**ENVIRONMENTAL PROTECTION AGENCY**

**40 CFR Part 63**

**[AD–FRL–5955–1]**

**RIN 2060–AE34**

# National Emission Standards for Hazardous Air Pollutants: Oil and Natural Gas Production and Natural Gas Transmission and Storage

**AGENCY:** Environmental Protection Agency (EPA).

**ACTION:** Proposed rules and notice of public hearing.

**SUMMARY:** These proposed national emission standards for hazardous air pollutants (NESHAP) would limit emissions of hazardous air pollutants (HAP) from oil and natural gas production and natural gas transmission and storage facilities. These proposed rules would implement section 112 of the Clean Air Act (Act) and are based on the Administrator's determination that oil and natural gas production and natural gas transmission and storage facilities emit HAP identified on the EPA's list of 188 HAP.

The EPA estimates that approximately 65,000 megagrams per year (Mg/yr) of HAP are emitted from major and area sources in these source categories. The primary HAP emitted by the facilities covered by these proposed standards include benzene, toluene, ethyl benzene, mixed xylenes (collectively referred to as BTEX), and n-hexane. Benzene is carcinogenic and all can cause toxic effects following exposure. The EPA estimates that these proposed NESHAPs would reduce HAP emissions in the oil and natural gas production source category by 57 percent and in the natural gas transmission storage source category by 36 percent.

Also, the EPA is amending the list of source categories established under section 112(c) of the Act. Natural gas transmission and storage is being listed as a category of major sources and oil and natural gas production is being listed as a category of area sources in addition to its major source listing.

**DATES:** *Comments.* Comments must be received on or before April 7, 1998. For information on submitting electronic comments see the **SUPPLEMENTARY INFORMATION** section of this document.

*Public Hearing.* A public hearing will be held, if requested, to provide interested persons an opportunity for oral presentation of data, views, or arguments concerning the proposed standards for the oil and natural gas production and the natural gas transmission and storage. If anyone contacts the EPA requesting to speak at a public hearing by March 9, 1998, a public hearing will be held on March 23, 1998, beginning at 9:30 a.m. Persons interested in attending the hearing should notify Ms. JoLynn Collins, telephone (919) 541–5671, Waste and Chemical Processes Group (MD–13), to verify that a hearing will occur.

*Request to Speak at a Hearing.* Persons wishing to present oral testimony must contact the EPA by March 9, 1998, by contacting Ms. JoLynn Collins, Waste and Chemical Processes Group (MD–13), U.S. Environmental Protection Agency, Research Triangle Park, NC 27711, telephone (919) 541–5671.

**ADDRESSES:** *Comments.* Comments should be submitted (in duplicate, if possible) to: Air and Radiation Docket and Information Center (MC–6102), Attention: Docket No. A–94–04, U.S. Environmental Protection Agency, 401 M Street, SW, Washington, DC 20460. The EPA requests that a separate copy of comments also be sent to Stephen Shedd, USEPA, Office of Air Quality Planning and Standards, Research Triangle Park, NC 27711, telephone (919) 541–5397, fax (919) 541–0246 and E-mail: Shedd.Steve@EPAMAIL.EPA.GOV. Comments and data may also be submitted electronically by following the instructions listed in **SUPPLEMENTARY INFORMATION.** No confidential business information (CBI) should be submitted through e-mail.

*Background Information Document.* The background information document (BID) may be obtained from the U.S. Environmental Protection Library (MD–35), Research Triangle Park, NC 27711, telephone (919) 541–2777. Please refer to ''National Emissions Standards for Hazardous Air Pollutants for Source Categories: Oil and Natural Gas Production and Natural Gas Transmission and Storage—Background Information for Proposed Standards'' (EPA–453/R–94–079a, April 1997) for the BID. This document may also be obtained electronically from the EPA's Technology Transfer Network (TTN) (see **SUPPLEMENTARY INFORMATION** for access information).

*Docket.* A docket, No. A–94–04, containing information considered by the EPA in development of the proposed standards for the oil and natural gas production and natural gas transmission and storage source categories, is available for public inspection between 8:00 a.m. and 4:00 p.m., Monday through Friday (except for Federal holidays) at the following address: U.S. Environmental Protection Agency, Air and Radiation Docket and Information Center (MC–6102), 401 M Street SW., Washington DC 20460, telephone: (202) 260–7548. The docket is located at the above address in Room M–1500, Waterside Mall (ground floor). The proposed regulations, BID, and other supporting information are available for inspection and copying. A reasonable fee may be charged for copying.

**FOR FURTHER INFORMATION CONTACT:** For information concerning the proposed standards, contact Ms. Martha Smith, Waste and Chemical Processes Group, Emission Standards Division (MD–13), U.S. Environmental Protection Agency, Research Triangle Park, NC 27711, (919) 541–2421, or electronically at: smith.martha@epamail.epa.gov.

**SUPPLEMENTARY INFORMATION:** *Regulated Entities.* Regulated categories and entities include:

| Category | Examples of regulated entities |
|---|---|
| Industry .... | Condensate tank batteries, glycol dehydration units, natural gas processing plants, and natural gas transmission and storage facilities. |

This table is not intended to be exhaustive, but rather provides a guide for readers regarding entities likely to be regulated by this action. This table lists the types of entities that the EPA is now aware could potentially be regulated by this action. Other types of entities not listed in the table could also be regulated. To determine whether your facility is regulated by this action, you should carefully examine the applicability criteria in §§ 63.760 and 63.1270 of the rules. If you have questions regarding the applicability of this action to a particular entity, consult the person listed in the preceding **FOR FURTHER INFORMATION CONTACT** section.

Electronic comments can be sent directly to EPA at: A-and-R-Docket@epamail.epa.gov. Electronic comments must be submitted as an ASCII file avoiding the use of special characters and any form of encryption. Comments and data will also be accepted on disks in WordPerfect in 5.1 or 6.1 file format or ASCII file format. All comments and data in electronic form must be identified by the docket number A–94–04. Electronic comments on this proposed rule may be filed online at many Federal Depository Libraries.

This document, the proposed regulatory texts, and BID are available in Docket No. A–94–04 or by request from the EPA's Air and Radiation Docket and Information Center (see **ADDRESSES**) or access through the EPA web site at: http://www.epa.gov/ttn/oarpg.

The following outline is provided to aid in reading the preamble to the proposed oil and natural gas production and natural gas transmission and storage NESHAPs.



## I. Background

*A. Purpose of the Proposed Standards*

The Act was developed, in part,

> * * * to protect and enhance the quality of the Nation's air resources so as to promote the public health and welfare and productive capacity of its population [the Act, section 101(b)(1)].

Oil and natural gas production and natural gas transmission and storage facilities are major and area sources of HAP emissions. The EPA estimates that approximately 65,000 Mg/yr of HAP are emitted from major and area sources in the oil and natural gas production source category and 320 Mg/yr of HAP are emitted from major and area sources in the natural gas transmission and storage source category. The primary HAP associated with oil and natural gas that have been identified include BTEX and n-hexane. Exposure to these chemicals has been demonstrated to cause adverse health effects. The adverse health effects associated with the exposure to these specific HAP are discussed briefly in the following paragraphs. In general, these findings have only been shown with concentrations higher than those in the ambient air.

Benzene, one of the HAP associated with this NESHAP, has been classified as a known human carcinogen on the basis of observed increases in the incidence of leukemia in exposed workers. In addition, short-term inhalation of high benzene levels may cause nervous system effects such as drowsiness, dizziness, headaches, and unconsciousness in humans. At even higher concentrations of benzene, exposure may cause death, while lower concentrations may irritate the skin, eyes, and upper respiratory tract. Long-term inhalation exposure to benzene may cause various disorders of the blood, and toxicity to the immune system. Reproductive disorders in women, as well as developmental effects in animals, have also been reported for benzene exposure.

Short-term inhalation of relatively high concentrations of toluene by humans may cause nervous system effects such as fatigue, sleepiness, headaches, and nausea, as well as irregular heartbeat. Repeated exposure to high concentrations may cause additional nervous system effects, including incoordination, tremors, decreased brain size, involuntary eye movements, and may impair speech, hearing, and vision. Long-term exposure of toluene in humans has also been reported to irritate the skin, eyes, and respiratory tract, and to cause dizziness, headaches, and difficulty with sleep. Children whose mothers were exposed to toluene before birth may suffer nervous system dysfunction, attention deficits, and minor face and limb defects. Inhalation of toluene by pregnant women may also increase the risk of spontaneous abortion. Not enough information exists to determine toluene's carcinogenic potential.

Short-term inhalation of high levels of ethyl benzene in humans may cause throat and eye irritation, chest constriction, and dizziness. Long-term inhalation of ethyl benzene by humans may cause blood disorders. Animal studies have reported blood, liver, and kidney effects associated with ethyl benzene inhalation. Birth defects have been reported in animals exposed via inhalation; whether these effects may occur in humans is not known. Not enough information exists concerning ethyl benzene for determination of its carcinogenic potential.

Short-term inhalation of high levels of mixed xylenes (a mixture of three closely-related compounds) in humans may cause irritation of the nose and throat, nausea, vomiting, gastric irritation, mild transient eye irritation, and neurological effects. Long-term inhalation of high levels of xylene in humans may result in nervous system effects such as headaches, dizziness, fatigue, tremors, and incoordination. Other reported effects noted include labored breathing, heart palpitation, severe chest pain, abnormal heart functioning, and possible effects on the blood and kidneys. Developmental effects have been reported from xylene exposure via inhalation in animals. Not enough information exists to determine the carcinogenic potential of mixed xylenes.

Short-term inhalation of high levels of n-hexane in humans may cause mild central nervous system effects (dizziness, giddiness, slight nausea, and headache) and irritation of the skin and mucous membranes. Long-term inhalation exposure of high levels of n-hexane in humans has been reported to cause nerve damage expressed as numbness in the extremities, muscular weakness, blurred vision, headache, and fatigue. Reproductive effects have been reported in animals after inhalation exposure (testicular damage in rats). Not enough information exists concerning n-hexane for determination of its carcinogenic potential.

The EPA estimates that the proposed NESHAP would reduce HAP emissions from those impacted HAP emission points in the oil and natural gas production source category by 57 percent and would reduce HAP emissions from triethylene glycol (TEG) dehydration units in the natural gas transmission and storage source category by 36 percent.

*B. Technical Basis for the Proposed Standards*

Section 112 of the Act regulates stationary sources of HAP. Section 112(b) of the Act lists 188 chemicals, compounds or groups of chemicals as HAP. The EPA is directed by section 112 to regulate the emission of HAP from stationary sources by establishing national emission standards.

Section 112(a)(1) of the Act defines a major source as:

> * * * any stationary source or group of stationary sources located within a contiguous area and under common control that emits or has the potential-to-emit considering controls, in the aggregate 10 tons per year (tpy) or more of any HAP or 25 tpy or more of any combination of HAP.

An area source is defined as a stationary source that is not a major source.

For major sources, the statute requires the EPA to establish standards to reflect the maximum degree of reduction in HAP emissions through application of maximum achievable control technology (MACT). Further, the EPA must establish standards that are no less stringent than the level of control defined under section 112(d)(3) of the Act, often referred to as the MACT floor. The proposed standards for major sources in the oil and natural gas production and natural gas transmission and storage source categories are based on the MACT floor for these source categories.

In developing standards for area sources of HAP emissions, the EPA has discretion to establish standards based on (1) MACT, (2) generally available control technology (GACT), or (3) management practices that reduce the emission of HAP. The proposed standards for selected area source TEG dehydration units are based on GACT. There is no statutory ''floor'' level of control for GACT.

Information on industry processes and operations, HAP emission points, and HAP emission reduction techniques were collected through section 114 questionnaires that were distributed to companies in the oil and natural gas production and natural gas transmission and storage source categories. The companies provided information on representative facilities.

This information was used, in part, as the technical basis in determining the MACT level of control for the emission points covered under the proposed standards. In addition to information collected in the questionnaires, the EPA considered information available in the general literature, as well as information submitted by industry on technical issues subsequent to the questionnaire responses.

*C. Stakeholder and Public Participation*

Numerous representatives of the oil and natural gas industry and other interested parties were consulted in the development of the proposed standards. Industry assisted in data gathering, arranging site visits, technical review, and sharing of industry-sponsored data collection activities. A data base comprised of all industry-supplied information was developed in the evaluation of HAP emissions and air emission controls for these proposed standards.

Estimates of HAP emissions from representative facilities in each industry segment were developed by the EPA. To estimate HAP emissions from glycol dehydration units in both the oil and natural gas production and natural gas transmission and storage source categories, the EPA utilized an emission model, GRI-GLYCalc ™ (Version 3.0), developed by the Gas Research Institute (GRI). Inputs used by the EPA for this model were primarily developed from information supplied by industry.

The trade associations and organizations that participated in the development of the proposed rules on a regular basis include (1) the American Petroleum Institute (API) and (2) GRI. Other interested parties that participated in the development of the proposed standards include the Independent Petroleum Association of America (IPAA), the Audubon Society, the Interstate Oil and Gas Compact Commission (IOGCC), the American Gas Association (AGA), and the Interstate Natural Gas Association of America (INGAA).

These interested parties, in addition to individual companies in the oil and natural gas industry, were offered the opportunity to provide technical review and comment during the development of the proposed standards. In addition, interested parties provided technical review and comment on the preliminary draft BID and preliminary draft standards.

Representatives from other EPA offices and programs were included in the regulatory development process. These representatives' responsibilities included review and internal concurrence with the proposed standards. Therefore, the EPA believes that the impact of these proposed regulations to other EPA offices and programs has been adequately considered during the development of these regulations.

This notice also solicits comment on the proposed standards and offers a chance for a public hearing on the proposals in order to provide interested persons the opportunity for oral presentation of data, views, or arguments concerning the proposed standards.

## II. Source Category Descriptions

*A. Source Category List*

Oil and natural gas production was included on the EPA's initial list of categories of major sources of HAP emissions established under section 112(c)(1) of the Act. This list was published on July 16, 1992 (57 FR 31576).

The EPA included natural gas transmission and storage in the proposed initial listing of source categories that was published in 1991. The EPA's preliminary analysis that led to natural gas transmission and storage being listed as a source category was based on the estimated emissions of the HAP ethylidene dichloride (1,1-dichloroethane). Comments received on the proposed initial list indicated that these estimates were not accurate.

Based on its review of comments for the final initial list, the EPA decided that it did not have sufficient available information that supported that this source category could contain a major source of HAP. Thus, the natural gas transmission and storage source category was not included as a distinct source category in the final initial list of source categories of major sources of HAP.

In the development of the proposed standards for the oil and natural gas production source category, information was obtained on glycol dehydration unit BTEX emissions that are representative of both oil and natural gas production facilities and natural gas transmission and storage facilities. The information obtained indicates that natural gas transmission and storage facilities have the potential to be major HAP sources. In addition, industry has stated to the EPA that there are major source TEG dehydration units in the natural gas transmission and storage source category. Therefore, the EPA is amending the source category list to add the natural gas transmission and storage source category as a major source category and, with this notice, is proposing a regulation that would apply to major sources in this source category.

The EPA has made a determination that there are area sources in the oil and natural gas production source category that present a threat of adverse effects to human health and the environment. Based on this determination, referred to as an ''area source finding,'' the EPA is amending the source category list to add oil and natural gas production to the list of area source categories established under section 112(c)(1) of the Act. The area source finding supporting this listing is discussed in section V of this preamble.

Glycol dehydration units located at natural gas transmission and storage facilities have similar HAP emissions and emission potential to those located at oil and natural gas production facilities. The EPA is currently evaluating whether TEG dehydration units located at natural gas transmission and storage facilities that are area sources constitute an unacceptable risk to public health or the environment and should be listed and regulated as an area source. The EPA is soliciting information and comment in this notice regarding the location and HAP emissions from area source TEG dehydration units in the natural gas transmission and storage source category (see sections V and X for further discussion).

The documentation supporting the listing of oil and natural gas production as a source category (''Documentation for Developing the Initial Source Category List,'' EPA–450/3–91–030, July 1992) describes the source category as including

> * * * the processing and upgrading of crude oil prior to entering the petroleum refining process and natural gas prior to entering the transmission line.

During the development of the proposed rules, industry requested that HAP emissions associated with distribution of hydrocarbon liquids after the point of custody transfer be addressed within the scope of the organic liquids distribution (non-gasoline) source category and not the oil and natural gas production source category. Custody transfer, as defined in a previous rule, means transfer, after processing and/or treatment in the producing operations, from storage vessels or automatic transfer facilities to pipelines or any other forms of transportation. Industry representatives commented that there are differences in the HAP emission potential from facilities involved in the distribution of petroleum liquids after the point of custody transfer relative to other processes and operations in the oil and natural gas production source category.

The EPA, after evaluation of industry comments, is proposing that HAP emissions associated with the distribution of hydrocarbon liquids after the point of custody transfer would be more appropriately addressed as part of the organic liquids distribution (non-gasoline) source category. Therefore, the proposed rule for the oil and natural gas production source category would not apply to those facilities that distribute hydrocarbon liquids after the point of custody transfer (see proposed regulation for definition of custody transfer).

Facilities involved in the organic liquids distribution (non-gasoline) sector of the petroleum industry include (but are not limited to) gathering stations, trunk-line stations, and station storage vessel farms. The organic liquids distribution (non-gasoline) source category is scheduled for regulation under section 112 of the Act by November 15, 2000.

The EPA plans to define the organic liquids distribution (non-gasoline) source category (within that rulemaking) as including those facilities that distribute hydrocarbon liquids after the point of custody transfer. This will eliminate the potential for overlapping regulatory requirements between the oil and natural gas production and organic liquids distribution (non-gasoline) source categories.

### *B. Hazardous Air Pollutant Types*

The primary HAP associated with the oil and natural gas production and natural gas transmission and storage source categories include BTEX and n-hexane. In addition, available information indicates that 2,2,4-trimethylpentane (iso-octane), formaldehyde, acetaldehyde, naphthalene, and ethylene glycol may be present in certain process and emission streams. Carbon disulfide ($CS_2$), carbonyl sulfide (COS), and BTEX may also be present in the tail gas streams from amine treating and sulfur recovery units.

### *C. Facility Types*

The oil and natural gas production and natural gas transmission and storage source categories consist of various facilities used to recover and treat products (hydrocarbon liquids and gases) from production wells. These source categories include the processing, storage, and transport of these products to (1) the point of custody transfer for the oil and natural gas production source category or (2) the point of delivery to the local distribution company (LDC) or final end user for the natural gas transmission and storage source category. The facilities in the oil and natural gas production source category that the EPA is proposing requirements for include (1) glycol dehydration units, (2) condensate tank batteries, and (3) natural gas processing plants. The EPA is also proposing requirements for glycol dehydration units located at facilities in the natural gas transmission and storage source category.

#### 1. Glycol Dehydration Units

The most widely used dehydration process in these source categories is glycol dehydration. TEG dehydration units account for the majority of glycol dehydration units, with ethylene glycol (EG) and diethylene glycol (DEG) dehydration units accounting for the remaining population of glycol dehydration units. In the dehydration process, natural gas is contacted with glycol to remove water present in the natural gas. Some portion of the HAP present in the natural gas are also removed by the glycol. The ''rich'' glycol is then heated in a reboiler to remove water vapor and other contaminants prior to recirculation in the process. The reboiler vent of the glycol dehydration unit is the primary identified source of HAP emissions for these source categories.

#### 2. Tank Batteries

The term ''tank battery'' refers to the collection of process equipment used to separate, upgrade, store, and transfer extracted petroleum products and separated streams. These facilities handle crude oil and condensate up to the custody transfer of these products to facilities in the organic liquids distribution (non-gasoline) source category. Separation and dehydration of natural gas can also occur at a tank battery. A tank battery may serve an individual production well or a collection of wells in the field.

Tank batteries can be broadly classified as black oil tank batteries or condensate tank batteries. Black oil means hydrocarbon (petroleum) liquid with a gas-to-oil ratio (GOR) less than 50 cubic meters ($m^3$) (1,750 cubic feet ($ft^3$)) per barrel and an API gravity less than

40 degrees (°). Condensate means hydrocarbon liquid that condenses because of changes in temperature, pressure, or both, and remains liquid at standard conditions. The majority of tank batteries, approximately 85 percent, are black oil tank batteries and the remainder are condensate tank batteries.

The primary identified HAP emission points at tank batteries include (1) process vents associated with glycol dehydration units and (2) tanks and vessels storing volatile oils, condensate, and other similar hydrocarbon liquids that have a flash emission potential. Condensate tank batteries typically incorporate a glycol dehydration unit in the process system.

The EPA proposes to exempt from the oil and natural gas production NESHAP those facilities that handle black oil exclusively. This exemption is based on the EPA's proposed interpretation of associated equipment in section 112(n)(4) of the Act. The EPA is proposing that associated equipment be defined as all equipment associated with a production well up to the point of custody transfer, except that glycol dehydration units and storage vessels with flash emissions would not be associated equipment. The EPA believes that this proposed definition will provide the relief that Congress intended in section 112(n)(4) for the numerous, widely dispersed, small emission points in the oil and natural gas production source category (such as black oil tank batteries) while preserving the EPA's ability to require appropriate MACT or GACT controls for the most significant identified HAP emission points in this source category (see section VII of this preamble for a detailed discussion of associated equipment).

3. Natural Gas Processing Plants

A natural gas processing plant conditions natural gas by separating natural gas liquids (NGLs) from field natural gas and, in addition, may fractionate the NGLs into separate components such as ethane, propane, butane, and natural gasoline. Natural gas processing may also include amine treating and sulfur recovery units onsite to treat natural gas streams.

The primary identified HAP emission points at natural gas processing plants include (1) the glycol dehydration unit reboiler vent, (2) storage tanks, particularly those tanks that handle volatile oils and condensates that may be significant contributors to overall HAP emissions due to flash emissions, and (3) equipment leaks from those components handling hydrocarbon streams that contain HAP constituents. Other potential HAP emission point process vents are the tail gas stream from amine treating processes and sulfur recovery units. Limited information has been identified on the potential for HAP emissions from these operations. Recent research published by GRI indicates that these emission points have the potential to be significant sources of HAP emissions. Comment is requested on potential HAP emissions and emission rates from these operations and potential applicable air emission controls.

4. Natural Gas Transmission and Storage Facilities

The natural gas transmission and storage source category consists of transmission pipelines used for the long distance transport of natural gas and underground natural gas storage facilities. These facilities typically extend from the natural gas processing plant to the local distribution company that delivers natural gas to the final end user. In cases where there is no processing, these facilities may be located anywhere from the well to the final end user.

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).

Underground natural gas storage facilities are subsurface facilities that store natural gas that has been transferred from its original location for the primary purpose of load balancing. Load balancing is the process of equalizing the receipt and delivery of natural gas (i.e., utilized for stockpiling natural gas for periods of high demand, in particular, the winter heating season). Processes and operations that may be located at an underground storage facility include, but are not limited to, compression and dehydration.

The primary identified HAP emission point at natural gas transmission and storage facilities is the glycol dehydration unit reboiler vent.

5. Facility Populations

There are a large number of glycol dehydration units and tank batteries in the United States. The estimated population of glycol dehydration units presented in various industry studies range from under 20,000 to over 45,000 glycol dehydration units.

For the purpose of estimating nationwide impacts of this proposed NESHAP, the EPA selected 40,000 as the estimated total domestic population of all types of dehydration units. Of this total, an estimated 38,000 are glycol dehydration units and 2,000 are solid desiccant dehydration units.

Based on typical tank battery configurations and two studies conducted for the API, the EPA estimates that there are approximately 94,000 tank batteries. Of this total, the EPA estimates that there are 81,000 black oil tank batteries and 13,000 condensate tank batteries.

In 1996, according to the Oil and Gas Journal, there were approximately 700 natural gas processing plants.

The natural gas transmission and storage source category includes over 480,000 kilometers (300,000 miles) of high-pressure transmission pipelines and over 300 underground storage facilities. A recent GRI report estimates that there are 1,900 compressor stations located along transmission pipelines.

The EPA estimates that approximately 440 existing facilities would be affected by the proposed requirements of the production NESHAP for major sources. In addition, the EPA estimates that out of an estimated 37,000 glycol dehydration units at area sources of HAP, 520 existing TEG dehydration units would be affected by the proposed standards for area sources because they meet or exceed the throughput and benzene emission action levels and are also located in counties designated as urban (see section III of this preamble for a discussion of area source action levels).

The EPA estimates that about 5 existing facilities would be affected by the proposed requirements of the natural gas transmission and storage NESHAP for major sources.

## III. Summary of Proposed Standards

### *A. Proposed Standards for Oil and Natural Gas Production for Major and Area Sources*

The proposed action would amend title 40, chapter I, part 63 of the Code of Federal Regulations (CFR) by adding a new subpart HH—National Emission Standards for Hazardous Air Pollutants from Oil and Natural Gas Production Facilities. The proposed standards would apply to owners and operators of facilities that process, upgrade, or store (1) hydrocarbon liquids (with the exception of those facilities that handle black oil exclusively) to the point of custody transfer and (2) natural gas from the well up to and including the natural gas processing plant. Standards are proposed that would limit HAP emissions from the following emission points at facilities that are major sources of HAP (1) process vents on glycol dehydration units, (2) storage vessels with flash emissions, and (3) equipment leaks at natural gas processing plants. In addition, standards are proposed that would limit HAP emissions from selected area source TEG dehydration units.

As required by the Clean Air Act, the determination of a facility's potential-to-emit HAP and, therefore, its status as a major or area source, is based on the total of all HAP emissions from all activities at a facility, except that emissions from oil or gas exploration or production wells (and their associated equipment) and emissions from pipeline compressor or pump stations may not be combined. A definition of associated equipment is proposed in the proposed rulemaking. Further discussion of the definition of associated equipment is presented in section VII(A) of this preamble.

1. General Standards

The proposed standards for oil and natural gas production facilities would require that the owner or operator of a major source of HAP reduce HAP emissions from glycol dehydration units and storage vessels through the application of air emission control equipment or pollution prevention measures. In addition, the owner or operator of a natural gas processing plant that is a major source would be required to reduce HAP emissions from equipment leaks by establishing a leak detection and repair (LDAR) program.

The owner or operator of selected area source TEG dehydration units that meet the criteria in the proposed standards would be required to reduce HAP emissions from those TEG dehydration units.

Owners and operators of facilities that process and store black oil exclusively would not be subject to the proposed standards. Black oil is defined in the proposed oil and natural gas production NESHAP as a hydrocarbon liquid with (1) a GOR less than 50 $m^3$ (1,750 $ft^3$) per barrel and (2) an API gravity less than 40°.

2. Glycol Dehydration Unit Provisions

The proposed standards would require that all process vents at glycol dehydration units that are located at major HAP sources be controlled unless (1) the actual flowrate of natural gas to the glycol dehydration unit is less than 85 thousand cubic meters per day ($m^3$/day) (3.0 million standard cubic feet per day (MMSCF/D), on an annual average basis, or (2) if benzene emissions from the major source glycol dehydration unit are less than 0.9 Mg/yr (1 tpy).

HAP emissions from process vents at certain area source TEG dehydration units would be required to be controlled unless (1) the actual flowrate of natural gas to the glycol dehydration unit is less than 85 thousand $m^3$/day (3.0 MMSCF/D), on an annual average basis, or (2) if benzene emissions from the area source glycol dehydration unit are less than 0.9 Mg/yr (1 tpy). The proposed requirements are the same for existing and new (1) major source glycol dehydration units and (2) selected area source TEG dehydration units that meet the specified criteria.

In its analysis of available data, the EPA could not determine any level of emission control for those glycol dehydration units with low annual natural gas throughputs (less than 85 thousand $m^3$/day (3.0 MMSCF/D), on an annual average basis, or a low benzene emission rate (less than 0.9 Mg/yr (1 tpy)). Thus, the EPA is proposing the annual throughput and benzene emission rate cutoffs for major sources. In addition, the EPA's analysis indicated that control of HAP emissions below these cutoff levels was not cost-effective for area source glycol dehydration units.

The EPA is proposing an additional applicability criteria for area source TEG dehydration units. The additional proposed criteria would limit air emission controls to those selected area source TEG dehydration units located in counties classified as urban areas.

Since the Act does not provide a definition of urban area, the EPA used the U.S. Department of Commerce's Bureau of the Census statistical data to classify every county in the U.S. into one of three classifications (1) Urban-1 counties, (2) Urban-2 counties, or (3) Rural counties. Urban-1 counties consist of counties with metropolitan statistical areas (MSA) with a population greater than 250,000. Urban-2 counties are defined as all other counties designated urban by the Bureau of Census (areas which comprise one or more central places and the adjacent densely settled surrounding fringe that together have a minimum of 50,000 persons). The urban fringe consists of contiguous territory having a density of at least 1,000 persons per square mile. Rural counties are those counties not designated as urban by the Bureau of the Census (see docket item A–94–04, II–I–9).

Figure 1 shows the methodology for assigning counties to each of the three classifications. As seen in this diagram, if any part of a county contains an Urban-1 area then the entire county is classified as an Urban-1 area. For all remaining counties, if greater than 50 percent of the population is classified as urban, then that county is classified as an Urban-2 area. Counties not designated as Urban-1 or Urban-2 by the above method are classified as Rural areas.

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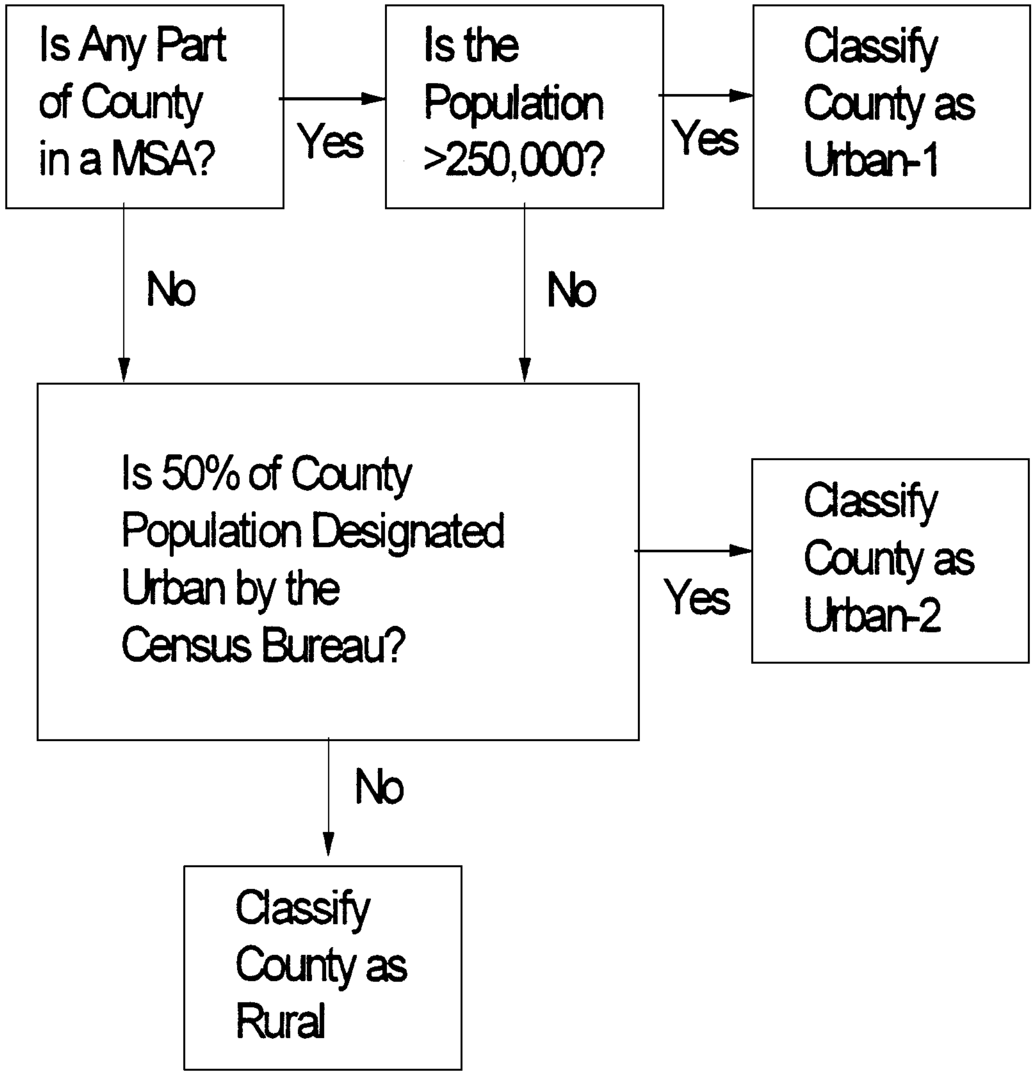


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**Figure 1. Urban/Rural County Classification Methodology**

Thus, only those area source TEG dehydration units that (1) meet or exceed the actual natural gas throughput applicability criteria, (2) meet or exceed the benzene emission rate applicability criteria, and (3) are located in a county classified as either Urban-1 or Urban-2 would be required to apply air emission controls on all process vents at those units.

The EPA also evaluated a risk-based distance applicability threshold criterion as an alternative to the urban area applicability criteria. This method (subsequently referred to as the ''risk-distance'' method) would target those area source TEG dehydration units for regulation that present a potential health risk to exposed populations. Under the risk-distance method, each area source TEG dehydration unit that may be subject to control, based on actual natural gas throughput and benzene emission rate, would have the option of conducting a site-specific risk assessment. If this site-specific risk assessment resulted in a maximum incremental lifetime cancer risk above some threshold level, then the source would be required to install controls necessary to reduce that risk to an acceptable level.

After its evaluation of applicability alternatives, the EPA rejected the risk-distance method. The risk based approach would focus solely on the protection of the most exposed individual rather than the general population. In addition, the EPA believes that the use of the urban area as an applicability criteria provides ease of implementation. This approach (1) limits the group of affected sources to a well defined urban area group, (2) minimizes the non-productive burden by exempting the non-urban area group of owners-operators and regulatory agencies from compliance assessments, and (3) provides a straightforward approach to compliance. Area sources will not need to perform analyses to determine if they are affected by the rule if they screen out based on the urban area criteria. Only those owner-operators of area source TEG dehydration units in urban areas would need to evaluate the need for control devices. By contrast, under the risk distance approach, all owner-operators would need to do an analysis. The EPA is requesting comment, along with supporting documentation, on the use of a risk-distance criteria for regulation of area source TEG dehydration units as an alternative to the urban area criteria (see section X of this preamble).

Glycol dehydration units that are required to use air emission controls would be required to connect each process vent on the glycol dehydration unit to an air emission control system that reduces HAP emissions by 95 percent or greater (or to an outlet concentration of 20 parts per million by volume (ppmv) for combustion devices). Pollution prevention measures, such as process modifications that reduce the amount of HAP emissions generated, would be allowed as an alternative, provided they achieve a HAP emission reduction, from uncontrolled levels, of 95 percent or greater.

### 3. Storage Vessel Provisions

Standards are proposed for existing and new storage vessels containing hydrocarbon liquids (other than black oil) that are located at major HAP sources. The types of storage vessels that would be regulated are those with the potential for flash emissions and that have an actual throughput of hydrocarbon liquids equal to or greater than 500 barrels per day (BPD).

Flash emissions from storage occur when a hydrocarbon liquid with a high vapor pressure flows from a pressurized vessel into a vessel with a lower pressure. Flash emissions typically occur when a hydrocarbon liquid, such as condensate, is transferred from a production separator to a storage vessel. The proposed standards for storage vessels with the potential for flash emissions would require that a storage vessel be equipped with an air emission control system if the hydrocarbon liquid in the storage vessel has a GOR equal to or greater than 50 $m^3$ (1,750 $ft^3$) per barrel or an API gravity equal to or greater than 40° (i.e., the storage vessel has a potential for flash emission losses). In addition, the storage vessel must have an actual throughput of hydrocarbon liquids equal to or greater than 500 BPD.

A storage vessel containing a hydrocarbon liquid subject to control under the proposed standards would have to be equipped with a cover vented through a closed-vent system to a control device that recovers or destroys HAP emissions with an efficiency of 95 percent or greater (or to an outlet concentration of 20 ppmv for combustion devices). The EPA has included the 20 ppmv cutoff for cases where the HAP emission concentration is already low, and meeting a 95 percent reduction in emissions cannot be achieved.

A pressurized storage vessel that is designed to operate as a closed system would be considered in compliance with the proposed requirements for storage vessels. External and internal floating roofs that meet certain design criteria would also be allowed.

### 4. Standards for Equipment Leaks

The proposed rule requires owners and operators of natural gas processing plants that are major HAP sources to control HAP emissions from leaks from each piece of equipment that contains or contacts a liquid or gas that has a total HAP concentration equal to or greater than 10 percent by weight. The proposed equipment leak standards would not apply to equipment that operates less than 300 hours per year.

For equipment subject to these standards at either an existing or new source, the owner or operator is required to implement a LDAR program and perform equipment modifications, where necessary. 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 on the Alaskan North Slope would be exempt from some of the routine LDAR monitoring requirements.

### 5. Air Emission Control Equipment Requirements

Specific performance and operating requirements are proposed for each control device installed by the owner or operator. Closed-vent systems would be required to operate with no detectable emissions. Any type of control device would be allowed that reduces the mass content of either total organic compounds (less methane and ethane) or total HAP in the gases vented to the device by 95 percent by weight or greater (or to an outlet concentration of 20 ppmv for combustion devices).

Certain specifications for covers apply based on the type of cover and where the cover is installed. Requirements are specified for vapor leak-tight covers, and external and internal floating roofs installed on storage vessels.

### 6. Test Methods and Procedures

An owner or operator must be able to demonstrate that exemption from control criteria are met when controls are not applied. For example, owners or operators of glycol dehydration units that do not install air emission controls because the benzene emission rate from the unit is less than 0.9 Mg/yr (1 tpy) must be able to demonstrate that the benzene emission rate from the unit is less than 0.9 Mg/yr (1 tpy). In general, the selected exemption criteria minimize the demonstration burden on owners and operators.

Procedures for demonstrating the HAP emission reduction efficiency of control devices and HAP concentration would be consistent with procedures established in previously promulgated

NESHAP that apply to emission sources similar to those addressed in the proposed standards. Engineering calculations, modeling (using EPA-approved models), and previous test results will generally be acceptable means of demonstrating compliance, except where such means are not conclusive. Test procedures are specified in the proposed rule for use when testing is required to demonstrate compliance.

An alternative test procedure is provided to demonstrate control efficiency for when a condenser is used for controlling emissions from a glycol dehydration unit reboiler vent. The inclusion of the alternative test procedure is appropriate in this standard because of difficulties associated with testing the inlet to a condenser in this application.

Procedures and test methods are also specified for detection of equipment leaks.

7. Monitoring and Inspection Requirements

The proposed standards would require that the owner or operator periodically inspect and monitor air emission control equipment. Visual inspections and leak detection monitoring is required for certain types of covers to ensure gaskets and seals are in good condition and for closed-vent systems to ensure all fittings remain leak-tight.

An owner or operator would also be required to visually inspect and test covers and closed-vent systems to determine and ensure that they operate with no detectable emissions.

The proposed standards would also require semi-annual inspection and leak detection monitoring of covers and annual inspection and leak detection monitoring of closed-vent systems.

The proposed standards would require continuous monitoring of control device operation through the use of automated instrumentation. The automated instrumentation would be used to measure and record control device operating parameters indicating continuous compliance with the standards.

8. Recordkeeping and Reporting Requirements

The recordkeeping and reporting requirements associated with the proposed standards would primarily be those specified in the part 63 General Provisions (40 CFR part 63, subpart A). Major sources would be subject to all of the requirements of the General Provisions with the exception that (1) owners or operators would be allowed up to one year from the effective date of the standards to submit the initial notification described in § 63.9, paragraph (b) of subpart A and (2) owners or operators are allowed to submit (a) excess emissions and continuous monitoring system (CMS) performance reports and (b) startup, shutdown, and malfunction reports semi-annually instead of quarterly. The EPA selected these specific exceptions due to the large number of facilities that would need to submit notifications or reports related to the proposed NESHAP. The EPA believes that these exceptions will not adversely affect the implementation of the proposed regulation or reduce its impact on HAP emissions.

Area sources would be subject to all of the requirements of the General Provisions with the exception that (1) owners or operators of existing area sources would be allowed up to one year from the effective date of the standards to submit the initial notification required by the General Provisions, (2) an owner or operator of an area source would not be required to develop and maintain a startup, shutdown, and malfunction plan and would only need to submit reports of malfunctions when they are not corrected within a specified time period, and (3) excess emissions and continuous monitoring reporting would be done annually, rather than as required by the General Provisions.

*B. Proposed Standards for Natural Gas Transmission and Storage for Major Sources*

The proposed standards would amend title 40, chapter I, part 63 CFR by adding a new subpart HHH—National Emission Standards for Hazardous Air Pollutants from Natural Gas Transmission and Storage Facilities. The standards would apply to owners and operators of facilities that process, upgrade, transport or store natural gas prior to delivery to a LDC or a final end user.

1. General Standards

The proposed rule would require that process vents on glycol dehydration units that are located at major HAP sources be controlled unless (1) the actual flowrate of natural gas to the glycol dehydration unit is less than 85 thousand $m^3$/day (3.0 MMSCF/D), on an annual average basis, or (2) if benzene emissions from the major source glycol dehydration unit are less than 0.9 Mg/yr (1 tpy). The proposed requirements are the same for existing and new glycol dehydration units.

Glycol dehydration units that are required to use air emission controls would be required to connect each process vent on the glycol dehydration unit to an air emission control system that reduces HAP emissions by 95 percent or more or to an outlet concentration of 20 ppmv for combustion devices. As with the proposed standards for the oil and natural gas production NESHAP, pollution prevention measures, such as process modifications that reduce the amount of HAP emissions generated, would be allowed as an alternative provided they achieve a HAP emission reduction of 95 percent or greater or to an outlet concentration of 20 ppmv for combustion devices.

The EPA had insufficient information available to determine whether (1) significant HAP-emitting storage vessels warranting control are located at natural gas transmission and storage facilities or (2) whether the same storage vessel regulatory controls being proposed for the oil and natural gas production source category should be applied to the natural gas transmission and storage source category. Therefore, the EPA is soliciting comment in this proposal (see section X) on whether the storage vessels being proposed for control under the oil and natural gas production regulation are similar to those that exist at natural gas transmission and storage facilities. The EPA is specifically requesting information on (1) the type(s) of storage vessels at natural gas transmission and storage facilities and (2) whether the existing control level of storage vessels at natural gas transmission and storage facilities is similar to the existing control level of storage vessels at oil and natural gas production facilities.

2. Air Emission Control Equipment Requirements

Specific performance and operating requirements are proposed for each control device installed by the owner or operator. Closed-vent systems would be required to operate with no detectable emissions. Any type of control device would be allowed that reduces the mass content of either total organic compounds (less methane and ethane) or total HAP in the gases vented to the device by 95 percent by weight or greater (or to an outlet concentration of 20 ppmv for combustion devices).

3. Monitoring and Inspection Requirements

The proposed monitoring and inspection requirements are (1) periodic control equipment monitoring, (2) periodic leak detection monitoring for closed-vent systems to ensure all fittings remain leak-tight, (3) semi-annual inspection and leak detection monitoring of covers, (4) annual inspection and leak detection monitoring of closed-vent systems, and (5) continuous monitoring of control device operation. Continuous monitoring would require the use of automated instrumentation that would measure and record control device compliance operating parameters.

4. Recordkeeping and Reporting Requirements

The recordkeeping and reporting requirements associated with the proposed standards would primarily be those specified in the part 63 General Provisions (40 CFR Part 63 subpart A). Major sources would be subject to all of the requirements of the General Provisions, except that (1) owners or operators would be allowed up to one year from the effective date of the standards to submit the initial notification required under § 63.9, paragraph (b) of subpart A and (2) owners or operators are allowed to submit excess emissions, CMS performance reports, and startup, shutdown, and malfunction reports semi-annually instead of quarterly. These exceptions were selected to maintain consistency between the major source provisions of these proposed regulations.

## IV. Summary of Environmental, Energy and Economic Impacts

### *A. HAP Emission Reductions*

For major sources, it is estimated by the EPA that the proposed oil and natural gas production standards for existing sources would result in a reduction of HAP emissions from 39,000 Mg/yr to 9,000 Mg/yr. In addition, HAP emissions would be reduced by 3,000 Mg/yr for new sources over the first 3 years after promulgation of these proposed standards.

For existing area source TEG dehydration units in the oil and natural gas production source category, the EPA estimates that the proposed standards would result in a reduction of HAP emissions from 19,000 Mg/yr to 16,000 Mg/yr. In addition, HAP emissions would be reduced by 330 Mg/yr for new sources over the first 3 years after promulgation of these proposed standards.

Tables 1 and 2 present the major and area source emission reductions, in addition to other environmental, energy, and cost impacts, that the EPA estimates would occur from the implementation of the proposed standards for oil and natural gas production.

The EPA estimates that the proposed natural gas transmission and storage standards for existing sources would result in a reduction of HAP emissions from 320 Mg/yr to 210 Mg/yr. No new major sources are anticipated in the first three years after promulgation of this proposed NESHAP. Table 3 presents the major source emission reductions, in addition to other environmental, energy, and cost impacts, that the EPA estimates would occur from the implementation of the proposed standards for existing natural gas transmission and storage facilities.

The air emission reductions achieved by these proposed standards, when combined with the air emission reductions achieved by other standards mandated by the Act, will accomplish the primary goal of the Act to

> * * * enhance the quality of the Nation's air resources so as to promote the public health and welfare and the productive capacity of its population.

TABLE 1.—SUMMARY OF ESTIMATED ENVIRONMENTAL, ENERGY, AND ECONOMIC IMPACTS FOR THE PROPOSED OIL AND NATURAL GAS PRODUCTION STANDARDS FOR EXISTING AND NEW MAJOR SOURCES

| Impact category | Existing | New |
|---|---|---|
| Estimated number of impacted facilities | 440 | 44 |
| Emission reductions (Mg/yr): | | |
| HAP | 30,000 | 3,000 |
| VOC | 61,000 | 6,100 |
| Methane | 7,000 | 700 |
| Secondary environmental emission increases (Mg/yr): | | |
| Sulfur oxides | <1 | <1 |
| Nitrogen oxides | 5 | <1 |
| Carbon monoxide | <1 | <1 |
| Energy (Kilowatt hours per year) | 38,000 | 3,800 |
| Implementation costs (Million of July 1993 $): | | |
| Total installed capital | 6.5 | 0.7 |
| Total annual | 4.0 | 0.4 |

TABLE 2.—SUMMARY OF ESTIMATED ENVIRONMENTAL, ENERGY, AND ECONOMIC IMPACTS FOR THE PROPOSED OIL AND NATURAL GAS PRODUCTION STANDARDS FOR EXISTING AND NEW AREA SOURCES

| Impact category | Existing | New |
|---|---|---|
| Estimated number of impacted facilities | 520 | 52 |
| Emission reductions (Mg/yr): | | |
| HAP | 3,300 | 330 |
| VOC | 7,200 | 720 |
| Methane | 1,500 | 150 |
| Secondary environmental emission increases (Mg/yr): | | |
| Sulfur oxides | <1 | <1 |
| Nitrogen oxides | 2 | <1 |
| Carbon monoxide | <1 | <1 |
| Energy (Kilowatt hours per year) | None | None |
| Implementation costs (Million of July 1993 $): | | |
| Total installed capital | 6.9 | 0.7 |
| Total annual | 6.2 | 0.6 |

TABLE 3.—SUMMARY OF ESTIMATED ENVIRONMENTAL, ENERGY, AND ECONOMIC IMPACTS FOR THE PROPOSED NATURAL GAS TRANSMISSION AND STORAGE STANDARDS FOR EXISTING MAJOR SOURCES [a]

| Impact category | Existing |
|---|---|
| Estimated number of impacted facilities | 5 |
| Emission reductions (Mg/yr): | |
| HAP | 110 |
| VOC | 1,400 |
| Methane | 54 |
| Secondary environmental emission increases (Mg/yr): | |
| Sulfur oxides | None |
| Nitrogen oxides | None |
| Carbon monoxide | None |
| Energy (Kilowatt hours per year) | None |
| Implementation costs (Thousand of July 1993 $): | |
| Total installed capital | 57 |
| Total annual | 46 |

[a] No new major sources are anticipated for this source category after the effective date for new sources and in the first three years following promulgation of the proposed rule.

*B. Secondary Environmental Impacts*

Other environmental impacts are those associated with operation of certain air emission control devices. The adverse secondary air impacts would be minimal in comparison to the primary HAP reduction benefits from the implementation of the proposed control options for major and for selected area oil and natural gas sources. The estimated national annual increase in secondary air pollutant emissions that would result from the use of a flare to comply with the proposed standards is estimated to be less than 1.0 Mg (1.1 ton) for both sulfur oxide ($SO_X$) and carbon monoxide (CO) and less than 7 Mg (8 tons) for nitrogen oxides ($NO_X$). These estimates are for both major and area oil and natural gas production sources. There are no anticipated increases in secondary air pollutant emissions from the implementation of the proposed control options for major sources at natural gas transmission and storage facilities.

The adverse water impacts anticipated from the implementation of control options for the proposed standards are expected to be minimal. The water impacts associated with the installation of a condenser system for the glycol dehydration unit reboiler vent would be minimal. This is because the condensed water collected with the hydrocarbon condensate can be directed back into the system for reprocessing with the hydrocarbon condensate or, if separated, combined with produced water for disposal by reinjection.

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

There are no adverse solid waste impacts anticipated from the implementation of the proposed standards.

*C. Energy Impacts*

Energy impacts are those energy requirements associated with the operation of emission control devices. The annual energy requirements for each vapor collection/recovery system installed to comply with the oil and natural gas production proposed standards is estimated to be 300 kilowatt hours per year (kw-hr/yr). It is estimated that approximately 125 oil and natural gas production major source facilities would install one or more of these control options. There would be no national energy demand increase from the operation of any of the control options analyzed under the proposed oil and natural gas production standards for area sources and the national energy demand increase for major sources would be an estimated 38,000 kw-hr/yr.

There would be no national energy demand increase from the operation of any of the control options analyzed under the proposed natural gas transmission and storage standards for major sources.

The proposed standards 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. Thus, the proposed standards have a positive impact associated with the recovery of non-renewable energy resources.

*D. Cost Impacts*

The estimated total capital cost to comply with the proposed rule for major sources in the oil and natural gas production source category is approximately $6.5 million. The total capital cost for area sources is estimated to be approximately $6.9 million.

The total estimated net annual cost to industry to comply with the proposed requirements for major sources in the oil and natural gas production source category is approximately $4.0 million. The total net annual cost for area source TEG dehydration units is approximately $6.2 million. 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.

The estimated total capital cost to comply with the proposed rule for major sources in the natural gas transmission and storage source category is approximately $57,000.

The total estimated net annual cost to industry to comply with the proposed requirements for major sources in the natural gas transmission and storage source category is approximately $46,000. As with the oil and natural gas production total estimated annual cost to industry, this annual cost estimate includes (1) the cost of capital, (2) operating and maintenance costs, (3) the cost of MIRR, and (4) any associated product recovery credits.

The EPA's impact analyses consider a facility's ability to handle collected vapors. Some remotely located facilities may not be able to use collected vapor for fuel or recycle it back into the process. In addition, it may not be technically feasible for some facilities to utilize the non-condensable vapor streams from condenser systems as an alternative fuel source safely. An option for these facilities is to combust these vapors by flaring.

These concerns are reflected in the analyses conducted by the EPA. In its analyses, the EPA estimated that (1) 45 percent of all impacted facilities will be able to use collected vapors from installed control options as an alternative fuel source for an on-site combustion device such as a process heater or the glycol dehydration unit firebox, (2) 45 percent will be able to recycle collected vapors from installed control options into a low pressure header system for combination with other hydrocarbon streams handled at the facility, and (3) 10 percent will direct all collected vapor to an on-site flare.

*E. Economic Impacts*

The EPA prepared an economic impact analysis that evaluates the impacts of the regulation on affected producers, consumers, and society. The economic analysis focuses on the regulatory effects on the U.S. natural gas market that is modeled as a national, perfectly competitive market for a homogenous commodity. The analysis does not include a model to assess the regulatory effects on the world crude oil market because the regulation is anticipated to affect less than 5 percent of the total U.S. crude oil production, and thus, it is unlikely to have any influence on the U.S. supply of crude oil or world crude oil prices.

The imposition of regulatory costs on the natural gas market result in negligible changes in natural gas prices, output, employment, foreign trade, and business closures. Price and output changes as a result of the regulation are less than 0.01 of one percent, which is significantly less than observed market trends. For example, between 1992 and 1993 the average change in wellhead price increased by 14 percent, while domestic production rose by 3 percent.

The total annual social cost of the regulation is $10 million for major and areas sources combined. This value accounts for the compliance cost imposed on producers, as well as market adjustments that influence the revenues to producers and consumption by end users, plus the associated deadweight loss to society of the reallocation of resources.

## V. Area Source Finding

The EPA performed an analysis to determine the potential threat of adverse effects on human health and the environment due to HAP emissions from TEG dehydration units in the oil and natural gas production source category and the feasibility and impacts of controlling these emissions. The EPA refers to this determination as an ''area source finding.'' The three primary components of an area source finding are (1) a risk assessment conducted for area source TEG dehydration units, (2) an evaluation of the technical feasibility and associated costs of air emission controls, and (3) an assessment of the economic impacts associated with installation of controls.

The EPA conducted a risk assessment for area source TEG dehydration units. The detailed risk assessment is available for review in EPA Air Docket A–94–04 and the item entry number is II–B–20.

The HAP included in the risk assessment were BTEX and n-hexane. These are the primary HAP emitted by TEG dehydration units. Toluene, ethyl benzene, and n-hexane were evaluated for potential non-cancer impacts. The predicted human exposure levels associated with the estimated emission of these HAP from area source TEG dehydration units did not meet or exceed the levels of concern when compared to the available human health reference levels. Mixed xylenes were not quantitatively analyzed since the EPA does not have an appropriate human health benchmark for assessing human xylene exposure by the inhalation pathway.

The predicted exposures associated with the estimated emission of benzene from area source triethylene glycol dehydration units result in a maximum individual risk (MIR) of $3\times10^{-4}$ and an annual cancer incidence ranging from <1 (assuming all facilities are located in rural areas) to 2 (assuming all facilities are located in urban areas). The predicted maximum individual risk from this analysis is above the EPA's historical action level range of $1\times10^{-6}$ to $1\times10^{-4}$.

The types of controls used on TEG dehydration units are able to achieve a minimum of 95 percent HAP emission reduction. In the parts of the U.S. where the vast majority of natural gas is produced and processed, condensers are typically used to reduce emissions from TEG dehydration units. Flares are also used to reduce emissions from TEG dehydration units.

Unlike flares, which destroy emissions through combustion, condensers capture emissions and allow for the recovery of hydrocarbon liquids (condensate) entrained in the emission stream, thus conserving a valuable non-renewable resource. Properly operated condensers used at TEG dehydration units, that have a flash tank in the overall dehydration system design, have a HAP/volatile organic compound (VOC) control efficiency of 95 percent.

The application of condensers and flares to area source TEG dehydration units have been observed on actual operating units that are typical of those in this industry. Thus, condensers and flares are a technically feasible and demonstrated control option for area source TEG dehydration units.

The economic impact analysis performed to evaluate the impacts of the major and area source provisions of the proposed regulation supports the area source finding. The results of this economic analysis are summarized in section IV of this preamble.

The total annual social cost of the regulation is estimated to be $10 million for major and area sources combined (approximately $4.0 million for major sources and $6.2 million for area sources). This value accounts for the compliance cost imposed on producers, as well as market adjustments that influence the revenues to producers and consumption by end-users, plus the associated deadweight loss to society of the reallocation of resources.

Regulation of area source TEG dehydration units in the oil and natural gas production source category is supported by: (1) The estimated MIR of $3\times10^{-4}$ for HAP emissions from this area source category, (2) technically feasible, effective, and demonstrated control options (condensers and flares) that are readily available for reducing emissions from area source TEG dehydration units, and (3) the results the economic impact analysis that supports the minimal economic impact associated with installation of the identified control options.

The EPA is proposing criteria that would target area source TEG dehydration units for control: (1) Which have benzene emissions, (2) that can be cost-effectively controlled, and (3) where potential human exposures are greatest. These criteria are based on actual natural gas throughput, benzene emission rate, and location in a county classified as urban.

The actual natural gas throughput (on an annual average basis) action levels for area source TEG dehydration units analyzed by the EPA were: (1) 113 thousand $m^3$/day (4.0 MMSCF/D) or greater, (2) 85 thousand $m^3$/day (3.0 MMSCF/D) or greater, (3) 42 thousand $m^3$/day (1.5 MMSCF/D) or greater, and (4) 8.5 thousand $m^3$/day (0.3 MMSCF/D) or greater. Based on its evaluation of projected impacts and the cost-effectiveness of installed controls, the EPA selected 85 thousand $m^3$/day (3.0 MMSCF/D) actual natural gas throughput as an action level for area source TEG dehydration units.

The EPA also selected an action level for area sources based on actual benzene emissions from each area source TEG dehydration unit. Benzene is a known human carcinogen that is typically emitted from glycol dehydration units.

In addition, the EPA selected location as a criterion for control based on the county-level urban versus rural location of area source TEG dehydration units. Only those area source TEG dehydration units located in counties classified as urban (see section III of this preamble) and also meeting or exceeding the actual natural gas throughput and benzene emission rate action levels would be required to install air emission controls for HAP under the proposed rule.

## VI. Glycol Dehydration Unit Nationwide HAP Emissions Estimates

Glycol dehydration units are estimated to account for up to 90 percent of HAP emissions from the oil and natural gas industry. The EPA used GRI-GLYCalc™ Version 3.0, an emissions estimation computer program developed by GRI, to estimate HAP emissions from glycol dehydration units. This program is regarded within industry and the EPA as an accurate simulation tool for estimating emissions of organic compounds from glycol dehydration units.

The EPA developed HAP, VOC, and methane emission estimates for a series of representative model glycol dehydration units representative of those that operate within this industry. Nationwide emissions were then estimated by extrapolating from model glycol dehydration unit estimates.

Two inputs to the methodology used by the EPA to estimate nationwide HAP emissions from glycol dehydration units that greatly influence the result are: (1) The average HAP concentration of field natural gas prior to the first processing stage, and (2) the average total number of times that natural gas is dehydrated by all dehydration methods between the wellhead and the end user. Based on extensive discussions with industry, and review of available information and application of engineering judgment, the EPA selected a value of 200 ppmv for the average BTEX concentration of field natural gas and a value of 1.6 for the average number of times that natural gas is dehydrated by all dehydration methods between the wellhead and the end user. Estimated HAP emissions from all glycol dehydration units (at both major and area sources of HAP) are 55,000 Mg/yr.

The EPA acknowledges that there are uncertainties inherent in any estimate of nationwide HAP emissions for industries as large and as diverse as the oil and natural gas production or natural gas transmission and storage source categories. However, the EPA believes that the engineering judgments and methodology used in developing the nationwide HAP emissions estimates for these industries are reasonable given the available information. The EPA requests comment on the methodology and engineering judgments made when developing the nationwide glycol dehydration unit HAP emissions estimates for these source categories. The EPA specifically requests alternative emission estimation methodologies, supported by documentation demonstrating how an alternative methodology would yield improved estimates.

## VII. Definition of Major Source for the Oil and Natural Gas Industry

### *A. Definition of ''Associated Equipment''*

Whether a facility is a major source or an area source of HAP emissions under section 112 of the Act is important for two reasons. First, different requirements may be established for major and area sources. Second, a source that is a major source under section 112 of the Act is also subject to requirements for major sources under the Federal operating permit program authorized by title V of the Act. Area sources may also be subject to title V permitting requirements, but the EPA has discretion to defer or waive these requirements.

For some oil and natural gas operations, it is clearly apparent what constitutes a facility (e.g., a natural gas processing plant). For others, however, it may not be clear what constitutes a facility. This is particularly true for field operations in the oil and natural gas production source category.

An oil or natural gas production field, for example, may cover many square miles. Within this area, there can be a large number of production wells, connected by pipeline, to small (satellite) or larger (centralized) locations, such as tank batteries, where storage or intermediate processing occurs prior to transmission to further processing steps. Leasing and mineral rights agreements can give oil and natural gas companies control over a large area of contiguous property.

According to the statutory definition in section 112(a)(1), HAP emissions from all emissions points within a contiguous area and under common control must be counted in a major source determination. A strict interpretation of the statutory definition of major source as applied to this industry could mean that HAP emissions must be aggregated from emission points separated by considerable distances. This distance could be well beyond the distances that separate equipment at a typical facility.

The Congress addressed the unique aspects of the oil and natural gas production industry in special provisions included in section 112(n)(4) of the Act that apply to HAP emissions from oil and natural gas wells and pipeline and compressor facilities. Section 112(n)(4)(A) states

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

The language in section 112(n)(4)(A) makes it clear that, for the purpose of implementing standards for major sources under section 112(d) for this industry, HAP emissions from oil and natural gas exploration and production wells with their associated equipment cannot be aggregated in making major source determinations.

However, the statutory language provides no definition of ''associated equipment.'' Neither is a clear intent evident in the legislative history of the Act's 1990 amendments. The legislative history does indicate that the Congress, in drafting section 112(n)(4), believed that wells and their associated equipment generally: (1) Have low HAP emissions, and (2) are typically located in widely dispersed geographic areas, rather than concentrated in a single area.

A definition of associated equipment is important to implementing standards for this industry for two reasons. First, because the statute prevents the aggregation of HAP emissions from wells and their associated equipment in making major source determinations, the definition of associated equipment can influence which sources are subject to requirements for major sources and which are subject to requirements for area sources. Second, the definition of associated equipment affects the regulation of area sources in the oil and natural gas source category. Section 112(n)(4)(B) states

The Administrator shall not list oil and gas production wells (with its associated equipment) as an area source under subsection (c), except that the Administrator may establish an area source category for oil and gas production wells located in any metropolitan statistical area with a population in excess of 1 million, if the Administrator determines that emissions of hazardous air pollutants from such wells present more than a negligible risk of adverse effects to public health.

Thus, production wells (with their associated equipment) may not be regulated as an area source, but production wells as an individual area source may be regulated by the Administrator under section 112(n)(4)(B) upon an adverse risk determination.

In the absence of clear guidance in the statute, the EPA considered options for defining associated equipment. In extensive discussions with industry and trade association representatives, the EPA evaluated a wide range of options.

One option considered was a definition based on a narrow interpretation of associated equipment that would include only limited equipment in close proximity to a well as associated with that well. Another option considered was a definition based on a broad interpretation of associated equipment that would extend the inclusion of equipment far beyond the well as associated equipment. The initial options considered by the EPA for defining associated equipment and the EPA's assessment of each are discussed below.

The narrowest interpretation option would be that a well and its associated equipment consists of only the well, defined as all equipment below the ground surface, and the pressure maintenance and flow control device attached to the well. For an exploratory well, the typical pressure maintenance and flow control device is the blow out preventer (BOP). For a production well, the typical pressure maintenance and flow control device is referred to as the ''Christmas tree,'' which may include a BOP. This interpretation would provide a technical meaning to the term associated equipment, but would provide limited substantive meaning.

As a practical matter, the term ''well with its associated equipment'' under this option would not provide any additional relief to industry from the aggregation of HAP emissions in a major source determination beyond what would have been provided if Congress had only used the term ''well'' in section 112(n)(4) of the Act. On this basis, the EPA did not select this narrow interpretation for proposal.

An option initially suggested by industry is that all production equipment be considered associated equipment. This is the broadest possible interpretation of the term associated equipment and would extend the definition to the boundaries of the source category, which are (1) to the point of custody transfer for hydrocarbon liquids and (2) to the natural gas transmission and storage source category for natural gas. Under this interpretation, industry maintains that no aggregation of HAP emissions should be allowed, even in situations commonly acknowledged to be a single facility. Only individual emission points which, by themselves, emit 10 tpy or more of any one HAP or 25 tpy or more of any combination of HAP would be regulated as major sources under this interpretation.

The EPA rejects this broad interpretation as an option for defining associated equipment for several reasons. First, an interpretation of the language in section 112(n)(4) that would define all equipment as associated with a well, regardless of (1) the type of equipment, (2) any processing or commingling of streams that may occur, or (3) distance from the well, would suggest that the Congress intended that aggregation of HAP emissions not be allowed within this industry under any circumstances. When viewed within the framework of section 112, the EPA does not believe this to be the case.

For example, a natural gas processing plant has numerous HAP emission points closely grouped together. These points may include one or more glycol dehydration units, condensate storage vessels, several gas treatment and separation steps, and various containers. These HAP emission points may emit, in total, HAP in excess of 25 tpy. Each HAP emission point within the natural gas processing plant, however, may emit less than 10 tpy of any one HAP or 25 tpy of any combination of HAP.

If all equipment within the plant were defined as associated equipment, then the plant would not be considered a major source subject to MACT standards. It is, therefore, conceivable that the natural gas processing plant that meets the criteria of a major source could go unregulated by MACT standards under this scenario, even though surrounding populations were exposed to HAP emissions at a level that would trigger the application of MACT standards in other similar industries.

In addition, this option would include (as associated equipment) HAP emission points that the EPA has determined are large individual sources of HAP. In particular, available information indicates that glycol dehydration units and storage vessels emit substantial quantities of HAP.

Glycol dehydration units are the largest identified HAP emission point in the oil and natural gas production source category, accounting for about 90 percent of estimated total HAP emissions from this source category based on available information used in the EPA's analysis. Individually, glycol dehydration units may emit total HAP in amounts from less than 0.9 Mg/yr to substantially above major source levels.

Also, a single storage vessel with flash emissions may emit several megagrams of HAP per year.

The EPA firmly believes that glycol dehydration units and storage vessels with flash emissions are not the type of small HAP emission points that Congress intended to be included in the definition of associated equipment. Further, as previously discussed in section V of this preamble, the EPA has made an area source finding that benzene emissions from TEG dehydration units pose a significant risk to public health.

The EPA does not intend to regulate TEG dehydration units that emit small amounts of HAP. However, the EPA has an obligation to provide public health protection where there is risk from exposure to HAP emissions. If TEG dehydration units were included as associated equipment, the EPA's ability to provide protection to persons at risk from exposure would be severely limited through section 112(n)(4)(B).

For all the reasons set out above, defining all equipment as associated equipment was rejected as an option for proposal by the EPA. However, the EPA believes that the use of custody transfer within an interpretation (along with other criteria) is a good method for delineating between equipment that is associated and not associated with a well.

A variety of interpretations of associated equipment intermediate of those two extremes are also possible. Through discussions with industry and trade association representatives, the EPA considered several intermediate options based on drawing a line of demarcation downstream from the well. Equipment before this line of demarcation would be deemed to be associated with a well and equipment beyond the line would not be considered associated. The point in the processing of oil or natural gas at which such a line of demarcation could be drawn might be tied to where a certain product processing or transfer step takes place.

Three intermediate options, using this approach, define associated equipment as including all equipment up to (1) the point where initial processing of an extracted hydrocarbon stream takes place, (2) the point of physical commingling of the extracted hydrocarbon stream with streams from other wells, and (3) the point of custody transfer, with exceptions for selected affected sources.

The EPA evaluated each of these options with several objectives in mind. First, the option chosen should provide substantive meaning to the term associated equipment and prevent the aggregation of small, scattered HAP emission points in major source determinations. Second, the option chosen should be easily implementable. That is, it should be clear to the regulated community and enforcement personnel what is associated equipment and what is not associated equipment. Finally, the option chosen should not preclude the aggregation of the most significant HAP emission points in the source category. Additionally, the option chosen should not restrict the EPA's ability to regulate glycol dehydration units as area sources.

An option tied to the point of initial processing would meet only the last of these objectives. Initial processing for many extracted hydrocarbon liquid and natural gas streams occurs immediately after the stream has left the well. Typical processing steps that may occur at a well site include gas/oil separation, heating/treating, and dehydration. The only equipment in addition to the Christmas tree that would be included as associated equipment under this option would be storage vessels in which no treating or separation takes place.

Thus, little additional relief from HAP emission aggregation would be provided by an associated equipment definition based on initial processing. Also, the term ''point of initial processing'' is not a term commonly used and understood in the source category, a fact that would likely lead to confusion between enforcement agencies and the regulated community.

Selecting an option based on the point of physical commingling of streams would provide additional substantive meaning to the term associated equipment and possible relief from HAP emission aggregation in situations where a stream from a single well undergoes processing prior to mixing with streams from other wells (the storage vessels and processing equipment would be associated with that well). However, the EPA sees great potential for confusion under this option, as the same equipment that would be considered associated equipment at a single well facility might not be associated equipment where streams from multiple wells are combined prior to processing.

Another option is the use of the point of custody transfer in combination with allowing HAP emission aggregation for selected affected sources. For the proposed production regulation, the EPA defines custody transfer (which has been previously defined in other standards) as transfer, after processing and/or treatment in the producing operations, from storage vessels or automatic transfer facilities to pipelines or any other forms of transportation. The EPA considers the point at which natural gas enters a natural gas processing plant as a point of custody transfer for the proposed regulation.

From an implementation perspective, this is an attractive option. According to industry and trade association representatives, the term custody transfer is commonly used and understood within the oil and natural gas production source category. Selecting this option would simplify the owner or operator's regulatory compliance determination for a specified piece of equipment. The point of custody transfer often denotes contractually the point of change in ownership of equipment or product. Therefore, defining associated equipment as all equipment up to the point of custody transfer is a good approach for delineating a line of demarcation between equipment that is associated and equipment that is not associated. This approach is the same as the broadest interpretation of associated equipment as initially proposed by industry, however, selected affected sources are not included as associated equipment.

Glycol dehydration units and storage vessels with flash emissions are often located before the point of custody transfer. Many glycol dehydration units, for example, are located on single wells or at condensate tank batteries. As discussed previously, the EPA feels strongly that because glycol dehydration units and storage vessels with flash emissions are significant sources of HAP emissions, they are not the HAP emission points intended by Congress to be associated equipment under section 112(n)(4).

Therefore, the EPA is proposing that associated equipment be defined as all equipment associated with a production well up to the point of custody transfer, except that glycol dehydration units and storage vessels with flash emissions would not be associated equipment. The EPA believes that this proposed definition will provide the relief that Congress intended in section 112(n)(4) while preserving the EPA's ability to require appropriate MACT or GACT controls for the most significant identified HAP emission points in the oil and natural gas production source category. The EPA considers the point at which natural gas enters a natural gas processing plant as a point of custody transfer for natural gas streams and HAP emission aggregation is allowed at natural gas processing plants. Natural gas processing plants are included in the scope of the oil and natural gas production NESHAP.

*B. Definition of Facility*

As discussed in the previous section, it is not clear for many oil and gas field operations what constitutes a facility and, consequently, exactly where facility boundaries exist for the purpose of a major source determination. With many operations connected by pipeline and located on common oil and gas leases that extend for miles, the meaning of the phrase, ''located within a contiguous area under common control,'' used in section 112(a)(1) of the Act to describe sources that should be grouped in a major source determination, is not often clear when applied to oil and natural gas field operations. Relief from the possible need to aggregate emissions from certain small, widely dispersed, HAP emission sources is provided in the language of section 112(n)(4), and in the EPA's proposed definition of associated equipment. However, potential for confusion still exists concerning when non-associated equipment should be aggregated. Thus, the EPA is proposing further clarification of what constitutes a facility for the purposes of major source determinations in the oil and natural gas production and natural gas transmission and storage source categories.

The EPA's objective in developing a definition of facility for this proposed rulemaking is to identify criteria that would define a grouping of emission points that meet the intent of the section 112(a)(1) language, ''located within a contiguous area and under common control,'' but in terms that are meaningful and easily understood within the regulated industries. Examples of general facility types in the oil and natural gas production source category include natural gas processing plants, offshore production platforms, central tank batteries, satellite tank batteries, and individual well sites. Compressor stations and underground storage facilities are examples of facilities in the natural gas transmission and storage source category.

Though some facilities in the oil and natural gas production source category, such as natural gas processing plants, fit the profile of a typical industrial facility and are easy to define, other facilities (e.g., production field facilities) do not fit the typical profile. Substantial differences exist between the majority of typical oil and natural production field operations and traditional industrial facilities that are regulated under the Act. Industrial facilities typically have distinct physical boundaries or fencelines. Emission points at these facilities are generally in close proximity to or collocated with one another (contiguous) and located within an area boundary, the entirety of which (other than roads, railroads, etc.) is under the physical control of the same owner (common ownership).

Typical oil and natural gas production field facilities do not adhere to this profile. The owners or operators of production field facilities typically do not own or control the surface property that lies between two or more production field facilities. Rather, the owners or operators of production field facilities control only the surface area that is necessary to operate the physical structures used in oil and natural gas production. Production facilities may be connected by underground flow or gathering lines but are essentially separate independent facilities. Production equipment sharing the same close physical location (e.g., a well site, tank battery, or graded pad) is likely to be under common control and in a contiguous area. However, production equipment that is physically separated within or across leases (to serve different wells and connected by flow or gathering lines) is not contiguous based on surface rights and is not likely to be under common control.

The EPA intends that a facility definition as it applies to the oil and natural gas production source category should lead to an aggregation of emissions in a major source determination that is reasonable, consistent with the intent of the Act, and easily implementable. In this source category, functionally related equipment is generally located at what is referred to as the same surface site. Surface site means the graded pad, gravel pad, foundation, platform, or immediate physical location on which equipment is located. Defining facility based on individual surface site would, in the EPA's view, identify groupings of equipment on which major source determinations would be made that are consistent with the EPA's intent. For example, a definition on this basis would require aggregation of emissions from significant HAP emission sources that are closely grouped, such as two or more glycol dehydration units on the same graded pad treating a natural gas stream. Glycol dehydration units located on different graded pads, for example at separate tank batteries, would presumably not be functionally related (i.e., the units treat different streams) and in most cases would be separated by considerable distance. Consequently, the EPA does not believe it would be reasonable to combine emissions from these units. Finally, because the term surface site is well understood within industry and easily recognizable by enforcement authorities, a facility definition on this basis should be easily implementable. For these reasons, the EPA is proposing a facility definition based on individual surface site. For further clarification, the EPA is also proposing that equipment located on different oil and gas properties (oil and gas lease, mineral fee tract, subsurface unit area, surface fee tract, or surface lease track) shall not be aggregated.

Another objective of the EPA in developing a definition of facility was to minimize, where possible and reasonable, the burden on owners and operators in making a major source determination. The EPA's evaluation of HAP emission sources in production field operations indicates that the two primary HAP emission points at field operation facilities are glycol dehydration units and storage tanks with flash emissions, and that other potential HAP emission points at these facilities (e.g., equipment leaks) will be inconsequential to the determination of a facility's major source status. Therefore, the EPA is proposing that for the purpose of a major source determination, a production field facility would be limited to glycol dehydration units and storage tanks with flash emission potential. The EPA believes that by eliminating the need to quantify HAP emissions from small sources at such facilities, the burden on an owner or operator to make a major source determination would be greatly reduced, while still ensuring an accurate classification of the facility as a major or area source of HAP emissions.

The EPA specifically requests comments on the proposed definition of facility. Specifically the EPA requests comments on whether the proposed definition appropriately implements the intent of the major source definition in section 112(a)(1) for the oil and natural gas production and natural gas transmission and storage source categories, or if another definition would better implement this intent.

## VIII. Rationale for Proposed Standards

### *A. Selection of Hazardous Air Pollutants for Control*

The EPA believes that it is not appropriate to select all organic HAP listed under section 112(b) of the Act for regulation under the proposed NESHAP. Of the 188 compounds listed, only a limited number are emitted from oil and natural gas facilities. Consequently, the EPA developed a list of the specific HAP to be regulated in the proposed rules. However, all 188 listed HAP must be considered in any major source determination under the General Provisions to 40 CFR Part 63.

To select which HAP are to be regulated under the proposed NESHAP, the EPA evaluated the potential for HAP to be emitted from oil and natural gas facilities. Based on this evaluation, the EPA is proposing that the following specific HAP be regulated under the proposed NESHAP: acetaldehyde, benzene (including benzene in gasoline), carbon disulfide, carbonyl sulfide, ethyl benzene, ethylene glycol, formaldehyde, n-hexane, naphthalene, toluene, 2,2,4-trimethylpentane (iso-octane), and mixed xylenes, including o-xylene, m-xylene, and p-xylene.

The EPA decided to develop a set of control options for this industry to control HAP emissions as a class rather than developing a series of control options to control emissions of each individual HAP on the list. Consequently, the control options considered are directed towards the control of total HAP emissions.

### *B. Selection of Emission Points*

The EPA identified the primary types of HAP emission points at oil and natural gas facilities. The three primary HAP emission point types are (1) process vents, (2) storage vessels, and (3) equipment leaks.

The primary process vent HAP emission point is the glycol dehydration unit reboiler vent. A glycol dehydration unit reboiler regenerates glycol used in the dehydration of natural gas by separating the water from the glycol. The glycol also attracts aromatic compounds, including BTEX and n-hexane during the dehydration process. These HAP, along with the water vapor and other gases, are emitted through the glycol dehydration unit reboiler vent.

In addition, glycol dehydration units may incorporate the use of a gas condensate glycol separator (GCG separator or flash tank). The rich glycol, which has absorbed water vapor from the natural gas stream, leaves the bottom of the absorption column of a glycol dehydration unit and is directed either to (1) GCG separator (flash tank) and then a reboiler or (2) directly to a reboiler where the water is boiled off the rich glycol. If the system includes a GCG separator (flash tank), the gas separated from the rich glycol is typically (1) recycled to the header system, (2) used for fuel, or (3) used as a stripping gas. The GCG separator (flash tank) vent is a potential HAP emission point if vented to the atmosphere.

Other potential HAP emission point process vents are the tail gas streams from amine treating processes and sulfur recovery units. Limited data have been identified that indicate the potential for HAP emissions from these operations. Thus, HAP emissions from amine treating processes and sulfur recovery units have not been estimated. Recent research published by GRI indicates that these emission points have the potential to be significant sources of HAP emissions. Comment is requested on potential HAP emissions and emission rates from these operations and potential applicable air emission controls.

Storage vessels have also been identified as a HAP emission point. Storage vessels used in the oil and natural gas industry include storage vessels with flash emissions. Storage vessels in the oil and natural gas production source category are commonly equipped with fixed roofs. Emissions from fixed-roof storage vessels with flash emissions are a result of breathing, working, and (primarily) flash losses.

Pipeline pigging and storage of pipeline pigging wastes is a potential HAP emission point in the transmission sector of the oil and natural gas industry. Only limited qualitative data have been identified that indicate the potential for HAP emissions from this operation. Thus, HAP emissions have not been estimated. Comment is requested on potential HAP emissions from storage of pipeline pigging wastes and potential applicable emission controls.

Valves, pump seals, and other pieces of equipment servicing HAP-containing streams have the potential to leak. A majority of facilities in the oil and natural gas industry do not have LDAR programs. Therefore, equipment leaks from that equipment servicing HAP-containing streams have been identified as a potential HAP emission point.

In addition to the above HAP emission points, the EPA evaluated the potential regulation of other HAP emission points. These included (1) containers, (2) equipment leaks at tank batteries and offshore production platforms, (3) production surface impoundments, and (4) waste and wastewater management units.

Insufficient data were submitted in the Air Emissions Survey Questionnaire responses for the other potential HAP emission points of containers, equipment leaks at tank batteries and offshore production platforms, production surface impoundments, and waste and wastewater management units to allow for determination of existing control levels. Thus, a review of other data sources was conducted to identify information on existing control levels for these potential HAP emission points.

For these other HAP emission points, the review of available information did not indicate any apparent pattern of existing emission controls. Thus, it has been determined that the existing level of control for this collection of other HAP emission points is no control.

*C. Definition of Affected Source*

The term affected source is used in part 63 regulations to designate the emission sources or group of sources that are regulated by a standard. Each standard must define what the affected source is for purposes of that specific standard.

The EPA has discretion to establish a narrow or broad definition of affected source, as appropriate for a particular rule. A broad definition would be in terms of groups of equipment. A narrow definition would designate specific pieces of equipment or emission points as separate affected sources.

For the proposed oil and natural gas production and natural gas transmission and storage NESHAPs, a narrow definition of affected source is proposed for most HAP emission points. The affected sources under the oil and natural gas production NESHAP include (1) each glycol dehydration unit located at a major source of HAP, (2) each TEG dehydration unit located at an area source of HAP, and (3) each storage vessel with flash emissions located at a major source of HAP.

For the proposed standards for equipment leaks at natural gas processing plants, the EPA is proposing a broad definition of affected source. Specifically, the group of equipment targeted by fugitive emission standards (pumps, pressure relief devices, valves, flanges, etc. that operate in organic HAP service) are designated as one affected source, except that compressors would each be a separate affected source. The implication of this broader definition is that the replacement of an individual component, such as a valve, would not be considered the construction of a new affected source, which triggers reporting requirements for new sources.

The affected source under the natural gas transmission and storage NESHAP is each glycol dehydration unit located at a major source of HAP.

*D. Determination of MACT Floor*

As described in this preamble, the Act defines a minimum level of control for standards established under section 112(d), referred to as the MACT floor. For a source category with 30 or more sources, such as with the oil and natural gas production and natural gas transmission and storage source categories, the MACT floor for existing sources shall not be less stringent than the average emission limitation achieved in practice by the best performing 12 percent of existing sources. Standards more stringent than the floor may be established based on a consideration of cost, environmental, energy, and other impacts.

The EPA is to establish standards based on available information. Available information for the MACT floor analysis for these source categories consists primarily of data gathered from industry responses to survey questionnaires. The surveys were designed to collect information representative of processes and operations in these source categories.

1. MACT Floor for Existing Sources

*Oil and Natural Gas Production-Glycol Dehydration Unit Vents; Natural Gas Transmission and Storage-Glycol Dehydration Unit Vents.* The MACT floor for all process vents at glycol dehydration units (including area source TEG dehydration units in the oil and natural gas production source category) is 95 percent HAP emission reduction, which correlates with the existing control level estimated to be achieved through the use of condensers.

*Oil and Natural Gas Production-Storage Vessels.* The MACT floor for existing storage vessels containing material with a GOR equal to or greater than 50 $m^3$ (1,750 $ft^3$) per barrel or an API gravity equal to or greater than 40° and an actual throughput equal to or greater than 500 BPD (i.e., storage vessel with flash emissions) is the installation and operation of a cover that is connected through a closed-vent system to a 95 percent efficient control device. A pressurized storage vessel that is designed to operate as a closed system is considered in compliance with the requirements for storage vessels.

*Oil and Natural Gas Production-Equipment Leaks.* The MACT floor levels for equipment leaks apply only to those components at natural gas processing plants handling material with a total HAP content equal to or greater than 10 percent by weight.

The MACT floor for equipment leaks at natural gas processing plants is judged to be at the new source performance standard (NSPS) level of control for natural gas processing plants. The NSPS level of control is equal to that of 40 CFR part 61, subpart V (equipment leaks NESHAP). Since the pollutants targeted for control under the proposed standards are HAP, the proposed standards cross-reference the requirements from the equipment leaks NESHAP.

The proposed standards require monthly monitoring of equipment with a leak definition of 10,000 ppmv VOC. Based on the component counts and other characteristics of the model natural gas processing plants, it is estimated that the NESHAP LDAR program would attain a 70 percent HAP emission reduction from uncontrolled cases. The proposed standards allow existing natural gas processing plants subject to the NSPS to comply only with those requirements.

2. MACT Floor for New Sources

In the review of available information, the EPA did not identify a method of control applicable to all types of new sources that would achieve a greater level of HAP emission reduction than the MACT floor for existing sources. Therefore, the MACT floor for new sources in the oil and natural gas production and natural gas transmission and storage source categories is the same as the MACT floor for existing sources.

*E. Oil and Natural Gas Production NESHAP-Regulatory Alternatives for Existing and New Major Sources*

The EPA evaluated two regulatory alternatives for existing and new major sources in the oil and natural gas production source category. The first regulatory alternative is the MACT floor levels for the identified HAP emission points. A second regulatory alternative was evaluated that included the installation of combustion control systems for process vents and storage tanks at all impacted major sources. Combustion systems typically have a control efficiency of 98 percent, or greater, as compared with the control systems in Regulatory Alternative 1, which achieve an emission reduction efficiency of 95 percent.

Regulatory Alternative 1 (MACT floor) would achieve a nationwide decrease in HAP emissions from all HAP emission points at major sources of approximately 77 percent. In the EPA's judgement, the costs (and the associated cost-effectiveness) of going beyond the floor would be greatly disproportional to the additional HAP emission reduction that would be achieved. The costs and average and incremental cost-effectiveness of the two regulatory alternatives are presented in Table 4. Based on this and other information, the EPA selected Regulatory Alternative 1 (MACT floor) as the basis for the proposed standards. In addition, the EPA did not select Regulatory Alternative 2 since the control options evaluated (combustion systems) involved the destruction of a recoverable non-renewable resource and did not encourage the application of pollution prevention techniques.

TABLE 4.—COMPARISON OF REGULATORY ALTERNATIVE COST IMPACTS FOR THE PROPOSED OIL AND NATURAL GAS PRODUCTION STANDARDS—MAJOR SOURCE PROVISIONS

| Cost category | Regulatory alternative | |
|---|---|---|
| | 1 (MACT floor) | 2 |
| Implementation costs (Million of July 1993 $): | | |
| Total installed capital | 6.5 | 18 |
| Total annual | 4.0 | 23 |
| Cost-effectiveness ($/Megagram HAP): | | |
| Average | 130 | 740 |
| Incremental | .......................... | 19,000 |

These standards would impact those glycol dehydration units, at major sources, with an actual natural gas throughput equal to or greater than 85 thousand $m^3$/day (3.0 MMSCF/D), on an annual average basis, unless it is demonstrated that benzene emissions from the unit were less than 0.9 Mg/yr (1 tpy).

*F. Oil and Natural Gas Production NESHAP-Regulatory Alternatives for Existing and New Area Sources*

The EPA evaluated four regulatory alternatives for TEG dehydration units at existing and new area sources at oil and natural gas production sources. Each regulatory alternative is characterized in terms of an action level, above which HAP emissions must be controlled. The action levels considered are expressed as the actual annual average flow rate of natural gas (in thousand $m^3$/day (MMSCF/D)) to the TEG dehydration unit. The action levels for the regulatory alternatives are (1) 113 thousand $m^3$/day (4.0 MMSCF/D) or greater, (2) 85 thousand $m^3$/day (3.0 MMSCF/D) or greater, (3) 42 thousand $m^3$/day (1.5 MMSCF/D) or greater, and (4) 8.5 thousand $m^3$/day (0.3 MMSCF/D) or greater.

Based on an evaluation of the projected action level impacts and costs-effectiveness, the EPA selected Regulatory Alternative 2 as representative of GACT for TEG dehydration units at area sources of HAP. Alternative 2 would impact those TEG dehydration units with an actual natural gas throughput equal to or greater than 85 thousand $m^3$/day (3.0 MMSCF/D), on an annual average basis, unless it is demonstrated that benzene emissions from the unit were less than 0.9 Mg/yr (1 tpy).

It is the objective of the EPA to structure the rules for area sources in a way that protects exposed populations. The EPA also needs to minimize the cost to industry to control units where there would be less human exposure and overall cancer incidence from exposure to HAP emissions from area source TEG dehydration units.

Therefore, the EPA is proposing a criterion that no unit would have to be controlled if it is demonstrated that emissions of benzene from the unit are less than 0.9 Mg/yr (1 tpy), either uncontrolled or with controls in place under federally enforceable limits. As noted previously, benzene is a known human carcinogen that is typically emitted from TEG dehydration units.

The EPA is also proposing the use of a population-based action level in conjunction with the actual natural gas throughput and benzene emission rate action levels for area source TEG dehydration units. The EPA selected an action level based on the county-level urban versus rural location of area source TEG dehydration units. Only those selected area source TEG dehydration units located in counties classified as urban (see section III of this preamble) and also meeting or exceeding the actual natural gas throughput and benzene emission rate action levels will be required to install air emission controls on all process vents.

*G. Natural Gas and Transmission NESHAP-Regulatory Alternatives for Existing and New Major Sources*

The EPA evaluated two regulatory alternatives for existing and new major sources in the natural gas transmission and storage source category. The first regulatory alternative is the MACT floor level for all process vents at glycol dehydration units. A second regulatory alternative was evaluated that included the installation of combustion control systems for process vents at all impacted major sources. Combustion systems typically have a control efficiency of 98 percent, or greater, as compared with the control systems in Regulatory Alternative 1 which achieve an emission reduction efficiency of 95 percent.

Regulatory Alternative 1 (MACT floor) would achieve a nationwide decrease in HAP emissions from major sources of approximately 95 percent. The costs and the associated cost-effectiveness of going beyond the floor would be greatly disproportional to the additional HAP emission reduction that would be achieved. The costs and average and incremental cost-effectiveness of the two regulatory alternatives are presented in Table 5. Based on this and other information, the EPA selected Regulatory Alternative 1 (MACT floor) as the basis for the proposed standards. In addition, the EPA did not select Regulatory Alternative 2 since the control options evaluated (combustion systems) involved the destruction of a recoverable non-renewable resource and did not encourage the application of pollution prevention techniques.

TABLE 5.—COMPARISON OF REGULATORY ALTERNATIVE COST IMPACTS FOR THE PROPOSED NATURAL GAS TRANSMISSION AND STORAGE STANDARDS

| Cost category | Regulatory alternative | |
|---|---|---|
| | 1 (MACT floor) | 2 |
| Implementation costs (Thousand of July 1993 $): | | |
| Total installed capital | 57 | 230 |
| Total annual | 46 | 250 |
| Cost-effectiveness ($/Megagram HAP): | | |
| Average | 420 | 2,100 |
| Incremental | ........................ | 20,000 |

*H. Selection of Format*

Section 112(d) of the Act requires that emission standards for control of HAP be prescribed unless, in the judgement of the Administrator, it is not feasible to prescribe or enforce emission standards. Section 112(h) identifies two conditions under which it is not considered feasible to prescribe or enforce emission standards. These conditions include (1) if the HAP cannot be emitted through a conveyance device or (2) if the application of measurement methodology to a particular class of sources is not practicable due to technological or economic limitations. If emission standards are not feasible to prescribe or enforce, then the Administrator may instead promulgate equipment, work practice, design or operational standards, or a combination thereof.

Formats for emission standards include (1) percent reduction, (2) concentration limits, or (3) a mass emission limit. For the proposed NESHAPs, standards solely expressed as a percent, concentration, or mass emission reduction would not alone appropriately reflect the technologies on which the proposed standards are based and ensure that the intended emissions reductions are achieved. Therefore, the proposed standards are a combination of (1) emission standards and (2) equipment, design, work practice, and operational standards.

The format chosen for glycol dehydration unit (including area source TEG dehydration units subject to the proposed oil and natural gas production NESHAP) process vent streams is a HAP weight-percent reduction requirement that applies to the control device. A weight-percent reduction format is appropriate for streams with HAP concentrations above 1,000 ppmv because such a format ensures the 95 percent control level requirement. The format for the proposed storage vessel provisions is a combination of a weight-percent reduction and inspection, repair, and work practice requirements. The inspection, repair, and work practice requirements are necessary to ensure the proper operation and integrity of control equipment.

For equipment leak sources, such as pumps and valves, the EPA has previously determined that it is not feasible to prescribe or enforce emission standards. Except for those items of equipment for which standards can be set at a specific concentration. The only method of measuring emissions is total enclosure of individual items of equipment, collection of emissions for a specified time period, and measurement of the emissions. This procedure, known as bagging, is a time-consuming and prohibitively expensive technique considering the great number of individual items of equipment in a typical process unit.

The proposed standards for equipment leaks at natural gas processing plants incorporate several formats, including equipment, design, base performance levels, work practices, and operational practices. The proposed formats are the same as for the natural gas processing plant (on-shore) NSPS and the 40 CFR part 61, subpart V equipment leaks (fugitive emissions) NESHAP.

*I. Selection of Test Methods and Procedures*

Test methods and procedures specified in the proposed standards would be used to demonstrate compliance. Procedures and methods included in the proposed standards are, where appropriate, based on procedures and methods previously developed by the EPA for use in implementing standards for sources similar to those being proposed for regulation. Methods and procedures are included to determine the following (1) no detectable emissions, (2) volatile organic HAP (VOHAP) concentration, (3) control device performance (i.e., control-efficiency), and (4) annual average flow rate of field natural gas to a glycol dehydration unit.

### *J. Selection of Monitoring and Inspection Requirements*

Control devices used to comply with the proposed standards need to be properly operated and maintained if the standards are to be achieved on a long-term basis. The EPA considered two monitoring options for these NESHAPs (1) the use of CMS and (2) the use of monitors that measure operating parameters that can be directly related to the emission control performance of a particular control device.

The CMS that use gas chromatography to measure individual gaseous organic HAP compound chemicals are not practical for applications where multiple organic HAP chemicals are to be monitored, as is typical with oil and natural gas production and natural gas transmission and storage facilities.

An alternative is to use a CMS to measure total VOC or total hydrocarbons (THC) as a surrogate for total organic HAP. These CMS, however, provide a measure of the relative concentration level of a mixture of organic chemicals, rather than a quantified level of the organic species present.

Based on these reasons, the EPA rejected requiring the use of CMS for the proposed NESHAPs. Instead, the EPA selected monitoring of control device operating parameters indicative of air emission control performance as the appropriate approach to monitoring.

The proposed NESHAPs specify the types of parameters that can be monitored for common types of control devices. These parameters were selected because they are good indicators of control device performance and because continuous parameter monitoring instrumentation is available at a reasonable cost. An owner or operator could be approved, on a case-by-case basis, to monitor parameters not specifically listed in the proposed standards.

The established operating parameters for each control device will be incorporated in the operating permit issued for a facility (or, in the absence of an operating permit, the established levels will be directly enforceable) and will be used to determine a facility's compliance status. Excursions outside the established operating parameter values will be considered violations of the applicable emission standards, except when the excursion is caused by a startup, shutdown, or malfunction that meets the criteria specified in the part 63 General Provisions (40 CFR part 63 subpart A).

Continuous monitoring is not feasible for those emission points required to comply with certain equipment standards and work practice standards (e.g., storage vessels equipped with only covers, pumps and valves subject to LDAR programs). In such cases, failure to install and maintain the required equipment or properly implement the LDAR program constitutes a violation of the applicable equipment or work practice standards.

The owner or operator of a glycol dehydration unit that does not install controls would be required to install a flow monitor to demonstrate that the actual natural gas flow rate to the unit is less than the action level of 85 thousand $m^3$/day (3.0 MMSCF/D), on an annual average basis. If a flow monitor is installed, it must have an accuracy of within 2 percent.

### *K. Selection of Recordkeeping and Reporting Requirements*

The EPA may require an owner or operator of a source to establish and maintain records and prepare and submit notifications and reports. General recordkeeping and reporting requirements for all NESHAP are specified in the part 63 General Provisions (40 CFR 63.9 and 40 CFR 63.10).

The proposed standards would require sources to submit (1) initial notification reports, (2) notification of compliance status reports, and (3) other periodic reports (e.g., startup, shutdown and malfunction report, excess emissions report, CMS performance test report).

All recordkeeping and reporting requirements proposed for major sources are consistent with the General Provision requirements, except that (1) the initial notification would not be due for a year and (2) the startup, shutdown and malfunction report, excess emissions report, and CMS performance test report would be required semi-annually rather than quarterly unless otherwise specified by the State regulatory authority.

The EPA is proposing fewer recordkeeping and reporting requirements for oil and natural gas production area sources. Specifically, the owners and operators of applicable area sources are not subject to (1) the requirements in § 63.6, paragraph (e) of the General Provisions for developing and maintaining a startup, shutdown, and malfunction plan or (2) the requirements in § 63.10, paragraph (d) for reporting actions consistent with the plan. The owners and operators of applicable area sources are required to submit a report identifying occurrences of startup, shutdown, or malfunction when these events happen or are anticipated to happen.

Further, the periodic excess emissions reports and summary reports, as described in § 63.10 paragraph (e)(3) of the General Provisions, are required on a less frequent basis than for major sources. For area sources, these reports are required annually (i.e., major sources need to submit these reports semi-annually). This was done to reduce the recordkeeping and reporting burden on owners and operators of affected facilities.

## IX. Relationship to Other Standards and Programs under the Act

### *A. Relationship to the Part 70 and Part 71 Permit Programs*

Under title V of the Act, the EPA established a permitting program (part 70 and part 71 permitting program) that requires all owners and operators of HAP-emitting sources to obtain an operating permit (57 FR 32251, July 21, 1992). Sources subject to the permitting program (i.e., oil and natural gas production and natural gas transmission and storage sources) are required to submit complete permit applications within a year after a State program is approved by the EPA or, where a State program is not approved, within a year after a program is promulgated by the EPA. If the State where the facility is located does not have an approved permitting program, the owner or operator of a facility must submit the application to the EPA Regional Office in accordance with the requirements of the part 63 General Provisions (40 CFR 63 subpart A).

In addition, section 502(a) of the Act expressly gives the Administrator the discretion to exempt one or more area source categories (in whole or in part) from the requirement to obtain a permit under 42 U.S.C. 7661a(a).

* * * if the Administrator finds that compliance with such requirements is impracticable, infeasible, or unnecessarily burdensome on such categories.

One critical factor that the EPA considers as part of the ''unnecessarily burdensome'' criteria is the degree to which the standard is implementable outside of a permit, such that the permit would provide minimal additional benefit with regard to source-specific tailoring of the standards.

All area source TEG dehydration units impacted by the provisions of the proposed standards must (1) comply with the compliance schedule within the rule, (2) perform monitoring of the required parameters for ensuring compliance, and (3) follow the limited recordkeeping and reporting requirements. Therefore, the primary goal of significant reductions in HAP emissions, particularly BTEX and n-hexane, would be achieved, regardless of whether a permit is required. Unless otherwise required by the State, the owner or operator of an area source subject to the proposed standards is not required to obtain a permit under part 70 of title 40 CFR.

*B. Relationship Between the Oil and Natural Gas Production and the Organic Liquids Distribution (Non-Gasoline) Source Categories*

The EPA believes that a clear applicability demarcation is necessary to distinguish those sources that would be subject to the proposed oil and natural gas production NESHAP and those that would be subject to the organic liquids distribution (non-gasoline) NESHAP, which is scheduled for promulgation by the year 2000.

The proposed standards for the oil and natural gas production source category identify the source category and applicability as including facilities up to the point of custody transfer. The EPA intends to define the organic liquids distribution (non-gasoline) source category as including those facilities that handle and distribute organic liquids (non-gasoline) from the point of custody transfer.

*C. Relationship of Proposed Standards to the Pollution Prevention Act*

The Congress passed and the President signed into law the Pollution Prevention Act of 1990 (PPA) making pollution prevention a national policy. Section 6602(b) identifies an environmental management hierarchy in which pollution

> * * * should be prevented or reduced whenever feasible; pollution that cannot be prevented should be recycled in an environmentally safe manner, whenever feasible; pollution that cannot be prevented or recycled should be treated in an environmentally safe manner, whenever feasible; and disposal or other releases into the environment should be employed only as a last resort * * *

In short, preventing pollution before it is created is preferable to trying to manage, treat or dispose of it after it is created.

According to PPA section 6603, source reduction is defined as reducing the generation and release of hazardous substances, pollutants, wastes, contaminants or residuals at the source, usually within a process. The term includes equipment or technology modifications, process or procedure modifications, reformulation or redesign of products, substitution of raw materials, and improvements in housekeeping, maintenance, training, or inventory control. Source reduction does not include any practice that alters the physical, chemical, or biological characteristics or the volume of a hazardous substance, pollutant, or contaminant through a process or activity that is not integral to or necessary for producing a product or providing a service.

Pertaining to these proposals, section 6604(b)(2) of the PPA directs the EPA to, among other things,

> * * * review regulations of the Agency prior and subsequent to their proposal to determine their effect on source reduction.

The EPA believes that these proposed standards are consistent with the purpose of the Clean Air Act's requirement to consider source reduction technologies. The EPA's emphasis on source reduction hierarchy is also entirely consistent with the Act, particularly the air toxics provision (section 112) that requires the maximum achievable emission reductions through measures that

> * * * reduce the volume of, or eliminate emissions of, such pollutants through process changes, substitution of materials or other modifications; * * *

In the proposed standards, the EPA has incorporated the application of the environmental source reduction management hierarchy. These proposed standards encourage source reduction by (1) control of HAP air emissions through the use of condensers and vapor collection/recovery systems and (2) allowing for the use of system optimization on glycol dehydration units through the adjustment of the glycol circulation rate. This adjustment may significantly reduce related HAP emissions because, on average, the glycol circulation rate is double the necessary rate.

*D. Relationship of Proposed Standards to the Natural Gas STAR Program*

The Natural Gas STAR Program is a voluntary, cooperative program between the EPA and the natural gas industry to promote cost-effective methods for reducing methane emissions. The program, part of the U.S. Climate Change Action Plan, outlines a set of initiatives that will enable the profitable reduction of greenhouse gas emissions. The first phase of the program was initiated in 1993 with companies in the natural gas transmission and distribution industry. The 38 partner companies are currently capturing 36.8 million $m^3$ (1.3 billion $ft^3$ (bcf)) of methane annually, worth almost $3 million.

The natural gas production industry program was initiated in 1995. When fully implemented in the year 2000, Natural Gas STAR companies are projected to recover more than 710 million $m^3$ (25 bcf) of methane annually, worth an estimated $50 million.

Under this program, partners agree to implement two best management practices (BMPs) when cost-effective. These include (1) identifying and replacing high-bleed pneumatic devices and (2) installing GCG separators (flash tank separators) on glycol dehydration units and recovering the separated methane stream. Additionally, the EPA has agreed to assist partner companies in the removal of unjustified regulatory barriers to implementing these practices.

The standards proposed for the oil and natural gas production and natural gas transmission and storage source categories do not create regulatory barriers to implementing the BMPs encouraged under this program. The control requirements for glycol dehydration units at major sources and selected area sources would require control of the flash tank separator vent, if present. This would encourage further product recovery and reduction of HAP and methane air emissions and enhance the product recovery and emission reduction goals of the Natural Gas STAR Program.

*E. Overlapping Regulations*

The proposed standards clarify the applicability of 40 CFR part 63, subpart HH (oil and natural gas production NESHAP) equipment leak provisions by stating that existing oil and natural gas production sources subject to subpart HH and 40 CFR part 60, subpart KKK (onshore natural gas processing plants NSPS) are required only to comply with subpart KKK.

## X. Solicitation of Comments

Comments are specifically requested on several aspects of the proposed standards. These topics are summarized below.

### *A. Potential-to-Emit*

The EPA is currently in the process of developing a separate rulemaking to address several potential-to-emit (PTE) issues. Until the EPA takes final action on the proposal, any determination of PTE made to determine a facility's applicability status under a relevant part 63 standard should be made according to requirements set forth in the relevant standard and in the General Provisions.

Industry representatives have commented that both oil and natural gas production and natural gas transmission and storage facilities often have a maximum capacity (based on physical and operational design) to emit higher than inherent physical limitations would allow. Concern was expressed that potential emissions could be overestimated and a facility could be subject to the Act requirements affecting major sources despite inherent limitations (e.g., depletion of oil and natural gas reservoirs).

The EPA is committed to providing technical assistance on the type of inherent physical and operational design features that may be considered acceptable in determining the PTE for certain source categories. Therefore, the EPA is evaluating and solicits specific recommendations, along with supporting documentation, on how inherent limitations should be addressed for oil and natural gas production and natural gas transmission and storage facilities.

### *B. Definition of Facility*

The EPA specifically requests comments on the proposed definition of facility. Specifically, the EPA requests comments on whether the proposed definition appropriately implements the intent of the major source definition in section 112(a)(1) for the oil and natural gas production and natural gas transmission and storage source categories, or if another definition would better implement this intent.

### *C. Interpretation of ''Associated Equipment'' in Section 112(n)(4) of the Act*

As discussed in section V of this preamble, the EPA has proposed a definition for the term ''associated equipment'' to implement the special provisions of section 112(n)(4) of the Act for the oil and natural gas production source category. Comments are specifically requested on the EPA's proposed definition.

If there is disagreement with the EPA's proposed definition, the EPA requests that the commenter provide alternative definition options, along with supporting documentation, that would provide the relief intended by Congress for this industry while preserving the EPA's ability to regulate HAP emissions from glycol dehydration units, storage vessels with flash emissions, and equipment leaks.

### *D. Regulation of Area Source Glycol Dehydration Units*

The EPA does not intend to regulate TEG dehydration units that have low HAP emissions or units in areas where there is little or no potential threat of adverse health effects from exposure to HAP emissions from TEG dehydration units. The rules, as proposed, include applicability cutoffs of (1) 85 thousand $m^3$/day (3.0 MMSCF/D) of flow to the unit, on an annual average basis, or (2) 0.9 Mg/yr (1 tpy) of benzene emissions.

The EPA is proposing an additional action level based on the county-level urban versus rural location of area source TEG dehydration units. Thus, only those selected area source TEG dehydration units located in counties classified as urban (see section III of this preamble) and also meeting or exceeding the actual natural gas throughput and benzene emission rate action levels will be required to install air emission controls on all process vents. Units (1) below these cutoffs or (2) located in counties classified as rural would not have to be controlled for HAP emissions under the proposed rules.

The EPA evaluated the use of a risk-distance applicability criteria as an alternative to the urban area criteria. The EPA is requesting comment, along with supporting documentation, on the use of a risk-distance applicability criteria for focussing the area source provisions of this proposed regulation to only those area source TEG dehydration units that meet a risk-distance criteria for applicability.

TEG dehydration units located at natural gas transmission and storage facilities emit similar emissions and have a similar emission potential to those located at oil and natural gas production facilities. However, insufficient information was available to conduct an area source finding analysis for the natural gas transmission and storage source category.

The EPA is currently evaluating whether TEG dehydration units located at natural gas transmission and storage area sources result in an unacceptable risk and should be listed and regulated as an area source. The EPA is soliciting comment, along with supporting documentation, in this notice on the emissions, location, and number of TEG dehydration units located at natural gas transmission and storage area sources. Information supplied to the EPA should either support or negate the need for an area source listing.

### *E. HAP Emission Points*

The EPA specifically requests information on potential HAP emissions that may be associated with (1) process vents at amine treating units and sulfur plants, (2) transfer and storage of pipeline pigging wastes, and (3) combustion sources located at oil and natural gas production and natural gas transmission and storage facilities. The EPA has not identified sufficient data to adequately address the potential of HAP emissions from these emission points in these source categories. Thus, the EPA is requesting comment, along with supporting documentation, on HAP emissions from these emission points.

### *F. Storage Vessels at Natural Gas Transmission and Storage Facilities*

The EPA had insufficient information to determine whether significant HAP-emitting storage vessels warranting control are located at natural gas transmission and storage facilities that are major sources of HAP. Therefore, the EPA is soliciting information and comment, along with supporting documentation, regarding the storage vessels located at these sources.

Specifically, the EPA is requesting information and comment, along with supporting documentation, on whether the storage vessels currently being proposed for control under the oil and natural gas production NESHAP are similar to those located at natural gas transmission and storage facilities.

### *G. Cost Impact and Production Recovery Credits*

The EPA specifically requests comments on the cost impact and the production recovery credits as discussed in section IV of the preamble. In addition to its solicitation for comments, the EPA also requests documentation to support cost impact or recovery credit comments.

## XI. Administrative Requirements

### *A. Docket*

The docket for these rulemakings is A–94–04. The docket is an organized and complete file of all the information considered by the EPA in the development of this rulemaking. The principal purposes of the docket are (1) to allow interested parties a means to identify and locate documents so that they can effectively participate in the rulemaking process and (2) to serve as the record in case of judicial review (except for interagency review materials) [section 307(d)(7)(A) of the Act]. This docket contains copies of the regulatory text, BID, BID references, and technical memoranda documenting the information considered by the EPA in the development of the proposed rules. The docket is available for public inspection at the EPA's Air and Radiation Docket and Information Center, the location of which is given in the **ADDRESSES** section of this notice.

*B. Paperwork Reduction Act*

The information collection requirements in these proposed rules 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.* Information Collection Request (ICR) documents have been prepared by the EPA (ICR Nos. 1788.01 and 1789.01) and copies may be obtained from Sandy Farmer, OPPE Regulatory Information Division; U.S. Environmental Protection Agency (2137); 401 M Street, S.W.; Washington, DC 20460 or by calling (202) 260–2740.

Information is required to ensure compliance with the provisions of the proposed rules. If the relevant information were collected less frequently, the EPA would not be reasonably assured that a source is in compliance with the proposed rules. In addition, the EPA's authority to take administrative action would be reduced significantly.

The proposed rules would require that facility owners or operators retain records for a period of five years, which exceeds the three year retention period contained in the guidelines in 5 CFR 1320.6. The five year retention period is consistent with the provisions of the General Provisions of 40 CFR Part 63, and with the five year records retention requirement in the operating permit program under Title V of the CAA.

All information submitted to the EPA for which a claim of confidentiality is made will be safeguarded according to the EPA policies set forth in Title 40, Chapter 1, Part 2, Subpart B, Confidentiality of Business Information. See 40 CFR 2; 41 FR 36902, September 1, 1976; amended by 43 FR 3999, September 8, 1978; 43 FR 42251, September 28, 1978; and 44 FR 17674, March 23, 1979. Even where the EPA has determined that data received in response to an ICR is eligible for confidential treatment under 40 CFR Part 2, Subpart B, the EPA may nonetheless disclose the information if it is ''relevant in any proceeding'' under the statute [42 U.S.C. 7414(C); 40 CFR 2.301(g)]. The information collection complies with the Privacy Act of 1974 and Office of Management and Budget (OMB) Circular 108.

Information to be reported consists of emission data and other information that are not of a sensitive nature. No sensitive personal or proprietary data are being collected.

The estimated annual average hour burden for the major source provisions of the proposed oil and natural gas production NESHAP is 169 hours per respondent. The estimated annual average cost of this burden is $7,300 for each of the estimated 484 existing and new (projected) respondents.

The estimated annual average hour burden for the area source provisions of the proposed oil and natural gas production NESHAP is 56 hours per respondent. The estimated annual average cost of this burden is $2,400 for each of the estimated 572 existing and new (projected) respondents.

The estimated annual average hour burden for the major source provisions of the proposed natural gas transmission and storage NESHAP is 77 hours per respondent. The estimated annual average cost of this burden is $3,300 for each of the estimated 5 existing respondents.

Reports are required on a semi-annual and annual basis (depending upon the reports) and as required, as in the case of startup, shutdown, and malfunction plans. Burden means the total time, effort, or financial resources expended by persons to generate, maintain, retain, or disclose or provide information to or for a Federal agency. This includes the time needed to review instructions; develop, acquire, install, and utilize technology and systems for the purposes of collecting, validating, and verifying information, processing and maintaining information, and disclosing and providing information; adjust the existing ways to comply with any previously applicable instructions and requirements; train personnel to be able to respond to a collection of information; search data sources; complete and review the collection of information; and transmit or otherwise disclose the information.

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 are listed in 40 CFR part 9 and 48 CFR Chapter 15.

Comments are requested on the EPA's need for this information, the accuracy of the provided burden estimates, and any suggested methods for minimizing respondent burden, including through the use of automated collection techniques. Send comments on the ICRs to the Director, OPPE Regulatory Information Division; U.S. Environmental Protection Agency (2137); 401 M Street, S.W., Washington, DC 20460; and to the Office of Information and Regulatory Affairs, Office of Management and Budget, 725 17th Street, N.W., Washington, DC 20503, marked ''Attention: Desk Officer for EPA.'' Include the ICR number(s) in any correspondence. Since OMB is required to make a decision concerning the ICR's between 30 and 60 days after February 6, 1998, a comment to OMB is best assured of having its full effect if OMB receives it by March 9, 1998. The final rules will respond to any OMB or public comments on the information collection requirements contained in this proposal.

*C. Executive Order 12866*

Under Executive Order 12866 [58 FR 5173 (October 4, 1993)], the EPA must determine whether the regulatory action is ''significant'' and therefore subject to OMB review and the requirements of the Executive Order. The criteria set forth in section 1 of the Order for determining whether a regulation is a significant rule are as follows: (1) Is likely to have an annual effect on the economy of $100 million or more, or adversely and materially affect a sector of the economy, productivity, competition, jobs, the environment, public health or safety, or State, local or tribal governments or communities; (2) is likely to create a serious inconsistency or otherwise interfere with an action taken or planned by another agency; (3) is likely to materially alter the budgetary impact of entitlements, grants, user fees or loan programs, or the rights and obligations of recipients thereof; or (4) is likely to raise novel legal or policy issues arising out of legal mandates, the President's priorities, or the principles set forth in the Executive Order.

Based on criteria 1, 2, and 3, this action is not a ''significant regulatory action'' within the meaning of Executive Order 12866. However, the OMB has deemed it significant under criterion 4 and has requested review of this proposed rulemaking package. Therefore, the EPA submitted this action to OMB for review. Changes made in response to OMB suggestions or recommendations are documented in the public record.

*D. Regulatory Flexibility*

The Regulatory Flexibility Act (RFA) generally requires an agency to conduct a regulatory flexibility analysis of any rule subject to notice and comment rulemaking requirements, unless the agency certifies that the rule will not have a significant economic impact on a substantial number of small entities. Small entities include small businesses, small not-for-profit enterprises, and small governmental jurisdictions. These proposed rules will not have a significant economic impact on a substantial number of small entities. According to Wards Business Directory (1993), there are 1,152 firms in the seven affected Standard Industrial Classification (SIC) codes and 735 of these firms meet the Small Business Administration (SBA) definition of a small entity.

The number of affected small entities for these rules is likely to be minimal due to several considerations in these rules that minimize the burden on all firms, both small and large. These considerations include exempting from control requirements those glycol dehydration units located at major or area sources with (1) an actual flowrate of natural gas to the glycol dehydration unit less than 85 $m^3$/day (3.0 MMSCF/D), on an annual average basis, or (2) benzene emissions less than 0.9 Mg/yr (1 tpy). In addition, emission controls are limited to those area source glycol dehydration units located in urban areas.

In a screening of potential impacts on a sample of small entities, the EPA found that there are minimal impacts on these entities. The weighted average of control costs as a percent of sales is 0.09 of one percent for the small firms in the sample, while a maximum value of 1.1 percent results for only two of these firms. The analysis also indicates that with the regulations, the change in measures of profitability are minimal (i.e., 0.11 of one percent change in the cost-to-sales ratio for small firms), and there are no indications of financial failures or employment losses for both small and large firms. The screening analysis for these rules is detailed in the Economic Impact Analysis (see Docket No. A–94–04).

Therefore, I certify that this action will not have a significant economic impact on a substantial number of small entities.

*E. Unfunded Mandates*

Title II of the Unfunded Mandate Reform Act of 1995 (UMRA), Public Law 104–4, establishes requirements for Federal agencies to assess the effects of their regulatory actions on State, local, and tribal governments and the private sector. Under section 202 of the UMRA, the EPA generally must prepare a written statement, including a cost-benefit analysis, for the proposed and final rules with ''Federal mandates'' that may result in expenditures to State, local, and tribal governments, in the aggregate, or to the private sector, of $100 million or more in any one year. Before promulgating an EPA rule for which a written statement is needed, section 205 of the UMRA generally requires the EPA to identify and consider a reasonable number of regulatory alternatives and adopt the least costly, most cost-effective, or least burdensome alternative that achieves the objectives of the rule. The provisions of section 205 do not apply when they are inconsistent with applicable law. Moreover, section 205 allows the EPA to adopt an alternative other than the least costly, most cost-effective, or least burdensome alternative if the Administrator publishes with the final rule an explanation why that alternative was not adopted. Before the EPA establishes any regulatory requirements that may significantly or uniquely affect small governments, including tribal governments, it must have developed under section 203 of the UMRA a small government agency plan. The plan must provide for notifying potentially affected small governments, enabling officials of affected small governments to have meaningful and timely input in the development of the EPA regulatory proposals with significant Federal intergovernmental mandates, and informing, educating, and advising small governments on compliance with the regulatory requirements.

The EPA has determined that these rules do not contain a Federal mandate that may result in expenditures of $100 million or more for State, local, and tribal governments, in the aggregate or the private sector in any one year. The EPA's total estimated annual net costs of the proposed rules is $10 million, including MIRR costs. Thus, today's rules are not subject to the requirements of sections 202 and 205 of the UMRA.

The EPA has determined that these rules contain no regulatory requirements that might significantly or uniquely affect small governments. No small government entities have been identified that have involvement with these source categories and, as such, are not covered by the regulatory requirements of the proposed regulations.

**List of Subjects in 40 CFR Part 63**

Environmental protection, Air pollution control, Air emissions control, Associated equipment, Black oil, Condensate, Custody transfer, Equipment leaks, Glycol dehydration units, Hazardous air pollutants, Hazardous substances, Natural gas, Intergovernmental relations, Natural gas processing plants, Natural gas transmission and storage, Oil and natural gas production, Pipelines, Organic liquids distribution (non-gasoline), Reporting and recordkeeping requirements, Storage vessels, Tank batteries, Tanks, Triethylene glycol.

Dated: November 24, 1997.

**Carol M. Browner,**

*Administrator.*

For the reasons set out in the preamble, title 40, chapter I, part 63 of the Code of Federal Regulations is proposed to be amended as follows:

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

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

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

2. Part 63 is amended by adding subpart HH to read as follows:

## Subpart HH—National Emission Standards for Hazardous Air Pollutants From Oil and Natural Gas Production Facilities

Sec.

## Subpart HH—National Emission Standards for Hazardous Air Pollutants From Oil and Natural Gas Production Facilities

### § 63.760 Applicability and designation of affected source.

(a) This subpart applies to the owners or operators of emission points, as specified in paragraph (b) of this section, that are located at oil and natural gas production facilities that meet the specified criteria in paragraphs (a)(1), (a)(2), and (a)(3) of this section.

(1) Facilities that process, upgrade, or store hydrocarbon liquids prior to the point of custody transfer;

(2) Facilities that process, upgrade, or store natural gas prior to the point at which natural gas enters the natural gas transmission and storage source category or is delivered to a final end user; and

(3) Both major and area sources of HAP.

(b) The affected sources for major sources are listed in paragraph (b)(1) of this section and for area sources in paragraph (b)(2) of this section.

(1) For major sources, the affected source shall comprise each emission point located at a facility that meets the criteria specified in paragraph (a) of this section and listed in paragraphs (b)(1)(i) through (b)(1)(iv) of this section.

(i) Each glycol dehydration unit;

(ii) Each storage vessel with flash emissions;

(iii) The group of all ancillary equipment, except compressors; and

(iv) Compressors intended to operate in volatile organic hazardous air pollutant service (as defined in § 63.761).

(2) For area sources, the affected source includes each triethylene glycol dehydration unit located at a facility that meets the criteria specified in paragraph (a) of this section.

(c) [Reserved]

(d) The owner or operator of a facility that does not contain an affected source as specified in paragraph (b) of this section is not subject to the requirements of this subpart.

(e) The owner or operator of a facility that exclusively processes, stores, or transfers black oil (as defined in § 63.761) is not subject to the requirements of this subpart.

(f) The owner or operator of an affected source shall achieve compliance with the provisions of this subpart by the dates specified in paragraphs (f)(1) and (f)(2) of this section.

(1) The owner or operator of an affected source the construction or reconstruction of which commenced before February 6, 1998, shall achieve compliance with the provisions of the subpart as expeditiously as practical after [the date of publication of the final rule], but no later than three years after [the date of publication of the final rule] except as provided for in § 63.6(i).

(2) 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 startup or [the date of publication of the final rule], whichever date is later.

(g) The following provides owners or operators of an affected source with information on overlap of this subpart with other regulations for equipment leaks.

(1) After the compliance dates specified in paragraph (f) of this section, ancillary equipment that is subject to this subpart and that is also subject to and controlled under the provisions of 40 CFR part 60, subpart KKK is only required to comply with the requirements of 40 CFR part 60, subpart KKK.

(2) After the compliance dates specified in paragraph (f) of this section, ancillary equipment that is subject to this subpart and is also subject to and controlled under the provisions of 40 CFR part 61, subpart V is only required to comply with the requirements of 40 CFR part 61, subpart V.

(3) After the compliance dates specified in paragraph (f) of this section, ancillary equipment that is subject to this subpart and is also subject to and controlled under the provisions of subpart H of this part is only required to comply with the requirements of subpart H of this part.

(h) An owner or operator of an affected source that is a major source or located at a major source and is subject to the provisions of this subpart is also subject to 40 CFR part 70 permitting requirements. Unless otherwise required by the State, the owner or operator of an area source subject to the provisions this subpart is not required to obtain a permit under part 70 of title 40 of the Code of Federal Regulations.

### § 63.761 Definitions.

All terms used in this subpart shall have the meaning given them in the Clean Air Act, subpart A of this part (General Provisions), and in this section. If the same term is defined in subpart A and in this section, it shall have the meaning given in this section for purposes of this subpart.

*Alaskan North Slope* means the approximately 180,000 square kilometer area (69,000 square mile area) extending from the Brooks Range to the Arctic Ocean.

*Ancillary equipment* means any of the following pieces of equipment: pumps, compressors, pressure relief devices, sampling connection systems, open-ended valves or lines, valves, flanges and other connectors, or product accumulator vessels.

*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.

*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 with the potential for flash emissions.

*Average concentration,* as used in this subpart, means the annual average flow rate, as determined according to the procedures specified in § 63.772(b).

*Black oil* means hydrocarbon (petroleum) liquid with a gas-to-oil ratio (GOR) less than 50 cubic meters (1,750 cubic feet) per barrel and an API gravity less than 40 degrees.

*Boiler* means any enclosed combustion device that extracts useful energy in the form of steam and that is not an incinerator.

*Closed-vent system* means a system that is not open to the atmosphere and that is composed of piping, ductwork, connections, and, if necessary, flow inducing devices that transport gas or vapor from an emission point to a control device or back into the process. If gas or vapor from regulated equipment is routed to a process (e.g., to a fuel gas system), the process shall not be considered a closed vent system and is not subject to closed vent system standards.

*Combustion device* means an individual unit of equipment such as a flare, incinerator, process heater, or boiler used for the combustion of volatile organic hazardous air pollutant vapors.

*Compressor* means a piece of equipment that increases the pressure of a process gas by positive displacement, employing linear movement of the drive shaft.

*Condensate* means hydrocarbon liquid that condenses because of changes in temperature, pressure, or both, and remains liquid at standard conditions.

*Continuous recorder* means a data recording device that either records an instantaneous data value at least once every 15 minutes or records 15-minute or more frequent block average values.

*Continuous seal* means a seal that forms a continuous closure that completely covers the space between the wall of the storage vessel and the edge of the floating roof. A continuous seal may be a vapor-mounted, liquid-mounted, or metallic shoe seal.

*Control device* means any equipment used for recovering or oxidizing hazardous air pollutant (HAP) and volatile organic compound (VOC) vapors. Such equipment includes, but is not limited to, absorbers, carbon adsorbers, condensers, incinerators, flares, boilers, and process heaters. For the purposes of this subpart, if gas or vapor from regulated equipment is used, reused, returned back to the process, or sold, then the recovery system used, including piping, connections, and flow inducing devices, are not considered to be control devices.

*Cover* means a device which is placed on top of or over a material such that the entire surface area of the material is enclosed and sealed, to reduce emissions to the atmosphere. A cover may have openings (such as access hatches, sampling ports, and gauge wells) if those openings are necessary for operation, inspection, maintenance, or repair of the unit on which the cover is installed, provided that each opening is closed and sealed when the opening is not in use. In addition, a cover may have one or more safety devices. Examples of a cover include a fixed-roof installed on a tank, an external floating roof installed on a tank, and a lid installed on a drum or other container.

*Custody transfer* means the transfer of hydrocarbon liquids or natural gas, after processing and/or treatment in the producing operations, from storage vessels or automatic transfer facilities to pipelines or any other forms of transportation. For the purposes of this subpart, the EPA considers the point at which natural gas enters a natural gas processing plant as a point of custody transfer.

*Equipment leak* means emissions of hazardous air pollutants from a pump, compressor, pressure relief device, sampling connection system, open-ended valve or line, valve, or instrumentation system.

*Facility* means any grouping of equipment: where hydrocarbon liquids are processed, upgraded, or stored prior to the point of custody transfer; or where natural gas is processed, upgraded, or stored prior to entering the natural gas transmission source category. For the purpose of a major source determination, means oil and natural gas production and processing equipment that is located within the boundaries of an individual surface site. Equipment that is part of a facility will typically be located within close proximity to other equipment located at the same facility. Pieces of production equipment or groupings of equipment located on different oil and gas leases, mineral fee tracts, lease tracts, subsurface unit areas, surface fee tracts, or surface lease tracts shall not be considered part of the same facility. Examples of facilities in the oil and natural gas production source category include, but are not limited to, well sites, satellite tank batteries, central tank batteries, graded pad sites, and natural gas processing plants.

*Field natural gas* means natural gas extracted from a production well prior to entering the first stage of processing, such as dehydration.

*Fill* or *filling* means the introduction of a material into a storage vessel.

*Fixed-roof* means a cover that is mounted on a waste management unit or storage vessel in a stationary manner and that does not move with fluctuations in liquid level.

*Flame zone* means the portion of the combustion chamber in a boiler occupied by the flame envelope.

*Flash tank.* See definition for gas-condensate-glycol (GCG) separator.

*Flow indicator* means a device that indicates whether gas flow is present in a line.

*Gas-condensate-glycol (GCG) separator* means a two-or three-phase separator through which the ''rich'' glycol stream of a glycol dehydration unit is passed to remove entrained gas and hydrocarbon liquid. The GCG separator is commonly referred to as a flash separator or flash tank.

*Gas-to-oil ratio* (GOR) means the number of standard cubic meters (cubic feet) of gas produced per barrel of crude oil or other hydrocarbon liquid.

*Glycol dehydration unit* means a device in which a liquid glycol absorbent directly contacts a natural gas stream (that is circulated counter current to the glycol flow) and absorbs water vapor in a contact tower or absorption column (absorber). The glycol contacts and absorbs water vapor and other gas stream constituents from the natural gas and becomes ''rich'' glycol. This glycol is then regenerated by distilling the water and other gas stream constituents in the glycol dehydration unit reboiler. The distilled or ''lean'' glycol is then recycled back to the absorber.

*Glycol dehydration unit reboiler vent* means the vent through which exhaust from the reboiler of a glycol dehydration unit passes from the reboiler to the atmosphere.

*Glycol dehydration unit process vent* means either the glycol dehydration unit reboiler vent or the vent from the GCG separator (flash tank).

*Hazardous air pollutants* or *HAP* means the chemical compounds listed in section 112(b) of the Act. All chemical compounds listed in section 112(b) of the Act need to be considered when making a major source determination. Only the HAP compounds listed in Table 1 of this subpart need to be considered when determining applicability and compliance.

*Hydrocarbon liquid* means any naturally occurring, unrefined petroleum liquid.

*In VOHAP service* means that a piece of ancillary equipment either contains or contacts a fluid (liquid or gas) which has a total volatile organic HAP (VOHAP) concentration equal to or greater than 10 percent by weight as determined according to the provisions of 40 CFR 61.245(d).

*Major source,* as used in this subpart, shall have the same meaning as in § 63.2, except that:

(1) Emissions from any oil or gas exploration or production well (with its associated equipment (as defined in this section)) and emissions from any pipeline compressor or pump station shall not be aggregated with emissions from other similar units, to determine whether such emission points or stations are major sources, even when emission points are in a contiguous area or under common control;

(2) Emissions from processes, operations, or equipment that are not part of the same facility, as defined in this section, shall not be aggregated; and

(3) For facilities that are production field facilities, only HAP emissions from glycol dehydration units and storage tanks with flash emission potential shall be counted in a major source determination.

*Natural gas* means the gaseous mixture of hydrocarbon gases and vapors, primarily consisting of methane, ethane, propane, butane, pentane, and hexane, along with water vapor and other constituents.

*Natural gas liquids* (NGLs) means the hydrocarbons, such as ethane, propane, butane, pentane, natural gasoline, and condensate that are extracted from field gas.

*Natural gas processing plant* (gas plant) means any processing site engaged in:

(1) The extraction of natural gas liquids from field gas; or

(2) The fractionation of mixed NGLs to natural gas products.

*No detectable emissions* means no escape of HAP from a device or system to the atmosphere as determined by:

(1) Testing the device or system in accordance with the requirements of § 63.772(c); and

(2) No visible openings or defects in the device or system such as rips, tears, or gaps.

*Operating parameter value* means a minimum or maximum value established for a control device or process parameter which, if achieved by itself or in combination with one or more other operating parameter values, determines that an owner or operator has complied with an applicable emission limitation or standard.

*Operating permit* means a permit required by 40 CFR part 70 or part 71.

*Organic monitoring device* means a unit of equipment used to indicate the concentration level of organic compounds exiting a recovery device based on a detection principle such as infra-red, photoionization, or thermal conductivity.

*Point of material entry* means at the point where a material first enters a source subject to this subpart.

*Primary fuel* means the fuel that provides the principal heat input (i.e., more than 50-percent) to the device. To be considered primary, the fuel must be able to sustain operation without the addition of other fuels.

*Process heater* means a device that transfers heat liberated by burning fuel directly to process streams or to heat transfer liquids other than water.

*Produced water* means water:

(1) That is extracted from the earth from an oil or natural gas production well; or

(2) That is separated from crude oil, condensate, or natural gas after extraction.

*Production field facilities* means those facilities located prior to the point of custody transfer.

*Production well* means any hole drilled in the earth from which crude oil, condensate, or field natural gas is extracted.

*Relief device* means a device used only to release an unplanned, non-routine discharge. A relief device discharge can result from an operator error, a malfunction such as a power failure or equipment failure, or other unexpected cause that requires immediate venting of gas from process equipment in order to avoid safety hazards or equipment damage.

*Safety device* means a device that is not used for planned or routine venting of liquids, gases, or fumes from the unit or equipment on which the device is installed; and the device remains in a closed, sealed position at all times except when an unplanned event requires that the device open for the purpose of preventing physical damage or permanent deformation of the unit or equipment on which the device is installed in accordance with good engineering and safety practices for handling flammable, combustible, explosive, or other hazardous materials. Examples of unplanned events which may require a safety device to open include failure of an essential equipment component or a sudden power outage.

*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.

*Storage vessel with the potential for flash emissions* means any storage vessel that contains a hydrocarbon with a GOR equal to or greater than 50 cubic meters (1,750 cubic feet) per barrel or an API gravity equal to or greater than 40 degrees.

*Surface site* means the graded pad, gravel pad, foundation, platform, or immediate physical location upon which equipment is physically affixed.

*Tank battery* means a collection of equipment used to separate, treat, store, and transfer crude oil, condensate, natural gas, and produced water. A tank battery typically receives crude oil, condensate, natural gas, or some combination of these extracted products from several production wells for accumulation and separation prior to transmission to a natural gas plant or petroleum refinery. A tank battery may or may not include a glycol dehydration unit.

*Temperature monitoring device* means a unit of equipment used to monitor temperature and having an accuracy of ±1 percent of the temperature being monitored expressed in °C, or ±0.5°C, whichever is greater.

*Total organic compounds* or *TOC,* as used in this subpart, means those compounds measured according to the procedures of Method 18, 40 CFR part 60, appendix A.

*Urban area* is defined by use of the U.S. Department of Commerce's Bureau of the Census statistical data to classify every county in the U.S. into one of the three classifications:

(1) Urban-1 areas which consist of metropolitan statistical areas (MSA) with a population greater than 250,000;

(2) Urban-2 areas which are defined as all other areas designated urban by the Bureau of Census (areas which comprise one or more central places and the adjacent densely settled surrounding fringe that together have a minimum of 50,000 persons). The urban fringe consists of contiguous territory having a density of at least 1,000 persons per square mile; or

(3) Rural areas which are those counties not designated as urban by the Bureau of the Census.

*Volatile organic hazardous air pollutant concentration* or *VOHAP concentration* means the fraction by weight of all HAP contained in a material as determined in accordance with procedures specified in § 63.772(a).

**§ 63.762 [Reserved]**

**§ 63.763 [Reserved]**

**§ 63.764 General standards.**

(a) Table 2 of this subpart specifies the provisions of subpart A (General Provisions) that apply and those that do not apply to owners and operators of affected sources subject to this subpart.

(b) All reports required under this subpart shall be sent to the Administrator at the appropriate address listed in § 63.13. If acceptable to both the Administrator and the owner or operator of a source, reports may be submitted on electronic media.

(c) Except as specified in paragraph (e) of this section, the owner or operator of an affected source located at an existing or new major source shall comply with the standards in this subpart as specified in paragraphs (c)(1) through (c)(3) of this section.

(1) For each glycol dehydration unit process vent subject to this subpart, the owner or operator shall comply with the requirements specified in paragraphs (c)(1)(i) through (c)(1)(iii) of this section.

(i) The owner or operator shall comply with the control requirements for glycol dehydration unit process vents specified in § 63.765;

(ii) The owner or operator shall comply with the monitoring requirements of § 63.773; and

(iii) The owner or operator shall comply with the recordkeeping and reporting requirements of §§ 63.774 and 63.775.

(2) For each storage vessel with the potential for flash emissions and an actual throughput of hydrocarbon liquids equal to or greater than 500 barrels per day (BPD), the owner or operator shall comply with the requirements specified in paragraphs (c)(2)(i) through (c)(2)(iii) of this section.

(i) The control requirements for storage vessels specified in § 63.766;

(ii) The monitoring requirements of § 63.773; and

(iii) The recordkeeping and reporting requirements of §§ 63.774 and 63.775.

(3) For ancillary equipment (as defined in § 63.761) at a natural gas processing plant subject to this subpart, the owner or operator shall comply with the requirements for equipment leaks specified in § 63.769.

(d) The owner or operator of an affected source located at an area source of HAP emissions shall comply with the standards in this subpart as specified in paragraphs (d)(1) through (d)(3) of this section.

(1) The control requirements for glycol dehydration unit process vents specified in § 63.765;

(2) The monitoring requirements of § 63.773; and

(3) The recordkeeping and reporting requirements of §§ 63.774 and 63.775.

(e) The owner or operator is exempt from the requirements of paragraphs (c)(1) and (d) of this section if the actual annual average flow of gas to the glycol dehydration unit is less than 85 thousand cubic meters per day (3.0 million standard cubic feet per day) or emissions of benzene from the unit to the atmosphere are less than 0.9 megagram per year (1 ton per year). The flow of natural gas to the unit and the emissions of benzene from the unit shall be determined by the procedures specified in § 63.772(b). This determination must be made available to the Administrator upon request. In addition, the owner or operator is exempt from the requirements of paragraph (d) of this section if the glycol dehydration unit is not located in a county classified as an Urban area as defined in § 63.761.

(f) Each owner or operator of a major HAP source subject to this subpart is required to apply for a 40 CFR part 70 or part 71 operating permit from the appropriate permitting authority. If the Administrator has approved a State operating permit program under 40 CFR part 70, the permit shall be obtained from the State authority. If the State operating permit program has not been approved, the owner or operator of a source shall apply to the EPA Regional Office pursuant to 40 CFR part 71.

(g) Unless otherwise required by the State, the owner or operator of an area source subject to the provisions of this subpart is not required to obtain a permit under part 70 of title 40 of the Code of Federal Regulations.

(h) An owner or operator of an affected source that is:

(1) A major source or located at a major source; or

(2) An area source subject to the provisions of this subpart that is in violation of an operating parameter value is in violation of the applicable emission limitation or standard.

**§ 63.765 Glycol dehydration unit process vents standards.**

(a) This section applies to each glycol dehydration unit process vent that must be controlled for HAP emissions as specified in § 63.764(c)(1)(i) and (d)(1).

(b) Except as provided in paragraph (c) of this section, an owner or operator of a glycol dehydration unit process vent shall comply with the requirements specified in paragraphs (b)(1) and (b)(2) of this section.

(1) For each glycol dehydration unit process vent, the owner or operator shall control air emissions by connecting the process vent to a control device through a closed-vent system designed and operated in accordance with the requirements of § 63.771(c) and (d).

(2) One or more safety devices that vent directly to the atmosphere may be used on the air emission control equipment complying with paragraph (b)(1) of this section.

(c) As an alternative to the requirements of paragraph (b) of this section, the owner or operator may comply with one of the requirements specified in paragraphs (c)(1) through (c)(3) of this section.

(1) The owner or operator shall control air emissions by connecting the process vent to a process natural gas line through a closed-vent system designed and operated in accordance with the requirements of § 63.771(c).

(2) The owner or operator shall demonstrate, to the Administrator's satisfaction, that the total HAP emissions to the atmosphere from the glycol dehydration unit reboiler vent and GCG separator (flash tank) vent (if present) are reduced by 95 percent through process modifications.

(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 HAP emissions to the atmosphere from the glycol dehydration unit reboiler vent and GCG separator (flash tank) vent are reduced by 95 percent.

**§ 63.766 Storage vessel standards.**

(a) This section applies to each storage vessel that must be controlled for HAP emissions as specified in § 63.764(c)(2).

(b) The owner or operator of a storage vessel shall comply with one of the control requirements specified in paragraphs (b)(1) through (b)(3) of this section.

(1) The owner or operator of a storage vessel using a cover that is connected through a closed-vent system to a control device shall use a cover that is designed and operated in accordance with the requirements of § 63.771(b). The closed-vent system and control device shall be designed and operated in accordance with the requirements of § 63.771(c) and (d).

(2) The owner or operator of a pressure storage vessel that is designed to operate as a closed system shall operate the storage vessel with no detectable emissions at all times that material is in the storage vessel, except as provided for in paragraph (c) of this section.

(3) The owner or operator of a storage vessel using a fixed-roof cover with an internal floating roof shall use a fixed-roof cover with an internal floating roof designed and operated in accordance with the requirements of 40 CFR 60.112b(a)(1).

(c) One or more safety devices that vent directly to the atmosphere may be used on the storage vessel and air emission control equipment complying with paragraphs (b)(1) through (b)(3) of this section.

**§ 63.767 [Reserved]**

**§ 63.768 [Reserved]**

**§ 63.769 Equipment leak standards.**

(a) This section applies to ancillary equipment and compressors (as defined in § 63.761) at natural gas processing plants that contain or contact a fluid (liquid or gas) that has a total VOHAP concentration equal to or greater than 10 percent by weight (determined according to the provisions of 40 CFR 61.245(d)) and that operates equal to or greater than 300 hours per calendar year.

(b) This section does not apply to ancillary equipment and compressors for which the owner or operator is meeting the requirements specified in subpart H of this part; or is meeting the requirements specified in 40 CFR part 60, subpart KKK.

(c) For each piece of ancillary equipment and compressors subject to this section located at an existing or new source, the owner or operator shall meet the requirements specified in 40 CFR 61.241 through 61.247, except as specified in paragraphs (c)(1) through (c)(8) of this section.

(1) Each pressure relief device in gas/vapor service shall be monitored quarterly and within 5 days after each pressure release to detect leaks, except under the following conditions.

(i) If an owner or operator has obtained permission from the Administrator to use an alternative means of emission limitation that achieves a reduction in emissions of VOHAP at least equivalent to that achieved by the control required in this subpart.

(ii) If the pressure relief device is located in a nonfractionating facility that is monitored only by non-facility personnel, it may be monitored after a pressure release the next time the monitoring personnel are on site, instead of within 5 days. Such a pressure relief device shall not be allowed to operate for more than 30 days after a pressure release without monitoring.

(2) For pressure relief devices, if an instrument reading of 10,000 parts per million or greater is measured, a leak is detected.

(3) For pressure relief devices, when a leak is detected, it shall be repaired as soon as practicable, but no later than 15 calendar days after it is detected, except if a delay in repair of equipment is granted under 40 CFR 61.242–10.

(4) Sampling connection systems are exempt from the requirements of 40 CFR 61.242–5.

(5) Pumps in VOHAP 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 standard cubic meters per day (10 million standard cubic feet per day) or more of field gas are exempt from the routine monitoring requirements of 40 CFR 61.242–2(a)(1) and paragraphs 61.242–7(a), and paragraphs (c)(1) through (c)(3) of this section.

(6) Pumps in VOHAP service, valves in gas/vapor and light liquid service, and pressure relief devices in gas/vapor service within a natural gas processing plant that is located on the Alaskan North Slope are exempt from the routine monitoring requirements of 40 CFR 61.242–2(a)(1) and 61.242–7(a), and paragraphs (c)(1) through (c)(3) of this section.

(7) Reciprocating compressors in wet gas service are exempt from the compressor control requirements of 40 CFR 61.242–3.

(8) Flares used to comply with this subpart shall comply with the requirements of § 63.11(b).

**§ 63.770 [Reserved]**

**§ 63.771 Control requirements.**

(a) This section applies to each cover, closed-vent system, and control device installed and operated by the owner or operator to control air emissions.

(b) *Cover requirements.* (1) The cover and all openings on the cover (e.g., access hatches, sampling ports, and gauge wells) shall be designed to operate with no detectable emissions when all cover openings are secured in a closed, sealed position.

(2) The owner or operator shall determine that the cover operates with no detectable emissions by testing each opening on the cover in accordance with the procedures specified in § 63.772(c) the first time material is placed into the unit on which the cover is installed. If a leak is detected and cannot be repaired at the time that the leak is detected, the material shall be removed from the unit and the unit shall not be used until the leak is repaired.

(3) 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 paragraphs (c) and (d) of this section.

(c) *Closed-vent system requirements.* (1) The closed-vent system shall route all gases, vapors, and fumes emitted from the material in the unit to a control device that meets the requirements specified in paragraph (d) of this section.

(2) The closed-vent system shall be designed and operated with no detectable emissions.

(3) 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, the owner or operator shall meet the requirements specified in paragraphs (c)(3)(i) and (c)(3)(ii) of this section.

(i) For each bypass device, except as provided for in paragraph (c)(3)(ii) of this section, the owner or operator shall either:

(A) Install, calibrate, maintain, and operate a flow indicator at the inlet to the bypass device that indicates at least once every 15 minutes whether gas, vapor, or fume flow is present in the bypass device; or

(B) Secure the valve installed at the inlet to the bypass device in the closed position using a car-seal or a lock-and-key type configuration. The owner or operator shall visually inspect the seal or closure mechanism at least once every month to verify that the valve is maintained in the closed position.

(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 (c)(3)(i) of this section.

(d) *Control device requirements.* (1) The control device used to reduce HAP emissions in accordance with the standards of this subpart shall be one of the control devices specified in paragraphs (d)(1)(i) through (d)(1)(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 in accordance with one of the following performance requirements:

(A) Reduces the mass content of either TOC or total HAP in the gases vented to the device by 95 percent by weight or greater as determined in accordance with the requirements of § 63.772(e);

(B) Reduces the concentration of either TOC or total HAP 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 § 63.772(e); or

(C) Operates at a minimum residence time of 0.5 second at a minimum temperature of 760°C. 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.

(ii) A vapor recovery device (e.g. carbon adsorption system or condenser) or other 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 percent by weight or greater as determined in accordance with the requirements of § 63.772(e).

(iii) A flare that is designed and operated in accordance with the requirements of § 63.11(b).

(2) Each control device used to comply with this subpart shall be operated at all times when material is placed in a unit vented to the control device, except when maintenance or repair of a unit cannot be completed without a shutdown of the control device. An owner or operator may vent more than one unit to a control device used to comply with this subpart.

(3) The owner or operator shall demonstrate that a control device achieves the performance requirements of paragraph (d)(1) of this section as specified in paragraphs (d)(3)(i) through (d)(3)(iv) of this section.

(i) An owner or operator shall demonstrate using either a performance test as specified in paragraph (d)(3)(iii) of this section or a design analysis as specified in paragraph (d)(3)(iv) of this section the performance of each control device except for the following:

(A) A flare;

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

(C) A boiler or process heater into which the vent stream is introduced with the primary fuel; or

(D) 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.

(ii) An owner or operator shall demonstrate the performance of each flare in accordance with the requirements specified in § 63.11(b).

(iii) For a performance test conducted to meet the requirements of paragraph (d)(3)(i) of this section, the owner or operator shall use the test methods and procedures specified in § 63.772(e).

(iv) For a design analysis conducted to meet the requirements of paragraph (d)(3)(i) of this section, the design analysis shall meet the requirements specified in paragraphs (d)(3)(iv)(A) and (d)(3)(iv)(B) of this section.

(A) The design analysis shall include analysis of the vent stream characteristics and control device operating parameters for the applicable control device as specified in paragraphs (d)(3)(iv)(A)(*1*) through (d)(3)(iv)(A)(*6*) of this section.

(*1*) For a thermal vapor incinerator, the design analysis shall include the vent stream composition, constituent concentrations, and flow rate and shall establish the design minimum and average temperatures in the combustion zone and the combustion zone residence time.

(*2*) For a catalytic vapor incinerator, the design analysis shall include the vent stream composition, constituent concentrations, and flow rate and shall establish the design minimum and average temperatures across the catalyst bed inlet and outlet, and the design service life of the catalyst.

(*3*) For a boiler or process heater, the design analysis shall include the vent stream composition, constituent concentrations, and flow rate; shall establish the design minimum and average flame zone temperatures and combustion zone residence time; and shall describe the method and location where the vent stream is introduced into the flame zone.

(*4*) For a condenser, the design analysis shall include the vent stream composition, constituent concentrations, flow rate, 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.

(*5*) For a carbon adsorption system that regenerates the carbon bed directly on-site in a control device such as a fixed-bed adsorber, the design analysis shall include the vent stream composition, constituent concentrations, flow rate, 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 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.

(*6*) For a carbon adsorption system that does not regenerate the carbon bed directly on-site in the control device, such as a carbon canister, the design analysis shall include the vent stream composition, constituent concentrations, flow rate, relative humidity, and temperature, and shall establish the design exhaust vent stream organic compound concentration level, capacity of carbon bed, type and working capacity of activated carbon used for 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.

(B) If the owner or operator and the Administrator do not agree on a demonstration of control device performance using a design analysis then the disagreement shall be resolved using the results of a performance test performed by the owner or operator in accordance with the requirements of paragraph (d)(3)(iii) of this section. The Administrator may choose to have an authorized representative observe the performance test.

(4) The owner or operator shall operate each control device in accordance with the requirements specified in paragraphs (d)(4)(i) through (d)(4)(iii) of this section.

(i) The control device shall be operating at all times when gases, vapors, and fumes are vented from the unit or units through the closed-vent system to the control device.

(ii) For each control device monitored in accordance with the requirements of § 63.773(d), the owner or operator shall operate the control device such that the actual value of each operating parameter required to be monitored in accordance with the requirements of § 63.773(d)(3) is greater than the minimum operating parameter value or less than the maximum operating parameter value, as appropriate, established for the control device in accordance with the requirements of § 63.773(d)(4).

(iii) Failure by the owner or operator to operate the control device in accordance with the requirements of paragraph (d)(4)(ii) of this section shall constitute a violation of the applicable emission standard of this subpart.

(5) For each carbon adsorption system used as a control device to meet the requirements of paragraph (d)(1) of this section, the owner or operator shall manage the carbon as specified in paragraphs (c)(5)(i) and (c)(5)(ii) of this section.

(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.

(ii) All carbon removed from the control device shall be managed in one of the following manners:

(A) Regenerated or reactivated in a thermal treatment unit for which the owner or operator has either been issued a final permit under 40 CFR part 270, and designed and operated the unit in accordance with the requirements of 40 CFR part 264, subpart X; or certified compliance with the interim status requirements of 40 CFR part 265, subpart P.

(B) Burned in a hazardous waste incinerator for which the owner or operator has been issued a final permit under 40 CFR part 270, and designed and operated the unit in accordance with the requirements of 40 CFR part 264, subpart O.

(C) Burned in a boiler or industrial furnace for which the owner or operator has either been issued a final permit under 40 CFR part 270, and designed and operated the unit in accordance with the requirements of 40 CFR part 266, subpart H, or certified compliance with the interim status requirements of 40 CFR part 266, subpart H.

**§ 63.772 Test methods and compliance procedures.**

(a) Determination of material VOHAP or HAP concentration for applicability to the equipment leak standards under this subpart (§ 63.769).

(1) An owner or operator is not required to determine the VOHAP or HAP concentration for materials placed in units subject to this subpart using air emission controls in accordance with the requirements of § 63.766.

(2) An owner or operator shall perform a VOHAP or HAP concentration determination at the following times:

(i) When the material enters the facility in a storage vessel, the owner or operator shall perform a VOHAP or HAP concentration determination for each storage vessel.

(ii) When the material enters the facility as a continuous, uninterrupted flow of material through a pipeline or other means, the owner or operator shall:

(A) Perform an initial VOHAP or HAP concentration determination before the first time any portion of the material is placed in a unit subject to this subpart; and

(B) Perform a new VOHAP or HAP concentration determination whenever changes to the material could potentially cause the VOHAP or HAP concentration of the material to increase to a level that is equal to or greater than the applicable VOHAP or HAP concentration limits specified in § 63.769.

(3) An owner or operator shall determine the VOHAP or HAP concentration of a material using either direct measurement as specified in paragraph (a)(4) of this section or knowledge of the material as specified in paragraph (a)(5) of this section.

(4) Direct measurement to determine VOHAP or HAP concentration.

(i) For the purpose of determining the VOHAP or HAP concentration at the point of entry, samples of the material shall be collected from the storage vessel, pipeline, or other device used to deliver the material to the facility before the material is either:

(A) Combined with other material; or

(B) Conveyed, handled, or otherwise managed in such a manner that the surface of the material is open to the atmosphere.

(ii) For the purpose of determining the VOHAP or HAP concentration at the point of treatment, samples shall be collected at or after the point of treatment but before the point where this material is either:

(A) Combined with other materials;

(B) Conveyed, handled, or otherwise managed in such a manner that the surface of the material is open to the atmosphere; or

(C) Placed in a unit subject to this subpart.

(iii) The VOHAP or HAP concentration on a mass-weighted average basis shall be determined using the procedure specified in paragraphs (a)(4)(iii)(A) through (a)(4)(iii)(D) of this section when the material flows as a continuous stream for periods less than or equal to 1 hour.

(A) A sufficient number of samples, but no less than four samples, shall be collected to represent the VOHAP or HAP composition for the entire quantity of material. All of the samples shall be collected within a 1-hour period.

(B) Each sample shall be collected in accordance with the requirements specified in ''Test Methods for Evaluating Solid Waste, Physical/Chemical Methods,'' EPA Publication No. SW–846.

(C) Each collected sample shall be prepared and analyzed in accordance with the requirements of Method 305, 40 CFR part 63, appendix A or Method 25D, 40 CFR part 60, appendix A.

(D) The VOHAP or HAP concentration shall be calculated by using the results for all samples analyzed in accordance with paragraph (a)(4)(iii)(C) of this section and the following equation:

$$\overline{C} = \frac{1}{n} \times \sum_{i=1}^{n} C_i$$

where:

C=VOHAP or HAP concentration of the material on a mass-weighted basis, parts per million by weight.

I=Individual sample ''I'' of the material. n=Total number of samples of material collected (at least 4) within a 1-hour period.

$C_i$=Measured VOHAP or HAP concentration of sample ''I'' as determined in accordance with the requirements of § 63.772(a)(4)(iii)(C), parts per million by weight.

(iv) The VOHAP or HAP concentration on a mass-weighted average basis shall be determined using the procedures specified in paragraphs (a)(4)(iv)(A) through (a)(4)(iv)(E) of this section when the material flows as a continuous stream of material for periods greater than 1-hour.

(A) The averaging period to be used for determining the VOHAP concentration on a mass-weighted average basis shall be designated and recorded. The averaging period shall represent any time interval that the material flows until the time that a new VOHAP or HAP concentration determination must be performed pursuant to the requirements of paragraph (b) of this section. The averaging period shall not exceed 1 year.

(B) A sufficient number of samples, but no less than four samples, shall be collected to represent the complete range of VOHAP or HAP compositions and VOHAP or HAP quantities that occur in the material stream during the entire averaging period due to normal variations in the operating conditions for the source, process, or unit generating the material. Examples of such normal variations are seasonal variations in material quantity, cyclic process operations, or fluctuations in ambient temperature.

(C) Each sample shall be collected in accordance with the requirements specified in ''Test Methods for Evaluating Solid Waste, Physical/Chemical Methods,'' EPA Publication No. SW–846. Sufficient information shall be recorded to document the material quantity and the operating conditions for the source, process, or unit generating the material represented by each sample collected.

(D) Each collected sample shall be prepared and analyzed in accordance with the requirements of Method 305, 40 CFR part 63, appendix A or Method 25D, 40 CFR part 60, appendix A.

(E) The VOHAP or HAP concentration on a mass-weighted average basis shall be calculated by using the results for all samples analyzed in accordance with paragraph (a)(4)(vi)(D) of this section and the following equation:

$$\overline{C} = \frac{1}{Q_T} \times \sum_{i=1}^{n} \left(Q_i \times C_i\right)$$

where:

C=VOHAP or HAP concentration of the material on a mass weighted basis, parts per million by weight.

I=Individual sample ''I'' of the material. n=Total number of samples of the material collected (at least 4) for the averaging period (not to exceed 1 year).

$Q_i$=Mass quantity of stream represented by $C_i$, kg/hr.

$Q_T$=Total mass quantity of material during the averaging period, kilograms per hour.

$C_i$=Measured VOHAP or HAP concentration of sample ''I'' as determined in accordance with the requirements of

§ 63.772(a)(4)(iv)(D), parts per million by weight.

(5) Knowledge of the material to determine VOHAP or HAP concentration.

(i) Sufficient information shall be prepared and recorded that documents the basis for the owner or operator's knowledge of the material's VOHAP or HAP concentration. Examples of information that may be used as the basis for knowledge of the material include: VOHAP or HAP material balances for the source, process, or unit generating the material; species-specific VOHAP or HAP chemical test data for the material from previous testing still applicable to the current operations; documentation that material is generated by a process for which no materials containing VOHAP or HAP are used; or previous test data for other locations managing the same type of material.

(ii) If test data are used as the basis for knowledge of the material, then the owner or operator shall document the test method, sampling protocol, and the means by which sampling variability and analytical variability are accounted for in the determination of the VOHAP or HAP concentration. For example, an owner or operator may use HAP concentration test data that are validated in accordance with Method 301, 40 CFR part 63, appendix A as the basis for knowledge of the material.

(iii) An owner or operator using species-specific VOHAP or HAP chemical concentration test data as the basis for knowledge of the material that is a produced water stream may adjust the test data results to the corresponding total VOHAP or HAP concentration value that would be reported had the samples been analyzed using Method 305, 40 CFR part 63, appendix A. To adjust these data, the measured concentration for each individual VOHAP or HAP chemical species contained in the material is multiplied by the appropriate species-specific adjustment factor listed in table 34 in the appendix to 40 CFR part 63, subpart G.

(b) Determination of glycol dehydration unit flow rate or benzene emissions. The procedures of this paragraph shall be used by an owner or operator to determine flow rate or benzene emissions to meet the criteria for an exemption from control requirements under § 63.764(e).

(1) The determination of actual flow rate of natural gas to a glycol dehydration unit shall be made using the procedures of either paragraph (b)(1)(i) or (b)(1)(ii) of this section.

(i) The owner or operator shall install and operate a monitoring instrument that directly measures flow to the glycol dehydration unit with an accuracy of plus or minus 2 percent; or

(ii) The owner or operator shall document that the actual annual average flow rate of the dehydration unit is less than 85 thousand cubic meters per day (3.0 million standard cubic feet per day).

(2) The determination of benzene emissions from a glycol dehydration unit shall be made using the procedures of either paragraph (b)(2)(i) or (b)(2)(ii) of this section.

(i) The owner or operator shall determine annual benzene emissions using the model GRI–GLYCalc™, Version 3.0 or higher. Inputs to the model shall be representative of actual operating conditions of the glycol dehydration unit; or

(ii) The owner or operator shall determine an average mass rate of benzene emissions in kilograms per hour through direct measurement by performing three runs of Method 18, 40 CFR Part 60, appendix A (or an equivalent method), and averaging the results of the three runs. Annual emissions in kilograms per year shall be determined by multiplying the mass rate by the number of hours the unit is operated per year. This result shall be multiplied by 1.1023 $E^{-03}$ to convert to tons per year.

(c) No detectable emissions test procedure.

(1) The no detectable emissions test procedure shall be conducted in accordance with Method 21, 40 CFR part 60, appendix A.

(2) The detection instrument shall meet the performance criteria of Method 21, 40 CFR part 60, appendix A, except that the instrument response factor criteria in section 3.1.2(a) of Method 21 shall be for the average composition of the fluid and not for each individual organic compound in the stream.

(3) The detection instrument shall be calibrated before use on each day of its use by the procedures specified in Method 21, 40 CFR part 60, appendix A.

(4) Calibration gases shall be as follows:

(i) Zero air (less than 10 parts per million by volume hydrocarbon in air); and

(ii) A mixture of methane in air at a concentration less than 10,000 parts per million by volume.

(5) The background level shall be determined according to the procedures in Method 21, 40 CFR part 60, appendix A.

(6) The arithmetic difference between the maximum organic concentration indicated by the instrument and the background level shall be compared with the value of 500 parts per million by volume. If the difference is less than 500 parts per million by volume, then no HAP emissions are detected.

(d) [Reserved]

(e) Control device performance test procedures. This paragraph applies to the performance testing of control devices. Owners or operators may elect to use the alternative procedures in paragraph (f) of this section for performance testing of a condenser used to control emissions from a glycol dehydration unit process vent.

(1) Method 1 or 1A, 40 CFR part 60, appendix A, as appropriate, shall be used for selection of the sampling sites at the inlet and outlet of the control device.

(i) To determine compliance with the control device percent reduction requirement specified in § 63.771(d)(1), sampling sites shall be located at the inlet of the control device as specified in paragraphs (e)(1)(i)(A) and (e)(1)(i)(B) of this section, and at the outlet of the control device.

(A) The control device inlet sampling site shall be located after the final product recovery device.

(B) If a vent stream is introduced with the combustion air, or as a secondary fuel, into a boiler or process heater with a design capacity less than 44 megawatts, selection of the location of the inlet sampling sites shall ensure the measurement of total HAP or TOC concentration, as applicable, in all vent streams and primary and secondary fuels.

(ii) To determine compliance with the enclosed combustion device total HAP concentration limit specified in § 63.771(d)(1)(i)(B), the sampling site shall be located at the outlet of the device.

(2) The gas volumetric flow rate shall be determined using Method 2, 2A, 2C, or 2D, 40 CFR part 60, appendix A, as appropriate.

(3) To determine compliance with the control device percent reduction requirement in § 63.771(d)(1)(i), the owner or operator shall use Method 18, 40 CFR part 60, appendix A; alternatively, any other method or data that has been validated according to the applicable procedures in Method 301, 40 CFR part 63, appendix A may be used. The following procedures shall be used to calculate percent reduction efficiency:

(i) 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.

(ii) The mass rate of either TOC (minus methane and ethane) or total HAP ($E_i$, $E_o$) shall be computed.

(A) The following equations shall be used: where:

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

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

Where:

$C_{ij}$, $C_{oj}$= 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.

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

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

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

$K_2$ =Constant, $2.494 \times 10^{-6}$ (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.

(B) When the TOC mass rate is calculated, all organic compounds (minus methane and ethane) measured by Method 18, 40 CFR part 60, appendix A shall be summed using the equation in paragraph (e)(3)(ii)(A) of this section.

(C) When the total HAP mass rate is calculated, only HAP chemicals listed in Table 1 of this subpart shall be summed using the equation in paragraph (e)(3)(ii)(A) of this section.

(iii) The percent reduction in TOC (minus methane and ethane) or total HAP shall be calculated as follows

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

Where:

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

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

$E_o$ =Mass rate of TOC (minus methane and ethane) or total HAP at the outlet of the control device, as calculated under paragraph (e)(3)(ii) of this section, kilograms TOC per hour or kilograms HAP 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, the weight-percent reduction of total HAP or TOC (minus methane and ethane) across the device shall be determined by comparing the TOC (minus methane and ethane) or total HAP in all combusted vent streams and primary and secondary fuels with the TOC (minus methane and ethane) or total HAP exiting the device, respectively.

(4) To determine compliance with the enclosed combustion device total HAP concentration limit specified in § 63.771(d)(1)(i)(B), the owner or operator shall use Method 18, 40 CFR part 60, appendix A to measure either TOC (minus methane and ethane) or total HAP. Alternatively, any other method or data that has been validated according to Method 301, 40 CFR part 63, appendix A, may be used. The following procedures shall be used to calculate parts per million by volume concentration, corrected to 3 percent oxygen:

(i) 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.

(ii) The TOC concentration or total HAP concentration shall be calculated according to paragraph (e)(4)(ii)(A) or (e)(4)(ii)(B) of this section.

(A) The TOC concentration is the sum of the concentrations of the individual components and shall be computed for each run using the following equation:

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

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.

(B) The total HAP concentration shall be computed according to the equation in paragraph (e)(4)(ii)(A) of this section, except that only HAP chemicals listed in Table 1 of this subpart shall be summed.

(iii) The TOC concentration or total HAP concentration shall be corrected to 3 percent oxygen as follows:

(A) The emission rate correction factor or excess air, integrated sampling and analysis procedures of Method 3B, 40 CFR part 60, appendix A shall be used to determine the oxygen concentration. The samples shall be taken during the same time that the samples are taken for determining TOC concentration or total HAP concentration.

(B) The TOC or HAP concentration shall be corrected for percent oxygen by using the following equation:

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

Where:

Cc = TOC concentration or total HAP concentration corrected to 3 percent oxygen, dry basis, parts per million by volume.

$C_m$ = TOC concentration or total HAP concentration, dry basis, parts per million by volume.

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

(f) As an alternative to the procedures in paragraph (e) of this section, an owner or operator may elect to use the procedures documented in the Gas Research Institute Report entitled, ‘‘Atmospheric Rich/Lean Method for Determining Glycol Dehydrator Emissions’’ (GRI–95/0368.1).

**§ 63.773 Inspection and monitoring requirements.**

(a) This section applies to an owner or operator using air emission controls in accordance with the requirements of §§ 63.765 and 63.766.

(b) *Cover inspection and monitoring requirements.* (1) Each cover used in accordance with the requirements of § 63.766 shall be visually inspected and monitored for no detectable emissions by the owner or operator using the procedure specified in paragraph (b)(3) of this section, except as provided for in paragraph (b)(2) of this section.

(2) An owner or operator is exempt from performing the cover inspection and monitoring requirements specified in paragraph (b)(3) of this section for the following units:

(i) A storage vessel internal floating roof that is inspected and monitored in accordance with the requirements of 40 CFR 60.113b(a); or

(ii) A storage vessel external floating roof that is inspected and monitored in accordance with the requirements of 40 CFR 60.113b(b).

(iii) If a storage vessel is buried partially or entirely underground, an owner or operator is required to perform the cover inspection and monitoring requirements specified in paragraph (b)(3) of this section only for those portions of the storage vessel cover and those connections to the storage vessel cover or tank body (e.g., fill ports, access hatches, gauge wells, etc.) that extend to or above the ground surface and can be opened to the atmosphere.

(3) Inspection and monitoring of a cover shall be performed as follows:

(i) The cover and all cover openings shall be initially visually inspected and monitored for no detectable emissions on or before the date that the unit on which the cover is installed becomes subject to the provisions of this subpart and at other times as requested by the Administrator.

(ii) At least once every six months following the initial visual inspection and monitoring for no detectable emissions required under paragraph (b)(3)(i) of this section, the owner and operator shall visually inspect and monitor the cover and each cover opening, except for following cover openings:

(A) A cover opening that has continuously remained in a closed, sealed position for the entire period since the last time the cover opening was visually inspected and monitored for no detectable emissions;

(B) A cover opening that is designated as unsafe to inspect and monitor in accordance with paragraph (b)(3)(v) of this section;

(C) A cover opening on a cover installed and placed in operation before February 6, 1998, that is designated as difficult to inspect and monitor in accordance with paragraph (b)(3)(vi) of this section.

(iii) To visually inspect a cover, the owner or operator shall view the entire cover surface and each cover opening in a closed, sealed position for evidence of any defect that may affect the ability of the cover or cover opening to continue to operate with no detectable emissions. A visible hole, gap, tear, or split in the cover surface or a cover opening is defined as a leak which shall be repaired in accordance with paragraph (b)(3)(vii) of this section.

(iv) To monitor a cover for no detectable emissions, the owner or operator shall use the following procedure:

(A) For all cover connections and seals, except for the seals around a rotating shaft that passes through a cover opening, if the monitoring instrument indicates an instrument concentration reading greater than 500 parts per million by volume minus the background level, then a leak is detected. Each detected leak shall be repaired in accordance with paragraph (b)(3)(vii) of this section.

(B) For the seals around a rotating shaft that passes through a cover opening, if the monitoring instrument indicates an instrument concentration reading greater than 10,000 parts per million by volume then a leak is detected. Each detected leak shall be repaired in accordance with paragraph (b)(3)(vii) of this section.

(v) An owner or operator may designate a cover as an unsafe to inspect and monitor cover if all of the following conditions are met:

(A) The owner or operator determines that inspection or monitoring of the cover would expose a worker to dangerous, hazardous, or other unsafe conditions.

(B) The owner or operator develops and implements a written plan and schedule to inspect the cover using the procedure specified in paragraph (b)(3)(iii) of this section and monitor the cover using the procedure specified in paragraph (b)(3)(iv) of this section as frequently as practicable during those times when a worker can safely access the cover.

(vi) An owner or operator may designate a cover installed and placed in operation before February 6, 1998 as a difficult to inspect and monitor cover if all of the following conditions are met:

(A) The owner or operator determines that inspection or monitoring the cover requires elevating a worker to a height greater than 2 meters (approximately 7 feet) above a support surface; and

(B) The owner and operator develops and implements a written plan and schedule to inspect the cover using the procedure specified in paragraph (b)(3)(iii) of this section, and monitors the cover using the procedure specified in paragraph (b)(3)(iv) of this section at least once per calendar year.

(vii) When a leak is detected by either of the methods specified in paragraph (b)(3)(iii) or (b)(3)(iv) of this section, the owner or operator shall make a first attempt at repairing the leak no later than five calendar days after the leak is detected. Repair of the leak shall be completed as soon as practicable, but no later than 15 calendar days after the leak is detected. If repair of the leak cannot be completed within the 15-day period, then the owner or operator shall not add material to the unit on which the cover is installed until the repair of the leak is completed.

(c) *Closed-vent system inspection and monitoring requirements.* (1) The owner or operator shall visually inspect and monitor each closed-vent system for no detectable emissions at the following times:

(i) On or before the date that the unit connected to the closed-vent system becomes subject to the provisions of this subpart;

(ii) At least once per year after the date that the closed-vent system is inspected in accordance with the requirements of paragraph (c)(1)(i) of this section; and

(iii) At other times as requested by the Administrator.

(2) To visually inspect a closed-vent system, the owner or operator shall view the entire length of ductwork, piping and connections to covers and control devices for evidence of visible defects (such as holes in ductwork or piping and loose connections) that may affect the ability of the system to operate with no detectable emissions. A visible hole, gap, tear, or split in the closed-vent system is defined as a leak which shall be repaired in accordance with paragraph (c)(4) of this section.

(3) To monitor a closed-vent system for no detectable emissions, the owner or operator shall use Method 21, 40 CFR part 60, appendix A to test each closed-vent system joint, seam, or other connection. For the annual leak detection monitoring after the initial leak detection monitoring, the owner or operator is not required to monitor those closed-vent system components which continuously operate at a pressure below atmospheric pressure or those closed-vent system joints, seams, or other connections that are permanently or semi-permanently sealed (e.g., a welded joint between two sections of metal pipe or a bolted and gasketed pipe flange).

(4) When a leak is detected by either of the methods specified in paragraph (c)(2) or (c)(3) of this section, the owner or operator shall make a first attempt at repairing the leak no later than five calendar days after the leak is detected. Repair of the leak shall be completed as soon as practicable, but no later than 15 calendar days after the leak is detected.

(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 monitoring system in accordance with the requirements of paragraphs (d)(3) through (d)(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 continuously achieving the applicable performance requirements of § 63.771.

(2) An owner or operator is exempt from the monitoring requirements specified in paragraphs (d)(3) through (d)(5) of this section for the following types of control devices:

(i) A boiler or process heater in which all vent streams are introduced with primary fuel; or

(ii) A boiler or process heater with a design heat input capacity equal to or greater than 44 megawatts.

(3) The owner or operator shall 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)(3)(i), (d)(3)(ii), or (d)(3)(iii) of this section. The monitoring equipment shall be installed, calibrated, and maintained in accordance with the equipment manufacturer's specifications or other written procedures that provide adequate assurance that the equipment would reasonably be expected to monitor accurately. The continuous recorder shall be a data recording device that either records an instantaneous data value at least once every 15 minutes or records 15-minute or more frequent block average values. The owner or operator shall use any of the following continuous monitoring systems:

(i) A continuous monitoring system that measures the following operating parameters as applicable:

(A) For a thermal vapor incinerator, a temperature monitoring device equipped with a continuous recorder. The monitoring device shall have an accuracy of ±1 percent of the temperature being monitored in °C, or ±0.5°C, whichever value is greater. The temperature sensor shall be installed at a location in the combustion chamber downstream of the combustion zone.

(B) For a catalytic vapor incinerator, a temperature monitoring device equipped with a continuous recorder. The device shall be capable of monitoring temperature at two locations and have an accuracy of ±1 percent of the temperature being monitored in °C, or ±0.5°C, whichever value is greater. One temperature sensor shall be installed in the vent stream at the nearest feasible point to the catalyst bed inlet and a second temperature sensor shall be installed in the vent stream at the nearest feasible point to the catalyst bed outlet.

(C) For a flare, a heat sensing monitoring device equipped with a continuous recorder that indicates the continuous ignition of the pilot flame.

(D) For a boiler or process heater with a design heat input capacity of less than 44 megawatts, a temperature monitoring device equipped with a continuous recorder. The temperature monitoring device shall have an accuracy of ±1 percent of the temperature being monitored in °C, or ±0.5°C, whichever value is greater. The temperature sensor shall be installed at a location in the combustion chamber downstream of the combustion zone.

(E) For a condenser, a temperature monitoring device equipped with a continuous recorder. The temperature monitoring device shall have an accuracy of ±1 percent of the temperature being monitored in °C, or ±0.5°C, whichever value is greater. The temperature sensor shall be installed at a location in the exhaust vent stream from the condenser.

(F) For a regenerative-type carbon adsorption system, an integrating regeneration stream flow monitoring device equipped with a continuous recorder and a carbon bed temperature monitoring device equipped with a continuous recorder. The integrating regeneration stream flow monitoring device shall have an accuracy of ±10 percent and measure the total regeneration stream mass flow during the carbon bed regeneration cycle. The temperature monitoring device shall have an accuracy of ±1 percent of the temperature being monitored in °C, or ±0.5°C, whichever value is greater and measure the carbon bed temperature after regeneration and within 15 minutes of completing the cooling cycle and the duration of the carbon bed steaming cycle.

(ii) 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.

(iii) A continuous monitoring system that measures alternative operating parameters other than those specified in paragraph (d)(3)(i) or (d)(3)(ii) of this section upon approval of the Administrator as specified in § 63.8(f)(1) through (f)(5).

(4) For each operating parameter monitored in accordance with the requirements of paragraph (d)(3) of this section, 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. Each minimum or maximum operating parameter value shall be established as follows:

(i) If the owner or operator conducts performance tests in accordance with the requirements of § 63.771 to demonstrate that the control device achieves the applicable performance requirements specified in § 63.771, 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 control device design analysis and manufacturer recommendations.

(ii) If the owner or operator uses control device design analysis in accordance with the requirements of § 63.771(d)(3)(iv) to demonstrate that the control device achieves the applicable performance requirements specified in § 63.771(d)(1), then the minimum operating parameter value or the maximum operating parameter value shall be established based on the control device design analysis and the control device manufacturer's recommendations.

(5) The owner or operator shall regularly inspect the data recorded by the continuous monitoring system to determine whether the control device is operating in accordance with the applicable requirements of § 63.771(d).

### § 63.774 Recordkeeping requirements.

(a) The recordkeeping provisions of 40 CFR part 63, subpart A that apply and those that do not apply to owners and operators of sources subject to this subpart are listed in Table 2 of this subpart.

(b) Except as specified in paragraphs (c) and (d) of this section, each owner or operator of a source subject to this subpart shall maintain the records specified in paragraphs (b)(1) and (b)(2) of this section in accordance with the requirements of § 63.10(b)(1) (General Provisions):

(1) Records specified in § 63.10(b)(2);

(2) 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).

(c) The owner or operator of an area source subject to the control requirements for triethylene glycol dehydration unit process vents in § 63.765 is exempt from the requirements of § 63.6(e)(3) and § 63.10(b)(2)(iv) and (b)(2)(v).

(d) An owner or operator that is exempt from control requirements under § 63.764(e) shall maintain a record of the design capacity (in terms of natural gas flow rate to the unit per day) of each glycol dehydration unit that is not controlled according to the requirements of § 63.764(c)(1)(i) and (d)(1).

### § 63.775 Reporting requirements.

(a) The reporting provisions of 40 CFR part 63, subpart A that apply and those that do not apply to owners and operators of sources subject to these subparts are listed in Table 2 of this subpart.

(b) Each owner or operator of a major source subject to this subpart shall submit the following reports to the Administrator:

(1) An Initial Notification described in § 63.9(a) through (d), except that the notification required by § 63.9(b)(2) shall be submitted not later than one year after the effective date of this standard.

(2) A Notification of Performance Tests specified in §§ 63.7 and 63.9(e) and (g).

(3) A Notification of Compliance Status specified in § 63.9(h).

(4) Performance test reports specified in § 63.10(d)(2) and performance evaluation reports specified in § 63.10(e)(2). Separate performance evaluation reports as described in § 63.10(e)(2) are not required if the information is included in the report specified in paragraph (b)(6) of this section.

(5) Startup, shutdown, and malfunction reports specified in § 63.10(d)(5) shall be submitted as required. Separate startup, shutdown, or malfunction reports as described in § 63.10(d)(5) are not required if the information is included in the report specified in paragraph (b)(6) of this section.

(6) The excess emission and CMS performance report and summary report specified in § 63.10(e)(3) shall be submitted on a semi-annual basis (i.e., once every 6-month period). The summary report shall be entitled ''Summary Report—Gaseous Excess Emissions and Continuous Monitoring System Performance.''

(7) The owner or operator shall meet the requirements specified in paragraph (b) of this section for any emission point or material that becomes subject to the standards in this subpart due to an increase in flow, concentration, or other parameters equal to or greater than the limits specified in this subpart.

(8) For each control device other than a flare used to meet the requirements of this subpart, the owner or operator shall submit the following information for each operating parameter required to be monitored in accordance with the requirements of § 63.773(d):

(i) The minimum operating parameter value or maximum operating parameter value, as appropriate for the control device, established by the owner or operator to define the conditions at which the control device must be operated to continuously achieve the applicable performance requirements of § 63.771(d)(1).

(ii) An explanation of the rationale for why the owner or operator selected each of the operating parameter values established in paragraph (d)(1) of this section. 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).

(9) Each owner or operator of a major source subject to this subpart that is not subject to the control requirements for glycol dehydration unit process vents in § 63.765 is exempt from all reporting requirements for major sources in this subpart.

(c) Each owner or operator of an area source subject to the control requirements of this subpart for triethylene glycol dehydration unit process vents in § 63.765 shall submit the following reports to the Administrator:

(1) An Initial Notification described in § 63.9 (a) through (d), except that the notification required by § 63.9(b)(2) shall be submitted not later than one year after the effective date of this standard.

(2) A Notification of Performance Tests specified in §§ 63.7 and 63.9 (e) and (g).

(3) A Notification of Compliance Status specified in § 63.9(h).

(4) Performance test reports specified in § 63.10(d)(2) and performance evaluation reports specified in § 63.10(e)(2). Separate performance evaluation reports as described in § 63.10(e)(2) are not required if the information is included in the report specified in paragraph (c)(6) of this section.

(5) A report describing any malfunctions that are not corrected within two calendar days of the malfunction, to be submitted within seven calendar days of the uncorrected malfunction.

(6) A summary report as specified in § 63.10(e)(3) shall be submitted on an annual basis (i.e., once every 12-month period). The summary report shall be entitled ''Summary Report—Gaseous Excess Emissions and Continuous Monitoring System Performance.''

(7) The owner or operator shall meet the requirements specified in this paragraph for any emission point or material that becomes subject to the standards in this subpart due to an increase in flow or concentration mass parameters equal to or greater than the limits specified in § 63.764 (b), (c), or (d).

(8) For each control device other than a flare used to meet the requirements of this subpart, the owner or operator shall submit the following information for each operating parameter required to be monitored in accordance with the requirements of § 63.773(d):

(i) The minimum operating parameter value or maximum operating parameter value, as appropriate for the control device, established by the owner or operator to define the conditions at which the control device must be operated to continuously achieve the applicable performance requirements of § 63.771(d)(1).

(ii) An explanation of the rationale for why the owner or operator selected each of the operating parameter values established in paragraph (d)(1) of this section. This explanation shall include any data and calculations used to develop the value and a description of why this value indicates that the control device is operating in accordance with the applicable requirements of § 63.771(d)(1).

(9) Each owner or operator of an area source subject to this subpart that is not subject to the control requirements for glycol dehydration unit process vents in § 63.765 is exempt from all reporting requirements in this subpart.

### § 63.776 Delegation of authority [Reserved]

### § 63.777 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 §§ 63.764 through 63.771, the Administrator will publish in the **Federal Register** a notice 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.

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

(c) Any person seeking permission to use an alternative means of compliance under this section shall collect, verify, and submit to the Administrator information demonstrating that the alternative achieves equivalent emission reductions.

**§ 63.778 [Reserved]**

**§ 63.779 [Reserved]**

TABLE 1 TO SUBPART HH.—LIST OF HAZARDOUS AIR POLLUTANTS FOR SUBPART HH

| CAS Number [a] | Chemical name |
|---|---|
| 75070 | Acetaldehyde. |
| 71432 | Benzene (includes benzene in gasoline). |
| 75150 | Carbon disulfide. |
| 463581 | Carbonyl sulfide. |
| 100414 | Ethyl benzene. |
| 107211 | Ethylene glycol. |
| 50000 | Formaldehyde. |
| 110543 | n-Hexane. |
| 91203 | Naphthalene. |
| 108883 | Toluene. |
| 540841 | 2,2,4-Trimethylpentane. |
| 1330207 | Xylenes (isomers and mixture). |
| 95476 | o-Xylene. |
| 108383 | m-Xylene. |
| 106423 | p-Xylene. |

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

TABLE 2 TO SUBPART HH.—APPLICABILITY OF 40 CFR PART 63 GENERAL PROVISIONS TO SUBPART HH

| General provisions reference | Applicable to subpart HH | Comment |
|---|---|---|
| § 63.1(a)(1) | Yes. | |
| § 63.1(a)(2) | Yes. | |
| § 63.1(a)(3) | Yes. | |
| § 63.1(a)(4) | Yes. | |
| § 63.1(a)(5) | No | Section reserved. |
| § 63.1(a)(6)–(a)(8) | Yes. | |
| § 63.1(a)(9) | No | Section reserved. |
| § 63.1(a)(10) | Yes. | |
| § 63.1(a)(11) | Yes. | |
| § 63.1(a)(12)–(a)(14) | Yes. | |
| § 63.1(b)(1) | No | Subpart HH specifies applicability. |
| § 63.1(b)(2) | Yes. | |
| § 63.1(b)(3) | No. | |
| § 63.1(c)(1) | No | Subpart HH specifies applicability. |
| § 63.1(c)(2) | Yes | Unless required by the State, area sources subject to subpart HH are exempted from permitting requirements. |
| § 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 HH. |
| § 63.3(a)–(c) | Yes. | |
| § 63.4(a)(1)–(a)(3) | Yes. | |
| § 63.4(a)(4) | No | Section reserved. |
| § 63.4(a)(5) | Yes. | |
| § 63.4(b) | Yes. | |
| § 63.4(c) | Yes. | |
| § 63.5(a)(1) | Yes. | |
| § 63.5(a)(2) | No | Preconstruction review required only for major sources that commence construction after promulgation of the standard. |
| § 63.5(b)(1) | Yes. | |
| § 63.5(b)(2) | No | Section reserved. |
| § 63.5(b)(3) | Yes. | |
| § 63.5(b)(4) | Yes. | |
| § 63.5(b)(5) | Yes. | |
| § 63.5(b)(6) | Yes. | |
| § 63.5(c) | No | Section reserved. |
| § 63.5(d)(1) | Yes. | |
| § 63.5(d)(2) | Yes. | |
| § 63.5(d)(3) | Yes. | |
| § 63.5(d)(4) | Yes. | |
| § 63.5(e) | Yes. | |
| § 63.5(f)(1) | Yes. | |
| § 63.5(f)(2) | Yes. | |
| § 63.6(a) | Yes. | |
| § 63.6(b)(1) | Yes. | |
| § 63.6(b)(2) | Yes. | |
| § 63.6(b)(3) | Yes. | |
| § 63.6(b)(4) | Yes. | |

TABLE 2 TO SUBPART HH.—APPLICABILITY OF 40 CFR PART 63 GENERAL PROVISIONS TO SUBPART HH—Continued

| General provisions reference | Applicable to subpart HH | Comment |
|---|---|---|
| § 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)–(c)(4) | No | Sections reserved. |
| § 63.6(c)(5) | Yes. | |
| § 63.6(d) | No | Section reserved. |
| § 63.6(e) | Yes/No | Area sources exempt from paragraph (e)(3). |
| § 63.6(f)(1) | Yes. | |
| § 63.6(f)(2) | Yes. | |
| § 63.6(f)(3) | Yes. | |
| § 63.6(g) | Yes. | |
| § 63.6(h) | No | Subpart HH does not require continuous emissions monitoring systems. |
| § 63.6(i)(1)–(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. | |
| § 63.7(a)(3) | Yes. | |
| § 63.7(b) | Yes. | |
| § 63.7(c) | Yes. | |
| § 63.7(d) | Yes. | |
| § 63.7(e)(1) | Yes. | |
| § 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)(2) | Yes. | |
| § 63.8(c)(3) | Yes. | |
| § 63.8(c)(4) | No. | |
| § 63.8(c)(5)–(c)(8) | Yes. | |
| § 63.8(d) | Yes. | |
| § 63.8(e) | Yes. | |
| § 63.8(f)(1)–(f)(5) | Yes. | |
| § 63.8(f)(6) | No | Subpart HH does not require continuous emissions monitoring. |
| § 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 | Sources are given one year (rather than 120 days) to submit this notification. |
| § 63.9(b)(3) | Yes. | |
| § 63.9(b)(4) | Yes. | |
| § 63.9(b)(5) | Yes. | |
| § 63.9(c) | Yes. | |
| § 63.9(d) | Yes. | |
| § 63.9(e) | Yes. | |
| § 63.9(f) | No. | |
| § 63.9(g) | Yes. | |
| § 63.9(h)(1)–(h)(3) | Yes. | |
| § 63.9(h)(4) | No | Section reserved. |
| § 63.9(h)(5)–(h)(6) | Yes. | |
| § 63.9(i) | Yes. | |
| § 63.9(j) | Yes. | |
| § 63.10(a) | Yes. | |
| § 63.10(b)(1) | Yes. | |
| § 63.10(b)(2) | Yes/No | Area sources are exempt from paragraphs (b)(2)(iv) and (v). |
| § 63.10(b)(3) | No. | |
| § 63.10(c)(1) | Yes. | |
| § 63.10(c)(2)–(c)(4) | No | Sections reserved. |
| § 63.10(c)(5)–(c)(8) | Yes. | |
| § 63.10(c)(9) | No | Section reserved. |

TABLE 2 TO SUBPART HH.—APPLICABILITY OF 40 CFR PART 63 GENERAL PROVISIONS TO SUBPART HH—Continued

| General provisions reference | Applicable to subpart HH | Comment |
| --- | --- | --- |
| § 63.10(c)(10)–(c)(15) | Yes. | |
| § 63.10(d)(1) | Yes. | |
| § 63.10(d)(2) | Yes. | |
| § 63.10(d)(3) | Yes. | |
| § 63.10(d)(4) | Yes. | |
| § 63.10(d)(5) | Yes/No | Subpart HH requires major sources to submit a startup, shutdown and malfunction report semi-annually; area sources are exempt. |
| § 63.10(e) | Yes/No | Subpart HH requires major sources to submit continuous monitoring system performance reports semi-annually; area sources are required to send these reports annually. |
| § 63.10(f) | Yes. | |
| § 63.11(a)–(b) | Yes. | |
| § 63.12(a)–(c) | Yes. | |
| § 63.13(a)–(c) | Yes. | |
| § 63.14(a)–(b) | Yes. | |
| § 63.15(a)–(b) | Yes. | |

B. Part 63 is amended by adding subpart HHH to read as follows:

**Subpart HHH—National Emission Standards for Hazardous Air Pollutants from Natural Gas Transmission and Storage Facilities**



## Subpart HHH—National Emission Standards for Hazardous Air Pollutants From Natural Gas Transmission and Storage Facilities

### § 63.1270 Applicability and designation of affected source.

(a) This subpart applies to owners or 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 and that are major sources of hazardous air pollutant (HAP) emissions.

(b) The affected source is each glycol dehydration unit.

(c) The owner or operator of a facility that does not contain an affected source, as specified in paragraph (b) of this section, is not subject to the requirements of this subpart.

(d) The owner or operator of each affected source shall achieve compliance with the provisions of this subpart by the following dates:

(1) The owner or operator of an affected source the construction or reconstruction of which commenced before February 6, 1998, shall achieve compliance with the provisions of the subpart as expeditiously as practical after [the date of publication of the final rule], but no later than three years after [the date of publication of the final rule] except as provided for in § 63.6(i).

(2) 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 startup or [the date of publication of the final rule], whichever date is later.

(e) An owner or operator of an affected source that is a major source or located at a major source and is subject to the provisions of this subpart is also subject to 40 CFR part 70 permitting requirements.

### § 63.1271 Definitions.

All terms used in this subpart shall have the meaning given to them in the Clean Air Act, subpart A of this part (General Provisions), and in this section. If the same term is defined in subpart A and in this section, it shall have the meaning given in this section for purposes of this subpart.

*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 with the potential for flash emissions.

*Average concentration,* as used in this subpart, means the flow-weighted annual average concentration, as determined according to the procedures specified in § 63.1282(a).

*Boiler* means any enclosed combustion device that extracts useful energy in the form of steam and is not an incinerator.

*Closed-vent system* means a system that is not open to the atmosphere and is composed of piping, ductwork, connections, and, if necessary, flow inducing devices that transport gas or vapor from an emission point to a control device or back into the process. If gas or vapor from regulated equipment is routed to a process (e.g., to a fuel gas system), the process shall not be considered a closed vent system and is not subject to closed vent system standards.

*Combustion device* means an individual unit of equipment, such as a flare, incinerator, process heater, or boiler, used for the combustion of volatile organic compound vapors.

*Compressor station* means any permanent combination of equipment that supplies energy to move natural gas at increased pressure from fields, in transmission pipelines, or into storage.

*Continuous recorder* means a data recording device that either records an instantaneous data value at least once every 15 minutes or records 15-minute or more frequent block average values.

*Control device* means any equipment used for recovering or oxidizing hazardous air pollutant (HAP) and volatile organic compound (VOC) vapors. Such equipment includes, but is not limited to, absorbers, carbon adsorbers, condensers, incinerators, flares, boilers, and process heaters. For the purposes of this subpart, if gas or vapor from regulated equipment is used, reused, returned back to the process, or sold, then the recovery system used, including piping, connections, and flow inducing devices, is not considered to be control devices.

*Facility* means any grouping of equipment where natural gas is processed, compressed, or stored prior to entering a pipeline to a local distribution company or to a final end user. A facility for this source category typically is: A natural gas compressor station that receives natural gas via pipeline, from an underground natural gas storage operation, from a condensate tank battery, or from a natural gas processing plant; or An underground natural gas storage operation. The emission points associated with these phases include, but are not limited to, process vents. Processes that may have vents include, but are not limited to, dehydration, and compressor station engines. Facility, for the purpose of a major source determination, means natural gas transmission and storage equipment that is located inside the boundaries of an individual surface site connected by ancillary equipment, such as gas flow lines, roads, or power lines. Equipment that is part of a facility will typically be located within close proximity to other equipment located at the same facility. Natural gas transmission and storage equipment or groupings of equipment located on different gas leases, mineral fee tracts, lease tracts, subsurface unit areas, surface fee tracts, or surface lease tracts shall not be considered part of the same facility.

*Flame zone* means the portion of the combustion chamber in a boiler occupied by the flame envelope.

*Flow indicator* means a device which indicates whether gas flow is present in a line.

*Gas-condensate-glycol (GCG) separator* means a two-or three-phase separator through which the ''rich'' glycol stream of a glycol dehydration unit is passed to remove entrained gas and hydrocarbon liquid. The GCG separator is commonly referred to as a flash separator or flash tank.

*Glycol dehydration unit* means a device in which a liquid glycol directly contacts a natural gas stream (that is circulated counter current to the glycol flow) and absorbs water vapor in a contact tower or absorption column (absorber). The glycol contacts and absorbs water vapor and other gas stream constituents from the natural gas and becomes ''rich'' glycol. This glycol is then regenerated by distilling the water and other gas stream constituents in the glycol dehydration unit reboiler. The distilled or ''lean'' glycol is then recycled back to the absorber.

*Glycol dehydration unit reboiler vent* means the vent through which exhaust from the reboiler of a glycol dehydration unit passes from the reboiler to the atmosphere.

*Glycol dehydration unit process vent* means either the glycol dehydration unit reboiler vent or the vent from the GCG separator (flash tank).

*Hazardous air pollutants* or *HAP* means the chemical compounds listed in section 112(b) of the Act. All chemical compounds listed in section 112(b) of the Act need to be considered when making a major source determination. Only the HAP compounds listed in Table 1 of this subpart need to be considered when determining applicability and compliance.

*Incinerator* means an enclosed combustion device that is used for destroying organic compounds. Auxiliary fuel may be used to heat waste gas to combustion temperatures. Any energy recovery section shall not be physically formed into one manufactured or assembled unit with the combustion section; rather, the energy recovery section shall be a separate section following the combustion section and the two are joined by ducts or connections carrying flue gas. The above energy recovery section limitation does not apply to an energy recovery section used solely to permit the incoming vent stream or combustion air.

*Major source*, as used in this subpart, shall have the same meaning as in § 63.2, except that:

(1) Emissions from any oil or gas exploration or production well (with its associated equipment) and emissions from any pipeline compressor or pump station shall not be aggregated with emissions from other similar units, whether or not such units are in a contiguous area or under common control; and

(2) Emissions from processes, operations, and equipment that are not part of the same facility, as defined in this section, shall not be aggregated.

*Natural gas* means the gaseous mixture of hydrocarbon gases and vapors, primarily consisting of methane, ethane, propane, butane, pentane, and hexane, along with water vapor and other constituents.

*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).

*No detectable emissions* means no escape of hazardous air pollutants (HAP) from a device or system to the atmosphere as determined by:

(1) Testing the device or system in accordance with the requirements of § 63.1282(d); and

(2) No visible openings or defects in the device or system such as rips, tears, or gaps.

*Operating parameter value* means a minimum or maximum value established for a control device or process parameter which, if achieved by itself or in combination with one or more other operating parameter values, determines that an owner or operator has complied with an applicable emission limitation or standard.

*Operating permit* means a permit required by 40 CFR part 70 or part 71.

*Organic monitoring device* means a unit of equipment used to indicate the concentration level of organic compounds exiting a recovery device based on a detection principle such as infra-red, photoionization, or thermal conductivity.

*Point of material entry* means at the point where a material first enters a source subject to this subpart.

*Primary fuel* means the fuel that provides the principal heat input (i.e., more than 50-percent) to the device. To be considered primary, the fuel must be able to sustain operation without the addition of other fuels.

*Process heater* means a device that transfers heat liberated by burning fuel directly to process streams or to heat transfer liquids other than water.

*Safety device* means a device that is not used for planned or routine venting of liquids, gases, or fumes from the unit or equipment on which the device is installed; and the device remains in a closed, sealed position at all times except when an unplanned event requires that the device open for the purpose of preventing physical damage or permanent deformation of the unit or equipment on which the device is installed in accordance with good engineering and safety practices for handling flammable, combustible, explosive, or other hazardous materials. Examples of unplanned events which may require a safety device to open include failure of an essential equipment component or a sudden power outage.

*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 constructed primarily of non-earthen materials (e.g., wood, concrete, steel, plastic) that provide structural support.

*Temperature monitoring device* means a unit of equipment used to monitor temperature and having an accuracy of ±1 percent of the temperature being monitored expressed in °C, or ±0.5°C, whichever is greater.

*Total organic compounds* or *TOC,* as used in this subpart, means those compounds measured according to the procedures of Method 18, 40 CFR part 60, appendix A.

*Underground storage* means the subsurface facilities utilized for storing natural gas that has been transferred from its original location for the primary purpose of load balancing, which is the process of equalizing the receipt and delivery of natural gas. Processes and operations that may be located at an underground storage facility include, but are not limited to, compression and dehydration.

**§ 63.1272 [Reserved]**

**§ 63.1273 [Reserved]**

**§ 63.1274 General standards.**

(a) 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:

(1) The control requirements for glycol dehydration unit process vents specified in § 63.1275,

(2) The monitoring requirements of § 63.1283, and

(3) The recordkeeping and reporting requirements of §§ 63.1284 and 63.1285.

(b) The owner or operator is exempt from the requirements of paragraph (a) of this section if the actual annual average flow of natural gas to the glycol dehydration unit is less than 85 thousand cubic meters per day (3.0 million standard cubic feet per day) or emissions of benzene from the unit to the atmosphere are less than 0.9 megagram per year (1 ton per year). The flow of gas to the unit and emissions of benzene from the unit shall be determined by the procedures specified in § 63.1282(a). This determination must be made available to the Administrator upon request.

(c) Each owner or operator of a major HAP source subject to this subpart is required to apply for a part 70 or part 71 operating permit from the appropriate permitting authority. If the Administrator has approved a State operating permit program under 40 CFR part 70, the permit shall be obtained from the State authority. If the State operating permit program has not been approved, the owner or operator of a source shall apply to the EPA Regional Office pursuant to 40 CFR part 71.

(d) An owner or operator of an affected source that is a major source or located at a major source subject to the provisions of this subpart that is in violation of an operating parameter value is in violation of the applicable emission limitation or standard.

**§ 63.1275 Glycol dehydration unit process vents standards.**

(a) This section applies to each glycol dehydration unit process vent required to meet the air emission control requirements specified in § 63.1274(a).

(b) Except as provided in paragraph (c) of this section, the following air emission control requirements apply to glycol dehydration unit process vents at an existing or new source.

(1) For each glycol dehydration unit process vent, the owner or operator shall control air emissions by connecting the process vent through a closed-vent system to a control device designed and operated in accordance with the requirements of § 63.1281(c) and (d).

(2) One or more safety devices that vent directly to the atmosphere may be used on the air emission control equipment complying with paragraph (b)(1) of this section.

(c) As an alternative to the requirements of paragraph (b) of this section, the owner or operator may comply with one of the following:

(1) The owner or operator shall control air emissions by connecting the process vent to a process natural gas line through a closed-vent system designed and operated in accordance with the requirements of § 63.1281(c) and (d).

(2) The owner or operator shall demonstrate, to the Administrator's satisfaction, that total HAP emissions to the atmosphere from the glycol dehydration unit reboiler vent and GCG separator (flash tank) vent (if present) are reduced by 95 percent through process modifications.

(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 HAP emissions to the atmosphere from the glycol dehydration unit reboiler vent and GCG separator (flash tank) vent are reduced by 95 percent.

**§ 63.1276 [Reserved]**

**§ 63.1277 [Reserved]**

**§ 63.1278 [Reserved]**

**§ 63.1279 [Reserved]**

**§ 63.1280 [Reserved]**

**§ 63.1281 Control equipment requirements.**

(a) This section applies to each closed-vent system, and control device installed and operated by the owner or operator to control air emissions in accordance with the standards of this subpart.

(b) [Reserved]

(c) *Closed-vent system requirements.* (1) The closed-vent system shall route all gases, vapors, and fumes emitted from the material in the unit to a control device that meets the requirements specified in paragraph (d) of this section.

(2) The closed-vent system shall be designed and operated with no detectable emissions.

(3) 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, the owner or operator shall meet the following requirements:

(i) For each bypass device except as provided for in paragraph (c)(3)(ii) of this section, the owner or operator shall either:

(A) Install, calibrate, maintain, and operate a flow indicator at the inlet to the bypass device that indicates at least once every 15 minutes whether gas, vapor, or fume flow is present in the bypass device; or

(B) Secure the valve installed at the inlet to the bypass device in the closed position using a car-seal or a lock-and-key type configuration. The owner or operator shall visually inspect the seal or closure mechanism at least once every month to verify that the valve is maintained in the closed position.

(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 (c)(3)(i) of this section.

(d) *Control device requirements.* (1) The control device shall be one of the following devices:

(i) An enclosed combustion device (e.g., thermal vapor incinerator, catalytic vapor incinerator, boiler, or process heater) that is designed and operated in accordance with one of the following performance requirements:

(A) Reduces the mass content of either TOC or total HAP in the gases vented to the device by 95 percent by weight or greater, as determined in accordance with the requirements of § 63.1282(d);

(B) Reduces the concentration of either TOC or a total HAP 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 § 63.1282(d)(4); or

(C) Operates at a minimum residence time of 0.5 second at a minimum temperature of 760°C. 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.

(ii) A vapor recovery device (e.g., condenser) 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 percent by weight or greater as determined in accordance with the requirements of § 63.1282(d).

(iii) A flare that is designed and operated in accordance with the requirements of § 63.11(b).

(2) Each control device used to comply with this subpart shall be operated at all times when material is placed in a unit vented to the control device except when maintenance or repair of a unit cannot be completed without a shutdown of the control device. An owner or operator may vent more than one unit to a control device used to comply with this subpart.

(3) The owner or operator shall demonstrate that a control device achieves the performance requirements of paragraph (d)(1) of this section as follows:

(i) An owner or operator shall demonstrate, using either a performance test as specified in paragraph (d)(3)(iii) of this section or a design analysis as specified in paragraph (d)(3)(iv) of this section, the performance of each control device except for the following:

(A) A flare;

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

(C) A boiler or process heater into which the vent stream is introduced with the primary fuel; or

(D) A boiler or process heater burning hazardous waste for which the owner or operator either has 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.

(ii) An owner or operator shall demonstrate the performance of each flare in accordance with the requirements specified in § 63.11(b).

(iii) For a performance test conducted to meet the requirements of paragraph (d)(3)(i) of this section, the owner or operator shall use the test methods and procedures specified in § 63.1282(d) or (e).

(iv) For a design analysis conducted to meet the requirements of paragraph (d)(3)(i) of this section, the design analysis shall meet the following requirements:

(A) The design analysis shall include analysis of the vent stream characteristics and control device operating parameters for the applicable control device type as follows:

(*1*) For a thermal vapor incinerator, the design analysis shall address the vent stream composition, constituent concentrations, and flow rate and shall establish the design minimum and average temperatures in the combustion zone and the combustion zone residence time.

(*2*) For a catalytic vapor incinerator, the design analysis shall address the vent stream composition, constituent concentrations, flow rate, and shall establish the design minimum and average temperatures across the catalyst bed inlet and outlet, and the design service life of the catalyst.

(*3*) For a boiler or process heater, the design analysis shall address the vent stream composition, constituent concentrations, and flow rate; shall establish the design minimum and average flame zone temperatures and combustion zone residence time; and shall describe the method and location where the vent stream is introduced into the flame zone.

(*4*) For a condenser, the design analysis shall address the vent stream composition, constituent concentrations, flow rate, 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.

(*5*) For a carbon adsorption system that regenerates the carbon bed directly on-site in the control device such as a fixed-bed adsorber, the design analysis shall address the vent stream composition, constituent concentrations, flow rate, 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 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.

(*6*) For a carbon adsorption system that does not regenerate the carbon bed directly on-site in the control device such as a carbon canister, the design analysis shall address the vent stream composition, constituent concentrations, flow rate, relative humidity, and temperature and shall establish the design exhaust vent stream organic compound concentration level, capacity of carbon bed, type and working capacity of activated carbon used for carbon bed, and design carbon replacement interval based on the total carbon working capacity of the control device and source operating schedule.

(B) If the owner or operator and the Administrator do not agree on a demonstration of control device performance using a design analysis then the disagreement shall be resolved using the results of a performance test performed by the owner or operator in accordance with the requirements of paragraph (d)(3)(iii) of this section. The Administrator may choose to have an authorized representative observe the performance test.

(4) The owner or operator shall operate each control device in accordance with the following requirements:

(i) The control device shall be operating at all times when gases, vapors, and fumes are vented from the unit or units through the closed-vent system to the control device.

(ii) For each control device monitored in accordance with the requirements of § 63.1283(d), the owner or operator shall operate the control device such that the actual value of each operating parameter required to be monitored in accordance with the requirements of § 63.1283(d)(3) is greater than the minimum operating parameter value or less than the maximum operating parameter value, as appropriate, established for the control device in accordance with the requirements of § 63.1283(d)(4).

(iii) Failure by the owner or operator to operate the control device in accordance with the requirements of paragraph (d)(4)(ii) of this section shall constitute a violation of the applicable emission standard of this subpart.

(5) For each carbon adsorption system used as a control device to meet the requirements of paragraph (d)(1) of this section, the owner or operator shall manage the carbon as follows:

(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.

(ii) All carbon removed from the control device shall be managed in one of the following manners:

(A) Regenerated or reactivated in a thermal treatment unit for which the owner or operator has either been issued a final permit under 40 CFR part 270, and designs and operates the unit in accordance with the requirements of 40 CFR part 264, subpart X; or certified compliance with the interim status requirements of 40 CFR part 265, subpart P.

(B) Burned in a hazardous waste incinerator for which the owner or operator has been issued a final permit under 40 CFR part 270, and designs and operates the unit in accordance with the requirements of 40 CFR part 264, subpart O.

(C) Burned in a boiler or industrial furnace for which the owner or operator has either been issued a final permit under 40 CFR part 270, and designs and operates the unit in accordance 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.

**§ 63.1282 Test methods and compliance procedures.**

(a) Determination of glycol dehydration unit flow rate or benzene emissions. The procedures of this paragraph shall be used by an owner or operator to determine flow rate or benzene emissions to meet the criteria for an exemption from control requirements under § 63.1274(b).

(1) The determination of actual flow rate of natural gas to a glycol dehydration unit shall be made using the procedures of either paragraph (a)(1)(i) or (a)(1)(ii) of this section.

(i) The owner or operator shall install and operate a monitoring instrument that directly measures flow to the glycol dehydration unit with an accuracy of plus or minus 2 percent.

(ii) The owner or operator shall document that the actual annual average flow rate of the dehydration unit is less than 85 thousand cubic meters per day (3.0 million standard cubic feet per day).

(2) The determination of benzene emissions from a glycol dehydration unit shall be made using the procedures of either paragraph (a)(2)(i) or (a)(2)(ii) of this section.

(i) The owner or operator shall determine annual benzene emissions using the model GRI-GLYCalc™, Version 3.0 or higher. Inputs to the model shall be representative of actual operating conditions of the glycol dehydration unit.

(ii) The owner or operator shall determine an average mass rate of benzene emissions in kilograms per hour through direct measurement by performing three runs of Method 18 in 40 CFR part 60, appendix A (or an equivalent method), and averaging the results of the three runs. Annual emissions in kilograms per year shall be determined by multiplying the mass rate by the number of hours the unit is operated per year. This result shall be multiplied by 1.1023 $E^{-03}$ to convert to tons per year.

(b) No detectable emissions test procedure.

(1) The procedure shall be conducted in accordance with Method 21, 40 CFR part 60, appendix A.

(2) The detection instrument shall meet the performance criteria of Method 21, 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 fluid, and not for each individual organic compound in the stream.

(3) The detection instrument shall be calibrated before use on each day of its use by the procedures specified in Method 21, 40 CFR part 60, appendix A.

(4) Calibration gases shall be as follows:

(i) Zero air (less than 10 parts per million by volume hydrocarbon in air); and

(ii) A mixture of methane in air at a methane concentration of less than 10,000 parts per million by volume.

(5) The background level shall be determined according to the procedures in Method 21, 40 CFR part 60, appendix A.

(6) The arithmetic difference between the maximum organic concentration indicated by the instrument and the background level shall be compared with the value of 500 parts per million by volume. If the difference is less than 500 parts per million by volume, then no HAP emissions are detected.

(c) [Reserved]

(d) Control device performance test procedures. This paragraph applies to the performance testing of control devices. Owners or operators may elect to use the alternative procedures in paragraph (e) of this section for performance testing of a condenser used to control emissions from a glycol dehydration unit process vent.

(1) Method 1 or 1A of 40 CFR part 60, appendix A, as appropriate, shall be used for selection of the sampling sites at the inlet and outlet of the control device.

(i) To determine compliance with the control device percentage of reduction requirement specified in § 63.1281(d)(1)(i)(A) or § 63.1281(d)(1)(ii)(A), sampling sites shall be located at the inlet of the control device as specified in paragraphs (d)(1)(i)(A) and (d)(1)(i)(B) of this section, and at the outlet of the control device.

(A) The control device inlet sampling site shall be located after the final product recovery device.

(B) If a vent stream is introduced with the combustion air, or as a secondary fuel, into a boiler or process heater with a design capacity less than 44 megawatts, selection of the location of the inlet sampling sites shall ensure the measurement of total HAP or TOC concentration, as applicable, in all vent streams and primary and secondary fuels.

(ii) To determine compliance with the enclosed combustion device total HAP concentration limit specified in § 63.1281(d)(1)(i)(B), the sampling site shall be located at the outlet of the device.

(2) The gas volumetric flow rate shall be determined using Method 2, 2A, 2C, or 2D, 40 CFR part 60, appendix A, as appropriate.

(3) To determine compliance with the control device percentage of reduction requirement specified in § 63.1281(d)(1)(i)(A) or § 63.1281(d)(1)(ii)(A), the owner or operator shall use Method 18 of 40 CFR part 60, appendix A of this chapter; alternatively, any other method or data that has 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:

(i) 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.

(ii) The mass rate of either TOC (minus methane and ethane) or total HAP ($E_i$, $E_o$) shall be computed.

(A) The following equations shall be used:

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

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

Where:

$C_{ij}$, $C_{oj}$=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.

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

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

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

$K_2$=Constant, 2.494×10 − 6 (parts per million) − 1 (gram-mole per standard cubic meter) (kilogram/gram) (minute/hour), where standard temperature is 20°C.

(B) When the TOC mass rate is calculated, all organic compounds (minus methane and ethane) measured by Method 18, of 40 CFR part 60, appendix A shall be summed using the equation in paragraph (d)(3)(ii)(A) of this section.

(C) When the total HAP mass rate is calculated, only HAP chemicals listed in Table 1 of this subpart shall be summed using the equation in paragraph (d)(3)(ii)(A) of this section.

(iii) The percentage of reduction in TOC (minus methane and ethane) or total HAP shall be calculated as follows

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

Where:

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

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

$E_o$=Mass rate of TOC (minus methane and ethane) or total HAP at the outlet of the control device, as calculated under paragraph (d)(3)(ii) of this section, kilograms TOC per hour or kilograms HAP 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, the weight-percentage of reduction of total HAP or TOC (minus methane and ethane) across the device shall be determined by comparing the TOC (minus methane and ethane) or total HAP in all combusted vent streams and primary and secondary fuels with the TOC (minus methane and ethane) or total HAP exiting the device, respectively.

(4) 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 Method 18, 40 CFR part 60, appendix A to measure either TOC (minus methane and ethane) or total HAP. Alternatively, any other method or data that has been validated according to Method 301, 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:

(i) 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.

(ii) The TOC concentration or total HAP concentration shall be calculated according to paragraph (d)(4)(ii)(A) or (d)(4)(ii)(B) of this section.

(A) The TOC concentration ($C_{TOC}$) is the sum of the concentrations of the individual components and shall be computed for each run using the following equation:

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

Where:

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

$C_{ji}$=Concentration of sample components 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.

(B) The total HAP concentration ($C_{HAP}$) shall be computed according to the equation in paragraph (d)(4)(ii)(A) of this section, except that only HAP chemicals listed in Table 1 of this subpart shall be summed.

(iii) The TOC concentration or total HAP concentration shall be corrected to 3 percent oxygen as follows:

(A) The emission rate correction factor or excess air, integrated sampling and analysis procedures of Method 3B, 40 CFR part 60, appendix A shall be used to determine the oxygen concentration ($\%O_{2d}$). The samples shall be taken during the same time that the samples are taken for determining TOC concentration or total HAP concentration.

(B) The concentration corrected to 3 percent oxygen ($C_c$) shall be computed using the following equation:

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

Where:

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

$C_m$=TOC concentration or total HAP concentration, dry basis, parts per million by volume.

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

(e) As an alternative to the procedures in paragraph (d) of this section, an owner or operator may elect to use the procedures documented in the Gas Research Institute Report entitled, ‘‘Atmospheric Rich/Lean Method for Determining Glycol Dehydrator Emissions,’’ (GRI–95/0368.1).

**§ 63.1283 Inspection and monitoring requirements.**

(a) This section applies to an owner or operator using air emission controls in accordance with the requirements of § 63.1275.

(b) [Reserved]

(c) *Closed-vent system inspection and monitoring requirements.* (1) The owner or operator shall visually inspect and monitor for no detectable emissions each closed-vent system at the following times:

(i) On or before the date that the unit connected to the closed-vent system becomes subject to the provisions of this subpart;

(ii) At least once per year after the date that the closed-vent system is inspected in accordance with the requirements of paragraph (c)(1)(i) of this section; and

(iii) At other times as requested by the Administrator.

(2) To visually inspect a closed-vent system, the owner or operator shall view

the entire length of ductwork, piping and connections to covers and control devices for evidence of visible defects (such as holes in ductwork or piping and loose connections) that may affect the ability of the system to operate with no detectable emissions. A visible hole, gap, tear, or split in the closed-vent system is defined as a leak which shall be repaired in accordance with paragraph (c)(4) of this section.

(3) To monitor a closed-vent system for no detectable emissions, the owner or operator shall use Method 21, 40 CFR part 60, appendix A to test each closed-vent system joint, seam, or other connection. For the annual leak detection monitoring after the initial leak detection monitoring, the owner or operator is not required to monitor those closed-vent system components which continuously operate at a pressure below atmospheric pressure or those closed-vent system joints, seams, or other connections that are permanently or semi-permanently sealed (*e.g.*, a welded joint between two sections of metal pipe or a bolted and gasketed pipe flange).

(4) When a leak is detected by either of the methods specified in paragraph (c)(2) or (c)(3) of this section, the owner or operator shall make a first attempt at repairing the leak no later than 5 calendar days after the leak is detected. Repair of the leak shall be completed as soon as practicable, but no later than 15 calendar days after the leak is detected.

(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 monitoring system in accordance with the requirements of paragraphs (d)(3) through (d)(5) of this section that will allow a determination be made whether the control device is continuously achieving the applicable performance requirements of § 63.1281.

(2) An owner or operator is exempted from the monitoring requirements specified in paragraphs (d)(3) through (d)(5) of this section for the following types of control devices:

(i) A boiler or process heater in which all vent streams are introduced with primary fuel; or

(ii) A boiler or process heater with a design heat input capacity equal to or greater than 44 megawatts.

(3) The owner or operator shall 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)(3)(i), (d)(3)(ii), or (d)(3)(iii) of this section. The monitoring equipment shall be installed, calibrated, and maintained in accordance with the equipment manufacturer's specifications or other written procedures that provide adequate assurance that the equipment would reasonably be expected to monitor accurately. The continuous recorder shall be a data recording device that either records an instantaneous data value at least once every 15 minutes or records 15-minute or more frequent block average values. The owner or operator shall use any of the following continuous monitoring systems:

(i) A continuous monitoring system that measures the following operating parameters as applicable:

(A) For a thermal vapor incinerator, a temperature monitoring device equipped with a continuous recorder. The monitoring device shall have an accuracy of ±1 percent of the temperature being monitored in °C, or ±0.5 °C, whichever value is greater. The temperature sensor shall be installed at a location in the combustion chamber downstream of the combustion zone.

(B) For a catalytic vapor incinerator, a temperature monitoring device equipped with a continuous recorder. The device shall be capable of monitoring temperature at two locations and have an accuracy of ±1 percent of the temperature being monitored in °C, or ±0.5 °C, whichever value is greater. One temperature sensor shall be installed in the vent stream at the nearest feasible point to the catalyst bed inlet and a second temperature sensor shall be installed in the vent stream at the nearest feasible point to the catalyst bed outlet.

(C) For a flare, a heat sensing monitoring device equipped with a continuous recorder that indicates the continuous ignition of the pilot flame.

(D) For a boiler or process heater with a design heat input capacity of less than 44 megawatts, a temperature monitoring device equipped with a continuous recorder. The temperature monitoring device shall have an accuracy of ±1 percent of the temperature being monitored in °C, or ±0.5 °C, whichever value is greater. The temperature sensor shall be installed at a location in the combustion chamber downstream of the combustion zone.

(E) For a condenser, a temperature monitoring device equipped with a continuous recorder. The temperature monitoring device shall have an accuracy of ±1 percent of the temperature being monitored in °C, or ±0.5 °C, whichever value is greater. The temperature sensor shall be installed at a location in the exhaust vent stream from the condenser.

(F) For a regenerative-type carbon adsorption system, an integrating regeneration stream flow monitoring device equipped with a continuous recorder, and a carbon bed temperature monitoring device equipped with a continuous recorder. The integrating regeneration stream flow monitoring device shall have an accuracy of ±10 percent and measure the total regeneration stream mass flow during the carbon bed regeneration cycle. The temperature monitoring device shall have an accuracy of ±1 percent of the temperature being monitored in °C, or ±0.5°C, whichever value is greater and measure the carbon bed temperature both after regeneration and within 15 minutes of completing the cooling cycle, and over the duration of the carbon bed steaming cycle.

(ii) 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.

(iii) A continuous monitoring system that measures alternative operating parameters other than those specified in paragraph (d)(3)(i) or (d)(3)(ii) of this section upon approval of the Administrator as specified in § 63.8 (f)(1) through (f)(5).

(4) For each operating parameter monitored in accordance with the requirements of paragraph (d)(3) of this section, 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. Each minimum or maximum operating parameter value shall be established as follows:

(i) If the owner or operator conducts performance tests in accordance with the requirements of § 63.1281 to demonstrate that the control device achieves the applicable performance requirements specified in § 63.1281, 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 control device design analysis and manufacturer recommendations.

(ii) If the owner or operator uses control device design analysis in accordance with the requirements of § 63.1281(d)(3)(iv) to demonstrate that the control device achieves the applicable performance requirements specified in § 63.1281(d)(1), then the minimum operating parameter value or the maximum operating parameter value shall be established based on the control device design analysis and the control device manufacturer's recommendations.

(5) The owner or operator shall regularly inspect the data recorded by the continuous monitoring system to determine whether the control device is operating in accordance with the applicable requirements of § 63.1281(d).

**§ 63.1284 Recordkeeping requirements.**

(a) The recordkeeping provisions of subpart A of this part that apply and those that do not apply to owners and operators of facilities subject to this subpart are listed in Table 2 of this subpart.

(b) Except as specified in paragraphs (c) and (d) of this section, each owner or operator of a facility subject to this subpart shall maintain the following records in accordance with the requirements of § 63.10(b)(1):

(1) Records specified in § 63.10(b)(2);

(2) Records specified in § 63.10(c) for each continuous monitoring system operated by the owner or operator in accordance with the requirements of § 63.1283(d).

(c) [Reserved]

(d) An owner or operator that is exempt from control requirements under § 63.1274(b) shall maintain a record of the design capacity (in terms of natural gas flow rate to the unit per day) of each glycol dehydration unit that is not controlled according to the requirements of § 63.1274(a).

**§ 63.1285 Reporting requirements.**

(a) The reporting provisions of subpart A of this part that apply and those that do not apply to owners and operators of facilities subject to this subpart are listed in Table 2 of this subpart.

(b) Each owner or operator of a facility subject to this subpart shall submit the following reports to the Administrator:

(1) An Initial Notification as described in § 63.9 (a) through (d), except that the notification required by § 63.9(b)(2) shall be submitted not later than one year after the effective date of this standard.

(2) A Notification of Performance Tests as specified in § 63.7(b), § 63.9(e), and § 63.9(g).

(3) A Notification of Compliance Status as specified in § 63.9(h).

(4) Performance test reports as specified in § 63.10(d)(2) and performance evaluation reports specified in § 63.10(e)(2). Separate performance evaluation reports as described in § 63.10(e)(2) are not required if the information is included in the summary report specified in paragraph (b)(6) of this section.

(5) Startup, shutdown, and malfunction reports, as specified in § 63.10(d)(5), shall be submitted as required. Separate startup, shutdown, or malfunction reports as described in § 63.10(d)(5)(i) are not required if the information is included in the report specified in paragraph (b)(6) of this section.

(6) The excess emission and CMS performance report and summary report as specified in § 63.10(e)(3) shall be submitted on a semi-annual basis (i.e., once every 6-month period). The summary report shall be entitled "Summary Report—Gaseous Excess Emissions and Continuous Monitoring System Performance."

(7) The owner or operator shall meet the requirements specified in paragraph (b) of this section for any emission point or material that becomes subject to the standards in this subpart due to an increase in flow, concentration, or other parameters equal to or greater than the limits specified in this subpart.

(8) For each control device other than a flare used to meet the requirements of this subpart, the owner or operator shall submit the following information for each operating parameter required to be monitored in accordance with the requirements of § 63.1283(d):

(i) The minimum operating parameter value or maximum operating parameter value, as appropriate for the control device, established by the owner or operator to define the conditions at which the control device must be operated to continuously achieve the applicable performance requirements of § 63.1281(d)(1).

(ii) An explanation of the rationale for why the owner or operator selected each of the operating parameter values established in § 63.1281(d). This explanation shall include any data and calculations used to develop the value and a description of why this value indicates that the control device is operating in accordance with the applicable requirements of § 63.1281(d)(1).

(9) Each owner or operator of a major source subject to this subpart that is not subject to the control requirements for glycol dehydration unit process vents in § 63.765 is exempt from all reporting requirements for major sources in this subpart.

(c) Each owner or operator of a facility subject to this subpart that is an area source is exempt from all reporting requirements in this subpart.

**§ 63.1286 Delegation of authority. [Reserved]**

**§ 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.

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

(c) Any person seeking permission to use an alternative means of compliance under this section shall collect, verify, and submit to the Administrator information showing that this means achieves equivalent emission reductions.

**§ 63.1288 [Reserved]**

**§ 63.1289 [Reserved]**

TABLE 1 TO SUBPART HHH—LIST OF HAZARDOUS AIR POLLUTANTS (HAP)

| CAS No.[a] | Chemical name |
|---|---|
| 75070 | Acetaldehyde. |
| 71432 | Benzene (includes benzene in gasoline). |
| 75150 | Carbon disulfide. |
| 463581 | Carbonyl sulfide. |
| 100414 | Ethyl benzene. |
| 107211 | Ethylene glyco. |
| 50000 | Formaldehyde. |
| 110543 | n-Hexane. |
| 91203 | Naphthalene. |
| 108883 | Toluene. |
| 540841 | 2,2,4-Trimethylpentane. |
| 1330207 | Xylenes (isomers and mixture). |
| 95476 | o-Xylene. |
| 108383 | m-Xylene. |
| 106423 | p-Xylenea. |

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

TABLE 2 OF SUBPART HHH.—APPLICABILITY OF 40 CFR PART 63 GENERAL PROVISIONS

| General provisions reference | Applicable to subpart HHH | Comment |
| --- | --- | --- |
| § 63.1(a)(1) | Yes. | |
| § 63.1(a)(2) | Yes. | |
| § 63.1(a)(3) | Yes. | |
| § 63.1(a)(4) | Yes. | |
| § 63.1(a)(5) | No. | Section reserved. |
| § 63.1(a)(6)–(a)(8) | Yes. | |
| § 63.1(a)(9) | No. | Section reserved. |
| § 63.1(a)(10) | Yes. | |
| § 63.1(a)(11) | Yes. | |
| § 63.1(a)(12)–(a)(14) | Yes. | |
| § 63.1(b)(1) | No. | Subpart HHH specifies applicability. |
| § 63.1(b)(2) | Yes. | |
| § 63.1(b)(3) | No. | |
| § 63.1(c)(1) | No. | Subpart HHH specifies applicability. |
| § 63.1(c)(2) | No. | |
| § 63.1(c)(3) | No. | Section reserved. |
| § 63.1(c)(4) | Yes. | |
| § 63.1(c)(5) | Yes. | |
| § 63.1(d) | No. | Section reserved. |
| § 63.1(e) | Yes. | |
| § 63.2 | Yes | Except definition of ''major source'' is unique for this source category and there are additional definitions included in subpart HHH. |
| § 63.3(a)–(c) | Yes. | |
| § 63.4(a)(1)–(a)(3) | Yes. | |
| § 63.4(a)(4) | No. | Section reserved. |
| § 63.4(a)(5) | Yes. | |
| § 63.4(b) | Yes. | |
| § 63.49(c) | Yes. | |
| § 63.5(a)(1) | Yes. | |
| § 63.5(a)(2) | No. | Preconstruction review required only for major sources that commence construction after promulgation of the standard. |
| § 63.5(b)(1) | Yes. | |
| § 63.5(b)(2) | No. | Section reserved. |
| § 63.5(b)(3) | Yes. | |
| § 63.5(b)(4) | Yes. | |
| § 63.5(b)(5) | Yes. | |
| § 63.5(b)(6) | Yes. | |
| § 63.5(c) | No. | Section reserved. |
| § 63.5(d)(1) | Yes. | |
| § 63.5(d)(2) | Yes. | |
| § 63.5(d)(3) | Yes. | |
| § 63.5(d)(4) | Yes. | |
| § 63.5(e) | Yes. | |
| § 63.5(f)(1) | Yes. | |
| § 63.5(f)(2) | Yes. | |
| § 63.6(a) | Yes. | |
| § 63.6(b)(1) | Yes. | |
| § 63.6(b)(2) | Yes. | |
| § 63.6(b)(3) | Yes. | |
| § 63.6(b)(4) | Yes. | |
| § 63.6(b)(5) | Yes. | |
| § 63.6(b)(6) | No. | Section reserved. |
| § 63.6(b)(7) | Yes. | |
| § 63.6(c)(1) | Yes. | |
| § 63.6(c)(2) | Yes. | |
| § 63.6(c)(3)–(c)(4) | No. | Sections reserved. |
| § 63.6(c)(5) | Yes. | |
| § 63.6(d) | No. | Section reserved. |
| § 63.6(e) | Yes. | |
| § 63.6(f)(1) | Yes. | |
| § 63.6(f)(2) | Yes. | |
| § 63.6(f)(3) | Yes. | |
| § 63.6(g) | Yes. | |
| § 63.6(h) | No. | Subpart HHH does not require the use of a continuous emissions monitoring system. |
| § 63.6(i)(1)–(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. | |

TABLE 2 OF SUBPART HHH.—APPLICABILITY OF 40 CFR PART 63 GENERAL PROVISIONS—Continued

| General provisions reference | Applicable to subpart HHH | Comment |
|---|---|---|
| § 63.7(a)(3) | Yes. | |
| § 63.7(b) | Yes. | |
| § 63.7(c) | Yes. | |
| § 63.7(d) | Yes. | |
| § 63.7(e)(1) | Yes. | |
| § 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)(2) | Yes. | |
| § 63.8(c)(3) | Yes. | |
| § 63.8(c)(4) | No.. | |
| § 63.8(c)(5)–(c)(8) | Yes. | |
| § 63.8(d) | Yes. | |
| § 63.8(e) | Yes. | |
| § 63.8(f)(1)–(f)(5) | Yes. | |
| § 63.8(f)(6) | No. | Subpart HHH does not require the use of a continuous emissions monitor. |
| § 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 | Sources are given one year (rather than 120 days) to submit this notification. |
| § 63.9(b)(3) | Yes. | |
| § 63.9(b)(4) | Yes. | |
| § 63.9(b)(5) | Yes. | |
| § 63.9(c) | Yes. | |
| § 63.9(d) | Yes. | |
| § 63.9(e) | Yes. | |
| § 63.9(f) | No. | |
| § 63.9(g) | Yes. | |
| § 63.9(h)(1)–(h)(3) | Yes. | |
| § 63.9(h)(4) | No. | Section reserved. |
| § 63.9(h)(5)–(h)(6) | Yes. | |
| § 63.9(i) | Yes. | |
| § 63.9(j) | Yes. | |
| § 63.10(a) | Yes. | |
| § 63.10(b)(1) | Yes. | |
| § 63.10(b)(2) | Yes. | |
| § 63.10(b)(3) | No. | |
| § 63.10(c)(1) | Yes. | |
| § 63.10(c)(2)–(c)(4) | No. | Sections reserved. |
| § 63.10(c)(5)–(c)(8) | Yes. | |
| § 63.10(c)(9) | No. | Section reserved. |
| § 63.10(c)(10)–(c)(15) | Yes. | |
| § 63.10(d)(1) | Yes. | |
| § 63.10(d)(2) | Yes. | |
| § 63.10(d)(3) | Yes. | |
| § 63.10(d)(4) | Yes. | |
| § 63.10(d)(5) | Yes | Subpart HHH requires major sources to submit startup, shutdown and malfunction report semi-annually. |
| § 63.10(e) | Yes | Subpart HHH requires major sources to submit continuous monitoring system performance reports semi-annually. |

TABLE 2 OF SUBPART HHH.—APPLICABILITY OF 40 CFR PART 63 GENERAL PROVISIONS—Continued

| General provisions reference | Applicable to subpart HHH | Comment |
| --- | --- | --- |
| § 63.10(f) | Yes. | |
| § 63.11(a)–(b) | Yes. | |
| § 63.12(a)–(c) | Yes. | |
| § 63.13(a)–(c) | Yes. | |
| § 63.14(a)–(b) | Yes. | |
| § 63.15(a)–(b) | Yes. | |

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