ENVIRONMENTAL PROTECTION AGENCY

40 CFR Parts 60 and 63

[EPA–HQ–OAR–2010–0505; FRL–9665–1]

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: Final rule.

SUMMARY: This action finalizes the review of new source performance standards for the listed oil and natural gas source category. In this action the EPA revised the new source performance standards for volatile organic compounds from leaking components at onshore natural gas processing plants and new source performance standards for sulfur dioxide emissions from natural gas processing plants. The EPA also established standards for certain oil and gas operations not covered by the existing standards. In addition to the operations covered by the existing standards, the newly established standards will regulate volatile organic compound emissions from gas wells, centrifugal compressors, reciprocating compressors, pneumatic controllers and storage vessels. This action also finalizes the residual risk and technology review for the Oil and Natural Gas Production source category and the Natural Gas Transmission and Storage source category. This action includes revisions to the existing leak detection and repair requirements. In addition, the EPA has established in this action emission limits reflecting maximum achievable control technology for certain currently uncontrolled emission sources in these source categories. This action also includes modification and addition of testing and monitoring and related notification, recordkeeping and reporting requirements, as well as other minor technical revisions to the national emission standards for hazardous air pollutants. This action finalizes revisions to the regulatory provisions related to emissions during periods of startup, shutdown and malfunction.

DATES: This final rule is effective on October 15, 2012. The incorporation by reference of certain publications listed in this rule is approved by the Director of the Federal Register as of October 15, 2012.

ADDRESSES: The EPA has established a docket for this action under Docket ID. No. EPA–HQ–OAR–2010–0505. All documents in the docket are listed on the *http://www.regulations.gov* Web site. Although listed in the index, some information is not publicly available, *e.g.,* confidential business information or other information whose disclosure is restricted by statute. Certain other material, such as copyrighted material, is not placed on the Internet and will be publicly available only in hard copy form. Publicly available docket materials are available either electronically through *http://www.regulations.gov* or in hard copy at the EPA's Docket Center, Public Reading Room, EPA West Building, Room Number 3334, 1301 Constitution Avenue NW., Washington, DC 20004. This Docket Facility is open from 8:30 a.m. to 4:30 p.m. Eastern Standard Time, 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: For further information about this final action, contact Mr. Bruce Moore, Sector Policies and Programs Division (E143–05), Office of Air Quality and Standards, Environmental Protection Agency, Research Triangle Park, North Carolina 27711, telephone number: (919) 541–5460; facsimile number: (919) 685–3200; email address: *moore.bruce@epa.gov*. For additional contact information, see the following **SUPPLEMENTARY INFORMATION** section.

SUPPLEMENTARY INFORMATION: For specific information regarding risk assessment and exposure modeling methodology, contact Mr. Mark Morris, Health and Environmental Impacts Division (C504–06), Office of Air Quality Planning and Standards, U.S. Environmental Protection Agency, Research Triangle Park, NC 27711; telephone number (919) 541–5416; fax number: (919) 541–0840; and email address: *morris.mark@epa.gov*.

Organization of This Document. The information presented in this preamble is organized as follows:

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:

API American Petroleum Institute
BACT Best Available Control Technology
BDT Best Demonstrated Technology
bpd Barrels Per Day
BMP Best Management Practice
BSER Best System of Emission Reduction
BTEX Benzene, Ethylbenzene, Toluene and Xylene
CAA Clean Air Act
CBM Coal Bed Methane
CDX Central Data Exchange
CEDRI Compliance and Emissions Data Reporting Interface
CFR Code of Federal Regulations
CO Carbon Monoxide
CO_2 Carbon Dioxide
CO_2e Carbon Dioxide Equivalent
DOE United States Department of Energy
e-GGRT Electronic Greenhouse Gas Reporting Tool
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 NEI code 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
PSIA Pounds per Square Inch Absolute
PTE Potential to Emit
QA Quality Assurance
RACT Reasonably Available Control Technology
RBLC RACT/BACT/LAER Clearinghouse
REC Reduced Emissions Completions
REL California EPA 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. Executive Summary

1. Purpose of the Regulatory Action

Responding to the requirements of a consent decree, this action finalizes several rules that apply to the oil and gas production industry and significantly reduce emissions of air pollutants. More particularly, the action finalizes:

• New source performance standards (NSPS) for the Crude Oil and Natural Gas Production and onshore natural gas processing plant source category. The EPA reviewed two existing NSPS for onshore natural gas processing plant source category under section 111(b) of the Clean Air Act (CAA). This action improves the existing NSPS and finalizes standards for certain crude oil and natural gas sources that are not covered by existing NSPS for this sector.

• National Emissions Standards for Hazardous Air Pollutants (NESHAP) for the Oil and Natural Gas Production source category and the Natural Gas Transmission and Storage source category. The EPA conducted risk and technology reviews (RTR) for these rules under section 112 of the CAA. In addition, the EPA has established emission limits for certain currently uncontrolled emission sources in these source categories. These limits reflect maximum achievable control technology (MACT).

2. Summary of the Major Provisions of the Regulatory Actions

New Source Performance Standards (NSPS). The newly established NSPS for the Crude Oil and Natural Gas Production source category regulate volatile organic compound (VOC) emissions from gas wells, centrifugal compressors, reciprocating compressors, pneumatic controllers, storage vessels and leaking components at onshore natural gas processing plants, as well as sulfur dioxide (SO_2) emissions from onshore natural gas processing plants. This rule sets cost-effective performance standards for:

Gas wells. The rule covers any gas well that is ''an onshore well drilled principally for production of natural gas.'' Oil wells (wells drilled principally for the production of crude oil) are not subject to this rule. For fractured and refractured gas wells, the rule generally requires owners/operators to use reduced emissions completions, also known as ''RECs'' or ''green completions,'' to reduce VOC emissions from well completions. To achieve these VOC reductions, owners and/or operators may use RECs or completion combustion devices, such as flaring, until January 1, 2015; as of January 1, 2015, owners and/or operators must use RECs and a completion combustion device. The rule does not require RECs where their use is not feasible, as specified in the rule. See sections IX.A and IX.B of this preamble for further discussion.

Storage vessels. Individual storage vessels in the oil and natural gas production segment and the natural gas processing, transmission and storage segments with emissions equal to or greater than 6 tons per year (tpy) must achieve at least 95.0 percent reduction in VOC emissions. See section IX.E of this preamble for further discussion.

Certain controllers. The rule sets a natural gas bleed rate limit of 6 scfh for individual, continuous bleed, natural gas-driven pneumatic controllers located between the wellhead and the point at which the gas enters the transmission and storage segment. For individual, continuous bleed, natural gas-driven pneumatic controllers located at natural gas processing plants, the rule sets a natural gas bleed limit of zero scfh. See section IX.C of this preamble for further discussion.

Certain compressors. The rule requires a 95.0 percent reduction of VOC emissions from wet seal centrifugal compressors located between the wellhead and the point at which the gas enters the transmission and storage segment. The rule also requires measures intended to reduce VOC emissions from reciprocating compressors located between the wellhead and the point where natural gas enters the natural gas transmission and storage segment. Owners and/or operators of these compressors must replace the rod packing based on specified usage or time. See section IX.D of this preamble for further discussion.

For onshore natural gas processing plants, this final action revises the existing NSPS requirements for leak detection and repair (LDAR) to reflect the procedures and leak thresholds established in the NSPS for Equipment Leaks of VOCs in the Synthetic Organic Chemicals Manufacturing Industry. This final action also revises the existing NSPS requirements for SO_2 emission reductions 99.8 percent to 99.9 percent based on reanalysis of the original data.

National Emissions Standards for Hazardous Air Pollutants (NESHAP). This action also revises the NESHAP for glycol dehydration unit process vents and leak detection and repair (LDAR) requirements. In the final rule for major sources at oil and natural gas production facilities, we have lowered the leak definition for valves at natural gas processing plants to 500 parts per million (ppm) and thus require the application of LDAR procedures at this level. In this final rule, we also have established MACT standards for ''small'' glycol dehydration units, which were unregulated under the initial NESHAP. Covered glycol dehydrators are those with an actual annual average natural gas flow rate less than 85,000 standard cubic meters per day (scmd) or actual average benzene emissions less than 1 ton per year (tpy), and they must meet unit-specific limits for benzene, ethylbenzene, toluene and xylene (BTEX).

In the final rule for major sources at natural gas transmission and storage facilities, we have established MACT standards for ''small'' glycol dehydrators also not regulated under the initial NESHAP. Covered glycol dehydrators are those with an actual annual average natural gas flow rate less than 283,000 scmd or actual average benzene emissions less than 0.90 Mg/yr, and they must meet unit-specific BTEX emission limits. v. See sections VII and X of this preamble for further discussion of both standards.

3. Costs and Benefits

Table 1 summarizes the costs and benefits of this action. See section XI of this preamble for further discussion.

TABLE 1—SUMMARY OF THE MONETIZED BENEFITS, SOCIAL COSTS AND NET BENEFITS FOR THE FINAL OIL AND NATURAL GAS NSPS AND NESHAP AMENDMENTS IN 2015

[Millions of 2008$] [1]

	Final NSPS	Final NESHAP amendments	Final NSPS and NESHAP amendments combined
Total Monetized Benefits [2]	N/A	N/A	N/A.
Total Costs [3]	−$15 million	$3.5 million	−$11 million.
Net Benefits	N/A	N/A	N/A.
Non-monetized Benefits [4]	11,000 tons of HAP	670 tons of HAP	12,000 tons of HAP.
	190,000 tons of VOC	1,200 tons of VOC	190,000 tons of VOC.
	1.0 million tons of methane	420 tons of methane	1.0 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 particulate matter (PM), as well as climate effects associated with methane, we have determined that quantification of those benefits and co-benefits cannot be accomplished for this rule in a defensible way. This is not to imply that there are no benefits or co-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 final NSPS reflects the inclusion of revenues from additional natural gas and hydrocarbon condensate recovery that are estimated as a result of the NSPS. Possible explanations for why there appear to be negative cost control technologies are discussed in the engineering costs analysis section in the Regulatory Impact Analysis (RIA).

[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. The specific control technologies for the final NSPS are anticipated to have minor secondary disbenefits, including an increase of 1.1 million tons of carbon dioxide (CO_2), 550 tons of nitrogen oxides (NO_X), 19 tons of PM, 3,000 tons of carbon monoxide (CO) and 1,100 tons of total hydrocarbons (THC), as well as emission reductions associated with the energy system impacts. The specific control technologies for the NESHAP are anticipated to have minor secondary disbenefits, but the EPA was unable to estimate the secondary disbenefits. The net CO_2-equivalent emission reductions are 18 million metric tons.

B. Does this action apply to me?

The regulated categories and entities potentially affected by the final standards are shown in Table 2 of this preamble.

TABLE 2—INDUSTRIAL SOURCE CATEGORIES AFFECTED BY THIS 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 is meant to provide a guide for readers regarding entities likely to be affected by this action. If you have any questions regarding the applicability of this action to a particular entity, consult either the air permitting authority for the entity or your EPA regional representative as listed in 40 CFR 60.4 or 40 CFR 63.13 (General Provisions).

C. What are the emission sources affected by this action?

1. What are the emission sources affected by the NSPS?

The emission sources affected by the NSPS include well completions, pneumatic controllers, equipment leaks from natural gas processing plants, sweetening units at natural gas processing plants, reciprocating compressors, centrifugal compressors and storage vessels which are constructed, modified or reconstructed after August 23, 2011. Well completions subject to the NSPS are limited to the flowback period following hydraulic fracturing operations at a gas well affected facility. These completions include those conducted at newly drilled and fractured wells, as well as completions conducted following refracturing operations that may occur at various times over the life of the well. Pneumatic controllers affected by the NSPS include continuous bleed, natural gas-driven pneumatic controllers with a natural gas bleed rate greater than 6 scfh and which commenced construction after August 23, 2011, in the oil and natural gas production segment (except for gas processing plants) and continuous bleed natural gas-driven pneumatic controllers which commenced construction after August 23, 2011, at natural gas processing plants. The NSPS applies to centrifugal compressors with wet seals and reciprocating compressors located in the natural gas production and processing segments. The NSPS also applies to equipment leaks from onshore natural gas processing plants and to storage vessels located in the oil and natural gas production segment, the natural gas processing segment and the natural gas transmission and storage segment. The NSPS also affects sweetening units located onshore that process natural gas from onshore or offshore wells.

2. What are the emission sources affected by the NESHAP?

The emission sources that are affected by the Oil and Natural Gas Production NESHAP (40 CFR part 63, subpart HH) or the Natural Gas Transmission and Storage NESHAP (40 CFR part 63, subpart HHH) include glycol dehydrators and equipment leaks.

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

In addition to being available in the docket, an electronic copy of this action will also be available on the World Wide Web (WWW). Following signature by the Administrator, a copy of the 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 RTR Web site at *http://www.epa.gov/ttn/vatw/rrisk/oarpg.html*. This information includes the most recent version of the rule, source category descriptions, detailed emissions and other data were used as inputs to the risk assessments.

E. Judicial Review

Under CAA section 307(b)(1), judicial review of this final rule is available only by filing a petition for review in the United States Court of Appeals for the District of Columbia Circuit by October 15, 2012. Under CAA section 307(d)(7)(B), only an objection to this final rule that was raised with reasonable specificity during the period for public comment (including any public hearing) can be raised during judicial review. This section also provides a mechanism for the EPA to convene a proceeding for reconsideration ''[i]f the person raising an objection can demonstrate to the Administrator that it was impracticable to raise such objection within [the period for public comment] or if the grounds for such objection arose after the period for public comment (but within the time specified for judicial review) and if such objection is of central relevance to the outcome of the rule[.]'' Any person seeking to make such a demonstration to us should submit a Petition for Reconsideration to the Office of the Administrator, Environmental Protection Agency, Room 3000, Ariel Rios Building, 1200 Pennsylvania Ave. NW., Washington, DC 20004, with a copy to the person listed in the preceding **FOR FURTHER INFORMATION CONTACT** section, and the Associate General Counsel for the Air and Radiation Law Office, Office of General Counsel (Mail Code 2344A), Environmental Protection Agency, 1200 Pennsylvania Ave. NW., Washington, DC 20004. Note, under CAA section 307(b)(2), the requirements established by this final rule may not be challenged separately in any civil or criminal proceedings brought by the EPA to enforce these requirements.

III. Background Information on the NSPS and NESHAP

A. What are the statutory authorities for the NSPS and NESHAP?

1. What is the statutory authority for the NSPS?

Section 111 of the 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. Whereas CAA section 112 standards are issued for new and existing stationary sources, standards of performance are issued for new and modified stationary sources. These standards are referred to as 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. However, the Administrator need not review any such standard if the ''Administrator determines that such review is not appropriate in light of readily available information on the efficacy'' of the standard. When conducting a review of an existing performance standard, the EPA has authority 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 BSER 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 select any control measures that will meet the emission limits. Upon promulgation, an NSPS becomes a national standard to which all new sources must comply.

2. What is the statutory authority for the NESHAP?

Section 112 of the CAA establishes a two-stage regulatory process to address emissions of 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 NESHAP for those sources. ''Major sources'' are those that emit or have the potential to emit (PTE) 10 tpy or more of a single HAP or 25 tpy or more of any combination of HAP. For major sources, the technology-based emission 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 MACT standards.

MACT standards are set 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 sections 112(d)(2)(A)–(E). A 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 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. CAA section 112(f)(2) 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 must be set (unless a more stringent standard is required to prevent an adverse environmental effect, taking into consideration costs, energy, safety and other relevant factors).

If the MACT standards for HAP that are ''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.''). As mentioned, 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.

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 has concluded that the EPA's interpretation of CAA section 112(f)(2) is a reasonable one. See *NRDC* v. *EPA,* 529 F.3d at 1083 (''[S]ubsection 112(f)(2)(B) expressly incorporates the EPA's interpretation of the Clean Air Act from the Benzene standard, complete with a citation to the **Federal Register**''). 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 in the *Residual Risk Report to Congress* 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)

[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.

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 are 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). See 54 FR 38046.

B. What is the litigation history?

On January 14, 2009, pursuant to section 304(a)(2) of the CAA, WildEarth Guardians and the San Juan Citizens Alliance filed a complaint in the United States District Court for the District of Columbia and alleged 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 5, 2010, the Court entered a consent decree that, as successively modified, required the EPA to sign by July 28, 2011,[2] 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 April 3, 2012. On April 2, 2012, the consent decree was modified to change the date for final action to no later than April 17, 2012.

C. What is the sector-based approach?

Sector-based approaches are based on integrated assessments of industrial operations 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, for example the NSPS and NESHAP, consistent with all 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 pollutants, 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 streamlines the monitoring, recordkeeping and reporting requirements, thus, reducing administrative and compliance complexities associated with complying with multiple regulations. In addition, the sector-based approach in this rule promotes a comprehensive control strategy that maximizes the co-control of multiple regulated pollutants while obtaining emission reductions as co-benefits.

D. What are the health effects of pollutants emitted from the oil and natural gas sector?

The final oil and natural gas sector NSPS and NESHAP amendments are expected to result in significant reductions in existing emissions and prevent new emissions from expansions of this industry. These emissions include HAP, VOC (a precursor to both $PM_{2.5}$ and ozone formation) and methane (a GHG and a precursor to global ozone formation). These emissions are associated with substantial health effects, welfare effects and climate effects. One HAP of particular concern from the oil and natural gas sector is benzene, which is a known human carcinogen. $PM_{2.5}$ is associated with health effects, including 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. Ozone is associated with health effects, including hospital and emergency department visits, school loss days and premature mortality, as well as injury to vegetation and climate effects.

IV. Summary of the Final NSPS Rule

A. What are the final actions relative to the NSPS for the Crude Oil and Natural Gas Production source category?

We are revising the existing NSPS, which regulate VOC emissions from equipment leaks and SO_2 emissions from sweetening units at onshore gas processing plants. In addition, we are promulgating standards for several new oil and natural gas affected facilities. The final standards apply to affected facilities that commence construction, reconstruction or modification after August 23, 2011, the date of the proposed rule.

The listed Crude Oil and Natural Gas Production source category covers, at a minimum, those operations for which we are establishing standards in this final rule. Table 3 summarizes the 40 CFR part 60, subpart OOOO standards. Further discussion of these changes may

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

be found below in this section and in sections V and IX of this preamble.

TABLE 3—SUMMARY OF 40 CFR PART 60, SUBPART OOOO EMISSION STANDARDS

Affected facility	Pollutant	Standard	Compliance dates
Hydraulically fractured wildcat and delineation wells.	VOC	Route flowback emissions to completion combustion device.	October 15, 2012.
Hydraulically fractured low pressure wells, non-wildcat and non-delineation wells.	VOC	Route flowback emissions to completion combustion device.	October 15, 2012.
All other hydraulically fractured gas wells	VOC	Route flowback emissions to completion combustion device.	Prior to January 1, 2015.
All other hydraulically fractured gas wells	VOC	Use REC and route flowback emissions to completion combustion device.	On or after January 1, 2015.
Centrifugal compressors with wet seals	VOC	Reduce emissions by 95 percent	October 15, 2012.
Reciprocating compressors	VOC	Change rod packing after 26,000 hours or after 36 months.	October 15, 2012.
Continuous bleed natural gas-driven pneumatic controllers at natural gas processing plants.	VOC	Natural gas bleed rate of zero	October 15, 2012.
Continuous bleed natural gas-driven pneumatic controllers with a bleed rate greater than 6 scfh between wellhead and natural gas processing plant or oil pipeline.	VOC	Natural gas bleed rate less than 6 scfh	October 15, 2013.
Storage vessels with VOC emissions equal to or greater than 6 tpy.	VOC	Reduce emissions by 95 percent	October 15, 2013.
Equipment leaks at onshore natural gas processing plants.	VOC	LDAR program	October 15, 2012.
Sweetening units at onshore natural gas processing plants.	SO_2	Reduce SO_2 emissions based on sulfur feed rate and sulfur content of acid gas.	October 15, 2012.

1. Standards for Gas Well Affected Facilities

We are finalizing operational standards for completions of hydraulically fractured and refractured gas wells. For purposes of this rule, well completion is defined as the flowback period beginning after hydraulic fracturing and ending with either well shut in or when the well continuously flows to the flow line or to a storage vessel for collection, whichever occurs first. The final rule applies to three subcategories of fractured and refractured gas wells for which well completion operations are conducted: (1) Wildcat (exploratory) and delineation gas wells; (2) non-wildcat and non-delineation gas wells for which the reservoir pressure is insufficient for a REC, commonly referred to as a ''green completion,'' to be performed, as determined by a simple calculation involving reservoir pressure, well depth and flow line pressure at the sales meter (we refer to these wells as ''low pressure gas wells'') and (3) other fractured and refractured gas wells. For subcategory (3) wells, each well completion operation begun on or after January 1, 2015, must employ REC in combination with use of a completion combustion device to control gas not suitable for entering the flow line (we refer to this as REC with combustion). For well completion operations at subcategory (1) wells (exploratory and delineation gas wells), subcategory (2) wells (low pressure gas wells) and for well completion operations begun prior to January 1, 2015, at subcategory (3) gas wells, the final rule requires the control of emissions using either REC with combustion or just a completion combustion device. Owners and operators are encouraged to use REC with combustion during this period.

Well completions subject to the standards are gas well completions following hydraulic fracturing and refracturing 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. As we explained in the proposal preamble, a completion operation associated with refracturing performed at a well is considered a modification under CAA section 111(a), because physical change occurs to the well resulting in emissions increases during the refracturing and completion operation. In response to comment, we further clarify this point in the final rule, including providing a specific modification provision for well completions in lieu of the General Provisions in 40 CFR 60.14. For a more detailed explanation, please see section IX.A of this preamble. The modification determination and resulting applicability of NSPS to the completion operation following refracturing of gas wells is limited strictly to the gas well affected facility and does not by itself trigger applicability 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 (that is, such equipment is not part of the affected facility).

The final rule provides that uncontrolled well completions conducted on gas wells that are subsequently refractured on or after the effective date of this rule are modifications and are subject to the NSPS. However, gas wells that undergo completion following refracturing are not considered modified and, as a result, are not affected facilities under the NSPS if the completion operation is conducted with the use, immediately upon flowback, of emission control techniques otherwise required on or after January 1, 2015, for new wells and satisfies other requirements, including notification, recordkeeping and reporting requirements.

In the final rule, we provide for a streamlined notification process for well completions at gas well affected facilities consisting of an email pre-notification no later than 2 days in advance of impending completion operations. The email must include information that had been part of the 30-day advance notification, as described in the proposed rule, including contact information for the owner and operator, well identification, geographic coordinates of the well and planned date of the beginning of flowback.

In the final rule, the recordkeeping and reporting requirements for well completions also provide for a streamlining option that owners and operators may choose in lieu of the standard annual reporting requirements. The standard annual report must include copies of all well completion records for each gas well affected facility for which a completion operation was performed during the reporting period. The alternative, streamlined annual report for gas well affected facilities requires submission of a list, with identifying information of all affected gas wells completed, electronic or hard copy photographs documenting REC in progress for each well for which REC was required and the self-certification required in the standard annual report. The operator retains a digital image of each REC in progress. The image must include a digital date stamp and geographic coordinates stamp to help link the photograph with the specific well completion operation.

2. Standards for Compressor Affected Facilities

The final rule requires measures to reduce VOC emissions from centrifugal and reciprocating compressors. Compressors located at the wellhead or in the transmission, storage and distribution segments are not covered by this final rule and, therefore, are not affected facilities. The final rule contains standards for wet seal centrifugal compressors located in the natural gas production segment and the natural gas processing segment up the point at which the gas enters the transmission and storage segment. The final standards require 95.0 percent reduction of the emissions from each wet seal centrifugal compressor affected facility. The standard can be achieved by capturing and routing the emissions to a control device that achieves an emission reduction of 95.0 percent.

The operational standards for reciprocating compressors in the final rule require replacement of the rod packing based on usage. The owner or operator of a reciprocating compressor affected facility is required to change the rod packing immediately when hours of operation reach 26,000 hours (equivalent to 36 months of continuous usage). Alternatively, owners or operators can elect to change the rod packing every 36 months in lieu of monitoring compressor operating hours. An owner or operator who elects to meet the 26,000 hour requirement is required to monitor the duration (in hours) that the compressor is operated, beginning on the date of initial startup of the reciprocating compressor affected facility, or on the date of the previous rod packing replacement, whichever is later.

3. Standards for Pneumatic Controller Affected Facilities

We are also finalizing pneumatic controller VOC standards. The affected facility is a continuous bleed, natural gas-driven pneumatic controller with a natural gas bleed rate greater than 6 scfh for which construction commenced after August 23, 2011, located (1) in the oil production segment between the wellhead and the point of custody transfer to an oil pipeline; or (2) in the natural gas production segment, excluding natural gas processing plants, between the wellhead and the point at which the gas enters the transmission and storage segment. Except for controllers located at natural gas processing plants, each continuous bleed, natural gas-driven pneumatic controller that emits more than 6 scfh is an affected facility if it is constructed or modified after August 23, 2011. Pneumatic controllers with a bleed rate of 6 scfh or less in the oil and natural gas production segment and all pneumatic controllers located in the natural gas transmission, storage and distribution segments are not covered by this final rule and, therefore, are not affected facilities. At natural gas processing plants, the affected facility is each individual continuous bleed natural gas-operated pneumatic controller, and the final rule includes a natural gas bleed rate limit of zero scfh. The final emission standards for pneumatic controllers at natural gas processing plants reflect the emission level achievable from the use of non-natural gas-driven pneumatic controllers. At other locations in the oil and natural gas production segment, the final rule includes a natural gas bleed rate limit of 6 standard cubic feet of gas per hour for an individual pneumatic controller. The standards provide exemptions in cases where it has been demonstrated that the use of a natural gas-driven pneumatic controller with a bleed rate above the applicable standard is required. However, as discussed in section IX.C, the EPA is allowing a 1-year phase-in period for pneumatic controllers in the final rule.

4. Standards for Storage Vessels

The final rule contains VOC standards for new, modified or reconstructed storage vessels located in the oil and natural gas production, natural gas processing and natural gas transmission and storage segments. The final rule, which applies to individual storage vessels, requires that storage vessels with VOC emissions equal to or greater than 6 tpy achieve at least 95.0 percent reduction in VOC emissions. For storage vessels constructed, modified or reconstructed at well sites with no wells already in production at the time of construction, modification or reconstruction, the final rule provides a 30-day period from startup for the owner or operator to determine whether the magnitude of VOC emissions from the storage vessel will be at least 6 tpy. If the storage vessel requires control, the final rule provides an additional 30 days for the control device to be installed and operational. For storage vessels constructed, modified or reconstructed at well sites with one or more wells already in production at the time of construction, modification or reconstruction, these estimation and installation periods are not provided because an estimate of VOC emissions can be made using information on the liquid production characteristics of the existing wells.

In addition, the final rule provides for a 1-year phase-in period for storage vessel controls. Refer to section IX.E.4 of this preamble for further discussion.

5. Standards for Affected Facilities Located at Onshore Natural Gas Processing Plants

For onshore natural gas processing plants, we are revising the existing NSPS requirements for LDAR to reflect the procedures and leak thresholds established by 40 CFR part 60, subpart VVa. Subpart VVa lowers the leak definition for valves from 10,000 ppm to 500 ppm, and requires the monitoring of connectors. Pumps, pressure relief devices and open-ended valves or lines are also monitored.

6. Standards for Sweetening Unit Affected Facilities at Onshore Natural Gas Processing Plants

The final rule regulates SO_2 emissions from natural gas processing plants by requiring affected facilities to reduce SO_2 emissions by recovering sulfur. The final rule incorporates the provisions of 40 CFR part 60, subpart LLL into 40 CFR part 60, subpart OOOO, and minor revisions were made to adapt the subpart LLL language to subpart OOOO. The final rule also increased the SO_2 emission reduction standard from the subpart LLL requirement of 99.8 percent to 99.9 percent for units with sulfur production rate of at least 5 long tons per day. This change is based on reanalysis of the original data used in the subpart LLL BSER analysis.

B. What are the effective and compliance dates for the final NSPS?

The revisions to the existing NSPS standards and the new NSPS standards promulgated in this action are effective on October 15, 2012. Affected facilities must be in compliance with the final standards on the effective date, October 15, 2012.

V. Summary of the Significant Changes to the NSPS Since Proposal

The previous section summarized the requirements that the EPA is finalizing in this rule. This section will discuss in greater detail the key changes the EPA has made since proposal. These changes result from the EPA's review of the additional data and information provided to us and our consideration of the many substantive and thoughtful comments submitted on the proposal.

We believe the changes make the final rule more flexible and cost-effective, address concerns with equipment availability, streamline recordkeeping and reporting requirements and improve clarity, while fully preserving or improving the public health and environmental protection required by the CAA.

A. Gas Well Affected Facilities

We have revised the requirements for gas well affected facilities since proposal in response to comment. The final rule applies to three subcategories of fractured and refractured gas wells for which well completion operations are conducted: (1) Wildcat (exploratory) and delineation gas wells; (2) non-wildcat and non-delineation gas wells for which the reservoir pressure is insufficient for a REC to be performed, as determined by a simple calculation involving reservoir pressure, well depth and flow line pressure at the sales meter (we refer to these wells as ''low pressure gas wells''); and (3) other fractured and refractured gas wells. In the proposed 40 CFR part 60, subpart OOOO, upon promulgation of this rule, each well completion or recompletion at a non-exploratory or non-delineation well would have had to employ REC with combustion. Because of uncertainties in the supply of equipment and labor over the near-term, we are now requiring this work practice standard for completion operations begun at subcategory (3) gas wells (non-exploratory and non-delineation wells) on or after January 1, 2015. Until this date, flowback emissions must either be controlled using REC or routed to a completion combustion device unless it is technically infeasible or unsafe to do so. Owners and operators are encouraged to use REC when available during this period. Completion operations at subcategory (1) gas wells (wildcat and delineation wells) and subcategory (2) gas wells (non-wildcat and non-delineation low pressure gas wells) begun on or after October 15, 2012 are required to control flowback emissions by using REC with combustion or by routing emissions to a completion combustion device alone unless it is technically infeasible or unsafe to do so.

The final rule includes a specific modification provision for well completions in lieu of the General Provisions in 40 CFR 60.14. For a more detailed explanation, please see section IX.A of this preamble. In addition, we have revised the definition of ''flowback period'' to more clearly define when the flowback period begins and ends.

In the proposed rule, all completions at existing wells (*i.e.,* those originally constructed on or before August 23, 2011) that are subsequently fractured or refractured were considered to be modifications. In the final rule, completions of wells that are refractured on or after the rule's effective date are not considered modified and, as a result, are not affected facilities under the NSPS, if the completion operation is conducted with the use, immediately upon flowback, of emission control techniques required on or after January 1, 2015, for new wells and satisfies other requirements, including notification, recordkeeping and reporting requirements.

In the proposed rule, we prescribed specific equipment to accomplish an REC. In the final rule, we have removed the required equipment specifications for REC and added operational standards that will result in minimizing emissions and maximizing product recovery. In light of the comments received, we conclude that it is inappropriate and unnecessary to prohibit the use of other equipment that can be used to accomplish an REC and that the operational standards can be achieved using a variety of equipment that can change from well to well.

Initial compliance requirements for gas well affected facilities have also been revised and streamlined. Owners and operators are now required to notify the Administrator of the actual date of each well completion operation by email no later than 2 days prior to the well completion operation, rather than the proposed requirement of notifying the Administrator of the date of the well completion operation within 30 days of the commencement of each well completion operation. The email must include information that had been part of the 30-day advance notification, as described in the proposed rule, including contact information for the owner and operator, well identification, geographic coordinates of the well and planned date of the beginning of flowback. However, if the owner or operator is subject to state regulations that require advance notification of well completions and has met those advance notification requirements, then the owner or operator is considered to have met the advance notification requirements for gas well completions under the NSPS.

In the final rule, the recordkeeping and reporting requirements for well completions also provide for a streamlining option that owners and operators may choose in lieu of the standard annual reporting requirements. The standard annual report must include copies of all well completion records for each gas well affected facility for which a completion operation was performed during the reporting period. The alternative, streamlined annual report for gas well affected facilities requires submission of a list, with identifying information of all affected gas wells completed, electronic or hard copy photographs documenting REC in progress for each well for which REC was required and the self-certification required in the standard annual report. The operator retains a digital image of each REC in progress. The image must include a digital date stamp and geographic coordinates stamp to help link the photograph with the specific well completion operation.

Refer to section IX.B of this preamble and the Responses to Comments document, available in the docket, for detailed discussion regarding these changes.

B. Centrifugal and Reciprocating Compressor Affected Facilities

In the final rule, we have made changes that impact both reciprocating and centrifugal compressor affected facilities in response to comments requesting clarification. Because we are not finalizing standards covering them, centrifugal and reciprocating compressors located in the transmission, storage and distribution segments are not affected facilities.

In the proposed rule, all centrifugal compressors would be required to use dry seals. We had also solicited comment on the use of wet seals with controls as an acceptable alternative to dry seals due to potential technical infeasibility of using dry seals for certain applications. Based on comments received, the final rule requires that centrifugal compressors with wet seals reduce emissions by 95.0

percent. The standard can be achieved by capturing and routing emissions from the wet seal fluid degassing system to a control device that reduces VOC emissions by 95.0 percent. Testing, monitoring, recordkeeping, reporting and notification requirements associated with the control devices have also been added. In contrast to the proposed rule, in the final rule, centrifugal compressors with dry seals are not affected facilities. More detailed discussion of this change is presented in section IX.D of this preamble.

As proposed, owners or operators of reciprocating compressor affected facilities were required to change rod packing after 26,000 hours of operation. This is equivalent to approximately 36 months of continuous operation. Based on comments we received, we are changing the final rule to provide operators the option of changing the rod packing every 36 months instead of tracking compressor hours of operation and changing rod packing after 26,000 hours of operation.

Refer to section IX.D of this preamble and the Responses to Comments document, available in the docket, for detailed discussion regarding these changes.

C. Pneumatic Controller Affected Facilities

For pneumatic controller affected facilities located in the oil and natural gas production segments, we have revised the definition of pneumatic controller affected facility from a single pneumatic controller to a single, continuous bleed, natural gas-driven pneumatic controller with a continuous bleed rate greater than 6 scfh for which construction, modification or reconstruction commenced after August 23, 2011. At natural gas processing plants, individual continuous bleed natural gas-operated pneumatic controllers for which construction, modification or reconstruction commenced after August 23, 2011, are affected facilities under this rule. As explained further in section IX.C of this preamble, this change provides clarity by more specifically defining the pneumatic controllers we intended to regulate in this final rule. In addition, only pneumatic controllers located prior to the point at which the gas enters the transmission and storage segment are subject to the NSPS. Because we are not finalizing standards covering them, controllers located in the transmission and storage segment are not affected facilities. The emission rates we proposed for pneumatic controllers have not changed in the final rule.

All new pneumatic controller affected facilities are required, in the final rule, to be tagged with the month and year of installation and identification that allows traceability to the records for that controller.

In the proposed rule, each pneumatic controller affected facility would have to comply upon promulgation. The final rule allows a 1-year phase-in beginning October 15, 2012 before the bleed rate limit is effective for an affected facility. We believe this is necessary for at least two reasons. First, owners and operators would demonstrate compliance based on information in the manufacturers' specification. We have concluded that such information is not always included in current manufacturers' specifications and a period of time is required for manufacturers to test their products and modify specifications to include the information. Second, we are not aware of any add-on control device that is or can be used to reduce VOC emissions from gas-driven pneumatic devices.

Finally, language in the proposed rule could have been interpreted to mean that all pneumatic controllers installed in any year after the proposal date must be reported each year, rather than those installed only during the reporting period. In order to clarify and streamline the recordkeeping and reporting requirements associated with pneumatic controllers, we are requiring only information concerning those affected facilities constructed, modified or reconstructed during the reporting period to be included in the annual report.

Refer to section IX.C of this preamble and the Responses to Comments document, available in the docket, for detailed discussion regarding these changes.

D. Storage Vessel Affected Facilities

We have modified the definition of "storage vessel" to exclude surge control vessels, knockout vessels and pressure vessels designed to operate without emissions to the atmosphere. In addition, we have clarified that we consider a storage vessel that is skid-mounted or permanently attached to something that is mobile (such as trucks, railcars, barges or ships) to be subject to 40 CFR part 60, subpart OOOO if it is intended to be located at a site for at least 180 consecutive days.

In the proposed rule, we established a throughput threshold for storage vessels below which they were not subject to the NSPS. In order to remove confusion with respect to the emission factors used to develop the throughput threshold and to address comments indicating significant difficulty measuring throughput, we have revised the final rule such that storage vessels that emit 6 tpy of VOC or more are subject to the NSPS, based on our analysis in the proposed rule showing that the proposed NSPS is cost-effective for storage vessels with that level of VOC emissions. In the final rule, for storage vessels constructed, modified or reconstructed at well sites with no wells already in production at the time of construction, the final rule provides a 30-day period for the owner or operator to determine whether the magnitude of VOC emissions from the storage vessel will be at least 6 tpy. If the storage vessel requires control, the final rule provides an additional 30 days for the control device to be installed and operational. For storage vessels constructed, modified or reconstructed at well sites with one or more wells already in production at the time of construction, modification or reconstruction, VOC emissions can be determined prior to startup. Accordingly, these estimation and installation periods are not necessary and, therefore, not provided.

Several requirements for storage vessels in the proposed rule pointed to 40 CFR part 63, subpart HH (the Oil and Natural Gas Production NESHAP). However, subpart HH regulates HAP while this NSPS regulates VOC. Therefore, in order to eliminate confusion caused by cross-referencing another regulation and to tailor the requirements for VOC regulation, we have incorporated the storage vessel requirements from subpart HH into 40 CFR part 60, subpart OOOO and modified those requirements, as appropriate for this rule.

In the proposed rule, each storage vessel required to reduce emissions would have to comply upon promulgation. In the final rule, owners or operators are allowed a 1-year phase-in beginning October 15, 2012 before the 95.0-percent control requirement is effective. We believe this is necessary because of initial problems securing control devices that are manufacturer-tested and have appropriate documentation for determining control efficiency. In addition, we believe that owners or operators will require a period of time to establish the need for controls and install them where called for. The 1-year phase-in will also allow owners or operators the necessary time to establish the need for a control device and procure and install the equipment.

Refer to section IX.E of this preamble and the Responses to Comments document, available in the docket, for detailed discussion regarding these changes.

E. Equipment Leaks Affected Facilities and Sweetening Unit Affected Facilities at Onshore Natural Gas Processing Plants

We have revised the identification of affected facilities for equipment leaks at natural gas processing plants. We proposed that compressors and equipment (as defined in the rule) located at onshore natural gas processing plants were affected facilities. As discussed above, compressors (reciprocating and centrifugal) have requirements under 40 CFR part 60, subpart OOOO that extend beyond the natural gas processing plant. To remove the duplicative requirements for compressors at natural gas processing plants, we have revised the identification of affected facility to exclude compressors from the standards that apply to equipment leaks at onshore natural gas processing plants. Refer to the Responses to Comments document, available in the docket, for detailed discussion regarding these affected facilities.

F. Changes to Notification, Recordkeeping and Reporting Requirements

In response to comment expressing concern with the burdens associated with demonstrating and monitoring compliance, we have reanalyzed the notification, recordkeeping and reporting requirements in the proposed rule and eliminated duplicative and unnecessary requirements for all emission points. For well completions, compressors, pneumatic controllers and storage vessels, we have removed the General Provisions notification requirements in 40 CFR 60.7(a)(1), (3) and (4). These requirements relate to notification of construction and initial performance testing and are more suited to construction of more traditional facilities (*e.g.,* gas processing plants, refineries and chemical plants) than the numerous individual pieces of apparatus (*e.g.,* individual pneumatic controllers, compressor and storage vessels) that are ''affected facilities'' under this final rule. Specific notification and initial compliance demonstration requirements in the final rule make the General Provisions notification requirements unnecessary for gas well affected facilities.

As mentioned previously, we have also streamlined the notification, recordkeeping and reporting requirements for gas well affected facilities. In place of a written notification of each well completion operation 30 days prior to the completion, owners or operators must submit a notification no later than 2 days prior to the date of the completion. This notification may be submitted by email. To avoid duplicative and potentially conflicting advance notification requirements, the final rule provides that owners or operators who are subject to state regulations that require advance notification of well completions and have met those notification requirements are considered to have met the advance notification requirements of the NSPS. Additionally, in lieu of the standard annual reporting requirements, the final rule allows submission of an annual report for gas well affected facilities that consists only of a list, with identifying information of all affected gas wells completed, electronic or hard copy photographs documenting REC in progress for each well for which REC was required and the self-certification required in the standard annual report.

In the affirmative defense provisions of the rule, a citation was corrected, minor wording changes were made and reporting requirements were refined. The provisions we retained in the final rule are those we believe are necessary to assure regulatory agencies and the public that the owner or operator is in compliance with the final rule. Refer to section IX.F of this preamble and the Responses to Comments document, available in the docket, for detailed discussion regarding these changes.

VI. Summary of the Final NESHAP Rules

A. What are the final rule actions relative to the Oil and Natural Gas Production (subpart HH) source category?

Table 4 summarizes the changes to 40 CFR part 63, subpart HH. Further discussion of these changes may be found below in this section and in sections VII and X of this preamble.

TABLE 4—SUMMARY OF CHANGES TO 40 CFR PART 63, SUBPART HH

Affected source	Nature of change	Standard
Small glycol dehydrators	Established MACT standards for previously unregulated source.	BTEX emission limit: New sources—4.66×10^{-6} g/scm-ppmv. Existing sources—3.28×10^{-4} g/scm-ppmv.
''Associated equipment''	Revised definition to exclude all storage vessels	N/A.
Valves—equipment leaks	Revised definition of leak	LDAR for valves must be applied at 500 ppm.
All affected sources	Eliminated exemption from compliance during periods of startup, shutdown and malfunction.	Standards apply at all times.

Pursuant to CAA sections 112(d)(2) and (3), we have established MACT standards for small glycol dehydrators that were not regulated in the initial NESHAP. In addition, we have revised the definition of ''associated equipment'' to exclude from the definition of that term all storage vessels, not just those with potential for flash emissions (PFE).

With regard to our CAA section 112(d)(6) review, we conclude that there have been no developments in practices, processes or control technologies for large glycol dehydrators and storage vessels with PFE. As noted at proposal, however, there have been relevant developments for equipment leaks, and we are finalizing the proposed revisions to the leak definition for valves at natural gas processing plants. Specifically, under CAA section 112(d)(6), we revised the leak definition for valves to 500 ppm, thus requiring the application of the leak detection and repair requirement at this lower detection level. We did not make other revisions to the standards pursuant to our CAA section 112(d)(6) review. Our review under CAA section 112(f)(2) also did not result in revision to the standards. We found that the MACT standards in 40 CFR part 63, subpart HH (coupled with the new MACT standard for small glycol dehydrators) provide an ample margin of safety to protect public health and prevent adverse environmental effects. Accordingly, we are re-adopting those standards to satisfy the requirements of CAA section 112(f).

Additionally, we amended 40 CFR part 63, subpart HH to apply the standards at all times and made other revisions relative to periods of startup, shutdown and malfunction. Lastly, the final rule revises and adds certain testing and monitoring and related notification, recordkeeping and reporting requirements and makes certain other minor technical revisions to the NESHAP.

1. Standards for Small Glycol Dehydration Units

In this final rule, we have established MACT standards under CAA sections 112(d)(2) and (3) for small glycol dehydration units, which were left unregulated in the initial NESHAP. This 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). The final MACT standards for small dehydrators at oil and gas production facilities require that existing affected sources at a major source meet a unit-specific BTEX limit of 3.28×10^{-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.

2. Standards for Equipment Leaks

In the final rule, as a result of our technology review under CAA section 112(d)(6), we are revising the leak definition for valves to 500 ppm, thus requiring the application of the LDAR requirement at this lower detection level. This leak definition applies only to valves at natural gas processing plants, and not other components.

3. Notification, Recordkeeping and Reporting Requirements

The final rule revises certain recordkeeping requirements of 40 CFR part 63, subpart HH. Specifically, facilities using carbon adsorbers as a control device are required to 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 of operation (*i.e.,* process equipment) or the air pollution control equipment and monitoring equipment.

In conjunction with the new MACT standards for small existing glycol dehydration units, owners and operators of such affected units are required to submit an initial notification within 1 year after they become subject to the provisions of this subpart or by October 15, 2013, whichever is later.

The final amendments to the NESHAP also include additional requirements for the contents of the periodic reports. The periodic reports are required to include periodic test results and information regarding any carbon replacement events that occurred during the reporting period. Additionally, periodic reports are required to 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 periodic report is also required to include a description of actions taken by an owner or operator during a malfunction of an affected source to minimize emissions, including actions taken to correct a malfunction.

B. What are the final rule amendments for the Natural Gas Transmission and Storage (subpart HHH) source category?

Table 5 summarizes the changes to 40 CFR part 63, subpart HHH. Further discussion of these changes may be found below in this section and in sections VII and X of this preamble.

TABLE 5—SUMMARY OF CHANGES TO 40 CFR PART 63, SUBPART HHH

Affected source	Nature of change	Standard
Small glycol dehydrators	Established MACT standards for previously unregulated source.	BTEX emission limit: New sources—5.44×10^{-5} g/scm-ppmv. Existing sources—3.01×10^{-4} g/scm-ppmv.
All affected sources	Eliminated exemption from compliance during periods of startup, shutdown and malfunction.	Standards apply at all times.

Pursuant to CAA section 112(d)(2) and (3), we have established MACT standards for small glycol dehydrators that were not regulated in the initial NESHAP. We have also amended 40 CFR part 63, subpart HHH to apply the standards at all times, and made other revisions relative to periods of startup, shutdown and malfunction. Lastly, the final rule revises and adds certain testing and monitoring and related notification, recordkeeping and reporting requirements, as well as makes other minor technical revisions to the NESHAP.

With regard to our CAA section 112(d)(6) review, we conclude that there have been no developments in practices processes or control technologies for large glycol dehydrators. We also found that the MACT standards in 40 CFR part 63, subpart HHH (coupled with the new MACT standard for small glycol dehydrators) provide an ample margin of safety to protect public health and prevent adverse environmental effects. Accordingly, we are re-adopting those standards to satisfy the requirements of CAA section 112(f). Thus, our reviews under CAA sections 112(d)(6) and 112(f)(2) did not result in any revisions to the standards.

1. Standards for Glycol Dehydration Units

In this final rule, we have established MACT standards for small glycol dehydration units in the Natural Gas Transmission and Storage source category. This 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 final MACT standard for this subcategory of small dehydrators requires existing affected sources to meet a unit-specific BTEX emission limit of 3.01×10^{-4} grams BTEX/scm-ppmv and new affected sources are required to meet a BTEX limit of 5.44×10^{-5} grams BTEX/scm-ppmv.

2. Notification, Recordkeeping and Reporting Requirements

The final rule revises certain recordkeeping requirements of 40 CFR part 63, subpart HHH. Specifically, facilities using carbon adsorbers as a control device are required to 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 of operation (*i.e.,* process equipment) or the air pollution control equipment and monitoring equipment.

In conjunction with the promulgation of the MACT standards for small glycol dehydration units, the final rule requires that owners and operators of such affected units submit an initial notification within 1 year after the unit becomes subject to the provisions of this subpart or by October 15, 2013, whichever is later.

The final amendments to the NESHAP also include additional requirements for the contents of the periodic reports. For 40 CFR part 63, subpart HHH, the periodic reports are required to include periodic test results and information regarding any carbon replacement events that occurred during the reporting period. Additionally, periodic reports are required to 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 periodic report is also required to include a description of actions taken by an owner or operator during a malfunction of an affected source to minimize emissions, including actions taken to correct a malfunction.

C. What is the effective date of this final rule and compliance dates for the standards?

The effective date of this rule is October 15, 2012.

The compliance date for new affected sources (those that commenced construction or reconstruction on or after August 23, 2011) is immediately upon initial startup or the effective date of the standards, October 15, 2012, whichever is later.

The compliance date for existing small glycol dehydration units that are subject to MACT for the first time (*i.e.,* those that commenced construction before August 23, 2011) is October 15, 2015.

An affected source at a production field facility that constructed before August 23, 2011, that was previously determined to be an area source but becomes a major source on October 15, 2012 due to the amendment to the associated equipment definition in 40 CFR part 63, subpart HH, has until October 15, 2015 to comply with the relevant emission standards.

The compliance date for valves at existing natural gas processing plants, constructed before August 23, 2011, due to the amendment to the leak definition in 40 CFR part 63, subpart HH, is 1 year after the effective date of the standards October 15, 2013.

VII. Summary of the Significant Changes to the NESHAP Since Proposal

The previous section described the requirements that the EPA is finalizing in this rule. This section discusses in greater detail the key changes the EPA is making from the proposal. These changes result from the EPA's review of the additional data and information provided to us and our consideration of the substantive comments submitted on the proposal.

We have retained the same approach and methodology to establishing the standards as described at proposal. We have, however, made some changes in response to comments, which are described further below. One change resulted in revisions to the MACT emission limits for small glycol dehydration units. In addition, based on the comments received, we are not finalizing the MACT standard for the subcategory of storage vessels without the PFE, which was a subcategory that was left unregulated in the 1999 40 CFR part 63, subpart HH rule. Specifically, based on our review of the comments, we believe that we need additional data and information to set an emission standard for storage vessels without the PFE, and we intend to collect the additional data and propose MACT emission standards under section 112(d)(2) and (3) of the CAA for such storage vessels. Finally, we are retaining the 0.9 Mg/yr compliance option for large dehydration units.

A. What are the significant changes since proposal for the Oil and Natural Gas Production (subpart HH) source category?

1. Changes Made to Amendments Proposed Under the Authority of CAA Sections 112(d)(2) and (3)

Under the authority of sections 112(d)(2) and (3) of the CAA, we proposed amendments to 40 CFR part 63, subpart HH by adding requirements for previously unregulated units; specifically, we proposed standards for small glycol dehydration units and storage vessels without the PFE.

In the final amendments for 40 CFR part 63, subpart HH, we have revised the proposed MACT standards for small glycol dehydration units in response to comments that we did not take into account variability in the development of the MACT floor. In our proposal, the MACT standards for existing affected sources was a unit-specific BTEX limit of 1.10×10^{-4} g BTEX/scm-ppmv and for new affected sources was a BTEX limit of 4.66×10^{-6} g BTEX/scm-ppmv. In this final rule, we accounted for variability by using an upper prediction limit to develop a revised BTEX emission limit for existing small glycol dehydration units of 3.28×10^{-4} grams BTEX/standard cubic meters (scm)-parts per million by volume (ppmv) and for new small glycol dehydration units the revised BTEX limit is 4.66×10^{-6} grams BTEX/scm-ppmv. The process for developing these emissions limitations is documented in the Response to Comments document and a technical memorandum, both of which are in the docket.

Finally, as noted above, in response to comments, we are not finalizing MACT standards for storage vessels without the PFE in this rule. We received numerous comments expressing concerns with how we established the proposed standards for this subcategory. In response to such comments, we have re-evaluated the proposed MACT standards and concluded that we need (and intend to gather) additional data on these sources in order to analyze and establish MACT emission standards for this subcategory of storage vessels under section 112(d)(2) and (3) of the CAA. See the Response to Comments document for additional discussion.

2. Changes Made to Amendments Proposed Under the Authority of CAA Section 112(f)(2)

We proposed to eliminate the 0.9 Mg/yr benzene compliance option for large glycol dehydration units because, in the proposed rule, we estimated that the emissions allowed as the result of this compliance option resulted in estimated cancer risks up to 400-in-1-million. We received multiple comments concerning our proposed risk estimate. After reviewing these comments, we discovered that we had significantly overestimated the allowable emissions associated with this compliance option. First, for several sources, including the source that we predicted had the 400-in-1 million MIR, we used an incorrect factor (or multiplier) to scale up actual emissions associated with sources that could utilize the compliance option level of 0.9 Mg/yr to allowables. We used an incorrect factor due to an inadvertent transcription error in our calculations. Second, we learned that the risk assessment supporting the proposed rule erroneously included several area sources, which are not subject to 40 CFR part 63, subpart HH and thus should not have been included in the CAA section 112(f) risk assessment. After revising the risk assessment to remove area sources, and considering the MACT standard promulgated today for small glycol dehydrators pursuant to CAA sections 112(d)(2) and (3), the MIR for the Oil and Natural Gas Production source category based on actual and allowable emissions is 10-in-1 million, compared to the 400-in-1 million[3] based on

[3] At proposal, we used an incorrect factor (or multiplier) in calculating allowable emissions for

Continued

allowable emissions and 40-in-1 million based on actual emissions that were estimated in the proposed rule.

As the result of our revised risk analysis, we have determined that approximately 120,000 people are estimated to have cancer risks at or above 1-in-1 million, compared to 160,000 people estimated in the proposed rule. Total estimated cancer incidence from the source category is 0.02 excess cancer cases per year, or one case in every 50 years. This estimate is unchanged from the proposed rule because the incidence from a small number of sources typically does not affect total incidence reported to one significant figure. The estimate from the proposed rule of maximum chronic non-cancer TOSHI value (0.1) is unchanged, driven by naphthalene emissions from fugitive sources. The maximum acute non-cancer hazard quotient value (9, based on the California EPA reference exposure level (REL) for benzene) is also unchanged from the proposed rule. Although driven by the same pollutant that drives the MIR, benzene, the maximum acute hazard quotient value did not change from the proposed rule because the source driving the acute value was not identified as an area source and, thus, remained in the revised analysis. It is common for the maximum acute hazard quotient and cancer MIR not to coincide because the acute value is strongly dependent on short-term meteorology and the distance to the facility property boundary, whereas the MIR is dependent on long-term meteorology and the distance to census block receptors. There are 13 cases in the source category (out of approximately 1,000 facilities) where the REL is exceeded by more than a factor of 2.

Based on the conservative nature of the acute exposure scenario used in the screening assessment for this source category, the EPA has judged that, considering all associated uncertainties, the potential for effects from acute exposures is low. Screening estimates of acute exposures were evaluated for each 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 present at this location at a time when both the peak emission rate and worst-case dispersion conditions occur. 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. The acute modeling scenario is worst-case because of the confluence of peak emission rates and worst-case dispersion conditions. Also, the generally sparse populations near the facilities with the highest estimated 1-hour exposures make it less likely that a person would be near the plant to be exposed.

We also conducted a facility-wide risk assessment. The maximum facility-wide risk estimate of 100-in-1 million is unchanged from the proposed rule. Also unchanged from proposal is the fact that the facility-wide risk is driven by emissions from reciprocating internal combustion engines (RICE) and these engines are not part of the Oil and Natural Gas Production source category. In fact, oil and natural gas production operations contribute only about one percent or less to the total facility-wide risks. In the last few years, the Agency has revised the MACT standards for certain RICE. See 75 FR 9648 and 51570. Although it is difficult to discern from the available data which types of RICE are driving the facility-wide risk, it is important to note that the 2005 National Emissions Inventory (NEI) data on which we modeled risk did not take into account the recent MACT revisions to the RICE rule. Finally, our assessment that the potential for significant human health risks due to multipathway exposures or adverse environmental effects is low has not changed since proposal (see 76 FR 52774).

Consistent with the approach established in the Benzene NESHAP, the EPA weighed all health risk measures and information, including the maximum individual cancer risk, the cancer incidence, the number of people exposed to a risk greater than 1-in-1-million, the distribution of risks in the exposed population, and the uncertainty of our risk calculations in determining whether the risk posed by emissions from Oil and Natural Gas Production is acceptable. In this case, because the MIR is well below 100-in-1-million, and because a number of other factors indicate relatively low risk concern, including low cancer incidence, low potential for adverse environmental effects or human health multi-pathway, and unlikely chronic and acute noncancer health impacts, we conclude that the level of risk associated with the Oil and Natural Gas Production source category MACT standards (including the small glycol dehydrator MACT standard issued here) is acceptable.[4]

In making our proposed ample margin of safety determination under CAA section 112(f)(2), we subsequently evaluated the risk reductions and costs associated with various emissions control options to determine whether we should impose additional standards to reduce risks further. As stated above, we made certain revisions to the risk assessment in response to comments and the resulting MIR for 40 CFR part 63, subpart HH is 10-in-1 million. We have not identified any emission control options that would reduce emissions and risk associated with subpart HH sources for glycol dehydration units and storage vessels. Our proposed amendment to remove the 0.9 Mg/yr compliance option does not affect the risk driver, which is fugitive emissions. As a result, we are retaining the 0.9 Mg/yr compliance option in the final rule. We have determined that the risks associated with the level of emissions allowed by the MACT standards are driven by fugitive emissions (*i.e.,* leaks).

Since a LDAR program is the typical method for reducing emissions from fugitive sources, we considered requiring a LDAR program to reduce risk for this source category. The NEI dataset for this source category contains approximately 2,500 emission points that we characterized as fugitive. These emission points are located at 639 facilities. The fugitive emissions associated with those 639 facilities are 747 tons of HAP.

In evaluating the effectiveness of a LDAR program at these facilities we looked at two different LDAR programs—one is a program equivalent to 40 CFR part 60, subpart VV, and the second is a more stringent program equivalent to 40 CFR part 60, subpart VVa.[5] A LDAR program equivalent to subpart VV can achieve emission reductions of approximately 39 percent with capital and annual costs of

the source that, at proposal, had an estimated MIR of 400-in-1 million. Since proposal, we have learned that this source is an area source and thus is not subject to the Subpart HH MACT standards. As such, we removed this source from our section 112(f) risk analysis. In any event, we have determined that even if this area source were to have actual emissions at the 0.9 Mg/yr level, its risk would be 3-in-1 million.

[4] We reach the same conclusion even if we do not consider the new MACT for small glycol dehydrators in our acceptability determination. Indeed, focusing solely on the standards in the existing MACT, the level of risk associated with such standards would remain 10-in-1 million, and thus our acceptability determination does not change. There is one facility that is a small glycol dehydrator that has an MIR of 10-in-1 million. After imposition of the MACT for small glycol dehydrators, however, this unit would have an MIR of 7-in-1 million. Also, see memorandum titled *Supplemental Facility Information Obtained from Various State/Local Agencies and Additional Analysis,* March 20, 2012.

[5] See memorandum titled *Equipment Leak Emission Reduction and Cost Analysis for Well Pads, Gathering and Boosting Stations, and Transmission and Storage Facilities Using Emission and Cost Data from the Uniform Standards,* April 17, 2012.

$237,700 and $79,419 per facility, respectively. Therefore, such a program for the 639 facilities would be expected to reduce emissions by 249 tons of HAP with total capital and annual costs of $152 million and $50.7 million, respectively. The cost effectiveness would be approximately $204,000 per ton of HAP.

A LDAR program equivalent to 40 CFR part 60, subpart VVa can achieve emission reductions of approximately 43 percent overall with capital and annual costs of $241,000 and $82,900 per facility, respectively. Therefore, an LDAR program for the 639 facilities would be expected to reduce emissions by 275 tons of HAP, with total capital and annual costs of $154 million and $53 million, respectively. The cost effectiveness would be approximately $193,000 per ton of HAP reduced. These additional control requirements would reduce the MIR for the source category from 10-in-1 million to approximately 7-in-1 million.

As explained in the proposal, in accordance with the approach established in the Benzene NESHAP, we weigh 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 and deciding whether standards are necessary to reduce risks further. Considering all of this information, we conclude that the costs of the options analyzed are not reasonable considering the emissions reductions and risk reductions potentially achievable with the control measures evaluated. Thus, we conclude that the MACT standards in 40 CFR part 63, subpart HH (coupled with the new MACT standard for small glycol dehydrators) provide an ample margin of safety to protect public health and prevent adverse environmental effects. Accordingly, we are re-adopting those standards to satisfy the requirements of CAA section 112(f).

3. Changes Made to Standards Proposed Under the Authority of CAA Section 112(d)(6)

As discussed in detail in the preamble for the proposed rule (76 FR 52784), we conducted a technology review for glycol dehydration units, storage vessels and equipment leaks under the authority of CAA section 112(d)(6). We assessed developments in practices, processes and control technologies sources for those regulated under the initial NESHAP and determined that it was cost-effective to lower the leak definition for valves at natural gas processing plants. We did not identify developments in practices, processes and control technologies for glycol dehydration units and storage vessels. As a result of this assessment, we proposed revisions to 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. No significant changes since proposal were made to the equipment leak standards proposed under the authority of section 112(d)(6) of the CAA.[6]

4. Other Changes to the Proposed Rule

We are revising the emission reduction demonstrated using the manufacturers performance test from 98.0 percent to 95.0 percent. Specifically, if an owner or operator chooses to install a combustion control device that is tested under, and passes, the prescribed manufacturers performance test the final rule states that the control device has demonstrated a destruction efficiency of 95.0 percent. This change is a result of comments and data provided on the actual performance of these devices in the field.

In the proposed rule, we proposed that the standards apply at all times and removed provisions that provided an exemption from the emission standards during SSM. In response to comments that the monitoring and reporting provisions related to excursions occurring during SSM events that remain in the subpart suggest exemption and therefore should be removed, we are removing these provisions in the final rule.

Refer to the Reponses to Comments document, available in the docket, for detailed discussion regarding these changes.

B. What are the significant changes since proposal for the Natural Gas Transmission and Storage (subpart HHH) source category?

1. Changes Made to Amendments Proposed Under the Authority of CAA Sections 112(d)(2) and (3)

Under the authority of sections 112(d)(2) and (3) of the CAA, we proposed amendments to 40 CFR part 63, subpart HHH by adding requirements for previously unregulated units; specifically, we proposed standards for small glycol dehydration units.

In the final amendments for 40 CFR part 63, subpart HHH, we have revised the proposed BTEX limits for small glycol dehydration units in response to comments that we did not take into account variability in the development of the MACT floor. We had proposed a unit-specific BTEX emission limit of 6.42×10^{-5} grams BTEX/scm-ppmv for existing sources and a BTEX limit of 1.10×10^{-5} g BTEX/scm-ppmv for new sources. In the final rule, we accounted for variability by using an upper prediction limit to develop a revised emission limit for existing affected sources of 3.10×10^{-4} g BTEX/scm-ppmv and for new affected sources is a BTEX limit of 5.44×10^{-5} grams BTEX/scm-ppmv. The process for developing these emissions limitations is documented in the response to comments document and a technical memorandum both of which can be found in the docket.

2. Changes to Amendments Proposed Under the Authority of CAA Section 112(f)(2)

We proposed to eliminate the 0.9 Mg/yr benzene compliance option for large glycol dehydration unit process vents because, in the proposed rule, we estimated that the emissions allowed as the result of this compliance option resulted in estimated cancer risks up to 90-in-1-million. In response to comments, we learned that the risk assessment supporting the proposed rule erroneously included some sources that have permanently shut down, and several area sources, which are not subject to 40 CFR part 63, subpart HHH and, thus, should not have been included in the CAA section 112(f) risk assessment. After revising the risk assessment to remove these sources and considering the MACT standards promulgated here pursuant to CAA section 112(d)(2) and (3), the MIR for the Natural Gas Transmission and Storage source category based on actual and allowable emissions is 20-in-1 million, compared to the 90-in-1 million based on allowable emissions and 20-in-1 million based on actual emissions estimated in the proposed rule.

As the result of our revised risk analysis, we have determined that approximately 1,100 people are estimated to have cancer risks at or above 1-in-1 million, compared to 2,500 people estimated in the proposed rule. Total estimated cancer incidence from the source category is 0.001 excess cancer cases per year, or one case in every 1,000 years. This estimate is unchanged from the proposed rule

[6] Memorandum from Brown, Heather, EC/R Inc., to Moore, Bruce, U.S. EPA, titled *Technology Review for the Final Amendments to Standards for the Oil and Natural Gas Production and Natural Gas Transmission and Storage Source Categories.*

because the incidence from a small number of sources typically does not affect total incidence reported to one significant figure. The estimate from the proposed rule of maximum chronic non-cancer TOSHI value (0.2) is unchanged, driven by benzene emissions from fugitive sources. The maximum acute non-cancer hazard quotient value (4, based on the benzene REL) changed from the proposed rule; the value in the proposed rule was 5, but was associated with an area source that was removed from the risk assessment. There are two cases in the source category (out of approximately 300 facilities) where the REL is exceeded by more than a factor of 2.

Based on the conservative nature of the acute exposure scenario used in the screening assessment for this source category, the EPA has judged that, considering all associated uncertainties, the potential for effects from acute exposures is low. Screening estimates of acute exposures were evaluated for each 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 present at this location at a time when both the peak emission rate and worst-case dispersion conditions occur. 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. The acute modeling scenario is worst-case because of the confluence of peak emission rates and worst-case dispersion conditions. Also, the generally sparse populations near the facilities with the highest estimated 1-hour exposures make it less likely that a person would be near the plant to be exposed.

We also conducted a facility-wide risk assessment. The maximum facility-wide risk estimate of 200-in-1 million is unchanged from the proposed rule. Also unchanged from proposal is the fact that the facility-wide risk is driven by emissions from reciprocating internal combustion engines (RICE) and these engines are not part of the Natural Gas Transmission and Storage source category. In fact, natural gas transmission and storage operations contribute only about one percent or less to the total facility-wide risks. In the last few years, the Agency has revised the MACT standards for certain RICE. See 75 FR 9648 and 51570. Although it is difficult to discern from the available data which types of RICE are driving the facility-wide risk, it is important to note that the 2005 NEI data on which we modeled risk did not take into account the recent MACT revisions to the RICE rule. Finally, our assessment that the potential for significant human health risks due to multipathway exposures or adverse environmental effects is low has not changed since proposal (see 76 FR 52774).

Consistent with the approach established in the Benzene NESHAP, the EPA weighed all health risk measures and information, including the maximum individual cancer risk, the cancer incidence, the number of people exposed to a risk greater than 1-in-1-million, the distribution of risks in the exposed population and the uncertainty of our risk calculations in determining whether the risk posed by emissions from natural gas transmission and storage is acceptable. In this case, because the MIR is well below 100-in-1-million, and because a number of other factors indicate relatively low risk concern, including low cancer incidence, low potential for adverse environmental effects or human health multi-pathway effects, and unlikely chronic and acute noncancer health impacts, we conclude that the level of risk associated with the Natural Gas Transmission and Storage source category MACT standards (including those MACT standards issued here) is acceptable.[7]

In making our proposed ample margin of safety determination under CAA section 112(f)(2), we subsequently evaluated the risk reductions and costs associated with various emissions control options to determine whether we should impose additional standards to reduce risks further. As stated above, we made certain revisions to the risk assessment in response to comments and the resulting MIR for 40 CFR part 63, subpart HHH is 20-in-1 million. We have not identified any emission control options that would reduce emissions and risk associated with subpart HHH sources for glycol dehydration units. Our proposed amendment to remove the 0.9 Mg/yr compliance option does not affect the risk driver, which is fugitive emissions. As a result, we are retaining the 0.9 Mg/yr compliance option in the final rule.

We have determined that the risks associated with the level of emissions allowed by the MACT standards are driven by fugitive emissions (*i.e.,* leaks). Since a LDAR program is the typical method for reducing emissions from fugitive sources, we evaluated the costs and emissions reductions associated with requiring such a program to reduce risk for this source category. The NEI dataset for the natural gas transmission and storage source category contains approximately 314 emission points that we characterized as being fugitive in nature. These emission points are located at 212 facilities. The fugitive emissions associated with those 212 facilities are 187 tons of HAP.

In evaluating the effectiveness of a LDAR program at these facilities we looked at two different LDAR programs—one is a program equivalent to 40 CFR part 60, subpart VV, and the second is a more stringent program equivalent to 40 CFR part 60, subpart VVa.[8] A LDAR program equivalent to subpart VV can achieve emission reductions of approximately 51 percent with capital and annual costs of $361,800 and $142,600 per facility, respectively. Therefore, such a program for 212 facilities would be expected to reduce emissions by 95.4 tons of HAP and have total capital and annual costs of $76.7 million and $30.2 million, respectively. The cost effectiveness would be approximately $317,000 per ton of HAP.

A LDAR program equivalent to 40 CFR part 60, subpart VVa can achieve emission reductions of approximately 78 percent overall with capital and annual costs of $369,500 and $154,300 per facility, respectively. Therefore, a LDAR program for 212 facilities would be expected to reduce emissions by 146 tons of HAP with total capital and annual costs of $78.3 million and $32.7 million, respectively. The cost effectiveness would be approximately $224,000 per ton of HAP. These additional control requirements would reduce the MIR from the source category to approximately 3-in-1 million for the subpart VVa level of control and 7-in-1-million for the 40 CFR part 60, subpart VV level of control.

As explained in the proposal, in accordance with the approach established in the Benzene NESHAP, we weigh 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 and

[7] We reach the same conclusion even if we do not consider the new MACT for small glycol dehydrators in our acceptability determination. Indeed, focusing solely on the standards in the existing MACT, the level of risk associated with such standards would remain 20-in-1 million, and thus our acceptability determination would not change. The glycol dehydrators analyzed all had risks well below 20-in-1 million.

[8] See memorandum titled *Equipment Leak Emission Reduction and Cost Analysis for Well Pads, Gathering and Boosting Stations, and Transmission and Storage Facilities Using Emission and Cost Data from the Uniform Standards,* dated April 17, 2012.

deciding whether standards are necessary to reduce risks further. Considering all of this information, we conclude that the costs of the options analyzed are not reasonable considering the emissions reductions and risk reductions potentially achievable with the control measures. Thus, we conclude that the MACT standards in 40 CFR part 63, subpart HHH (coupled with the new MACT standard for small glycol dehydrators) provide an ample margin of safety to protect public health and prevent adverse environmental effects. Accordingly, we are re-adopting those standards to satisfy the requirements of CAA section 112(f)(2).

3. Changes Made to Amendments Proposed Under the Authority of CAA Section 112(d)(6)

As discussed in detail in the preamble for the proposed rule (76 FR 52784), we conducted a technology review for glycol dehydration units under the authority of CAA section 112(d)(6). We did not identify developments in practices, processes and control technologies for large glycol dehydration units. As a result of this assessment, we did not propose amendments to 40 CFR part 63, subpart HHH. We have not made any changes since proposal under the authority of CAA section 112(d)(6).[9] Further discussion on our technology review analysis can be found in section X.C of this preamble, and in the Response to Comments document.

4. Other Changes to the Proposed Rule

We are revising the emission reduction efficiency demonstration using the manufacturer's performance test from 98.0 percent to 95.0 percent. Specifically, if an owner or operator chooses to install a combustion control device that is tested under, and passes, the prescribed manufacturer's performance test, the final rule states that the control device has demonstrated a reduction efficiency of 95.0 percent. This change is a result of comments and data provided on the actual performance of these devices in the field.

In the proposed rule, we proposed that the standards apply at all times and removed provisions that provided an exemption from the emission standards during SSM. In response to comments that the monitoring and reporting provisions related to excursions occurring during SSM events that remain in the subpart suggest exemption and therefore should be removed, we are removing these provisions in the final rule.

[9] See footnote 6.

VIII. Compliance Related Issues Common to the NSPS and NESHAP

A. How do the rules address startup, shutdown and 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 are 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.

As proposed in the NESHAP, we have eliminated the SSM exemption in this rule. Consistent with *Sierra Club* v. *EPA,* the EPA has established standards in both rules that apply at all times. We have also revised Table 3 (the NESHAP General Provisions table) in several respects. For example, we have eliminated the incorporation of the NESHAP General Provisions' requirement that the source develop an SSM plan. We have also eliminated or revised certain NESHAP recordkeeping and reporting that related to the SSM exemption. The EPA has attempted to ensure that we have not included in the regulatory language, for the NSPS and NESHAP, any provisions that are inappropriate, unnecessary or redundant in the absence of the SSM exemption.

In establishing the standards in both rules, the EPA has taken into account startup and shutdown periods and, for the reasons explained in section IX of this preamble for the NSPS and in section X of this preamble for the NESHAP, did not establish different standards for those periods. Based on the information available in the record about actual operations during startups and shutdowns, 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) and as ''any sudden, infrequent, and not reasonably preventable failure of air pollution control equipment, process equipment, or a process to operate in a normal or usual manner * * *'' (40 CFR 60.2). The EPA has determined that CAA sections 111 and 112 do not require that emissions that occur during periods of malfunction be factored into development of CAA section 111 or 112 standards.

CAA section 111 standards—See section III of this preamble for a detailed discussion on how the EPA sets or revises CAA section 111 NSPS to reflect the degree of emission limitation achievable through the application of the BSER.

CAA section 112 standards—Under CAA section 112, emissions standards for new sources must be no less stringent than the level ''achieved'' by the best controlled similar source and for existing sources, generally must be no less stringent than the average emission limitation ''achieved'' by the best performing 12 percent of sources in the category. Nothing in CAA section 112 directs the agency to consider malfunctions in determining the level ''achieved'' by the best performing or best controlled sources when setting emission standards. Moreover, while the EPA accounts for variability in setting emissions standards consistent with the CAA section 112 case law, nothing in that case law requires the agency to consider malfunctions as part of that analysis. CAA section 112 uses the concept of ''best controlled'' and ''best performing'' unit in defining the level of stringency that CAA section 112 performance standards must meet. Applying the concept of ''best controlled'' or ''best performing'' to a unit that is malfunctioning presents significant difficulties, as malfunctions are sudden and unexpected events.

Further, accounting for malfunctions in setting NESHAP or NSPS standards would be difficult, if not impossible, given the myriad different types of malfunctions that can occur across all sources in the category and given the difficulties associated with predicting or accounting for the frequency, degree and duration of various malfunctions that might occur. As such, the performance of units that are malfunctioning is not ''reasonably'' foreseeable. See, *e.g., Sierra Club* v.

EPA, 167 F.3d 658, 662 (D.C. Cir. 1999) (''[T]he EPA typically has wide latitude in determining the extent of data-gathering necessary to solve a problem. We generally defer to an agency's decision to proceed on the basis of imperfect scientific information, rather than to 'invest the resources to conduct the perfect study.' ''); see, also, *Weyerhaeuser Co.* 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.''). In addition, in the NESAHP context, the goal of a best controlled or best performing source is to operate in such a way as to avoid malfunctions of the source and accounting for malfunctions could lead to standards that are significantly less stringent than levels that are achieved by a well-performing non-malfunctioning source. Similarly, in the NSPS context, accounting for malfunctions when setting standards of performance under CAA section 111, 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 could lead to standards that are significantly less stringent than levels that are achieved by a well-performing non-malfunctioning source. The EPA's approach to malfunctions is consistent with CAA section 112 and CAA section 111 and is a reasonable interpretation of the statute.

Finally, the EPA recognizes that even equipment that is properly designed and maintained can sometimes fail and that such failure can sometimes cause a violation 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, adding to the final NSPS and NESHAP an affirmative defense to civil penalties for violations of emission standards that are caused by malfunctions. See 40 CFR 63.761 for sources subject to the Oil and Natural Gas Production MACT standards; 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 have added 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 or Natural Gas Transmission and Storage 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 NSPS must prove by a preponderance of the evidence that it has met all of the elements set forth in 40 CFR 60.41Da (NSPS). See 40 CFR 22.24. The criteria ensure that the affirmative defense is available only where the event that causes a violation of the emission standard meets the narrow definition of malfunction in 40 CFR 60.2 (NSPS) and 40 CFR 63.2 (NESHAP), respectively, (sudden, infrequent, not reasonably preventable and not caused by poor maintenance and/or careless operation). For example, the final NSPS and NESHAP provide that to successfully assert the affirmative defense, the source must prove by a preponderance of the evidence that the violation ''[w]as caused by a sudden, infrequent, and unavoidable failure of air pollution control and 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 MACT standards, 40 CFR 63.1272 for sources subject to the Natural Gas Transmission and Storage MACT standards, and 40 CFR 60.5415(h) for the Standards of Performance for Crude Oil and Natural Gas Production, Transmission and Distribution, and to prevent future malfunctions. For example, the final NSPS and NESHAP provide that the source must prove by a preponderance of the evidence that ''[r]epairs were made as expeditiously as possible when a violation occurred * * *'' and that ''[a]ll possible steps were taken to minimize the impact of the violation 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 part 22.27).

The EPA proposed and is now finalizing an affirmative defense in the final NSPS and NESHAP in an attempt to balance a tension, inherent in many types of air regulations, to ensure adequate compliance, while simultaneously recognizing that, despite the most diligent of efforts, emission standards may be violated under circumstances beyond the control of the source. The EPA must establish emission standards that ''limit the quantity, rate, or concentration of emissions of air pollutants on a continuous basis.'' 42 U.S.C. 7602(k) (defining ''emission limitation and emission standard''). See, generally, *Sierra Club* v. *EPA,* 551 F.3d 1019, 1021 (D.C. Cir. 2008). Thus, the EPA is required to ensure that CAA section 112 emissions standards are continuous. The affirmative defense for malfunction events meets this requirement by ensuring that, even where there is a malfunction, the emission standard is still enforceable through injunctive relief. While ''continuous'' standards, on the one hand, are required, there is also case law indicating that, in many situations, it is appropriate for the EPA to account for the practical realities of technology. For example, in *Essex Chemical* v. *Ruckelshaus,* 486 F.2d 427, 433 (D.C. Cir. 1973), the District of Columbia Circuit acknowledged that, in setting standards under CAA section 111, ''variant provisions'' such as provisions allowing for upsets during startup, shutdown and equipment malfunction ''appear necessary to preserve the reasonableness of the standards as a whole and that the record does not support the 'never to be exceeded' standard currently in force.'' See, also, *Portland Cement Ass'n* v. *Ruckelshaus,* 486 F.2d 375 (D.C. Cir. 1973). Though intervening case law such as *Sierra Club* v. *EPA* and the CAA 1977 amendments call into question the relevance of these cases today, they support the EPA's view that a system that incorporates some level of flexibility is reasonable. The affirmative defense simply provides for a defense to civil penalties for violations that are proven to be beyond the control of the source. By incorporating an affirmative defense, the EPA has formalized its approach to upset events. In a Clean

Water Act setting, the Ninth Circuit required this type of formalized approach when regulating ''upsets beyond the control of the permit holder.'' *Marathon Oil Co.* v. *EPA,* 564 F.2d 1253, 1272–73 (9th Cir. 1977); see, also, *Mont. Sulphur & Chem. Co.* v. *EPA,* 2012 U.S. App. LEXIS 1056 (Jan 19, 2012) (rejecting industry argument that reliance on the affirmative defense was not adequate). *But see Weyerhaeuser Co.* v. *Costle,* 590 F.2d at 1057–58 (holding that an informal approach is adequate). The affirmative defense provisions give the EPA the flexibility to both ensure that its emission standards are ''continuous,'' as required by 42 U.S.C. 7602(k), and account for unplanned upsets and, thus, support the reasonableness of the standard as a whole.

Refer to preamble section IX for the NSPS, preamble section X for the NESHAP and the Response to Comments document for both the NSPS and the NESHAP, available in the docket, for detailed discussions regarding these changes.

B. How do the NSPS and NESHAP provide for compliance assurance?

The final rule includes various notification, recordkeeping and reporting requirements that we believe provide a robust compliance assurance program, while reducing burden and streamlining requirements. The EPA also considered a variety of innovative compliance approaches that could maximize compliance and transparency, while minimizing burden on the regulated community and regulators. More detailed information on public comments received and the EPA's responses are included in sections IX and X of the preamble or in the response to comments document.

1. Notification, Recordkeeping and Reporting Requirements

For well completions, owners or operators are required to submit an email notification no later than 2 days prior to each anticipated well completion. The notification must identify the owner or operator and provide the American Petroleum Institute (API) well number, geographical coordinates of the affected wells and the estimated date of commencement of the flowback period immediately following hydrofracturing. The owner or operator must keep records identifying each well completion operation and documenting the portions of the flowback period when the gas was recovered, combusted or vented.

Annually, owners or operators of all affected facilities under the NSPS, including gas wells, compressors, pneumatic controllers, storage vessels and gas processing plants, must report any deviation from the NSPS requirements during the reporting period. Each annual report must include a signed certification by a senior company official that attests to the truth, accuracy and completeness of the report. For affected gas wells, the report must also identify each well completion conducted during the reporting period and submit detailed completion records for each well as part of the annual report.

In the final rule, the recordkeeping and reporting requirements for well completions also provide a streamlining option that owners and operators may choose in lieu of the standard annual reporting requirements. The alternative, streamlined annual report for gas well affected facilities requires submission of a list, with identifying information of all affected gas wells completed, electronic or hard copy photographs documenting REC in progress for each well for which REC was required and the self-certification required in the standard annual report. The operator retains a digital image of each REC in progress. The image must include a digital date stamp and geographic coordinates stamp to help link the photograph with the specific well completion operation. The owner or operator is not required to submit detailed completion records as part of the annual report.

For centrifugal compressors with wet seal systems, the annual report must include identification of each affected facility constructed, modified or reconstructed during the reporting period. The annual report for reciprocating compressors must identify each reciprocating compressor constructed, modified or reconstructed during the reporting period. The report also must include, for each affected compressor, the elapsed time of operation since the most recent rod packing change as of the end of the reporting period. For affected pneumatic controllers and storage vessels, the annual report must identify each affected facility constructed, modified or reconstructed during the reporting period.

Owners or operators who conduct certain performance tests on control devices must report results of those tests using the Electronic Reporting Tool (ERT). Further discussion of reporting of emissions tests is presented in section VIII.D of this preamble.

NESHAP

The final amendments to 40 CFR part 63, subparts HH and 40 CFR part 63, subpart HHH revise certain recordkeeping requirements. Specifically, facilities using carbon adsorbers as a control device are now required to keep records of their carbon replacement schedule and records of each carbon replacement. We are requiring that owners and operators that use a manufacturer's tested control device keep records of visible emissions readings and flowrate calculations and records of periods when the pilot flame is absent. The final amendments require records of the date of each semi-annual maintenance inspection be maintained. Finally, 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 conjunction with the final MACT standards for small glycol dehydration units, owners and operators of such units are required to submit an initial notification within 1 year after becoming subject to 40 CFR part 63, subpart HH or by October 15, 2013, whichever is later.

Similarly, in conjunction with the final MACT standards for small glycol dehydration units in the final 40 CFR part 63, subpart HHH amendments, owners and operators of small glycol dehydration units are required to submit an initial notification within 1 year after becoming subject to subpart HHH or by October 15, 2013, whichever is later.

The final amendments to 40 CFR part 63, subpart HH and 40 CFR part 63, subpart HHH include new requirements for the contents of Notification of Compliance Status Reports. The owners and operators are required to include an electronic copy of the performance test results for the manufacturer's tested control device, if applicable; the predetermined carbon replacement schedule for carbon adsorbers, if applicable; and data related to the manufacturer's performance tests conducted for certain models of control devices, if compliance is being achieved using the manufacturer's performance tests.

The final amendments to the NESHAP also include additional requirements for the contents of periodic reports. Each semiannual report must include a signed certification by a senior company official that attests to the truth, accuracy and completeness of the report. For both 40 CFR part 63, subpart HH and 40 CFR part 63, subpart HHH, in the final amendments, periodic reports are required to include periodic test results and information regarding any carbon replacement events that occurred during the reporting period. Owners and operators are also required to include in the periodic reports information regarding any excursions that occur when the inlet gas flow rate deviates from that identified in the manufacturer's performance test, and any excursions caused when visible emissions exceed the maximum allowable duration.

Owners or operators who conduct certain performance tests on control devices must report results of those tests using the ERT. Further discussion of reporting of emissions tests is presented in section VIII.C below.

2. Innovative Compliance Approaches

At proposal, given the number and diversity of sources potentially affected by the NSPS and/or the NESHAP, we solicited comments on optional compliance tools that could reduce compliance burden and enhance transparency. Specifically, we asked for suggestions on: (1) Registration of wells and advance notification of planned completions; (2) use of third party verification; and (3) electronic reporting using existing mechanisms. We received comments on each of the topics above and have presented summaries of those comments and the EPA's responses in the Response to Comments document. The commenters were generally opposed to third party verification. However, one suggestion was a voluntary random verification program, similar to one used in the past for gasoline marketing, where operators who participated in this program potentially could receive lower priority for enforcement inspections by regulators. Other suggested innovative approaches include use of social media, including Facebook and Twitter, plus new technologies such as quick response codes, to provide timely public notification and access to compliance records for individual wells and other affected facilities. Other suggestions included use of a centralized database for industry and public access to compliance information. Further discussion of these approaches is provided in the response to comments. While we considered these suggestions, we did not adopt them in the final rule, for reasons explained further in the Responses to Comments document.

C. What are the requirements for submission of performance test data to the EPA?

The EPA must have performance test data to conduct effective reviews of CAA sections 111, 112 and 129 standards, as well as for many other purposes, including compliance determinations, emission factor development and annual emission rate determinations.

As stated in the proposal preamble, the EPA is taking a step to increase the ease and efficiency of data submittal and data accessibility. Specifically, the EPA is requiring owners and operators of oil and natural gas sector facilities to submit electronic copies of required performance test reports.

As mentioned in the proposal preamble, data entry will be conducted through an electronic emissions test report structure called the ERT. The ERT will generate an electronic report which will be submitted to the EPA's Central Data Exchange (CDX) through the Compliance and Emissions Data Reporting Interface (CEDRI). A description of the ERT can be found at *http://www.epa.gov/ttn/chief/ert/index.html* and CEDRI can be accessed through the CDX Web site (*www.epa.gov/cdx*).

The requirement to submit performance test data electronically to the EPA does not create any additional performance testing and would apply only to those performance tests conducted using test methods that are supported by the ERT. A list of the pollutants and test methods supported by the ERT is available at *http://www.epa.gov/ttn/chief/ert/index.html*.

The major advantages of electronic reporting are more fully explained in the proposal preamble.

An important benefit of using the ERT is that the performance test data will become available to the public through WebFIRE. Having such data publicly available enhances transparency and accountability.

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 will save industry; state, local and tribal agencies; and the EPA significant time, money and effort while improving the quality of emission inventories and, as a result, air quality regulations.

IX. Summary of Significant NSPS Comments and Responses

For purposes of this document, the text within the comment summaries was provided by the commenter(s) and represents their opinion(s), regardless of whether the summary specifically indicates that the statement is from a commenter(s) (*e.g.,* ''The commenter states'' or ''The commenters assert''). The comment summaries do not represent the EPA's opinion unless the response to the comment specifically agrees with all or a portion of the comment.

A. Major Comments Concerning Applicability

1. Activities That Constitute a Modification

Comment: Referring to the definition of ''modification'' in section 111(a)(4) of the CAA, one commenter asserts that a modification occurs only if two things happen: (1) There must be a ''physical change or change in the method of operation,'' and (2) the change must result in an emissions increase.

The commenter states that, in the context of the New Source Review program, the District of Columbia Circuit Court has opined that ''Congress's use of the word 'any' in defining a 'modification' means that all types of 'physical changes' are covered'' (*New York* v. *EPA,* 443 F.3d 880, 890 (D.C. Cir. 2006)) and that the District of Columbia Circuit Court has determined that ''the plain language of the CAA indicates that Congress intended to apply NSR to changes that increase actual emissions instead of potential or allowable emissions.'' *New York* v. *EPA,* 413 F.3d 3, 40 (DC Cir. 2005).

However, according to the commenter, the Supreme Court has concluded that the CAA section 111 definition of modification does not have to have the same meaning under the NSPS and New Source Review (NSR) programs (*Environmental Defense* v. *Duke Energy Corp.,* 127 S. Ct. 1423, 1434 (2007)), and, thus, the EPA has latitude within the context of CAA section 111 to implement different rules regarding modifications.

The commenter believes, in particular, that the EPA's regulatory definition of ''modification'' under the NSPS program provides several categories of activities that alone, are not to be considered modifications, including ''maintenance, repair, and replacement which the Administrator determines to be routine for a source category,'' and ''an increase in production rate that can be accomplished without a capital expenditure.'' 40 CFR 60.14(e). The commenter believes these provisions reflect the fact that Congress established the NSPS program for ''new'' sources. According to the commenter, without these exclusions, even the most minor activities would convert an existing source into a ''new source.'' The commenter states that the premise behind characterizing these activities as not being ''changes'' is that they all contemplate that the plant will continue to be operated in a manner consistent with its original design and, thus, is not a ''new'' facility.

We also received a number of comments objecting to consideration of recompletion activities[10] as modifications, claiming that it is a significant departure from the definition of ''modification'' under the General Provision at 40 CFR 60.14. Some commenters argue that well completion expenditures do not meet the regulatory definition of ''capital expenditure'' while others argue that they are maintenance activities excluded in 40 CFR 60.14 others note that we have not traditionally regulated temporary ''construction'' activities.[11]

Response: In this final rule, the EPA addresses modifications in the context of well completions and has deleted the proposed definition of ''modification,'' though the underlying rationale presented in the proposal remains, and we are providing alternative regulatory text. Pursuant to this final rule and as discussed below, well completions conducted on gas wells that are refractured on or after the effective date of this rule are considered modifications and subject to the NSPS, with the exception of such well completions that, immediately upon flowback, use emission control techniques otherwise required for new wells and satisfy other requirements for gas well facilities, including notification, recordkeeping and reporting requirements.

As discussed in the proposal, the EPA has chosen to depart from the definition of modification in 40 CFR 60.14 with respect to regulation of wells that primarily produce natural gas. As explained in the proposal and elsewhere in the preamble for this rule, the VOC emissions from the flowback following refracturing of gas wells are significant, the EPA has identified cost-effective controls to reduce VOC emissions during this operating phase, and these controls are required for only a relatively short time during the well's operating life. The EPA therefore concludes that it is appropriate for treatment of these activities to depart from the definition of modification in 40 CFR 60.14 to ensure that emissions from these activities are controlled.

We do not in this package question the broad appropriateness of the NSPS General Provisions at 40 CFR 60.14. However, as the General Provisions on modification in 40 CFR 60.14 themselves recognize, they may not be appropriate in all cases. Given the significant, although short-term, increase in emissions from flowback caused by refracturing activities when such activities are not controlled, and the cost-effective nature of the control on such emissions, we have concluded that covering these refracturing activities is appropriate even if it requires departing from the General Provisions' definition of modification.

Specifically, we are providing in the final rule at 40 CFR 60.5365:

(h) The following provisions apply to gas well facilities that are hydraulically refractured.

(1) A gas well facility that conducts a well completion operation following hydraulic refracturing is not an affected facility, provided that the requirements of § 60.5375 are met. For purposes of this provision, the dates specified in § 60.5375(a) do not apply, and such facilities, as of the effective date of this rule, must meet the requirements of § 60.5375(a)(1)–(4).

(2) A well completion operation following hydraulic refracturing at a gas well facility not conducted pursuant to § 60.5375 is a modification to the gas well affected facility.

(3) Refracturing of a gas well facility does not affect the modification status of other equipment, process units, storage vessels, compressors, or pneumatic controllers located at the well site.

(4) Sources initially constructed after August 23, 2011, are considered affected sources regardless of this provision.

As a result of this provision, a modification of a well, defined as ''an onshore well drilled principally for production of natural gas,'' occurs when a well is refractured on or after the effective date of this rule, except when the owner or operator of a well controls emissions during the completion operation by the use, immediately upon flowback, of emission control techniques otherwise required for new wells, as discussed more below.[12]

Consistency With the Definition of Modification

This provision is consistent with the statutory definition of modification contained in CAA 111(a)(4).[13] As discussed in the proposal, CAA section 111(a)(4) defines a modification based on two requirements: (1) A physical change and (2) an emissions increase. The consistency of our approach with these two elements is discussed below.

Physical Change

Uncontrolled completion following refracturing of gas wells fits well within the statutory definition of modification (the refracturing results in a physical change which causes flowback and an increase in emissions relative to the emissions level prior to the refracturing). Accordingly, the NSPS' treatment of modification applies to completions of hydraulically refractured gas wells.

One commenter contends that recompletion does not constitute physical change even if there is re-perforation because it is an expected part of well operation. However, both the CAA and our regulation define modification to mean ''physical change'' without providing any qualification to that term, thus indicating that the term ''physical change'' is very broad to include any physical change. The commenter's interpretation of the term ''physical change'' is without support.

Emissions Increase

As a result of these physical changes, a multi-day period of flowback of natural gas, hydrocarbon condensate, water and sand is necessary to clean up the formation and wellbore prior to production of gas for sale. This flowback period is characterized by release of substantial amounts of VOC-containing natural gas and hydrocarbon condensate that would not have occurred absent the refracturing operation, thus meeting the second part of the statutory test—an increase in the amount of emissions.

As discussed in the proposal, EPA's data indicate that uncontrolled well completions with hydraulic refracturing consistently result in VOC emissions that were not present prior to such activities. Data in comments received also confirm that these uncontrolled

[10] At proposal, EPA used the term ''recompletion'' to describe completions of previously fractured new gas wells that are refractured at some future date, and we specified that such actions are considered modifications. In addition, we used the term ''recompletion'' to describe completions of existing wells (*i.e.,* those wells that were constructed before August 23, 2011) that subsequently are fractured for the first time or that are refractured.

[11] We disagree with the commenter. Fracturing and refracturing are not maintenance activities. On the contrary, these are essential processes that allow production of gas from shale and other formations, either during the initial development of a well or in development of new horizons within a previously fractured well. We also disagree with the characterization that we are regulating ''construction activities.'' Rather we are regulating the emissions resulting from the physical change.

[12] While we have not done so often, in situations such as this, where there is a defined set of physical changes that inevitably lead to an emissions increase, regulatory certainty and clarity can be provided by, as EPA is doing, providing a categorical listing of activities that constitute modifications. See, *e.g.,* 40 CFR 60.751 (addressing landfills; definition of modification); 40 CFR 60.100a(c) (addressing refineries; stayed pending reconsideration).

[13] We need not address if *New York* v. *EPA,* 443 F.3d 880, 890 (D.C. Cir. 2006) compels the result here. As we explain, in the body of this preamble our approach is consistent with CAA section 111(a)(4), and we provide a reasonable rationale for adopting the approach we take here.

refracturing activities result in significant VOC emissions. Our data indicate very low VOC emissions from gas wells (2.6 tpy on average) at the wellhead during ongoing production prior to such activities. In light of the above, we reasonably conclude that such activities result in an increase in the amount of VOC emissions and, therefore, constitute a modification.

We reject the comments suggesting that we should adopt the prior fracturing activity as the baseline for determining if an emission increase has occurred.[14] We note that these comments appear in part to rely upon a misunderstanding of the EPA's longstanding practice that the relevant baseline for determining an emissions increase under the NSPS is not based on the potential emissions profile associated with a prior physical change or the original construction but rather the emissions immediately prior to the physical change. See 57 FR 32314, 32330 (July 21, 1992) (explaining that, under CAA section 111(a), an emission increase is based on current potential emissions rather than original design capacity). Accordingly, under historical regulations, the proposed regulatory language and the final rule that ''initial production volumes may have been higher than subsequent re-completions or refracturing operations because the formation has been depleted by production activities'' does not mean that there would not be an emissions increase. Ongoing emissions during day-to-day production are very small and are not a function of well productivity, since these emissions originate from leaking valves and other components that do not leak more or less as production increases or declines. However, flowback emissions following refracturing are orders of magnitude greater than the production phase emissions.

Moreover, adoption of a prior fracturing activity as the baseline for comparison here is inappropriate. The purpose of the refracturing activity is to increase production from its current level. As explained above, at least for the short term, VOC emissions from the affected facility increase as a direct result of the physical change.[15] That is, these emissions would not have (and could not have) occurred without the physical change. Accordingly, we conclude that reliance on the prior fracturing activity as a baseline is inappropriate.[16]

De Minimis Exception

We recognize that there are reasons to limit the scope of the modification definition so as to not include certain well-controlled refracturing activities performed by sources. We recognize that the approach that we are taking in this final rule differs from the approach that we have taken in the past, as it excludes certain emission increases associated with a physical change from constituting a modification based on the *de minimis* exception. This exception allows agency flexibility in interpreting a statute to prevent ''pointless expenditures of effort'' and has been previously recognized by the United States Court of Appeals for the District of Columbia Circuit as an appropriate tool when interpreting the CAA section 111(a)(4) definition of modification in the context of New Source Review. *Alabama Power Co.* v. *Costle,* 636 F.2d 323, 360 (D.C. Cir. 1979).

Since the inception of the NSPS program, certain emission controls could be used by a source to avoid having an activity constitute a modification provided that the controls prevented emissions from increasing. As the District of Columbia Circuit explained:

> Under provisions of the regulations that are not challenged in this litigation, the operator of an existing facility can make any alterations he wishes in the facility without becoming subject to the NSPS as long as the level of emissions from the altered facility does not increase. Thus the level of emissions before alterations take place, rather than the strict NSPS, effectively defines the standard that an altered facility must meet.

Asarco Inc. v. *EPA,* 578 F.2d 319, 328–29 (D.C. Cir. 1978); see, also, 75 FR 54970, 54996 (September 9, 2010) (''However, sources always have the option of adding sufficient NO_X control to avoid an hourly emissions increase and avoid thus triggering the modification provision.''). We have allowed such controls to permit the source to avoid being considered ''modified'' if the controls fully negate the emissions increase.

In this case, we are providing that where a source has in place, and, immediately upon flowback, applies emission controls equivalent to those required for a new source (as specified in 40 CFR 60.5375(a)(1) through (4)), the physical change will not constitute a modification despite the small remaining emission increase. Specifically, well completions conducted by sources for refractured wells and with the use, immediately upon flowback, of emission controls equivalent to those required for new sources will not be considered a modification, due to the *de minimis* increase in emissions of such wells using these controls. Several unique factors justify finding that application of the *de minimis* doctrine is appropriate here.

First, to qualify for the exclusion from the definition of modification the source must be using controls equivalent to those required were it to trigger the NSPS. As a result, the imposition of the NSPS would not yield additional regulatory or environmental benefits. See *Environmental Defense Fund, Inc.* v. *EPA,* 82 F.3d 451, 466 (D.C. Cir. 1996). Second, as a result of imposition of controls emissions are very low in magnitude. This is both with respect to the size of the increase associated with the physical change and the total emissions from the unit after the physical change. Third, the emissions associated with the change, and peak emissions post change, are time-limited. A well completion is a discrete activity, occurring over a 3–10-day period on an occasional basis, which may be as infrequent as once every 10 years. This is different from the type of emitting activity typically regulated as a modification under NSPS, which would involve ongoing emissions indefinitely into the future. Further, a source qualifying for this exception must comply with the recordkeeping and reporting requirements that are required of new sources. Accordingly, the increase in emissions from the physical

[14] One commenter relies on a passage from a proposed, but never finalized, rule preamble to argue that under the NSPS emission increase test prechange emissions are based on the highest level achievable in the 5 years immediately preceding a physical change. The passage, however, is not addressing the NSPS test generally applicable to modifications, but, rather, is addressing a specific regulatory provision applicable to modifications at electric utility steam generating units (EUSGU). See 70 FR 61081, 61089 (October 20, 2005). Specifically, the preamble discussion is describing 40 CFR 60.14(h), which states that a change at an EUSGU will not be a modification if ''such change does not increase the maximum hourly emissions achievable at the unit during the five years prior to the change.'' See, also, 57 FR 32314, 32330 (July 21, 1992) (adopting 40 CFR 60.14(h) and contrasting the provision with the pre-existing test).

[15] Our data show that the magnitude of ongoing VOC emissions from a producing gas well is approximately 2.6 tpy or about 14 pounds per day, while the magnitude of VOC emissions is 23 tons over an average period of 7 days, or about 6,600 pounds per day, during a completion operation following refracturing. At this time, we do not have similar data on emissions from oil wells.

[16] One commenter claims that one cannot determine whether a given well completion activity qualifies as a modification based on the proposed definition because it is infeasible to measure the amount of flowback emission according to the EPA in proposing a work practice standard. However, nothing in CAA 111(a)(4) and 40 CFR 60.2 requires quantification of the amount of emission increase, only that there be an increase as a result of the physical change. In addition, the commenter's argument would appear to apply equally to any time we set a work practice.

change, and the total amount of additional emissions, will be very small.

We are providing the *de minimis* exception discussed above to provide states with flexibility in application of their permitting authority and resources. Commenters pointed out that a number of state permitting programs are triggered for sources that are subject to an NSPS as a result of a modification. The EPA recognizes that states are the most appropriate entities to determine whether and how sources should be permitted, and we have concern regarding potential impacts of this final rule on states' permitting resources. Accordingly, with this final rule, we intend that states retain the discretion to determine whether refracturing activities by sources employing control techniques that are required for new wells will require changes in that source's permit status.

Clarifying Changes

Although we are not finalizing the proposed definition of ''modification'' for the reasons discussed above, we believe it is important to address certain comments regarding the proposed definition in order to clarify the agency's intent as it relates to well completions. For example, we included ''natural gas'' in the proposed definition for ''modification'' in recognition that our proposed work practice requirements for well completions use natural gas as a surrogate for VOC. We consider natural gas to be an appropriate surrogate for VOC for well completion activities because our analyses of data on composition of natural gas at the wellhead indicated that emissions of natural gas during well completions contain various chemical species that are VOC. The inclusion of natural gas in the proposed definition for modification was not an indication that EPA was proposing natural gas as a pollutant to be regulated, as some commenters mistakenly thought.

We also received comment objecting to defining ''modification'' based on increase in the ''amount of emission'' instead of ''emission rate'' as provided in the General Provisions for modifications in 40 CFR 60.14. We had intended but were not clear in our proposed rule that the definition would apply only to well completions. In the final rule, we have promulgated the provisions discussed above regarding well provisions in lieu of the proposed definition for modification to clarify our intent.

Finally, this provision is intended to address comments suggesting confusion associated with our proposed definition of ''modification'' and the separate, proposed provision in 40 CFR 60.5420 that a workover is considered a modification. The second of these provisions is being removed in light of comments that there is no common understanding of this term and, as a result, it may be interpreted to cover more than the fracturing activities the EPA intended to cover.[17]

In summary, as a result of the comments and considerations discussed above, the final rule provides that well completions conducted on gas wells that are refractured on or after the effective date of this rule are modifications and are subject to the NSPS. However, gas wells that undergo completion following refracturing, with the use, immediately upon flowback, of emission control techniques otherwise required for new wells and that satisfy other requirements for gas well facilities, including notification, recordkeeping and reporting requirements, are not considered modified and, as a result, are not affected facilities under the NSPS. This provision is consistent with the NSPS program's history of allowing sources to use certain emission controls to avoid having an activity constitute a modification. In this situation, we consider it appropriate to require notification, recordkeeping and reporting requirements in order to ensure that a source is meeting the requirements to avail itself of this provision. We believe this approach will encourage early use of REC and will result in 1,000 to 1,500 REC that would not otherwise occur during the REC phase-in period ending January 1, 2015, discussed in section IX.B of this preamble.

2. Regulation of Methane and Other Pollutants

Comment: One commenter believes that under CAA section 111, the EPA must regulate each dangerous pollutant emitted by sources in the oil and gas source category in more than *de minimis* quantities for which controls are available and asserts that the EPA has failed to do so. In particular, the commenter states that the EPA must regulate methane, particulate matter (PM), hydrogen sulfide and nitrogen oxides (NO_X) from oil and gas operations. The commenter states that the EPA's explanation of why it declined to regulate certain pollutants does not discuss PM or hydrogen sulfide, address the most important sources of NO_X or offer a legal justification for its failure to regulate methane. The commenter interprets the CAA to mean that the EPA must, every 8 years, (1) review its standards (as it has done here), (2) determine whether it is ''appropriate'' to revise them, including whether it is appropriate to add additional pollutants to the standards, and (3) if so, revise them accordingly.

Response: In this rule, we are not taking final action with respect to regulation of methane. Rather, we intend to continue to evaluate the appropriateness of regulating methane with an eye toward taking additional steps if appropriate. On November 8, 2010, EPA finalized reporting requirements for the petroleum and natural gas industry under 40 CFR Part 98, the regulatory framework for the Greenhouse Gas Reporting Program (GHGRP). Beginning in September 2012, this program requires annual reporting of greenhouse gases (GHG) from large emissions sources and fuel suppliers in the United States. Petroleum and natural gas facilities will report annual methane and carbon dioxide (CO_2) emissions from equipment leaks and venting, and emissions of CO_2, methane and nitrous oxide from flaring, onshore production stationary and portable combustion emissions, and combustion emissions from stationary equipment involved in natural gas distribution. The EPA estimates that the rule will cover 85 percent of the total GHG emissions from the United States petroleum and natural gas industry with approximately 2,800 facilities reporting. The data submitted under the GHGRP will provide important information on the location and magnitude of GHG emissions from petroleum and natural gas systems and will allow petroleum and natural gas facilities to track their own emissions, compare them to similar facilities and aid in identifying cost-effective opportunities to reduce emissions in the future.

As noted in the proposal, the control measures that the EPA is requiring for VOC result in substantial methane reductions as a co-benefit. Over time, collection of data through the GHGRP and other sources will help EPA evaluate whether it is appropriate to directly regulate methane from the oil and gas sources covered by this rule. The EPA will be in a better position to characterize (1) the extent of methane emissions from these sources that will remain after imposition of controls

[17] We are not considering ''workovers'' to be modifications because: (1) They include truly routine activities; (2) in most instances we would anticipate only a small emissions increase, if any; and (3) we have no reason to think that these wells differ in emission profile or control options from non-fractured wells (or fractured wells after flow back), and accordingly we have not identified a BSER that would apply following any such modification.

required by this rule; and (2) whether additional measures are available and appropriate for addressing such emissions.

With regard to other pollutants, including PM, H_2S and NO_X, many of the sources of PM and NO_X within the Crude Oil and Natural Gas Production source category are within the scope of units covered by other NSPS and will be evaluated in the context of subsequent revisions of those rules, if appropriate. This approach is consistent with what the agency articulated when we promulgated the original oil and gas rules. See 49 FR 2637. For example, NSPS covering stationary reciprocating internal combustion engines (40 CFR part 60, subparts IIII and JJJJ) and combustion turbines (40 CFR part 60, subpart KKKK) regulate emissions of PM and NO_X from sources found in this category. These engines and turbines are found in a variety of locations in this category including gathering and boosting stations, natural gas processing plants and natural gas transmission and storage facilities. In addition, some mobile source regulations (40 CFR part 1039) cover nonroad engines such as those used on drilling rigs, electrical generators and hydraulic fracturing pumps. As we discussed at proposal (see 76 FR 52756) most, if not all, of the process heaters and boilers used in this category fall below applicability thresholds for EPA's boiler rules (40 CFR part 60, subparts Db and Dc). Although these smaller heaters and boilers are generally within the scope of this category, we received no quantitative data in the public comments on NO_X or PM emissions from these units. Given the broad coverage of the PM and NO_X sources in this category by other NSPS we did not depart from the approach adopted in 1984 of considering these pollutants in development of other standards.

Although the NSPS does not provide direct regulation of H_2S, the VOC control requirements in the final rule achieve reductions of H_2S a co-benefit in cases where H_2S is otherwise emitted in the oil and natural gas production segment. While amine treatment and sulfur recovery are routinely employed both upstream and at natural gas processing plants to remove H_2S from the natural gas stream, we believe that it would not be reasonable or cost-effective to require amine units and sulfur recovery for every emission point in the oil and natural gas production segment. We received no public comments suggesting other control technologies that could be applied to control H_2S in the field. Such emissions occur in the field as fugitive emissions at the wellhead and vented emissions from well completions, storage vessels, pneumatic controllers and compressors. However, as mentioned above, the VOC control measures provided in the final rule for well completions, storage vessels, pneumatic controllers and compressors greatly reduce any H_2S emissions along with the VOC emissions controlled.

3. Expanded Scope of the Source Category

Comment: One commenter states that, in the preamble, the EPA makes reference to its proposal to significantly expand the scope of oil and gas operations that would be covered by the new NSPS, and states that ''[t]o the extent that 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'' (citing 76 FR 52745, August 23, 2011). The commenter is not aware of any authority pursuant to which the EPA may affect a significant expansion of the category list merely through the language of the preamble in an NSPS rulemaking. The commenter states that, in a related context, the CAA requires that the EPA engage in consultation with state governors and air pollution control agencies, suggesting that more than a preamble reference is needed in order to expand the category list and impose NSPS requirements on the new and unique affected sources addressed in this rule. See 42 U.S.C. 7411(f)(3). The commenter asserts that the sources the EPA seeks to regulate are different types of stationary sources than gas processing plant, and contends that oil and gas production wells are stationary sources, but are, clearly, not processing plants.

Response: Because EPA has concluded that the currently listed Oil and Natural Gas source category covers at least those operations in this industry for which we are finalizing standards, we need not address what steps the agency must take if expanding a source category.[18] As we explained in the preamble to the proposed rule, when the EPA initially listed this source category, it did so in a document where it described its listings as broad. 76 FR at 52745.[19] Contrary to commenters assertions, the EPA has viewed this source category listing very broadly. Specifically, when promulgating the first sets of standards of performance for this source category, we stated that the source category ''encompass[es] the operations of exploring for crude oil and natural gas products, *drilling for these products, removing them from beneath the earth's surface,* and processing these products from oil and gas fields for distribution to petroleum refineries and gas pipelines.'' 49 FR at 2637 (emphasis added). That preamble linked the endangerment finding under CAA section 111(a) to the industry as a whole: ''The crude oil and natural gas production *industry* causes or contributes significantly to air pollution that may reasonably be anticipated to endanger public health or welfare'' (*Emphasis added*). 49 FR 2636. The statements above affirm our conclusion that the currently listed Oil and Natural Gas source category covers all operations for which we are setting standards. That the original NSPS's only set standards for a limited set of sources within the category cannot be taken to imply that other units were not within the scope of this original listing. See, *e.g., Nat'l Lime Ass'n* v. *EPA,* 627 F.2d at 426 n. 27 (noting that the EPA set standards for only certain kiln types within the source category). Indeed, the preamble to the 1984 proposed NSPS rule directly addresses regulation of wells, concluding that the agency was not setting standards at that time; not because they were outside the scope of the source category, but because the agency was unable at that time to identify ''[b]est demonstrated control technology.'' 49 FR at 2637. As all of the units that we are regulating fall within the scope of the original listing, we need not address what steps would be necessary were we to expand the scope of the listing.

B. Major Comments Concerning Well Completions

1. Applicability and Exemptions

a. Well Exemptions

Comment: One commenter suggests adding ''appraisal wells'' as a third subcategory of well to be exempt from the REC requirements, and defines these wells as those drilled in an area where the reservoir has not been classified for that area as containing proved reserves of natural gas. According to the commenter, adding this definition and exemption better reflects the universe of wells for which a gas flow line system

[18] For the same reason, we need not address the comment claiming that CAA section 111(f)(3) requires that the EPA consult with state governors before amending CAA section 111(b) listing.

[19] While not required to do so, we have included the Background Information Document for the listing rule in the docket for this rule. We note that those documents shed no additional light on the scope of the listing beyond our interpretation of the listing preamble described in the proposed rule.

will not be available. The commenter adds that it also avoids a potential problem where a shale play appraisal well system is effectively compelled to install a flow line system before the wells are determined to be economically viable, in order to assure compliance with 40 CFR part 60, subpart OOOO.

Response: The EPA recognizes that a flow line at the well pad is a necessary precondition to capture flowback gas for emissions control so that the REC process has an outlet for the captured gas. However, the EPA does not agree that appraisal wells need to be exempt. Appraisal wells are drilled and then logged to assess productivity. If well logs indicate that the well is productive, then fracturing will be performed, and the cost to fracture, complete and produce the well, including installing a flow line, will be incurred. If the well logs indicate the well is not economically productive, then no fracturing occurs and the NSPS does not apply. The EPA, therefore, believes it is reasonable to require appraisal wells that are hydraulically fractured to comply with Subcategory 3 rule requirements.

b. Threshold for Low Pressure (Low Volume) Gas Wells and Wells with Low or No VOC Emissions

Comment: One commenter expresses support for the REC requirements and urges the EPA to limit the number of well completions exempted from the requirements as much as possible. Several commenters contend that not all well completions can be conducted successfully under a requirement to flow back to the flow line, since the imposition of the flow line backpressure may reduce the flowback gas velocity sufficiently so that it is not energetic enough to clean up the well of liquid and sand. One commenter recommends that any well whose reservoir pressure (measured at the wellhead immediately after perforation) is less than 4 times (in absolute units) the line pressure measured at the flow meter, would be exempt from any requirement to flow to sales during the flowback period. According to the commenter, variability in reservoir and line pressures across the United States makes setting a specific pressure threshold difficult.

Response: The EPA has established three subcategories of wells in response to public comments, as described above. One of those categories comprises non-wildcat and non-delineation low pressure gas wells. Low pressure gas wells are defined as wells with reservoir pressure and vertical well depth such that 0.445 times static reservoir pressure (in pounds per square inch absolute (psia)) minus 0.038 times the vertical well depth (in feet) minus 67.578 psia is less than the flow line pressure at the sales meter. Thus, wells above this pressure differential must implement REC, while wells below this pressure differential are required to route emissions to a completion combustion device.

The EPA solicited comment in the proposed rule on situations where REC may be infeasible and criteria and thresholds for distinguishing well completion operations in those situations from others where REC is feasible. As noted above, several commenters highlighted the technical issues that prevent an operator from implementing an REC on a low pressure gas well, which is the inability to attain a gas velocity sufficient to clean up the well when flowing against the flow line backpressure. Based on this information, the EPA agrees that a pressure differential threshold is reasonable and addresses the technical limitations of low pressure gas wells to produce to the flow line during completion.

As noted above, a commenter recommended specific approaches to developing a pressure threshold, including specifying that any well whose reservoir pressure is less than 4 times (in absolute units) the line pressure measured at the flow meter would be exempt from any requirement to flow to the flow line during the flowback period. This recommendation is based on a flowing bottom hole to reservoir pressure ratio of 1:2 and a line pressure to flowing bottom hole pressure of 1:2. The EPA concurs with the commenter that flowing bottom hole pressure can be represented as half of the reservoir pressure for this rule. The EPA disagrees with the commenter that line pressure can be represented as half of the flowing bottom hole pressure for this rule since this pressure relationship can be more accurately determined using the Turner equation for liquids unloading from a well paired with models relating fluid velocity to pressure drop. Therefore, the EPA has modeled a worst-case pressure drop factor between the line pressure and flowing bottom hole pressure and has established a pressure threshold using this factor and the 1:2 factor for flowing bottom hole pressure to reservoir pressure. The result of this modeling is the equation discussed above in the definition of low pressure gas wells.

As discussed in the proposal preamble, potential control options are REC with combustion or a completion combustion device alone. Because REC may not always be technically feasible for wells that fall below the pressure threshold, the EPA has determined that the BSER for reducing VOC emissions for this subcategory of wells is a completion combustion control device. However, the EPA encourages the use of REC with combustion should that be a viable option for any well within this subcategory. Therefore, in the final rule, for non-wildcat and non-delineation wells with a pressure drop below the differential described above, the EPA requires the use of either a completion combustion device or REC with combustion to control gas not suitable for entering the flow line.

Comment: Several commenters address parameters for defining which well completions would be subject to REC requirements. Commenters request that the EPA exempt wells with low VOC concentrations from the REC requirements and not issue the proposed standards before reconsidering the emissions estimates. One commenter suggests that the EPA exempt hydraulically fractured natural gas horizontal wells with *de minimis* VOC concentrations because the cost per ton of VOC reductions is extremely high for these wells and the emissions from the combustion of the produced gas could worsen ozone formation in the area. Commenters also provide, as examples, some wells with low or no VOC as support for exempting wells with a low VOC content or for exempting certain classes of wells such as coal bed methane. Several commenters contend that coal bed methane wells have low VOC, while several other commenters contend that coal bed methane wells have no VOC. Some commenters provide examples of coal bed methane wells with low VOC or no VOC, and one commenter provides an example of a shale gas well with no VOC.

Response: The EPA acknowledges that the VOC concentration in natural gas can vary across wells and reservoir types such as coal bed methane (CBM), shale and tight sands. However, the information provided in the comment is insufficient for the EPA to determine that any specific class of wells, or wells with VOC concentration below a specific threshold, would not be cost-effective to regulate, as the commenters recommend. For example, several commenters contend that CBM wells have low or no emissions. In response to comments received, the EPA assessed the VOC content of CBM wells, including a review of the gas composition data presented in the gas composition memo[20] available in the docket and in an article[21] by the United States Geological Survey. The VOC concentrations among CBM wells will vary and are not always low. The limited CBM data submitted by the commenter, while suggesting low-VOC concentrations at some CBM wells, is not to the contrary. Accordingly, we conclude that it would be inappropriate to provide a categorical exclusion for such wells.

We also have determined that providing a low-VOC concentration exclusion would be inappropriate, both because the submitted data do not support such an exclusion (they do not demonstrate that such circumstances are frequent) and because of implementation concerns. Specifically, even if such a VOC concentration threshold described above can be determined, to ensure compliance with the rule, an operator would have to determine with certainty before production, whether a particular well was going to be above or below the threshold in order to mobilize the necessary capture equipment and secure a flow line, etc. This would require the operator to determine the reservoir composition, *e.g.,* the gas composition prior to separation, in advance of the well completion (*i.e.,* the determination of whether the well would be subject to the NSPS would have to be performed before the information on which to base such a determination would be available). Although nearby existing wells could potentially provide some indication of the general VOC content of the gas from the future well in question, there would be no assurance of certainty. In addition, the operator would need to certify that the reservoir sample is going to stay consistent and representative of the gas stream throughout the full completion process through multiple gas composition analyses.

Taking into account the variability in VOC concentrations across reservoir types, the EPA's cost analysis illustrates that these requirements are cost-effective, especially when taking into account the gas savings. Compliance with a VOC concentration threshold-based rule for well completions could actually increase the burden to the operator by requiring numerous compositional analyses to demonstrate compliance with the rule.

c. Definition of Gas Well

Comment: Several commenters mentioned that the proposed definition of ''gas well'' was unclear due to the term ''principal production'' used in describing what the well produces. One commenter requests that the definition of gas well be modified to be each respective state's definition of gas well. The commenter states that, by doing this, the EPA would eliminate any confusion associated with having to apply different criteria (NSPS versus state regulations) for how to define a well-type in assessing the applicability of the rule.

Response: In response to comments requesting further clarity in the definition, the EPA has revised the definition. The proposed definition was ''*Gas well* means an onshore well, the principal production of which at the mouth of the well is gas.'' In the final rule, in response to the comments we received, the EPA has revised the definition to exclude the phrase ''at the mouth of the well is gas.'' Based on this revision, the definition for the final rule is ''*Gas well or natural gas well* means an onshore well drilled principally for production of natural gas.''

EPA's intent in setting standards for completion of hydraulically fractured gas wells is to require reduced emissions completions for wells where infrastructure is generally present to get recovered natural gas to market. Our understanding is that owners and operators plan their operations to extract a target product and evaluate whether the appropriate infrastructure is available to ensure their product has a viable path to market before completing a well. We expect that the final rule will result in control of hydraulically fractured gas wells drilled in the four formation types generally accepted as gas-producing formations: (1) High-permeability gas, (2) shale gas, (3) other tight reservoir rock or (4) coal seam. We believe that the wording changes made to the definition of ''gas well'' clarify the intent so that implementing agencies and industry will not be burdened with complex applicability determinations.

With respect to using State gas well definitions, basing applicability on different definitions from State to State could introduce inconsistencies that are counter to the goal of nationwide regulation. We believe the NSPS, being a national rule, should contain a single definition applicable nationwide. However, states may choose to use a definition more expansive than our definition for their programs.

Comment: One commenter states that, based on the EPA's discussion in Section 4 of the Technical Support Document (TSD), it appears the EPA's intent is to require reduced emissions completions only for natural gas wells. The commenter supports that the EPA applied reduced emissions completions only to natural gas wellhead facilities and excluded oil wellhead facilities and other types of gas wells which have little or no VOC emissions. The commenter states that, as shown on page 4–13 on Table 4.4, *Nationwide Baseline Emissions from Uncontrolled Oil and Gas Well Completions and Recompletions,* of the TSD, there are only 134 tpy of VOC emissions from oil well completions and recompletions for the entire United States, which is not worth regulating.

One commenter recommends the following revision: ''Gas well means a well, the principal production of which at the mouth of the well is [add: hydrocarbon gas, not CO_2] * * * 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.'' One commenter proposes the following revision: ''Gas well means a well, [DELETE the principal production of which at the mouth of the well is gas] completed for production of natural gas from one or more gas zones or reservoirs. Such wells contain no completions for the production of crude oil.'' The commenter also proposes the following revision: ''Gas well means a well [STRIKETHROUGH: the principal production of which at the mouth of the well is gas.] [ADD TEXT: completed for production of natural gas from one or more gas zones or reservoirs. Such wells contain no completions for the production of crude oil.]''

Response: Although some wells drilled in crude oil formations may produce associated gas along with the oil, without a gas infrastructure present, the EPA does not have sufficient data on VOC emissions during completion of hydraulically fractured oil wells to set standards for these operations at this time.[22] As a result, the final rule will not affect drilling of oil wells.

[20] Memorandum from Brown, Heather, EC/R Inc., to Moore, Bruce, EPA/OAQPS/SPPD, *Composition of Natural Gas for use in the Oil and Natural Gas Sector Rulemaking,* July 28, 2011. Docket ID No. EPA–HQ–OAR–2010–0505–0084.

[21] Rice, Dudley, *Composition and Origins of Coalbed Gas,* U.S. Geological Survey, Denver, Colorado.

[22] In the proposed rule, we briefly assessed well completions of hydraulically fractured oil wells and did not believe that either REC or a completion combustion device is cost effective for reducing VOC emissions from such operations. We note, however, that this brief assessment of oil wells in the proposed rule was based on limited information at the time and that more information is needed for us to fully evaluate the VOC emissions and control options for these operations.

d. Availability of Infrastructure to Convey Gas to Market

Comment: Various commenters have asserted that, in some cases, REC cannot be performed on some wells because there is no gathering line available to convey gas produced during the completion flowback period.

Response: As explained above, it is our understanding that owners and operators plan their operations to extract a target product and evaluate whether the appropriate infrastructure access is available to ensure their product has a viable path to market before completing a well. However, in the standards for gas well affected facilities, the provisions of 40 CFR 60.5375(a)(1) through (4) apply to all fractured gas wells that are not exploratory wells, delineation wells or low pressure wells. These standards require that the well completion flowback be conducted using a combination of collection (*i.e.,* REC), combustion and venting, depending on the characteristics of the flowback material and feasibility of routing the gas to a collection system to be conveyed to market. Section 60.5375(a)(3) provides:

> ''You must capture and direct flowback emissions that cannot be directed to the flow line to a completion combustion device * * *''.

We believe that owners and operators of gas wells subject to 40 CFR 60.5375(a) that require REC for a portion of the flowback period will exercise due diligence in coordinating the completion event with availability of a flow line to convey captured gas to market. However, there may be cases in which, for some reason, the well is completed and flowback occurs without suitable flow line available. In those isolated cases, we believe 40 CFR 60.5375(a)(3) provides for gas not being collected and instead combusted or vented pursuant to that section.

e. Fracturing of Wells Using Nitrogen and Carbon Dioxide

Comment: One commenter suggested that wells that are fractured using nitrogen or CO_2 should be exempt from the NSPS but did not provide supporting rationale. Other commenters expressed concern that inert gases such as nitrogen are not flammable, making compliance with the combustion provisions of the NSPS impossible.

Response: We believe that the standards for well completions adequately address the concerns expressed by operators using nitrogen and/or CO_2 for fracturing. We provided in the proposed rule, and further clarified in the final rule, that these standards require that the well completion flowback be conducted using a combination of collection (*i.e.,* REC), combustion and venting, depending on the characteristics (including flammability) of the flowback material and feasibility of routing the gas to a collection system to be conveyed to market. Both the proposed and final rules express our intent to require REC only where there is salable quality gas to the gather line. See 76 FR 52800 and 40 CFR 60.5375(a)(2) of the final rule.

Section 60.5375(a)(3) in the final rule provides: ''you must capture and direct flowback emissions that cannot be directed to the flow line to a completion combustion device, except in conditions that may result in a fire hazard or explosion, or where high heat emissions from a completion combustion device may negatively impact tundra, permafrost or waterways. Completion combustion devices must be equipped with a reliable continuous ignition source over the duration of flowback.''

Under this provision, operators who employ energized fracturing using inert gases and cannot route the flowback gas to a collection system because of poor gas quality must direct the flowback to a completion combustion device with a continuous ignition source. Although part of the flowback gases directed to the combustion device would not be flammable, the ignition source will ignite the flammable portion of the flowback, including VOC. Therefore, the presence of inert gases such as nitrogen and CO_2 in the flowback gas has no bearing on the VOC reduction we expect to achieve through the NSPS or on compliance with provisions of the final rule.

2. Rule Should Not Prescribe Equipment

Comment: Several commenters suggest revising 40 CFR 60.5375(a)(2) equipment requirements to be less prescriptive, especially in cases where use of specified or all listed equipment may not be necessary, and to provide flexibility to include newly developing technology. Other commenters assert that language in 40 CFR 60.5375(a)(1) and (2) stating that source owners or operators should ''minimize the emissions associated with venting of hydrocarbon fluids and gas'' and that ''[a]ll salable gas must be routed to the gas gathering line as soon as practicable'' is vague and recommended a requirement that facility owners follow a Best Management Practice (BMP) plan that the EPA could develop, informed by the Natural Gas STAR program.

Response: The EPA agrees that prescribing specific equipment to accomplish a reduced emissions completion is not necessary and has revised the rule language to not prescribe specific equipment. The operational standards provided in the NSPS allow the operator flexibility to perform the REC using equipment and practices best determined by the operator. As a result, we believe that a BMP plan developed by the EPA would not provide a higher degree of emissions control and could hinder innovation.

3. Availability of Equipment and Trained Personnel

Comment: Commenters state that the supply of REC equipment and personnel is insufficient to meet the requirements of the proposed rule, applied nationally. According to commenters, proper surface equipment, collection infrastructure and qualified personnel are not readily available; they assert that this equipment is fairly specialized, the shops licensed to make it are limited and some of the components require a long lead time. For these reasons, commenters indicate that compliance by the issuance date of the rule would be unrealistic and that the EPA should provide a longer compliance period.

Response: Based on information submitted by commenters, we have reason to believe that, currently, there is already significant demand for REC equipment. For example, Colorado, Wyoming, the City of Fort Worth, Texas, and the City of Southlake, Texas, require REC under certain conditions. Additionally, public comments, reports to the EPA's Natural Gas STAR Program and press statements from companies indicate that some producers implement REC voluntarily, based upon economic and environmental objectives. If REC were to be immediately required of all well completions, NSPS would place significant additional demands on REC equipment supply and experienced personnel.

As the near-term supply of REC equipment and trained personnel will be insufficient to meet the new national demand for equipment and labor, immediate compliance with the REC requirements could be impossible, potentially causing producers to delay well completions until appropriate equipment and labor are available. Resulting delays in well completions while awaiting equipment availability could cause a decrease in the nationwide natural gas supply and would drive up the cost of completions doing REC. It is not the EPA's intent to set in motion a series of events through this rule that has the potential to affect the natural gas supply and increased cost of REC would undermine our BSER analysis. Accordingly, it is important that the EPA consider the availability of REC equipment and personnel in its BSER analysis.

Through EPA and industry events and collaborative studies, the EPA has interacted with operating companies that have extensive experience implementing REC. In particular, the EPA developed a detailed study [23] on REC in collaboration with service providers. Based on this experience, the EPA has gained extensive information on this technology. Despite these efforts, the EPA is not aware of any quantitative information on the current and future supply of workers trained in REC techniques.

The EPA received data on the current and future supply of REC equipment. According to one commenter, about 300 REC units are in use today, with the ability to process about 4,000 wells per year, and 1,300 additional units would be required to perform 20,000 REC per year. About 1,600 units performing 20,000 REC/year implies a REC productivity rate of about 12.5 REC/year/unit, or roughly each unit performing one REC per month, on average.

The NSPS proposal estimated 9,300 REC performed for new natural gas well completions and 12,200 REC performed for existing natural gas well completions following refracturing would be required, in addition to those already required by state regulations. In the analysis supporting the final rule, the EPA revised estimates show 11,403 hydraulically fractured and 1,417 hydraulically refractured natural gas well completions will be performed in a representative year, which includes completions in states which currently have REC requirements. The revised estimate also reflects a change in the refracture frequency of existing wells from 10 percent to 1 percent based on information provided by commenters. Of the total hydraulically fractured well completions, the EPA estimates that about 11,300 REC will be required nationally on the basis of the final rule's provisions for wildcat (exploratory) and delineation wells, flowback gas pressure and natural gas well completions conducted on existing gas wells that are subsequently fractured or refractured. This estimate excludes REC required by state regulations.

Assuming a REC unit performs 12.5 REC/year, as is asserted by the commenter, about 900 units would be required. This implies a current shortfall of about 600 units, based upon the numbers and assumptions provided by the commenter. The commenter states that industry can deliver about 50 units per quarter, after a 1-year build-up period. Given that the EPA does not have an alternative estimate of the number of REC units industry can produce per year, we adopt the estimate of 50 units per quarter for this analysis, although the EPA disagrees with the assumption that a 1-year build-up period is required. Using the commenter's assumptions, it would take about 4.25 years to meet demand. This scenario is depicted in Scenario A in Table 6 below, assuming compliance is initiated at the beginning of the second quarter, 2012, and the industry begins delivering 50 units per quarter roughly 1 year after the compliance date.

Surveys conducted by one commenter indicate that nine companies expect to perform more REC than the current stock is capable of. Given this growing demand, it is reasonable to assume industry can deliver units during the build-up period of the first year of implementation, which would reduce the time required to meet full demand another year to a total of about 3.25 years (Scenario B).

The EPA also assessed whether the productivity of equipment in use could be higher than the 12.5 REC/year/unit derived from the comment, and the potential impact of such increase on the equipment supply. The EPA estimated that flowback periods will typically be 3 to 10 days with 7 being a reasonable average. Therefore, because it is likely that a REC unit could be moved to another well site and be in operation in less than 20 to 27 days, it is reasonable to conclude that each REC unit can perform more than 12.5 REC/year.

If the utilization rate of REC units is increased gradually from performing 12.5 REC/year/unit to 14 to 18 REC/year/unit, the time required to build the supply of REC units decreases (Scenarios C–G). As Table 6 shows, each 1 REC/year/unit increase reduces the build-up time by about 1 quarter. As is shown in Scenarios C and G, increasing the utilization rate of REC to 14 to 18 REC/unit/year with industry supplying new units beginning with the compliance date would provide between 1.75 and 2.75 years for full build-out of the REC unit supply by the beginning of calendar year 2015.

TABLE 6—REC UNIT SUPPLY ANALYSIS

Scenario	A	B	C	D	E	F	G
RECs Required	11,301	11,301	11,301	11,301	11,301	11,301	11,301
RECs/year/unit	12.5	12.5	14.0	15.0	16.0	17.0	18.0
Units Needed	904	904	807	753	706	665	628
Stock in Existence (assume industry can build 50 units/quarter; assuming industry starts with 300 units); compliance begins approximately at the end of the second quarter, 2012.							
2012 (Q1)	300	300	300	300	300	300	300
2012 (Q2)	300	300	300	300	300	300	300
2012 (Q3)	300	350	350	350	350	350	350
2012 (Q4)	300	400	400	400	400	400	400
2013 (Q1)	300	450	450	450	450	450	450
2013 (Q2)	300	500	500	500	500	500	500
2013 (Q3)	350	550	550	550	550	550	550
2013 (Q4)	400	600	600	600	600	600	600
2014 (Q1)	450	650	650	650	650	650	650
2014 (Q2)	500	700	700	700	700	700	....
2014 (Q3)	550	750	750	750	750	....	....
2014 (Q4)	600	800	800	800	....	....	....
2015 (Q1)	650	850	850	....	....	....	....

[23] Available at: *http://www.epa.gov/gasstar/documents/reduced_emissions_completions.pdf.*

TABLE 6—REC UNIT SUPPLY ANALYSIS—Continued

Scenario	A	B	C	D	E	F	G
2015 (Q2)	700	900					
2015 (Q3)	750	950					
2015 (Q4)	800						
2016 (Q1)	850						
2016 (Q2)	900						
2014 (Q3)	950						

Because of uncertainties in the supply of equipment and labor over the near-term, and based on our analysis described above, the EPA concludes that REC may not always be available through 2014. Therefore, during this period, the BSER for well completions is to combust completion emissions. REC with combustion as an alternative to combustion is permitted by the rule so that facilities that are able to obtain REC equipment may still capture completion emissions using a REC. After January 1, 2015, capturing completion emissions using a REC will be considered BSER. This period will permit the companies producing REC units to increase production to levels sufficient to meet new demand. In addition, because more REC will be performed as a result of this rule, the EPA believes that producers will take advantage of scale economies and use REC units at a higher rate of productivity than the rate implied by comments received.

The EPA believes that the NSPS, as finalized, will minimize the risks of producers slowing well completion-related activities to obtain appropriate equipment and labor. While there would be NO_X formation as a result from the additional combustion of completion emissions during the phase-in period, VOC emissions reductions would be maintained because completion emissions will be either combusted or captured. The EPA maintains that the benefit of the VOC reduction during the phase-in period far outweighs the secondary impact of NO_X formation during pit flaring. The phase-in period would also minimize the possibility that the cost of REC equipment and labor increases over the near-term, enabling producers to better plan efficient use of existing and new capital and labor, and providing additional time for innovation in REC technologies and/or practices. We believe this period provides ample time for this technology to be built and available for use.

At the same time, for wells undergoing recompletions during the period prior to January 1, 2015, the terms of 40 CFR 60.5365(h), which specify that ''[a] gas well facility that conducts a well completion operation following hydraulic refracturing is not an affected facility, provided that the requirements of section 60.5375 are met,'' may provide an additional incentive for producers to use REC units prior to January 1, 2015, if they can obtain appropriate equipment and labor. Also, considering the requirement in some states that any source subject to a federal NSPS must get a state minor source air permit, we anticipate that the desire to avoid even short term delays caused by state permitting, as well as the associated costs, will serve as an incentive for the use of REC during well completion operation following hydraulic refracturing, including operations prior to January 1, 2015. Furthermore, as January 1, 2015, approaches it is highly likely that providers of REC equipment and related services will be increasing availability of such equipment and services in ways that benefit supply and price. For these reasons, the EPA anticipates that during the period between promulgation and January 1, 2015, between 1,000 and 1,500 wells will be recompleted with REC units, notwithstanding the requirements of 40 CFR 60.5375(a) and the combustion option they provide.

4. Cost and Emissions Calculations

Comment: Some commenters request the EPA to fully explain or reconsider the 10-percent rate of refracturing of wells.

Response: In response to comment, the EPA has reevaluated the assumption that, on average, each fractured gas well is re-fractured every 10 years, which equates to approximately 10 percent of fractured gas wells being re-fractured each year, based on drilling and re-fracture records from an industry representative. Based on its review of the comment, including references noted in the comment and other information available to the agency, the EPA concluded that it had overestimated the re-fracturing frequency. The information reviewed by the EPA, which, altogether, represent over 20,000 gas wells over multiple years, some as far back as 2000, indicate that the annual recompletion frequency can be as low as 0.1 percent and as high as 0.8 percent. Based on this information, the EPA has revised its estimate of re-fracturing frequency from 10 percent to 1 percent of fractured gas wells per year. The EPA rounded the figures provided by the companies to reflect the uncertainty in the data.

5. Definition of Affected Facility

Comment: Several commenters assert that a well completion is different from a well workover and should be better defined in the rule.

Response: Based on the comments received, the EPA acknowledges that the term ''workover'' is a general term that may have a number of different meanings. Based on the various definitions of the term provided by the commenters, we realize that workover may be interpreted to include routine maintenance activities that we did not intend to cover under the rule and which result in no increase in emissions. Therefore, in the final rule we have revised the definition of ''well completion operation'' to exclude the term ''workover'' and, instead, include the phrase ''with hydraulic fracturing.''

C. Major Comments Concerning Pneumatic Controllers

1. Definition of Affected Facility

Comment: Some commenters request that the EPA consider excluding or exempting emergency and/or safety system devices (such as a pilot operated pressure relief valve). According to one commenter, safety system devices typically do not emit gas unless there is an emergency, have a near-zero VOC-level static state and, if regulated, could be replaced by substandard, cheaper technology of spring operated valves which would create much more leakage of gas into the environment.

With regard to emergency situations, another commenter argues that the proposed standards that apply to pneumatic controller affected facilities (40 CFR 60.5390(b)) could inhibit safe plant operation during an emergency because they require that each pneumatic controller located at a natural gas processing plant have zero natural gas emissions. According to the commenter, a gas-powered controller is a reliable alternative for safe plant operation during emergencies, and the commenter suggests that the final rule include an exception to allow gas plants to use natural gas-driven pneumatic controllers for emergency plant shutdown and subsequent startup.

With regard to high-bleed pneumatic controllers, several commenters request that the EPA further explain when the use of high-bleed pneumatic controllers is allowed and provide specific examples of exemptions. The commenters suggest exemptions that address situations such as those where the natural gas includes impurities that could increase the likelihood of fouling a low-bleed pneumatic controller, such as paraffin or salts; where weather conditions could degrade pneumatic controller performance; during emergency conditions; where flow is not sufficient for low-bleed pneumatic controllers; where electricity is not available; and where engineering judgment recommends their use to maintain safety, reliability or efficiency. Several commenters request that the EPA provide additional information about how to demonstrate that the use of high-bleed pneumatic controllers is predicated, as stated in proposed 40 CFR 60.5390(a). The commenters suggest that this exemption is very vague, will allow for excessive emissions and is not enforceable.

Response: The EPA included in the proposed rule exemptions from the NSPS to allow the use of a controller with a natural gas bleed rate greater than 6 scfh due to functional needs. These exemptions include, but are not limited to, response time, safety and actuation of valves. These functional exemptions to the requirement address the commenters' concerns of safety, emergency and otherwise non-routine situations that require the use of a controller with a natural gas bleed rate greater than 6 scfh. In response to comments regarding vagueness of the proposed exemption, the EPA revised this exemption provision in the final rule. We believe the provision in the final rule clarifies the scope of this exemption.

Comment: Several commenters express concerns with the proposed rule's treatment of various types of pneumatic devices and controllers. One commenter requests that the EPA clarify in 40 CFR part 60, subpart OOOO that intermittent bleed pneumatic devices are not affected sources. Another commenter asserts that continuous low-bleed controllers that replace existing continuous low-bleed controllers should not be ''affected facilities.'' According to this commenter, some designed high-bleed devices may be isolated from the gas pressure with a valve and operated manually on an intermittent basis. The commenter wants clarification in the rule that will allow an operator to use a high-bleed device if it is operated in a manner that keeps its emission levels less than 6 scfh.

One commenter requests that the EPA clarify in the final rule that the distribution segment and self-contained devices that release gas to a downstream pipeline instead of to the atmosphere are exempt. Another commenter argues that no-bleed pneumatic devices have zero emissions and, thus, should not be included in the proposed rule.

One commenter discusses the use of solar-powered controllers, fuel-cell powered controllers and mechanically-controlled devices in remote locations as an alternative to natural gas where grid electricity is not available. This commenter also recommends that the EPA set a zero emissions standard based upon no-bleed devices wherever electricity (either from a grid or from field power sources) is available within a reasonable distance from the facility and suggests that the EPA could establish an exemption to no-bleed devices where low-bleed devices are necessary because no-bleed devices cannot be feasibly installed.

Another commenter states the definition of ''pneumatic controller'' is unclear and should be revised.

Response: In the final rule, the EPA has revised the definition of ''affected facility'' for pneumatic controllers in the production segment [24] to address a number of the comments described above. Specifically, for pneumatic controllers at gas processing plants where the standard is zero bleed rate, we have defined the affected facility as a continuous bleed natural gas-driven pneumatic controller. For other areas in the production segment (*i.e.,* excluding gas processing plants), where the standard is a bleed rate of 6 scfh or less, we have defined the affected facility as a continuous bleed natural gas-driven pneumatic controller operating at a bleed rate greater than 6 scfh. By defining the pneumatic controllers affected facilities to be continuous bleed and gas-driven, we clarify that the NSPS does not apply to intermittent bleed devices, no-bleed pneumatic devices (by design), self-contained devices and devices driven by instrument air. The revised definitions also exclude from the NSPS coverage owners and operators who are already using (including replacement) pneumatic controllers that meet the applicable standards, thus, relieving them from the cost and other burdens related to compliance.

Regarding the comments related to solar-powered controllers, fuel-cell powered controllers, mechanically-controlled devices and no-bleed devices wherever electricity is available, we considered these types of devices in the BSER analysis, as discussed in the TSD. Any such controller system would require a backup system (consisting of at least an electrical generator) to operate the controllers when the primary system was inoperable. When considering the cost of the backup system, these options were not cost-effective. We, therefore, do not believe that they are BSER for reducing VOC emissions from pneumatic controllers where grid electricity is not available. We also decline to set a zero emission standard ''wherever electricity * * * is available within a reasonable distance,'' as a commenter suggests. We have no information, nor has the commenter provided any, on how to determine the suggested ''reasonable distance.''

Comment: Several commenters request an exemption for all affected facilities handling gas with less than 10-percent VOC content by weight. Some commenters offer suggestions for such exemption, such as requiring recordkeeping of the gas VOC content in order for a facility to maintain the exemption.

One commenter believes that the EPA should delete the pneumatic controller requirements because most of the gas emitted is methane, and there is little VOC emission reduction benefit. Another commenter suggests limiting applicability to pneumatic controllers at natural gas processing plants or upstream of processing that exceeds a defined VOC threshold.

Several commenters opine that pneumatic device definitions and applicability should be based on VOC emissions, not natural gas as a surrogate. Commenters assert that the 6 scfh high-bleed/low-bleed threshold value is unsupported, that natural gas VOC content varies widely and that, in most cases, unconventionally produced CBM and shale gas have little, if any, measurable VOC.

Several commenters also wanted to exclude pneumatic controllers driven by a specified percentage of VOC.

[24] The NSPS does not cover pneumatic controllers in the distribution segment. The EPA did not address those controllers in the proposed rule. Although the EPA had proposed standards for pneumatic controllers in the transmission and storage segment, for reasons explained in section IX.C.2 of this preamble, the EPA did not include such standards in the final rule.

According to the commenters, regulating the use of compressed air or ''instrument air'' or other gas having little or no VOC would impose a significant burden on the industry without any added benefit.

Response: The EPA disagrees with the comment that the pneumatic controller standards must be based on VOC emissions instead of natural gas bleed rate as a surrogate for VOC emissions rate. Natural gas is being used as a surrogate for VOC given the proportional relationship between them. When a natural gas stream is emitted to the atmosphere, VOC in the gas also reaches the atmosphere since it is a component of the natural gas stream. The natural gas emissions occur without any physical separation, chemical separation or chemical reaction process of the chemical species within the natural gas; therefore, the proportion of VOC in natural gas is not altered during the course of being emitted to the atmosphere, and natural gas is an appropriate surrogate for VOC. As an example, when the natural gas emissions change, the VOC emissions change proportionately. In addition, measuring the VOC content of a pneumatic controller's bleed gas adds cost burden to companies and, to the EPA's knowledge, vendors/manufacturers do not report the VOC emissions from a pneumatic controller primarily because the VOC emissions would depend on the gas composition at the site the pneumatic controller is located.

In the preamble to the proposed rule, the EPA set forth its BSER analysis for pneumatic controllers. In the TSD, the EPA has provided cost-effectiveness calculations for the proposed pneumatic device emission limits. The commenters do not dispute the EPA's analysis. Rather, the commenters ask that the EPA establish a VOC threshold. However, the commenters have not provided information on how an appropriate threshold can be established. One commenter suggests a threshold of 10-percent VOC content by weight, but has not provided supporting information justifying this threshold. However, for the reasons stated in the response to comment in section IX.C.2 of this preamble, the EPA has decided not to cover in this final rule the pneumatic controllers in the transmission and storage segment. With respect to those controllers we are not taking final action at this time.

Comment: One commenter suggested that the EPA provide a phase-in period to allow manufacturers and companies time to designate which controllers qualify as low-bleed. This commenter further notes that bleed rates are not specified for pneumatic controllers or are inconsistently represented without distinguishing between the continuous bleed stream and the actuation stream rates within the gas consumption specifications.

Response: In the proposed rule, for pneumatic controllers [25] in the production segment other than gas processing plants, the EPA proposed a performance standard of a natural gas bleed rate of 6 scfh to reflect the use of a low-bleed controller, which we had determined to be the BSER for reducing VOC emissions from pneumatic controllers in the production segment.[26] Owners and operators would demonstrate compliance based on information in the manufacturers' specifications for the pneumatic controllers, which we had believed would provide either the bleed rate or relevant information for such determination. Upon further investigation, in light of the comments, we conclude that such information is not always included in current manufacturers' specifications. We anticipate that manufacturers who currently do not provide the relevant information for determining bleed rate would adjust to this need and begin testing their products and provide the necessary information on the products' specifications. Based on public comments and other available information, the EPA believes that an adjustment period is needed, during which owners and operators could face increased cost and, in some instances, difficulty in obtaining necessary supplies due to the limited number of currently available controllers with adequate documentation for determining bleed rate. In light of the above, we conclude that a low-bleed controller is not the BSER for pneumatic controller affected facilities in the production segment (excluding gas processing plants) during this first year. As explained in the proposed rule, we are not aware of any add-on controls that are or can be used to reduce VOC emissions from gas driven pneumatic devices. 76 FR 52760. One commenter broadly suggests that we consider flares, combustion devices and vapor recovery, but provides no supporting information. In light of the above, we conclude that there is no BSER for pneumatic controller affected sources in the production segment (excluding gas processing plants) during the ''adjustment period'' mentioned above.

In determining the length of the adjustment period, the EPA evaluated relevant comments and available information, including information from promulgation and implementation of 40 CFR part 98, subpart W of the Greenhouse Gas Reporting rule. Subpart W requires operators to conduct a complete inventory and report to EPA the number of low- and high-bleed pneumatic devices, as those terms are defined in subpart W, over a 3-year period (*i.e.,* ⅓ of their devices every year over a 3-year period) starting January 2011. We believe that efforts are well under way for manufacturers to provide necessary information to help facilities subject to subpart W determine the pneumatic controllers' bleed rates and comply with the reporting rule requirements, ⅓ of which must be reported by September 2012 and another third by September 2013 and the entire inventory by September 2014. In light of the above, we do not believe that owners and operators would face the difficulty described above beyond the first year after this NSPS becomes effective. After this first year of ''adjustment period,'' we believe owners and operators should have no problem securing controllers with relevant documentation for determining bleed rate. Therefore, beginning the second year, the BSER remains the low-bleed controllers, as proposed.

For the reasons stated above, the final rule contains no standards for pneumatic controller affected facilities in the production segment during the first year after this rule becomes effective, but, thereafter, requires that all new and modified affected facilities to meet a VOC limit of 6 scfh natural gas bleed rate to reflect the use of a low-bleed controller. The need for adequate manufacturers' specifications is not an issue for pneumatic controllers at natural gas processing plants. For pneumatic controller affected facilities at natural gas processing plants, we had proposed a zero VOC emission limit, the compliance of which can be demonstrated by the use of a non-gas-driven controller system. As noted by commenters, most natural gas processing plants already use non-gas-driven technology such as instrument air systems for safety and operational reasons. While one cannot distinguish

[25] For the reasons explained earlier in this section, we have changed the definitions of the pneumatic controller affected facility in the production segment other than gas processing plants to be a continuous bleed natural gas driven pneumatic controller with a natural gas bleed rate greater than 6 scfh. This change does not affect the proposed BSER analysis and VOC limit, which apply to high-bleed pneumatic controllers in the final rule.

[26] For reasons explained in section IX.C.2 of this preamble, unrelated to the comment at issue, the final rule does not include standards for pneumatic controllers in the transmission and storage segment.

gas-driven pneumatic controllers of different bleed-rates without information from manufacturers, a non-gas-driven controller can be easily identified by visual inspection. Therefore, no change is made since proposal to the standards for pneumatic controller affected facilities at gas processing plants.

In response to comments that units already in stock at the time of proposal cannot be used, the EPA clarifies that pneumatic controllers that were already in stock or ordered prior to August 23, 2011, are considered existing sources and, therefore, their installation is not subject to the pneumatic controllers NSPS in this final rule.

2. Controllers in the Transmission and Storage Segment

Comment: Several commenters requested the EPA reevaluate requirements for pneumatic controller/devices in the natural gas transmission segment of the industry. The commenters argue that the proposed rule's applicability is too broad and would result in an undue recordkeeping and permitting burden.

Several commenters recommend that 40 CFR part 60, subpart OOOO should limit pneumatic controller applicability to upstream processes. Some commenters suggest that, for natural gas transmission and storage, either pneumatic controllers should be completely excluded or subpart OOOO should limit applicability to equipment located at ''conventional'' facilities, *e.g.,* within the fence line at a compressor stations. One commenter recommends limiting the emission limit requirement to controllers at natural gas processing plants or locations upstream from gas processing that exceed a defined VOC threshold. The commenter suggests that this exclusion would reduce administrative costs in two ways: Mandatory recordkeeping and reporting would be removed and the documentation required to explain why excluded controllers would no longer be necessary would be removed. Another commenter suggests that the EPA state in the final rule that NSPS/NESHAP applicability alone should not trigger minor source permitting requirements.

Response: The EPA agrees that cost and other compliance burdens are important considerations in a rulemaking. In fact, the EPA believes that such consideration is particularly important here given that coverage of the transmission sector would result in a significant number of sources and owner and operators that are not subject to the current standards. Specifically, were we to finalize standards, we estimate that we would end up covering an additional 67 sources. We estimate VOC emissions from these units to be 0.1 tpy per facility or about 6 tpy nationwide for new sources, which is well below the level emitted by other affected facilities in this sector.

While our analysis suggests that this is an important set of sources to regulate, given the large number of sources, and the relatively low level of VOC emitted from these sources, we have concluded that additional evaluation of these compliance and burden issues is appropriate prior to taking final action on pneumatic controllers in the transmission and storage segment. For this reason, the requirements for pneumatic controllers in the final rule only apply to production through processing segments. Our current data indicate that the VOC content of the natural gas used for pneumatic controllers in the transmission and storage segment is low, while higher VOC content natural gas is used in the segments we are regulating. Also, for the reasons explained in the previous response to comment, no VOC threshold will be included in this regulation.

3. Cost and Emissions Calculations

Comment: One commenter asserts that the EPA's estimate of 14,000 new and replaced controllers in a given year is grossly underestimated. By the commenter's data and calculations, approximately 750,000 controllers in Texas alone may need to be replaced (unless an exemption is granted) once a well becomes subject to the new rule.

Response: The commenter incorrectly claims that the EPA's estimate of the number of pneumatic controllers installed in a given year is 14,000. In Section 5.3.2 of the TSD, the EPA explains its methodology for estimating the number of pneumatic controllers in both gas/oil production and gas transmission and storage. Table 5–3 of the TSD gives a breakdown of snap-acting versus bleed controllers and shows the total number of controllers to be 33,673. The commenter did not provide data to support its claim that there are 750,000 pneumatic controllers in Texas, or that all of them have bleed rates higher than the proposed NSPS requirements such that any future replacement would require the use of a different model (*i.e.,* low bleed or no bleed, depending on its location) of controller. In any event, the EPA has analyzed and determined that such replacement is cost-effective. One explanation for the commenter's high estimate may be a misunderstanding of the applicability of the final rule. We remind the commenter that the final rule does not apply to existing sources, unless the existing source is replaced, modified or reconstructed after August 23, 2011.

D. Major Comments Concerning Compressors

1. Compressors in the Transmission and Storage Segment

Comment: One commenter stated that the agency should exempt reciprocating and centrifugal compressors in the transmission and storage sector located after the point of custody transfer, because there is low-VOC content in natural gas from that sector. Another commenter urged the EPA to revise 40 CFR 60.5365 to exclude centrifugal compressors not associated with the Crude Oil and Natural Gas Production, Transmission, and Distribution sector. One commenter noted that some large natural gas customers (who are not in the Crude Oil and Natural Gas Production, Transmission, and Distribution sector) have natural gas centrifugal compressors that are used to increase the pressure of natural gas for use in an industrial process, or to compress natural gas used as the fuel in compressed natural gas vehicles.

One commenter argued further that even without regard to fundamental flaws stated in the five factors or methods, there still would be only trivial and inconsequential VOC reductions relative to the national VOC inventory. The commenter observed that achieving VOC reductions of 1 percent of the national anthropogenic VOC inventory would require over 21,000 regulations at 6.9 tpy, and that the EPA's estimated annual VOC reductions for compressors was similarly inconsequential. Nor, said the commenter, had the EPA adequately considered administrative burdens associated with reporting, recordkeeping and permitting. The commenter said the trivial, incremental emissions reductions that would result from the rule failed to justify the associated compliance costs and that the final rule should exclude transmission and storage sources. Another commenter expressly called on the EPA to reanalyze VOC emissions reductions and to reassess whether the rule would be cost effective. Also taking issue with supportive data, another commenter said the EPA should suspend rulemaking and expand its fact-finding to include a statistically significant sampling of affected sources. One commenter suggested that the EPA exclude centrifugal compressor facilities that compress natural gas that is less than 10 percent, weight basis, VOC. The commenter stated that compression of gas that does not contain VOC should not be subject to standards for VOC. The commenter believes this is consistent with equipment leak rules which do not regulate components that are not in VOC service.

Response: The EPA agrees with the commenter that natural gas in the transmission and storage segment has low-VOC content. The EPA notes that cost and other compliance burdens are important considerations in a rulemaking. We estimated the VOC emissions reductions from these units located in the transmission and storage segment to be 14.1 tpy for reciprocating compressors and 6.6 tpy for centrifugal compressors, which is well below the level emitted by other affected facilities in this segment. The EPA has not fully considered compliance burden for reciprocating and centrifugal compressors in the transmission and storage segment and is, therefore, not ready to take final action with respect to these sources. While our analysis suggests that this is an important set of sources to regulate, given the number of sources, and the relatively low level of VOC emitted from these sources, we have concluded that additional evaluation of these compliance and burden issues is appropriate prior to taking final action on reciprocating and centrifugal compressors in the transmission and storage segment.

Also, no VOC threshold will be included in this regulation given the arbitrary nature of defining one using available data. We believe this revision also addresses centrifugal compressors not associated with the Crude Oil and Natural Gas Production, Transmission, and Distribution sector.

2. Dry Seals Versus Wet Seals

Comment: Several commenters address the issue of whether the EPA should permit the use of a system other than dry seal to control emissions from centrifugal compressors. Some commenters provide information on situations where dry seal systems for centrifugal compressors are not technically feasible, such as where gas composition is inadequate, in some processing plants that already have a capture system in place, and in retrofits of some existing compressors due to housing design or operational requirements. Commenters opine that the rule should allow compliance using either system, depending upon particular circumstances, and should not preclude use of a wet seal-equipped compressor with controls capable of meeting a 95-percent VOC control efficiency or routing captured seal-oil gas to a fuel gas, recycling or other processing system. According to another commenter, it would not be feasible to capture gas that escapes from a centrifugal compressor and route it back to a low-pressure fuel stream for combustion as fuel gas; although such a process would capture a minimal amount of VOC emissions, the high cost of equipment to recapture the emissions would make the method described cost-prohibitive.

Commenters generally concurred that a 95-percent reduction in emissions was achievable through installing a capture system on a wet seal compressor. In addition, commenters disagreed with the EPA's cost estimates and concluded that a wet seal capture system is cost effective.

Response: In the preamble to the proposed rule, the EPA proposed that a dry seal system is the BSER for centrifugal compressors, but solicited comments on situations where the use of a dry seal is infeasible or otherwise inappropriate and wet seal is the only option. 76 FR 52762. As noted above, several commenters provided information on situations where dry seals are not technically feasible. Therefore, the EPA has concluded that dry seal is not the BSER for all new and modified centrifugal compressors. Instead, the EPA separately evaluates the control options for wet seal compressors. The EPA has identified one control option through its review of available information, including comments and other information obtained since proposal. The option is to route captured seal-oil gas to the compressor suction, fuel gas system or flare, all of which can achieve 95-percent control efficiency.

Based on the discrepancy between commenters' and the EPA's cost data, the EPA re-evaluated its cost information for this control option. The EPA cost estimates in the proposed rule assumed the use of a new flare to combust the captured seal oil gas, and, based on commenter information, the EPA is revising this assumption since a flare or other combustion source is expected to be available in gas processing facilities. From reviewing comments received, the EPA is aware that the captured gas is not always routed to a flare but in many cases is routed back to the compressor suction or fuel system. Given this information, the EPA has re-evaluated the costs for the centrifugal compressor wet seal capture system and determined a system of this type, in which the seal oil degassing vents are routed to fuel gas, compressor suction or an existing flare would cost $22,000. The estimated cost includes an intermediate pressure degassing drum, new piping, gas demister/filter and a pressure regulator for the fuel line. With this cost, the estimated VOC control cost effectiveness is $161/ton of VOC for the processing segment. If savings are included, the cost effectiveness for VOC control is −$2,408/ton of VOC.

In light of the above, we have determined that the control option described above is the BSER for wet seal compressors. Accordingly, the final NSPS would require that wet seal compressors reduce emission by 95 percent. For dry seal compressors, the only emission control option we have identified is the use of dry seal. Accordingly, there is no requirement in the final rule for dry seal compressors, and dry seal compressors are not affected facilities under the NSPS.

3. New Source Definition

Comment: Several commenters oppose the proposal in 40 CFR 60.5365(b) and (c) that a reciprocating compressor be considered as ''commenced construction'' on the date of installation at a facility. Commenters argue that the EPA was ''arbitrary and capricious'' in proposing to apply the concept of ''commenced construction'' in the NSPS context to a relocated compressor, because the agency had no ''reasoned explanation'' for making the change and that applying the concept of ''commenced construction'' to a relocated compressor is contrary to the plain language of the CAA.

Response: The EPA traditionally defines the term ''commence construction,'' as it applies to an equipment, to mean the time an owner or operator has entered into a contractual obligation to acquire the equipment. This is reflected in the definition of ''commenced'' in the General Provisions at 40 CFR 60.2, as well as in the relevant NSPS (see, *e.g.,* 40 CFR 60.4230(a) of subpart JJJJ). We, therefore, agree with the commenters that our proposed definition of ''commence construction'' in 40 CFR 60.5365(b) and 40 CFR 60.5365(c) as the time of installation is a deviation from our traditional view. Upon reviewing the comments and re-evaluating the proposed definition, we conclude that there is no discernible difference between the compressors at issue and other equipment subject to NSPS that would make such deviation necessary or appropriate in this case. We have, therefore, removed these specific definitions of ''commence construction'' in 40 CFR 60.5365(b) and 40 CFR 60.5365(c) in the final rule.

The NSPS also does not apply to relocated compressors. As provided in the NSPS General Provisions at 40 CFR 60.14(e)(6), relocation of an existing facility is not modification.

E. Major Comments Concerning Storage Vessels

1. Applicability Threshold Metric

Comment: Numerous commenters objected to the EPA's proposed use of liquid throughput to determine which storage vessels should be subject to the standards, asserting that the high variability in volatility of stored liquids and other parameters affecting emissions makes throughput a poor indicator of VOC emissions. The commenters indicate that, as a result, basing applicability on throughput would bring many storage vessels with low VOC emissions (some less than 1 tpy) under the standard and the required emission controls would not be cost-effective. Some commenters point out that certain storage vessels with high emissions might not be subject to the standards based on throughput.

Response: In its BSER analysis for storage vessels, the EPA estimated the VOC emissions for storage vessels with various levels of throughputs to determine the cost effectiveness of control. In that analysis, the EPA estimated that storage vessels with throughput rates of 1 barrel per day (bpd) of condensate or 20 bpd of crude oil are equivalent to VOC emissions of 6 tpy and determined that control is cost effective for these storage vessels. The EPA agrees with the comments that throughput is not a good indicator of VOC emissions and, therefore, not appropriate for determining the standards' applicability. However, the EPA has received no comment contesting the EPA's conclusion that regulating storage vessels emitting 6 tpy or more of VOC is cost effective and appropriate (the basis of our proposed throughput limit). Accordingly, in the final rule, the storage vessels NSPS applies to those emitting 6 tpy or more of VOC. This change from proposal would ensure that controls will be required only on those storage vessels where they can be applied cost effectively. This approach also allows for broader coverage across all types of storage vessels, regardless of the fluid that is stored or where the storage vessel may be located. The final rule reflects this change and has established a VOC emissions threshold of 6 tpy for storage vessels to require control. Based on our revised cost analysis, we determined that storage vessels with VOC emissions equal to or greater than 6 tpy or greater were cost effective to control at $3,400/ton of VOC. The final rule requires each facility to determine its own emission factor and calculate the estimated emissions from each storage vessel.

2. Definition of Affected Facility

Comment: Numerous commenters commented on the definition of storage vessel in 40 CFR part 60, subpart OOOO, calling for greater clarity and consistency and requesting that certain activities or equipment be included or excluded from the definition.

Response: The EPA agrees with the commenters who assert that a more specific and consistent definition of a storage vessel is needed. The revised definition more clearly focuses on identifying which units are considered storage vessels under this subpart and which units are not and describes a storage vessel using terminology similar to that used in 40 CFR part 63, subpart HH. We believe it is important to be somewhat consistent in terminology because the NSPS and NESHAP both apply to the oil and natural production segment where these tanks are primarily located. We also removed the emissions threshold from the definition and, instead, based the standard in 40 CFR 60.5395 on the VOC emission rate of the storage vessel. In response to comments requesting clarification on whether mobile units are considered storage vessels, we have set a minimum amount of time (180 consecutive days) that the storage vessel must be stationed at the same site before it is subject to 40 CFR part 60, subpart OOOO. Our reasoning for setting this minimum amount of time is discussed in the response to comment immediately below. Additionally, we have not excluded wastewater storage vessels, as the NSPS requires control for all storage vessels emitting at least 6 tpy of VOC. Further, some wastewater tanks containing significant amounts of organic compounds could exceed VOC emissions of 6 tpy. Finally, the revised definition includes specific exemptions for process vessels and pressure vessels to clarify that these units are not considered storage vessels. Since the applicability of subpart OOOO, as finalized, is not based on throughput, we believe it is not necessary to specify which types of stored materials are regulated and which are not, as suggested by commenters. If a stored material is emitting at least 6 tpy of VOC, then the storage vessel will need to reduce its VOC emissions by 95 percent.

Comment: Some commenters assert that the EPA should limit applicability to storage vessels that are stationary and should clarify the meaning of ''stationary'' to include or exclude certain types of storage vessels.

Additionally, the EPA received comments requesting that the stationary aspect of the ''storage vessel'' definition should be consistent with other rules, while acknowledging the particular scenarios unique to the oil and gas production segment. The commenter notes that the stationary aspect of a storage vessel is typically addressed by the EPA in terms of whether it is reasonably portable, although the EPA sometimes addresses portability based on the size of the vessel. The commenter states that another criterion specified by the EPA in several regulations is that ''vessels permanently attached to motor vehicles'' are not storage vessels, and the EPA has issued a determination that this exemption extends to storage vessels ''equipped with a permanently attached wheel assembly and a truck hitch'' (U.S. Environmental Protection Agency, letter from George T. Czerniak to Ken Comey, Flint Hills Resources L.P., September 2, 2004). According to the commenter, this renders most so-called frac tanks, Baker tanks, International Organization for Standardization tanks, etc., exempt from the storage vessel provisions when this form of definition is used. However, the commenter recognizes that such storage vessels sometimes become effectively ''stationary'' in oil and gas production operations and suggests that storage vessels should be deemed stationary if they remain at a given site for more than 180 consecutive days, consistent with the period of time allowed under 40 CFR 60.14(g) to achieve compliance after a modification. The commenter notes that this 180-day period is reasonable given that the definition of non-road engines in 40 CFR 89.2 allows a period of 12 consecutive months.

The commenter also points out that cost effectiveness of the proposed control measures has been evaluated under the assumption that storage vessels remain in place for the useful life of the control equipment, and, thus, the control costs are amortized over a period of years. Since the cost per ton of emission reductions would be much higher if the controls were applied to a storage vessel that is only on site temporarily, the commenter believes that a cost-effectiveness analysis for permanent storage vessels would not be valid for temporary storage vessels, and, thus, the control requirements for permanent storage vessels are not justified for temporary storage vessels. The commenter provides recommended language for the definition of ''storage vessel'' that addresses this and other concerns. Another commenter similarly states that costly control requirements are not appropriate for temporary storage vessels (on site less than 180 days).

Response: Based on the commenter's suggestion, the EPA has revised the definition of storage vessel to clarify that a storage vessel is subject to 40 CFR part 60, subpart OOOO if it remains on a given site for more than 180 consecutive days.

In general, we agree with the commenter's discussion about the EPA's past practices related to storage vessels. In particular, we agree that the inherent differences between ''mobile'' or temporary storage vessels in this source category and other categories indicate that they should be regulated differently. As mentioned in the previous response, there are many storage vessels in this source category that travel from site to site, so we did not feel it was appropriate to exclude all of these mobile storage vessels from control requirements. Many temporary storage vessels in this source category are typically bringing in material such as fracking fluid to well sites and can stay at a well site for up to several months in order to receive flowback. These storage vessels are considered to be an essential part of the drilling and production operation, more akin to how permanent storage vessels are utilized in the refining and organic chemical manufacturing sectors, rather than to conventional tank trucks that are typically excluded in other EPA rules. Therefore, we believe that 180 days is an appropriate period of time to establish a temporary tank as being subject to 40 CFR part 60, subpart OOOO, and, therefore, potentially required to install controls.

3. References to MACT Standards

Comment: The EPA received comment asserting that the outcome of its best demonstrated technology (BDT) analysis for proposed 40 CFR part 60, subpart OOOO was calculated to achieve the same level of control as 40 CFR part 63, subpart HH—undermining the BDT determination and effectively (and unlawfully) extending subpart HH major source MACT requirements to area source storage vessels.

As a result, the commenter asserts that the EPA's analysis precludes other potentially relevant regulatory alternatives—such as marginally less effective controls that might be applied to a broader range of storage vessels. The commenter states that the EPA's failure to consider other control techniques and other levels of control efficiency that might be achieved by its preferred techniques is arbitrary and capricious.

Response: The commenter incorrectly asserts that the EPA's NSPS for storage vessels was designed to achieve the same level of control as MACT in 40 CFR part 63, subpart HH. In *Portland Cement Assoc.* v. *EPA,* 665 F.3d 177 (D.C. Cir. 2011), the United States Court of Appeals for the District of Columbia Circuit rejected an argument that the EPA adopted NESHAP PM standards for NSPS, noting that the EPA arrived at the same limit for both NESHAP and NSPS using two different mechanisms. Similarly, in this case, although both the NESHAP and the NSPS require 95-percent control, the EPA established the two standards based on separate mechanisms. The EPA established the MACT standard in 1998 pursuant to section 112(d)(2) and (3) of the CAA. In contrast, the EPA established the NSPS based on BSER analysis under CAA section 111. The BSER analysis for storage vessels consists of the same steps as those for other affected sources evaluated in the proposed NSPS. Specifically, the EPA evaluated available information to identify VOC control options. The EPA then assessed various aspects of the control options, including their VOC reduction potentials, their cost effectiveness and secondary air impacts. The commenter did not claim that any part of the EPA's BSER analysis above was inaccurate or inappropriate. For the reasons stated above, the commenter's assertion is without support.

The commenter also claims that the EPA only analyzed two controls and, therefore, failed to consider other ''potentially relevant regulatory alternatives.'' However, the commenter did not identify any other control option for the EPA's consideration. The commenter simply suggests that the EPA should consider some less effective controls, which the commenter claims would have led to greater coverage. Without more information, it is unclear whether a less effective control than that we have identified would, in fact, qualify as BSER for controlling VOC emissions from storage vessels or would have resulted in coverage of additional storage vessels.

Comment: Two commenters state that the cost of the performance tests, monitoring, recordkeeping, etc., that are required through cross-references to 40 CFR part 63, subpart HH were not adequately considered by the EPA in the cost-effectiveness determination for 40 CFR part 60, subpart OOOO, which applies to dispersed locations that do not have electricity or automation, and have limited remote transmitting unit space.

Response: The EPA does not take into account monitoring, recordkeeping and reporting costs in determining cost effectiveness of controls and in evaluating BSER. Based on this and other comments detailed in the response to comments for this final rulemaking, the EPA removed from 40 CFR part 60, subpart OOOO the citations to the requirements for performance tests, monitoring, recordkeeping, etc., in 40 CFR part 63, subpart HH and incorporated these subpart HH requirements into subpart OOOO. During the incorporation process, we made minor revisions to the subpart HH requirements, as appropriate for subpart OOOO. For example, we removed references to glycol dehydrators and paragraphs listed as ''reserved.''

4. Availability of Control Equipment

Comment: Some commenters believe that there will be a shortage of control equipment available to meet the proposed storage vessel requirements, and recommend revisions to the compliance deadline for storage vessels based on a variety of considerations, including the availability of control devices, lead time needed for manufacturer testing of their combustors to be compliant with the NSPS and time needed to install the compliant devices.

Response: We agree that it will likely take some time beyond the promulgation date of the NSPS for combustor manufacturers to have control devices constructed, tested, documented and available for operators to install in efforts to comply with the storage vessel requirements of the NSPS. Under the final rule, operators are not required to conduct individual performance tests on combustors installed in the field if the combustor manufacturer tests and documents for the owner or operator that the model achieves a control efficiency of 95.0 percent. The time required for testing and documentation is often longer than for a single model when manufacturers provide multiple models for varying applications based on capacity. We believe this testing and documentation program would require an ''adjustment period'' for manufacturers to be ready to supply the operators with the correct equipment they need.

We considered whether it would be feasible for on-site testing to mitigate the shortage of manufacturer tested combustors. Although owners and operators can test their individual combustors in the field to determine combustor efficiency, such emissions testing is expensive and can only be performed if testing consultants are available to conduct the testing. We believe that immediately after the effective date of the NSPS there will be a shortage of available testing consultants concurrent with the shortage of pre-tested combustor models. As a result, we conclude that on-site testing would not sufficiently mitigate the difficulty of owners and operators complying with the NSPS.

We evaluated whether controls other than combustors would be available during this adjustment period. Although vapor recovery units (VRU) can provide 95.0-percent control for storage vessels and are one means of meeting the storage vessel standards in the NSPS, VRU cannot be used in every situation. For example, storage vessels located remotely where there is no available electrical service may not be able to be controlled using VRU. In addition, storage vessels with low concentration emission streams or fluctuating emissions may not be amenable to control by VRU. Further, VRU installations would also require on-site testing, and owners and operators would be hampered by the same consultant shortage situation described above for combustors.

In light of the above, we conclude that there is no BSER for storage vessel affected sources during the first year after promulgation, which we believe is appropriate for the adjustment period mentioned above. At the end of this adjustment period, we believe owners and operators should have no problem securing control devices that are manufacturer-tested and have appropriate documentation for determining control efficiency. Accordingly, the final rule provides for a 1-year phase-in beginning October 15, 2012 before the 95.0-percent control requirement is effective.

With regard to providing time for operators to establish the need for controls and install them where called for, the EPA agrees that some lag time may be needed after initial start-up for the owner or operator to determine the long-term production level of a well and to procure the appropriate control equipment. The EPA evaluated the approach taken in the Wyoming rules for new sources, which allows from 30 to 90 days for a source to achieve compliance, depending on the area of the state. Wyoming allows only 30 days in ozone nonattainment areas, 60 days for concentrated development areas or 90 days elsewhere in the state. The EPA believes that 60 days is a reasonable period for controlling new storage vessels at wells sites with no wells already in production.

However, for replacement storage vessels or additional storage vessels at well sites with one or more wells already in production, we believe the operator already should have information on liquid composition and throughput. This information would allow estimation of VOC emissions to determine applicability of control requirements and for acquisition and installation of a control device concurrent with the replacement or additional storage vessel being installed. In the final rule, for storage vessels constructed, modified or reconstructed at well sites with no well already in production, we have provided for a 30-day period for throughput to stabilize and for the operator to estimate VOC emissions to determine whether a control device will be required. If VOC emissions are estimated to be at least 6 tpy, the operator is provided an additional 30 days for the control device to become operational. We believe that the Wyoming experience illustrates that this will be sufficient time to size and obtain suitable controls.

F. Major Comments Concerning Notification, Recordkeeping and Reporting Requirements

1. 30-Day Notification and Annual Reports

Comment: Multiple commenters state that the 30-day advance notification of well completions under 40 CFR 60.5420(a) should be removed from the final rule. Commenters assert that this and notification requirements in 40 CFR 60.7(a) are unduly burdensome and costly, not adequately explained, not related to verifying compliance with the proposed rule and could conflict with the need to protect proprietary business information.

Multiple commenters also note that industry's estimate of annual completions is several times higher than the EPA's estimate of 20,000 completions following fracturing and completions following refracturing annually. The commenters believe that these requirements will likely overwhelm both regulated entities and state regulators alike. Commenters offer suggestions, including requiring annual certifications or maintaining records available for inspection, reducing the proposed advance notification requirement to 5–10 days and considering notification programs such as those in Texas and Wyoming. Different commenters support or oppose requiring a 30-day advance notice with follow-up notification of 1–2 days before an impending completion.

Several commenters suggest that the EPA should coordinate with state and local agencies to eliminate duplicative recordkeeping and reporting requirements, and that records of interest other than those submitted to the respective Oil and Gas Commissions should only be required to be retained and available upon inspection, similar to other permit requirements.

Several commenters do not agree that an annual report under 40 CFR 60.7(a)(1), 40 CFR 60.7(a)(3) and 40 CFR 60.7(a)(4) adds any value for verifying compliance and the EPA should remove this requirement from the final rule. The commenters add that the best method for compliance is for an owner or operator to maintain necessary records and to have the records available for review during an on-site inspection. One commenter suggests the annual report should include for each type of affected facility (1) the total number of affected facilities at the site; (2) the number of facilities that became affected facilities during the reporting period; (3) the number of exempted facilities; and (4) the number of affected facilities with a non-compliance situation during the reporting period. One commenter suggests that it would be easier for facilities to submit an annual report on a set date each year, and multiple affected facilities could be included in a single report. Two commenters propose that all notifications for each year be delivered in a single annual report corresponding to the reporting period in which the affected facilities become subject to the rule. One commenter suggests that operators should be required to keep records at the nearest manned office, but reports should only be required if they are requested by the EPA.

The commenters recommend, where feasible, streamlining the final notification and reporting requirements to eliminate unduly burdensome notification and reporting requirements.

Response: The EPA agrees that certain notification, recordkeeping and reporting requirements in the General Provisions are unduly burdensome for the new affected facilities in this NSPS. For that reason, well completions, pneumatic controllers and storage vessels will be exempt from the notifications required by 40 CFR 60.7(a)(1), (3) and (4). We agree that notifications of well completions should be as streamlined as possible to remove excess burden from both the owners and operators and regulatory agencies, as well. As a result, we have removed the 30-day advance notification requirement and instead are requiring an advance notice via email to the EPA or delegated authority no later than 2 days prior to completion.

To avoid duplicative and potentially conflicting notification requirements and to relieve notification burden from owners and operators, we have added a provision in the final rule that, if an owner or operator has met the state requirements for advance notification of well completions, then the owner and operator are considered to have met the advance notification requirement for gas well completions under the NSPS.

We also believe that the operator should be provided flexibility to use new technology to document compliance that would result in less paperwork burden on the part of the operators themselves and on regulators. To lessen the reporting burden, the final recordkeeping and reporting requirements for well completions also provide for a streamlining option that owners and operators may choose in lieu of the standard annual reporting requirements. The standard annual report must include copies of all well completion records for each gas well affected facility for which a completion operation was performed during the reporting period. The alternative, streamlined annual report for gas well affected facilities requires submission of a list, with identifying information of all affected gas wells completed, electronic or hard copy photographs documenting REC in progress for each well for which REC was required and the self-certification required in the standard annual report. The operator retains a digital image of each REC in progress. The image must include a digital date stamp and geographic coordinates stamp to help link the photograph with the specific well completion operation. Operators are not required to take advantage of the optional recordkeeping and reporting approach, as some may choose to follow the standard reporting requirements. Under either approach, the report must include a record of all deviations during the reporting period in cases where well completion operations with hydraulic fracturing were not performed in compliance with the requirements for each gas well affected facility.

Comment: One commenter requested that the EPA add a self-certification requirement to the annual report similar to that used in the title V program. The commenter recommended that the final rule require the annual report to include a statement signed by a senior official of the facility attesting to the truth, accuracy and completeness of the report.

The commenter also requested that the EPA require that the annual reports be submitted electronically to facilitate making the reports publicly available. The commenter suggested using social media outlets, smart phone applications and other electronic means to make the annual reports readily available.

Response: The EPA agrees that self-certification is an important mechanism for assuring the public that the information submitted by each facility is accurate. In addition, the title V program has successfully employed self-certification since its inception. Therefore, we are requiring self-certification, based on requirements in the title V program, in the final rule.

While we agree that having annual reports readily available to the public is a desirable goal, we did not identify any reporting programs or electronic databases that may be used for this purpose without significant modification. Therefore, we are not requiring annual reports to be submitted electronically, but we will continue to evaluate this option in the future.

2. Duplicative Recordkeeping and Reporting Requirements

Comment: Multiple commenters state that the notification, recordkeeping, monitoring and annual reporting requirements in the proposed NSPS are duplicative and extremely burdensome for operators and for state regulators with limited resources. The commenters make both general and specific recommendations to revise the reporting requirements in the final rule to eliminate duplication and reduce burden or better inform the public and regulatory agencies about deviations. Some commenters would eliminate all or some reports, while others argue that reporting is an essential compliance and enforcement mechanism and that additional information should be provided. Some commenters feel that an owner or operator should maintain necessary records and have them available for review.

Commenters want the compliance assurance requirements to be appropriate for the oil and gas industry and commensurate to the environmental benefit that will be generated. For example, some commenters feel that the EPA should exempt small sources regulated under this rule from the notification and reporting requirements.

Response: We have considered these and other related comments presented in the response to comments regarding the proposed reporting requirements. The EPA agrees that certain notification, recordkeeping and reporting requirements are unduly burdensome and believes it is important to minimize the burden of reporting requirements. However, as noted in several comments, states and other enforcement entities are confronting limited resources and visiting sites is not always practical and is particularly challenging in this industry. For that reason, the EPA believes notifications and reporting requirements are vital to ensure compliance with our regulations. Therefore, the EPA has evaluated the proposed notification, recordkeeping and reporting requirements in an effort to streamline the requirements to reduce burden on both industry and enforcement at the same time, assuring compliance with the NSPS. In the final rule, the EPA has removed or otherwise revised proposed reporting requirements that the EPA believes to be duplicative or unnecessary, including, but not limited to, those raised in the comments. These changes will streamline the reporting process and reduce the reporting burden on sources, including small sources. For example, as previously discussed, well completions and continuous bleed natural gas controllers are exempt from the notifications required by 40 CFR 60.7(a)(1), 40 CFR 60.7(a)(3) and 40 CFR 60.7(a)(4). In addition, the EPA has revised the rule language such that only continuous bleed natural gas controllers installed, modified or replaced during the reporting period are reported in the annual report. In addition, the EPA has revised the 30-day individual notification requirement for well completions, as discussed above.

3. Electronic Reporting of Emissions Data

Comment: Commenters suggest a variety of ways in which electronic reporting could be structured and implemented, with attention to coordination with various CAA requirements and programs to avoid duplicative and potentially burdensome requirements. Several commenters support electronic reporting of emissions data from all sources to be stored on existing EPA databases, such as the Electronic Greenhouse Gas Reporting Tool (e-GGRT) or added to the Toxics Release Inventory, and available to the public. These commenters believe that communities must have access to air quality information in order to protect public health. One commenter objects to the use of e-GGRT as a reporting mechanism in place of a state's own tracking system, where the state has enforcement responsibility for the emissions date and tracking of sources subject to the proposed rule. The commenters also suggested a variety of ways in which electronic reporting could be structured and implemented.

Several commenters oppose the implementation of electronic reporting at this time and are concerned that an ERT will result in numerous complications and undue additional burden. The commenters point out that the EPA's experience with e-GGRT indicates that considerable time and resources are needed to develop and implement efficient systems and to ensure that electronic reporting enhances efficiency rather than incurring additional burden on affected sources. The commenters state that a potential disadvantage associated with an ERT is that new and/or alternative test methods would not be in the system. In addition, the commenters believe that an ERT could be complicated and burdensome for smaller companies that lack environmental personnel or experience with electronic reporting under other rules. The commenters suggest that if the EPA delegates authority to states to implement and enforce the standards, some states may be unable or unwilling to accept electronic reports. The commenters urge the EPA to consider other more simplified options to report only the needed information.

Response: While the EPA supports and encourages electronic reporting, after further consideration of all the comments, we do not believe the e-GGRT is the appropriate mechanism for electronic reporting under this rule, as recommended by some commenters. The e-GGRT is not designed to accept all of the types of information required to be reported under the final rule, and significant modification of the system would be required to make it operational for this rule.

However, the final rule does include reporting of performance test data via the ERT. The EPA must have performance test data to conduct effective reviews of CAA sections 112 and 129 standards, as well as for many other purposes, including compliance determinations, emission factor development and annual emission rate determinations. In conducting these required reviews, the EPA has found it ineffective and time consuming, not only for us, but also for regulatory agencies and source owners and operators, 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.

In the final rule, as a step to increase the ease and efficiency of data submittal and improve data accessibility, the EPA is requiring the electronic submittal of select performance test data. Data entry will be through an electronic emissions test report structure called the ERT. The ERT will generate an electronic report which will be submitted using the CEDRI. The submitted report is submitted through the EPA's CDX network for storage in the WebFIRE database making submittal of data very straightforward and easy. Webfire is the EPA's online emissions factor repository, retrieval and development tool. The WebFIRE database is open to the public and contains the EPA's recommended emissions factors for criteria and HAP for industrial and non-industrial processes. Emissions data collected from the oil and natural gas sector, as well as many other sectors, will be used to update our emissions factors. The data will also be used by the EPA's rule writers to make better informed decisions and learn more detailed information about emissions from sources. The electronic reporting requirement in this rule (and other NSPS/NESHAP rules) is only for test methods that are supported by the ERT.

One major advantage of submitting 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 what testing information 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.

State, local and tribal agencies can also benefit from a more streamlined and accurate review of electronic data submitted to them. The ERT allows for an electronic review process rather than a manual data assessment making review and evaluation of the data and calculations easier and more efficient. Finally, another benefit of submitting data to WebFIRE electronically is that these data will greatly improve the overall quality of the existing and new emission 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 will be able to ensure that emission factors, when updated, represent the most current range of operational practices.

X. Summary of Significant NESHAP Comments and Responses

For purposes of this document, the text within the comment summaries was provided by the commenter(s) and represents their opinion(s), regardless of whether the summary specifically indicates that the statement is from a commenter(s) (*e.g.,* ''The commenter states'' or ''The commenters assert''). The comment summaries do not represent the EPA's opinion unless the response to the comment specifically agrees with all or a portion of the comment.

A. Major Comments Concerning Previously Unregulated Sources

Comment: One commenter asserts that, although the EPA's original MACT analysis covered all storage vessels, it issued a MACT standard at that time that applied to storage vessels with the PFE only. The commenter states that, while they support the EPA's effort to correct this omission, the initial analysis for the tanks that the agency did regulate in 1999 was seriously flawed, and the proposed rule provides no justification for continuing to rely on a 13-year old analysis to propose a MACT standard for an entirely new universe of storage vessel sources. Thus, according to the commenter, the EPA's failure to properly calculate the MACT floor in setting the MACT standard for storage vessels violates CAA section 112(d)(2) and (3).

The commenter states that, because this method has been found to be unlawful and substantially more data are available at this time, the EPA must now recalculate the MACT floor and MACT limits for tanks with the PFE. *Cement Kiln Recycling Coalition, et. al.* v. *U.S. EPA,* 255 F.3d 855, 863–64 (D.C. Cir. 2001). The commenter asserts that, in addition and partly as a consequence of its unlawful reliance on the prior standards, the EPA also has failed to fulfill the beyond-the-floor requirement of CAA section 112(d)(2). The commenter opines that, absent an up-to-date analysis based on current emission controls, an appropriate beyond-the-floor determination cannot be made.

Two commenters do not believe that the dataset used is representative of currently operating small glycol dehydrators. One commenter believes that the EPA has not satisfied section 112(d)(2) and (3) of the CAA and that the EPA needs to calculate the MACT limit based on the best-performing sources that currently exist.

One commenter recommends that the EPA base its MACT floor analyses on emissions data from a representative population of small dehydrators that characterize the population of affected sources within the category or subcategory. The commenter reports that more current data sources may be available, such as dehydrator emissions data reported to state agencies in annual emission reports or in permit applications.

One commenter opines that the EPA's proposal misses the opportunity and fails to fulfill the agency's responsibility to properly calculate the MACT for all sources in this sector based on current, reliable and representative emission test data. The commenter believes that, by relying on an incomplete and outdated dataset to set MACT floors and limits, the EPA has ignored data demonstrating trends in practices, processes and technologies and the resulting improved performance that CAA section 112(d) mandates. The commenter asserts that the EPA ignores the potential HAP emissions that the control devices themselves emit by failing to collect such emissions data from facilities that have installed control devices. The commenter argues that the EPA must collect the appropriate emission test data needed in order to recalculate and set a proper MACT for glycol dehydrators, storage vessels and equipment leaks.

One commenter states that section 112 of the CAA requires the EPA to set a NESHAP for each category or subcategory of ''major sources'' of HAP emissions. 42 U.S.C. 7412(d)(1). The commenter asserts that the EPA must set CAA section 112(d) emission standards based on ''maximum achievable control technology'' or ''MACT.'' The commenter states that the EPA largely bases its MACT proposal for small glycol dehydrators on emissions data collected from the industry during the development of the original MACT standards. 76 FR 52768. The commenter contends that the data were collected prior to 1997 and did not adequately represent the emissions profile at that time, and do not reflect the significant changes in the industry and other technological developments that have occurred during the past 13 years. According to the commenter, the EPA has not provided a reasoned explanation of how those data could be representative of currently operating glycol dehydrators and associated emission reductions, and how proposals based on those data can currently meet the MACT requirements for new and existing sources. The commenter states that the dehydrator technology performance in 1997 was not accurately reflected in the legacy EPA dataset and has advanced significantly in the past 13 years. Consequently, according to the commenter, the EPA has not provided a reasoned explanation of how those data could be representative of currently operating glycol dehydrators and associated emission reductions, and how proposals based on those data can currently meet the MACT requirements for new and existing sources. The commenter believes this is critical because the 2005 NEI data reveal that improvements in the environmental performance of the category have progressed such that there are far more units in service with lower emissions than reflected in the 1997 data.

One commenter states that the EPA did not collect recent data regarding emissions of HAP, including BTEX, from small glycol dehydrators in either source sector in support of this rulemaking. Instead, according to the commenter, the EPA appears to have relied on data collected in the prior MACT rulemaking, going back to 1998 or prior. The commenter believes that the EPA's analysis is flawed and questionable because it simply relies on the best-performing sources that existed a decade ago and fails to identify the best controlled sources today. The commenter contends that it is unlikely that these MACT standards reflect either the current best controlled similar source emissions or the average of the top 12 percent of the currently best controlled sources. The commenter states that, while the EPA appropriately proposes to set a MACT limit for these sources for the first time, the EPA's use of out-dated data fails to demonstrate that its proposed limit is stringent enough in light of significant developments in emission control technologies and practices that have occurred since 1998.

Response: One commenter argues that EPA has not satisfied sections 112(d)(2) and (3) of the CAA, because the MACT standards set in the 1999 rule have not been re-calculated using current data. To the extent the commenter is arguing that CAA section 112(d)(6) requires that the EPA recalculate the MACT standards set in 1999, based on current emissions test data, the commenter is incorrect. In *NRDC* v. *EPA,* 529 F.3d 1077, 1084 (D.C. Cir. 2008), the District of Columbia Circuit held that it ''[did] not think the words 'review, and revise as necessary' can be construed reasonably as imposing any such obligation'' to re-calculate the MACT floors. *NRDC* v. *EPA,* 529 F.3d 1077, 1084 (D.C. Cir. 2008).

Moreover, in this action, we did not re-open the MACT standards in 40 CFR part 63, subpart HH for large glycol dehydrators, storage vessels with the PFE and equipment leaks for or in 40 CFR part 63, subpart HHH for large glycol dehydrators. As such, the commenter's request that we re-calculate those standards based on current emissions data is outside the scope of this rulemaking. We did, however, conduct a CAA section 112(d)(6) technology review for subpart HH and determined that there have been no developments in practices, processes or control technologies for large glycol dehydrators, storage vessels with the PFE and equipment leaks and that there have been developments for equipment leaks. See *Technology Review for the Final Amendments to Standards for the Oil and Natural Gas Production and Natural Gas Transmission and Storage Source Categories* and responses on section 112(d)(6) comments below. We also conducted a CAA section 112(d)(6) technology review for subpart HHH and determined that there have been no developments in practices, processes or control technologies for large glycol dehydrators. *Id.*

The remaining comments focus on the data the agency used to set the proposed MACT standards for small glycol dehydrators, which were left unregulated in the 1999 rule. The commenters claim that the data the EPA used to set the BTEX MACT standards for the small glycol dehydrators subcategory are outdated and that the EPA must collect new data. However, CAA section 112(d)(3) specifically provides that the Agency is to determine the average emission limit achieved by the best performing 12 percent of existing sources ''(for which the Administrator has emissions information).'' Thus, the EPA is not required to collect information if it determines that the information it has is sufficient for it to calculate the MACT standards consistent with the requirements of CAA section 112. Although the available emissions information is over a decade old, the available controls for reducing BTEX emissions from small glycol dehydrators and their control efficiencies have remained the same during this period, and the commenters have not provided any data to the contrary.[27] We,

[27] Memorandum from Brown, Heather, EC/R Inc., to Moore, Bruce, U.S. EPA, titled *Technology Review for the Final Amendments to Standards for the Oil and Natural Gas Production and Natural* Continued

therefore, believe the data we have are still representative of the performance of the small dehydrators.

Moreover, we believe that the collection and analysis of additional data would take time and further delay control of these sources, which we do not think is warranted where, as here, we believe the data on BTEX emissions for the subcategory of small glycol dehydrators are still representative of these sources' performance today and the commenter did not provide any data that indicates otherwise.

Finally, for small glycol dehydrators, we considered using more current available data, like the 2005 NEI, however, the NEI dataset lacks specific information that we believe is relevant to identifying the best performing units. Specifically, the NEI data lacks information on inlet HAP content and gas throughput, both of which affect a glycol dehydrator's HAP emissions. Inlet HAP content varies from well site to well site. A well-controlled glycol dehydrator at a well site with high inlet HAP content may have higher HAP emissions than a totally uncontrolled glycol dehydrator at a well site with a low inlet HAP content. Natural gas throughput also affects a glycol dehydrator's overall emissions (*i.e.,* low throughput units will tend to have lower overall emissions, and vice versa). For the reasons stated above, in addition to emissions, we need to consider the inlet HAP content and gas throughput of the small glycol dehydrators in order to properly identify the best performing sources and establish the MACT standard for this subcategory. However, information on natural gas throughput and inlet HAP content is not included in the NEI or any other readily available data source. Therefore, we used the 1997 data which included such information for the small dehydrators.

Comment: One commenter supports the EPA's regulation of previously unregulated sources in the oil and natural gas sector and the commenter asserts that CAA sections 112(c) and 112(k) (Urban Air Toxics Strategy) support their position regarding the regulation of previously unregulated sources. The commenter asserts that historical regulation of emission sources within the sector leaves a large number of dehydrators, storage vessels and equipment at gas processing plants unregulated. Additionally, the commenter states that historical regulation has also not limited emissions from a number of other emission sources (*i.e.,* wells, pneumatic devices, compressor seals, valves, or flanges or other production equipment located at oil and gas production facilities or natural gas storage transmission facilities).

One commenter supports the EPA's recognition of the need to control emissions from previously uncontrolled emission points and commends the EPA on addressing small glycol dehydration units and storage vessels without the PFE. The commenters request that the EPA address all of the uncontrolled HAP emission points of which it is aware.

Response: This rule establishes MACT standards for major sources of small glycol dehydrators that were left unregulated in the 1999 MACT rule. As explained further below, in several recent rulemakings, we have chosen to fix certain underlying defects in existing MACT standards under CAA sections 112(d)(2) and (3), which are the provisions that directly govern the initial promulgation of MACT standards (see National Emission Standards for Hazardous Air Pollutants From Petroleum Refineries, October 28, 2009, 74 FR 55670; and National Emission Standards for Hazardous Air Pollutants: Group I Polymers and Resins; Marine Tank Vessel Loading Operations; Pharmaceuticals Production; and the Printing and Publishing Industry, April 21, 2011, 76 FR 22566). We believe that this approach is reasonable because using those provisions ensures that the process and considerations are those associated with initially establishing a MACT standard, and it is reasonable to make corrections following the process that would have been followed if we had not made an error at the time of the original promulgation. We appreciate the commenter's support for regulating small glycol dehydrators.

Although the agency had proposed MACT standards under CAA sections 112(d)(2) and (3) for the subcategory of storage vessels without the PFE, we are not finalizing those standards here. Based on our review of the comments, we believe that we need additional data in order to set an emission standard for these vessels. We intend to collect the appropriate data and propose a MACT emission standard under CAA sections 112(d)(2) and (3) of the CAA.

The commenter identifies certain emission sources, other than small glycol dehydrators and storage vessels without the PFE (*e.g.,* wells), that it alleges are uncontrolled. CAA section 112(n)(4)(A) prohibits aggregation of emissions from any oil and gas exploration or production wells (with their associated equipment) in determining major source status or for any purpose under CAA section 112. In light of this prohibition on aggregation, and the fact that the sources identified by the commenter likely would not, if viewed alone, qualify as a major source, it is not clear whether emissions from the sources identified by the commenter can be addressed by a major source NESHAP.[28]

The commenter also references CAA section 112(k) (and the Urban Air Toxic Strategy). CAA section 112(k) is designed to address area source emissions in urban areas. This rule involves a review of 40 CFR part 63, subparts HH and HHH, both of which address major sources, not area sources. Further, oil and gas production facilities are typically not sited in urban areas.

To the extent that the commenter is requesting EPA to list area source oil and gas production wells, such a request is outside the scope of this action. See CAA section 112(n)(4)(B) (specifying certain requirements for listing ''oil and gas production wells (with its associated equipment)'' as an area source category).

B. Major Comments Concerning the Risk Review

Comment: One commenter states that the EPA's analysis for 40 CFR part 63, subpart HH revealed two facilities (Hawkins Gas Plant, Hawkins, Texas, and Kathleen Tharp 2, Huffman, Texas) with a cancer MIR greater than 100-in-1 million based on MACT allowable emissions. The commenter notes that since the EPA determined that these facilities had a cancer MIR greater than 100-in-1 million based on MACT allowable emissions, the EPA determined that the risks are unacceptable for the Oil and Natural Gas Production MACT source category and additional regulation was needed. However, the commenter believes these results are entirely incorrect due to fundamental errors in the EPA's calculations of MACT allowable risk for these two facilities. In addition, even if the analysis had been correct, the commenter states there are significant issues associated with the data for both of these facilities, which the commenter discusses in detail, that the commenter believes are sufficient to invalidate the results and the EPA's conclusion that risks from the Oil and Natural Gas Production source category are unacceptable.

Response: We have reviewed our risk results for the Oil and Natural Gas Production source category and agree

Gas Transmission and Storage Source Categories. Dated April 17, 2012.

[28] Even if the commenter were to identify an unregulated emission point under the NESHAP, it can always petition the agency to revise the 1999 MACT standards.

with the commenter that a number of errors were made in our analysis, including those noted by the commenter. As explained in VII.A.2 of this preamble, we have revised the risk assessment for this major source category to correct certain mistakes made in the analysis supporting the proposed rule.

Based on our revised risk assessment, in which we evaluated the risks that remain after promulgation of the original MACT standards, as well as the MACT standards for small glycol dehydrators established in this final rule, we have determined the risks for the Oil and Natural Gas Production major source category are acceptable and that the MACT standards (including those promulgated here for small glycol dehydrators) provide an ample margin of safety. Further, we are retaining the 0.9 Mg/yr benzene compliance alternative, which we had proposed to remove based on our incorrect conclusion that this alternative was driving the risk for this major source category.

Comment: One commenter states that the EPA bases the decision to eliminate the 0.9 Mg/yr benzene emission limitation for 40 CFR part 63, subpart HHH on two basic factors: (1) It would reduce the cancer MIR from 90-in-1 million to 20-in-1 million, and (2) the cost effectiveness to comply with this option is reasonable. The commenter states that both of these conclusions are erroneous.

First, the commenter states that removal of 0.9 Mg/yr benzene alternative does not reduce risk. The commenter states that the EPA's own technical analysis indicates that removal of the 0.9 Mg/yr benzene alternative would have no effect on the MIR.

Secondly, the commenter states that the EPA's cost analysis is severely flawed. The commenter also states that the EPA noted at proposal, that the cost-effectiveness associated with removing the 0.9 Mg/yr benzene compliance alternative for natural gas transmission and storage facilities was reasonable. However, the commenter explained that the cost estimates used by the EPA in the ample margin of safety determination are inadequate. According to the commenter, the EPA did not conduct any analysis using actual data. Rather, the commenter notes that the EPA used costs estimated for small dehydrators and made general assumptions to estimate an upper-end cost effectiveness for removing the 0.9 Mg/yr benzene alternative limit for large dehydrators at natural gas transmission and storage facilities. The commenter believes that, in general, the emission reductions for dehydrators forced to switch from the 0.9 Mg/yr benzene alternative to 95-percent control would be considerably less than those achieved by small dehydrators. The commenter further notes that the cost-effectiveness calculated for small dehydrators is based on a 95-percent reduction from an uncontrolled baseline level. According to the commenter, if a large dehydrator has installed controls to meet the 0.9 Mg/yr alternative benzene limitation, the cost effectiveness must be based on the incremental reduction between the existing controls and 95 percent. The commenter states that the EPA has provided no evidence that these incremental reductions would be greater than or equal to the 95-percent reductions that would be achieved for smaller dehydrators. In conclusion, the commenter states that the rationale used by the EPA in the preamble to support the removal of the 0.9 Mg/yr compliance alternative for dehydrators at natural gas transmission and storage facilities under section 112(f)(2) of the CAA is not supported by any of the background technical documentation and analyses. The commenter believes that the EPA has no basis under any other CAA authority for this action.

Response: In response to comments, we re-examined our risk assessment for the Natural Gas Transmission and Storage source category and discovered a number of errors, which we have discussed in more detail in section VII.B.2 of this preamble. As explained in that section, we have revised the risk assessment for this major source category to correct the mistakes. Based on our revised risk assessment, in which we evaluated the risks that remain after promulgation of the original MACT standards, as well as the MACT standards for small glycol dehydrators in this final rule, we have determined that the risks for the Oil and Gas Transmission and Storage major source category are acceptable and that the MACT standards (including those promulgated here) provide an ample margin of safety. Further, we are retaining the 0.9 Mg/yr benzene compliance alternative, which we had proposed to remove based on our incorrect conclusion that it was driving the risk for this major source category. We agree with the commenter that removal of the 0.9 Mg/yr benzene compliance alternative does not reduce risks for this major source category. Because we are retaining this compliance alternative, we need not address the comment on the cost effectiveness of removing this alternative.

C. Major Comments Concerning the Technology Review

Comment: One commenter states that, in conducting an 8-year review, the EPA must ''look back'' at the earlier standard and ascertain whether: (1) The standard was adopted using procedures that comply with the law as it has come to be interpreted by the courts; (2) the EPA had sufficiently accurate and comprehensive data at the time of the initial standard setting respecting the emissions profile of the category and properly identified the best performing unit(s); and (3) the EPA had properly used the available data.

The commenter states the EPA then must ''look around'' using currently available data and determine whether: (1) The emissions profile of the industry has changed in a way that would substantially affect the MACT floor calculations (the commenter adds that this includes consideration of any increase in the number of good performing units available for use in the existing source MACT floor calculation and in the performance of the best performing unit); (2) data gaps or uncertainties that affected the earlier decision have been resolved in the interim or can be resolved using new information available to the agency; (3) costs or other factors have changed in a way that would substantially affect the ''beyond-the-floor'' determination; (4) the use of improved practices, processes or technologies (including improvements in the performance of existing technologies) has become more prevalent than at the time of the initial standard setting; or (5) whether newer regulatory requirements, work practices or emission limitations (including state and local jurisdiction air pollution standards and federal enforcement actions), which are more stringent than the existing CAA section 112(d) standard, have shown the achievement or achievability of greater emission reductions than the existing standard requires.

Response: As explained in the preamble to the proposed rule, our technology review 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 at issue here. We first reviewed the available information. In this regard, we reviewed a variety of sources of data, including data obtained in subsequent air toxics rules to see if any practices, processes and control technologies considered in these actions could be applied to emission sources in the source categories at issue here. We also consulted the EPA's Reasonably Available Control Technology (RACT)/Best Available Control Technology (BACT)/Lowest Achievable Emission Rate (LAER) Clearinghouse (RBLC) and the Natural Gas STAR program. At proposal, we explained that we consider 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.

The commenter views CAA section 112(d)(6) differently. It appears to argue that CAA section 112(d)(6) requires that the EPA recalculate the MACT based on current data and technology. The same argument was posed to the District of Columbia Circuit, and the Court ''[did] not think that the words 'review, and revise as necessary' can be construed reasonably as imposing any such obligation.'' *NRDC* v. *EPA,* 529 F.3d 1077, 1084 (D.C. Cir. 2008). Thus, contrary to the commenter's assertion, the EPA is not required pursuant to CAA section 112(d)(6) to re-calculate the floors it set in 1999.

To the extent the commenter is arguing that CAA section 112(d)(6) mandates that the EPA correct any deficiency in an underlying MACT standard when it conducts the ''technology review'' under that section, we disagree. We believe that CAA section 112 does not expressly address this issue, and the EPA has discretion in determining how to address a purported flaw in a promulgated standard. CAA section 112(d)(6) provides that the agency must review and revise ''as necessary.'' The ''as necessary'' language must be read in the context of the provision, which focuses on the review of developments that have occurred since the time of the original promulgation of the MACT standard and thus should not be read as a mandate to correct flaws that existed at the time of the original promulgation.

In several recent rulemakings, we have chosen to fix underlying defects in existing MACT standards under CAA sections 112(d)(2) and (3), the provisions that directly govern the initial promulgation of MACT standards (see National Emission Standards for Hazardous Air Pollutants From Petroleum Refineries, October 28, 2009, 74 FR 55670; and National Emission Standards for Hazardous Air Pollutants: Group I Polymers and Resins; Marine Tank Vessel Loading Operations; Pharmaceuticals Production; and the Printing and Publishing Industry, April 21, 2011, 76 FR 22566). We believe that our approach is reasonable because using those provisions ensures that the process and considerations are those associated with initially establishing a MACT standard, and it is reasonable to make corrections following the process that would have been followed if we had not made an error at the time of the original promulgation. As explained elsewhere, we are not finalizing MACT standards for the subcategory of storage vessels without the PFE, which were unregulated in the 1999 rule, because after evaluating the available data and comments received, we believe that we need additional data in order to set an emission standard for these vessels. We are, however, finalizing MACT standards under CAA sections 112(d)(2) and (3) for the subcategory of small glycol dehydration units.

With regard to our CAA section 112(d)(6) review, we found no significant developments in practices, processes and control technologies for reducing emissions from large glycol dehydrators and storage vessels with PFE.[29] Accordingly, we are not revising these standards under CAA section 112(d)(6).

The EPA also conducted a technology review evaluating various options for controlling HAP emissions from equipment leaks. As described in the proposed rule (76 FR 52784), we evaluated advancements in controlling this emissions source since the original standards were promulgated, including the emission reduction potential and associated cost-effectiveness of these advancements. As a result of our review, we revised the leak definition for valves at natural gas processing plants to 500 ppm, thus, requiring the application of the LDAR requirement at this lower detection level. As discussed above, the commenter appears to be arguing that the EPA must redo the MACT floor and beyond-the-floor analysis under CAA sections 112(d)(2) and (3) within its CAA section 112(d)(6) technology review, which we disagree.

[29] See footnote 25.

Comment: One commenter states that the EPA's technology review for storage vessel control technologies is limited and makes incorrect assumptions. The commenter contends that without further support, the public cannot understand and the EPA cannot justify its proposed decision; therefore, the EPA's proposal is arbitrary and capricious. The commenter adds that the EPA must conduct an updated beyond-the-floor analysis for storage vessels, by determining the ''maximum degree of reduction in emissions'' that is achievable, as required under CAA section 112(d)(2). The commenter states that the proposed rule fails to provide any discussion of a beyond-the-floor determination for storage vessels.

One commenter states that the EPA must examine advances in vapor recovery unit technology and reconsider floating roof technology for tanks containing liquids that do not have the PFE. The commenter contends that the EPA improperly rejected technology advances and developments in pollution prevention systems found in its own RBLC database and employed by its own Natural Gas STAR partners. Specifically, according to the commenter, the EPA failed to evaluate the performance achieved by systems that use thermal or catalytic oxidizers, either alone or in combination with condensers. According to the commenter, the EPA's RBLC review identified a BACT determination for dehydrator efficiency of 98 percent. The commenter also urges the EPA to evaluate the use of combustion devices and vapor recovery units that capture vent steam from the tank and turn it into a saleable product by recompressing the hydrocarbon vapors. The commenter contends that the EPA rejects technology advances by asserting that those technologies were considered in the 1999 rulemaking, but fails to provide support for its decision in either the record of the 1999 rulemaking or the current record. The commenter contends that the EPA must provide a basis for its decisions and conclusions.

Response: For the reasons discussed in the prior response, the EPA disagrees with the commenter's assertion that it must re-do the MACT floor calculations, including the beyond-the-floor determination, for the standards that the agency set in 1999. As to the technologies identified by the commenter, they were in existence and considered by the EPA at the time the EPA promulgated the original MACT standards for storage vessels.[30 31] In addition, we are not finalizing control requirements for storage vessels without the PFE, as described in section VII.A of this preamble. The record does not support the assertion that the technologies identified by the commenter have advanced in terms of HAP emission reduction or have become significantly more cost effective. As explained in the preamble to the proposed rule (76 FR 52785), we examined technologies that were similar to the cover and route emissions to a control device that the MACT floor requires and, thus, would not result in reductions beyond the existing MACT requirements. Further, evaluation of technologies in the RBLC did not produce any applicable practices, processes or control technologies that were not considered during the original MACT for storage vessels with flash emissions.[32]

D. Major Comments Concerning Notification, Recordkeeping and Reporting Requirements

1. Annual Reports

Comment: One commenter requested that the EPA add a self-certification requirement to the annual report similar to that used in the title V program. The commenter recommended that the final rule require the annual report to include a statement signed by a senior official of the facility attesting to the truth, accuracy and completeness of the report.

The commenter also requested that the EPA require that the annual reports be submitted electronically to facilitate making the reports publicly available. The commenter suggested using social media outlets, smart phone applications and other electronic means to make the annual reports readily available.

Response: The EPA agrees that self-certification is an important mechanism for assuring the public that the information submitted by each facility is accurate. In addition, the title V program has successfully employed self-certification for since its inception. Therefore, we are requiring self-certification, based on requirements in the title V program, in the final rule.

While we agree that having annual reports readily available to the public is a desirable goal, we did not identify any reporting programs or electronic databases that may be used for this purpose without significant modification. Therefore, we are not requiring annual reports to be submitted electronically, but we will continue to evaluate this option in the future.

2. Electronic Reporting of Emissions Data

Several commenters raised similar issues regarding reporting of emissions data under the NESHAP as under the NSPS, described *supra,* and our responses there apply equally here. Please see comments and responses in section IX.F.3 of this preamble.

XI. What are the cost, environmental and economic impacts of the final NESHAP and NSPS amendments?

A. What are the air 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 final 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 finalized limits for glycol dehydration units, we have estimated that the HAP emissions reductions will be 670 tons for existing units subject to the final 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.

The primary baseline used for the impacts analysis of our NSPS for completions of hydraulically fractured natural gas wells takes into account REC conducted pursuant to state regulations covering these operations and estimates of REC performed voluntarily. To account for REC performed in regulated states, the EPA subsumed emissions reductions and compliance costs in states where these completion-related emissions are already controlled into the baseline. Additionally, based on public comments and reports to the EPA's Natural Gas STAR program, the EPA recognizes that some producers conduct well completions using REC techniques voluntarily for economic and/or environmental objectives as a normal part of business. To account for emissions reductions and costs arising from voluntary implementation of pollution controls, the EPA used information on total emission reductions reported to the EPA by partners of the EPA Natural Gas STAR. This estimate of this voluntary REC activity in the absence of regulation is also included in the baseline.[33] More detailed discussion on the derivation of the baseline is presented in a technical memorandum in the docket, as well as in the Regulatory Impact Analysis (RIA).

Additionally, in the RIA, we provide summary-level estimates of emissions reductions and engineering compliance costs for a case where no voluntary REC are assumed to occur. This alternative case is presented in order to show impacts if conditions were such that REC were no longer performed on a voluntary basis, but, rather, were compelled by the regulation, and serves, in part, to capture the inherent uncertainty in projecting voluntary activity into the future. As such, this alternative case establishes the full universe of emissions reductions that are guaranteed by this NSPS (those that are required to occur under the rule, including those that would likely occur voluntarily). While the primary baseline may better represent actual costs (and emissions reductions) beyond those already expected under business as usual, the alternative case better captures the full amount of emissions reductions where the NSPS acts as a backstop to ensure that emission reduction practices occur (practices covered by this rule).

Under the final NSPS, we have estimated that the emissions reductions to be about 190,000 tons VOC affected facilities subject to the NSPS. The NSPS is also expected to concurrently reduce 1.0 million tons methane and 11,000 tons HAP. We estimate that direct reductions in HAP, methane and VOC for the final rules combined total about 12,000 tons, 1.0 million tons and 190,000 tons, respectively. If voluntary action is not deducted from the NSPS baseline, the emissions reductions achieved by the final NSPS in HAP, methane and VOC are estimated at

[30] See footnote 25.

[31] See EPA Legacy Docket A–94–04 MACT floor memos II–A–006 and –007.

[32] See footnote 25.

[33] Voluntary short-term actions (such as REC) are challenging to capture accurately in a prospective analysis, as such, reductions are not guaranteed to continue. However, Natural Gas STAR represents a nearly 20-year voluntary initiative with participation from 124 natural gas companies operating in the United States, including 28 producers, over a wide historical range of natural gas prices. This unique program and dataset, the significant impact of voluntary REC on the projected cost and emissions reductions (due to significant REC activity), and the fact that REC can actually increase natural gas recovered from natural gas wells (offering a clear incentive to continue the practice), led the agency to conclude that it was appropriate to estimate these particular voluntary actions in the baseline for this rule.

about 19,000 tons, 1.7 million tons and 290,000 tons, respectively.

The EPA received several comments regarding the emission factor selected to calculate whole gas emissions (and the associated VOC emissions) from hydraulically fractured well completions. Comments focused on the data behind the emission factor, what the emission factor is intended to represent and the procedures used to develop the emission factor from the selected data sets. We reviewed all information received and have decided to retain the data set and the analysis conducted to develop the emission factor of 9,000 thousand cubic feet (Mcf) per completion. More detailed discussion is presented in a technical memorandum on this subject in the docket.

B. 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 environmental controls analyzed under the final NESHAP amendments and final NSPS.

The final NESHAP amendments and final 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 final standards will result in net annual costs savings of about $11 million (in 2008 dollars) 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.

C. What are the cost impacts?

The estimated total capital cost to comply with the final amendments to 40 CFR part 63, subpart HH for major sources in the Oil and Natural Gas Production source category is approximately $2.6 million. The total capital cost for the final 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 $140,000. All costs are in 2008 dollars.

The total estimated net annual cost to industry to comply with the final amendments to 40 CFR part 63, subpart HH for major sources in the Oil and Natural Gas Production source category is approximately $3.3 million. The total net annual cost for final 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 $180,000. 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 final NSPS is approximately $25 million in 2008 dollars. The total estimated net annual cost to industry to comply with the final NSPS is estimated to be approximately $170 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 final 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/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 43 million Mcf (43 billion cubic feet) of natural gas and 160,000 barrels of condensate are estimated to be recovered by control requirements in 2015. Using the price assumptions, the estimated revenues from natural gas and condensate recovery are approximately $180 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 final NSPS to be about $15 million. Totals may not sum due to independent rounding.

If voluntary action is not deducted from the baseline, capital costs for the NSPS are estimated at $25 million and annualized costs without revenues from product recovery for the NSPS are estimated at $330 million. In this scenario, given the assumptions about product prices, estimated revenues from product recovery are $350 million, yielding an estimated cost of savings of about $22 million.

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 final NSPS. At $4.22/Mcf, the price forecast reported in the 2011 Annual Energy Outlook in 2008 dollars, the annualized cost savings for the final NSPS are estimated at about $24 million. As indicated by this difference, the 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 final NSPS breaks-even from an estimated engineering costs perspective is around $3.66/Mcf. A $1/Mcf change in the wellhead natural gas price leads to a $43 million change in the annualized engineering costs of the final NSPS. Consequently, annualized engineering costs estimates would increase to about $29 million under a $3/Mcf price or decrease to about −$58 million under a $5/Mcf price. For further details on this sensitivity analysis, please refer the RIA for this rulemaking located in the docket.

D. What are the economic impacts?

The analysis of energy system impacts EPA performed using the United States Department of Energy's (DOE) National Energy Modeling System (NEMS) shows that domestic natural gas production is not likely to change in 2015 as a result of the final rules, the year used in the RIA to analyze impacts. Average natural gas prices are also not estimated to change in response to the final rules. Domestic crude oil production is not expected to change, while average crude oil prices are estimated to decrease slightly (about $0.01/barrel or about 0.01 percent at the wellhead for onshore production in the lower 48 states). All prices are in 2008 dollars. The NEMS-based analysis estimates in the year of analysis, 2015, that net imports of natural gas and crude oil will not change.

E. What are the benefits of this final rule?

The final 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 final rules combined are anticipated to reduce 12,000 tons of HAP, 190,000 tons of VOC (a precursor to both PM (2.5 microns and less) ($PM_{2.5}$) and ozone formation) and 1.0 million tons of methane (a GHG and a precursor to global ozone formation). 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 $PM_{2.5}$ 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.[34] 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. VOC emissions are precursors to both $PM_{2.5}$ and ozone formation. As documented in previous analyses (U.S. EPA, 2006 [35] and U.S. EPA, 2010 [36]), exposure to $PM_{2.5}$ and ozone is associated with significant public health effects. $PM_{2.5}$ is associated with health effects, including premature mortality for adults and infants, cardiovascular morbidity such as heart attacks, and respiratory morbidity such as asthma attacks, acute and chronic bronchitis, hospital admissions and emergency room visits, work loss days, restricted activity days and respiratory symptoms, as well as visibility impairment.[37] Ozone is associated with health effects, including hospital and emergency department visits, school loss days and premature mortality, as well as injury to vegetation and climate effects.[38]

In addition to the improvements in air quality and resulting benefits to human health and non-climate welfare effects previously discussed, this 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 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.[39] 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 requires emission control technologies and regulatory alternatives that will significantly decrease HAP and VOC emissions from the oil and natural gas sector in the United States. As a co-benefit, the emission control measures the industry will use to reduce HAP and VOC emissions will also decrease methane emissions. The NESHAP Amendments and the NSPS combined are expected to reduce methane emissions annually by about 1.0 million short tons or about 19 million metric tons CO_2e. After considering the secondary impacts of this rule as 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 18 million metric tons CO_2e. The methane reductions represent about 7 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). 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 4 million typical passenger cars off the road or eliminating electricity use from about 2 million typical homes each year.[40]

The EPA recognizes that the methane reductions from this rule will provide for significant economic climate benefits to society just described. However, the 2009–2010 Interagency Social Cost of Carbon Work Group did not produce directly modeled estimates of the social cost of methane. In the absence of direct model estimates from the interagency analysis, the EPA has used a ''global warming potential (GWP) approach'' to estimate the dollar value of this rule's methane co-benefits. Specifically, the EPA converted methane to CO_2 equivalents using the GWP of methane, then multiplied these CO_2 equivalent emission reductions by the social cost of carbon developed by the Interagency Social Cost of Carbon Work Group.

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

[34] Previous studies have estimated the monetized benefits-per-ton of reducing VOC emissions associated with the effect that those emissions have on ambient $PM_{2.5}$ levels and the health effects associated with $PM_{2.5}$ exposure (Fann, Fulcher, and Hubbell, 2009). While these ranges of benefit-per-ton estimates provide useful context for the break-even analysis, the geographic distribution of VOC emissions from the oil and gas sector are not consistent with emissions modeled in Fann, Fulcher, and Hubbell (2009). In addition, the benefit-per-ton estimates for VOC emission reductions in that study are derived from total VOC emissions across all sectors. Coupled with the larger uncertainties about the relationship between VOC emissions and $PM_{2.5}$ and the highly localized nature of air quality responses associated with HAP and VOC reductions, these factors lead us to conclude that the available VOC benefit-per-ton estimates are not appropriate to calculate monetized benefits of these rules, even as a bounding exercise.

[35] 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.*

[36] 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.*

[37] 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.*

[38] 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.*

[39] U.S. EPA (2011), *2011 U.S. Greenhouse Gas Inventory Report* Executive Summary available on the internet at *http://epa.gov/climatechange/emissions/downloads11/US-GHG-Inventory-2011–Executive-Summary.pdf,* accessed 02/13/12.

[40] U.S. EPA. *Greenhouse Gas Equivalency Calculator* available at: *http://www.epa.gov/cleanenergy/energy-resources/calculator.html,* accessed 04/09/12.

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.*[41] Applying this approach to the methane reductions estimated for the NESHAP Amendments and NSPS, the 2015 climate co-benefits vary by discount rate and range from about $100 million to approximately $1.3 billion; the mean social cost of carbon at the 3-percent discount rate results in an estimate of about $440 million in 2015.[42]

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. 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 the 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.[43] 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 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 the GWP of 21 from the IPCC Second Assessment Report to estimate the methane climate co-benefits for this oil and gas rule. The EPA uses the 21 GWP in order to provide estimates more consistent with global GHG inventories, which currently use GWP from the IPCC Second Assessment Report, and with the US GHG Reporting program. See the Regulatory Impact Analysis for further details.

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.

For the final NESHAP amendments, a break-even analysis suggests that HAP emissions would need to be valued at $5,200 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 final 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 $2,900 per ton or the methane emissions would need to be valued at $8,300 per ton for the co-benefits to exceed the costs. All estimates are in 2008 dollars. For the final 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),[44] 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.

XII. Statutory and Executive Order Reviews

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

Under section 3(f)(1) of 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 the Office of Management and Budget (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 Regulatory Impact Analysis (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 7 shows the results of the cost and benefits analysis for these final rules.

[41] 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 02/12/12.

[42] The ratio of domestic to global benefits of emission reductions varies with key parameter assumptions. See Interagency Working Group on Social Cost of Carbon. 2010. *Technical Support Document: Social Cost of Carbon for Regulatory Impact Analysis Under Executive Order 12866.*

[43] 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.*

[44] 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.

TABLE 7—SUMMARY OF THE MONETIZED BENEFITS, SOCIAL COSTS AND NET BENEFITS FOR THE FINAL OIL AND NATURAL GAS NSPS AND NESHAP AMENDMENTS IN 2015

[Millions of 2008$] [1]

	Final NSPS	Final NESHAP amendments	Final NSPS and NESHAP amendments combined
Total Monetized Benefits [2]	N/A	N/A	N/A.
Total Costs [3]	−$15 million	$3.5 million	−$11 million.
Net Benefits	N/A	N/A	N/A.
Non-monetized Benefits [4]	11,000 tons of HAP 190,000 tons of VOC 1.0 million tons of methane	670 tons of HAP 1,200 tons of VOC 420 tons of methane	12,000 tons of HAP. 190,000 tons of VOC. 1.0 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 particulate matter (PM) as well as climate effects associated with methane, we have determined that quantification of those benefits and co-benefits cannot be accomplished for this rule in a defensible way. This is not to imply that there are no benefits or co-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 final NSPS reflects the inclusion of revenues from additional natural gas and hydrocarbon condensate recovery that are estimated as a result of the NSPS. Possible explanations for why there appear to be negative cost control technologies are discussed in the engineering costs analysis section in the RIA.

[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. The specific control technologies for the final NSPS are anticipated to have minor secondary disbenefits, including an increase of 1.1 million tons of carbon dioxide (CO_2), 550 tons of nitrogen oxides (NO_X), 19 tons of PM, 3,000 tons of CO and 1,100 tons of total hydrocarbons (THC), as well as emission reductions associated with the energy system impacts. The specific control technologies for the NESHAP are anticipated to have minor secondary disbenefits, but the EPA was unable to estimate these secondary disbenefits. The net CO_2-equivalent emission reductions are 18 million metric tons.

B. Paperwork Reduction Act

The information collection requirements in this rule have been submitted for approval to the Office of Management and Budget (OMB) under the *Paperwork Reduction Act,* 44 U.S.C. 3501, *et seq.* The information collection requirements are not enforceable until OMB approves them.

The ICR documents prepared by the EPA have been assigned EPA ICR numbers 2437.01, 2438.01, 2439.01 and 2440.01. The information requirements 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 CAA section 114 (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. This final rule requires 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.

When a malfunction occurs, sources must report them according to the applicable reporting requirements of 40 CFR part 63, subpart HH or 40 CFR part 63, subpart HHH. An affirmative defense to civil penalties for exceedances of emission limits that are caused by malfunctions is available to a source if it can demonstrate that certain criteria and requirements are satisfied. 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 reasonable preventable, and not caused by poor maintenance and/or careless operation) and where the source took necessary actions to minimize emissions. In addition, the source must meet certain notification and reporting requirements. For example, the source must prepare a written root cause analysis and submit a written report to the Administrator documenting that it has met the conditions and requirements for assertion of the affirmative defense.

For this rule, the EPA is adding affirmative defense to the estimate of burden in the ICR. To provide the public with an estimate of the relative magnitude of the burden associated with an assertion of the affirmative defense position adopted by a source, the EPA has provided administrative adjustments to this ICR that shows what the notification, recordkeeping and reporting requirements associated with the assertion of the affirmative defense might entail. The EPA's estimate for the required notification, reports, and records, including the root cause analysis, associated with a single incident totals approximately totals $3,141 and is based on the time and effort required of a source to review relevant data, interview plant employees, and document the events surrounding a malfunction that has caused an exceedance of an emission limit. The estimate also includes time to produce and retain the record and reports for submission to the EPA. The EPA provides this illustrative estimate of this burden, because these costs are only incurred if there has been a violation, and a source chooses to take advantage of the affirmative defense.

The EPA provides this illustrative estimate of this burden because these costs are only incurred if there has been a violation and a source chooses to take advantage of the affirmative defense. Given the variety of circumstances under which malfunctions could occur, as well as differences among sources' operation and maintenance practices, we cannot reliably predict the severity and frequency of malfunction-related excess emissions events for a particular source. It is important to note that the

EPA has no basis currently for estimating the number of malfunctions that would qualify for an affirmative defense. Current historical records would be an inappropriate basis, as source owners or operators previously operated their facilities in recognition that they were exempt from the requirement to comply with emissions standards during malfunctions. Of the number of excess emissions events reported by source operators, only a small number would be expected to result from a malfunction (based on the definition above), and only a subset of excess emissions caused by malfunctions would result in the source choosing to assert the affirmative defense. Thus, we believe the number of instances in which source operators might be expected to avail themselves of the affirmative defense will be extremely small.

For this reason, we estimate a total of 39 such occurrences for all sources subject to 40 CFR part 63, subpart HH, a total of three such occurrences for all sources subject to 40 CFR part 63, subpart HHH, and a total of 6 such occurrences for all sources subject to 40 CFR part 60, subparts KKK and LLL over the 3-year period covered by this ICR. We expect to gather information on such events in the future, and will revise this estimate as better information becomes available.

The annual monitoring, reporting, and recordkeeping burden for this collection (averaged over the first 3 years after the effective date of the standards) is estimated to be $20.1 million. This includes 384,866 labor hours per year at a total labor cost of $19.5 million per year, and annualized capital costs of $0.36 million, and annual operating and maintenance costs of $0.20 million. This estimate includes initial and annual performance tests, semiannual excess emission reports, developing a monitoring plan, notifications and recordkeeping. All burden estimates are in 2008 dollars and represent the most cost-effective monitoring approach for affected facilities. 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. When these ICR are approved by OMB, the agency will publish a technical amendment to 40 CFR part 9 in the **Federal Register** to display the OMB control numbers for the approved information collection requirements contained in the final rule.

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 as defined by NAICS codes 211111, 211112, 221210, 486110 and 486210; 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.

For the final NSPS, the EPA performed an analysis for impacts on a sample of expected affected small entities by comparing compliance costs to entity revenues. The baseline used in this analysis takes into account REC conducted pursuant to state regulations covering these operations and estimates of REC performed voluntarily. To account for REC performed in regulated states, the EPA subsumed emissions reductions and compliance costs in states where these completion-related emissions are already controlled into the baseline. Additionally, based on public comments and reports to the EPA's Natural Gas STAR program, the EPA recognizes that some producers conduct well completions using REC techniques voluntarily for economic and/or environmental objectives as a normal part of business. To account for emissions reductions and costs arising from voluntary implementation of pollution controls, the EPA used information on total emission reductions reported to the EPA by partners of the EPA Natural Gas STAR. This estimate of this voluntary REC activity in the absence of regulation is also included in the baseline. More detailed discussion on the derivation of the baseline is presented in a technical memorandum in the docket, as well as in the RIA.

Based upon the analysis in the RIA, which is in the Docket, when revenue from additional natural gas product recovered is not included, we estimate that 123 of the 127 small firms analyzed (97 percent) are likely to have impacts less than 1 percent in terms of the ratio of annualized compliance costs to revenues. Meanwhile, four firms (3 percent) are likely to have impacts greater than 1 percent. Three of these four firms are likely to have impacts greater than 3 percent. However, when revenue from additional natural gas product recovery is included, we estimate that none of the analyzed firms will have an impact greater than 1 percent.

For the final NESHAP amendments, we estimate that 11 of the 35 firms (31 percent) that own potentially affected facilities are small entities. The EPA performed an analysis for impacts on all expected affected small entities by comparing compliance costs to entity revenues. Among the small firms, none are likely to have impacts greater than 1 percent in terms of the ratio of annualized compliance costs to revenues.

After considering the economic impact of the combined NSPS and NESHAP amendments on small entities, I certify this action will not have a significant impact on a substantial number of small entities (SISNOSE). While both the NSPS and NESHAP amendment would individually result in a no SISNOSE finding, the EPA performed an additional analysis in order to certify the rule in its entirety. This analysis compared compliance costs to entity revenues for the total of all the entities affected by the NESHAP amendments and the sample of entities analyzed for the NSPS. When revenues from additional natural gas product sales are not included, 132 of the 136 small firms (97 percent) in the sample are likely to have impacts of less than 1 percent in terms of the ratio of annualized compliance costs to revenues. Meanwhile, four firms (3 percent) are likely to have impacts greater than 1 percent. Three of these four firms are likely to have impacts greater than 3 percent. When revenues from additional natural gas product sales are included, none of the 136 small firms (100 percent) are likely to have impacts greater than 1 percent.

Our 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 occur over a short span of time, during which the additional product recovery is also accomplished and payments for recovered products are settled.

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.

D. Unfunded Mandates Reform Act

This final action does not contain a federal mandate under the provisions of Title II of the Unfunded Mandates Reform Act of 1995 (UMRA), 2 U.S.C. 1531–1538 for state, local, and tribal governments, in the aggregate, or to the private sector. The action would not result in expenditures of $100 million or more for state, local, and tribal governments, in the aggregate, or to the private sector in any 1 year. Thus, this final rule is not subject to the requirements of sections 202 or 205 of UMRA.

This final 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 because it contains no requirements that apply to such governments nor does it impose obligations upon them.

E. Executive Order 13132: Federalism

This action 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. These final rules primarily affect private industry, and do not impose significant economic costs on state or local governments. On the contrary, we believe the modification provisions discussed in section IX.A for well completions conducted at gas wells constructed on or before August 23, 2011, will reduce permitting burden borne by the States. These provisions will result in fewer sources becoming affected facilities under the NSPS while achieving emission reductions beginning October 15, 2012 equal to those achieved by new sources beginning January 1, 2015. Thus, Executive Order 13132 does not apply to this action.

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

Subject to the Executive Order 13175 (65 FR 67249, November 9, 2000) the EPA may not issue a regulation that has tribal implications, that imposes substantial direct compliance costs, and that is not required by statute, unless the Federal government provides the funds necessary to pay the direct compliance costs incurred by tribal governments, or the EPA consults with tribal officials early in the process of developing the proposed regulation and develops a tribal summary impact statement.

The EPA has concluded that this action will not have tribal implications because it doesn't impose a significant cost to the tribal government. However, there are significant tribal interests because of the growth of the oil and gas production industry in Indian country.

The EPA initiated a consultation process with tribal officials early in the process of developing this regulation to permit them to have meaningful and timely input into its development. During the consultation process, the EPA conducted outreach and information meetings prior to the proposal in 2010. The EPA met with the Inter Tribal Environmental Council, which include many of the Region VI tribes, The Tribal leadership summit in Region X, and Tribal Energy Conference hosted by Ft. Belknap, and the National Tribal Forum.

After the proposal was published, letters were sent to all tribal leaders offering to consult on a government-to-government basis on the rule. As part of the consultation process and in response to these letters, an outreach call was held on October 12, 2011. Tribes that participated on this call were: Fond du Lac Band of Lake Superior Chippewa, Fort Belknap Indian Community, Forest County Potawatomi Community, Southern Ute Indian Tribe, and Pueblo of Santa Clara.

In this meeting the tribes were presented the information in the proposal. The tribes asked general clarifying questions but did not provide specific comments. Comments on the proposal were received from an affiliate of the Southern Ute Indian Tribe. The commenter expressed concern about the impacts of the rule on natural gas and oil production operations on the Southern Ute Indian reservation and requested additional time to evaluate the impacts. In response to this and other requests, the comment period was extended. More specific comments can be found in the docket.

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

This action is not subject to Executive Order 13045 (62 FR 19885, April 23, 1997) because the Agency does not believe the environmental health risks or safety risks addressed by this action present a disproportionate risk to children. This action would not relax the control measures on existing regulated sources. The EPA's risk assessments (included in the docket for this final rule) demonstrate that the existing regulations are associated with an acceptable level of risk and provide an ample margin of safety to protect public health.

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

This action is not a ''significant energy action'' as defined in Executive Order 13211 (66 FR 28355, May 22, 2001), because it is not likely to have a significant adverse effect on the supply, distribution, or use of energy. These final 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 final NESHAP amendments are unlikely to have a significant adverse effect on the supply, distribution, or use of energy. As such, the final NESHAP amendments are not ''significant energy actions'' as defined in Executive Order 13211, (66 FR 28355, May 22, 2001). The final NSPS is also unlikely to have a significant adverse effect on the supply, distribution, or use of energy. As such, the final NSPS is not a ''significant energy action'' as defined in Executive Order 13211 (66 FR 28355, May 22, 2001).

The basis for these determinations is as follows. 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 final NSPS also captures saleable condensates. The revenues from additional natural gas and condensate recovery are expected to offset the costs of implementing the final rules.

We use the NEMS to estimate the impacts of the combined final rules 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 DOE and is used to produce the Annual Energy Outlook, a reference publication that provides detailed forecasts of the United States energy economy.

Based on public comments and reports to EPA's Natural Gas STAR program, the EPA recognizes that some producers conduct well completions using REC techniques, which are required by the final NSPS for certain completions of hydraulically fractured and refractured natural gas wells, voluntarily based upon economic and environmental objectives. The baseline used for the energy system impacts analysis takes into account REC conducted pursuant to state regulations covering these operations and estimates of REC performed voluntarily. To account for REC performed in regulated states, the EPA subsumed emissions reductions and compliance costs in states where these completion-related emissions are already controlled into the baseline. Additionally, based on public comments and reports to the EPA's Natural Gas STAR program, the EPA recognizes that some producers conduct well completions using REC techniques voluntarily for economic and/or environmental objectives as a normal part of business. To account for emissions reductions and costs arising from voluntary implementation of pollution controls, the EPA used information on total emission reductions reported to the EPA by partners of the EPA Natural Gas STAR. This estimate of this voluntary REC activity in the absence of regulation is also included in the baseline. More detailed discussion on the derivation of the baseline is presented in a technical memorandum in the docket, as well as in the RIA.

The analysis of energy system impacts for the final NSPS under the primary baseline shows that domestic natural gas production is not likely to change in 2015, the year used in the RIA to analyze impacts. Average natural gas prices are also not estimated to change in response to the final rules. Domestic crude oil production is not expected to change, while average crude oil prices are estimated to decrease slightly (about $0.01/barrel or about 0.01 percent at the wellhead for onshore production in the lower 48 states). All prices are in 2008 dollars. The NEMS-based analysis estimates in the year of analysis, 2015, that net imports of natural gas and crude oil will not change.

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 final 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 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.

This final rulemaking involves technical standards. Three VCS were identified as applicable for the purpose of these rules. The VCS ASTM D6522–00 (2005), *Standard Test Method for the Determination of Nitrogen Oxides, Carbon Monoxide, and Oxygen Concentrations in Emissions From Natural Gas-Fired Reciprocating Engines, Combustion Turbines, Boilers and Process Heaters Using Portable Analyzers,* is an acceptable alternative to EPA Methods 3A and 10 for identifying nitrogen oxides, carbon monoxide, and oxygen concentrations when the fuel is natural gas. The VCS ASTM D6420–99 (2004), *Test Method for Determination of Gaseous Organic Compounds by Direct Interface Gas Chromatography/Mass Spectrometry,* is an acceptable alternative to EPA Method 18. The VCS ANSI/ASME PTC 19.10–1981 (Part 10, Instruments and Apparatus), *Flue and Exhaust Gas Analyses* is an acceptable alternative to EPA Methods 3B and 16A manual portion only, not the instrumental portion.

No potential VCS were identified for EPA Methods 1A, 2A, 2D, 21, and 22.

During the search, if the title or abstract (if provided) of the VCS described technical sampling and analytical procedures that were similar to the EPA's reference method, the EPA ordered a copy of the standard and reviewed it as a potential equivalent method. All potential standards were reviewed to determine the practicality of the VCS for this action. This review requires significant method validation data that meet the requirements of EPA Method 301 for accepting alternative methods or scientific, engineering and policy equivalence to procedures in the EPA reference methods. The EPA may reconsider determinations of impracticality when additional information is available for particular VCS.

The search identified 18 other VCS that were potentially applicable for these rules in lieu of the EPA reference methods. After reviewing the available standards, the EPA determined that 18 candidate VCS (ASTM D3154–00 (2006), ASTM D3464–96 (2007), ASTM D3796–90 (2004), ISO 10780:1994, ASME B133.9–1994 (2001), ANSI/ASME PTC 19.10–1981 Part 10, ASTM D5835–95 (2007), ISO 10396:1993, ISO 12039:2001, ASTM D6522–00 (2005), CAN/CSA Z223.2–M86 (1999), CAN/CSA Z223.21–M1978, ASTM D3162–94 (2005), ASTM D4323–84 (2009), ASTM D6060–96 (2001), ISO 14965:2000(E), EN 12619 (1999), ASTM D4855–97 (2002)) identified for measuring emissions of pollutants or their surrogates subject to emission standards in the rules would not be practical due to lack of equivalency, documentation, validation data and other important technical and policy considerations. Refer to the memorandum in the docket for further details on the EPA's review of these VCS.

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 environmental justice. Its main provision directs Federal agencies, to the greatest extent practicable and permitted by law, to make environmental justice part of their mission by identifying and addressing, as appropriate, disproportionately high and adverse human health or environmental effects of their programs, policies and activities on minority populations and low income populations in the United States.

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

To examine the potential for any environmental justice issues that might be associated with each source category, we evaluated the percentages of various social, demographic, and economic groups within the at-risk population living near the facilities where these source categories are located and compared them to national averages. The development of demographic analyses to inform the consideration of environmental justice issues in the EPA rulemakings is an evolving science.

The EPA conducted a demographic analysis, focusing on populations within 50 km of any facility in each of the source categories that are estimated to have HAP exposures which result in cancer risks of 1-in-1 million or greater or non-cancer hazard indices of 1 or greater based on estimates of current HAP emissions. The results of this analysis are documented in the technical report: *Risk and Technology Review—Analysis of Socio-Economic Factors for Populations Living Near Oil & Natural Gas Production Facilities,* located in the docket for this rulemaking.

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 non-cancer 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.

To promote meaningful involvement, the EPA conducted three public hearings on the proposal. The hearings were held in Pittsburgh, Pennsylvania, on September 27, 2011, Denver, Colorado, on September 28, 2011, and Arlington, Texas, on September 29, 2011. A total of 261 people spoke at the three hearings and 735 people attended the hearings. The attendees at the hearings included private citizens, community-based and environmental organizations, industry representatives, associations representing industry and local and state government officials.

K. Congressional Review Act

The Congressional Review Act, 5 U.S.C. 801, *et seq.,* as added by the Small Business Regulatory Enforcement Fairness Act of 1996, generally provides that before a rule may take effect, the agency promulgating the rule must submit a rule report, which includes a copy of the rule, to each House of the Congress and to the Comptroller General of the United States. The EPA will submit a report containing this final rule and other required information to the United States Senate, the United States House of Representatives, and the Comptroller General of the United States prior to publication of the final rule in the **Federal Register**. A major rule cannot take effect until 60 days after it is published in the **Federal Register**. This action is a ''major rule'' as defined by 5 U.S.C. 804(2). The final rules will be effective on October 15, 2012.

List of Subjects

40 CFR Part 60

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

40 CFR Part 63

Environmental protection, Administrative practice and procedures, Air pollution control, Hazardous substances, Incorporation by reference, Reporting and recordkeeping requirements, Volatile organic compounds.

Dated: April 17, 2012.

Lisa P. Jackson,

Administrator.

For the reasons set out in the preamble, title 40, chapter I of the Code of Federal Regulations is 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) introductory text, (a)(7), (a)(86), (a)(91), and (a)(92);

■ b. Adding paragraphs (a)(95), (a)(96), (a)(97), and (a)(98); and

■ c. Revising paragraph (h) introductory text and (h)(4) to read as follows:

§ 60.17 Incorporations by reference.

* * * * *

(a) The following materials are available for purchase from at least one of the following addresses: American Society for Testing and Materials (ASTM), 100 Barr Harbor Drive, Post Office Box C700, West Conshohocken, PA 19428–2959, Telephone (610) 832–9585, and are also available at the following Web site: *http://www.astm.org;* or ProQuest, 789 East Eisenhower Parkway, Ann Arbor, MI 48106–1346, Telephone (734) 761–4700, and are also available at the following Web site: *http://www.proquest.com.*

* * * * *

(7) ASTM D86–96, Standard Test Method for Distillation of Petroleum Products (Approved April 10, 1996), IBR approved for §§ 60.562–2(d), 60.593(d), 60.593a(d), 60.633(h) and 60.5401(f).

* * * * *

(86) ASTM D6522–00 (Reapproved 2005), Standard Test Method for Determination of Nitrogen Oxides, Carbon Monoxide, and Oxygen Concentrations in Emissions from Natural Gas-Fired Reciprocating Engines, Combustion Turbines, Boilers, and Process Heaters Using Portable Analyzers (Approved October 1, 2005), IBR approved for table 2 of subpart JJJJ of this part, and §§ 60.5413(b) and (d).

* * * * *

(91) ASTM E169–93, Standard Practices for General Techniques of Ultraviolet-Visible Quantitative Analysis (Approved May 15, 1993), IBR approved for §§ 60.485a(d), 60.593(b), 60.593a(b), 60.632(f) and 60.5400(f).

(92) ASTM E260–96, Standard Practice for Packed Column Gas Chromatography (Approved April 10, 1996), IBR approved for §§ 60.485a(d), 60.593(b), 60.593a(b), 60.632(f), 60.5400(f) and 60.5406(b).

* * * * *

(95) ASTM D3588–98 (Reapproved 2003) Standard Practice for Calculating Heat Value, Compressibility Factor, and Relative Density of Gaseous Fuels (Approved May 10, 2003), IBR approved for § 60.5413(d).

(96) ASTM D4891–89 (Reapproved 2006) Standard Test Method for Heating Value of Gases in Natural Gas Range by Stoichiometric Combustion (Approved June 1, 2006), IBR approved for § 60.5413(d).

(97) ASTM D1945–03 (Reapproved 2010), Standard Test Method for Analysis of Natural Gas by Gas Chromatography (Approved January 1, 2010), IBR approved for § 60.5413(d).

(98) ASTM D5504–08, Standard Test Method for Determination of Sulfur Compounds in Natural Gas and Gaseous Fuels by Gas Chromatography and Chemiluminescence (Approved June 15, 2008), IBR approved for § 60.5413(d).

* * * * *

(h) The following material is available for purchase from the American Society of Mechanical Engineers (ASME), Three Park Avenue, New York, NY 10016–5990, Telephone (800) 843–2763, and are also available at the following Web site: *http://www.asme.org*.

* * * * *

(4) ANSI/ASME PTC 19.10–1981, Flue and Exhaust Gas Analyses [Part 10, Instruments and Apparatus] (Issued August 31, 1981), IBR approved for §§ 60.56c(b), 60.63(f), 60.106(e), 60.104a(d), (h), (i) and (j), 60.105a(d), (f) and (g), 60.106a(a), 60.107a(a), (c) and (d), tables 1 and 3 of subpart EEEE, tables 2 and 4 of subpart FFFF, table 2 of subpart JJJJ, §§ 60.4415(a), 60.2145(s) and (t), 60.2710(s), (t) and (w), 60.2730(q), 60.4900(b) and 60.5220(b), tables 1 and 2 to subpart LLLL, tables 2 and 3 to subpart MMMM, §§ 60.5406(c) and 60.5413(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 forth 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 forth 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, consisting of 60.5360 through 60.5430, 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 commence construction, modification or reconstruction after August 23, 2011.

§ 60.5365 Am I subject to this subpart?

You are subject to the applicable provisions of this subpart if you are the owner or operator of one or more of the onshore affected facilities listed in paragraphs (a) through (g) of this section for which you commence construction, modification or reconstruction after August 23, 2011.

(a) Each gas well affected facility, which is a single natural gas well.

(b) Each centrifugal compressor affected facility, which is a single centrifugal compressor using wet seals that is located between the wellhead and the point of custody transfer to the natural gas transmission and storage segment. A centrifugal compressor located at a well site, or an adjacent well site and servicing more than one well site, is not an affected facility under this subpart.

(c) Each reciprocating compressor affected facility, which is a single reciprocating compressor located between the wellhead and the point of custody transfer to the natural gas transmission and storage segment. A reciprocating compressor located at a well site, or an adjacent well site and servicing more than one well site, is not an affected facility under this subpart.

(d)(1) For the oil production segment (between the wellhead and the point of custody transfer to an oil pipeline), each pneumatic controller affected facility, which is a single continuous bleed natural gas-driven pneumatic controller operating at a natural gas bleed rate greater than 6 scfh.

(2) For the natural gas production segment (between the wellhead and the point of custody transfer to the natural gas transmission and storage segment and not including natural gas processing plants), each pneumatic controller affected facility, which is a single continuous bleed natural gas-driven pneumatic controller operating at a natural gas bleed rate greater than 6 scfh.

(3) For natural gas processing plants, each pneumatic controller affected facility, which is a single continuous bleed natural gas-driven pneumatic controller.

(e) Each storage vessel affected facility, which is a single storage vessel, located in the oil and natural gas production segment, natural gas processing segment or natural gas transmission and storage segment.

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

(1) Addition or replacement of equipment for the purpose of process improvement that is accomplished without a capital expenditure shall not by itself be considered a modification under this subpart.

(2) Equipment associated with a compressor station, dehydration unit, sweetening unit, underground storage vessel, 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 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.

(3) The equipment within a process unit of an affected facility located at onshore natural gas processing plants and described in paragraph (f) 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 at onshore natural gas processing plants 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 §§ 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, 60.5410(g), 60.5415(g), and 60.5423 of this subpart.

(h) The following provisions apply to gas well facilities that are hydraulically refractured.

(1) A gas well facility that conducts a well completion operation following hydraulic refracturing is not an affected facility, provided that the requirements of § 60.5375 are met. For purposes of this provision, the dates specified in § 60.5375(a) do not apply, and such facilities, as of October 15, 2012, must meet the requirements of § 60.5375(a)(1) through (4).

(2) A well completion operation following hydraulic refracturing at a gas well facility not conducted pursuant to § 60.5375 is a modification to the gas well affected facility.

(3) Refracturing of a gas well facility does not affect the modification status of other equipment, process units, storage vessels, compressors, or pneumatic controllers located at the well site.

(4) Sources initially constructed after August 23, 2011, are considered affected sources regardless of this provision.

§ 60.5370 When must I comply with this subpart?

(a) You must be in compliance with the standards of this subpart no later than October 15, 2012 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 well affected facilities?

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

(a) Except as provided in paragraph (f) of this section, for each well completion operation with hydraulic fracturing begun prior to January 1, 2015, you must comply with the requirements of paragraphs (a)(3) and (4) of this section unless a more stringent state or local emission control requirement is applicable; optionally, you may comply with the requirements of paragraphs (a)(1) through (4) of this section. For each new well completion operation with hydraulic fracturing begun on or after January 1, 2015, you must comply with the requirements in paragraphs (a)(1) through (4) of this section.

(1) For the duration of flowback, route the recovered liquids into one or more storage vessels or re-inject the recovered liquids into the well or another well, and route the recovered gas into a gas flow line or collection system, re-inject the recovered gas into the well or another well, use the recovered gas as an on-site fuel source, or use the recovered gas for another useful purpose that a purchased fuel or raw material would serve, with no direct release to the atmosphere. If this is infeasible, follow the requirements in paragraph (a)(3) of this section.

(2) All salable quality gas must be routed to the gas flow line as soon as

practicable. In cases where flowback emissions cannot be directed to the flow line, you must follow the requirements in paragraph (a)(3) of this section.

(3) You must capture and direct flowback emissions to a completion combustion device, except in conditions that may result in a fire hazard or explosion, or where high heat emissions from a completion combustion device may negatively impact tundra, permafrost or waterways. Completion combustion devices must be equipped with a reliable continuous ignition source over the duration of flowback.

(4) You have a general duty to safely maximize resource recovery and minimize releases to the atmosphere during flowback and subsequent recovery.

(b) You must maintain a log for each well completion operation at each gas well affected facility. The log must be completed on a daily basis for the duration of the well completion operation 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 well affected facilities as required by § 60.5410.

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

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

(f)(1) For each gas well affected facility specified in paragraphs (f)(1)(i) and (ii) of this section, you must comply with the requirements of paragraphs (f)(2) and (3) of this section.

(i) Each well completion operation with hydraulic fracturing at a gas well affected facility meeting the criteria for a wildcat or delineation well.

(ii) Each well completion operation with hydraulic fracturing at a gas well affected facility meeting the criteria for a non-wildcat low pressure gas well or non-delineation low pressure gas well.

(2) You must capture and direct flowback emissions to a completion combustion device, except in conditions that may result in a fire hazard or explosion, or where high heat emissions from a completion combustion device may negatively impact tundra, permafrost or waterways. Completion combustion devices must be equipped with a reliable continuous ignition source over the duration of flowback. You must also comply with paragraphs (a)(4) and (b) through (e) of this section.

(3) You must maintain records specified in § 60.5420(c)(1)(iii) for wildcat, delineation and low pressure gas 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 for each centrifugal compressor affected facility.

(a)(1) You must reduce VOC emissions from each centrifugal compressor wet seal fluid degassing system by 95.0 percent or greater.

(2) If you use a control device to reduce emissions, you must equip the wet seal fluid degassing system with a cover that meets the requirements of § 60.5411(b) and is connected through a closed vent system that meets the requirements of § 60.5411(a) to a control device that meets the conditions specified in § 60.5412.

(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 according to either paragraph (a)(1) or (2) of this section.

(1) 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 October 15, 2012, or the date of the most recent reciprocating compressor rod packing replacement, whichever is later.

(2) Prior to 36 months from the date of the most recent rod packing replacement, or 36 months from the date of startup for a new reciprocating compressor for which the rod packing has not yet been replaced.

(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) of this section are exempt from this requirement.

(a) The requirements of paragraph (b) or (c) of this section are not required if you determine that the use of a pneumatic controller affected facility with a bleed rate greater than 6 standard cubic feet per hour is required based on functional needs, including but not limited to response time, safety and positive actuation.

(b)(1) Each pneumatic controller affected facility at a natural gas processing plant must have a bleed rate of zero.

(2) Each pneumatic controller affected facility at a natural gas processing plant must be tagged with the month and year of installation, reconstruction or modification, and identification information that allows traceability to the records for that pneumatic controller as required in § 60.5420(c)(4)(iv).

(c)(1) Each pneumatic controller affected facility constructed, modified or reconstructed on or after October 15, 2013 at a location between the wellhead and a natural gas processing plant must have a bleed rate less than or equal to 6 standard cubic feet per hour.

(2) Each pneumatic controller affected facility at a location between the wellhead and a natural gas processing plant must be tagged with the month and year of installation, reconstruction or modification, and identification information that allows traceability to the records for that controller as required in § 60.5420(c)(4)(iii).

(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?

Except as provided in paragraph (d) of this section, you must comply with the standards in this section no later than October 15, 2013 for each storage vessel affected facility constructed, modified or reconstructed after August 23, 2011, with VOC emissions equal to or greater than 6 tpy, as determined in paragraph (a) of this section.

(a) *Emissions determination*—(1) *Well sites with no other wells in production.* For each storage vessel constructed, modified or reconstructed at a well site with no other wells in production, you must determine the VOC emission rate for each storage vessel affected facility using any generally accepted model or calculation methodology within 30 days after startup, and minimize emissions to the extent practicable during the 30-day period using good engineering practices. For each storage vessel affected facility emitting more than 6 tpy VOC, you must reduce VOC emissions by 95.0 percent or greater within 60 days after startup.

(2) *Well sites with one or more wells already in production.* For each storage vessel constructed, modified or reconstructed at a well site with one or more wells already in production, you must determine the VOC emission rate for each storage vessel affected facility using any generally accepted model or calculation methodology upon startup. For each storage vessel affected facility emitting more than 6 tpy VOC, you must reduce VOC emissions by 95.0 percent or greater upon startup.

(b) *Control requirements.* (1) If you use a control device (such as an enclosed combustion device or vapor recovery device) to reduce emissions, you must equip the storage vessel with a cover that meets the requirements of § 60.5411(b) and is connected through a closed vent system that meets the requirements of § 60.5411(a) to a control device that meets the conditions specified in § 60.5412.

(2) If you use a floating roof to reduce emissions, you must meet the requirements of § 60.112b(a)(1) or (2) and the relevant monitoring, inspection, recordkeeping, and reporting requirements in 40 CFR part 60, subpart Kb.

(c) *Compliance, notification, recordkeeping, and reporting.* (1) You must demonstrate initial compliance with standards that apply to storage vessel affected facilities as required by § 60.5410.

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

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

(d) *Exemptions.* This section does not apply to storage vessels subject to and controlled in accordance with the requirements for storage vessels in 40 CFR part 60, subpart Kb, or 40 CFR part 63, subparts G, CC, HH, WW, or HHH.

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

This section applies to the group of all equipment, 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 E169–93, E168–92, or E260–96 (incorporated by reference as specified in § 60.17) must be used.

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

(a) You may comply with the following exceptions to the provisions of § 60.5400(a) and (b).

(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 500 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 that does not have the 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) 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 D86–96 (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

D86–96 (incorporated by reference as specified in § 60.17).

(g) An owner or operator may use the following provisions instead of § 60.485a(b)(2): A calibration drift assessment shall be performed, at a minimum, at the end of each monitoring day. Check the instrument using the same calibration gas(es) that were used to calibrate the instrument before use. Follow the procedures specified in Method 21 of appendix A–7 of this part, Section 10.1, except do not adjust the meter readout to correspond to the calibration gas value. Record the instrument reading for each scale used as specified in § 60.486a(e)(8). Divide these readings by the initial calibration values for each scale and multiply by 100 to express the calibration drift as a percentage. If any calibration drift assessment shows a negative drift of more than 10 percent from the initial calibration value, then all equipment monitored since the last calibration with instrument readings below the appropriate leak definition and above the leak definition multiplied by (100 minus the percent of negative drift/divided by 100) must be re-monitored. If any calibration drift assessment shows a positive drift of more than 10 percent from the initial calibration value, then, at the owner/operator's discretion, all equipment since the last calibration with instrument readings above the appropriate leak definition and below the leak definition multiplied by (100 plus the percent of positive drift/divided by 100) may be re-monitored.

§ 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:

$$X = KQ_aY$$

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 E260–96 (incorporated by reference as specified in § 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 vessels. 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 or ANSI/ASME PTC 19.10–1981, Part 10 (manual portion only) (incorporated by reference as specified in § 60.17) 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 vessels 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)(1).

(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 interval. 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?

The Tutwiler procedure may be found in the 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).

(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, Grains H_2S 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

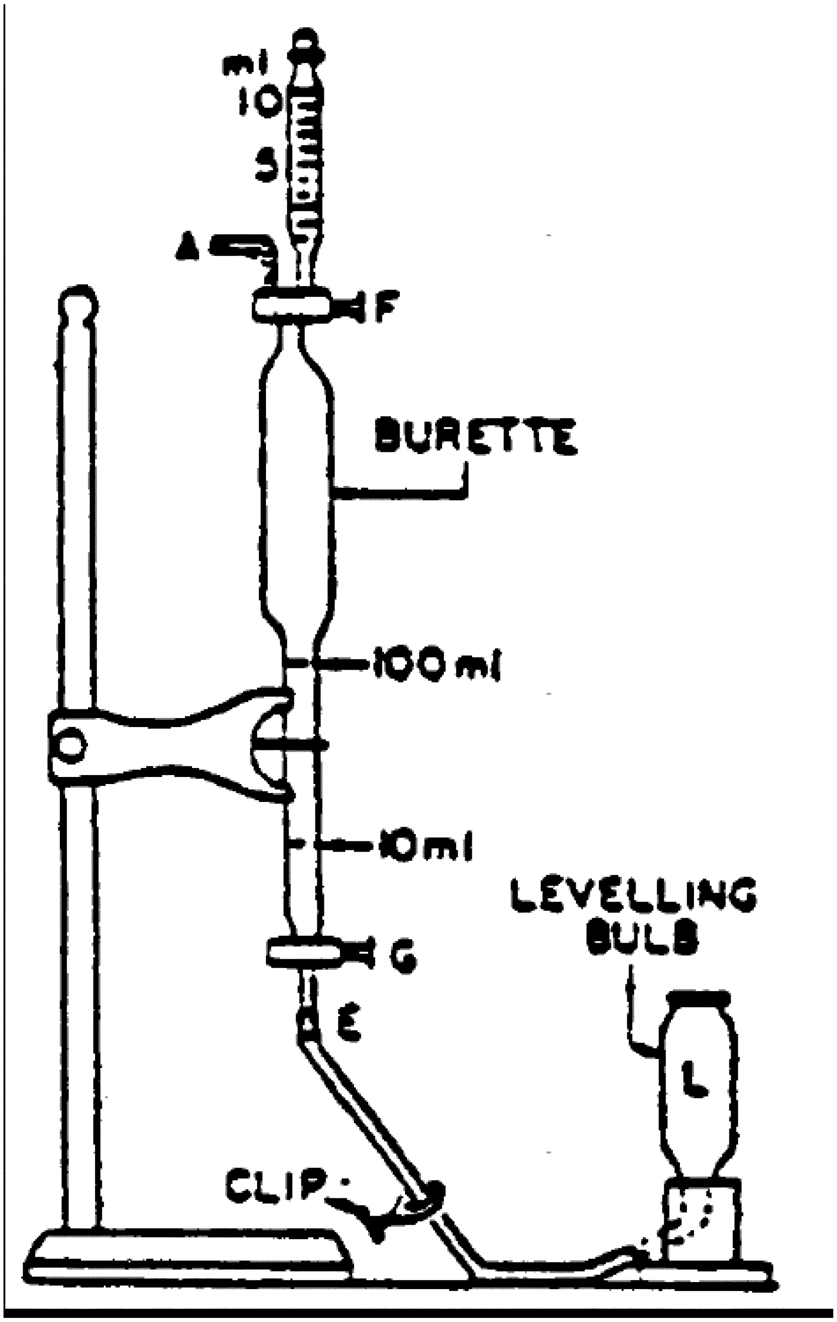

Figure 1. Tutwiler burette (lettered items mentioned in text).

BILLING CODE 6560–50–C

§ 60.5410 How do I demonstrate initial compliance with the standards for my gas well affected facility, my centrifugal compressor affected facility, my reciprocating compressor affected facility, my pneumatic controller affected facility, my storage vessel affected facility, and my equipment leaks and sweetening unit 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 October 15, 2012 or upon initial startup, whichever is later, and ends no later than one year after the initial startup date for your affected facility or no later than one year after October 15, 2012. The initial compliance period may be less than one full year.

(a) To achieve initial compliance with the standards for each well completion operation conducted at your gas well affected facility you must comply with paragraphs (a)(1) through (a)(4) of this section.

(1) You must submit the notification required in § 60.5420(a)(2).

(2) You must submit the initial annual report for your well affected facility as required in § 60.5420(b).

(3) You must maintain a log of records as specified in § 60.5420(c)(1) for each well completion operation conducted during the initial compliance period.

(4) For each gas well affected facility subject to both § 60.5375(a)(1) and (3), you must maintain records of one or more digital photographs with the date the photograph was taken and the latitude and longitude of the well site imbedded within or stored with the digital file showing the equipment for storing or re-injecting recovered liquid, equipment for routing recovered gas to the gas flow line and the completion combustion device (if applicable) connected to and operating at each gas well completion operation that occurred during the initial compliance period. As an alternative to imbedded latitude and longitude within the digital photograph, the digital photograph may consist of a photograph of the equipment connected and operating at each well completion operation with a photograph of a separately operating GIS device within the same digital picture, provided the latitude and longitude output of the GIS unit can be clearly read in the digital photograph.

(b)(1) To achieve initial compliance with standards for your centrifugal compressor affected facility you must reduce VOC emissions from each centrifugal compressor wet seal fluid degassing system by 95.0 percent or greater as required by § 60.5380 and as demonstrated by the requirements of § 60.5413.

(2) If you use a control device to reduce emissions, you must equip the wet seal fluid degassing system with a cover that meets the requirements of § 60.5411(b) and is connected through a closed vent system that meets the requirements of § 60.5411(a) to a control device that meets the conditions specified in § 60.5412.

(3) You must conduct an initial performance test as required in § 60.5413 within 180 days after initial startup or by October 15, 2012, whichever is later, and you must comply with the continuous compliance requirements in § 60.5415(b).

(4) You must conduct the initial inspections required in § 60.5416.

(5) You must install and operate the continuous parameter monitoring systems in accordance with § 60.5417.

(6) You must submit the notifications required in 60.7(a)(1), (3), and (4).

(7) You must submit the initial annual report for your centrifugal compressor affected facility as required in § 60.5420(b) for each centrifugal compressor affected facility

(8) You must maintain the records as specified in § 60.5420(c)(3).

(c) To achieve initial compliance with the standards for each reciprocating compressor affected facility you must comply with paragraphs (c)(1) through (4) of this section.

(1) During the initial compliance period, you must continuously monitor the number of hours of operation or track the number of months since the last rod packing replacement.

(2) You must submit the notifications required in 60.7(a)(1), (3), and (4).

(3) You must submit the initial annual report for your reciprocating compressor as required in § 60.5420(b).

(4) You must maintain the records as specified in § 60.5420(c)(3) for each reciprocating compressor affected facility.

(d) To achieve initial compliance with emission standards for your pneumatic controller affected facility you comply with the requirements specified in paragraphs (d)(1) through (6) of this section.

(1) If applicable, you have demonstrated by maintaining records as specified in § 60.5420(c)(4)(ii) of your determination that the use of a pneumatic controller affected facility with a bleed rate greater than 6 standard cubic feet of gas per hour is required as specified in § 60.5390(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 located between the wellhead and a natural gas processing plant and the manufacturer's design specifications indicate that the controller emits less than or equal to 6 standard cubic feet of gas per hour.

(4) You must tag each new pneumatic controller affected facility according to the requirements of § 60.5390(b)(2).

(5) You must include the information in paragraph (d)(1) of this section and a listing of the pneumatic controller affected facilities specified in paragraphs (d)(2) and (3) of this section in the initial annual report submitted for your pneumatic controller affected facilities constructed, modified or reconstructed during the period covered by the annual report according to the requirements of § 60.5420(b).

(6) You must maintain the records as specified in § 60.5420(c)(4) for each pneumatic controller affected facility.

(e) To achieve initial compliance with the emission standards for your storage vessel affected facility you must comply with paragraphs (e)(1) through (9) of this section.

(1) You have determined the VOC emission rate within 30 days after startup for storage vessels constructed, modified or reconstructed at well sites with no other wells in production, and you must use good engineering practices to minimize emissions during the 30-day period.

(2) You must determine the VOC emission rate upon startup for storage vessels constructed, modified or reconstructed at well sites with one or more wells already in production.

(3) For storage vessel affected facilities emitting more than 6 tpy VOC, you must reduce VOC emissions by 95.0 percent or greater within 60 days after startup for storage vessels constructed, modified or reconstructed at well sites with no other wells in production, or upon startup for storage vessels constructed, modified or reconstructed at well sites with one or more wells already in production.

(4) If you use a control device to reduce emissions, you must equip the storage vessel with a cover that meets the requirements of § 60.5411(b) and is connected through a closed vent system that meets the requirements of § 60.5411(a) to a control device that meets the conditions specified in § 60.5412 within 60 days after startup for storage vessels constructed, modified

or reconstructed at well sites with no other wells in production, or upon startup for storage vessels constructed, modified or reconstructed at well sites with one or more wells already in production.

(5) You must conduct an initial performance test as required in § 60.5413 within 180 days after initial startup or within 180 days of October 15, 2013, whichever is later, and must conduct the compliance demonstration in § 60.5415(b).

(6) You must conduct the initial inspections required in § 60.5416.

(7) You must install and operate continuous parameter monitoring systems in accordance with § 60.5417.

(8) You must submit the information in paragraphs (e)(1) through (7) of this section in the initial annual report as required in § 60.5420(b).

(9) You must maintain the records as specified in § 60.5420(c)(5) for each storage vessel affected facility.

(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 (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 (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 (2) of this section in the initial annual report submitted for your sweetening unit affected facilities at onshore natural gas processing plants.

§ 60.5411 What additional requirements must I meet to determine initial compliance for my closed vent systems routing materials from storage vessels and centrifugal compressor wet seal degassing systems?

You must meet the applicable requirements of this section for each cover and closed vent system used to comply with the emission standards for your storage vessel or centrifugal compressor affected facility.

(a) *Closed vent system requirements.* (1) You must design the closed vent system to route all gases, vapors, and fumes emitted from the material in the storage vessel or wet seal fluid degassing system to a control device that meets the requirements specified in § 60.5412.

(2) You must design and operate the closed vent system with no detectable emissions as demonstrated by § 60.5416(b).

(3) You must meet the requirements specified in paragraphs (a)(3)(i) and (ii) of this section if the closed vent system contains one or more bypass devices that could be used to divert all or a portion of the gases, vapors, or fumes from entering the control device.

(i) Except as provided in paragraph (a)(3)(ii) of this section, you must comply with either paragraph (a)(3)(i)(A) or (B) of this section for each bypass device.

(A) You must properly install, calibrate, maintain, and operate a flow indicator at the inlet to the bypass device that could divert the stream away from the control device to the atmosphere that is capable of taking periodic readings as specified in § 60.5416(a)(4) and sounds an alarm when the bypass device is open such that the stream is being, or could be, diverted away from the control device to the atmosphere.

(B) You must secure the bypass device valve installed at the inlet to the bypass device in the non-diverting position using a car-seal or a lock-and-key type configuration.

(ii) Low leg drains, high point bleeds, analyzer vents, open-ended valves or lines, and safety devices are not subject to the requirements of paragraph (a)(3)(i) of this section.

(b) *Cover requirements.* (1) The cover and all openings on the cover (*e.g.,* access hatches, sampling ports, and gauge wells) shall form a continuous barrier over the entire surface area of the liquid in the storage vessel or wet seal fluid degassing system.

(2) Each cover opening shall be secured in a closed, sealed position (*e.g.,* covered by a gasketed lid or cap) whenever material is in the unit on which the cover is installed except during those times when it is necessary to use an opening as follows:

(i) To add material to, or remove material from the unit (this includes openings necessary to equalize or balance the internal pressure of the unit following changes in the level of the material in the unit);

(ii) To inspect or sample the material in the unit;

(iii) To inspect, maintain, repair, or replace equipment located inside the unit; or

(iv) To vent liquids, gases, or fumes from the unit through a closed-vent system to a control device designed and operated in accordance with the requirements of paragraph (a) of this section.

§ 60.5412 What additional requirements must I meet for determining initial compliance with control devices used to comply with the emission standards for my storage vessel or centrifugal compressor affected facility?

You must meet the applicable requirements of this section for each control device used to comply with the emission standards for your storage vessel or centrifugal compressor affected facility.

(a) If you use a control device to meet the emission reduction standard in § 60.5380(a)(1) for your centrifugal compressor or § 60.5395(a)(1) or (2) for your storage vessel, you must use one of the control devices specified in paragraphs (a)(1) through (3) of this section. You must demonstrate that the control device achieves the performance requirements using the performance test methods and procedures specified in § 60.5413.

(1) You must design and operate an enclosed combustion device (*e.g.,* thermal vapor incinerator, catalytic vapor incinerator, boiler, or process heater) in accordance with one of the performance requirements specified in paragraphs (a)(1)(i) through (iv) of this section.

(i) You must reduce the mass content of VOC in the gases vented to the device by 95.0 percent by weight or greater as determined in accordance with the requirements of § 60.5413.

(ii) You must reduce the concentration of TOC in the exhaust gases at the outlet to the device to a level equal to or less than 20 parts per million by volume on a dry basis corrected to 3 percent oxygen as determined in accordance with the requirements of § 60.5413.

(iii) You must operate at a minimum temperature of 760 °C for a control device that can demonstrate a uniform combustion zone temperature during the performance test conducted under § 60.5413.

(iv) If a boiler or process heater is used as the control device, then you must introduce the vent stream into the flame zone of the boiler or process heater.

(2) You must design and operate a vapor recovery device (*e.g.,* carbon adsorption system or condenser) or other non-destructive control device to reduce the mass content of VOC in the gases vented to the device by 95.0 percent by weight or greater as determined in accordance with the requirements of § 60.5413. The vapor recovery device must meet the design analysis requirements of § 60.5413(c).

(3) You must design and operate a flare in accordance with the requirements of § 60.5413.

(b) You must operate each control device in accordance with the requirements specified in paragraphs (b)(1) and (2) of this section.

(1) You must operate each control device used to comply with this subpart at all times when gases, vapors, and fumes are vented from the storage vessel affected facility, as required under § 60.5395, or wet seal fluid degassing system affected facility, as required under § 60.5380, through the closed vent system to the control device. You may vent more than one affected facility to a control device used to comply with this subpart.

(2) For each control device monitored in accordance with the requirements of § 60.5417, you must demonstrate compliance according to the requirements of § 60.5415(e)(2), as applicable.

(c) For each carbon adsorption system used as a control device to meet the requirements of paragraph (a)(2) of this section, you must manage the carbon in accordance with the requirements specified in paragraphs (c)(1) or (2) of this section.

(1) Following the initial startup of the control device, you must replace all carbon in the control device with fresh carbon on a regular, predetermined time interval that is no longer than the carbon service life established according to § 60.5413(c)(2) or (3) for the carbon adsorption system. You must maintain records identifying the schedule for replacement and records of each carbon replacement as required in § 60.5420(c)(6).

(2) You must either regenerate, reactivate, or burn the spent carbon removed from the carbon adsorption system in one of the units specified in paragraphs (c)(2)(i) through (vii) of this section.

(i) Regenerate or reactivate the spent carbon in a thermal treatment unit for which you have been issued a final permit under 40 CFR part 270 that implements the requirements of 40 CFR part 264, subpart X.

(ii) Regenerate or reactivate the spent carbon in a thermal treatment unit equipped with and operating air emission controls in accordance with this section.

(iii) Regenerate or reactivate the spent carbon in a thermal treatment unit equipped with and operating organic air emission controls in accordance with an emissions standard for VOC under another subpart in 40 CFR part 60 or this part.

(iv) Burn the spent carbon in a hazardous waste incinerator for which the owner or operator has been issued a final permit under 40 CFR part 270 that implements the requirements of 40 CFR part 264, subpart O.

(v) Burn the spent carbon in a hazardous waste incinerator which you have designed and operated in accordance with the requirements of 40 CFR part 265, subpart O.

(vi) Burn the spent carbon in a boiler or industrial furnace for which you have been issued a final permit under 40 CFR part 270 that implements the requirements of 40 CFR part 266, subpart H.

(vii) Burn the spent carbon in a boiler or industrial furnace that you have designed and operated in accordance with the interim status requirements of 40 CFR part 266, subpart H.

§ 60.5413 What are the performance testing procedures for control devices used to demonstrate compliance at my storage vessel or centrifugal compressor affected facility?

This section applies to the performance testing of control devices used to demonstrate compliance with the emissions standards for your storage vessel or centrifugal compressor affected facility. You must demonstrate that a control device achieves the performance requirements of § 60.5412(a) using the performance test methods and procedures specified in paragraph (b) of this section. For condensers, you may use a design analysis as specified in paragraph (c) of this section in lieu of complying with paragraph (b) of this section.

(a) *Performance test exemptions.* You are exempt from the requirements to conduct performance tests and design analyses if you use any of the control devices described in paragraphs (a)(1) through (7) of this section.

(1) A flare that is designed and operated in accordance with § 60.18(b). You must conduct the compliance determination using Method 22 at 40 CFR part 60, appendix A–7, to determine visible emissions.

(2) A boiler or process heater with a design heat input capacity of 44 megawatts or greater.

(3) A boiler or process heater into which the vent stream is introduced with the primary fuel or is used as the primary fuel.

(4) A boiler or process heater burning hazardous waste for which you have either been issued a final permit under 40 CFR part 270 and comply with the requirements of 40 CFR part 266, subpart H; or you have certified compliance with the interim status requirements of 40 CFR part 266, subpart H.

(5) A hazardous waste incinerator for which you have been issued a final permit under 40 CFR part 270 and comply with the requirements of 40 CFR part 264, subpart O; or you have certified compliance with the interim status requirements of 40 CFR part 265, subpart O.

(6) A performance test is waived in accordance with § 60.8(b).

(7) A control device that can be demonstrated to meet the performance requirements of § 60.5412(a) through a performance test conducted by the manufacturer, as specified in paragraph (d) of this section.

(b) *Test methods and procedures.* You must use the test methods and procedures specified in paragraphs (b)(1) through (5) of this section, as applicable, for each performance test conducted to demonstrate that a control device meets the requirements of § 60.5412(a). You must conduct the initial and periodic performance tests according to the schedule specified in paragraph (b)(5) of this section.

(1) You must use Method 1 or 1A at 40 CFR part 60, appendix A–1, as appropriate, to select the sampling sites specified in paragraphs (b)(1)(i) and (ii) of this section. Any references to particulate mentioned in Methods 1 and 1A do not apply to this section.

(i) Sampling sites must be located at the inlet of the first control device, and at the outlet of the final control device, to determine compliance with the control device percent reduction requirement specified in § 60.5412(a)(1)(i) or (a)(2).

(ii) The sampling site must be located at the outlet of the combustion device to determine compliance with the enclosed combustion device total TOC concentration limit specified in § 60.5412(a)(1)(ii).

(2) You must determine the gas volumetric flowrate using Method 2, 2A, 2C, or 2D at 40 CFR part 60, appendix A–2, as appropriate.

(3) To determine compliance with the control device percent reduction performance requirement in § 60.5412(a)(1)(i) or (a)(2), you must use Method 25A at 40 CFR part 60, appendix A–7. You must use the procedures in paragraphs (b)(3)(i)

through (iv) of this section to calculate percent reduction efficiency.

(i) For each run, you must take either an integrated sample or a minimum of four grab samples per hour. If grab sampling is used, then the samples must be taken at approximately equal intervals in time, such as 15-minute intervals during the run.

(ii) You must compute the mass rate of TOC (minus methane and ethane) using the equations and procedures specified in paragraphs (b)(3)(ii)(A) and (B) of this section.

(A) You must use the following equations:

$$E_i = K_2 \left(\sum_{j=1}^{n} C_{ij} M_{ij} \right) Q_i$$

$$E_o = K_2 \left(\sum_{j=1}^{n} C_{oj} M_{oj} \right) Q_o$$

Where:

E_i, E_o = Mass rate of TOC (minus methane and ethane) at the inlet and outlet of the control device, respectively, dry basis, kilogram per hour.

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 °C.

C_{ij}, C_{oj} = Concentration of sample component j of the gas stream at the inlet and outlet of the control device, respectively, dry basis, parts per million by volume.

M_{ij}, M_{oj} = Molecular weight of sample component j of the gas stream at the inlet and outlet of the control device, respectively, gram/gram-mole.

Q_i, Q_o = Flowrate of gas stream at the inlet and outlet of the control device, respectively, dry standard cubic meter per minute.

n = Number of components in sample.

(B) When calculating the TOC mass rate, you must sum all organic compounds (minus methane and ethane) measured by Method 25A at 40 CFR part 60, appendix A–7 using the equations in paragraph (b)(3)(ii)(A) of this section.

(iii) You must calculate the percent reduction in TOC (minus methane and ethane) as follows:

$$R_{cd} = \frac{E_i - E_o}{E_i} * 100\%$$

Where:

R_{cd} = Control efficiency of control device, percent.

E_i = Mass rate of TOC (minus methane and ethane) at the inlet to the control device as calculated under paragraph (b)(3)(ii) of this section, kilograms TOC per hour or kilograms HAP per hour.

E_o = Mass rate of TOC (minus methane and ethane) at the outlet of the control device, as calculated under paragraph (b)(3)(ii) of this section, kilograms TOC per hour per hour.

(iv) If the vent stream entering a boiler or process heater with a design capacity less than 44 megawatts is introduced with the combustion air or as a secondary fuel, you must determine the weight-percent reduction of total TOC (minus methane and ethane) across the device by comparing the TOC (minus methane and ethane) in all combusted vent streams and primary and secondary fuels with the TOC (minus methane and ethane) exiting the device, respectively.

(4) You must use Method 25A at 40 CFR part 60, appendix A–7 to measure TOC (minus methane and ethane) to determine compliance with the enclosed combustion device total VOC concentration limit specified in § 60.5412(a)(1)(ii). You must calculate parts per million by volume concentration and correct to 3 percent oxygen, using the procedures in paragraphs (b)(4)(i) through (iii) of this section.

(i) For each run, you must take either an integrated sample or a minimum of four grab samples per hour. If grab sampling is used, then the samples must be taken at approximately equal intervals in time, such as 15-minute intervals during the run.

(ii) You must calculate the TOC concentration for each run as follows:

$$C_{TOC} = \sum_{i=1}^{x} \frac{\left(\sum_{j=i}^{n} C_{ji} \right)}{x}$$

Where:

C_{TOC} = Concentration of total organic compounds minus methane and ethane, dry basis, parts per million by volume.

C_{ji} = Concentration of sample component j of sample i, dry basis, parts per million by volume.

n = Number of components in the sample.

x = Number of samples in the sample run.

(iii) You must correct the TOC concentration to 3 percent oxygen as specified in paragraphs (b)(4)(iii)(A) and (B) of this section.

(A) You must use the emission rate correction factor for excess air, integrated sampling and analysis procedures of Method 3A or 3B at 40 CFR part 60, appendix A, ASTM D6522–00 (Reapproved 2005), or ANSI/ASME PTC 19.10–1981, Part 10 (manual portion only) (incorporated by reference as specified in § 60.17) to determine the oxygen concentration. The samples must be taken during the same time that the samples are taken for determining TOC concentration.

(B) You must correct the TOC concentration for percent oxygen as follows:

$$C_c = C_m \left(\frac{17.9}{20.9 - \%O_{2d}} \right)$$

Where:

C_c = TOC concentration corrected to 3 percent oxygen, dry basis, parts per million by volume.

C_m = TOC concentration, dry basis, parts per million by volume.

$\%O_{2d}$ = Concentration of oxygen, dry basis, percent by volume.

(5) You must conduct performance tests according to the schedule specified in paragraphs (b)(5)(i) and (ii) of this section.

(i) You must conduct an initial performance test within 180 days after initial startup for your affected facility. You must submit the performance test results as required in § 60.5420(b)(7).

(ii) You must conduct periodic performance tests for all control devices required to conduct initial performance tests except as specified in paragraphs (b)(5)(ii)(A) and (B) of this section. You must conduct the first periodic performance test no later than 60 months after the initial performance test required in paragraph (b)(5)(i) of this section. You must conduct subsequent periodic performance tests at intervals no longer than 60 months following the previous periodic performance test or whenever you desire to establish a new operating limit. You must submit the periodic performance test results as specified in § 60.5420(b)(7). Combustion control devices meeting the criteria in either paragraph (b)(5)(ii)(A) or (B) of this section are not required to conduct periodic performance tests.

(A) A control device whose model is tested under, and meets the criteria of paragraph (d) of this section.

(B) A combustion control device tested under paragraph (b) of this section that meets the outlet TOC performance level specified in § 60.5412(a)(1)(ii) and that establishes a correlation between firebox or combustion chamber temperature and the TOC performance level.

(c) *Control device design analysis to meet the requirements of § 60.5412(a).* (1) For a condenser, the design analysis must include an analysis of the vent stream composition, constituent concentrations, flowrate, relative humidity, and temperature, and must 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.

(2) For a regenerable carbon adsorption system, the design analysis shall include the vent stream composition, constituent concentrations, flowrate, relative humidity, and temperature, and shall establish the design exhaust vent stream organic compound concentration level, adsorption cycle time, number and capacity of carbon beds, type and working capacity of activated carbon used for the carbon beds, design total regeneration stream flow over the period of each complete carbon bed regeneration cycle, design carbon bed temperature after regeneration, design carbon bed regeneration time, and design service life of the carbon.

(3) For a nonregenerable carbon adsorption system, such as a carbon canister, the design analysis shall include the vent stream composition, constituent concentrations, flowrate, relative humidity, and temperature, and shall establish the design exhaust vent stream organic compound concentration level, capacity of the carbon bed, type and working capacity of activated carbon used for the carbon bed, and design carbon replacement interval based on the total carbon working capacity of the control device and source operating schedule. In addition, these systems will incorporate dual carbon canisters in case of emission breakthrough occurring in one canister.

(4) If you and the Administrator do not agree on a demonstration of control device performance using a design analysis, then you must perform a performance test in accordance with the requirements of paragraph (b) of this section to resolve the disagreement. The Administrator may choose to have an authorized representative observe the performance test.

(d) *Performance testing for combustion control devices—manufacturers' performance test.* The manufacturer must demonstrate that a specific model of combustion control device achieves the performance requirements in paragraph (d)(1) of this section by conducting a performance test as specified in paragraphs (d)(2) through (8) of this section. You must submit a test report for each combustion control device in accordance with the requirements in paragraphs (d)(9) of this section.

(1) The manufacturer must meet the performance test criteria in paragraphs (d)(1)(i) through (iii) of this section.

(i) The control device model tested must meet the emission levels in paragraphs (d)(1)(i)(A) through (C) of this section.

(A) Method 22 at 40 CFR part 60, appendix A–7, results under paragraph (d)(6)(iv) of this section with no indication of visible emissions.

(B) Average Method 25A at 40 CFR part 60, appendix A–7, results under paragraph (d)(8) of this section equal to or less than 10.0 parts per million by volume-wet THC as propane corrected to 3.0 percent carbon dioxide, and

(C) Average carbon monoxide emissions determined under paragraph (d)(6)(iii) of this section equal to or less than 10 parts per million by volume-dry, corrected to 3.0 percent carbon dioxide.

(ii) The manufacturer must determine a maximum inlet gas flow rate, which must not be exceeded for each control device model to achieve the criteria in paragraph (d)(1)(i) of this section.

(iii) A control device meeting the emission levels in paragraph (d)(1)(i)(A) through (C) of this section must demonstrate a minimum destruction efficiency of 95.0 percent for VOC regulated under this subpart.

(2) Performance testing must consist of three one-hour (or longer) test runs for each of the four firing rate settings in paragraphs (d)(2)(i) through (iv) of this section, making a total of 12 test runs per test. The manufacturer must use propene (propylene) gas for the testing fuel. An independent third-party laboratory (not affiliated with the control device manufacturer or fuel supplier) must perform all fuel analyses.

(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 up 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 up 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 up 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) The manufacturer must test all models employing multiple enclosures simultaneously and with all burners operational. The manufacturer must report results for each enclosure individually and for the average of the emissions from all interconnected combustion enclosures/chambers. Control device operating data must be collected continuously throughout the performance test using an electronic Data Acquisition System and strip chart. The manufacturer must submit data with the test report in accordance with paragraph (d)(9) of this section.

(4) The manufacturer must conduct inlet testing as specified in paragraphs (d)(4)(i) through (iii) of this section.

(i) The fuel flow metering system must be located in accordance with Method 2A at 40 CFR part 60, appendix A–1, (or other approved procedure) to measure fuel flow rate at the control device inlet location. You must position the fitting for filling fuel sample containers a minimum of eight pipe diameters upstream of any inlet fuel flow monitoring meter.

(ii) The manufacturer must determine the inlet flow rate using Method 2A at 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) The manufacturer must conduct inlet fuel sampling in accordance with the criteria in paragraph (d)(5) of this section.

(5) The manufacturer must conduct inlet fuel sampling as specified in paragraphs (d)(5)(i) and (ii) of this section.

(i) At the inlet fuel sampling location, the manufacturer must 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 must be conducted as specified in paragraphs (d)(5)(i)(A) through (C) of this section.

(A) Open the canister sampling valve at the beginning of the total hydrocarbon test, and close the canister at the end of the total hydrocarbon test.

(B) Fill one canister for each total hydrocarbon test run.

(C) Label the canisters individually and record on a chain of custody form.

(ii) The manufacturer must analyze each fuel sample using the methods in paragraphs (d)(5)(ii)(A) through (D) of this section. You must include the results in the test report in paragraph (d)(9) of this section.

(A) Hydrocarbon compounds containing between one and five atoms of carbon plus benzene using ASTM D1945–03 (Reapproved 2010) (incorporated by reference as specified in § 60.17).

(B) Hydrogen (H_2), carbon monoxide (CO), carbon dioxide (CO_2), nitrogen (N_2), oxygen (O_2) using ASTM D1945–03 (Reapproved 2010) (incorporated by reference as specified in § 60.17).

(C) Carbonyl sulfide, carbon disulfide plus mercaptans using ASTM D5504–08 (incorporated by reference as specified in § 60.17).

(D) Higher heating value using ASTM D3588–98 (Reapproved 2003) or ASTM D4891–89 (Reapproved 2006) (incorporated by reference as specified in § 60.17).

(6) The manufacturer must conduct outlet testing in accordance with the criteria in paragraphs (d)(6)(i) through (iv) and (d)(7) of this section.

(i) The manufacturer must sample and measure flowrate in accordance with the following:

(A) The manufacturer must position the outlet sampling location a minimum of four 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 must be used.

(B) The manufacturer must measure flow rate using Method 1 at 40 CFR part 60, appendix A–1 for determining flow measurement traverse point location, and Method 2 at 40 CFR part 60, appendix A–1 for measuring 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 must be used to obtain an accurate flow profile.

(ii) The manufacturer must determine molecular weight as specified in paragraph (d)(7) of this section.

(iii) The manufacturer must determine carbon monoxide using Method 10 at 40 CFR part 60, appendix A–4 or ASTM D6522–00 (Reapproved 2005) (incorporated by reference as specified in § 60.17). The manufacturer must run the test at the same time and with the sample points used for the Method 25A at 40 CFR part 60, appendix A–7, testing. An instrument range of 0–10 parts per million by volume-dry (ppmvd) must be used.

(iv) The manufacturer must determine visible emissions using Method 22 at 40 CFR part 60, appendix A–7. The test must 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.

(7) The manufacturer must determine molecular weight as specified in paragraphs (d)(7)(i) and (ii) of this section.

(i) The manufacturer must collect an integrated bag sample during the Method 4 at 40 CFR part 60, appendix A–3, moisture test. The manufacturer must analyze the bag sample using a gas chromatograph-thermal conductivity detector (GC–TCD) analysis meeting the criteria in paragraphs (d)(7)(i)(A) through (D) of this section.

(A) Collect the integrated sample throughout the entire test, and collect representative volumes from each traverse location.

(B) Purge the sampling line with stack gas before opening the valve and beginning to fill the bag.

(C) Knead or otherwise vigorously mix the bag contents prior to the gas chromatograph analysis.

(D) Modify the gas chromatograph-thermal conductivity detector calibration procedure in Method 3C at 40 CFR part 60, appendix A–2 by using EPA Alt–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, repeat the initial calibration using at least three concentration levels.

(ii) The manufacturer must report the molecular weight of oxygen, carbon dioxide, methane, and nitrogen and include in the test report submitted under § 60.5420(b)(7). The manufacturer must determine moisture using Method 4 at 40 CFR part 60, appendix A–3. Traverse both ports with the Method 4 at 40 CFR part 60, appendix A–3, sampling train during each test run. The manufacturer must not introduce ambient air into the Method 3C at 40 CFR part 60, appendix A–2, integrated bag sample during the port change.

(8) The manufacturer must determine total hydrocarbons as specified by the criteria in paragraphs (d)(8)(i) through (vii) of this section.

(i) Conduct THC sampling using Method 25A at 40 CFR part 60, appendix A–7, except the option for locating the probe in the center 10 percent of the stack is not 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 must consist of three Method 25A at 40 CFR part 60, appendix A–7, 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.

(v) THC measurements must be reported in terms of ppmvw as propane.

(vi) THC results must be corrected to 3 percent CO_2, as measured by Method 3C at 40 CFR part 60, appendix A–2.

(vii) Subtraction of methane/ethane from the THC data is not allowed in determining results.

(9) For each combustion control device model tested by the manufacturer under this section, you must maintain records of the information listed in paragraphs (d)(9)(i) through (vi) of this section.

(i) A full schematic of the control device and dimensions of the device components.

(ii) The design net heating value (minimum and maximum) of the device.

(iii) The test fuel gas flow range (in both mass and volume). Include the minimum and maximum allowable inlet gas flow rate.

(iv) The air/stream injection/assist ranges, if used.

(v) The test parameter ranges listed in paragraphs (d)(9)(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) You must include all calibration quality assurance/quality control data, calibration gas values, gas cylinder certification, and strip charts annotated with test times and calibration values in the test report.

§ 60.5415 How do I demonstrate continuous compliance with the standards for my gas well 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 well affected facility, you must demonstrate continuous compliance by submitting the reports required by § 60.5420(b) and maintaining the records for each completion operation specified in § 60.5420(c)(1).

(b) For each centrifugal compressor affected facility, you must demonstrate continuous compliance according to paragraphs (b)(1) and (2) of this section.

(1) You must reduce VOC emissions from the wet seal fluid degassing system by 95.0 percent or greater.

(2) If you use a control device to reduce emissions, you must demonstrate continuous compliance according to paragraph (e)(2) of this section.

(3) You must submit the annual report required by 60.5420(b) and maintain the records as specified in § 60.5420(c)(2).

(c) For each reciprocating compressor affected facility, you must demonstrate continuous compliance according to paragraphs (c)(1) through (3) of this section.

(1) You must continuously monitor the number of hours of operation for each reciprocating compressor affected facility or track the number of months since initial startup, or October 15, 2012, or the date of the most recent reciprocating compressor rod packing replacement, whichever is later.

(2) You must submit the annual report as required in § 60.5420(b) and maintain records as required in § 60.5420(c)(3).

(3) You must replace the reciprocating compressor rod packing before the total number of hours of operation reaches 26,000 hours or the number of months since the most recent rod packing replacement reaches 36 months.

(d) For each pneumatic controller affected facility, you must demonstrate continuous compliance according to paragraphs (d)(1) through (3) of this section.

(1) You must continuously operate the pneumatic controllers as required in § 60.5390(a), (b), or (c).

(2) You must submit the annual report as required in § 60.5420(b).

(3) You must maintain records as required in § 60.5420(c)(4).

(e) For each storage vessel affected facility for which the VOC emissions are greater than 6 tpy, you must demonstrate continuous compliance according to paragraphs (e)(1) and (2) of this section.

(1) You must reduce VOC emissions from each storage vessel are reduced by 95.0 percent or greater.

(2) If you use a control device to reduce VOC emissions, you must demonstrate continuous compliance with the performance requirements of § 60.5412(a)(2) using the procedure specified in paragraphs (e)(2)(i) through (vii) of this section. If you use a condenser as the control device to achieve the requirements specified in § 60.5412(a)(2), you may demonstrate compliance according to paragraph (e)(2)(viii) of this section. You may switch between compliance with paragraphs (e)(2)(i) through (vii) of this section and compliance with paragraph (e)(2)(viii) of this section only after at least 1 year of operation in compliance with the selected approach. You must provide notification of such a change in the compliance method in the next Annual Report, as required in § 60.5420(b), following the change.

(i) You must operate below (or above) the site specific maximum (or minimum) parameter value established according to the requirements of § 60.5417(f)(1).

(ii) You must calculate the daily average of the applicable monitored parameter in accordance with § 60.5417(e) except that the inlet gas flow rate to the control device must not be averaged.

(iii) Compliance with the operating parameter limit is achieved when the daily average of the monitoring parameter value calculated under paragraph (e)(2)(ii) of this section is either equal to or greater than the minimum monitoring value or equal to or less than the maximum monitoring value established under paragraph (e)(2)(i) of this section. When performance testing of a combustion control device is conducted by the device manufacturer as specified in § 60.5413(d), compliance with the operating parameter limit is achieved when the inlet gas flow rate is equal to or less than the value established under § 60.5413(d)(1)(ii).

(iv) You must operate the continuous monitoring system required in § 60.5417 at all times the affected source is operating, 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). 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. You are required to complete monitoring system repairs in response to monitoring system malfunctions and to return the monitoring system to operation as expeditiously as practicable.

(v) You may not use data recorded during monitoring system malfunctions, repairs associated with monitoring system malfunctions, or required monitoring system quality assurance or control activities in calculations used to report emissions or operating levels. You must use all the data collected during all other required data collection periods to assess the operation of the control device and associated control system.

(vi) Failure to collect required data is a deviation of the monitoring requirements, 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).

(vii) If you use a combustion control device to meet the requirements of § 60.5412(a), you must demonstrate compliance by installing a device tested under the provisions in § 60.5413(d) and complying with the criteria in paragraphs (e)(2)(vii)(A) through (D) of this section.

(A) The inlet gas flow rate must meet the range specified by the manufacturer. You must measure the flow rate as specified in § 60.5417(d)(1)(viii)(A).

(B) A pilot flame must be present at all times of operation. You must monitor the pilot flame in accordance with § 60.5417(d)(1)(viii)(B).

(C) You must operate the combustion control device with no visible emissions, except for periods not to exceed a total of 5 minutes during any 2 consecutive hours. You must perform a visible emissions test using Method 22 at 40 CFR part 60, appendix A–7 monthly. The observation period must be 2 hours and must follow Method 22.

(D) Compliance with the operating parameter limit is achieved when the criteria in paragraphs (e)(2)(vii)(D)(*1*) through (*5*) are met.

(*1*) The inlet gas flow rate monitored under paragraph (e)(2)(vii)(A) of this section is equal to or below the maximum established by the manufacturer.

(*2*) The pilot flame is present at all times; and

(*3*) During the visible emissions test performed under paragraph (e)(2)(vii)(C) 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 must follow the requirements in paragraphs (e)(2)(vii)(D)(*4*) and (*5*) of this section.

(*4*) Following the first failure, you must replace the fuel nozzle(s) and burner tubes.

(*5*) If, following replacement of the fuel nozzle(s) and burner tubes as specified in paragraph (e)(2)(vii)(D)(*4*) of this section, the visible emissions test is not passed in the next scheduled test, you must either conduct a performance test as specified in § 60.5413, or replace the device with another control device whose model was tested and meets the requirements in § 60.5413(d).

(viii) If you use a condenser as the control device to achieve the percent reduction performance requirements specified in § 60.5412(a)(2), you must demonstrate compliance using the procedures in paragraphs (e)(2)(viii)(A) through (E) of this section.

(A) You must establish a site-specific condenser performance curve according to § 60.5417(f)(2).

(B) You must calculate the daily average condenser outlet temperature in accordance with § 60.5417(e).

(C) You must determine the condenser efficiency for the current operating day using the daily average condenser outlet temperature calculated under paragraph (e)(2)(viii)(B) of this section and the condenser performance curve established under paragraph (e)(2)(viii)(A) of this section.

(D) Except as provided in paragraphs (e)(2)(viii)(D)(*1*) and (*2*) of this section, at the end of each operating day, you must calculate the 365-day rolling average TOC emission reduction, as appropriate, from the condenser efficiencies as determined in paragraph (e)(2)(viii)(C) of this section.

(*1*) After the compliance dates specified in § 60.5370, if you have less than 120 days of data for determining average TOC emission reduction, you must calculate the average TOC emission reduction for the first 120 days of operation after the compliance dates. You have demonstrated compliance with the overall 95.0 percent reduction requirement if the 120-day average TOC emission reduction is equal to or greater than 95.0 percent.

(*2*) After 120 days and no more than 364 days of operation after the compliance date specified in § 60.5370, you must calculate the average TOC emission reduction as the TOC emission reduction averaged over the number of days between the current day and the applicable compliance date. You have demonstrated compliance with the overall 95.0 percent reduction requirement, if the average TOC emission reduction is equal to or greater than 95.0 percent.

(E) If you have data for 365 days or more of operation, you have demonstrated compliance with the TOC emission reduction if the rolling 365-day average TOC emission reduction calculated in paragraph (e)(2)(viii)(D) of this section is equal to or greater than 95.0 percent.

(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 (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 violations of emission standards 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 violations 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 standard, you must timely meet the reporting requirements in § 60.5420(a), and must prove by a preponderance of evidence that:

(i) The violation:

(A) Was caused by a sudden, infrequent, and unavoidable failure of air pollution control 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) Was not part of a recurring pattern indicative of inadequate design, operation, or maintenance; and

(ii) Repairs were made as expeditiously as possible when a violation occurred. Off-shift and overtime labor were used, to the extent practicable to make these repairs; and

(iii) The frequency, amount and duration of the violation (including any bypass) were minimized to the maximum extent practicable; and

(iv) If the violation 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 violation 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 violation 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, the purpose of which is to determine, correct, and eliminate the primary causes of the malfunction and the violation resulting from the malfunction event at issue. The analysis shall also specify, using best monitoring methods and engineering judgment, the amount of any emissions that were the result of the malfunction.

(2) Report. The owner or operator seeking to assert an affirmative defense shall submit a written report to the Administrator with all necessary supporting documentation, that it has met the requirements set forth in paragraph (h)(1) of this section. This affirmative defense report shall be included in the first periodic compliance, deviation report or excess emission report otherwise required after the initial occurrence of the violation of the relevant standard (which may be the end of any applicable averaging period). If such compliance, deviation report or

excess emission report is due less than 45 days after the initial occurrence of the violation, the affirmative defense report may be included in the second compliance, deviation report or excess emission report due after the initial occurrence of the violation of the relevant standard.

§ 60.5416 What are the initial and continuous cover and closed vent system inspection and monitoring requirements for my storage vessel and centrifugal compressor affected facility?

For each closed vent system or cover at your storage vessel or centrifugal compressor affected facility, you must comply with the requirements of paragraphs (a) through (g) of this section.

(a) *Inspections.* Except as provided in paragraphs (e) and (f) of this section, you must inspect each closed vent system according to the procedures and schedule specified in paragraphs (a)(1) and (2) of this section, inspect each cover according to the procedures and schedule specified in paragraph (a)(3) of this section, and inspect each bypass device according to the procedures of paragraph (a)(4) of this section.

(1) For each closed vent system joint, seam, or other connection that is permanently or semi-permanently sealed (*e.g.,* a welded joint between two sections of hard piping or a bolted and gasketed ducting flange), you must meet the requirements specified in paragraphs (a)(1)(i) and (ii) of this section.

(i) Conduct an initial inspection according to the test methods and procedures specified in paragraph (b) of this section to demonstrate that the closed vent system operates with no detectable emissions. You must maintain records of the inspection results as specified in § 60.5420(c)(6).

(ii) Conduct annual visual inspections for defects that could result in air emissions. Defects include, but are not limited to, visible cracks, holes, or gaps in piping; loose connections; or broken or missing caps or other closure devices. You must monitor a component or connection using the test methods and procedures in paragraph (b) of this section to demonstrate that it operates with no detectable emissions following any time the component is repaired or replaced or the connection is unsealed. You must maintain records of the inspection results as specified in § 60.5420(c)(6).

(2) For closed vent system components other than those specified in paragraph (a)(1) of this section, you must meet the requirements of paragraphs (a)(2)(i) through (iii) of this section.

(i) Conduct an initial inspection according to the test methods and procedures specified in paragraph (b) of this section to demonstrate that the closed vent system operates with no detectable emissions. You must maintain records of the inspection results as specified in § 60.5420(c)(6).

(ii) Conduct annual inspections according to the test methods and procedures specified in paragraph (b) of this section to demonstrate that the components or connections operate with no detectable emissions. You must maintain records of the inspection results as specified in § 60.5420(c)(6).

(iii) Conduct annual visual inspections for defects that could result in air emissions. Defects include, but are not limited to, visible cracks, holes, or gaps in ductwork; loose connections; or broken or missing caps or other closure devices. You must maintain records of the inspection results as specified in § 60.5420(c)(6).

(3) For each cover, you must meet the requirements in paragraphs (a)(3)(i) and (ii) of this section.

(i) Conduct visual inspections for defects that could result in air emissions. Defects include, but are not limited to, visible cracks, holes, or gaps in the cover, or between the cover and the separator wall; broken, cracked, or otherwise damaged seals or gaskets on closure devices; and broken or missing hatches, access covers, caps, or other closure devices. In the case where the storage vessel is buried partially or entirely underground, you must inspect only those portions of the cover that extend to or above the ground surface, and those connections that are on such portions of the cover (*e.g.,* fill ports, access hatches, gauge wells, etc.) and can be opened to the atmosphere.

(ii) You must initially conduct the inspections specified in paragraph (a)(3)(i) of this section following the installation of the cover. Thereafter, you must perform the inspection at least once every calendar year, except as provided in paragraphs (e) and (f) of this section. You must maintain records of the inspection results as specified in § 60.5420(c)(7).

(4) For each bypass device, except as provided for in § 60.5411, you must meet the requirements of paragraphs (a)(4)(i) or (ii) of this section.

(i) Set the flow indicator to take a reading at least once every 15 minutes at the inlet to the bypass device that could divert the steam away from the control device to the atmosphere.

(ii) If the bypass device valve installed at the inlet to the bypass device is secured in the non-diverting position using a car-seal or a lock-and-key type configuration, visually inspect the seal or closure mechanism at least once every month to verify that the valve is maintained in the non-diverting position and the vent stream is not diverted through the bypass device. You must maintain records of the inspections according to § 60.5420(c)(8).

(b) *No detectable emissions test methods and procedures.* If you are required to conduct an inspection of a closed vent system or cover at your storage vessel or centrifugal compressor affected facility as specified in paragraphs (a)(1), (2), or (3) of this section, you must meet the requirements of paragraphs (b)(1) through (13) of this section.

(1) You must conduct the no detectable emissions test procedure in accordance with Method 21 at 40 CFR part 60, appendix A–7.

(2) The detection instrument must meet the performance criteria of Method 21 at 40 CFR part 60, appendix A–7, except that the instrument response factor criteria in section 3.1.2(a) of Method 21 must be for the average composition of the fluid and not for each individual organic compound in the stream.

(3) You must calibrate the detection instrument before use on each day of its use by the procedures specified in Method 21 at 40 CFR part 60, appendix A–7.

(4) Calibration gases must be as specified in paragraphs (b)(4)(i) and (ii) of this section.

(i) Zero air (less than 10 parts per million by volume hydrocarbon in air).

(ii) A mixture of methane in air at a concentration less than 10,000 parts per million by volume.

(5) You may choose to adjust or not adjust the detection instrument readings to account for the background organic concentration level. If you choose to adjust the instrument readings for the background level, you must determine the background level value according to the procedures in Method 21 at 40 CFR part 60, appendix A–7.

(6) Your detection instrument must meet the performance criteria specified in paragraphs (b)(6)(i) and (ii) of this section.

(i) Except as provided in paragraph (b)(6)(ii) of this section, the detection instrument must meet the performance criteria of Method 21 at 40 CFR part 60, appendix A–7, except the instrument response factor criteria in section 3.1.2(a) of Method 21 must be for the average composition of the process fluid, not each individual volatile organic compound in the stream. For process streams that contain nitrogen, air, or other inerts that are not organic hazardous air pollutants or volatile organic compounds, you must calculate the average stream response factor on an inert-free basis.

(ii) If no instrument is available that will meet the performance criteria specified in paragraph (b)(6)(i) of this section, you may adjust the instrument readings by multiplying by the average response factor of the process fluid, calculated on an inert-free basis, as described in paragraph (b)(6)(i) of this section.

(7) You must determine if a potential leak interface operates with no detectable emissions using the applicable procedure specified in paragraph (b)(7)(i) or (ii) of this section.

(i) If you choose not to adjust the detection instrument readings for the background organic concentration level, then you must directly compare the maximum organic concentration value measured by the detection instrument to the applicable value for the potential leak interface as specified in paragraph (b)(8) of this section.

(ii) If you choose to adjust the detection instrument readings for the background organic concentration level, you must compare the value of the arithmetic difference between the maximum organic concentration value measured by the instrument and the background organic concentration value as determined in paragraph (b)(5) of this section with the applicable value for the potential leak interface as specified in paragraph (b)(8) of this section.

(8) A potential leak interface is determined to operate with no detectable organic emissions if the organic concentration value determined in paragraph (b)(7) of this section is less than 500 parts per million by volume.

(9) *Repairs.* In the event that a leak or defect is detected, you must repair the leak or defect as soon as practicable according to the requirements of paragraphs (b)(9)(i) and (ii) of this section, except as provided in paragraph (d) of this section.

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

(ii) Repair must be completed no later than 15 calendar days after the leak is detected.

(10) *Delay of repair.* Delay of repair of a closed vent system or cover for which leaks or defects have been detected is allowed if the repair is technically infeasible without a shutdown, or if you determine that emissions resulting from immediate repair would be greater than the fugitive emissions likely to result from delay of repair. You must complete repair of such equipment by the end of the next shutdown.

(11) *Unsafe to inspect requirements.* You may designate any parts of the closed vent system or cover as unsafe to inspect if the requirements in paragraphs (e)(1) and (2) of this section are met. Unsafe to inspect parts are exempt from the inspection requirements of paragraphs (a)(1) through (3) of this section.

(A) You determine that the equipment is unsafe to inspect because inspecting personnel would be exposed to an imminent or potential danger as a consequence of complying with paragraphs (a)(1), (2), or (3) of this section.

(B) You have a written plan that requires inspection of the equipment as frequently as practicable during safe-to-inspect times.

(12) *Difficult to inspect requirements.* You may designate any parts of the closed vent system or cover as difficult to inspect, if the requirements in paragraphs (b)(12)(i) and (ii) of this section are met. Difficult to inspect parts are exempt from the inspection requirements of paragraphs (a)(1) through (3) of this section.

(i) You determine that the equipment cannot be inspected without elevating the inspecting personnel more than 2 meters above a support surface.

(ii) You have a written plan that requires inspection of the equipment at least once every 5 years.

(13) *Records.* Records shall be maintained as specified in this section and in § 60.5420(c)(9).

§ 60.5417 What are the continuous control device monitoring requirements for my storage vessel or centrifugal compressor affected facility?

You must meet the applicable requirements of this section to demonstrate continuous compliance for each control device used to meet emission standards for your storage vessel or centrifugal compressor affected facility.

(a) You must install and operate a continuous parameter monitoring system for each control device as specified in paragraphs (c) through (j) of this section, except as provided for in paragraph (b) of this section. If you install and operate a flare in accordance with § 60.5412(a)(3), you are exempt from the requirements of paragraphs (e) and (f) of this section.

(b) You are exempt from the monitoring requirements specified in paragraphs (c) through (j) of this section for the control devices listed in paragraphs (b)(1) and (2) of this section.

(1) A boiler or process heater in which all vent streams are introduced with the primary fuel or is used as the primary fuel.

(2) A boiler or process heater with a design heat input capacity equal to or greater than 44 megawatts.

(c) You must design and operate the continuous monitoring system so that a determination can be made on whether the control device is achieving the applicable performance requirements of § 60.5412. For each continuous parameter monitoring system, you must meet the specifications and requirements in paragraphs (c)(1) through (4) of this section.

(1) Each continuous parameter monitoring system must measure data values at least once every hour and record the parameters in paragraphs (c)(1)(i) or (ii) of this section.

(i) Each measured data value.

(ii) Each block average value for each 1-hour period or shorter periods calculated from all measured data values during each period. If values are measured more frequently than once per minute, a single value for each minute may be used to calculate the hourly (or shorter period) block average instead of all measured values.

(2) You must prepare a site-specific monitoring plan that addresses the monitoring system design, data collection, and the quality assurance and quality control elements outlined in paragraphs (c)(2)(i) through (v) of this section. You must install, calibrate, operate, and maintain each continuous parameter monitoring system in accordance with the procedures in your approved site-specific monitoring plan.

(i) The performance criteria and design specifications for the monitoring system equipment, including the sample interface, detector signal analyzer, and data acquisition and calculations.

(ii) Sampling interface (*e.g.,* thermocouple) location such that the monitoring system will provide representative measurements.

(iii) Equipment performance checks, system accuracy audits, or other audit procedures.

(iv) Ongoing operation and maintenance procedures in accordance with provisions in § 60.13(b).

(v) Ongoing reporting and recordkeeping procedures in accordance with provisions in § 60.7(c), (d), and (f).

(3) You must conduct the continuous parameter monitoring system equipment performance checks, system accuracy audits, or other audit procedures specified in the site-specific monitoring plan at least once every 12 months.

(4) You must conduct a performance evaluation of each continuous parameter monitoring system in

accordance with the site-specific monitoring plan.

(d) You must install, calibrate, operate, and maintain a device equipped with a continuous recorder to measure the values of operating parameters appropriate for the control device as specified in either paragraph (d)(1), (2), or (3) of this section.

(1) A continuous monitoring system that measures the operating parameters in paragraphs (d)(1)(i) through (viii) of this section, as applicable.

(i) For a thermal vapor incinerator that demonstrates during the performance test conducted under § 60.5413 that combustion zone temperature is an accurate indicator of performance, a temperature monitoring device equipped with a continuous recorder. The monitoring device must have a minimum accuracy of ±1 percent of the temperature being monitored in °C, or ±2.5 °C, whichever value is greater. You must install the temperature sensor at a location representative of the combustion zone temperature.

(ii) For a catalytic vapor incinerator, a temperature monitoring device equipped with a continuous recorder. The device must be capable of monitoring temperature at two locations and have a minimum accuracy of ±1 percent of the temperature being monitored in °C, or ±2.5 °C, whichever value is greater. You must install one temperature sensor in the vent stream at the nearest feasible point to the catalyst bed inlet, and you must install a second temperature sensor in the vent stream at the nearest feasible point to the catalyst bed outlet.

(iii) For a flare, a heat sensing monitoring device equipped with a continuous recorder that indicates the continuous ignition of the pilot flame.

(iv) For a boiler or process heater, a temperature monitoring device equipped with a continuous recorder. The temperature monitoring device must have a minimum accuracy of ±1 percent of the temperature being monitored in °C, or ±2.5 °C, whichever value is greater. You must install the temperature sensor at a location representative of the combustion zone temperature.

(v) For a condenser, a temperature monitoring device equipped with a continuous recorder. The temperature monitoring device must have a minimum accuracy of ±1 percent of the temperature being monitored in °C, or ±2.8 °C, whichever value is greater. You must install the temperature sensor at a location in the exhaust vent stream from the condenser.

(vi) For a regenerative-type carbon adsorption system, a continuous monitoring system that meets the specifications in paragraphs (d)(1)(vi)(A) and (B) of this section.

(A) The continuous parameter monitoring system must 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. You must check the mechanical connections for leakage at least every month, and you must perform a visual inspection at least every 3 months of all components of the flow continuous parameter monitoring system for physical and operational integrity and all electrical connections for oxidation and galvanic corrosion if your flow continuous parameter monitoring system is not equipped with a redundant flow sensor; and

(B) The continuous parameter monitoring system must measure and record the average carbon bed temperature for the duration of the carbon bed steaming cycle and measure the actual carbon bed temperature after regeneration and within 15 minutes of completing the cooling cycle. The temperature monitoring device must have a minimum accuracy of ±1 percent of the temperature being monitored in °C, or ±2.5 °C, whichever value is greater.

(vii) For a nonregenerative-type carbon adsorption system, you must monitor the design carbon replacement interval established using a performance test performed as specified in § 60.5413(b). The design carbon replacement interval must be based on the total carbon working capacity of the control device and source operating schedule.

(viii) For a combustion control device whose model is tested under § 60.5413(d), a continuous monitoring system meeting the requirements of paragraphs (d)(1)(viii)(A) and (B) of this section.

(A) The continuous monitoring system must measure gas flow rate at the inlet to the control device. The monitoring instrument must have an accuracy of ±2 percent or better.

(B) A heat sensing monitoring device equipped with a continuous recorder that indicates the continuous ignition of the pilot flame.

(2) A continuous monitoring system that measures the concentration level of organic compounds in the exhaust vent stream from the control device using an organic monitoring device equipped with a continuous recorder. The monitor must meet the requirements of Performance Specification 8 or 9 of 40 CFR part 60, appendix B. You must install, calibrate, and maintain the monitor according to the manufacturer's specifications.

(3) A continuous monitoring system that measures operating parameters other than those specified in paragraph (d)(1) or (2) of this section, upon approval of the Administrator as specified in § 60.13(i).

(e) You must calculate the daily average value for each monitored operating parameter for each operating day, using the data recorded by the monitoring system, except for inlet gas flow rate. 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.

(f) For each operating parameter monitor installed in accordance with the requirements of paragraph (d) of this section, you must comply with paragraph (f)(1) of this section for all control devices. When condensers are installed, you must also comply with paragraph (f)(2) of this section.

(1) You must 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 § 60.5412(a). You must establish each minimum or maximum operating parameter value as specified in paragraphs (f)(1)(i) through (iii) of this section.

(i) If you conduct performance tests in accordance with the requirements of § 60.5413(b) to demonstrate that the control device achieves the applicable performance requirements specified in § 60.5412(a), then you must establish the minimum operating parameter value or the maximum operating parameter value 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.

(ii) If you use a condenser design analysis in accordance with the requirements of § 60.5413(c) to demonstrate that the control device achieves the applicable performance requirements specified in § 60.5412(a), then you must establish the minimum operating parameter value or the maximum operating parameter value based on the condenser design analysis and supplemented, as necessary, by the condenser manufacturer's recommendations.

(iii) If you operate a control device where the performance test requirement was met under § 60.5413(d) to demonstrate that the control device achieves the applicable performance requirements specified in § 60.5412(a), then you must establish the maximum inlet gas flow rate based on the performance test and supplemented, as necessary, by the manufacturer recommendations.

(2) If you use a condenser as specified in paragraph (d)(1)(v) of this section, you must establish a condenser performance curve showing the relationship between condenser outlet temperature and condenser control efficiency, according to the requirements of paragraphs (f)(2)(i) and (ii) of this section.

(i) If you conduct a performance test in accordance with the requirements of § 60.5413(b) to demonstrate that the condenser achieves the applicable performance requirements in § 60.5412(a), then the condenser performance curve must 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.

(ii) If you use a control device design analysis in accordance with the requirements of § 60.5413(c)(1) to demonstrate that the condenser achieves the applicable performance requirements specified in § 60.5412(a), then the condenser performance curve must be based on the condenser design analysis and supplemented, as necessary, by the control device manufacturer's recommendations.

(g) A deviation 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 (g)(1) through (g)(6) of this section being met. If you monitor multiple operating parameters for the same control device during the same operating day and more than one of these operating parameters meets a deviation criterion specified in paragraphs (g)(1) through (6) of this section, then a single excursion is determined to have occurred for the control device for that operating day.

(1) A deviation occurs when the daily average value of a monitored operating parameter is less than the minimum operating parameter limit (or, if applicable, greater than the maximum operating parameter limit) established in paragraph (f)(1) of this section.

(2) If you meet § 60.5412(a)(2), a deviation occurs when the 365-day average condenser efficiency calculated according to the requirements specified in § 60.5415(e)(8)(iv) is less than 95.0 percent.

(3) If you meet § 60.5412(a)(2) and you have less than 365 days of data, a deviation occurs when the average condenser efficiency calculated according to the procedures specified in § 60.5415(e)(8)(iv)(A) or (B) is less than 90.0 percent.

(4) A deviation occurs when the monitoring data are not available for at least 75 percent of the operating hours in a day.

(5) If the closed vent system contains one or more bypass devices that could be used to divert all or a portion of the gases, vapors, or fumes from entering the control device, a deviation occurs when the requirements of paragraphs (g)(5)(i) and (ii) of this section are met.

(i) For each bypass line subject to § 60.5411(a)(3)(i)(A), the flow indicator indicates that flow has been detected and that the stream has been diverted away from the control device to the atmosphere.

(ii) For each bypass line subject to § 60.5411(a)(3)(i)(B), if the seal or closure mechanism has been broken, the bypass line valve position has changed, the key for the lock-and-key type lock has been checked out, or the car-seal has broken.

(6) For a combustion control device whose model is tested under § 60.5413(d), a deviation occurs when the conditions of paragraphs (g)(6)(i) or (ii) are met.

(i) The inlet gas flow rate exceeds the maximum established during the test conducted under § 60.5413(d).

(ii) Failure of the monthly visible emissions test conducted under § 60.5415(e)(7)(iii) occurs.

§ 60.5420 What are my notification, reporting, and recordkeeping requirements?

(a) You must submit the notifications required in § 60.7(a)(1) and (4), and according to paragraphs (a)(1) and (2) of this section, if you own or operate one or more of the affected facilities specified in § 60.5365 that was constructed, modified, or reconstructed during the reporting period.

(1) If you own or operate a gas well, pneumatic controller or storage vessel affected facility you are not required to submit the notifications required in § 60.7(a)(1), (3), and (4).

(2)(i) If you own or operate a gas well affected facility, you must submit a notification to the Administrator no later than 2 days prior to the commencement of each well completion operation listing the anticipated date of the well completion operation. The notification shall include contact information for the owner or operator; the API well number, the latitude and longitude coordinates for each well in decimal degrees to an accuracy and precision of five (5) decimals of a degree using the North American Datum of 1983; and the planned date of the beginning of flowback. You may submit the notification in writing or in electronic format.

(ii) If you are subject to state regulations that require advance notification of well completions and you have met those notification requirements, then you are considered to have met the advance notification requirements of paragraph (a)(2)(i) of this section.

(b) *Reporting requirements.* You must submit annual reports containing the information specified in paragraphs (b)(1) through (6) of this section to the Administrator and performance test reports as specified in paragraph (b)(7) of this section. The initial annual report is due 30 days after the end of the initial compliance period as determined according to § 60.5410. 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 (6) of this section. Annual reports may coincide with title V reports as long as all the required elements of the annual report are included. You may arrange with the Administrator a common schedule on which reports required by this part may be submitted as long as the schedule does not extend the reporting period.

(1) The general information specified in paragraphs (b)(1)(i) through (iv) 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.

(iv) A certification by a responsible official of truth, accuracy, and completeness. This certification shall state that, based on information and belief formed after reasonable inquiry, the statements and information in the document are true, accurate, and complete.

(2) For each gas well affected facility, the information in paragraphs (b)(2)(i) through (ii) of this section.

(i) Records of each well completion operation as specified in paragraph (c)(1)(i) through (iv) of this section for each gas well affected facility conducted during the reporting period. In lieu of submitting the records specified in paragraph (c)(1)(i) through (iv), the owner or operator may submit a list of the well completions with hydraulic fracturing completed during the reporting period and the records required by paragraph (c)(1)(v) of this section for each well completion.

(ii) Records of deviations specified in paragraph (c)(1)(ii) of this section that occurred during the reporting period.

(3) For each centrifugal compressor affected facility, the information specified in paragraphs (b)(3)(i) and (ii) of this section.

(i) An identification of each centrifugal compressor using a wet seal system constructed, modified or reconstructed during the reporting period.

(ii) Records of deviations specified in paragraph (c)(2) of this section that occurred during the reporting period.

(iii) If required to comply with § 60.5380(a)(1), the records of closed vent system and cover inspections specified in paragraph (c)(6) of this section.

(4) For each reciprocating compressor affected facility, the information specified in paragraphs (b)(4)(i) through (ii) of this section.

(i) The cumulative number of hours or operation or the number of months since initial startup, October 15, 2012, or since the previous reciprocating compressor rod packing replacement, whichever is later.

(ii) Records of deviations specified in paragraph (c)(3)(iii) of this section that occurred during the reporting period.

(5) For each pneumatic controller affected facility, the information specified in paragraphs (b)(5)(i) through (v) of this section.

(i) An identification of each pneumatic controller constructed, modified or reconstructed during the reporting period, including the identification information specified in § 60.5390(c)(2).

(ii) If applicable, documentation that the use of pneumatic controller affected facilities with a natural gas bleed rate greater than 6 standard cubic feet per hour are required and the reasons why.

(iii) Records of deviations specified in paragraph (c)(4)(v) of this section that occurred during the reporting period.

(6) For each storage vessel affected facility, the information in paragraphs (b)(6)(i) through (iii) of this section.

(i) An identification of each storage vessel with VOC emissions greater than 6 tpy constructed, modified or reconstructed during the reporting period.

(ii) Documentation that the VOC emission rate is less than 6 tpy for meeting the requirements in § 60.5395(a).

(iii) Records of deviations specified in paragraph (c)(5)(iii) of this section that occurred during the reporting period.

(7)(i) Within 60 days after the date of completing each performance test (see § 60.8 of this part) as required by this subpart you must submit the results of the performance tests required by this subpart to EPA's WebFIRE database by using the Compliance and Emissions Data Reporting Interface (CEDRI) that is accessed through EPA's Central Data Exchange (CDX) (*www.epa.gov/cdx*). Performance test data must be submitted in the file format generated through use of EPA's Electronic Reporting Tool (ERT) (see *http://www.epa.gov/ttn/chief/ert/index.html*). Only data collected using test methods on the ERT Web site are subject to this requirement for submitting reports electronically to WebFIRE. Owners or operators who claim that some of the information being submitted for performance tests is confidential business information (CBI) must submit a complete ERT file including information claimed to be CBI on a compact disk or other commonly used electronic storage media (including, but not limited to, flash drives) to EPA. The electronic media must be clearly marked as CBI and mailed to U.S. EPA/OAPQS/CORE CBI Office, Attention: WebFIRE Administrator, MD C404–02, 4930 Old Page Rd., Durham, NC 27703. The same ERT file with the CBI omitted must be submitted to EPA via CDX as described earlier in this paragraph. At the discretion of the delegated authority, you must also submit these reports, including the confidential business information, to the delegated authority in the format specified by the delegated authority.

(ii) All reports required by this subpart not subject to the requirements in paragraph (a)(2)(i) of this section must be sent to the Administrator at the appropriate address listed in § 63.13 of this part. The Administrator or the delegated authority may request a report in any form suitable for the specific case (*e.g.,* by commonly used electronic media such as Excel spreadsheet, on CD or hard copy). The Administrator retains the right to require submittal of reports subject to paragraph (a)(2)(i) and (ii) of this section in paper format.

(c) *Recordkeeping requirements.* You must maintain the records identified as specified in § 60.7(f) and in paragraphs (c)(1) through (10) of this section. All records must be maintained for at least 5 years.

(1) The records for each gas well affected facility as specified in paragraphs (c)(1)(i) through (v) of this section.

(i) Records identifying each well completion operation for each gas well affected facility;

(ii) Records 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 well affected facility that occurred during the reporting period. You must maintain the records specified in paragraphs (c)(1)(iii)(A) and (B) of this section.

(A) For each gas well affected facility required to comply with the requirements of § 60.5375(a), you must record: The location of the well; the API well number; the duration of flowback; duration of recovery to the flow 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 well 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 flow line.

(iv) For each gas well facility for which you claim an exception under § 60.5375(a)(3), you must record: The location of the well; the API well number; the specific exception claimed; the starting date and ending date for the period the well operated under the exception; and an explanation of why the well meets the claimed exception.

(v) For each gas well affected facility required to comply with both § 60.5375(a)(1) and (3), records of the digital photograph as specified in § 60.5410(a)(4).

(2) For each centrifugal compressor affected facility, you must maintain records of deviations in cases where the centrifugal compressor was not operated in compliance with the requirements specified in § 60.5380.

(3) For each reciprocating compressors affected facility, you must maintain the records in paragraphs (c)(3)(i) through (iii) of this section.

(i) Records of the cumulative number of hours of operation or number of months since initial startup or October 15, 2012, 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.

(iii) Records of deviations in cases where the reciprocating compressor was not operated in compliance with the requirements specified in § 60.5385.

(4) For each pneumatic controller affected facility, you must maintain the records identified in paragraphs (c)(4)(i) through (v) of this section.

(i) Records of the date, location and manufacturer specifications for each pneumatic controller constructed, modified or reconstructed.

(ii) Records of the demonstration that the use of pneumatic controller affected facilities with a natural gas bleed rate greater than 6 standard cubic feet per hour are required and the reasons why.

(iii) If the pneumatic controller is not located at a natural gas processing plant, records of the manufacturer's specifications indicating that the controller is designed such that natural gas bleed rate is less than or equal to 6 standard cubic feet per hour.

(iv) If the pneumatic controller is located at a natural gas processing plant, records of the documentation that the natural gas bleed rate is zero.

(v) Records of deviations in cases where the pneumatic controller was not operated in compliance with the requirements specified in § 60.5390.

(5) For each storage vessel affected facility, you must maintain the records identified in paragraphs (c)(5)(i) through (iv) of this section.

(i) If required to reduce emissions by complying with § 60.5395, the records specified in § 60.5416 of this subpart.

(ii) Records of the determination that the VOC emission rate is less than 6 tpy per storage vessel for the exemption under § 60.5395(a), including identification of the model or calculation methodology used to calculate the VOC emission rate.

(iii) Records of deviations in cases where the storage vessel was not operated in compliance with the requirements specified in §§ 60.5395, 60.5411, 60.5412, and 60.5413.

(iv) For vessels that are skid-mounted or permanently attached to something that is mobile (such as trucks, railcars, barges or ships), records indicating the number of consecutive days that the vessel is located at a site in the oil and natural gas production segment, natural gas processing segment or natural gas transmission and storage segment. If a vessel is removed from a site and, within 30 days, is either returned to or replaced by another vessel at the site to serve the same or similar function, then the entire period since the original vessel was first located at the site, including the days when the storage vessel was removed, will be added to the count towards the number of consecutive days.

(6) For each storage vessel or centrifugal compressor subject to the closed vent system inspection requirements of § 60.5416(a)(1) and (2), records of each inspection.

(7) For each storage vessel or centrifugal compressor subject to the cover requirements of § 60.5416(a)(3), a record of each inspection.

(8) For each storage vessel or centrifugal compressor subject to the bypass requirements of § 60.5416(a)(4), a record of each inspection or a record each time the key is checked out or a record of each time the alarm is sounded.

(9) For each closed vent system used to comply with this subpart that must operate with no detectable emissions, a record of the monitoring conducted in accordance with § 60.5416(b)(13).

(10) Records of the schedule for carbon replacement (as determined by the design analysis requirements of § 60.5413(c)(2) or (3)) and records of each carbon replacement as specified in § 60.5412(c)(1).

(11) For each storage vessel or centrifugal compressor subject to the control device requirements of § 60.5412, records of minimum and maximum operating parameter values, continuous parameter monitoring system data, calculated averages of continuous parameter monitoring system data, results of all compliance calculations, and results of all inspections.

§ 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 report of excess emissions to the Administrator in your annual report if you had excess emissions during the reporting period. 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.

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.

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.

Bleed rate means the rate in standard cubic feet per hour at which natural gas is continuously vented (bleeds) from a pneumatic controller.

Centrifugal compressor means any machine for raising the pressure of a natural gas by drawing in low pressure natural gas and discharging significantly higher pressure natural gas by means of mechanical rotating vanes or impellers. Screw, sliding vane, and liquid ring compressors are not centrifugal compressors for the purposes of this subpart.

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.

Compressor station means any permanent combination of one or more compressors that move natural gas at increased pressure from fields, in transmission pipelines, or into storage.

Continuous bleed means a continuous flow of pneumatic supply natural gas to the process control device (*e.g.,* level control, temperature control, pressure control) where the supply gas pressure is modulated by the process condition, and then flows to the valve controller where the signal is compared with the process set-point to adjust gas pressure in the valve actuator.

Custody transfer means the transfer of natural gas after processing and/or treatment in the producing operations, or from storage vessels or automatic transfer facilities or other such equipment, including product loading racks, to pipelines or any other forms of transportation.

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).

Deviation means any instance in which an affected source subject to this subpart, or an owner or operator of such a source:

(1) Fails to meet any requirement or obligation established by this subpart including, but not limited to, any emission limit, operating limit, or work practice standard;

(2) Fails to meet any term or condition that is adopted to implement an applicable requirement in this subpart and that is included in the operating permit for any affected source required to obtain such a permit; or

(3) Fails to meet any emission limit, operating limit, or work practice standard in this subpart during startup, shutdown, or malfunction, regardless of whether or not such failure is permitted by this subpart.

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, 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 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. Completion combustion devices as defined in this section are not considered flares.

Flow line means a pipeline used to transport oil and/or gas from the well to a processing facility, a mainline pipeline, re-injection, or other useful purpose.

Flowback means the process of allowing fluids to flow from a natural gas well following a treatment, either in preparation for a subsequent phase of treatment or in preparation for cleanup and returning the well to production. The flowback period begins when material introduced into the well during the treatment returns to the surface immediately following hydraulic fracturing or refracturing. The flowback period ends with either well shut in or when the well is producing continuously to the flow line or to a storage vessel for collection, whichever occurs first.

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 or natural gas well means an onshore well drilled principally for production of natural gas.

Hydraulic fracturing or refracturing means the process of directing pressurized fluids containing any combination of water, proppant, and any added chemicals to penetrate tight formations, such as shale or coal formations, that subsequently require high rate, extended flowback to expel fracture fluids and solids during completions.

Hydraulic refracturing means conducting a subsequent hydraulic fracturing operation at a well that has previously undergone a hydraulic fracturing operation.

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(g)(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.

Intermittent/snap-action pneumatic controller means a pneumatic controller that vents non-continuously.

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 pressure gas well means a well with reservoir pressure and vertical well depth such that 0.445 times the reservoir pressure (in psia) minus 0.038 times the vertical well depth (in feet) minus 67.578 psia is less than the flow line pressure at the sales meter.

Natural gas-driven pneumatic controller means a pneumatic controller powered by pressurized natural gas.

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. A Joule-Thompson valve, a dew point depression valve, or an isolated or standalone Joule-Thompson skid is not a natural gas processing plant.

Natural gas transmission means the pipelines used for the long distance transport of natural gas (excluding processing). Specific equipment used in natural gas transmission includes the land, mains, valves, meters, boosters, regulators, storage vessels, dehydrators, compressors, and their driving units and appurtenances, and equipment used for transporting gas from a production plant, delivery point of purchased gas, gathering system, storage area, or other wholesale source of gas to one or more distribution area(s).

Nonfractionating plant means any gas plant that does not fractionate mixed natural gas liquids into natural gas products.

Non-natural gas-driven pneumatic controller 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.

Pneumatic controller means an automated instrument used for maintaining a process condition such as liquid level, pressure, delta-pressure and temperature.

Pressure vessel means a storage vessel that is used to store liquids or gases and is designed not to vent to the atmosphere as a result of compression of the vapor headspace in the pressure vessel during filling of the pressure vessel to its design capacity.

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 following fracturing or refracturing where gas flowback that is otherwise vented is captured, cleaned, and routed to the flow line or collection system, re-injected into the well or another well, used as an on-site fuel source, or used for other useful purpose that a purchased fuel or raw material would serve, with no direct release to the atmosphere.

Reduced sulfur compounds means H_2S, carbonyl sulfide (COS), and carbon disulfide (CS_2).

Responsible official means one of the following:

(1) For a corporation: A president, secretary, treasurer, or vice-president of the corporation in charge of a principal business function, or any other person who performs similar policy or decision-making functions for the corporation, or a duly authorized representative of such person if the representative is responsible for the overall operation of one or more manufacturing, production, or operating facilities applying for or subject to a permit and either:

(i) The facilities employ more than 250 persons or have gross annual sales or expenditures exceeding $25 million (in second quarter 1980 dollars); or

(ii) The delegation of authority to such representatives is approved in advance by the permitting authority;

(2) For a partnership or sole proprietorship: A general partner or the proprietor, respectively;

(3) For a municipality, State, Federal, or other public agency: Either a principal executive officer or ranking elected official. For the purposes of this part, a principal executive officer of a Federal agency includes the chief executive officer having responsibility for the overall operations of a principal geographic unit of the agency (*e.g.,* a Regional Administrator of EPA); or

(4) For affected facilities:

(i) The designated representative in so far as actions, standards, requirements, or prohibitions under title IV of the Clean Air Act or the regulations promulgated thereunder are concerned; or

(ii) The designated representative for any other purposes under part 60.

Routed to a process or route to a process means the emissions are conveyed via a closed vent system 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, regardless of whether such gas is sold.

Storage vessel means a unit that is constructed primarily of nonearthen materials (such as wood, concrete, steel, fiberglass, or plastic) which provides structural support and is designed to contain an accumulation of liquids or other materials. The following are not considered storage vessels:

(1) Vessels that are skid-mounted or permanently attached to something that is mobile (such as trucks, railcars, barges or ships), and are intended to be located at a site for less than 180 consecutive days. If you do not keep or are not able to produce records, as required by § 60.5420(c)(5)(iv), showing that the vessel has been located at a site for less than 180 consecutive days, the vessel described herein is considered to be a storage vessel since the original vessel was first located at the site.

(2) Process vessels such as surge control vessels, bottoms receivers or knockout vessels.

(3) Pressure vessels designed to operate in excess of 204.9 kilopascals and without emissions to the atmosphere.

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 sour 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 SO2 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 vessel means a storage vessel 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 flowback of petroleum or natural gas from newly drilled wells to expel drilling and reservoir fluids and tests the reservoir flow characteristics, which may vent produced hydrocarbons to the atmosphere via an open pit or tank.

Well completion operation means any well completion with hydraulic fracturing or refracturing occurring at a gas well affected facility.

Well site means one or more 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
$Y < 10$	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.

As stated in § 60.5425, you must comply with the following applicable General Provisions:

TABLE 3 TO SUBPART OOOO OF PART 60—APPLICABILITY OF GENERAL PROVISIONS TO SUBPART OOOO

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).
§ 60.8	Performance tests	Yes	Performance testing is required for control devices used on storage vessels and centrifugal compressors.
§ 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	Except that § 60.18 does not apply to flares.
§ 60.19	General notification and reporting requirement	Yes.	

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

■ 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. Revising paragraphs (b) introductory text, (b)(28), and (b)(64);
■ b. Adding paragraphs (b)(73), (74), and (75); and
■ c. Revising paragraphs (i) introductory text and (i)(1) to read as follows:

§ 63.14 Incorporations by reference.

* * * * *

(b) The following materials are available for purchase from at least one of the following addresses: American Society for Testing and Materials (ASTM), 100 Barr Harbor Drive, Post Office Box C700, West Conshohocken, PA 19428–2959, Telephone (610) 832–9585, and are also available at the following Web site: *http://www.astm.org*; or ProQuest, 789 East Eisenhower Parkway, Ann Arbor, MI 48106–1346, Telephone (734) 761–4700, and are also available at the following Web site: *http://www.proquest.com.*

* * * * *

(28) ASTM D6420–99 (Reapproved 2004), Standard Test Method for Determination of Gaseous Organic Compounds by Direct Interface Gas Chromatography-Mass Spectrometry (Approved October 1, 2004), IBR approved for §§ 60.485(g), 60.485a(g), 63.772(a), 63.772(e), 63.1282(a), 63.1282(d), 63.2351(b), 63.2354(b) and table 8 to subpart HHHHHHH of this part.

* * * * *

(64) ASTM D6522–00 (Reapproved 2005), Standard Test Method for Determination of Nitrogen Oxides, Carbon Monoxide, and Oxygen Concentrations in Emissions from Natural Gas Fired Reciprocating Engines, Combustion Turbines, Boilers, and Process Heaters Using Portable Analyzers, approved October 1, 2005, IBR approved for table 4 to subpart ZZZZ of this part, table 5 to subpart DDDDD of this part, table 4 to subpart JJJJJJ of this part and §§ 63.772(e), 63.772(h), 63.1282(d) and 63.1282(g).

* * * * *

(73) ASTM D1945–03 (Reapproved 2010) Standard Test Method for Analysis of Natural Gas by Gas Chromatography (Approved January 1, 2010), IBR approved for §§ 63.772(h) and 63.1282(g).

(74) ASTM D3588–98 (Reapproved 2003) Standard Practice for Calculating Heat Value, Compressibility Factor, and Relative Density of Gaseous Fuels (Approved May 10, 2003), IBR approved for §§ 63.772(h) and 63.1282(g).

(75) ASTM D4891–89 (Reapproved 2006) Standard Test Method for Heating Value of Gases in Natural Gas Range by Stoichiometric Combustion (Approved June 1, 2006), IBR approved for §§ 63.772(h) and 63.1282(g).

* * * * *

(i) The following material is available for purchase from at least one of the following addresses: American Society of Mechanical Engineers (ASME), Three Park Avenue, New York, NY 10016–

5990, Telephone (800) 843–2763, and are also available at the following Web site: *http://www.asme.org*; or HIS, Incorporated, 15 Inverness Way East, Englewood, CO 80112, Telephone (877) 413–5184, and are also available at the following Web site: *http://global.ihs.com*.

(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), 63.772(e), 63.772(h), 63.865(b), 63.1282(d), 63.1282(g), 63.3166(a), 63.3360(e), 63.3545(a), 63.3555(a), 63.4166(a), 63.4362(a), 63.4766(a), 63.4965(a), 63.5160(d), 63.9307(c), 63.9323(a), 63.11148(e), 63.11155(e), 63.11162(f), 63.11163(g), 63.11410(j), 63.11551(a) and 63.11646(a), 63.11945, table 5 to subpart DDDDD of this part, table 4 to subpart JJJJJ of this part, table 5 to subpart UUUUU 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)(i);
■ c. Revising paragraph (a)(1)(iii);
■ d. Revising paragraph (a)(2);
■ e. Revising paragraph (b)(1)(i);
■ f. Adding paragraph (c);
■ g. Revising paragraph (f) introductory text;
■ h. Revising paragraph (f)(1);
■ i. Revising paragraph (f)(2);
■ j. Adding paragraphs (f)(7), (f)(8), and (f)(9); and
■ k. Removing and reserving paragraph (g)(1).

The revisions and additions 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.

(i) If the owner or operator documents, to the Administrator's satisfaction, a decline in annual natural gas or hydrocarbon liquid throughput, as appropriate, each year for the 5 years prior to October 15, 2012, the owner or operator shall calculate the maximum natural gas or hydrocarbon liquid throughput used to determine maximum potential emissions according to the requirements specified in paragraph (a)(1)(i)(A) of this section. In all other circumstances, the owner or operator shall calculate the maximum throughput used to determine whether a facility is a major source in accordance with the requirements specified in paragraph (a)(1)(i)(B) of this section.

(A) The maximum natural gas or hydrocarbon liquid throughput is the average of the annual natural gas or hydrocarbon liquid throughput for the 3 years prior to October 15, 2012, multiplied by a factor of 1.2.

(B) The maximum natural gas or hydrocarbon liquid throughput is the highest annual natural gas or hydrocarbon liquid throughput over the 5 years prior to October 15, 2012, multiplied by a factor of 1.2.

* * * * *

(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.

* * * * *

(b) * * *

(1) * * *

(i) Each glycol dehydration unit as specified in paragraphs (b)(1)(i)(A) through (C) of this section.

(A) Each large glycol dehydration unit;

(B) Each small glycol dehydration unit for which construction commenced on or before August 23, 2011, is an existing small glycol dehydration unit; and

(C) Each small glycol dehydration unit for which construction commenced after August 23, 2011, is a new small glycol dehydration unit.

* * * * *

(c) Any source that determines it is not a major source but has actual emissions of 5 tons per year or more of a single HAP, or 12.5 tons per year or more of a combination of HAP (*i.e.,* 50 percent of the major source thresholds), shall update its major source determination within 1 year of the prior determination or October 15, 2012, whichever is later, and each year thereafter, using gas composition data measured during the preceding 12 months.

* * * * *

(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), (2), and (f)(7) through (9) 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 (6) of this section.

(1) Except as specified in paragraphs (f)(7) through (9) 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 (9) 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 existing small glycol dehydration unit, as defined in § 63.761, located at a major source, that commenced construction before August 23, 2011, must achieve compliance no later than October 15, 2015, except as provided in § 63.6(i).

(8) Each affected new small glycol dehydration unit, 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 October 15, 2012, whichever is later.

(9) A production field facility, as defined in § 63.761, constructed on or 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 October 15, 2012 must achieve compliance no later than October 15, 2015, except as provided in § 63.6(i).

* * * * *

■ 11. Section 63.761 is amended by:

■ a. Adding, in alphabetical order, definitions for the terms ''affirmative defense,'' ''BTEX,'' ''flare,'' ''large glycol dehydration unit,'' ''responsible official'' and ''small glycol dehydration unit'';

■ b. Revising the definitions for ''associated equipment,'' ''glycol dehydration unit baseline operations,'' and ''storage vessel''; 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.

* * * * *

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). A glycol dehydration unit complying with the 0.9 Mg/yr control option under § 63.765(b)(1)(ii) is considered to be a large dehydrator.

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.

* * * * *

Responsible official means one of the following:

(1) For a corporation: A president, secretary, treasurer, or vice-president of the corporation in charge of a principal business function, or any other person who performs similar policy or decision-making functions for the corporation, or a duly authorized representative of such person if the representative is responsible for the overall operation of one or more manufacturing, production, or operating facilities applying for or subject to a permit and either:

(i) The facilities employ more than 250 persons or have gross annual sales or expenditures exceeding $25 million (in second quarter 1980 dollars); or

(ii) The delegation of authority to such representatives is approved in advance by the permitting authority;

(2) For a partnership or sole proprietorship: a general partner or the proprietor, respectively;

(3) For a municipality, State, Federal, or other public agency: Either a principal executive officer or ranking elected official. For the purposes of this part, a principal executive officer of a Federal agency includes the chief executive officer having responsibility for the overall operations of a principal geographic unit of the agency (*e.g.,* a Regional Administrator of EPA); or

(4) For affected sources:

(i) The designated representative in so far as actions, standards, requirements, or prohibitions under title IV of the Act or the regulations promulgated thereunder are concerned; and

(ii) The designated representative for any other purposes under part 70.

* * * * *

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).

* * * * *

Storage vessel means a tank or other vessel that is designed to contain an accumulation of crude oil, condensate, intermediate hydrocarbon liquids, or produced water and that is constructed primarily of non-earthen materials (*e.g.,* wood, concrete, steel, plastic) that provide structural support. The following process units are not considered storage vessels: Surge control vessels and knockout vessels.

* * * * *

■ 12. Section 63.762 is revised to read as follows:

§ 63.762 Affirmative defense for violations of emission standards during malfunction.

(a) The provisions set forth in this subpart shall apply at all times.

(b) [Reserved]

(c) [Reserved]

(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 violations 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 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 standard, you must timely meet the reporting requirements in paragraph (d)(2) of this section, and must prove by a preponderance of evidence that:

(i) The violation:

(A) Was caused by a sudden, infrequent, and unavoidable failure of air pollution control 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) Was not part of a recurring pattern indicative of inadequate design, operation, or maintenance; and

(ii) Repairs were made as expeditiously as possible when a violation occurred. Off-shift and overtime labor were used, to the extent practicable to make these repairs; and

(iii) The frequency, amount and duration of the violation (including any bypass) were minimized to the maximum extent practicable; and

(iv) If the violation 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 violation 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 violation 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, the purpose of which is to determine, correct, and eliminate the primary causes of the malfunction and the violation resulting from the malfunction event at issue. The analysis shall also specify, using best monitoring methods and engineering judgment, the amount of any emissions that were the result of the malfunction.

(2) *Report.* The owner or operator seeking to assert an affirmative defense shall submit a written report to the Administrator with all necessary supporting documentation, that it has met the requirements set forth in paragraph (d)(1) of this section. This affirmative defense report shall be included in the first periodic compliance, deviation report or excess emission report otherwise required after the initial occurrence of the violation of the relevant standard (which may be the end of any applicable averaging period). If such compliance, deviation report or excess emission report is due less than 45 days after the initial occurrence of the violation, the affirmative defense report may be included in the second compliance, deviation report or excess emission report due after the initial occurrence of the violation of the relevant standard.

■ 13. Section 63.764 is amended by:
■ a. Revising paragraph (e)(1) introductory text;
■ b. Revising paragraph (i); and
■ c. Adding paragraph (j).

The revisions and addition read as follows:

§ 63.764 General standards.

* * * * *

(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).

The revisions 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).

(ii) The owner or operator of a large glycol dehydration unit 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 existing small glycol dehydration unit process vent, as defined in § 63.761, to the limit determined in Equation 1 of this section. You must limit BTEX emissions from each new small glycol dehydration unit process vent, as defined in § 63.761, to the limit determined in Equation 2 of this section. The limits determined using Equation 1 or Equation 2 must be met in accordance with one of the alternatives specified in paragraphs (b)(1)(iii)(A) through (D) of this section.

$$EL_{BTEX} = 3.28x10^{-4} * Throughput * C_{i,BTEX} * 365 \frac{days}{yr} * \frac{1\ Mg}{1x10^{6}\ grams}$$

Equation 1

Where:

EL_{BTEX} = Unit-specific BTEX emission limit, megagrams per year;

3.28×10^{-4} = BTEX emission limit, grams BTEX/standard cubic meter-ppmv;

Throughput = Annual average daily natural gas throughput, standard cubic meters per day.

$C_{i,BTEX}$ = average annual BTEX concentration of the natural gas at the inlet to the glycol dehydration unit, ppmv.

$$EL_{BTEX} = 4.66x10^{-6} * Throughput * C_{i,BTEX} * 365 \frac{days}{yr} * \frac{1\ Mg}{1x10^{6}\ grams}$$

Where:

EL_{BTEX} = Unit-specific BTEX emission limit, megagrams per year;

4.66×10^{-6} = BTEX emission limit, grams BTEX/standard cubic meter-ppmv;

Throughput = Annual average daily natural gas throughput, standard cubic meters per day.

$C_{i,BTEX}$ = average annual 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 § 63.771(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).

* * * * *

(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) through (iv) 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 any large glycol dehydration unit, benzene emissions are reduced to a level less than 0.90 megagrams per year.

(iii) For each existing small glycol dehydration unit, BTEX emissions are reduced to a level less than the limit calculated by Equation 1 of paragraph (b)(1)(iii) of this section.

(iv) For each new small glycol dehydration unit, BTEX emissions are reduced to a level less than the limit calculated by Equation 2 of paragraph (b)(1)(iii) of this section.

■ 15. Section 63.766 is amended by:
■ a. Adding paragraph (b)(3); and
■ b. Revising paragraph (d) to read as follows:

§ 63.766 Storage vessel standards.

* * * * *

(b) * * *

(3) The owner or operator shall control air emissions by connecting the cover, through a closed-vent system that meets the conditions specified in § 63.771(c), to a process natural gas line.

* * * * *

(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, subparts Kb or OOOO; or is subject to and controlled under the requirements specified under 40 CFR part 63 subparts G or CC. Storage vessels subject to and controlled under 40 CFR part 60, subpart OOOO shall submit the periodic reports specified in § 63.775(e).

■ 16. Section 63.769 is amended by:
■ a. Revising paragraph (b);
■ b. Revising paragraph (c) introductory text; and
■ c. Revising paragraph (c)(8).

The revisions 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 is subject to and controlled under the requirements specified in 40 CFR part 60, subpart OOOO. Ancillary equipment and compressors subject to and controlled under 40 CFR part 60, subpart OOOO shall submit the periodic reports specified in § 63.775(e).

(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 that for valves subject to § 61.242–7(b) or § 61.243–1, a leak is detected if an instrument reading of 500 ppm or greater is measured. A leak detected from a valve at a source constructed on or before August 23, 2011 shall be repaired in accordance with the schedule in § 61.242–7(d), or by October 15, 2013, whichever is later. A leak detected from a valve at a source constructed after August 23, 2011 shall be repaired in accordance with the schedule in § 61.242–7(d), or by October 15, 2012, whichever is later.

* * * * *

(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);
■ b. Revising the heading of paragraph (d);
■ c. Adding paragraph (d) introductory text;
■ d. Revising paragraph (d)(1)(i)(C);
■ e. Revising paragraph (d)(1)(ii);
■ f. Revising paragraph (d)(1)(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).

The revisions and additions 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) * * *

(C) Operates at a minimum temperature of 760 degrees C, provided the control device has demonstrated, under § 63.772(e), that combustion zone temperature is an indicator of destruction efficiency.

* * * * *

(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 (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 meet the levels specified in paragraphs (f)(1)(i)(A) or (B) of this section. 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.

(A) The mass content of BTEX in the gases vented to the device is reduced as determined in accordance with the requirements of § 63.772(e).

(B) The concentration of either TOC or total HAP in the exhaust gases at the outlet of the device is reduced to a level equal to or less than 20 parts per million by volume on a dry basis corrected to 3 percent oxygen as determined in accordance with the requirements of § 63.772(e).

(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).

(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. Revising paragraph (c)(6)(i);
■ e. Adding paragraph (d);
■ f. Revising paragraph (e) introductory text;
■ g. Revising paragraphs (e)(1)(i) through (v);
■ h. Revising paragraph (e)(2);
■ i. Revising paragraph (e)(3) introductory text;
■ j. Revising paragraph (e)(3)(i)(B);
■ k. Revising paragraph (e)(3)(iv)(C)(*1*);
■ l. Adding paragraphs (e)(3)(v) and (vi);
■ m. Revising paragraph (e)(4) introductory text;
■ n. Revising paragraph (e)(4)(i);
■ o. Revising paragraph (e)(5);
■ p. Revising paragraph (f) introductory text;
■ q. Revising paragraphs (f)(2) and (3);
■ r. Adding paragraphs (f)(4) through (6);
■ s. Revising paragraph (g) introductory text;
■ t. Revising paragraph (g)(1) and paragraph (g)(2) introductory text;
■ u. Revising paragraph (g)(2)(iii);
■ v. Revising paragraph (g)(3);
■ w. Adding paragraph (h); and
■ x. Adding paragraph (i).

The revisions and additions 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 (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.

(c) * * *

(6) * * *

(i) Except as provided in paragraph (c)(6)(ii) of this section, the detection instrument shall meet the performance criteria of Method 21 of 40 CFR part 60, appendix A, except the instrument response factor criteria in section 3.1.2(a) of Method 21 shall be for the average composition of the process fluid, not each individual volatile organic compound in the stream. For process streams that contain nitrogen, air, or other inert gases that are not organic hazardous air pollutants or volatile organic compounds, the average stream response factor shall be calculated on an inert-free basis.

* * * * *

(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. Flares shall meet the provisions in paragraph (e)(2) of this section. 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 § 63.771(d)(1)(i)(B), or the BTEX emission limit specified in § 63.765(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, ASTM D6522–00 (Reapproved 2005), or ANSI/ASME PTC 19.10–1981, Part 10 (manual portion only) (incorporated by reference as specified in § 63.14) 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 § 63.765(b)(1)(iii) the owner or operator shall use one of the following methods: Method 18, 40 CFR part 60, appendix A; ASTM D6420–99 (Reapproved 2004), as specified in § 63.772(a)(1)(ii) (incorporated by reference as specified in § 63.14); 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 (Reapproved 2004) (incorporated by reference as specified in § 63.14) 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 (*i.e.,* control devices installed on or before August 23, 2011) at major sources shall be conducted no later than October 15, 2015. If the owner or operator of an existing combustion control device at a 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 October 15, 2015. 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 demonstrating during the performance test under § 63.772(e) that combustion zone temperature is an indicator of destruction efficiency and operates at a minimum temperature of 760 degrees C.

(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 (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 flowrate 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 flowrate, compliance with the operating parameter limit is achieved when the value is equal to or less than the value established under § 63.772(h) or under the performance test conducted under § 63.772(e), as applicable.

(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 paragraph (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. During the first 5 minutes, incrementally 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, incrementally 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. During the first 5 minutes, incrementally 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, incrementally 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. During the first 5 minutes, incrementally ramp the firing rate to 30 percent of the maximum design rate. Hold at 30 percent for 5 minutes. In the 10–15 minute time range, incrementally 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 (h)(8)(iii) of this section.

(4) Inlet gas testing shall be conducted as specified in paragraphs (h)(4)(i) through (iii) of this section.

(i) The inlet gas flow metering system shall be located in accordance with Method 2A, 40 CFR part 60, appendix A–1, (or other approved procedure) to measure inlet gas flowrate at the control device inlet location. The fitting for filling inlet gas sample containers shall be located a minimum of 8 pipe diameters upstream of any inlet gas flow monitoring meter.

(ii) Inlet gas flowrate 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 inlet gas pressure and temperature at 5-minute intervals throughout each 60-minute THC test.

(iii) Inlet gas 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 gas sampling location, securely connect a Silonite-coated stainless steel evacuated canister fitted with a flow controller sufficient to fill the canister over a 3 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 each THC run.

(*2*) Fill one canister across the three test runs for each THC test such that one composite fuel sample exists for each test condition.

(*3*) Label the canisters individually and record on a chain of custody form.

(B) Each inlet gas 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 (Reapproved 2010) (incorporated by reference as specified in § 63.14).

(*2*) Hydrogen (H_2), carbon monoxide (CO), carbon dioxide (CO_2), nitrogen (N_2), oxygen (O_2) using ASTM D1945–03 (Reapproved 2010) (incorporated by reference as specified in § 63.14).

(*3*) Higher heating value using ASTM D3588–98 (Reapproved 2003) or ASTM D4891–89 (Reapproved 2006) (incorporated by reference as specified in § 63.14).

(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) Flowrate 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 or other pressure measurement device shall be used to obtain an accurate flow profile.

(ii) Molecular weight shall be determined as specified in paragraphs (h)(4)(iii)(B) and (h)(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 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, or ASTM D6522–00 (Reapproved 2005), (incorporated by reference as specified in § 63.14). 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.

(v) Excess air shall be determined using resultant data from the EPA Method 3C tests and EPA Method 3B, 40 CFR part 60, Appendix A, equation 3B–1 or ANSI/ASME PTC 19.10, 1981-Part 10 (manual portion only) (incorporated by reference as specified in § 63.14).

(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 each test.

(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.

(D) Excess combustion air shall be equal to or greater than 150 percent.

(ii) The manufacturer shall determine a maximum inlet gas flowrate 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 95.0 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 flowrate.

(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 flowrate.

(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 flowrate shall meet the range specified by the manufacturer. Flowrate shall be calculated 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 2 minutes during any hour. A visible emissions test using Method 22, 40 CFR part 60, Appendix A, shall be performed each calendar quarter. The observation period shall be 1 hour and shall be conducted according to EPA Method 22, 40 CFR part 60, Appendix A.

(4) Compliance with the operating parameter limit is achieved when the following criteria are met:

(i) The inlet gas flowrate 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 2 minutes during the observation period. Devices failing the visible emissions test shall follow manufacturers repair instructions, if available, or best combustion engineering practice as outlined in the unit inspection and maintenance plan, to return the unit to compliant operation. All repairs and maintenance activities for each unit shall be recorded in a maintenance and repair log and shall be available on site for inspection.

(iv) Following return to operation from maintenance or repair activity, each device must pass a Method 22 visual observation as described in paragraph (i)(3) 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 paragraph (d)(2);
■ e. Revising paragraph (d)(3)(i)(A);
■ f. Revising paragraph (d)(3)(i)(D);
■ g. Revising paragraph (d)(3)(i)(G);
■ h. Adding paragraph (d)(3)(i)(H);
■ i. Revising paragraph (d)(4);
■ j. Revising paragraph (d)(5)(i);
■ k. Revising paragraphs (d)(5)(ii)(A) through (C);
■ l. Revising paragraph (d)(6) introductory text;
■ m. Revising paragraphs (d)(6)(ii) and (iii);
■ n. Adding paragraph (d)(6)(vi);
■ o. Revising paragraph (d)(7); and
■ p. Removing paragraphs (d)(8) and (9).

The revisions and additions 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 (7) 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 (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) An owner or operator is exempt from the monitoring requirements specified in paragraphs (d)(3) through (7) of this section for the following types of control devices:

(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 ±2 percent of the temperature being monitored in °C, or ±2.5 °C, whichever value is greater. The temperature sensor shall be installed at a location representative of the combustion zone temperature.

* * * * *

(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 ±2 percent of the temperature being monitored in °C, or ±2.5 °C, whichever value is greater. The temperature sensor shall be installed at a location representative of the combustion zone temperature.

* * * * *

(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) and 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*) The owner or operator shall determine actual average inlet waste gas flowrate using the model GRI–GLYCalc ™, Version 3.0 or higher, ProMax, or AspenTech HYSYS. Inputs to the models shall be representative of actual operating conditions of the controlled unit. The determination shall be performed to coincide with the visible emissions test under § 63.772(i)(3);

(*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 § 63.771(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 flowrate 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 of 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) 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 (vi) 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 (vi) of this section, then a single excursion is determined to have occurred for the control device for that operating day.

* * * * *

(ii) For sources meeting § 63.771(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(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 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 flowrate exceeds the maximum established during the test conducted under § 63.772(h).

(B) Failure of the quarterly visible emissions test conducted under § 63.772(i)(3) occurs.

(7) For each excursion, the owner or operator shall be deemed to have failed to have applied control in a manner that achieves the required operating parameter limits. Failure to achieve the required operating parameter limits is a violation of this standard.

* * * * *

■ 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. Revising paragraph (b)(4)(iii);

■ f. Adding paragraph (b)(7)(ix); and

■ g. Adding paragraphs (g) through (i).

The revisions and additions 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 (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.

* * * * *

(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 a control device whose model is tested under § 63.772(h), the records required in paragraph (h) of this section.

(iii) Hourly records of the times and durations of all periods when the vent stream is diverted from the control device or the device is not operating.

* * * * *

(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(j), 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 calculations 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 (xiv); and
■ p. Adding paragraph (g).

The revisions and additions 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 (b)(1)(ii) of this section, 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 October 15, 2013, whichever is later. An affected source identified under § 63.760(f)(7) or (9) that plans to be an area source by October 15, 2015, 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.

* * * * *

(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 email 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 email to *Oil_and_Gas_PT@EPA.GOV* unless the test results for that model of combustion control device are posted at the following Web site: *epa.gov/airquality/oilandgas/.*

* * * * *

(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 the model of control device was tested by the manufacturer.

(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 (ix) 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 flowrate 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, repairs affected to the unit, and date the unit was returned to service.

* * * * *

(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).

(xiv) Certification by a responsible official of truth, accuracy, and completeness. This certification shall state that, based on information and belief formed after reasonable inquiry, the statements and information in the document are true, accurate, and complete.

* * * * *

(g) *Electronic reporting.* (1) Within 60 days after the date of completing each performance test (defined in § 63.2) as required by this subpart you must submit the results of the performance tests required by this subpart to EPA's WebFIRE database by using the Compliance and Emissions Data Reporting Interface (CEDRI) that is accessed through EPA's Central Data Exchange (CDX) (*www.epa.gov/cdx*). Performance test data must be submitted in the file format generated through use of EPA's Electronic Reporting Tool (ERT) (see *http://www.epa.gov/ttn/chief/ert/index.html*). Only data collected using test methods on the ERT Web site are subject to this requirement for submitting reports electronically to WebFIRE. Owners or operators who claim that some of the information being submitted for performance tests is confidential business information (CBI) must submit a complete ERT file including information claimed to be CBI on a compact disk or other commonly used electronic storage media (including, but not limited to, flash drives) to EPA. The electronic media must be clearly marked as CBI and mailed to U.S. EPA/OAPQS/CORE CBI Office, Attention: WebFIRE Administrator, MD C404–02, 4930 Old Page Rd., Durham, NC 27703. The same ERT file with the CBI omitted must be submitted to EPA via CDX as described earlier in this paragraph. At the discretion of the delegated authority, you must also submit these reports, including the confidential business information, to the delegated authority in the format specified by the delegated authority.

(2) All reports required by this subpart not subject to the requirements in paragraph (g)(1) of this section must be sent to the Administrator at the appropriate address listed in § 63.13. The Administrator or the delegated authority may request a report in any form suitable for the specific case (*e.g.,* by commonly used electronic media such as Excel spreadsheet, on CD or hard copy). 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)(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)(1)	No.	
§ 63.6(h)(2) through (h)(9)	Yes.	
§ 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(a)(4)	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)	No.	
§ 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)(1)	Yes.	
§ 63.8(d)(2)	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)	Yes.	
§ 63.9(g)	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 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 § 63.774(g) for recordkeeping of (1) occurrence and duration and (2) 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 (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.	
§ 63.10(e)(3)(i)(D)	Yes	Section reserved.
§ 63.10(e)(3)(ii) through (viii)	Yes.	
§ 63.10(e)(4)	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) through (q)	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 paragraph (b);

■ d. Revising paragraphs (d)(1) and (2); and

■ e. Adding paragraphs (d)(3) and (4).

The revisions and additions 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.

(b) The affected source is each new and existing glycol dehydration unit specified in paragraphs (b)(1) through (3) of this section.

(1) Each large glycol dehydration unit;

(2) Each small glycol dehydration unit for which construction commenced on or before August 23, 2011, is an existing small glycol dehydration unit.

(3) Each small glycol dehydration unit for which construction commenced after August 23, 2011, is a new small glycol dehydration unit.

* * * * *

(d) * * *

(1) Except as specified in paragraphs (d)(3) through (4) 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 this provisions of the 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 (4) 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 October 15, 2015, 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 October 15, 2012, whichever is later.

* * * * *

■ 24. Section 63.1271 is amended by:

■ a. Adding, in alphabetical order, definitions for the terms ''affirmative defense,'' ''BTEX,'' ''flare,'' ''large glycol dehydration units,'' ''responsible official'' and ''small glycol dehydration units;'' and

■ b. Revising the definition for ''glycol dehydration unit baseline operations.''

The additions and revision 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). A glycol dehydration unit complying with the 0.9 Mg/yr control option under 63.1275(b)(1)(ii) is considered to be a large dehydrator.

* * * * *

Responsible official means one of the following:

(1) For a corporation: A president, secretary, treasurer, or vice-president of the corporation in charge of a principal business function, or any other person who performs similar policy or decision-making functions for the corporation, or a duly authorized representative of such person if the representative is responsible for the overall operation of one or more manufacturing, production, or operating facilities applying for or subject to a permit and either:

(i) The facilities employ more than 250 persons or have gross annual sales or expenditures exceeding $25 million (in second quarter 1980 dollars); or

(ii) The delegation of authority to such representatives is approved in advance by the permitting authority;

(2) For a partnership or sole proprietorship: A general partner or the proprietor, respectively;

(3) For a municipality, State, Federal, or other public agency: Either a principal executive officer or ranking elected official. For the purposes of this part, a principal executive officer of a Federal agency includes the chief executive officer having responsibility for the overall operations of a principal geographic unit of the agency (*e.g.,* a Regional Administrator of EPA); or

(4) For affected sources:

(i) The designated representative in so far as actions, standards, requirements, or prohibitions under title IV of the Act or the regulations promulgated thereunder are concerned; and

(ii) The designated representative for any other purposes under part 70.

* * * * *

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).

* * * * *

■ 25. Section 63.1272 is revised to read as follows:

§ 63.1272 Affirmative defense for violations of emission standards during malfunction.

(a) The provisions set forth in this subpart shall apply at all times.

(b) [Reserved]

(c) [Reserved]

(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 violations of such standards that are caused by malfunction, as defined at § 63.2. 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 standard, you must timely meet the reporting requirements in paragraph (d)(2) of this section, and must prove by a preponderance of evidence that:

(i) The violation:

(A) Was caused by a sudden, infrequent, and unavoidable failure of air pollution control 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) Was not part of a recurring pattern indicative of inadequate design, operation, or maintenance; and

(ii) Repairs were made as expeditiously as possible when a violation occurred. Off-shift and overtime labor were used, to the extent practicable to make these repairs; and

(iii) The frequency, amount and duration of the violation (including any bypass) were minimized to the maximum extent practicable; and

(iv) If the violation 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 violation 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 violation 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, the purpose of which is to determine, correct, and eliminate the primary causes of the malfunction and the violation resulting from the malfunction event at issue. The analysis shall also specify, using best monitoring methods and engineering judgment, the amount of any emissions that were the result of the malfunction.

(2) *Report.* The owner or operator seeking to assert an affirmative defense shall submit a written report to the Administrator with all necessary supporting documentation, that it has met the requirements set forth in paragraph (d)(1) of this section. This affirmative defense report shall be included in the first periodic compliance, deviation report or excess emission report otherwise required after the initial occurrence of the violation of the relevant standard (which may be the end of any applicable averaging period). If such compliance, deviation report or excess emission report is due less than 45 days after the initial occurrence of the violation, the affirmative defense report may be included in the second compliance, deviation report or excess emission report due after the initial occurrence of the violation of the relevant standard.

■ 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).

The revisions and addition 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).

The revisions 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 (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) The owner or operator of a large glycol dehydration unit shall connect the process vent to a control device or a combination of control devices through a closed-vent system and the outlet benzene emissions from the control device(s) shall be less than 0.90 megagrams per year. 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), except that the performance requirements specified in § 63.1281(d)(1)(i) and (ii) do not apply.

(iii) You must limit BTEX emissions from each existing small glycol dehydration unit, as defined in § 63.1271, to the limit determined in Equation 1 of this section. You must limit BTEX emissions from each new small glycol dehydration unit process vent, as defined in § 63.1271, to the limit determined in Equation 2 of this section. The limits determined using Equation 1 or Equation 2, of this section, must be met in accordance with one of the alternatives specified in paragraphs (b)(1)(iii)(A) through (D) of this section.

$$EL_{BTEX} = 3.10x10^{-4} * Throughput * C_{i,BTEX} * 365 \frac{days}{yr} * \frac{1\,Mg}{1x10^6\,grams} \quad \text{Equation 1}$$

Where:

EL_{BTEX} = Unit-specific BTEX emission limit, megagrams per year;

3.10×10^{-4} = BTEX emission limit, grams BTEX/standard cubic meter-ppmv;

Throughput = Annual average daily natural gas throughput, standard cubic meters per day;

$C_{i,BTEX}$ = Annual average BTEX concentration of the natural gas at the inlet to the glycol dehydration unit, ppmv.

$$EL_{BTEX} = 5.44x10^{-5} * Throughput * C_{i,BTEX} * 365 \frac{days}{yr} * \frac{1\,Mg}{1x10^6\,grams} \quad \text{Equation 2}$$

Where:

EL_{BTEX} = Unit-specific BTEX emission limit, megagrams per year;

5.44×10^{-5} = BTEX emission limit, grams BTEX/standard cubic meter-ppmv;

Throughput = Annual average daily natural gas throughput, standard cubic meters per day;

$C_{i,BTEX}$ = Annual average 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) through (iv) 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 any large glycol dehydration unit, benzene emissions are reduced to a level less than 0.90 megagrams per year.

(iii) For each existing small glycol dehydration unit, BTEX emissions are reduced to a level less than the limit calculated in Equation 1 of paragraph (b)(1)(iii) of this section.

(iv) For each new small glycol dehydration unit, BTEX emissions are reduced to a level less than the limit calculated in Equation 2 of 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)(C);
■ e. Revising paragraphs (d)(1)(ii) and (iii);
■ f. Revising paragraph (d)(4)(i);
■ g. Revising paragraph (d)(5)(i);
■ h. Revising paragraph (e)(2);
■ i. Revising paragraph (e)(3) introductory text;
■ j. Revising paragraph (e)(3)(ii); and
■ k. Adding paragraph (f).

The revisions and additions 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) * * *

(C) Operates at a minimum temperature of 760 degrees C, provided the control device has demonstrated, under § 63.1282(d), that combustion zone temperature is an indicator of destruction efficiency.

* * * * *

(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 meet the levels specified in paragraphs (f)(1)(i)(A) or (B) of this section. 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.

(A) The mass content of BTEX in the gases vented to the device is reduced as determined in accordance with the requirements of § 63.1282(d).

(B) The concentration of either TOC or total HAP in the exhaust gases at the outlet of the device is reduced to a level equal to or less than 20 parts per million by volume on a dry basis corrected to 3 percent oxygen as determined in accordance with the requirements of § 63.1282(e).

(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).

(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. Revising paragraph (b)(6)(i);
■ e. Adding paragraph (c);
■ f. Revising paragraph (d) introductory text;
■ g. Revising paragraphs (d)(1)(i) through (v);
■ h. Revising paragraph (d)(2);
■ i. Revising paragraph (d)(3) introductory text;
■ j. Revising paragraph (d)(3)(i)(B);
■ k. Revising paragraph (d)(3)(iii) introductory text;
■ l. Revising paragraph (d)(3)(iv) introductory text;
■ m. Revising paragraph (d)(3)(iv)(C)(*1*);
■ n. Adding paragraphs (d)(3)(v) and (vi);
■ o. Revising paragraph (d)(4) introductory text;
■ p. Revising paragraph (d)(4)(i);
■ q. Revising paragraph (d)(5);
■ r. Revising paragraph (e) introductory text;
■ s. Revising paragraphs (e)(2) and (3);
■ t. Adding paragraphs (e)(4) through (e)(6);
■ u. Revising paragraph (f) introductory text;
■ v. Revising paragraph (f)(1);
■ w. Revising paragraph (f)(2) introductory text;
■ x. Revising paragraph (f)(2)(iii) introductory text, (f)(2)(iii)(A) and (f)(2)(iii)(B);
■ y. Revising paragraph (f)(3); and
■ z. Adding paragraphs (g) and (h).

The revisions and additions 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 (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 ASTM D6420–99 (Reapproved 2004) (incorporated by reference as specified in § 63.14), as specified in § 63.772(a)(1)(ii); 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.

(b) * * *

(6) * * *

(i) Except as provided in paragraph (b)(6)(ii) of this section, the detection instrument shall meet the performance criteria of Method 21 of 40 CFR part 60, appendix A, except the instrument response factor criteria in section 3.1.2(a) of Method 21 shall be for the average composition of the process fluid not each individual volatile organic compound in the stream. For process streams that contain nitrogen, air, or other inert gases that are not organic HAP or VOC, the average stream response factor shall be calculated on an inert-free basis.

* * * * *

(c) *Test procedures and compliance demonstrations for small glycol dehydration units.* This paragraph (c) 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. Flares shall meet the provisions in paragraph (d)(2) of this section. 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.

* * * * *

(iii) To determine compliance with the control device percent reduction performance requirement in § 63.1281(d)(1)(i)(A), 63.1281(d)(1)(ii), or 63.1281(e)(3)(ii), the owner or operator shall use either Method 18, 40 CFR part 60, appendix A, or Method 25A, 40 CFR part 60, appendix A; or ASTM D6420–99 (incorporated by reference as specified in § 63.14), as specified in § 63.772(a)(1)(ii); alternatively, any other method or data that have been validated according to the applicable procedures in Method 301 of appendix A of this part may be used. The following procedures shall be used to calculate the percentage of reduction:

* * * * *

(iv) To determine compliance with the enclosed combustion device total HAP concentration limit specified in § 63.1281(d)(1)(i)(B), the owner or operator shall use either Method 18, 40 CFR part 60, appendix A; or Method 25A, 40 CFR part 60, appendix A; or ASTM D6420–99 (Reapproved 2004) (incorporated by reference as specified in § 63.14), as specified in § 63.772(a)(1)(ii), to measure either TOC (minus methane and ethane) or total HAP. Alternatively, any other method or data that have been validated according to Method 301 of appendix A of this part, may be used. The following procedures shall be used to calculate parts per million by volume concentration, corrected to 3 percent oxygen:

* * * * *

(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, ASTM D6522–00 (Reapproved 2005), or ANSI/ASME PTC 19.10–1981, Part 10 (manual portion only) (incorporated by reference as specified in § 63.14) 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 § 63.1275(b)(1)(iii) the owner or operator shall use one of the following methods: Method 18, 40 CFR part 60, appendix A; ASTM D6420–99 (Reapproved 2004) (incorporated by reference as specified in § 63.14), 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 (Reapproved 2004) (incorporated by reference as specified in § 63.14) 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 (*i.e.,* control devices installed on or before August 23, 2011) at major sources shall be conducted no later than October 15, 2015. If the owner or operator of an existing combustion control device at a 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 October 15, 2015. 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 demonstrating during the performance test under § 63.1282(d) that combustion zone temperature is an indicator of destruction efficiency and operates at a minimum temperature of 760 degrees C.

(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 (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) or under the performance test conducted under § 63.1282(d), as applicable.

(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 or is equal to or greater than the minimum percent reduction necessary to meet the BTEX emission limit as determined in paragraph (f)(1) of this section.

* * * * *

(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 (g) 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. During the first 5 minutes, incrementally 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, incrementally 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. During the first 5 minutes, incrementally 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, incrementally 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. During the first 5 minutes, incrementally ramp the firing rate to 30 percent of the maximum design rate. Hold at 30 percent for 5 minutes. In the 10–15 minute time range, incrementally 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 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 inlet gas flow metering system shall be located in accordance with Method 2A, 40 CFR part 60, appendix A–1, (or other approved procedure) to measure inlet gas flowrate 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 gas flow monitoring meter.

(ii) Inlet gas flowrate 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 inlet gas pressure and temperature at 5-minute intervals throughout each 60-minute THC test.

(iii) Inlet gas sampling shall be conducted in accordance with the criteria in paragraphs (g)(4)(iii)(A) and (B) of this section.

(A) At the inlet gas sampling location, securely connect a Silonite-coated stainless steel evacuated canister fitted with a flow controller sufficient to fill the canister over a 3 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 each THC test run.

(*2*) Fill one canister across the three test runs for each THC test such that one composite fuel sample exists for each test condition.

(*3*) Label the canisters individually and record on a chain of custody form.

(B) Each inlet gas 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 (Reapproved 2010) (incorporated by reference as specified in § 63.14).

(*2*) Hydrogen (H_2), carbon monoxide (CO), carbon dioxide (CO_2), nitrogen (N_2), oxygen (O_2) using ASTM D1945–03 (Reapproved 2010) (incorporated by reference as specified in § 63.14).

(*3*) Higher heating value using ASTM D3588–98 (Reapproved 2003) or ASTM D4891–89 (Reapproved 2006) (incorporated by reference as specified in § 63.14).

(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) Flowrate 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 or other pressure measurement device 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 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 or ASTM D6522–00 (Reapproved 2005) (incorporated by reference as specified in § 63.14). 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.

(v) Excess air shall be determined using resultant data from the EPA Method 3C tests and EPA Method 3B, 40 CFR part 60, Appendix A, equation 3B–1 or ANSI/ASME PTC 19.10–1981, Part 10 (manual portion only) (incorporated by reference as specified in § 63.14).

(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 test run.

(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.

(D) Excess combustion air shall be equal to or greater than 150 percent.

(ii) The manufacturer shall determine a maximum inlet gas flowrate 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 95.0 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 flowrate.

(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 flowrate.

(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 flowrate shall meet the range specified by the manufacturer. Flowrate shall be calculated 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 2 minutes during any hour. A visible emissions test using Method 22, 40 CFR part 60, Appendix A, shall be performed each calendar quarter. The observation period shall be 1 hour and shall be conducted according to EPA Method 22, 40 CFR part 60, Appendix A.

(4) Compliance with the operating parameter limit is achieved when the following criteria are met:

(i) The inlet gas flowrate 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 2 minutes during the observation period. Devices failing the visible emissions test shall follow manufacturers repair instructions, if available, or best combustion engineering practice as outlined in the unit inspection and maintenance plan, to return the unit to compliant operation. All repairs and maintenance activities for each unit shall be recorded in a maintenance and repair log and shall be available on site for inspection.

(iv) Following return to operation from maintenance or repair activity, each device must pass a Method 22 visual observation as described in paragraph (h)(3) 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);
■ e. Revising paragraph (d)(3)(i)(A);
■ f. Revising paragraph (d)(3)(i)(D);
■ g. Revising paragraph (d)(3)(i)(G);
■ h. Adding paragraph (d)(3)(i)(H);
■ i. Revising paragraph (d)(4);
■ j. Revising paragraph (d)(5)(i);
■ k. Revising paragraphs (d)(5)(ii)(A) through (C);
■ l. Revising paragraph (d)(6) introductory text;
■ m. Revising paragraph (d)(6)(ii);
■ n. Adding paragraph (d)(6)(v);
■ o. Revising paragraph (d)(7); and
■ p. Removing and reserving paragraph (d)(8).

The additions and revisions 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 (7) 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) An owner or operator is exempted from the monitoring requirements specified in paragraphs (d)(3) through (7) of this section for the following types of control devices:

(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 ±2 percent of the temperature being monitored in °C, or ±2.5 °C, whichever value is greater. The temperature sensor shall be installed at a location representative of the combustion zone temperature.

* * * * *

(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 ±2 percent of the temperature being monitored in °C, or ±2.5 °C, whichever value is greater. The temperature sensor shall be installed at a location representative of the combustion zone temperature.

* * * * *

(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*) The owner or operator shall determine actual average inlet waste gas flowrate using the model GRI–GLYCalc™, Version 3.0 or higher, ProMax, or AspenTech HYSYS. Inputs to the models shall be representative of actual operating conditions of the controlled unit. The determination shall be performed to coincide with the visible emissions test under § 63.1282(h)(3);

(*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 flowrate 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)(v) 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 flowrate exceeds the maximum established during the test conducted under § 63.1282(g).

(B) Failure of the quarterly visible emissions test conducted under § 63.1282(h)(3) occurs.

(7) For each excursion, the owner or operator shall be deemed to have failed to have applied control in a manner that achieves the required operating parameter limits. Failure to achieve the required operating parameter limits is a violation of this standard.

(8) [Reserved]

* * * * *

■ 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. Revising paragraph (b)(4)(iii);

■ e. Adding paragraph (b)(7)(ix); and

■ f. Adding paragraphs (f), (g) and (h).

The revisions and additions 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.

(iii) Hourly records of the times and durations of all periods when the vent stream is diverted from the control device or the device is not operating.

* * * * *

(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(h), 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 calculations 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) introductory text;
■ e. Revising paragraph (d)(1) introductory text;
■ f. Revising paragraph (d)(1)(i);
■ g. Revising paragraph (d)(1)(ii) introductory text;
■ h. Revising paragraph (d)(2) introductory text;
■ i. Revising paragraph (d)(4) introductory text;
■ j. Revising paragraph (d)(4)(ii);
■ k. Adding paragraph (d)(4)(iv);
■ l. Revising paragraph (d)(10);
■ m. Adding paragraphs (d)(11) and (d)(12);
■ n. Revising paragraph (e)(2) introductory text;
■ o. Revising paragraph (e)(2)(ii)(B);
■ p. Adding paragraphs (e)(2)(ii)(D) and (E);
■ q. Adding paragraphs (e)(2)(x) through (xiii); and
■ r. Adding paragraph (g).

The revisions and additions 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 October 15, 2013, whichever is later. An affected source identified under § 63.1270(d)(3) that plans to be an area source by October 15, 2015, 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) Each owner or operator of a source subject to this subpart shall submit a Notification of Compliance Status Report as required under § 63.9(h) within 180 days after the compliance date specified in § 63.1270(d). In addition to the information required under § 63.9(h), the Notification of Compliance Status Report shall include the information specified in paragraphs (d)(1) through (12) of this section. This information may be submitted in an operating permit application, in an amendment to an operating permit application, in a separate submittal, or in any combination of the three. If all of the information required under this paragraph have been submitted at any time prior to 180 days after the applicable compliance dates specified in § 63.1270(d), a separate Notification of Compliance Status Report is not required. If an owner or operator submits the information specified in paragraphs (d)(1) through (12) of this section at different times, and/or different submittals, subsequent submittals may refer to previous submittals instead of duplicating and resubmitting the previously submitted information.

(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 email to *Oil_and_Gas_PT@EPA.GOV* unless the test results for that model of combustion control device are posted at the following Web site: *epa.gov/airquality/oilandgas/.*

* * * * *

(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) For each control device other than a flare used to meet the requirements of § 63.1274, the owner or operator shall submit the information specified in paragraphs (d)(4)(i) through (iv) of this section for each operating parameter required to be monitored in accordance with the requirements of § 63.1283(d).

* * * * *

(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 the model of control device was tested by the manufacturer.

(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 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 flowrate 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, repairs affected to the unit, and date the unit was returned to service.

* * * * *

(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).

(xiii) Certification by a responsible official of truth, accuracy, and completeness. This certification shall state that, based on information and belief formed after reasonable inquiry, the statements and information in the document are true, accurate, and complete.

* * * * *

(g) *Electronic reporting.* (1) Within 60 days after the date of completing each performance test (defined in § 63.2) as required by this subpart you must submit the results of the performance tests required by this subpart to EPA's WebFIRE database by using the Compliance and Emissions Data Reporting Interface (CEDRI) that is accessed through EPA's Central Data Exchange (CDX)(*www.epa.gov/cdx*). Performance test data must be submitted in the file format generated through use of EPA's Electronic Reporting Tool (ERT) (see *http://www.epa.gov/ttn/chief/ert/index.html*). Only data collected using test methods on the ERT Web site are subject to this requirement for submitting reports electronically to WebFIRE. Owners or operators who claim that some of the information being submitted for performance tests is confidential business information (CBI) must submit a complete ERT file including information claimed to be CBI on a compact disk or other commonly used electronic storage media (including, but not limited to, flash drives) to EPA. The electronic media must be clearly marked as CBI and mailed to U.S. EPA/OAPQS/CORE CBI Office, Attention: WebFIRE Administrator, MD C404–02, 4930 Old Page Rd., Durham, NC 27703. The same ERT file with the CBI omitted must be submitted to EPA via CDX as described earlier in this paragraph. At the discretion of the delegated authority, you must also submit these reports, including the confidential business information, to the delegated authority in the format specified by the delegated authority.

(2) All reports required by this subpart not subject to the requirements in paragraph (g)(1) of this section must be sent to the Administrator at the appropriate address listed in § 63.13. The Administrator or the delegated authority may request a report in any form suitable for the specific case (*e.g.,* by commonly used electronic media such as Excel spreadsheet, on CD or hard copy). 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.

* * * * *

■ 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

* * * * *

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)	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)	Yes.	
§ 63.4(a)(2)	Yes.	
§ 63.4(a)(3)	No	Section reserved.
§ 63.4(a)(4)	No	Section reserved.
§ 63.4(a)(5)	No	Section reserved.
§ 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)	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) 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)	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.	

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(h)(1)	No.	
§ 63.6(h)(2)	Yes.	
§ 63.6(h)(3)	No	Section reserved.
§ 63.6(h)(4) through (h)(9)	Yes.	
§ 63.6(i)(1) through (i)(14)	Yes.	
§ 63.6(i)(15)	No	Section reserved.
§ 63.6(i)(16)	Yes.	
§ 63.6(j)	Yes.	
§ 63.7(a)(1)	Yes.	
§ 63.7(a)(2)	Yes	But the performance test results must be submitted within 180 days after the compliance date.
§ 63.7(a)(3)	Yes.	
§ 63.7(a)(4)	Yes.	
§ 63.7(b)	Yes.	
§ 63.7(c)	Yes.	
§ 63.7(d)	Yes.	
§ 63.7(e)(1)	No.	
§ 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)	No.	
§ 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)(1)	Yes.	
§ 63.8(d)(2)	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)	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)	Yes.	
§ 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.	

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(b)(2)(i)	No.	
§ 63.10(b)(2)(ii)	No	See § 63.1284(f) for recordkeeping of (1) occurrence and duration and (2) 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.
§ 63.10(c)(10) through (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	Section reserved.
§ 63.10(e)(3)(i)(D)	Yes.	
§ 63.10(e)(3)(ii) through (e)(3)(viii)	Yes.	
§ 63.10(f)	Yes.	
§ 63.11(a) through (e)	Yes.	
§ 63.12(a) through (c)	Yes.	
§ 63.13(a) through (c)	Yes.	
§ 63.14(a) through (q)	Yes.	
§ 63.15(a) and (b)	Yes.	

[FR Doc. 2012–16806 Filed 8–15–12; 8:45 am]

BILLING CODE 6560–50–P