1) of this section. The owner or operator may seek an extension of this deadline for up to 30 additional days by submitting a written request to the Administrator before the expiration of the 45 day period. Until a request for an extension has been approved by the Administrator, the owner or operator is subject to the requirement to submit such report within 45 days of the initial occurrence of the exceedance.

26. Section 63.1274 is amended by:

a. Revising paragraph (c) introductory text;

b. Removing and reserving paragraph (d);

c. Revising paragraph (g); and

d. Adding paragraph (h) to read as follows:

§ 63.1274 General standards.

* * * * *

(c) The owner or operator of an affected source (*i.e.,* glycol dehydration unit) located at an existing or new major source of HAP emissions shall comply with the requirements in this subpart as follows:

* * * * *

(d) [Reserved]

* * * * *

(g) In all cases where the provisions of this subpart require an owner or operator to repair leaks by a specified time after the leak is detected, it is a violation of this standard to fail to take action to repair the leak(s) within the specified time. If action is taken to repair the leak(s) within the specified time, failure of that action to successfully repair the leak(s) is not a violation of this standard. However, if the repairs are unsuccessful, and a leak is detected, the owner or operator shall take further action as required by the applicable provisions of this subpart.

(h) At all times the owner or operator must operate and maintain any affected source, including associated air pollution control equipment and monitoring equipment, in a manner consistent with safety and good air pollution control practices for minimizing emissions. Determination of whether such operation and maintenance procedures are being used will be based on information available to the Administrator which may include, but is not limited to, monitoring results, review of operation and maintenance procedures, review of operation and maintenance records, and inspection of the source.

27. Section 63.1275 is amended by:

a. Revising paragraph (a);

b. Revising paragraph (b)(1);

c. Revising paragraph (c)(2); and

d. Revising paragraph (c)(3) to read as follows:

§ 63.1275 Glycol dehydration unit process vent standards.

(a) This section applies to each glycol dehydration unit subject to this subpart that must be controlled for air emissions as specified in paragraph (c)(1) of § 63.1274.

(b) * * *

(1) For each glycol dehydration unit process vent, the owner or operator shall control air emissions by either paragraph (b)(1)(i) or (b)(1)(iii) of this section.

(i) The owner or operator of a large glycol dehydration unit, as defined in § 63.1271, shall connect the process vent to a control device or a combination of control devices through a closed-vent system. The closed-vent system shall be designed and operated in accordance with the requirements of § 63.1281(c). The control device(s) shall be designed and operated in accordance with the requirements of § 63.1281(d).

(ii) [Reserved]

(iii) You must limit BTEX emissions from each small glycol dehydration unit, as defined in § 63.1271, to the limit determined in Equation 1 of this section. The limit must be met in accordance with one of the alternatives specified in paragraphs (b)(i)(iii)(A) through (D) of this section.

$$EL_{BTEX} = 6.42x10^{-5} * Throughput * C_{i,BTEX} * 365\ \frac{days}{yr} * \frac{1\ Mg}{1x10^{6}\ grams} \qquad \text{Equation 1}$$

Where:

EL_{BTEX} = Unit-specific BTEX emission limit, megagrams per year;

6.42×10^{-5} = BTEX emission limit, grams BTEX/standard cubic meter -ppmv;

Throughput = Annual average daily natural gas throughput, standard cubic meters per day

$C_{i,BTEX}$ = BTEX concentration of the natural gas at the inlet to the glycol dehydration unit, ppmv.

(A) Connect the process vent to a control device or combination of control devices through a closed-vent system. The closed vent system shall be designed and operated in accordance with the requirements of § 63.1281(c). The control device(s) shall be designed and operated in accordance with the requirements of § 63.1281(f).

(B) Meet the emissions limit through process modifications in accordance with the requirements specified in § 63.1281(e).

(C) Meet the emission limit for each small glycol dehydration unit using a combination of process modifications and one or more control devices through the requirements specified in paragraphs (b)(1)(iii)(A) and (B) of this section.

(D) Demonstrate that the emissions limit is met through actual uncontrolled operation of the small glycol dehydration unit. Document operational parameters in accordance with the requirements specified in § 63.1281(e) and emissions in accordance with the requirements specified in § 63.1282(a)(3).

* * * * *

(c) * * *

(2) The owner or operator shall demonstrate, to the Administrator's satisfaction, that the total HAP emissions to the atmosphere from the large glycol dehydration unit process vent are reduced by 95.0 percent through process modifications or a combination of process modifications and one or more control devices, in accordance with the requirements specified in § 63.1281(e).

(3) Control of HAP emissions from a GCG separator (flash tank) vent is not required if the owner or operator demonstrates, to the Administrator's satisfaction, that total emissions to the atmosphere from the glycol dehydration unit process vent are reduced by one of the levels specified in paragraph (c)(3)(i) or (iii) through the installation and operation of controls as specified in paragraph (b)(1) of this section.

(i) For any large glycol dehydration unit, HAP emissions are reduced by 95.0 percent or more.

(ii) [Reserved]

(iii) For each small glycol dehydration unit, BTEX emissions are reduced to a level less than the limit calculated in paragraph (b)(1)(iii) of this section.

28. Section 63.1281 is amended by:

a. Revising paragraph (c)(1);

b. Revising the heading of paragraph (d).

c. Adding paragraph (d) introductory text;

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

e. Revising paragraph (d)(1)(i)(C);

f. Revising paragraphs (d)(1)(ii) and (iii);

g. Revising paragraph (d)(4)(i);

h. Revising paragraph (d)(5)(i);

i. Revising paragraph (e)(2);

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

k. Revising paragraph (e)(3)(ii); and

l. Adding paragraph (f) to read as follows:

§ 63.1281 Control equipment requirements.

* * * * *

(c) * * *

(1) The closed-vent system shall route all gases, vapors, and fumes emitted from the material in an emissions unit to a control device that meets the requirements specified in paragraph (d) of this section.

* * * * *

(d) *Control device requirements for sources except small glycol dehydration units.* Owners and operators of small glycol dehydration units shall comply with the control requirements in paragraph (f) of this section.

(1) * * *

(i) An enclosed combustion device (*e.g.,* thermal vapor incinerator, catalytic vapor incinerator, boiler, or process heater) that is designed and operated in accordance with one of the following performance requirements:

* * * * *

(C) For a control device that can demonstrate a uniform combustion zone temperature during the performance test conducted under § 63.1282(d), operates at a minimum temperature of 760 °C.

* * * * *

(ii) A vapor recovery device (*e.g.,* carbon adsorption system or condenser) or other non-destructive control device that is designed and operated to reduce the mass content of either TOC or total HAP in the gases vented to the device by 95.0 percent by weight or greater as determined in accordance with the requirements of § 63.1282(d).

(iii) A flare, as defined in § 63.1271, that is designed and operated in accordance with the requirements of § 63.11(b).

* * * * *

(4) * * *

(i) Each control device used to comply with this subpart shall be operating at all times when gases, vapors, and fumes are vented from the emissions unit or units through the closed vent system to the control device as required under § 63.1275. An owner or operator may vent more than one unit to a control device used to comply with this subpart.

* * * * *

(5) * * *

(i) Following the initial startup of the control device, all carbon in the control device shall be replaced with fresh carbon on a regular, predetermined time interval that is no longer than the carbon service life established for the carbon adsorption system. Records identifying the schedule for replacement and records of each carbon replacement shall be maintained as required in § 63.1284(b)(7)(ix). The schedule for replacement shall be submitted with the Notification of Compliance Status Report as specified in § 63.1285(d)(4)(iv). Each carbon replacement must be reported in the Periodic Reports as specified in § 63.1285(e)(2)(xi).

* * * * *

(e) * * *

(2) The owner or operator shall document, to the Administrator's satisfaction, the conditions for which glycol dehydration unit baseline operations shall be modified to achieve the 95.0 percent overall HAP emission reduction, or BTEX limit determined in § 63.1275(b)(1)(iii), as applicable, either through process modifications or through a combination of process modifications and one or more control devices. If a combination of process modifications and one or more control devices are used, the owner or operator shall also establish the emission reduction to be achieved by the control device to achieve an overall HAP emission reduction of 95.0 percent for the glycol dehydration unit process vent or, if applicable, the BTEX limit determined in § 63.1275(b)(1)(iii) for the small glycol dehydration unit process vent. Only modifications in glycol dehydration unit operations directly related to process changes, including but not limited to changes in glycol circulation rate or glycol-HAP absorbency, shall be allowed. Changes in the inlet gas characteristics or natural gas throughput rate shall not be considered in determining the overall emission reduction due to process modifications.

(3) The owner or operator that achieves a 95.0 percent HAP emission reduction or meets the BTEX limit

determined in § 63.1275(b)(1)(iii), as applicable, using process modifications alone shall comply with paragraph (e)(3)(i) of this section. The owner or operator that achieves a 95.0 percent HAP emission reduction or meets the BTEX limit determined in § 63.1275(b)(1)(iii), as applicable, using a combination of process modifications and one or more control devices shall comply with paragraphs (e)(3)(i) and (e)(3)(ii) of this section.

* * * * *

(ii) The owner or operator shall comply with the control device requirements specified in paragraph (d) or (f) of this section, as applicable, except that the emission reduction or limit achieved shall be the emission reduction or limit specified for the control device(s) in paragraph (e)(2) of this section.

(f) *Control device requirements for small glycol dehydration units.* (1) The control device used to meet BTEX the emission limit calculated in § 63.1275(b)(1)(iii) shall be one of the control devices specified in paragraphs (f)(1)(i) through (iii) of this section.

(i) An enclosed combustion device (*e.g.,* thermal vapor incinerator, catalytic vapor incinerator, boiler, or process heater) that is designed and operated to reduce the mass content of BTEX in the gases vented to the device as determined in accordance with the requirements of § 63.1282(d). If a boiler or process heater is used as the control device, then the vent stream shall be introduced into the flame zone of the boiler or process heater; or

(ii) A vapor recovery device (*e.g.,* carbon adsorption system or condenser) or other non-destructive control device that is designed and operated to reduce the mass content of BTEX in the gases vented to the device as determined in accordance with the requirements of § 63.1282(d); or

(iii) A flare, as defined in § 63.1271, that is designed and operated in accordance with the requirements of § 63.11(b).

(2) The owner or operator shall operate each control device in accordance with the requirements specified in paragraphs (f)(2)(i) and (ii) of this section.

(i) Each control device used to comply with this subpart shall be operating at all times. An owner or operator may vent more than one unit to a control device used to comply with this subpart.

(ii) For each control device monitored in accordance with the requirements of § 63.1283(d), the owner or operator shall demonstrate compliance according to the requirements of either § 63.1282(e) or (h).

(3) For each carbon adsorption system used as a control device to meet the requirements of paragraph (f)(1) of this section, the owner or operator shall manage the carbon as required under (d)(5)(i) and (ii) of this section.

29. Section 63.1282 is amended by:

a. Revising paragraph (a) introductory text;

b. Revising paragraph (a)(1)(ii);

c. Revising paragraph (a)(2);

d. Adding paragraph (c);

e. Revising paragraph (d) introductory text;

f. Revising paragraphs (d)(1)(i) through (v);

g. Revising paragraph (d)(2);

h. Revising paragraph (d)(3) introductory text;

i. Revising paragraph (d)(3)(i)(B);

j. Revising paragraph (d)(3)(iv)(C)(*1*);

k. Adding paragraphs (d)(3)(v) and (vi);

l. Revising paragraph (d)(4) introductory text;

m. Revising paragraph (d)(4)(i);

n. Revising paragraph (d)(5);

o. Revising paragraph (e) introductory text;

p. Revising paragraphs (e)(2) and (e)(3);

q. Adding paragraphs (e)(4) through (e)(6);

r. Revising paragraph (f) introductory text;

s. Revising paragraph (f)(1);

t. Revising paragraph (f)(2) introductory text;

u. Revising paragraph (f)(2)(iii);

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

w. Adding paragraphs (g) and (h) to read as follows:

§ 63.1282 Test methods, compliance procedures, and compliance demonstrations.

(a) *Determination of glycol dehydration unit flowrate, benzene emissions, or BTEX emissions.* The procedures of this paragraph shall be used by an owner or operator to determine glycol dehydration unit natural gas flowrate, benzene emissions, or BTEX emissions.

(1) * * *

(ii) The owner or operator shall document, to the Administrator's satisfaction, the actual annual average natural gas flowrate to the glycol dehydration unit.

(2) The determination of actual average benzene or BTEX emissions from a glycol dehydration unit shall be made using the procedures of either paragraph (a)(2)(i) or (a)(2)(ii) of this section. Emissions shall be determined either uncontrolled or with federally enforceable controls in place.

(i) The owner or operator shall determine actual average benzene or BTEX emissions using the model GRI–GLYCalc™, Version 3.0 or higher, and the procedures presented in the associated GRI–GLYCalc™ Technical Reference Manual. Inputs to the model shall be representative of actual operating conditions of the glycol dehydration unit and may be determined using the procedures documented in the Gas Research Institute (GRI) report entitled ''Atmospheric Rich/Lean Method for Determining Glycol Dehydrator Emissions'' (GRI–95/0368.1); or

(ii) The owner or operator shall determine an average mass rate of benzene or BTEX emissions in kilograms per hour through direct measurement by performing three runs of Method 18 in 40 CFR part 60, appendix A (or an equivalent method), and averaging the results of the three runs. Annual emissions in kilograms per year shall be determined by multiplying the mass rate by the number of hours the unit is operated per year. This result shall be converted to megagrams per year.

* * * * *

(c) *Test procedures and compliance demonstrations for small glycol dehydration units.* This paragraph applies to the test procedures for small dehydration units.

(1) If the owner or operator is using a control device to comply with the emission limit in § 63.1275(b)(1)(iii), the requirements of paragraph (d) of this section apply. Compliance is demonstrated using the methods specified in paragraph (e) of this section.

(2) If no control device is used to comply with the emission limit in § 63.1275(b)(1)(iii), the owner or operator must determine the glycol dehydration unit BTEX emissions as specified in paragraphs (c)(2)(i) through (iii) of this section. Compliance is demonstrated if the BTEX emissions determined as specified in paragraphs (c)(2)(i) through (iii) are less than the emission limit calculated using the equation in § 63.1275(b)(1)(iii).

(i) Method 1 or 1A, 40 CFR part 60, appendix A, as appropriate, shall be used for selection of the sampling sites at the outlet of the glycol dehydration unit process vent. Any references to particulate mentioned in Methods 1 and 1A do not apply to this section.

(ii) The gas volumetric flowrate shall be determined using Method 2, 2A, 2C, or 2D, 40 CFR part 60, appendix A, as appropriate.

(iii) The BTEX emissions from the outlet of the glycol dehydration unit

process vent shall be determined using the procedures specified in paragraph (d)(3)(v) of this section. As an alternative, the mass rate of BTEX at the outlet of the glycol dehydration unit process vent may be calculated using the model GRI–GLYCalc™, Version 3.0 or higher, and the procedures presented in the associated GRI–GLYCalc™ Technical Reference Manual. Inputs to the model shall be representative of actual operating conditions of the glycol dehydration unit and shall be determined using the procedures documented in the Gas Research Institute (GRI) report entitled ''Atmospheric Rich/Lean Method for Determining Glycol Dehydrator Emissions'' (GRI–95/0368.1). When the BTEX mass rate is calculated for glycol dehydration units using the model GRI–GLYCalc™, all BTEX measured by Method 18, 40 CFR part 60, appendix A, shall be summed.

(d) *Control device performance test procedures.* This paragraph applies to the performance testing of control devices. The owners or operators shall demonstrate that a control device achieves the performance requirements of § 63.1281(d)(1), (e)(3)(ii), or (f)(1) using a performance test as specified in paragraph (d)(3) of this section. Owners or operators using a condenser have the option to use a design analysis as specified in paragraph (d)(4) of this section. The owner or operator may elect to use the alternative procedures in paragraph (d)(5) of this section for performance testing of a condenser used to control emissions from a glycol dehydration unit process vent. As an alternative to conducting a performance test under this section for combustion control devices, a control device that can be demonstrated to meet the performance requirements of § 63.1281(d)(1), (e)(3)(ii), or (f)(1) through a performance test conducted by the manufacturer, as specified in paragraph (g) of this section, can be used.

(1) * * *

(i) Except as specified in paragraph (d)(2) of this section, a flare, as defined in § 63.1271, that is designed and operated in accordance with § 63.11(b);

(ii) Except for control devices used for small glycol dehydration units, a boiler or process heater with a design heat input capacity of 44 megawatts or greater;

(iii) Except for control devices used for small glycol dehydration units, a boiler or process heater into which the vent stream is introduced with the primary fuel or is used as the primary fuel;

(iv) Except for control devices used for small glycol dehydration units, a boiler or process heater burning hazardous waste for which the owner or operator has either been issued a final permit under 40 CFR part 270 and complies with the requirements of 40 CFR part 266, subpart H, or has certified compliance with the interim status requirements of 40 CFR part 266, subpart H;

(v) Except for control devices used for small glycol dehydration units, a hazardous waste incinerator for which the owner or operator has been issued a final permit under 40 CFR part 270 and complies with the requirements of 40 CFR part 264, subpart O, or has certified compliance with the interim status requirements of 40 CFR part 265, subpart O.

* * * * *

(2) An owner or operator shall design and operate each flare, as defined in § 63.1271, in accordance with the requirements specified in § 63.11(b) and the compliance determination shall be conducted using Method 22 of 40 CFR part 60, appendix A, to determine visible emissions.

(3) For a performance test conducted to demonstrate that a control device meets the requirements of § 63.1281(d)(1), (e)(3)(ii), or (f)(1) the owner or operator shall use the test methods and procedures specified in paragraphs (d)(3)(i) through (v) of this section. The initial and periodic performance tests shall be conducted according to the schedule specified in paragraph (d)(3)(vi) of this section.

(i) * * *

(B) To determine compliance with the enclosed combustion device total HAP concentration limit specified in § 63.1281(d)(1)(i)(B), or the BTEX emission limit specified in § 63.1275(b)(1)(iii), the sampling site shall be located at the outlet of the combustion device.

* * * * *

(iv) * * *

(C) * * *

(*1*) The emission rate correction factor for excess air, integrated sampling and analysis procedures of Method 3A or 3B, 40 CFR part 60, appendix A, shall be used to determine the oxygen concentration ($\%O_{2d}$). The samples shall be taken during the same time that the samples are taken for determining TOC concentration or total HAP concentration.

* * * * *

(v) To determine compliance with the BTEX emission limit specified in § 63.1281(f)(1) the owner or operator shall use one of the following methods: Method 18, 40 CFR part 60, appendix A; ASTM D6420–99 (2004), as specified in § 63.772(a)(1)(ii); or any other method or data that have been validated according to the applicable procedures in Method 301, 40 CFR part 63, appendix A. The following procedures shall be used to calculate BTEX emissions:

(A) The minimum sampling time for each run shall be 1 hour in which either an integrated sample or a minimum of four grab samples shall be taken. If grab sampling is used, then the samples shall be taken at approximately equal intervals in time, such as 15-minute intervals during the run.

(B) The mass rate of BTEX (E_o) shall be computed using the equations and procedures specified in paragraphs (d)(3)(v)(B)(*1*) and (*2*) of this section.

(*1*) The following equation shall be used:

$$E_o = K_2\left(\sum_{j=1}^{n} C_{oj} M_{oj}\right) Q_o$$

Where:

E_o = Mass rate of BTEX at the outlet of the control device, dry basis, kilogram per hour.

C_{oj} = Concentration of sample component j of the gas stream at the outlet of the control device, dry basis, parts per million by volume.

M_{oj} = Molecular weight of sample component j of the gas stream at the outlet of the control device, gram/gram-mole.

Q_o = Flowrate of gas stream at the outlet of the control device, dry standard cubic meter per minute.

K_2 = Constant, 2.494×10^{-6} (parts per million) (gram-mole per standard cubic meter) (kilogram/gram) (minute/hour), where standard temperature (gram-mole per standard cubic meter) is 20 degrees C.

n = Number of components in sample.

(*2*) When the BTEX mass rate is calculated, only BTEX compounds measured by Method 18, 40 CFR part 60, appendix A, or ASTM D6420–99 (2004) as specified in § 63.772(a)(1)(ii), shall be summed using the equations in paragraph (d)(3)(v)(B)(*1*) of this section.

(vi) The owner or operator shall conduct performance tests according to the schedule specified in paragraphs (d)(3)(vi)(A) and (B) of this section.

(A) An initial performance test shall be conducted within 180 days after the compliance date that is specified for each affected source in § 63.1270(d)(3) and (4) except that the initial performance test for existing combustion control devices at existing major sources shall be conducted no later than 3 years after the date of publication of the final rule in the **Federal Register**. If the owner or operator of an existing combustion

control device at an existing major source chooses to replace such device with a control device whose model is tested under § 63.1282(g), then the newly installed device shall comply with all provisions of this subpart no later than 3 years after the date of publication of the final rule in the **Federal Register**. The performance test results shall be submitted in the Notification of Compliance Status Report as required in § 63.1285(d)(1)(ii).

(B) Periodic performance tests shall be conducted for all control devices required to conduct initial performance tests except as specified in paragraphs (e)(3)(vi)(B)(*1*) and (*2*) of this section. The first periodic performance test shall be conducted no later than 60 months after the initial performance test required in paragraph (d)(3)(vi)(A) of this section. Subsequent periodic performance tests shall be conducted at intervals no longer than 60 months following the previous periodic performance test or whenever a source desires to establish a new operating limit. The periodic performance test results must be submitted in the next Periodic Report as specified in § 63.1285(e)(2)(x). Combustion control devices meeting the criteria in either paragraph (e)(3)(vi)(B)(*1*) or (*2*) of this section are not required to conduct periodic performance tests.

(*1*) A control device whose model is tested under, and meets the criteria of, § 63.1282(g), or

(*2*) A combustion control device tested under § 63.1282(d) that meets the outlet TOC or HAP performance level specified in § 63.1281(d)(1)(i)(B) and that establishes a correlation between firebox or combustion chamber temperature and the TOC or HAP performance level.

* * * * *

(4) For a condenser design analysis conducted to meet the requirements of § 63.1281(d)(1), (e)(3)(ii), or (f)(1), the owner or operator shall meet the requirements specified in paragraphs (d)(4)(i) and (d)(4)(ii) of this section. Documentation of the design analysis shall be submitted as a part of the Notification of Compliance Status Report as required in § 63.1285(d)(1)(i).

(i) The condenser design analysis shall include an analysis of the vent stream composition, constituent concentrations, flowrate, relative humidity, and temperature, and shall establish the design outlet organic compound concentration level, design average temperature of the condenser exhaust vent stream, and the design average temperatures of the coolant fluid at the condenser inlet and outlet. As an alternative to the condenser design analysis, an owner or operator may elect to use the procedures specified in paragraph (d)(5) of this section.

* * * * *

(5) As an alternative to the procedures in paragraph (d)(4)(i) of this section, an owner or operator may elect to use the procedures documented in the GRI report entitled, ''Atmospheric Rich/Lean Method for Determining Glycol Dehydrator Emissions,'' (GRI–95/0368.1) as inputs for the model GRI–GLYCalc™, Version 3.0 or higher, to generate a condenser performance curve.

(e) *Compliance demonstration for control devices performance requirements.* This paragraph applies to the demonstration of compliance with the control device performance requirements specified in § 63.1281(d)(1), (e)(3)(ii), and (f)(1). Compliance shall be demonstrated using the requirements in paragraphs (e)(1) through (3) of this section. As an alternative, an owner or operator that installs a condenser as the control device to achieve the requirements specified in § 63.1281(d)(1)(ii), (e)(3)(ii), or (f)(1) may demonstrate compliance according to paragraph (f) of this section. An owner or operator may switch between compliance with paragraph (e) of this section and compliance with paragraph (f) of this section only after at least 1 year of operation in compliance with the selected approach. Notification of such a change in the compliance method shall be reported in the next Periodic Report, as required in § 63.1285(e), following the change.

* * * * *

(2) The owner or operator shall calculate the daily average of the applicable monitored parameter in accordance with § 63.1283(d)(4) except that the inlet gas flowrate to the control device shall not be averaged.

(3) Compliance is achieved when the daily average of the monitoring parameter value calculated under paragraph (e)(2) of this section is either equal to or greater than the minimum or equal to or less than the maximum monitoring value established under paragraph (e)(1) of this section. For inlet gas flowrate, compliance with the operating parameter limit is achieved when the value is equal to or less than the value established under § 63.1282(g).

(4) Except for periods of monitoring system malfunctions, repairs associated with monitoring system malfunctions, and required monitoring system quality assurance or quality control activities (including, as applicable, system accuracy audits and required zero and span adjustments), the CMS required in § 63.1283(d) must be operated at all times the affected source is operating. A monitoring system malfunction is any 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. Monitoring system repairs are required to be completed in response to monitoring system malfunctions and to return the monitoring system to operation as expeditiously as practicable.

(5) Data recorded during monitoring system malfunctions, repairs associated with monitoring system malfunctions, or required monitoring system quality assurance or control activities may not be used in calculations used to report emissions or operating levels. All the data collected during all other required data collection periods must be used in assessing the operation of the control device and associated control system.

(6) Except for periods of monitoring system malfunctions, repairs associated with monitoring system malfunctions, and required quality monitoring system quality assurance or quality control activities (including, as applicable, system accuracy audits and required zero and span adjustments), failure to collect required data is a deviation of the monitoring requirements.

(f) *Compliance demonstration with percent reduction or emission limit performance requirements—condensers.* This paragraph applies to the demonstration of compliance with the performance requirements specified in § 63.1281(d)(1)(ii), (e)(3) or (f)(1) for condensers. Compliance shall be demonstrated using the procedures in paragraphs (f)(1) through (f)(3) of this section.

(1) The owner or operator shall establish a site-specific condenser performance curve according to the procedures specified in § 63.1283(d)(5)(ii). For sources required to meet the BTEX limit in accordance with § 63.1281(e) or (f)(1) the owner or operator shall identify the minimum percent reduction necessary to meet the BTEX limit.

(2) Compliance with the percent reduction requirement in § 63.1281(d)(1)(ii), (e)(3), or (f)(1) shall be demonstrated by the procedures in paragraphs (f)(2)(i) through (iii) of this section.

* * * * *

(iii) Except as provided in paragraphs (f)(2)(iii)(A), (B), and (D) of this section, at the end of each operating day the owner or operator shall calculate the 30-day average HAP, or BTEX, emission reduction, as appropriate, from the condenser efficiencies as determined in paragraph (f)(2)(ii) of this section for the preceding 30 operating days. If the owner or operator uses a combination of process modifications and a condenser in accordance with the requirements of § 63.1281(e), the 30-day average HAP emission, or BTEX, emission reduction, shall be calculated using the emission reduction achieved through process modifications and the condenser efficiency as determined in paragraph (f)(2)(ii) of this section, both for the preceding 30 operating days.

(A) After the compliance date specified in § 63.1270(d), an owner or operator of a facility that stores natural gas that has less than 30 days of data for determining the average HAP, or BTEX, emission reduction, as appropriate, shall calculate the cumulative average at the end of the withdrawal season, each season, until 30 days of condenser operating data are accumulated. For a facility that does not store natural gas, the owner or operator that has less than 30 days of data for determining average HAP, or BTEX, emission reduction, as appropriate, shall calculate the cumulative average at the end of the calendar year, each year, until 30 days of condenser operating data are accumulated.

(B) After the compliance date specified in § 63.1270(d), for an owner or operator that has less than 30 days of data for determining the average HAP, or BTEX, emission reduction, as appropriate, compliance is achieved if the average HAP, or BTEX, emission reduction, as appropriate, calculated in paragraph (f)(2)(iii)(A) of this section is equal to or greater than 95.0 percent.

* * * * *

(3) Compliance is achieved based on the applicable criteria in paragraphs (f)(3)(i) or (ii) of this section.

(i) For sources meeting the HAP emission reduction specified in § 63.1281(d)(1)(ii) or (e)(3) if the average HAP emission reduction calculated in paragraph (f)(2)(iii) of this section is equal to or greater than 95.0 percent.

(ii) For sources required to meet the BTEX limit under § 63.1281(e)(3) or (f)(1), compliance is achieved if the average BTEX emission reduction calculated in paragraph (f)(2)(iii) of this section is equal to or greater than the minimum percent reduction identified in paragraph (f)(1) of this section.

* * * * *

(g) *Performance testing for combustion control devices—manufacturers' performance test.* (1) This paragraph applies to the performance testing of a combustion control device conducted by the device manufacturer. The manufacturer shall demonstrate that a specific model of control device achieves the performance requirements in (g)(7) of this section by conducting a performance test as specified in paragraphs (g)(2) through (6) of this section.

(2) Performance testing shall consist of three one-hour (or longer) test runs for each of the four following firing rate settings making a total of 12 test runs per test. Propene (propylene) gas shall be used for the testing fuel. All fuel analyses shall be performed by an independent third-party laboratory (not affiliated with the control device manufacturer or fuel supplier).

(i) 90–100 percent of maximum design rate (fixed rate).

(ii) 70–100–70 percent (ramp up, ramp down). Begin the test at 70 percent of the maximum design rate. Within the first 5 minutes, ramp the firing rate to 100 percent of the maximum design rate. Hold at 100 percent for 5 minutes. In the 10–15 minute time range, ramp back down to 70 percent of the maximum design rate. Repeat three more times for a total of 60 minutes of sampling.

(iii) 30–70–30 percent (ramp up, ramp down). Begin the test at 30 percent of the maximum design rate. Within the first 5 minutes, ramp the firing rate to 70 percent of the maximum design rate. Hold at 70 percent for 5 minutes. In the 10–15 minute time range, ramp back down to 30 percent of the maximum design rate. Repeat three more times for a total of 60 minutes of sampling.

(iv) 0–30–0 percent (ramp up, ramp down). Begin the test at 0 percent of the maximum design rate. Within the first 5 minutes, ramp the firing rate to 100 percent of the maximum design rate. Hold at 30 percent for 5 minutes. In the 10–15 minute time range, ramp back down to 0 percent of the maximum design rate. Repeat three more times for a total of 60 minutes of sampling.

(3) All models employing multiple enclosures shall be tested simultaneously and with all burners operational. Results shall be reported for the each enclosure individually and for the average of the emissions from all interconnected combustion enclosures/chambers. Control device operating data shall be collected continuously throughout the performance test using an electronic Data Acquisition System and strip chart. Data shall be submitted with the test report in accordance with paragraph (g)(8)(iii) of this section.

(4) Inlet testing shall be conducted as specified in paragraphs (g)(4)(i) through (iii) of this section.

(i) The fuel flow metering system shall be located in accordance with Method 2A, 40 CFR part 60, appendix A–1, (or other approved procedure) to measure fuel flow rate at the control device inlet location. The fitting for filling fuel sample containers shall be located a minimum of 8 pipe diameters upstream of any inlet fuel flow monitoring meter.

(ii) Inlet flow rate shall be determined using Method 2A, 40 CFR part 60, appendix A–1. Record the start and stop reading for each 60-minute THC test. Record the gas pressure and temperature at 5-minute intervals throughout each 60-minute THC test.

(iii) Inlet fuel sampling shall be conducted in accordance with the criteria in paragraphs (g)(4)(iii)(A) and (B) of this section.

(A) At the inlet fuel sampling location, securely connect a Silonite-coated stainless steel evacuated canister fitted with a flow controller sufficient to fill the canister over a 1 hour period. Filling shall be conducted as specified in the following:

(*1*) Open the canister sampling valve at the beginning of the total hydrocarbon (THC) test, and close the canister at the end of the THC test.

(*2*) Fill one canister for each THC test run.

(*3*) Label the canisters individually and record on a chain of custody form.

(B) Each fuel sample shall be analyzed using the following methods. The results shall be included in the test report.

(*1*) Hydrocarbon compounds containing between one and five atoms of carbon plus benzene using ASTM D1945–03.

(*2*) Hydrogen (H_2), carbon monoxide (CO), carbon dioxide (CO_2), nitrogen (N_2), oxygen (O_2) using ASTM D1945–03.

(*3*) Carbonyl sulfide, carbon disulfide plus mercaptans using ASTM D5504.

(*4*) Higher heating value using ASTM D3588–98 or ASTM D4891–89.

(5) Outlet testing shall be conducted in accordance with the criteria in paragraphs (g)(5)(i) through (v) of this section.

(i) Sampling and flowrate measured in accordance with the following:

(A) The outlet sampling location shall be a minimum of 4 equivalent stack diameters downstream from the highest peak flame or any other flow disturbance, and a minimum of one equivalent stack diameter upstream of

the exit or any other flow disturbance. A minimum of two sample ports shall be used.

(B) Flow rate shall be measured using Method 1, 40 CFR part 60, Appendix 1, for determining flow measurement traverse point location; and Method 2, 40 CFR part 60, Appendix 1, shall be used to measure duct velocity. If low flow conditions are encountered (*i.e.,* velocity pressure differentials less than 0.05 inches of water) during the performance test, a more sensitive manometer shall be used to obtain an accurate flow profile.

(ii) Molecular weight shall be determined as specified in paragraphs (g)(4)(iii)(B), and (g)(5)(ii)(A) and (B) of this section.

(A) An integrated bag sample shall be collected during the Method 4, 40 CFR part 60, Appendix A, moisture test. Analyze the bag sample using a gas chromatograph-thermal conductivity detector (GC–TCD) analysis meeting the following criteria:

(*1*) Collect the integrated sample throughout the entire test, and collect representative volumes from each traverse location.

(*2*) The sampling line shall be purged with stack gas before opening the valve and beginning to fill the bag.

(*3*) The bag contents shall be kneaded or otherwise vigorously mixed prior to the GC analysis.

(*4*) The GC–TCD calibration procedure in Method 3C, 40 CFR part 60, Appendix A, shall be modified by using EPAAlt-045 as follows: For the initial calibration, triplicate injections of any single concentration must agree within 5 percent of their mean to be valid. The calibration response factor for a single concentration re-check must be within 10 percent of the original calibration response factor for that concentration. If this criterion is not met, the initial calibration using at least three concentration levels shall be repeated.

(B) Report the molecular weight of: O_2, CO_2, methane (CH4), and N_2 and include in the test report submitted under § 63.775(d)(iii). Moisture shall be determined using Method 4, 40 CFR part 60, Appendix A. Traverse both ports with the Method 4, 40 CFR part 60, Appendix A, sampling train during each test run. Ambient air shall not be introduced into the Method 3C, 40 CFR part 60, Appendix A, integrated bag sample during the port change.

(iv) Carbon monoxide shall be determined using Method 10, 40 CFR part 60, Appendix A. The test shall be run at the same time and with the sample points used for the EPA Method 25A, 40 CFR part 60, Appendix A, testing. An instrument range of 0–10 per million by volume-dry (ppmvd) shall be used.

(v) Visible emissions shall be determined using Method 22, 40 CFR part 60, Appendix A. The test shall be performed continuously during each test run. A digital color photograph of the exhaust point, taken from the position of the observer and annotated with date and time, will be taken once per test run and the four photos included in the test report.

(6) Total hydrocarbons (THC) shall be determined as specified by the following criteria:

(i) Conduct THC sampling using Method 25A, 40 CFR part 60, Appendix A, except the option for locating the probe in the center 10 percent of the stack shall not be allowed. The THC probe must be traversed to 16.7 percent, 50 percent, and 83.3 percent of the stack diameter during the testing.

(ii) A valid test shall consist of three Method 25A, 40 CFR part 60, Appendix A, tests, each no less than 60 minutes in duration.

(iii) A 0–10 parts per million by volume-wet (ppmvw) (as propane) measurement range is preferred; as an alternative a 0–30 ppmvw (as carbon) measurement range may be used.

(iv) Calibration gases will be propane in air and be certified through EPA Protocol 1—''EPA Traceability Protocol for Assay and Certification of Gaseous Calibration Standards,'' September 1997, as amended August 25, 1999, EPA–600/R–97/121 (or more recent if updated since 1999).

(v) THC measurements shall be reported in terms of ppmvw as propane.

(vi) THC results shall be corrected to 3 percent CO_2, as measured by Method 3C, 40 CFR part 60, Appendix A.

(vii) Subtraction of methane/ethane from the THC data is not allowed in determining results.

(7) Performance test criteria:

(i) The control device model tested must meet the criteria in paragraphs (g)(7)(i)(A) through (C) of this section:

(A) Method 22, 40 CFR part 60, Appendix A, results under paragraph (g)(5)(v) of this section with no indication of visible emissions, and

(B) Average Method 25A, 40 CFR part 60, Appendix A, results under paragraph (g)(6) of this section equal to or less than 10.0 ppmvw THC as propane corrected to 3.0 percent CO_2, and

(C) Average CO emissions determined under paragraph (g)(5)(iv) of this section equal to or less than 10 parts ppmvd, corrected to 3.0 percent CO_2.

(ii) The manufacturer shall determine a maximum inlet gas flow rate which shall not be exceeded for each control device model to achieve the criteria in paragraph (g)(7)(i) of this section.

(iii) A control device meeting the criteria in paragraph (g)(7)(i)(A) through (C) of this section will have demonstrated a destruction efficiency of 98.0 percent for HAP regulated under this subpart.

(8) The owner or operator of a combustion control device model tested under this section shall submit the information listed in paragraphs (g)(8)(i) through (iii) in the test report required under § 63.775(d)(1)(iii).

(i) Full schematic of the control device and dimensions of the device components.

(ii) Design net heating value (minimum and maximum) of the device.

(iii) Test fuel gas flow range (in both mass and volume). Include the minimum and maximum allowable inlet gas flow rate.

(iv) Air/stream injection/assist ranges, if used.

(v) The test parameter ranges listed in paragraphs (g)(8)(v)(A) through (O) of this section, as applicable for the tested model.

(A) Fuel gas delivery pressure and temperature.

(B) Fuel gas moisture range.

(C) Purge gas usage range.

(D) Condensate (liquid fuel) separation range.

(E) Combustion zone temperature range. This is required for all devices that measure this parameter.

(F) Excess combustion air range.

(G) Flame arrestor(s).

(H) Burner manifold pressure.

(I) Pilot flame sensor.

(J) Pilot flame design fuel and fuel usage.

(K) Tip velocity range.

(L) Momentum flux ratio.

(M) Exit temperature range.

(N) Exit flow rate.

(O) Wind velocity and direction.

(vi) The test report shall include all calibration quality assurance/quality control data, calibration gas values, gas cylinder certification, and strip charts annotated with test times and calibration values.

(h) *Compliance demonstration for combustion control devices—manufacturers' performance test.* This paragraph applies to the demonstration of compliance for a combustion control device tested under the provisions in paragraph (g) of this section. Owners or operators shall demonstrate that a control device achieves the performance requirements of § 63.1281(d)(1), (e)(3)(ii) or (f)(1), by installing a device tested under paragraph (g) of this section and complying with the following criteria:

(1) The inlet gas flow rate shall meet the range specified by the manufacturer. Flow rate shall be measured as specified in § 63.1283(d)(3)(i)(H)(*1*).

(2) A pilot flame shall be present at all times of operation. The pilot flame shall be monitored in accordance with § 63.1283(d)(3)(i)(H)(*2*).

(3) Devices shall be operated with no visible emissions, except for periods not to exceed a total of 5 minutes during any 2 consecutive hours. A visible emissions test using Method 22, 40 CFR part 60, Appendix A, shall be performed monthly. The observation period shall be 2 hours and shall be used according to Method 22.

(4) Compliance with the operating parameter limit is achieved when the following criteria are met:

(i) The inlet gas flow rate monitored under paragraph (h)(1) of this section is equal to or below the maximum established by the manufacturer; and

(ii) The pilot flame is present at all times; and

(iii) During the visible emissions test performed under paragraph (h)(3) of this section the duration of visible emissions does not exceed a total of 5 minutes during the observation period. Devices failing the visible emissions test shall follow the requirements in paragraphs (h)(4)(iii)(A) and (B) of this section.

(A) Following the first failure, the fuel nozzle(s) and burner tubes shall be replaced.

(B) If, following replacement of the fuel nozzle(s) and burner tubes as specified in paragraph (h)(4)(iii)(A), the visible emissions test is not passed in the next scheduled test, either a performance test shall be performed under paragraph (d) of this section, or the device shall be replaced with another control device whose model was tested, and meets, the requirements in paragraph (g) of this section.

30. Section 63.1283 is amended by:

a. Adding paragraph (b);

b. Revising paragraph (d)(1) introductory text;

c. Revising paragraph (d)(1)(ii) and adding paragraphs (d)(1)(iii) and (iv);

d. Revising paragraph (d)(2)(i) and (d)(2)(ii);

e. Revising paragraphs (d)(3)(i)(A) and (B);

f. Revising paragraphs (d)(3)(i)(D) and (E);

g. Revising paragraphs (d)(3)(i)(F)(*1*) and (*2*);

h. Revising paragraph (d)(3)(i)(G);

i. Adding paragraph (d)(3)(i)(H);

j. Revising paragraph (d)(4);

k. Revising paragraph (d)(5)(i);

l. Revising paragraphs (d)(5)(ii)(A) through (C);

m. Revising paragraph (d)(6) introductory text;

n. Revising paragraph (d)(6)(ii);

o. Adding paragraph (d)(6)(v);

p. Revising paragraph (d)(8)(i)(A); and

q. Revising paragraph (d)(8)(ii) to read as follows:

§ 63.1283 Inspection and monitoring requirements.

* * * * *

(b) The owner or operator of a control device whose model was tested under 63.1282(g) shall develop an inspection and maintenance plan for each control device. At a minimum, the plan shall contain the control device manufacturer's recommendations for ensuring proper operation of the device. Semi-annual inspections shall be conducted for each control device with maintenance and replacement of control device components made in accordance with the plan.

* * * * *

(d) *Control device monitoring requirements.* (1) For each control device except as provided for in paragraph (d)(2) of this section, the owner or operator shall install and operate a continuous parameter monitoring system in accordance with the requirements of paragraphs (d)(3) through (9) of this section. Owners or operators that install and operate a flare in accordance with § 63.1281(d)(1)(iii) or (f)(1)(iii) are exempt from the requirements of paragraphs (d)(4) and (5) of this section. The continuous monitoring system shall be designed and operated so that a determination can be made on whether the control device is achieving the applicable performance requirements of § 63.1281(d), (e)(3), or (f)(1). Each continuous parameter monitoring system shall meet the following specifications and requirements:

* * * * *

(ii) A site-specific monitoring plan must be prepared that addresses the monitoring system design, data collection, and the quality assurance and quality control elements outlined in paragraph (d) of this section and in § 63.8(d). Each CPMS must be installed, calibrated, operated, and maintained in accordance with the procedures in your approved site-specific monitoring plan. Using the process described in § 63.8(f)(4), you may request approval of monitoring system quality assurance and quality control procedures alternative to those specified in paragraphs (d)(1)(ii)(A) through (E) of this section in your site-specific monitoring plan.

(A) The performance criteria and design specifications for the monitoring system equipment, including the sample interface, detector signal analyzer, and data acquisition and calculations;

(B) Sampling interface (*e.g.,* thermocouple) location such that the monitoring system will provide representative measurements;

(C) Equipment performance checks, system accuracy audits, or other audit procedures;

(D) Ongoing operation and maintenance procedures in accordance with provisions in § 63.8(c)(1) and (c)(3); and

(E) Ongoing reporting and recordkeeping procedures in accordance with provisions in § 63.10(c), (e)(1), and (e)(2)(i).

(iii) The owner or operator must conduct the CPMS equipment performance checks, system accuracy audits, or other audit procedures specified in the site-specific monitoring plan at least once every 12 months.

(iv) The owner or operator must conduct a performance evaluation of each CPMS in accordance with the site-specific monitoring plan.

(2) * * *

(i) Except for control devices for small glycol dehydration units, a boiler or process heater in which all vent streams are introduced with the primary fuel or are used as the primary fuel;

(ii) Except for control devices for small glycol dehydration units, a boiler or process heater with a design heat input capacity equal to or greater than 44 megawatts.

(3) * * *

(i) * * *

(A) For a thermal vapor incinerator that demonstrates during the performance test conducted under § 63.1282(d) that combustion zone temperature is an accurate indicator of performance, a temperature monitoring device equipped with a continuous recorder. The monitoring device shall have a minimum accuracy of ± 1 percent of the temperature being monitored in degrees C, or ± 2.5 degrees C, whichever value is greater. The temperature sensor shall be installed at a location representative of the combustion zone temperature.

(B) For a catalytic vapor incinerator, a temperature monitoring device equipped with a continuous recorder. The device shall be capable of monitoring temperatures at two locations and have a minimum accuracy of ± 1 percent of the temperatures being monitored in degrees C, or ± 2.5 degrees C, whichever value is greater. One temperature sensor shall be installed in the vent stream at the nearest feasible point to the catalyst bed inlet and a second temperature sensor shall be installed in the vent stream at the

nearest feasible point to the catalyst bed outlet.

* * * * *

(D) For a boiler or process heater, a temperature monitoring device equipped with a continuous recorder. The temperature monitoring device shall have a minimum accuracy of ± 1 percent of the temperature being monitored in degrees C, or ± 2.5 degrees C, whichever value is greater. The temperature sensor shall be installed at a location representative of the combustion zone temperature.

(E) For a condenser, a temperature monitoring device equipped with a continuous recorder. The temperature monitoring device shall have a minimum accuracy of ± 1 percent of the temperature being monitored in degrees C, or ± 2.8 degrees C, whichever value is greater. The temperature sensor shall be installed at a location in the exhaust vent stream from the condenser.

(F) * * *

(*1*) A continuous parameter monitoring system to measure and record the average total regeneration stream mass flow or volumetric flow during each carbon bed regeneration cycle. The flow sensor must have a measurement sensitivity of 5 percent of the flow rate or 10 cubic feet per minute, whichever is greater. The mechanical connections for leakage must be checked at least every month, and a visual inspection must be performed at least every 3 months of all components of the flow CPMS for physical and operational integrity and all electrical connections for oxidation and galvanic corrosion if your flow CPMS is not equipped with a redundant flow sensor; and

(*2*) A continuous parameter monitoring system to measure and record the average carbon bed temperature for the duration of the carbon bed steaming cycle and to measure the actual carbon bed temperature after regeneration and within 15 minutes of completing the cooling cycle. The temperature monitoring device shall have a minimum accuracy of ± 1 percent of the temperature being monitored in degrees C, or ± 2.5 degrees C, whichever value is greater.

(G) For a nonregenerative-type carbon adsorption system, the owner or operator shall monitor the design carbon replacement interval established using a performance test performed in accordance with § 63.1282(d)(3) and shall be based on the total carbon working capacity of the control device and source operating schedule.

(H) For a control device whose model is tested under § 63.1282(g):

(*1*) A continuous monitoring system that measures gas flow rate at the inlet to the control device. The monitoring instrument shall have an accuracy of plus or minus 2 percent or better.

(*2*) A heat sensing monitoring device equipped with a continuous recorder that indicates the continuous ignition of the pilot flame.

* * * * *

(4) Using the data recorded by the monitoring system, except for inlet gas flowrate, the owner or operator must calculate the daily average value for each monitored operating parameter for each operating day. If the emissions unit operation is continuous, the operating day is a 24-hour period. If the emissions unit operation is not continuous, the operating day is the total number of hours of control device operation per 24-hour period. Valid data points must be available for 75 percent of the operating hours in an operating day to compute the daily average.

(5) * * *

(i) The owner or operator shall establish a minimum operating parameter value or a maximum operating parameter value, as appropriate for the control device, to define the conditions at which the control device must be operated to continuously achieve the applicable performance requirements of § 63.1281(d)(1), (e)(3)(ii), or (f)(1). Each minimum or maximum operating parameter value shall be established as follows:

(A) If the owner or operator conducts performance tests in accordance with the requirements of § 63.1282(d)(3) to demonstrate that the control device achieves the applicable performance requirements specified in § 63.1281(d)(1), (e)(3)(ii), or (f)(1), then the minimum operating parameter value or the maximum operating parameter value shall be established based on values measured during the performance test and supplemented, as necessary, by a condenser design analysis or control device manufacturer's recommendations or a combination of both.

(B) If the owner or operator uses a condenser design analysis in accordance with the requirements of § 63.1282(d)(4) to demonstrate that the control device achieves the applicable performance requirements specified in § 63.1281(d)(1), (e)(3)(ii), or (f)(1), then the minimum operating parameter value or the maximum operating parameter value shall be established based on the condenser design analysis and may be supplemented by the condenser manufacturer's recommendations.

(C) If the owner or operator operates a control device where the performance test requirement was met under § 63.1282(g) to demonstrate that the control device achieves the applicable performance requirements specified in § 63.1281(d)(1), (e)(3)(ii) or (f)(1), then the maximum inlet gas flow rate shall be established based on the performance test and supplemented, as necessary, by the manufacturer recommendations.

(ii) * * *

(A) If the owner or operator conducts a performance test in accordance with the requirements of § 63.1282(d)(3) to demonstrate that the condenser achieves the applicable performance requirements in § 63.1281(d)(1), (e)(3)(ii), or (f)(1), then the condenser performance curve shall be based on values measured during the performance test and supplemented as necessary by control device design analysis, or control device manufacturer's recommendations, or a combination or both.

(B) If the owner or operator uses a control device design analysis in accordance with the requirements of § 63.1282(d)(4)(i) to demonstrate that the condenser achieves the applicable performance requirements specified in § 63.1281(d)(1), (e)(3)(ii), or (f)(1), then the condenser performance curve shall be based on the condenser design analysis and may be supplemented by the control device manufacturer's recommendations.

(C) As an alternative to paragraph (d)(5)(ii)(B) of this section, the owner or operator may elect to use the procedures documented in the GRI report entitled, ''Atmospheric Rich/Lean Method for Determining Glycol Dehydrator Emissions'' (GRI–95/0368.1) as inputs for the model GRI–GLYCalc™, Version 3.0 or higher, to generate a condenser performance curve.

(6) An excursion for a given control device is determined to have occurred when the monitoring data or lack of monitoring data result in any one of the criteria specified in paragraphs (d)(6)(i) through (d)(6)(v) of this section being met. When multiple operating parameters are monitored for the same control device and during the same operating day, and more than one of these operating parameters meets an excursion criterion specified in paragraphs (d)(6)(i) through (d)(6)(iv) of this section, then a single excursion is determined to have occurred for the control device for that operating day.

* * * * *

(ii) For sources meeting § 63.1281(d)(1)(ii), an excursion occurs when average condenser efficiency

calculated according to the requirements specified in § 63.1282(f)(2)(iii) is less than 95.0 percent, as specified in § 63.1282(f)(3). For sources meeting § 63.1281(f)(1), an excursion occurs when the 30-day average condenser efficiency calculated according to the requirements of § 63.1282(f)(2)(iii) is less than the identified 30-day required percent reduction.

* * * * *

(v) For control device whose model is tested under § 63.1282(g) an excursion occurs when:

(A) The inlet gas flow rate exceeds the maximum established during the test conducted under § 63.1282(g).

(B) Failure of the monthly visible emissions test conducted under § 63.1282(h)(3) occurs.

(8) * * *

(i) * * *

(A) During a malfunction when the affected facility is operated during such period in accordance with § 63.6(e)(1); or

* * * * *

(ii) For each control device, or combinations of control devices, installed on the same emissions unit, one excused excursion is allowed per semiannual period for any reason. The initial semiannual period is the 6-month reporting period addressed by the first Periodic Report submitted by the owner or operator in accordance with § 63.1285(e) of this subpart.

* * * * *

31. Section 63.1284 is amended by:

a. Revising paragraph (b)(3) introductory text;

b. Removing and reserving paragraph (b)(3)(ii);

c. Revising paragraph (b)(4)(ii);

d. Adding paragraph (b)(7)(ix); and

e. Adding paragraph (f), (g) and (h) to read as follows:

§ 63.1284 Recordkeeping requirements.

* * * * *

(b) * * *

(3) Records specified in § 63.10(c) for each monitoring system operated by the owner or operator in accordance with the requirements of § 63.1283(d). Notwithstanding the previous sentence, monitoring data recorded during periods identified in paragraphs (b)(3)(i) through (iv) of this section shall not be included in any average or percent leak rate computed under this subpart. Records shall be kept of the times and durations of all such periods and any other periods during process or control device operation when monitors are not operating or failed to collect required data.

* * * * *

(ii) [Reserved]

* * * * *

(4) * * *

(ii) Records of the daily average value of each continuously monitored parameter for each operating day determined according to the procedures specified in § 63.1283(d)(4) of this subpart, except as specified in paragraphs (b)(4)(ii)(A) through (C) of this section.

(A) For flares, the records required in paragraph (e) of this section.

(B) For condensers installed to comply with § 63.1275, records of the annual 30-day rolling average condenser efficiency determined under § 63.1282(f) shall be kept in addition to the daily averages.

(C) For a control device whose model is tested under § 63.1282(g), the records required in paragraph (g) of this section.

* * * * *

(7) * * *

(ix) Records identifying the carbon replacement schedule under § 63.1281(d)(5) and records of each carbon replacement.

* * * * *

(f) The owner or operator of an affected source subject to this subpart shall maintain records of the occurrence and duration of each malfunction of operation (*i.e.,* process equipment) or the air pollution control equipment and monitoring equipment. The owner or operator shall maintain records of actions taken during periods of malfunction to minimize emissions in accordance with § 63.1274(a), including corrective actions to restore malfunctioning process and air pollution control and monitoring equipment to its normal or usual manner of operation.

(g) Record the following when using a control device whose model is tested under § 63.1282(g) to comply with § 63.1281(d), (e)(3)(ii) and (f)(1):

(1) All visible emission readings and flowrate measurements made during the compliance determination required by § 63.1282(h); and

(2) All hourly records and other recorded periods when the pilot flame is absent.

(h) The date the semi-annual maintenance inspection required under § 63.1283(b) is performed. Include a list of any modifications or repairs made to the control device during the inspection and other maintenance performed such as cleaning of the fuel nozzles.

32. Section 63.1285 is amended by:

a. Revising paragraph (b)(1);

b. Revising paragraph (b)(6);

c. Removing paragraph (b)(7);

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

e. Revising paragraph (d)(1)(i);

f. Revising paragraph (d)(1)(ii) introductory text;

g. Revising paragraph (d)(2) introductory text;

h. Revising paragraph (d)(4)(ii);

i. Adding paragraph (d)(4)(iv);

j. Revising paragraph (d)(10);

k. Adding paragraphs (d)(11) and (d)(12);

l. Revising paragraph (e)(2) introductory text;

m. Revising paragraph (e)(2)(ii)(B);

n. Adding paragraphs (e)(2)(ii)(D) and (E);

o. Adding paragraphs (e)(2)(x), (xi) and (xii); and

p. Adding paragraph (g) to read as follows:

§ 63.1285 Reporting requirements.

* * * * *

(b) * * *

(1) The initial notifications required for existing affected sources under § 63.9(b)(2) shall be submitted as provided in paragraphs (b)(1)(i) and (ii) of this section.

(i) Except as otherwise provided in paragraph (b)(1)(ii) of this section, the initial notification shall be submitted by 1 year after an affected source becomes subject to the provisions of this subpart or by June 17, 2000, whichever is later. Affected sources that are major sources on or before June 17, 2000 and plan to be area sources by June 17, 2002 shall include in this notification a brief, nonbinding description of a schedule for the action(s) that are planned to achieve area source status.

(ii) An affected source identified under § 63.1270(d)(3) shall submit an initial notification required for existing affected sources under § 63.9(b)(2) within 1 year after the affected source becomes subject to the provisions of this subpart or by one year after publication of the final rule in the **Federal Register**, whichever is later. An affected source identified under § 63.1270(d)(3) that plans to be an area source by three years after publication of the final rule in the **Federal Register**, shall include in this notification a brief, nonbinding description of a schedule for the action(s) that are planned to achieve area source status.

* * * * *

(6) If there was a malfunction during the reporting period, the Periodic Report specified in paragraph (e) of this section shall include the number, duration, and a brief description for each type of malfunction which occurred during the reporting period and which caused or may have caused any applicable emission limitation to be exceeded. The report must also include a description of

actions taken by an owner or operator during a malfunction of an affected source to minimize emissions in accordance with § 63.1274(h), including actions taken to correct a malfunction.

* * * * *

(d) * * *

(1) If a closed-vent system and a control device other than a flare are used to comply with § 63.1274, the owner or operator shall submit the information in paragraph (d)(1)(iii) of this section and the information in either paragraph (d)(1)(i) or (ii) of this section.

(i) The condenser design analysis documentation specified in § 63.1282(d)(4) of this subpart if the owner or operator elects to prepare a design analysis; or

(ii) If the owner or operator is required to conduct a performance test, the performance test results including the information specified in paragraphs (d)(1)(ii)(A) and (B) of this section. Results of a performance test conducted prior to the compliance date of this subpart can be used provided that the test was conducted using the methods specified in § 63.1282(d)(3), and that the test conditions are representative of current operating conditions. If the owner or operator operates a combustion control device model tested under § 63.1282(g), an electronic copy of the performance test results shall be submitted via e-mail to *Oil_and_Gas_PT@EPA.GOV.*

* * * * *

(2) If a closed-vent system and a flare are used to comply with § 63.1274, the owner or operator shall submit performance test results including the information in paragraphs (d)(2)(i) and (ii) of this section. The owner or operator shall also submit the information in paragraph (d)(2)(iii) of this section.

* * * * *

(4) * * *

(ii) An explanation of the rationale for why the owner or operator selected each of the operating parameter values established in § 63.1283(d)(5) of this subpart. This explanation shall include any data and calculations used to develop the value, and a description of why the chosen value indicates that the control device is operating in accordance with the applicable requirements of § 63.1281(d)(1), (e)(3)(ii), or (f)(1).

* * * * *

(iv) For each carbon adsorber, the predetermined carbon replacement schedule as required in § 63.1281(d)(5)(i).

* * * * *

(10) The owner or operator shall submit the analysis prepared under § 63.1281(e)(2) to demonstrate that the conditions by which the facility will be operated to achieve the HAP emission reduction of 95.0 percent, or the BTEX limit in § 63.1275(b)(1)(iii) through process modifications or a combination of process modifications and one or more control devices.

(11) If the owner or operator installs a combustion control device model tested under the procedures in § 63.1282(g), the data listed under § 63.1282(g)(8).

(12) For each combustion control device model tested under § 63.1282(g), the information listed in paragraphs (d)(12)(i) through (vi) of this section.

(i) Name, address and telephone number of the control device manufacturer.

(ii) Control device model number.

(iii) Control device serial number.

(iv) Date of control device certification test.

(v) Manufacturer's HAP destruction efficiency rating.

(vi) Control device operating parameters, maximum allowable inlet gas flowrate.

* * * * *

(e) * * *

(2) The owner or operator shall include the information specified in paragraphs (e)(2)(i) through (xii) of this section, as applicable.

* * * * *

(ii) * * *

(B) For each excursion caused when the 30-day average condenser control efficiency is less than the value, as specified in § 63.1283(d)(6)(ii), the report must include the 30-day average values of the condenser control efficiency, and the date and duration of the period that the excursion occurred.

* * * * *

(D) For each excursion caused when the maximum inlet gas flow rate identified under § 63.1282(g) is exceeded, the report must include the values of the inlet gas identified and the date and duration of the period that the excursion occurred.

(E) For each excursion caused when visible emissions determined under § 63.1282(h) exceed the maximum allowable duration, the report must include the date and duration of the period that the excursion occurred.

* * * * *

(x) The results of any periodic test as required in § 63.1282(d)(3) conducted during the reporting period.

(xi) For each carbon adsorber used to meet the control device requirements of § 63.1281(d)(1), records of each carbon replacement that occurred during the reporting period.

(xii) For combustion control device inspections conducted in accordance with § 63.1283(b) the records specified in § 63.1284(h).

* * * * *

(g) *Electronic reporting.* (1) As of January 1, 2012, and within 60 days after the date of completing each performance test, as defined in § 63.2 and as required in this subpart, you must submit performance test data, except opacity data, electronically to the EPA's Central Data Exchange (CDX) by using the Electronic Reporting Tool (ERT) (see *http://www.epa.gov/ttn/chief/ert/ert_tool.html/).* Only data collected using test methods compatible with ERT are subject to this requirement to be submitted electronically into the EPA's WebFIRE database.

(2) All reports required by this subpart not subject to the requirements in paragraphs (g)(1) of this section must be sent to the Administrator at the appropriate address listed in § 63.13. If acceptable to both the Administrator and the owner or operator of a source, these reports may be submitted on electronic media. The Administrator retains the right to require submittal of reports subject to paragraph (g)(1) of this section in paper format.

33. Section 63.1287 is amended by revising paragraph (a) to read as follows:

§ 63.1287 Alternative means of emission limitation.

(a) If, in the judgment of the Administrator, an alternative means of emission limitation will achieve a reduction in HAP emissions at least equivalent to the reduction in HAP emissions from that source achieved under the applicable requirements in §§ 63.1274 through 63.1281, the Administrator will publish a notice in the **Federal Register** permitting the use of the alternative means for purposes of compliance with that requirement. The notice may condition the permission on requirements related to the operation and maintenance of the alternative means.

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34. Appendix to Subpart HHH of Part 63—Table is amended by revising Table 2 to read as follows:

Appendix to Subpart HHH of Part 63—Tables

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TABLE 2 TO SUBPART HHH OF PART 63—APPLICABILITY OF 40 CFR PART 63 GENERAL PROVISIONS TO SUBPART HHH

General provisions reference	Applicable to subpart HHH	Explanation
§ 63.1(a)(1)	Yes.	
§ 63.1(a)(2)	Yes.	
§ 63.1(a)(3)	Yes.	
§ 63.1(a)(4)	Yes.	
§ 63.1(a)(5)	No	Section reserved.
§ 63.1(a)(6) through (a)(8)	Yes.	
§ 63.1(a)(9)	No	Section reserved.
§ 63.1(a)(10)	Yes.	
§ 63.1(a)(11)	Yes.	
§ 63.1(a)(12) through (a)(14)	Yes.	
§ 63.1(b)(1)	No	Subpart HHH specifies applicability.
§ 63.1(b)(2)	Yes.	
§ 63.1(b)(3)	No.	
§ 63.1(c)(1)	No	Subpart HHH specifies applicability.
§ 63.1(c)(2)	No.	
§ 63.1(c)(3)	No	Section reserved.
§ 63.1(c)(4)	Yes.	
§ 63.1(c)(5)	Yes.	
§ 63.1(d)	No	Section reserved.
§ 63.1(e)	Yes.	
§ 63.2	Yes	Except definition of major source is unique for this source category and there are additional definitions in subpart HHH.
§ 63.3(a) through (c)	Yes.	
§ 63.4(a)(1) through (a)(3)	Yes.	
§ 63.4(a)(4)	No	Section reserved.
§ 63.4(a)(5)	Yes.	
§ 63.4(b)	Yes.	
§ 63.4(c)	Yes.	
§ 63.5(a)(1)	Yes.	
§ 63.5(a)(2)	No	Preconstruction review required only for major sources that commence construction after promulgation of the standard.
§ 63.5(b)(1)	Yes.	
§ 63.5(b)(2)	No	Section reserved.
§ 63.5(b)(3)	Yes.	
§ 63.5(b)(4)	Yes.	
§ 63.5(b)(5)	Yes.	
§ 63.5(b)(6)	Yes.	
§ 63.5(c)	No	Section reserved.
§ 63.5(d)(1)	Yes.	
§ 63.5(d)(2)	Yes.	
§ 63.5(d)(3)	Yes.	
§ 63.5(d)(4)	Yes.	
§ 63.5(e)	Yes.	
§ 63.5(f)(1)	Yes.	
§ 63.5(f)(2)	Yes.	
§ 63.6(a)	Yes.	
§ 63.6(b)(1)	Yes.	
§ 63.6(b)(2)	Yes.	
§ 63.6(b)(3)	Yes.	
§ 63.6(b)(4)	Yes.	
§ 63.6(b)(5)	Yes.	
§ 63.6(b)(6)	No	Section reserved.
§ 63.6(b)(7)	Yes.	
§ 63.6(c)(1)	Yes.	
§ 63.6(c)(2)	Yes.	
§ 63.6(c)(3) and (c)(4)	No	Section reserved.
§ 63.6(c)(5)	Yes.	
§ 63.6(d)	No	Section reserved.
§ 63.6(e)	Yes.	
§ 63.6(e)	Yes	Except as otherwise specified.
§ 63.6(e)(1)(i)	No	See § 63.1274(h) for general duty requirement.
§ 63.6(e)(1)(ii)	No.	
§ 63.6(e)(1)(iii)	Yes.	
§ 63.6(e)(2)	Yes.	
§ 63.6(e)(3)	No.	
§ 63.6(f)(1)	No.	
§ 63.6(f)(2)	Yes.	
§ 63.6(f)(3)	Yes.	
§ 63.6(g)	Yes.	
§ 63.6(h)	No	Subpart HHH does not contain opacity or visible emission standards.
§ 63.6(i)(1) through (i)(14)	Yes.	

TABLE 2 TO SUBPART HHH OF PART 63—APPLICABILITY OF 40 CFR PART 63 GENERAL PROVISIONS TO SUBPART HHH—Continued

General provisions reference	Applicable to subpart HHH	Explanation
§ 63.6(i)(15)	No	Section reserved.
§ 63.6(i)(16)	Yes.	
§ 63.6(j)	Yes.	
§ 63.7(a)(1)	Yes.	
§ 63.7(a)(2)	Yes	But the performance test results must be submitted within 180 days after the compliance date.
§ 63.7(a)(3)	Yes.	
§ 63.7(b)	Yes.	
§ 63.7(c)	Yes.	
§ 63.7(d)	Yes.	
§ 63.7(e)(1)	No.	
§ 63.7(e)(2)	Yes.	
§ 63.7(e)(3)	Yes.	
§ 63.7(e)(4)	Yes.	
§ 63.7(f)	Yes.	
§ 63.7(g)	Yes.	
§ 63.7(h)	Yes.	
§ 63.8(a)(1)	Yes.	
§ 63.8(a)(2)	Yes.	
§ 63.8(a)(3)	No	Section reserved.
§ 63.8(a)(4)	Yes.	
§ 63.8(b)(1)	Yes.	
§ 63.8(b)(2)	Yes.	
§ 63.8(b)(3)	Yes.	
§ 63.8(c)(1)	Yes.	
63.8(c)(1)(i)	No.	
§ 63.8(c)(1)(ii)	Yes.	
§ 63.8(c)(1)(iii)	Pending.	
§ 63.8(c)(2)	Yes.	
§ 63.8(c)(3)	Yes.	
§ 63.8(c)(4)	No.	
§ 63.8(c)(5) through (c)(8)	Yes.	
§ 63.8(d)	Yes.	
§ 63.8(d)(3)	Yes	Except for last sentence, which refers to an SSM plan. SSM plans are not required.
§ 63.8(e)	Yes	Subpart HHH does not specifically require continuous emissions monitor performance evaluations, however, the Administrator can request that one be conducted.
§ 63.8(f)(1) through (f)(5)	Yes.	
§ 63.8(f)(6)	No	Subpart HHH does not require continuous emissions monitoring.
§ 63.8(g)	No	Subpart HHH specifies continuous monitoring system data reduction requirements.
§ 63.9(a)	Yes.	
§ 63.9(b)(1)	Yes.	
§ 63.9(b)(2)	Yes	Existing sources are given 1 year (rather than 120 days) to submit this notification.
§ 63.9(b)(3)	Yes.	
§ 63.9(b)(4)	Yes.	
§ 63.9(b)(5)	Yes.	
§ 63.9(c)	Yes.	
§ 63.9(d)	Yes.	
§ 63.9(e)	Yes.	
§ 63.9(f)	No.	
§ 63.9(g)	Yes.	
§ 63.9(h)(1) through (h)(3)	Yes.	
§ 63.9(h)(4)	No	Section reserved.
§ 63.9(h)(5) and (h)(6)	Yes.	
§ 63.9(i)	Yes.	
§ 63.9(j)	Yes.	
§ 63.10(a)	Yes.	
§ 63.10(b)(1)	Yes	Section 63.1284(b)(1) requires sources to maintain the most recent 12 months of data on-site and allows offsite storage for the remaining 4 years of data.
§ 63.10(b)(2)	Yes.	
§ 63.10(b)(2)(i)	No.	
§ 63.10(b)(2)(ii)	No	See § 63.1284(f) for recordkeeping of occurrence, duration, and actions taken during malfunction.
§ 63.10(b)(2)(iii)	Yes.	
§ 63.10(b)(2)(iv) through (b)(2)(v)	No.	
§ 63.10(b)(2)(vi) through (b)(2)(xiv)	Yes.	
§ 63.10(b)(3)	No.	
§ 63.10(c)(1)	Yes.	
§ 63.10(c)(2) through (c)(4)	No	Sections reserved.
§ 63.10(c)(5) through (c)(8)	Yes.	
§ 63.10(c)(9)	No	Section reserved.

TABLE 2 TO SUBPART HHH OF PART 63—APPLICABILITY OF 40 CFR PART 63 GENERAL PROVISIONS TO SUBPART HHH—Continued

General provisions reference	Applicable to subpart HHH	Explanation
§ 63.10(c)(10) and (c)(11)	No	See § 63.1284(f)for recordkeeping of malfunctions
§ 63.10(c)(12) through (c)(14)	Yes.	
§ 63.10(c)(15)	No.	
§ 63.10(d)(1)	Yes.	
§ 63.10(d)(2)	Yes.	
§ 63.10(d)(3)	Yes.	
§ 63.10(d)(4)	Yes.	
§ 63.10(d)(5)	No	See § 63.1285(b)(6) for reporting of malfunctions.
§ 63.10(e)(1)	Yes.	
§ 63.10(e)(2)	Yes.	
§ 63.10(e)(3)(i)	Yes	Subpart HHH requires major sources to submit Periodic Reports semi-annually.
§ 63.10(e)(3)(i)(A)	Yes.	
§ 63.10(e)(3)(i)(B)	Yes.	
§ 63.10(e)(3)(i)(C)	No	Subpart HHH does not require quarterly reporting for excess emissions.
§ 63.10(e)(3)(ii) through (e)(3)(viii)	Yes.	
§ 63.10(f)	Yes.	
§ 63.11(a) and (b)	Yes.	
§ 63.11(c), (d), and (e)	Yes.	
§ 63.12(a) through (c)	Yes.	
§ 63.13(a) through (c)	Yes.	
§ 63.14(a) and (b)	Yes.	
§ 63.15(a) and (b)	Yes.	

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