United States
Environmental Protection
Agency

Office of Air Quality
Planning and Standards
Research Triangle Park, NC 27711

EPA-453/R-99-004b
May 1999

Air

EPA

NATIONAL EMISSION STANDARDS FOR HAZARDOUS AIR POLLUTANTS FOR SOURCE CATEGORIES: OIL AND NATURAL GAS PRODUCTION AND NATURAL GAS TRANSMISSION AND STORAGE - BACKGROUND INFORMATION FOR FINAL STANDARDS

SUMMARY OF PUBLIC COMMENTS AND RESPONSES

Office of Air Quality Planning and Standards
Clean Air
OAQPS

EPA-453/R-99-004b

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

Background Information for
Promulgated Standards - Summary of
Public Comments and Responses

Emission Standards Division

U. S. Environmental Protection Agency
Office of Air and Radiation
Office of Air Quality Planning and Standards
Research Triangle Park, NC 27711

May 1999

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ENVIRONMENTAL PROTECTION AGENCY

National Emission Standards for Hazardous Air Pollutants for Source Categories: Oil and Natural Gas Production and Natural Gas Transmission and Storage
Background Information for Promulgated Standards -
Summary of Public Comments and Responses

1 The final National Emission Standards for Hazardous Air Pollutants (NESHAP) will regulate emissions of hazardous air pollutants from oil and natural gas production and natural gas transmission and storage . Only those operations that are part of major sources under section 112(d) of the Clean Air Act as amended in 1990 will be regulated.

2 Copies of this document have been sent to the following Federal Departments: Labor, health and Human Services, Defense, Transportation, Agriculture, Commerce, interior, and Energy; the national Science Foundation; and the Council on environmental Quality; members of the State and Territorial Air Pollution program Administrators; the Association of Local Air Pollution Control Officials; EPA Regional Administrators; and other interested parties.

3 For additional information contact:

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4. Paper copies of this document may be obtained from:

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5. Electronic copies of this document may be obtained from the EPA's OAR Technology Transfer Network website (TTNWeb).

The TTNWeb is a collection of related Web sites containing information about many areas of air pollution science, technology, regulation, measurement, and prevention. The TTNWeb is directly accessible from the Internet via the World Wide Web at the following address: http//www.epa.gov/ttn

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1.0 SUMMARY

1.1 BACKGROUND

On February 6, 1998, the Environmental Protection Agency (EPA) proposed standards of performance for the oil and natural gas production source category (63 FR 6288) under authority of Section 111 of the Clean Air Act.

Public comments were requested on the proposal in the Federal Register. There were 54 commenters composed mainly of industry and trade associations. Also commenting were State and local agencies, consultants and engineers, environmental groups, and other interested parties.

The written comments were submitted, along with the responses to these comments, are summarized in this document. The summary of comments and responses serves as the basis for the revisions made to the standard between proposal and promulgation.

1.2 SUMMARY OF SIGNIFICANT CHANGES SINCE PROPOSAL

In response to comments received on the proposed standards, several changes have been made to the final rules. A summary of the substantive changes made since the proposal in response to comments is provided in the following sections. Additional information on the final rules is contained in the docket for this rule (Air Docket A-94-04).

1.2.1 Area Source Regulation

In the February 6, 1998 Federal Register notice (63 FR 6291), the EPA gave notice of its intention to add oil and natural gas production as an area source category, but did not amend the source category list to include such a category.

In order to ensure that regulations applicable to the area source category are consistent with the Urban Air Toxics Strategy, to be implemented under section 112(k) of the Act, the EPA has deferred the regulation of oil and natural gas production facilities which are area sources until the Urban Air Toxics Strategy is finalized. The EPA expects this strategy to be finalized later this year.

Several comment letters were received regarding the area source regulation. Since the regulation of area sources has been deferred, summaries of these comment letters and the EPA's responses to these comments are not included in this document.

1.2.2 Definition of Facility

The EPA developed the proposed definition of facility to (1) identify criteria that define a grouping of emission points that meet the intent of the language contained in section 112(a)(1) of the Act: ". . . located within a contiguous area and under common control, . . ."; and (2) contain terms that are meaningful and easily understood within the regulated industries. The proposed definition was based on individual surface sites and the idea 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 tract) shall not be aggregated. In addition, the proposed definition of a production field facility was limited to glycol dehydration units and storage vessels with the potential for flash emissions.

Several commenters responded to the EPA's request for comments on the definition of facility. The commenters requested clarification of, or suggested changes to, the proposed definition of facility.

In response to comments regarding specific clarification to the definition of facility, the EPA has made several changes to the definition of facility. The EPA modified the definition of facility to point to the definition of "surface site." In subpart HHH, the EPA has added a definition of "surface site," and modified the definition of facility to point to the new definition of "surface site."

The EPA further modified the definition of facility in subpart HH by: (1) specifying that "upgraded" means "the removal of impurities or other constituents to meet contract specifications"; (2) changing the term "unit areas" to "surface unit areas"; and (3) specifying that separate surface sites, whether or not connected by a road, waterway, power line or pipeline, would not be considered a part of the same facility.

Other commenters requested that the EPA clarify, within the definition of facility in subpart HHH, whether the EPA intended to exclude facilities used to store natural gas after the gas enters the local distribution system of a gas utility. The commenter recommended that the EPA clarify that the definition of facility applies all the way to the end user only if there is no local distribution company.

The affected source in the natural gas transmission and storage source category should run all the way to the end user only if there is no local distribution company. Therefore, the EPA modified the definition of facility in subpart HHH to state that if there is not a local distribution company, the facility runs to the end user.

1.2.3 Potential-to-Emit

Several commenters were concerned with the methods used to determine whether or not a facility was a major source. In particular, the EPA received several comment letters regarding the calculation of a facility's potential-to-emit (PTE) when determining a facility's major source status. The EPA received comments stating that the calculation of PTE should not be based on equipment operating capacity because it would result in overregulation, but should consider the inherent operating limitations of the facility (e.g., declining production levels over time). Other commenters recommended that the EPA should provide a simplified approach to calculate PTE, which takes into account design and operational limitations.

Several commenters were concerned that PTE estimates, as defined in the General Provisions, would be unrealistically high and would subject many small insignificant sources to the NESHAP requirements. The commenters requested that PTE be based on the inherent design and operational limitations of production and transmission and storage facilities, such as throughput rates.

According to commenters, the throughput of oil and natural gas production operations declines over time, and existing equipment is often designed, constructed and operated based on high initial production rates. Therefore, the commenters suggested that the facilities are usually operated at actual throughput rates that are much lower than the design capacities.

The EPA agrees that there are certain inherent throughput limitations associated with the production of oil and natural gas, primarily related to declining production rates. Therefore, the final subpart HH specifies a method for calculating maximum facility throughput to determine major source status and applicability to subpart HH. This method is based on a facility's past production rate and ability to document declining annual operations. However, it is the responsibility of the owner or operator to be aware of changes that could require a facility to recalculate its PTE and to do so in a timely manner. The owner or operator could be found in violation back until the point in time at which an engineering judgement would have shown that the facility was reasonably capable of emitting at major source thresholds.

The EPA also received comments that the EPA should consider the seasonal operation of natural gas storage facilities in estimating potential emissions, and that the facility's PTE cannot be based on withdrawal for the entire season at maximum capacity. The commenters explained that natural gas storage facilities must spend part of the year injecting gas, and that withdrawal rates decrease as the storage field's pressure drops.

The EPA agrees that natural gas storage facilities have inherent limitations due to the nature of their operations. Therefore, the final rule (subpart HHH) contains a method for calculating maximum facility throughput to determine major source status and applicability of subpart HHH. The method is based on the maximum withdrawal and injection rates and the working gas capacity for a given storage field.

Several commenters recommended a simplified approach to calculating PTE, such as screening equations similar to those developed for other NESHAP, to take into account design and operational limitations.

The EPA evaluated the use of an equation similar in structure to the Gasoline Distribution NESHAP, 40 CFR part 63, subpart R. After extended effort, the EPA found that the number of variables was too extensive to allow development of a manageable equation.

Therefore, as an alternative, the EPA developed a simplified major source determination (MSD) for HAP emission sources in the oil and natural gas production and natural gas transmission and storage source categories. The simplified MSD allows the owner or operator of a facility to easily determine (1) if they are major sources and whether NESHAP requirements apply to their facility, and (2) if they are required to obtain a title V operating permit.

The final subpart HH states that facilities, prior to the point of custody transfer, that have a facilitywide actual annual average natural gas throughput less than 18.4 thousand m^3/day and a facilitywide actual annual average hydrocarbon liquid throughput less than 39,700 liter/day are exempt from subpart HH.

Owners and operators of production facilities, after the point of custody transfer (including natural gas processing plants), must aggregate emissions from all HAP emissions units at the facility when determining whether or not the facility is a major source. Production facilities, after the point of custody transfer, are likely to have emission units in addition to glycol dehydration units and storage vessels, such as amine treaters and sulfur recovery units that are typically located at natural gas processing plants. Since these emissions units must be included in the total emissions for the facility, the EPA could not develop a cutoff that would reasonably ensure that sources operating below such a cutoff would not be major sources. Therefore, production facilities located after the point of custody transfer, including natural gas processing plants, do not qualify for the simplified major source determination.

Using the same procedure, the EPA developed an MSD for natural gas transmission and storage facilities where glycol dehydration units are the only HAP emission points. The final subpart HHH states that natural gas transmission and storage facilities operating with an actual annual average natural gas throughput below 28.3 thousand m^3/day are exempt from subpart HHH.

1.2.4 Averaging Periods

The proposed standards required a 95.0 percent control efficiency for all control devices, but did not specify over which averaging period the 95.0 percent should be determined. By not specifying an averaging period, the proposed rule required continuous compliance for all control devices. The EPA received several comment letters requesting that the EPA specify an averaging period. The commenters were particularly concerned that condensers could not achieve a 95.0 percent control efficiency on a continuous basis and that additional controls would be required to ensure compliance with the 95.0 percent requirement.

The commenters' primary point was that condensers are significantly affected by changes in ambient temperature. According to the commenters, when the ambient temperature is high, the condensers are less efficient. The commenters were concerned that during the warm summer months, condensers would not meet the control requirements. Therefore, the commenters specifically requested either a 30-day or a 12-month averaging period for compliance with the control requirements to balance changes in ambient temperature. In support of this request, the commenters maintained that using a longer averaging period would create no significant change in the emissions to the environment, but would substantially decrease the number of technical violations of the standard and reduce the administrative burden for the industry and the EPA.

The EPA reviewed the control efficiency and averaging period requirements in response to these comments. Based on the Agency's review of the possible options, the final rules require 95.0 percent control as a daily average. As an alternative for owners or operators that install condensers, the EPA has modified subpart HH to allow 95.0 percent condenser control as a 365-day rolling average, based on daily average condenser efficiency as a function of condenser outlet temperature (i.e., at the end of each operating day, the owner or operator calculates the daily average condenser outlet temperature, then calculates the 365-day average control efficiency for the preceding 365 days, including the current operating day).

Based on the information collected under the authority of section 114 of the Act, the comments received during the public comment period, and site visits, the EPA believes that an averaging period shorter than 365 days is appropriate for the natural gas transmission and storage source category. To the Agency's knowledge, glycol dehydration units located at storage facilities do not typically operate throughout the year. Therefore, the EPA was concerned that it would take more than 1 calendar year for a facility to obtain 365 days of data. Additionally, glycol dehydration units located at these sources do not typically operate during the warm summer months when condenser efficiency is lower. Although transmission facilities do operate for most of the year, the EPA believes that the HAP emission units in operation at these facilities are primarily compressors, and that most glycol dehydration units located at these facilities are used for withdrawing natural gas from storage (i.e., not likely to operate year-round). Therefore, for condensers installed on glycol dehydration units subject to control requirements under subpart HHH, the EPA has modified the requirements to specify that owners or operators that install condensers have the option of meeting a 95.0 percent control efficiency as a 30-day rolling average.

1.2.5 Process Modifications

Several commenters requested that the EPA allow for combinations of controls and process modifications to achieve the required control efficiency. The commenters provided several suggestions for modifying the language in §63.765(c)(2) stating that the owner or operator could reduce emissions from the glycol dehydration unit by 95.0 percent through process modifications or process modifications with controls.

The EPA agrees that owners or operators should be allowed to achieve a 95.0 percent emission reduction using process modifications or combinations of process modifications and one or more control devices. Therefore, the final rules contain requirements for demonstrating compliance with a 95.0 percent emission reduction using process modifications or a combination of process modifications and one or more control devices. In particular, the final rules require the owner or operator to demonstrate how emissions have been reduced and to what level, and that the facility continues to be operated such that the 95.0 percent emission reduction is maintained.

The final rules also require the owner or operator to document facility operations and to provide this information in the Periodic reports.

1.2.6 Standards for Natural Gas Transmission and Storage

The EPA received several comment letters expressing concern for the EPA's proposed standard for the natural gas transmission and storage source category. The commenters stated that the EPA did not have sufficient data to develop standards for the natural gas transmission and storage source category. The commenters requested that the EPA delay the natural gas transmission and storage portion of the proposed rulemaking to properly survey the industry for more meaningful data and assess whether a standard for the natural gas transmission and storage source category is necessary or achievable.

Several commenters explained that a review of the background information for proposed subpart HHH showed that the database consisted of information on the methods used in natural gas transmission from only two companies and no underground storage facilities. The commenters noted that the companies surveyed were predominately oil production facilities that handled gas as a by-product of oil production and that have higher HAP emissions because they handle more liquids with higher concentrations of HAP.

In response to these comments, the EPA collected additional data on glycol dehydration units in the natural gas transmission and storage source category through site visits and requests for information under the authority of section 114 of the Act.

Through these site visits and survey questionnaires, the EPA collected information from 83 facilities in the natural gas transmission and storage source category. The EPA considered this new information, along with the previously collected information on the natural gas transmission and storage source category, in developing a MACT floor for existing and new process vents on glycol dehydration units located at facilities in this source category. The EPA also used this information to better characterize processes and operations at natural gas transmission and storage facilities.

As stated in the January 15, 1999 supplemental notice (64 FR 2611), the additional data supported a MACT floor of 95.0 percent for existing and new natural gas transmission and storage facilities. In addition, the EPA announced that the Agency was considering raising the proposed throughput cutoff of 85 thousand m^3/day to 283 thousand m^3/day on an actual annual average basis. Glycol dehydration units operating below this cutoff would not be required to install controls under subpart HHH. The data did not warrant a change in the benzene emission cutoff of 0.90 Mg/yr.

The public comment period closed on February 16, 1999. The EPA received four comment letters in response to the EPA's request for comments and supporting information on the consideration of a 95.0 percent HAP emission reduction as the floor level of control, on the 283 thousand m^3/day natural gas throughput cutoff and the 0.90-Mg/yr benzene emission cutoff. The commenters agreed that exempting glycol dehydration units with actual annual average natural gas throughputs less than 283 thousand 78 m^3/day and with actual average benzene emissions less than 0.90 Mg/yr from the control requirements under subpart HHH was appropriate.

However, the commenters indicated that they did not agree with a MACT floor of 95.0 percent for the transmission and storage source category. The commenters requested that the final rule should either exempt existing sources controlled by condensers, or require that existing sources controlled with condensers be controlled to a different level (i.e., 70 percent) than the combustion technology-based MACT floor. The commenters stated that condensers could consistently achieve a 75 percent emission reduction and that requiring an additional 20 percentage points of emission reduction in HAP would be inconsistent with the cost-to-benefit analysis in the February 6, 1998 proposal.

The EPA does not believe that it is necessary to provide exemptions or alternative levels of control for existing glycol dehydration units that are controlled by condensers. The EPA believes that this would not be consistent with the Act, which specifies in section 112(d)(3) that for a source category with 30 or more sources (such as the transmission and storage source category), the MACT floor for existing sources shall not be less stringent than ". . . the average limitation achieved by the best performing 12 percent of the existing sources. . .." The data collected by the EPA indicated that the average limitation achieved by the top 12 percent of the existing glycol dehydration units located at natural gas transmission and storage facilities was 95.0 percent. Furthermore, the data indicated that the top 12 percent of the existing glycol dehydration units were controlled using combustion or a combination of combustion and condensation. Therefore, in accordance with the statute, the EPA established the MACT floor to be 95.0 percent for glycol dehydration units located at natural gas transmission and storage facilities, which corresponds to combustion.

However, the EPA agrees that the supplemental notice did not address the issue of averaging period for condensers in use at transmission and storage facilities. As stated in this preamble, the final rule allows an owner or operator that installs a condenser for control of HAP from glycol dehydration unit process vents to establish compliance with the 95.0 percent HAP emission reduction on a 30-day rolling average. In addition, the final rule allows the owner or operator to comply with one of the following: (1) 95.0 percent HAP emission reduction, (2) 20 parts per million by volume (ppmv) outlet HAP concentration for combustion devices, or (3) outlet emissions of 0.90 Mg/yr of benzene. The EPA believes that the 0.90 Mg/yr benzene emission limit and the 30-day averaging period for condensers provides sufficient flexibility for owners and operators of existing controlled glycol dehydration units.

1.2.7 Monitoring, Recordkeeping, and Reporting Requirements

The EPA received several comment letters claiming that the recordkeeping and reporting requirements of the proposed rule were extremely burdensome. The commenters requested that the EPA reduce the monitoring, recordkeeping, and reporting burden associated with the proposed rule. In particular, commenters were concerned that remote and unmanned facilities would be overburdened by the proposed monitoring, recordkeeping and reporting requirements. Commenters also requested that provisions be added to the rule to avoid duplicative reporting. Other commenters requested that flexibility to allow alternative monitoring, recordkeeping, and reporting be incorporated into the final rule.

The EPA recognizes that unnecessary monitoring, recordkeeping, and reporting requirements would burden both the source and enforcement agencies. Prior to proposal, the EPA attempted to reduce the amount of monitoring, recordkeeping, and reporting to only that which is necessary to demonstrate compliance.

Although the EPA has not removed the monitoring requirements for unmanned or remote facilities, the EPA did evaluate the possibility of reducing the requirements for unmanned facilities. The EPA concluded, however, that the monitoring requirements are the minimum necessary to ensure that control devices are operating to ensure compliance.

The EPA reevaluated whether monitoring, recordkeeping, and reporting requirements could be further reduced while maintaining the enforceability of the rule. Therefore, the EPA has made the following changes in the promulgated rule to further reduce the monitoring, recordkeeping, and reporting burden.

(1) Almost all reports have been consolidated into the Notification of Compliance Status report and the Periodic reports.

(2) If multiple tests are conducted for the same kind of emission point, using the same test method, only one complete test report is required to be submitted along with the summaries of the results of other tests.

(3) Site-specific test plans describing quality assurance in §63.7(c) of 40 CFR part 63, subpart A, are not specifically required in the individual subparts because the test methods cited in subparts HH and HHH already contain applicable quality assurance protocols. It should be noted that the Administrator would still have the authority to request a test plan.

(4) Periodic reports are required to be submitted semiannually for all facilities (the proposal required quarterly reports if monitored parameters were out of range more than a specified percentage of time).

(5) A reduction in the record retention requirements for monitored parameters. The proposal required values of monitored parameters to be recorded every 15 minutes and all 15-minute records had to be retained. The final rule requires monitored parameters to be recorded every hour and all hourly records to be retained.

1.3 SUMMARY OF IMPACTS OF PROMULGATED ACTION

The EPA estimated that the final oil and natural gas production standards will reduce nationwide emissions of HAP by approximately 30,000 megagrams per year (Mg/yr) from existing sources, and 3,000 Mg/yr from new sources. The final natural gas transmission and storage standards are estimated to reduce nationwide HAP emissions by 390 Mg/yr from existing sources. No new sources are anticipated for the natural gas transmission and storage source category after the effective date for new sources and in the first three years following promulgation of the subpart HHH.

The nationwide annual costs (including capital recovery) of the final rule are estimated to be approximately $4.0 million per year for existing major sources in the oil and natural gas production source category and $300,000 per year for existing natural gas transmission and storage major sources. The total annual costs for new major oil and natural gas production sources was estimated to be approximately $400,000 per year. The economic analysis determined that the oil and natural gas production 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. In addition the imposition of regulatory costs on the natural gas market has a negligible effect on natural gas prices, output, employment, foreign trade, and business profitability.

The secondary environmental impacts that occur as a result of this rule are expected to be minimal in comparison to the primary HAP reduction benefits from the implementation of the control options. The rule encourages the use of emission controls that recover hydrocarbon products (such as methane and condensate) that can be used onsite for fuel or reprocessed for sale.

The energy impacts associated with the operation of emission control devices are not significant. The EPA estimated that the annual energy requirements to be 38,000 kilowatt hours per year and result from the operation of vapor collection and recovery systems installed on storage vessels. The EPA estimated that add-on control systems (e.g., condensers and flares) would not require additional energy.

2.0 SUMMARY OF PUBLIC COMMENTS

A total of 50 letters commenting on the proposed standard and the background information document for the proposed standard were received. A public hearing was not requested. A list of commenters, their affiliations, and the EPA docket number assigned to their correspondence is given in Table 2-1.

For the purpose of orderly presentation, the comments have been categorized under the following topics:

1. APPLICABILITY
2. DEFINITIONS
3. ASSOCIATED EQUIPMENT
4. HAP EMISSION POINTS
5. IMPACTS
6. ECONOMIC ANALYSIS
7. LEGAL ISSUES [OTHER THAN ISSUES ASSOCIATED WITH THE EPA'S INTERPRETATION OF SECTION 112(n)(4)(A) AND (B)]
8. PERMIT ISSUES
9. ENFORCEMENT ISSUES
10. CONTROLS
11. MONITORING, RECORDKEEPING, AND REPORTING
12. TEST METHODS
13. COMPLIANCE
14. WORDING OF REGULATIONS (OTHER THAN APPLICABILITY AND DEFINITIONS)
15. GENERAL PROVISIONS
16. MISCELLANEOUS
17. GENERAL COMMENTS SPECIFIC TO SUBPART HHH (NOT OTHERWISE ADDRESSED)
18. COMMENTS RECEIVED ON THE JANUARY 15, 1999 SUPPLEMENTAL NOTICE (64 FR 2611)

TABLE 2-1. LIST OF COMMENTERS ON PROPOSED STANDARDS OF PERFORMANCE FOR OIL AND NATURAL GAS PRODUCTION AND NATURAL GAS TRANSMISSION AND STORAGE INDUSTRIES

Docket Item Number[a]	Commenter and Affiliation
IV-D-1	G. Von Bodungen Louisiana Department of Environmental Quality Office of Air Quality P.O. Box 82135 Baton Rouge, Louisiana 70844
IV-D-2	G. Holliday Holliday Environmental Services, Inc. P.O. Box 2508 Bellaire, Texas 77402
IV-D-3	J. Henderson TruTesT Analytical Consultants, Inc. 3500 North Causeway Boulevard, Suite 600 Metairie, Louisiana 70002
IV-D-4	R. Gow Questar Corp. P.O. Box 45433 Salt Lake City, Utah 84145
IV-D-5	T. LaSalle, HLP Engineering, Inc. barryh@linknet.net (Via e-mail)
IV-D-6	S. Knis The Dow Chemical Company Midland, Michigan 48675
IV-D-7	V. Lajiness The Coastal Corporation 500 Renaissance Center Detroit, Michigan 48243
IV-D-8	W. Ebarb Hi Trading and Transportation Group
IV-D-9	J. Matuszak The Peoples Gas Light and Coke Company 130 East Randolph Drive Chicago, Illinois 60601
IV-D-10	T. Hutchins El Paso Energy Company

TABLE 2-1 (continued)

Docket Item Number[a]	Commenter and Affiliation
IV-D-11	R. Metcalf Louisiana Mid-Continent Oil and Gas Association 801 North Boulevard, Suite 201 Baton Rouge, Louisiana 70802
IV-D-12	A. Evans Consumers Energy Company 1945 West Parnall Road Jackson, Mississippi 49201
IV-D-13	C. Reheis Western States Petroleum Association 1115 11th Street, Suite 150 Sacramento, California 95814
IV-D-14	T. Horn Harding Lawson Associates 202 Central SE, Suite 200 Albuqureque, New Mexico 87102
IV-D-15	J. Cantrell Gas Processors Association 6526 East 60th Street Tulsa, Oklahoma 74145
IV-D-16	B. Price Phillips Petroleum Company Bartelsville, Oklahoma 74004
IV-D-17	R. Taylor True Oil Company P.O. Drawer 2360 Casper, Wyoming 82602
IV-D-18	M. Wax Institute of Clean Air Companies 1660 L Street NW, Suite 1100 Washington, District of Columbia 20036
IV-D-19	W. Airey Vorys, Sater, Seymour, and Pease LLP 52 East Gay Street P.O. Box 1008 Columbus, Ohio 43216

TABLE 2-1 (continued)

Docket Item Number[a]	Commenter and Affiliation
IV-D-20	K. Beckett Jackson & Kelly 1600 Laidley Tower P.O. Box 553 Charleston, West Virginia 25322
IV-D-21	V. Ammirato Columbia Gas Transmission P.O. Box 1273 Charleston, West Virginia 25325
IV-D-22	R. Jones American Petroleum Institute 1220 L Street, Northwest Washington, District of Columbia 20005
IV-D-23	W. Flis Exxon Company, U.S.A. P.O. Box 2180 Houston, Texas 77252
IV-D-24	S. Waisley U.S. Department of Energy Washington, District of Columbia 20585
IV-D-25	D. McKinnon Manufacturers of Emission Controls Association 1660 L Street, Northwest, Suite 1100 Washington, District of Columbia 20036
IV-D-26	W. Doyle Marathon Oil Company 539 South Main Street Findlay, Ohio 45840
IV-D-27	M. Atherton Columbia Energy Group Service Corporation 12355 Sunrise Valley Drive, Suite 300 Reston, Virginia 20191
IV-D-28	C. Price Chemical Manufacturers Association 1300 Wilson Boulevard Arlington, Virginia 22209
IV-D-29	M. Chytilo Environmental Defense Center 906 Garden Street Santa Barbara, California 93101

TABLE 2-1 (continued)

Docket Item Number[a]	Commenter and Affiliation
IV-D-30	A. Lee Texaco, Inc. P.O. Box 509 Beacon, New York 12508
IV-D-31	L. Beal Interstate Natural Gas Association of America L. Traweek, American Gas Association (This comment letter contains a printing error in the topical report, please see item IV-G-13 for the correction to this problem.)
IV-D-32	M. Lev-On ARCO 444 S. Flower Street Los Angeles, California 90071
IV-D-33	M. McThomas Independent Oil and Gas Association of West Virginia P.O. Box 1791 Charleston, West Virginia 25326
IV-D-34	W. Sellars Chevron U.S.A. Production Company P.O. Box 1635 Houston, Texas 77251
IV-D-35	M. Blair Colorado Department of Public Health and Environment 4300 Cherry Creek Drive, South Denver, Colorado 80246
IV-D-36	B. Mathur Illinois Environmental Protection Agency
IV-D-37	B. Freeman Shell E&P Technology Company Bellaire Technology Center P.O. Box 481 Houston, Texas 77001
IV-D-38	M. Fish Enron Oil & Gas Company P.O. Box 4362 Houston, Texas 77210

TABLE 2-1 (continued)

Docket Item Number[a]	Commenter and Affiliation
IV-G-1	P. Cantle Santa Barbara County (California) Air Pollution Control District 26 Castilian Drive B-23 Goleta, California 93117
IV-G-2	J. Ives Rocky Mountain Oil & Gas Association 1900 Grant Street, Suite 510 Denver, Colorado 80203
IV-G-3	C. Matthews Interstate Oil and Gas Compact Commission P.O. Box 53127 Oklahoma City, Oklahoma 73152
IV-G-5	R. White TU Services, Inc. 1601 Bryan Street Dallas, Texas 75201
IV-G-7	R. Jones Dehy Condensers, Inc. 129 N. Glenwood Boulevard Tyler, Texas 75702
IV-G-9	P. Bennett KN Energy Inc. One Allen Center 500 Dallas Street, Suite 500 Houston, Texas 77002
IV-G-11	B. Russell Independent Petroleum Association of America 1101 Sixteenth Street, Northwest Washington, District of Columbia 20036
IV-G-12	M. Fox New Century Energies P.O. Box 840 Denver, Colorado 80202
IV-G-13	L. Beal Interstate Natural Gas Association of America 10 G Street, Northeast, Suite 700 Washington, District of Columbia 20002 (This document is a correction of the printing error in item IV-D-31.)
IV-G-14	Unsigned/Concerned citizen

TABLE 2-1 (continued)

Docket Item Number[a]	Commenter and Affiliation
IV-G-15	J. Courville Louisiana Department of Environmental Quality Air Quality Division P.O. Box 82135 Baton Rouge, Louisiana 70884
IV-G-16	F. Dowling Emission Testing Service, Inc. P.O. Box 15075 Baton Rouge, Louisiana 70895
IV-G-17	J. Monfries Metco Environmental P.O. Box 598 Addison, Texas 75001
IV-G-36	Vincent D. Lajiness Director, Environmental, Legislative, and Regulatory Affairs Coatal States Management 500 Renaissance Center Detroit, MI 48243
IV-G-37	Mr. Philip Bennett Manager, Government Affairs KN Interstate Gas Transmission Co. One Allen Center 500 Dallas Street, Suite 100 Houston, TX 77002
IV-G-38	Ms. Lisa Beal Director, Environmental Affairs Interstate Natural Gas Association of America 10 G Street, N.E. Suite 700 Washington, DC 20002
IV-G-39	Mr. Thomas D. Hutchins, P.E. Director, Environmental, Health & Safety El Paso Natural Gas Company P.O. Box 1492 El Paso, TX 79978-1492

[a] The docket number for this project is A-94-04. Dockets are on file at the EPA Headquarters in Washington, D.C.

2.1 APPLICABILITY

2.1.1 Determination of Major Source Status

Comment: Commenters IV-D-11, IV-D-13, IV-D-14, IV-D-15, IV-D-19, IV-D-22, IV-D-34, IV-D-37, IV-G-03, and IV-G-05 suggested that any source currently covered by a Federally, State, or otherwise enforceable limit (e.g., title V permit) should be able to include the control efficiency of the control device when calculating applicability to subparts HH and HHH.

Commenter IV-D-11 recommended that the EPA exempt facilities that were determined to be minor sources under part 70 from the major source definition. The commenter stated that not excluding "controlled" sources from the major source definition is inconsistent with the intent of section 112(a)(1) of the CAA. The commenter explained that several sources in Louisiana have applied federally enforceable controls well before the date of the proposal and that being considered "minor sources" under part 70, but "major sources" under this proposal is inconsistent for these sources. The commenter stated that the two programs must have identical interpretations of the term. According to the commenter, Louisiana sources would be penalized for reducing emissions several years before the proposal of the rule, which sends the wrong signal to the regulated community.

Commenter IV-D-34 requested that the EPA specifically require in §§63.760 and 63.771(d) that the potential to emit (PTE) for an affected source be determined "considering all controls and limitations at the source." Commenters IV-D-13 and IV-D-37 stated that the following must be assumed:

- the control device was installed before the enforcement date of the final national emission standards for hazardous air pollutants (NESHAP);
- the control device was installed pursuant to a State or local air quality law, ordinance, rule, requirement or company business practice that was in place before the enforcement date of the final NESHAP; and
- the operation and emission reductions achieved by the control device are federally enforceable through a facility's title V permit or through another means that would ensure federal enforceability.

According to the commenters, their proposed criteria provide a common sense method to calculate PTE for existing facilities that have existing control devices and that have achieved early emission reductions before the enforcement date of the final NESHAP. The commenters further stated that their proposed criteria also prevent a facility operator from avoiding the intent of title III of the Clean Air Act (CAA).

Response: **Facilities with HAP emissions equal to or greater than the major source levels as established in the CAAA of 1990 are subject to the major source provisions of subpart HH. As defined in §63.2 (subpart A), PTE estimates take into account those controls installed due to regulatory requirements of Federally-enforceable programs, which are defined in §63.2 and the part 70 permit programs. Therefore, facilities with controlled HAP emissions less than the major source thresholds would be considered area sources. Therefore, by referring to §63.2 of subpart A (see Table 2), subparts HH and HHH already contain the provisions requested by the commenters.**

For additional information on limiting PTE for section 112 purposes and for other reasons, please refer to the following memoranda: (1) January 25, 1995 Memorandum from John Seitz, Director, OAQPS, entitled "Options for Limiting the Potential to Emit (PTE) of a Stationary Source Under Section 112 and Title V of the Clean Air Act;" (2) August 27, 1996 Memorandum from John Seitz, Director, OAQPS, entitled "Extension of January 25, 1995 Potential to Emit Transition Policy;" and (3) July 10, 1998 Memorandum from John Seitz, Director, OAQPS, entitled "Second Extension of January 25, 1995 Potential to Emit Transition Policy and Clarification of Interim Policy."

Comment: Commenter IV-D-19 pointed to a court case (National Mining Congress v. EPA, a59 F.3d.1351, D.C. Cir.1995) where the District of Columbia (DC) Circuit Court of Appeals ruled that the EPA had not adequately justified the requirement in section 112 of the CAA that standards that place limits on PTE must be "federally enforceable." The commenter suggested that within this rulemaking, limits on PTE are not limited to those that are "federally enforceable" as stated in the General Provisions (40 CFR 63.2). According to the commenter, any physical or operational limitation on the capacity of a source to emit a pollutant is appropriate. The commenter also suggested that the effect a limitation would have on emissions should be either federally enforceable or legally and practically enforceable by the State.

Response: In the National Mining court case, the court required the EPA to reconsider the Federal enforceability requirement, but did not vacate the requirement. As a result, the requirement for federal enforceability is still in effect. The definition of PTE for the MACT program (40 CFR 63.2) is currently under review and the EPA is engaged in a rulemaking process to amend the requirements in the General Provisions. Therefore, the EPA has not modified subparts HH and HHH in response to this comment.

Comment: Commenters IV-D-08, IV-D-15, IV-D-17, IV-D-20, IV-D-22, IV-D-23, IV-D-34, IV-G-03, and IV-G-05 were concerned that PTE estimates, as defined in the General Provisions, would be unrealistically high and would subject many small insignificant sources to the maximum achievable control technology (MACT) requirements. Commenter IV-G-03 was concerned that the PTE calculations this would result in high costs for controlling low emission sources, and may force marginally economic wells into premature abandonment. These commenters, along with commenters IV-D-04, IV-D-13, IV-D-19, IV-D-26, IV-D-30, IV-D-31, and IV-G-11 requested that PTE be based on the inherent design and operational limitations of production and transmission and storage facilities, such as throughput rates.

Commenter IV-D-04 suggested that Gas Research Institute (GRI)--GLYCalc™, Version 3.0 or higher (GLYCalc) would allow for the inclusion of these operating conditions in determining applicability for affected sources.

According to commenters IV-D-15, IV-D-22, IV-D-31, IV-D-34, IV-G-02, IV-G-03, and IV-G-05, the throughput of oil and gas production operations decline over time, and existing equipment is often designed, constructed and operated based on high initial production rates. Therefore, the commenters suggested that the facilities are usually operated at actual throughput rates that are much lower than the design capacities. Commenter IV-D-15 remarked that the throughput or process rate of a unit is limited by the oil or gas available in the geographic area where it is located. The commenter explained that the product being handled has unique chemical characteristics such as American Petroleum Institute (API) gravity, gas-to-oil ratio (GOR), etc., which also affect the emissions from a unit. The commenter further explained that the other equipment at the site will also affect the potential emissions of a unit (i.e., capping the potential emissions).

According to commenters IV-D-05, IV-D-15, IV-D-22, IV-D-34, IV-G-03, and IV-G-05, several States have established, through their own permit programs, mechanisms to limit PTE. The commenters requested that this MACT defer to State programs. The commenters suggested that the methodology in the Texas Natural Resource Conservation Commission's (TNRCC) Oil and Gas Supplemental Guidance Memorandum be used to define the PTE at inherently limited sources. According to commenter IV-D-15, to calculate PTE using the TNRCC approach, the operator (1) averages the highest site product throughput over the past five years, (2) multiplies that average by 1.2 (raising the throughput 20 percent covers the possibility if minor fluctuations or changes), and (3) uses the highest impact chemical composition from the past five years. Texas also defines calculation methods for inherently limited emission units and documentation, monitoring and recordkeeping requirements. Commenter IV-D-34 also noted that

Wyoming allows exploration and production facilities to adopt design or other limitations under State regulations.

Commenter IV-D-22 also provided supplemental comments (IV-G-23) and recommended that the EPA either (1) specify methods for the oil and natural gas production source category to use in calculating PTE or (2) provide a simple federal synthetic minor source mechanism.

Response: **The EPA agrees that there are certain inherent throughput limitations associated with the production of oil and natural gas, primarily related to declining production rates. Therefore, the EPA has developed an approach for determining whether or not a facility is a major source subject to subpart HH. The final rule allows an owner or operator to calculate potential emissions using a maximum annual facility throughput that is calculated as follows:**

1. **If the owner or operator of a production facility documents, to the Administrator's satisfaction, a decline in annual natural gas or hydrocarbon liquid throughput, each year, for the five years prior to the effective date of subpart HH, the owner or operator must determine the maximum natural gas or hydrocarbon liquid throughput as the average of the annual natural gas or hydrocarbon liquid throughput for the three years prior to the effective date of subpart HH, multiplied by 1.2. This maximum throughput must be used to determine a facility's PTE.**

2. **If the owner or operator cannot document a decline in annual throughput each year for the five years prior to the effective date of subpart HH, the maximum throughput used to calculate PTE must be calculated as the highest annual natural gas or hydrocarbon liquid throughput over the five years prior to the effective date of subpart HH, multiplied by a factor of 1.2.**

3. **The owner or operator is required to document annual facility natural gas or hydrocarbon liquid throughput each year and if the facility's natural gas or hydrocarbon liquid throughput increases above the maximum throughput calculated**

in steps (1) or (2), the maximum throughput must be recalculated using the new, higher, throughput multiplied by the factor of 1.2.

4. **The owner or operator is also required to determine the maximum values for other parameters used to calculate PTE as the maximum for the period over which the maximum natural gas or hydrocarbon liquid throughput is determined in steps (1) or (2).**

Comment: Commenters IV-D-07 and IV-D-31 requested that the EPA consider the seasonal operation of natural gas storage facilities in estimating potential emissions and that the facility's PTE cannot be based on withdrawal for the entire season at maximum capacity. The commenters explained that natural gas storage facilities must spend part of the year injecting gas and that withdrawal rates decrease as the storage field's pressure drops.

Response: The EPA agrees that natural gas storage facilities have inherent limitations due to the nature of their operations. Information collected during site visits indicated that glycol dehydration units located at storage facilities normally operate in the winter when gas is being withdrawn from storage fields (Air Docket A-94-04 numbers IV-B-01 through IV-B-05). Therefore, the EPA believes that it is not appropriate for such facilities to estimate potential emissions based on year-round operation (i.e., 8,760 hr/yr). Therefore the EPA has developed the following procedure to determine major source status and applicability to subpart HHH for facilities that store natural gas or facilities that transport and store natural gas:

1. **The owner or operator calculates the number of hours it takes to complete a storage cycle for the facility. The storage cycle is the number of hours for the injection cycle, calculated using Equation 1, plus the number of hours for the withdrawal cycle, calculated using Equation 2.**

$$IC = \frac{WGC}{IR_{max}} \qquad (1)$$

where:

IC	**=**	**Facility injection cycle in hr/cycle.**
WGC	**=**	**Working gas capacity in m^3. The working gas capacity is defined as the maximum storage capacity minus the FERC cushion.[1]**
IR_{max}	**=**	**Maximum facility injection rate in m^3/hr.**

$$WC = \frac{WGC}{WR_{max}} \qquad (2)$$

where:

WC	**=**	**Facility withdrawal cycle in hr/cycle.**
WGC	**=**	**Working gas capacity in m^3 (same value used in equation 1).**
WR_{max}	**=**	**Maximum facility withdrawal rate in m^3/hr.**

2. **The owner or operator calculates the number of storage cycles per year using Equation 3.**

$$Cycle = \frac{8760\ hr/yr}{IC + WC} \qquad (3)$$

where:

Cycle	**=**	**Number of storage cycles for the facility per year (cycle/facility/yr).**

[1]The FERC cushion is the minimum gas capacity allowed for a storage field, as regulated by the Federal Energy Regulatory Commission.

IC = Number of hours for a facility injection cycle, calculated using Equation 1 (hr/cycle).

WC = Number of hours for a facility withdrawal cycle, calculated using Equation 2 (hr/cycle).

3. The owner or operator calculates the facilitywide maximum annual glycol dehydration unit hours of operation calculated using Equation 4.

$$Operation = Cycles \times WC \tag{4}$$

where:

Operation = Facilitywide maximum annual glycol dehydration unit hours of operation (hr/yr).

Cycles = Number of storage cycles for the facility per year, calculated in Equation 3 (cycle/facility/yr).

WC = Number of hours for a facility withdrawal cycle (hr/cycle) as calculated in Equation 2.

4. The owner or operator calculates the maximum facilitywide natural gas throughput using Equation 5.

$$Throughput = Operation \times WR_{max} \tag{5}$$

where:

Throughput = Maximum facilitywide natural gas throughput in m^3/yr.

Operation = Maximum facilitywide annual glycol dehydration unit hours of operation in hr/yr, as calculated in Equation 4.

WR_{max} = Maximum facility withdrawal rate in m^3/hr.

Since transmission facilities do not spend part of the year injecting gas into storage, the EPA believes that the approach for storage facilities is not appropriate. Therefore, the EPA has included different requirements in subpart HHH for these facilities to account for year-round operation. For facilities that only transport natural gas, the final subpart HHH requires owners or operators to calculate the maximum facility natural gas throughput as the highest annual natural gas throughput over the five years prior to the effective date of the rule, multiplied by 1.2.

The final subpart HHH also contains requirements for determining maximum values for other parameters used to calculated potential emissions and for documenting annual facility natural gas throughput. These requirements are the same as those specified for production.

Comment: Commenters IV-D-22, IV-D-26, IV-D-30, IV-D-34, IV-G-02, and IV-G-11 recommended a simplified approach to calculating PTE, such as screening equations similar to those developed for other NESHAP, to take into account design and operational limitations (e.g., Gasoline Distribution, 40 CFR part 63, subpart R).

Commenter IV-D-26 mentioned the possibility of a source category-specific definition for PTE. Commenter IV-G-02 stated that a simplified PTE analysis should be available for determining applicability to subparts HH and HHH for the following reasons:

- oil and gas equipment may be oversized compared with its available throughput (due to field depletion or future field development plans),
- operators must make decisions on several sources, and
- the EPA's definition of what must be aggregated in subparts HH and HHH for a major source determination can be different from the basis for major source determination for title V (63 FR 6300 - 6303 cited).

Commenter IV-D-22 recommended that §63.760(c) be amended to include the following text:

(1) The owner or operator of an affected source may demonstrate that the source is an area source for all purposes under this subpart by documenting and recording as required that either:

(i) [Reserved for screening equations, e.g., the result "x" of the following equation is "y"]; or

(ii) Specific operational or physical limitations adopted for the source result in an area source classification. Such limitations may include (1) parameters of the hydrocarbon fluid, (2) operating/production parameters of the facility, (3) parameters of the hydrocarbon reservoir, and (4) any other reasonable and enforceable parameter.

(2) An area source classification established pursuant to these criteria shall be treated as part of the design of the source if it is federally, state, or otherwise practically enforceable.

The commenter recommended that the EPA create a process within subpart HH that streamlines the specification of enforceable applicability criteria as referenced in modified §63.760(c)(ii), above. The commenter stated that they will submit supplemental comments providing appropriate criteria and outlining an appropriate methodology for establishing this process. In their supplemental comments (Air Docket A-94-04, number IV-G-23), the commenter recommended a screening process for determining major source status. This process included steps to (1) evaluated the source status of glycol dehydration units, (2) evaluate the source status for storage vessels, and (3) evaluate the source status of collocated equipment. The commenter also made recommendations monitoring, recordkeeping and reporting requirements.

Response: **The EPA evaluated the use of an equation similar in structure to the Gasoline Distribution NESHAP, 40 CFR part 63, subpart R. After extended effort, the EPA found that the number of variables was too extensive to allow development of a manageable equation.**

Therefore, as an alternative, the EPA has developed a simplified major source determination (MSD) for HAP emission sources in the oil and natural gas production and natural gas transmission and storage source categories, in addition to the PTE approach outlined in a previous comment. The simplified MSD allows the owner or operator of a facility to easily determine (1) if they are major sources and whether MACT requirements apply to their facility, and (2) if they are required to obtain a title V operating permit.

The objective of the simplified MSD is to set applicability thresholds that would reasonably ensure that no facilities operating below such a threshold would have HAP emissions greater than the major source thresholds of 10 tpy for individual HAP and 25 tpy for any combination of HAP as defined in the CAA. A detailed description of the development of this MSD is presented in the docket (Air Docket A-94-04 number IV-A-12).

To develop this MSD, the EPA reviewed "reasonable worst case" scenarios for use in development of the simplified MSD applicability levels. These "reasonable worst case" scenarios take into account such variables as throughput, HAP concentrations, and standard operating procedures.

Based on these scenarios, the EPA determined that oil and natural gas production facilities prior to the point of custody transfer, with a facilitywide actual annual average natural gas throughput less than 650 thousand standard cubic feet per day (scf/d) can be reasonable expected not to exceed the major source thresholds. Likewise, the EPA determined that oil and natural gas production facilities prior to the point of custody transfer with a facilitywide hydrocarbon liquid throughput less than 250 bpd can reasonably be expected not to exceed the major source thresholds.

Storage vessels make up a small percentage of emissions from a production facility and have different emission profiles as compared to glycol dehydration units. Therefore, the EPA determined that a production facility consisting of glycol dehydration units and storage vessels that meet the 650 thousand-scf/d natural gas throughput and the 250-bpd hydrocarbon liquid throughput thresholds can be expected not to exceed the major source thresholds.

Section 63.760 of final subpart HH contains an exemption that states that production facilities prior to the point of custody transfer, with a facilitywide natural gas throughput less than 650 thousand scf/d and a facilitywide hydrocarbon liquid throughput less than 250 bpd are exempt from subpart HH.

Owners and operators of production facilities after the point of custody transfer (including natural gas processing plants) are required to aggregate emissions from all HAP emissions units at the facility when determining whether or not a facility is a major source. Furthermore, production facilities after the point of custody transfer are likely to have other HAP emission units in addition to glycol dehydration units and storage vessels, such as amine treaters and sulfur recovery units which are typically located at natural gas processing plants. Since emissions from these emission points must be aggregated in determining the major source status of the facility, the EPA determined that it would be unreasonable to develop a throughput cutoff that would reasonably ensure that facilities operating below such cutoff would not be a major source. Therefore, production facilities located after the point of custody

transfer, including natural gas processing plants, do not qualify for the simplified MSD.

Using this same approach, the EPA determined that natural gas transmission and storage facilities with a facilitywide actual annual average natural gas throughput less than 1 million standard cubic feet per day (MMscf/d), can reasonably be expected not to exceed the major source thresholds (Air Docket A-94-04 number IV-A-15). Section 63.1270 of final subpart HHH states that facilities operating with an actual average annual natural gas throughput less than 1 MMscf/d are exempt from subpart HHH. However, since owners or operators of facilities in the natural gas transmission and storage source category must aggregate emissions from all HAP emissions units to determine major source status, this exemption only applies to facilities where glycol dehydration units are the only HAP emissions unit.

Comment: Commenter IV-D-26 recommended using the logic in the EPA's 1995 Potential to Emit Transition Policy. Under this policy, sources with low emissions (e.g., less than 50 percent of major source thresholds) may be deemed nonmajor if records of actual emissions are kept. Commenters IV-D-08, IV-D-20, and IV-D-22 suggested the use of written documentation of physical and operational limitations that would be federally, State, or otherwise practically enforceable. The commenters recommended that the EPA provide operators the ability to select maximum annual levels for product throughput, and continuous maximums for physical parameters of the product received and operating parameters under which the unit will be operated. The operator would then calculate PTE based on these maximums using accepted calculation procedures (e.g., Vasquez-Beggs, or GLYCalc) and MACT would apply if the aggregate PTE calculated based on maximums exceeds the major source thresholds.

Response: In the January 25, 1995 policy memorandum entitled "Options for Limiting the Potential to Emit (PTE) of a Stationary Source Under Section 112 and Title V of the Clean Air Act (Act)," the EPA issued a transition policy for section 112 and title V (this memorandum is available on the EPA's web site at Internet address http://www.epa.gov/ttn/oarpg/t5pgm.html). This transition policy addressed concerns that some sources may face gaps in the ability to acquire federally enforceable PTE limits because of delays in State adoption of EPA approval of programs or in their implementation. In order to ensure that such gaps would not create adverse consequences for States or for sources, the EPA provided that during a 2-year period extending from January 1995 through January 1997, for sources lacking federally enforceable limitations, State and local air regulators had the option of treating the following types of sources as non-major under section 112 and in their title V programs:

1. sources that maintain adequate records to demonstrate that their actual emissions are less than 50 percent of the applicable major source threshold, and have continued to operate at less than 50 percent of the threshold since January 1994, and

2. sources with actual emissions between 50 and 100 percent of the major source threshold, but which hold State-enforceable limits that are enforceable as a practical matter.

On August 27, 1996, this transition policy was extended until July 31, 1998 (Internet site http://www.epa.gov/ttn/oarpg/t5pgm.html). On July 10, 1998, in a memorandum entitled "Second Extension of January 25, 1995 Potential to Emit Transition Policy and Clarification of Interim Policy" (Internet site http://www.epa.gov/ttn/oarpg/t5pgm.html), the EPA announced a second extension of the transition policy.

These extensions were provided because the EPA is engaged in a rulemaking process to consider amendments to the current PTE requirements. Currently, the PTE rulemaking, which will address the PTE requirements in the General Provisions (40 CFR part 63, subpart A) and the title V operating permits program, has not been completed. These rule amendments will affect federal enforceability requirements for PTE limits under these programs. Thus, there will continue to be uncertainty with respect to federally enforceable limits. Therefore, in the July 10, 1998, the EPA extended the transition policy until December 31, 1999, or until the effective date of the final rule in the PTE rulemaking, whichever is sooner.

The EPA expects that the rulemaking will be completed before December 31, 1999, and owners or operators will have the option of complying with the PTE rulemaking as well as the procedures specified in subparts HH and HHH.

2.1.2 Exemptions

Black Oil

Comment: Commenters IV-D-17 and IV-D-24 were concerned about the exemption criteria for facilities that process, store, or transfer black oil. Commenter IV-D-24 supported the use of a black oil exemption in the proposed standards. Commenter IV-D-17 suggested that pipelines that transmit "black oil" should not be further considered a potential HAP source.

Response: As stated in the preamble to the proposed rule, pipelines that handle hydrocarbon liquids after the point of custody transfer are not within the scope of the oil and natural gas production source category (63 FR 6291). The EPA plans to define the organic liquids distribution (non-gasoline) source category to include those facilities that distribute hydrocarbon liquids after the point of custody transfer. Since black oil is

defined as a hydrocarbon liquid, facilities that transmit black oil after the point of custody transfer will be covered under the organic liquids distribution NESHAP. The EPA does not believe that addressing this issue within subpart HH is necessary.

<u>Comment:</u> Commenters IV-D-20 and IV-D-33 questioned the EPA's basis for the definition of *black oil* in subpart HH. Commenter IV-D-20 stated that it was unclear whether this definition was based upon an assessment of HAP emissions or upon the determination that black oil that meets this definition in certain quantities and stored in a specific manner would result in adverse impact upon human health and/or the environment.

Commenters IV-D-12, IV-D-33, and IV-D-38 requested changes to the GOR and API gravity cutoffs proposed in the definition of *black oil* in subpart HH. To be consistent with industry practice, commenter IV-D-12 requested that the definition of *black oil* be revised to a GOR of less than 5,000 standard cubic feet per barrel (scf/bbl) and commenters IV-D-12 and IV-D-38 requested an API gravity less than 50°. Commenter IV-D-33 requested that the threshold be changed from an API gravity of 40° to 45°, which would provide additional regulatory relief to producers already hindered by marginal production in the Appalachian region. According to the commenter, Appalachian Basin crude oil runs between 40 and 45°. [Note: The commenter had 45° instead of 40° as the proposed specific gravity threshold. A typographical error is likely.]

<u>Response:</u> During the development of proposed subpart HH, industry representatives stressed that their industry was composed of large numbers of facilities that handle black oil and that black oil was not a significant contributor to overall source category HAP emissions. The EPA evaluated the available information and agreed that facilities that process black oil were not significant sources of overall HAP emissions from the

source category. Therefore, the EPA developed an exemption for facilities that exclusively process, handle and store black oil.

Furthermore, the EPA did not identify control technologies designed to reduce HAP in use at existing facilities that exclusively process, handle, or store black oil. Therefore, the EPA determined that the MACT floor was no control. This determination was not made based on health risks associated with black oil.

The EPA developed the definition for black oil (Air Docket A-94-04 number IV-A-05) based on a series of articles by William D. McCain (primary author).[2,3] According to the information in these articles, five types of reservoir fluids exist: black oil, volatile oil, retrograde gas-condensate, wet gas, and dry gas. Of these, black oils and volatile oils exist as liquids in the reservoir. Black oil, which is a mixture of chemical species ranging from methane to large, heavy, nonvolatile molecules, is in solution with dry gas, which is primarily methane.[4] Volatile oils, which contain fewer heavy molecules, are in solution with retrograde gas, which has fewer of the heavy organic molecules.

Reservoir fluid types are indicated by rules of thumb based on initial producing GOR, stock-tank liquid gravity, and stock-tank liquid color. Fluid type is usually determined by initial producing GOR and can be confirmed using stock-tank

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[2] McCain, William D. "Heavy Components Control Reservoir Fluid Behavior." Journal of Petroleum Technology. September 1994. pages 746-750.

[3] McCain, William D. "Black Oils and Volatile Oils - What's the Difference." Petroleum Engineer International. November 1993. pages 24-27.

[4] Reference 2.

gravity and color. [Note: The distinction between initial producing GOR and producing GOR is important. As reservoir pressure decreases over time, the producing GOR for black oil increases. Therefore, if any other GOR is used, the facility may not appear to qualify for the exemption.] The rule-of-thumb for volatile oils is an initial producing GOR of at least 1,750 scf/bbl. Volatile oil is also suspected with a gravity of 40° or more and a color that is brown, reddish, orange, or green. The rule-of-thumb for black oil is an initial producing GOR less than 1,750 scf/bbl and an API gravity less than 45° and a color that is dark, usually black (sometimes with a greenish cast) or brown.

The EPA used the descriptions of black oil from these articles to develop the proposed definition of black oil. Since color determination is subjective, the EPA selected initial producing GOR and API gravity as quantifiable criteria for defining black oil. In addition, since the API gravity criteria overlap for black oil and volatile oil, the EPA chose the lower, more conservative value of 40° for the black oil definition. The EPA believes that using a higher API gravity to define black oil, such as 45 or 50° as recommended by the commenters, would increase the possibility that the liquid is a volatile oil, thus exempting sources that are likely to have higher HAP emissions. The criteria for defining black oil, which were obtained directly from widely recognized definitions of black oil and volatile oil that are used in the oil and natural gas industry, are technically sound for identifying which sources are included as black oil facilities. Therefore, the EPA has not made any changes to the definition of black oil in response to these comments.

Comment: Commenters IV-D-01 and IV-D-29 were concerned that the exemption criteria would exempt facilities with significant emissions. Commenter IV-D-01 requested that the EPA delete the provision exempting black oil facilities from the requirements of the subpart [§63.760(e)]. According to the commenter, most oil and gas production facilities in Louisiana would probably be exempt from the subpart. Furthermore, the commenter stated that oil with an API gravity of 40 degrees is light crude and is almost condensate. The commenter also stated that oil with a GOR of 1,750 scf/bbl would be expected to result in high gas production.

Commenter IV-D-29 supported lowering the black oil applicability thresholds from a gas-to-oil ratio (GOR) less than 1,750 scf/bbl and an API gravity less than 40° to a GOR of less than 1,250 scf/bbl and an API gravity less than 27 or 28°. The commenter was concerned that the proposed applicability thresholds for black oil would exempt nearly all tank batteries in Santa Barbara County, California (diesel fuel has an API gravity of 38°).

Response: Based on an evaluation of the available information, the EPA determined that there is a low potential for HAP emissions from black oil in the oil and natural gas production source category. The top 12 percent of facilities in this subcategory were not controlled, and due to the low emissions potential, it was determined to be not cost effective to go beyond the MACT floor. Therefore, the EPA established an exemption from regulatory requirements in subpart HH for those facilities that exclusively handle black oil.

Furthermore, based on the EPA's understanding of the characteristics of black oil, there may be significant gas production from facilities that exclusively handle black oil. However, this gas would primarily have a low moisture content, and generally have a low potential for HAP emissions. Therefore,

the EPA believes that facilities that process, store or handle black oil are not significant sources of HAP emissions and has not made any changes to the black oil definition in response to this comment. The EPA believes that the proposed applicability cutoffs are appropriate.

Comment: Commenter IV-D-02 recommended that the EPA eliminate the definition for *black oil* in subpart HH, and "define oil for purposes of part 63 as liquid hydrocarbons as Mineral Management Service (MMS) does (30 CFR §206.51)." The commenter agreed with the proposal to exempt black oil facilities provided the definition of *black oil* was correct. According to the commenter, defining black oil, which is dependant on many variables, makes subpart HH too complex, and makes enforcement impossible. The commenter stated that the EPA's definition of "black oil" is arbitrary and capricious, and "totally neglects long established and technically supportable definitions of condensate and oil." The commenter noted that the EPA did not include a discussion on reservoir condition of the hydrocarbon. The commenter stated that although the EPA was correct in dividing hydrocarbons into two categories (black oil and condensate), industry and MMS divide hydrocarbons differently into "oil" and "condensate." The commenter suggested that imposing two conflicting definitions of condensate and oil will result in unwarranted confusion within industry and the agency. The commenter felt that the EPA's approach to define "black oil" as something different from "oil" is not technically correct and is confusing.

Response: As stated in a previous response, the definition of black oil was developed using industry-defined terms. The EPA believes that the gas that evolves from black oil does not contain significant amounts of HAP. Therefore, the distinction between black oil and volatile oil is important. The commenter's proposed oil definition does not distinguish between volatile oil

and black oil. Therefore the EPA believes that a black oil definition based on the MMS definition of oil would exempt sources with significant HAP emissions.

Comment: Commenter IV-D-16 recommended that §63.760(e) be amended to allow for the production of 10 thousand cubic feet per day (MCF/D) of casing head gas for facilities that are otherwise subject to the black oil exemption. The commenter explained that most oil production facilities that process "black oil" produce a small amount of "casing-head gas." The commenter defined "casing-head gas" as a gas dissolved in the oil that separates from the oil as production occurs. According to the commenter, the casing-head gas produced by a black oil facility is not economically significant, but is a by-product of the oil production process.

Response: Instead of specifying casing head gas as being allowed, the EPA believes that any gas brought on site for fuel or gas generated from black oil should be allowed at a black oil facility. Therefore, §63.760(e)(1) states that for subpart HH, "...a black oil facility that uses natural gas for fuel, or generates gas from black oil..." is still exempt.

Glycol Dehydration Units

Comment: Several commenters referred to the flowrate and benzene emission rate exemptions for glycol dehydration units. Commenter IV-D-07 requested guidance on determining the annual average for dehydrator *de minimis* and recommended that the guidance be provided in §63.772(b). Commenters IV-D-24 and IV-D-35 supported the use of flowrate and benzene emission rate exemptions as it focuses on higher emissions, and according to commenter IV-D-35, triethylene glycol (TEG) units are usually located only at area sources. Commenter IV-D-12 requested that the EPA clarify the methods proposed for determining dehydrator HAP emission-based applicability and that the EPA provide examples to show how these methods should be applied.

<u>Response:</u> In response to several comments the EPA has made changes to final subparts HH and HHH to clarify the compliance demonstration requirements (see section 2.14 for further discussion). In addition, §§63.772(b) of final subpart HH and 63.1282(a) of final subpart HHH specify how the average natural gas flowrate is to be calculated. The final rules specify that emissions must be determined based on representative operations and the EPA believes that the owner or operator should have records for the representative operation of each glycol dehydration unit. The EPA will be publishing implementation guidance following promulgation of subparts HH and HHH.

<u>Comment:</u> Commenter IV-D-29 stated that they support the following:

(1) lowering the natural gas applicability threshold for glycol dehydration units from 85 thousand m^3 to 42 thousand m^3. The commenter stated that the EPA offered no real justification for the selected applicability threshold,

(2) lowering the benzene emission applicability threshold for glycol dehydration units from 0.9 ton per year to 0.5 ton per year. The commenter stated that the potential health effects of benzene exposure and the significance of total HAP emissions from the source category justify this change,

(3) replacing "or" with "and" when discussing glycol dehydration unit applicability thresholds. Thus, only those units that meet <u>both</u> the natural gas throughput <u>and</u> benzene emission rate would be exempted from the 95-percent control level, and

(4) establishing control measures for those glycol dehydration units that do meet all the applicability thresholds.

<u>Response:</u> The EPA evaluated several options in attempting to establish applicability criteria for glycol dehydration units. These options included a series of throughput, benzene emission rates, and the use of the term "or" or "and" within the applicability criteria. Based on its evaluation and to exempt those emission points with low HAP emissions, the EPA does not

believe that changing its applicability criteria for glycol dehydration units is necessary. Furthermore, there was no evidence available to the Administrator to suggest that sources with flow rates less than 3 MMscf/d or benzene emissions less than 1 tpy are controlled at the floor, and it was not cost effective to go beyond the floor.

Comment: Commenter IV-D-10 requested clarification of the term "benzene emissions to the atmosphere," for the 1 tpy cutoff. The commenter requested that the term mean actual benzene emissions.

Response: It was the EPA's intent to specify actual average benzene emissions and has revised proposed §§63.764(e) and 63.1274(b) (now codified at §63.764(e)(1) of final subpart HH and §63.1274(d)(1) of final subpart HHH) to clarify that actual average benzene emissions must be calculated for the 1-tpy exemption.

Comment: Commenter IV-D-05 stated that, as proposed, the regulations would exempt a glycol unit that processes less than 3 MMscf/d on an annual average, but is permitted to process more than 3 MMscf/d annually. The commenter stated that this would mean that PTE is not a factor as it historically has been in determining affected units.

Response: The EPA proposed this applicability criteria to exempt those glycol dehydration units for which the MACT floor was identified to be no control. These glycol dehydration units are not exempt from the subpart, but are exempt from the control requirements of subparts HH and HHH.[5] However, records of this

[5]It should be noted that these criteria are not related to the determination of PTE. Sources that meet these criteria are not subject to the control requirements of subparts HH and HHH, but are still subject the NESHAP. In a previous response, the EPA has announced the addition of an applicability cutoff for (continued...)

actual average throughput level (or the other applicability criteria) must be documented and maintained annually to remain exempted from the control requirements.

The EPA has knowledge of facilities that operate their glycol dehydration units above their nameplate capacity. Therefore, maintaining records of design capacity would not ensure operation below the throughput cutoffs. Therefore, §§63.774(d)(1) and 63.1284(d)(1) of the final rules specify that actual annual average natural gas throughput must be maintained, not the design capacity. Similarly, the final rules contain criteria for documenting actual average benzene emissions [codified at §§63.774(d)(2) and 63.1284(d)(2)].

Comment: Commenters IV-D-07 and IV-D-31 requested that the EPA make provisions in the PTE determination for fluctuations in water content and gas composition without having to sample the gas stream frequently.

Response: It is the EPA's understanding that, based on available information from the production industry, water content and gas composition remain relatively constant if the source of the input streams (such as reservoirs) does not change. However, although dramatic fluctuations in water content and gas compositions may occur in the transmission and storage industry, it is believed that they would be over a short period. Furthermore, since PTE is a worst case calculation, the EPA does not believe that frequent sampling would be required. However, sampling would be required if the source of the input stream

[5](...continued)
which production facilities and transmission and storage facilities below this value would not be subject to the NESHAP.

changed. Therefore, the EPA has not modified subparts HH and HHH in response to these comments.

Storage Vessels with the Potential for Flash Emissions

Comment: Commenter IV-D-03 requested that the proposed storage tank exemption/control criteria be based on "credible engineering test methods supported by fundamental principles of fluid phase behavior." The commenter provided a Society of Petroleum Engineers journal article entitled *Test Method for "Actual" True Vapor Pressure of Crude Oils*. The article presented data for flash gas emissions from black oil. According to the article, a 35^{o} API oil with a GOR of 13.4 scf/bbl had the flash gas emission potential to exceed benzene, toluene, ethyl benzene, xylene (BTEX) rates of 10 tpy with less than 5,000 bbl/day. The commenter noted that this oil would have been exempted from the control requirements. The commenter further noted that the DOE has degassed this oil to prevent such high emissions.

Commenter IV-G-01 suggested that breathing, working, and flashing losses from crude oil storage tanks are "significant" when storage tanks have gas to oil ratios and API gravities less than the minimums specified in subpart HH. The commenter provided an example calculation of tank emissions to show how HAP emissions from a crude oil storage tank could exceed 5 tons per year [and exceed 16 tons per year of total reactive organic compounds (ROC)]. The commenter was concerned that subpart HH, as currently written, may not reflect the maximum degree of reduction of HAP emissions for oil and gas production sources.

Response: The criteria of an API gravity equal to or greater than 40 degrees and an initial producing GOR equal to or greater than 0.31 m^3/liter were used in the proposed rule to define storage vessels with the potential for flash emissions. The EPA's analysis of storage vessels that contain hydrocarbon liquids that have API gravity and initial producing GOR higher

than these criteria indicate the potential for significant flash emissions.

The EPA developed the definition for storage vessels with the potential for flash emissions based on criteria (i.e., API gravity and GOR) that were easily recognized by industry personnel and relatively easy to obtain. Furthermore, these criteria are based on hydrocarbon liquid characteristics.

According to section 112(d)(1), the Administrator is required to establish emission standards for each category of major sources. Section 112(d)(1) states that "The Administrator may distinguish among classes, types, and sizes of sources within a category or subcategory in establishing such standards. . . ." In addition, section 112(d)(3) states that emission standards for existing sources in a category may be no less stringent than the MACT floor.

As stated in a previous response, the EPA has established that among the class of sources referred to as black oil facilities, the MACT floor is no control. For the class of sources defined as storage vessels with the potential for flash emissions (which includes storage vessels that do not process black oil), the EPA evaluated ". . . the average emission limitation achieved by the best performing 12 percent of the existing sources (for which the Administrator has emissions information),. . ." (section 112(d)(3)(A) of the Act). The EPA determined that the top 12 percent of existing storage vessels with the potential for flash emissions were controlled.

Comment: Commenter IV-D-03 provided an example, developed at the Strategic Petroleum Reserve, of a condensate with a GOR greater than 20,000 standard cubic feet per barrel (scf/bbl) and a 45° API gravity. The condensate was analyzed using the

EquiVap^{TM} method. The condensate stream was determined to have flash gas emissions potential due to true vapor pressures greater than atmospheric. However, EquiVap^{TM} also identified that after the liquid was further stabilized by the flash tank, no flash gas emissions were generated because the liquid had a true vapor pressure less than atmospheric. According to the commenter, the "arbitrary exemption/controls criteria would have required costly recovery and incineration of nonexistent flash gases from this stream even after it had been properly stabilized by the upstream flash tank."

Response: **The EPA recognizes that there could be specific situations, such as the ones analyzed by the commenters, where emissions of an exempted stream are higher than those of a non-exempted stream. In addition, there are many factors that affect whether flash emissions occur (e.g., pressure drop between two tanks, liquid vapor pressure, etc.). However, the EPA believes that this approach identifies hydrocarbon liquids that have a potential for significant flash emissions under conditions representative of industry operations.**

Comment: Commenter IV-G-01 requested guidance on how GOR should be measured.

Response: **The final subpart HH requires the owner or operator to determine the initial producing GOR for the definition of black oil and stock tank GOR for the definition of storage vessels with the potential for flash emissions. As stated in a previous response, this distinction is important because GOR changes with reservoir pressure. The EPA believes that requiring a GOR measurement at the stock tank will ensure that fluids with higher gas content (i.e., a greater potential for flash emissions) will be subject to the control requirements.**

In addition, the EPA has added a definition for *initial producing GOR* to subpart HH as follows:

> **_Initial producing GOR_ means the producing standard cubic feet of gas per stock tank barrel at the time that the reservoir pressure is above the bubblepoint pressure (or dewpoint pressure for a gas).**

The ratio of gas to oil should be constant until the bubblepoint or dewpoint is reached in the reservoir.[6] There are various methods within the industry available for measuring the GOR but there is not an approved EPA method. Although the EPA does not specify the method for subpart HH, the method used by the owner or operator must achieve a determination of the standard cubic feet of gas per stock tank barrel (scf/bbl) of the hydrocarbon liquid.

Comment: Commenter IV-D-01 questioned the basis for exempting storage vessels with an actual throughput less than 500 BPD [21,000 gallons per day (gal/day)] from control requirements [§63.764(c)(2)], and requested that the EPA delete the provision. According to the commenter, 500 BPD is a substantial throughput for the crude oil production in Louisiana. The commenter stated that due to the storage vessel exemptions most facilities in Louisiana would be exempt from this subpart.

Response: The data available to the EPA indicated that for the class of storage vessels not considered to have the potential for flash emissions (i.e., with API gravity less than 40° or a GOR less than 1,750 scf/bbl) and with a hydrocarbon liquid throughput less than 500 bpd, the MACT floor was no control and it was not cost effective to go beyond the floor [Air Docket A-94-04 numbers II-A-01 and II-D-50].

The EPA has added the throughput cutoff criterion to the storage vessels with the potential for flash emissions definition in final subpart HH. The final rule states that a storage vessel

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[6]Reference 2.

with the potential for flash emissions is defined as a storage vessel that contains an actual average hydrocarbon liquid with a stock tank GOR equal to or greater than 1,750 scf/bbl and an API gravity equal to or greater than 40 degrees, and a hydrocarbon liquid throughput equal to or greater than 500 bpd. By adding the throughput criterion to the definition of storage vessels with the potential for flash emissions, rather than as a cutoff specified in proposed §63.764(c)(2), storage vessels that do not meet the criteria for a storage vessel with the potential for flash emissions are not considered affected sources in the final rule and are not included in a facility's potential-to-emit (PTE) calculation for determining major source status.

Comment: Commenters IV-D-04, IV-D-22, IV-D-34, and IV-D-35 requested that the EPA clarify the averaging period for the 500-BPD exemption criterion for storage tanks. Commenter IV-D-04 assumed that it was meant to be an annual daily average basis. Commenter IV-D-35 suggested using a five-year rolling average based on maximum actual tank throughput. Commenter IV-D-34 requested that the storage tank throughput be based on an annual average. The commenter also suggested that the calculation of the 500-BPD threshold for storage tanks be based on a method similar to that proposed for glycol dehydration unit flow rates in §63.772(b)(1). Commenter IV-D-22 stated that there is no discussion in subpart HH or the preamble of how to determine applicability to the 500-BPD threshold for storage vessels. The commenter recommended that the EPA allow either monitoring of the flowrate, or other documentation (e.g., sales records) of the storage vessel flowrate, and that calculation of the 500 BPD limit be based on an annual average.

Response: As stated in a previous response, the 500-bpd throughput has been added to the definition of storage vessels with the potential for flash emissions. Thus, storage vessels

that do not meet this definition are exempt from subpart HH. Therefore, the EPA believes that establishing recordkeeping and reporting requirements for these units would be inappropriate.

However, §63.10(b)(3) contains recordkeeping requirements for applicability determination. Therefore, owners and operators with storage vessels that are not subject to subpart HH would be required under this section to maintain records of the applicability determination for these storage vessels.

<u>Comment:</u> Commenter IV-D-07 requested that the EPA clarify whether the regulation applies to the case where a tank battery has an average throughput less than 500 bbl/tank but a total throughput of greater than 500 bbl total.

<u>Response:</u> The throughput applicability criteria for storage vessels with the potential for flash emissions in final subpart HH applies to each storage vessel. Thus, a tank battery with a total actual throughput of more than 500 BPD that consists of several storage vessels, none of which has an actual average annual throughput equal to or greater than 500 BPD would not be subject to subpart HH, provided the GOR and API gravity criteria are met. Therefore, the EPA has not modified subpart HH in response to this comment.

<u>Comment:</u> Commenter IV-D-16 recommended that the EPA allow tanks with a specified percent HAP to be excluded from subpart HH. The commenter suggested that this would prevent a tank at a major source, with low HAP contents in the liquid, from being covered. According to the commenter, controls would not be effective since HAP emissions would be low due to the low HAP content in the liquid.

<u>Response:</u> The EPA has established that facilities that process, store or transfer black oil have a low potential for HAP emissions and are exempt from control requirements under subpart

HH. The EPA selected the criteria for defining storage vessels with the potential for flash emissions using parameters that are easily determined by the industry. Therefore, the EPA does not believe that specifying a percent HAP content for hydrocarbon liquids in subpart HH is necessary. Based on the EPA's knowledge of the industry, the black oil exemption, by itself, exempts approximately 85 percent of all tank batteries according to industry data.

<u>Comment:</u> Commenters IV-D-07 and IV-D-24 stated that they support exempting storage tanks that have the potential for flash emissions and a hydrocarbon throughput less than 500 BPD. However, the commenter IV-D-07 requested an exception for emergencies. Commenter IV-D-24 stated that the 500-BPD exemption avoids imposing costly controls on the smallest sources.

<u>Response:</u> Through the startup/shutdown/malfunction provisions in subpart HH, the EPA has attempted to address those emergencies that may be encountered by industry. Furthermore, the throughput exemption is based on an annual average, which should account for daily fluctuations in throughput. Thus, the EPA does not believe that an additional exemption is necessary in subpart HH.

<u>Comment:</u> Commenter IV-G-12 stated that subpart HH is lacking in that it does not distinguish between flashing and evaporation. According to the commenter, this lack of specificity could lead to confusion among sources and regulators concerning which vessels/substances are covered by the proposed rule. The commenter suggested that subpart HH be clarified to specify a temperature/phase relationship or maximum vapor pressure, as well as specifying the source and HAP content of the liquid stream that is being stored. The commenter presented examples. The commenter also stated that as an alternative the EPA could define the term "flashing" in thermodynamic terms (i.e., the change of state between liquid and vapor phases that

is not caused by the addition of thermal energy). The commenter was interested in exempting produced water from a production facility as well as lubricating oils, fuels, or other similar fluids.

<u>Response:</u> Temperature and vapor pressure are very dependant on stream composition. This variability makes it very difficult to establish boundary conditions for the types of hydrocarbon liquids processed in this industry. Furthermore, the EPA believes that API gravity and GOR are values that are well understood by the industry, and are usually readily available. The EPA does not believe that specifying a percent HAP content or maximum vapor pressure for hydrocarbon liquids in subpart HH is necessary. However, to clarify the term flash emissions, the EPA has added the following language to the definition of *storage vessels with the potential for flash emissions* that states "Flash emissions occur when dissolved hydrocarbons in the fluid evolve from solution when the fluid pressure is reduced and is not caused by the addition of thermal energy."

<u>Comment:</u> Commenter IV-G-01 was concerned that HAP and reactive organic compounds (ROC) emissions from storage vessels with the potential for flash emissions may be significant with a throughput less than 500 BPD. The commenter provided an example calculation for a storage tank with a throughput of 250 BPD, showing emissions from breathing, working and flashing losses. The example presented uncontrolled ROC emissions of 4.06 tpy and controlled ROC emissions of 0.20 tpy. Uncontrolled HAP emissions (including benzene, hexane, and 2,2,4-trimethylpentane) were estimated to be 1.31 tpy (uncontrolled) and 0.07 tpy (controlled).

<u>Response:</u> Based on the EPA's analysis, the storage vessel applicability cutoffs of hydrocarbon liquid throughput of 500 bpd, a GOR less than 1,750 scf/bbl, and an API gravity less than

40°, the storage vessels with significant HAP emissions will be controlled under this regulation. The example provided by the commenter did not show total HAP emissions greater than the major source thresholds of 10 tpy for individual HAP (the highest HAP emissions were estimated to be 0.69 tons of hexane per year, uncontrolled) or 25 tpy for any combination of HAP (total ROC emissions were estimated to be 4 tpy, uncontrolled). Therefore, since these emissions are well below the major source thresholds, the EPA maintains that the 500-BPD cutoff is reasonable, and has not changed the definition of storage vessels with the potential for flash emissions.

Other Exemptions

Comment: Commenter IV-D-01 questioned the basis for exempting reciprocating compressors in wet gas service from the compressor control requirements of §61.242-3, and requested that the EPA delete the provision. According to the commenter, if there was a leak, HAP released from a compressor in wet gas service would be higher than that released from a compressor in dry gas service, since the concentration of HAP is much higher in wet gas.

Response: The exemption for reciprocating compressor in wet gas service is consistent with 40 CFR subpart KKK, the Onshore Natural Gas Processing Plant New Source Performance Standards (NSPS). Therefore, the EPA has not removed this exemption from subpart HH.

2.1.3 Other Applicability Issues

Comment: Commenter IV-D-14 stated that many oil and gas production facilities are located in remote areas and do not have a substantive impact on human populations. The commenter asked what the underlying basis was behind the application of MACT requirements to HAP sources located in remote areas, whether the

CAA allowed for remote facilities to be exempted from MACT standards, and whether the EPA considered this in its rulemaking.

__Response:__ **The EPA does not have discretion in setting standards for major sources of HAP emissions, which must be implemented nationwide. Therefore, major sources located in remote areas must still comply with MACT.**

__Comment:__ Commenter IV-D-16 was concerned that the applicability section could be interpreted to mean that refinery Natural Gas Liquid (NGL) plants could be brought into coverage since they are at a refinery and at a major source. The commenter requested that a specific exemption be added to §63.760 for NGL Plants at refineries, to make it clear that it is not the intent of the regulation to cover refinery NGL Plants. According to the commenter, the rationale behind this exemption would be that NGL plants were not considered when the MACT floor was set and that these plants already have controls put on them by other regulations (e.g., SIP VOC regulations), therefore no environmental purpose would be served by drawing them into subpart HH.

Commenter IV-D-16 was also concerned that the applicability language could be misinterpreted to mean that existing major sources that have a single or very few gas wells collocated with the facility would be included. The commenter explained that a few wells have been drilled and are producing at existing major sources. According to the commenter, these plants should not be subjected to coverage by subpart HH merely because they are major sources for their primary activities and happen to have a single or a very few gas or oil wells on-site. The commenter recommended that the EPA exempt these facilities by making it clear that subpart HH applies only to oil and natural gas facilities that are major sources by themselves.

__Response:__ **The CAA requires the EPA to regulate major HAP sources. A major HAP source is defined 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. . . ." This means that the EPA is obligated to consider the whole site when determining if a source is major and to regulate co-located emission sources (e.g., production wells), when applicable. It should be noted that §63.760(d) states that if affected sources (glycol dehydration units, tank batteries, and ancillary equipment located at natural gas plants) are not present at a facility, there are no requirements under subpart HH.

Comment: Commenters IV-D-16 and IV-D-22 were concerned that proposed §63.760(b)(1)(iii) could be misinterpreted. The commenters recommended that §63.760(b) should be modified to clarify that only ancillary equipment located at natural gas plants are to be considered an affected source. Commenter IV-D-16 suggested that the EPA's intent was to include ancillary equipment as an affected source for gas plants in the preamble (63 FR 6295 and 6304). Commenter IV-D-22 suggested that the phrase "located at natural gas processing plants" be added to §§63.760(b)(1)(iii) and (iv).

Response: To clarify the applicability of subpart HH to ancillary equipment, the EPA agrees with the commenters that additional language is necessary, and will add the phrase "located at natural gas processing plants" to proposed §63.760(b)(1)(iii) and (iv) [now codified at §§63.760(b)(3) and (4) of final subpart HH].

Comment: Commenter IV-D-16 stated that the line between subpart HH and subpart HHH needs to be clarified so the same sources will not be covered by both rules.

Commenter IV-G-12 stated that they operate gas gathering systems that accept gas from third party wells at which no processing or treatment occurs. The commenter explained that this gas is often gathered and brought to a central compressor station where it is dehydrated and compressed and transferred to a transmission pipeline. Although it seems unlikely that a regulatory agency would try to aggregate emissions from the gathering and production operations, the commenter suggested that situations such as these be clarified in the final subpart HHH.

Commenter IV-D-21 cited two major problems with the EPA's approach to defining the scope of the source categories. First, the commenter suggested that subpart HHH lacks a clear definition that distinguishes natural gas transmission and storage facilities from natural gas production facilities. According to the commenter, subpart HH states that the natural gas transmission and storage source category begins at the point where natural gas enters the natural gas transmission and storage source category, but does not define this term. Additionally, subpart HHH does not define the term "transport or store natural gas." Therefore, the commenter was concerned that the regulated entity would be required to draw guidance from the separate definitions for "natural gas transmission" and "facility" operating in subpart HHH. However, according to the commenter, these two definitions provide contradictory guidance. For example, the commenter interpreted the term "natural gas transmission" to mean that the transmission and storage source category would begin only when the natural gas first enters the pipeline and the source category would not include any processing, either before or after initial entry into the pipeline. According to the commenter, this interpretation is supported by the definition of natural gas transmission by recognizing that processing can occur in the transmission and storage source category. The commenter recommended that the final rule include an express delineation of the source categories so the regulated community does not have to piece together the delineation from various provisions throughout subpart HHH.

According to the commenter, the second problem with subpart HHH is that it fails to acknowledge that natural gas transmission and storage facilities commonly process natural gas, both before and after introduction of natural gas into the main transmission line. The commenter cited the following examples of processing that are integral to natural gas transmission activities by minimizing the formation of hydrates: dehydration, removal of CO_2, and extraction of natural gas liquids. The commenter suggested that this interpretation of the definition of facility is also inconsistent with the BID, which notes that processing is included in the transmission and storage source category. The commenter further noted that processing occurs throughout the pipeline, the location of which is determined by such factors as gas quality and geographic location. The commenter requested that subpart HHH recognize the fact that processing occurs as part of transmission of natural gas.

To address the apparent lack of delineation between the production and transmission categories, the commenter recommended that a distinction between the two categories could be defined by reference to the point at which that transfer to the transmission company occurs. The commenter stated that processing operations that occur prior to the transfer point would fall within the gas production category, and those performed by the transmission company after the transfer would fall in the transmission and storage source category. According to the commenter, the BID states that natural gas is typically transferred at a meter station, but may occur at other points. The commenter stated that dehydrators operated by the transmission company after the transfer point would fall within the transmission and storage source category regardless of whether the dehydrators are located before or along the main transmission line.

<u>Response:</u> The natural gas transmission and storage definitions in subpart HHH were developed in consultation with natural gas transmission and storage stakeholders. The EPA believes that the definitions in subparts HH and HHH delineate the boundaries of the oil and natural gas production and natural gas transmission and storage source categories. The key points in this delineation are (1) the point of custody transfer, which

is a commonly understood definition within industry, and (2) the natural gas processing plant, which is a clearly defined facility within the production source category. Based on these discussions with industry, the EPA understood that there was only one point of custody transfer indicating the point at which natural gas entered the transmission pipeline. However, the EPA has made some changes to more clearly define the boundary between subparts HH and HHH.

The EPA believes that a compressor station located between a well and a natural gas processing plant or between the well and the point of custody transfer should be considered part of the oil and natural gas production source category. Therefore, to clarify this intent, the final subpart HH states that natural gas enters the natural gas transmission and storage source category after the natural gas processing plant, when present [§63.760(a)]. If no natural gas processing plant is present, natural gas enters the natural gas transmission and storage source category after the point of custody transfer. Subpart HHH also states that compressor stations that transport natural gas prior to the point of custody transfer, or to a natural gas processing plant (if present) are considered part of the oil and natural gas production source category [§63.1270(a)], and the following definition of custody transfer has been added to §63.1271:

> Custody transfer means the transfer of hydrocarbon liquids or natural gas: (1) after processing and/or treatment in the producing operations, or (2) from storage vessels or automatic transfer facilities, or other equipment, including product loading racks, to pipelines or any other forms of transportation.

The EPA has also made clarifying changes to the definition of facility in subparts HH and HHH.

2.2 DEFINITIONS

2.2.1 Facility

Several commenters responded to the EPA's request for comments on the definition of facility. The commenters requested clarification of or suggested changes to the proposed definition of facility. Commenter IV-D-35 agreed with the EPA's proposed definition of facility. The following paragraphs present more detailed comments on the definition of facility.

Comment: Commenter IV-D-02 was concerned that units, which may include large sections of land and many leases and which are under the control of a single operator, may be considered a single facility. According to the commenter, units are created when groups of leases are combined into a single entity, under common control, and some States require the formation of units. The commenter stated that since the terms "site" and "lease" (as contained in the definition of facility in §63.761) are not defined in the Act or in subpart HH, it is unclear whether a unit could be included within the term "lease" and whether a lease retains it's identity when included in a unit.

Therefore, the commenter requested that the EPA define facility to mean "the equipment at each individual well site and each individual tank battery or each individual gas or oil treating emplacement not located at the wellhead or tank battery."

Commenters IV-D-05 and IV-D-14 were confused about whether contiguous surface sites under common ownership would be considered separate facilities. Commenter IV-D-05 requested that the EPA modify the definition of *facility* in subpart HH to exclude contiguous graded pad sites. Commenter IV-D-14 stated that the term "surface site" could be interpreted as a single concrete pad, a grouping of concrete pads in a contiguous area, or a large graded area without any pads. According to the commenter, subpart HH could be interpreted to mean that two or more compressors on adjacent pads in a contiguous area are either separate facilities or single facilities. The commenter noted that this could also apply to several groupings of equipment used for different purposes but in the same graded area. The commenter requested that the EPA clarify the definition of facility to remove these uncertainties.

In addition, commenters IV-D-14 and IV-D-17 stated that subpart HH does not address the issue of ownership or its effects on the determination of what makes up a facility. The commenters asked whether equipment under separate ownership at the same surface site or adjacent surface sites could be considered a single facility. Commenter IV-D-17 suggested that, for clarification, a "facility" be defined to only include equipment within the boundaries of an individual surface site that operate under common ownership (e.g., central tank battery, graded pad site, etc.).

<u>Response:</u> The EPA developed the proposed definition of facility to: (1) identify criteria that define a grouping of emission points that meet the intent of the language contained in section 112(a)(1) of the Act: " . . . located within a contiguous area and under common control, . . . " and (2) contain terms that are meaningful and easily understood within the regulated industries. The proposed definition was based on individual surface sites and the idea 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 tract) shall not be aggregated. In addition, the proposed definition of a production field facility was limited to glycol dehydration units and storage vessels with the potential for flash emissions.

The EPA intended that the 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, be consistent with the intent of the Act, and be easily implementable.

The EPA believes that it would not be reasonable to aggregate emissions from surface sites that are located on the same lease, but are great distances apart. The definition of facility states that equipment located on different oil and natural gas properties (e.g., leases) are not to be aggregated. Although units (which are made up of more than lease or tract) are under common control, under the definition of facility, the equipment located on different leases contained within each unit would not be aggregated.

Under section 112(a)(1) of the act, a major source is defined as ". . . any stationary source or group of stationary sources located within a contiguous area and under common control. . . ." The EPA believes that by defining facility based on individual surface sites, the EPA has provided relief for individual surface sites that are located on the same lease, but are far apart, and excluding contiguous surface sites located on the same lease would be contrary to the intent of the Act.

Finally, the terms contained in the definition of facility (e.g., surface site and lease) are well understood within the industry and by enforcement agencies and the EPA does not believe that additional definitions or clarifications regarding these terms are necessary.

Comment: Commenter IV-D-05 suggested adding the term "permitized area" to the definition of facility in subpart HH. The commenter stated that mineral leases give operators control over large tracts of land. According to the commenter, adding the term "permitized area" would clarify the definition of facility where production equipment or equipment groupings on different oil and gas leases are described.

<u>Response:</u> The EPA believes that adding the term "permitized area" would add confusion to the definition of *facility* because some facilities may not have established "permitized areas," and different permitting authorities may define permitized areas differently. The EPA has not made the requested changes to the definition of *facility* in subpart HH.

<u>Comment:</u> Commenter IV-D-14 stated that subpart HH does not address the role of the process in which a grouping of equipment is engaged, in making the determination of what is a facility. The commenter explained that a graded area might contain a compressor station, one or more tank batteries, and a separate natural gas liquids plant. According to the commenter, each grouping of equipment may be considered a separate facility by the owner or operator, and each grouping may be found on separate concrete pads in a contiguous area under common control. The commenter asked whether these distinct operations would be considered a single facility under subpart HH, and requested the clarification of these issues.

<u>Response:</u> The definition of *major source*, as proposed in subpart HH (§63.761), has the same meaning as in §63.2, except that "emissions from processes, operations, or equipment that are not part of the same facility, as defined in this section, shall not be aggregated." A *facility*, as currently defined in §63.761, includes equipment within the boundaries of an individual surface site. The EPA believes that functionally-related equipment is generally located at the same surface site. Thus, the EPA believes that any grouping of equipment located on separate concrete pads (i.e., separate surface sites) would not be functionally-related; any grouping of equipment on separate surface sites would be treated as a separate facility for which emissions would not be aggregated. Furthermore, equipment located on the same surface site may be a separate facility,

depending on where the point of custody transfer is within the facility (e.g., the point at which natural gas enters a natural gas processing plant is a point of custody transfer and thus the natural gas processing plant would be considered a separate facility located on the same surface site).

Comment: Commenter IV-D-16 recommended that the definition of facility be modified to clarify that compressor engines are not covered by subpart HH. The commenter noted that vents for compressor engines are being covered by the Industrial Combustion Coordinated Rulemaking (ICCR) and should not be covered under subpart HH.

Response: Facilitywide HAP emissions after the point of custody transfer must be included in the major source determination. The EPA does not believe that engine vents from compressors should be excluded from the definition of *facility* in subpart HH because HAP emissions from these units would not be aggregated for major source determinations.

In addition, §63.760(b)(1) specifies the affected sources for subpart HH. Therefore, the EPA believes that there should be little confusion about which emission points are regulated under subpart HH. Therefore, the EPA has not specifically excluded engine vents for compressor engines from subpart HH requirements.

Comment: Commenters IV-D-08 and IV-D-22 recommended clarification to the definition of *facility* in subpart HH to include surface units and separate surface sites as tracts on which multiple groupings of equipment may be located without those separate groupings being designated as a "facility." In addition, the commenters recommended that the definition specify that connection by a road, a waterway, etc. does not cause two separate groupings of equipment at different sites to be part of the same facility. The commenters recommended the following changes:

> *Facility* means any grouping of equipment (1) where hydrocarbon liquids are processed, upgraded, or stored prior to the point of custody transfer, or (2) 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, facility <u>(including a building, structure, or installation)</u> 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 <u>or surface</u> unit areas, surface fee tracts, surface lease tracts, <u>or separate surface sites, whether or not connected by a road, waterway, walkway, power line or pipeline,</u> 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.

<u>**Response:**</u> **The EPA agrees with the commenter's recommendations and has made the suggested changes to the definition of *facility* in §63.761, except that the term "walkway" has not been included in the definition. The EPA believes that including this term would cause confusion for inspectors because a walkway between pieces of equipment could become a part of the boundary of a facility.**

<u>Comment:</u> Commenter IV-D-29 recommended that the EPA expand its definition of production field *facility* in subpart HH to include additional HAP emission points beyond glycol dehydration units and storage vessels with flash emission potential. The commenter stated that several sources in Santa Barbara and Ventura Counties that would otherwise be controlled would be exempt from subpart HH under the proposed definition.

Response: **One of the EPA's objectives was to develop a definition of facility that would comply with section 112(n)(4) of the Act and at the same time, reduce the burden on owners and operators in making a major source determination. The EPA's evaluation of HAP emission sources in production field operations suggested that other potential HAP emission points at these facilities (e.g., equipment leaks) would be inconsequential to the determination of a facility's major source status. The EPA believes that eliminating the need to quantify HAP emissions from small sources at production field facilities, would not affect the major source status determination, but would reduce the burden on owners or operators.**

Comment: Commenters IV-D-06 and IV-D-31 requested that the EPA clarify, within the definition of facility in subpart HHH, whether the EPA intended to exclude facilities used to store natural gas after the gas enters the local distribution system of a gas utility. Commenter IV-D-06 interpreted §63.1270(a) to mean that the affected source runs all the way to the affected end user, even if some local distribution company exists between the natural gas transmission and storage source and the end user. The commenter remarked that according to the preamble, this was not the EPA's intent. The commenter stated that the affected source is supposed to run all the way to the end user only if there is no local distribution company. The commenter recommended the following language to clarify §63.1270(a):

> (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 (if there is no local distribution company) to a final end user, and that are major sources of hazardous air pollutant (HAP) emissions.

The commenter also recommended changes to the definition of facility to clarify this point.

> *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 (if there is no local distribution company) 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 included, 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 and is connected by ancillary equipment, such as gas flow lines~~, roads,~~ or power lines.[7] 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.

The commenter stated that this comment may also apply to subpart HH.

Response: The affected source in the natural gas transmission and storage source category should run all the way to the end user only if there is no local distribution company. Therefore, the EPA has added the phrase "if there is no local distribution company" to §63.1270(a) and the definition of *facility* in subpart HHH. The EPA also agrees that roads are not equipment and has removed the term from the definition of facility in §63.1271 of subpart HHH.

Comment: Commenters IV-D-07 and IV-D-31 stated that since natural gas storage takes place in depleted gas wells, and liquids are transferred for processing to the plant, the

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[7]This particular change is for an unrelated reason: roads are not "equipment."

definition of *facility* suggests that a natural gas storage facility could qualify as a production facility. The commenters stated that these terms must be clarified to avoid this misunderstanding.

__Response:__ Subpart HH contains a definition of *field natural gas* which means " . . .natural gas that is extracted from a production well prior to entering the first stage of processing, such as dehydration." A *production well* is defined in §63.761 as a ". . . hole drilled in the earth from which ... field natural gas is extracted." Since the gas handled by a natural gas storage facility has been dehydrated, the natural gas handled by a storage facility would not be considered field natural gas. Therefore, given the definitions of *production well* and *field natural gas*, a natural gas storage field that uses a depleted gas well would not qualify as a production facility. The EPA does not believe that clarification to the definition of *facility* is necessary in response to this comment.

__Comment:__ Commenter IV-D-07 stated that in the preamble, the term "upgraded" is used concerning hydrocarbon liquids, but is not defined and should not be included in subpart HH.

__Response:__ The EPA agrees that clarification to the definition of the term "upgraded" is necessary. Therefore, the EPA has modified the definition of *facility* in subpart HH to specify that "upgraded" means "the removal of impurities or other constituents to meet contract specifications."

__Comment:__ Commenter IV-D-14 requested that the EPA clarify the term *graded pad* in subpart HH. According to the commenter, clarification of this term is critical in establishing the limits of a given "facility."

__Response:__ The term *graded pad* is a term that is commonly used in the industry. However, this term is used in the

definition of surface site, and is not appropriate as an example of a facility. Therefore, the EPA has removed this term from the definition of *facility*.

Comment: In their supplemental comments (IV-G-23), commenter IV-D-22 recommended that the EPA modify the definition of facility to clarify that product loading rack equipment falls within the EPA's definition of facility. The commenter recommended the following changes:

> *Facility* means any grouping of equipment ~~(1)~~ where hydrocarbon liquids, natural gas or natural gas liquids are processed, upgraded, or stored prior to a point of custody transfer~~, or (2) where natural gas is processed, upgraded, or stored prior to entering the natural gas transmission source category~~.

Response: The EPA does not believe that the commenter's recommendations are necessary. Natural gas liquids are defined in §63.761 as hydrocarbon liquids. Therefore, they are already covered in the definition of facility in subpart HH.

2.2.2 Other Comments on Definitions

Affected Source

Comment: Commenters IV-D-08 and IV-D-22 recommended the following new definition for *affected source*, which is "important to the successful implementation of subpart HH":

> *Affected source:* For major sources, each emission point located at a facility that meets the criteria specified in paragraph (a) and listed in paragraphs (b)(1)(i) through (b)(1)(iv) of Section 63.760; for area sources, each TEG dehydration unit located at a facility that meets the criteria specified in paragraph (a) of Section 63.760.

Response: The EPA believes that the addition of the term *affected source* to §63.761 is unnecessary since it is defined in §63.760(b).

Ancillary Equipment

Comment: Commenter IV-D-06 pointed out that subpart HH provides no definition for the term *product accumulator vessel*. The commenter stated that they did not know, and did not think the EPA knew, what a *product accumulator vessel* was. According to the commenter, new terms from the hazardous organic NESHAP (HON), "surge control vessel" and "bottoms receiver" have definitions the commenter can understand. The commenter recommended that the EPA use one or both terms in place of *product accumulator vessel*, if appropriate, and that the term *product accumulator vessel* be eliminated.

Response: The EPA agrees with the commenter that clarification to the definition of *ancillary equipment* is necessary and has modified the definition as follows:

> ***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~~.**

The term "compressors" was removed because they are listed separately in the subpart HH.

Comment: Commenter IV-D-22 recommended the following modification to the definition of *ancillary equipment* to clarify that such equipment is subject to subpart HH only if it is located at a natural gas processing plant:

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

Response: Section 63.769(a) states that the equipment leak standards apply to ancillary equipment at natural gas processing plants. The EPA believes that specifying that ancillary equipment is located at natural gas processing plants within the *ancillary equipment* definition would be redundant. The EPA has not altered the definition of *ancillary equipment* in response to this comment.

Black Oil

Comment: Commenter IV-D-22 recommended the following modification to the definition of *black oil* in subpart HH to clarify the point of measurement and averaging period for the GOR:

> *Black oil* means hydrocarbon (petroleum) liquid with an annual average wellhead gas-to-oil ratio (GOR) less than 50 cubic meters (1,750 cubic feet) per barrel and an API gravity of less than 40 degrees for the storage tank liquids.

Commenter IV-G-01 stated that the proposed definition of *black oil* does not state where the GOR applies and should be clarified. The commenter stated that it was not clear if the GOR applies at the storage tank where flashing occurs or at the subsurface reservoir.

Response: The EPA intends that the GOR should be measured as the initial producing GOR, rather than the average wellhead GOR. The EPA has added the phrase "initial producing" before GOR to the definition of *black oil*. The EPA has also added the following definition for *initial producing GOR* to §63.761.

> ***Initial producing GOR* means the producing standard cubic feet (scf) of gas per stock tank barrel (bbl) at the time that the reservoir pressure is above the bubblepoint pressure (or dewpoint pressure for a gas).**

Boiler

Comment: Commenter IV-D-06 recommended that the EPA amend the proposed definition of *boiler* to include resource conservation and recovery act (RCRA) industrial furnaces. The commenter explained that this change is necessary to provide those devices an exemption from performance testing. The commenter stated that the EPA should use the definition of *boiler* in §63.111 of subpart G of the HON, verbatim, as the definition of *boiler* in subpart HHH. The commenter stated that this comment also applies to subpart HH. The commenter suggested that an alternative would be to add separate provisions for industrial furnaces; however, the commenter noted that this would require more extensive drafting. Since all the relevant cross-references to RCRA regulations are the same for industrial furnaces as for boilers and the commenter stated that *adding industrial furnaces to the definition of a boiler would be easier*.

Commenter IV-D-22 recommended the following modification to the definition of *boiler* to be consistent with the ICCR:

> *Boiler* means an enclosed device using controlled flame combustion and having the primary purpose of recovering and exporting thermal energy in the form of steam or hot water.

<u>Response:</u> The EPA is not aware of any oil and natural gas production or natural gas transmission and storage facilities that would have RCRA industrial furnaces. However, the EPA does not see any reason to not incorporate the commenter's (IV-D-06) suggested language. In addition, the EPA has modified the definition of *boiler* in subparts HH and HHH to be consistent with the ICCR. The following definition of *boiler* has been added to §§63.761 and 63.1271:

> ***Boiler* means an enclosed device using controlled flame combustion and having the primary purpose of recovering and exporting thermal energy in the form of steam or hot water. Boiler also means any industrial furnace as defined in 40 CFR 260.10.**

<u>Closed Vent System</u>

<u>Comment:</u> Commenter IV-D-06 requested that the EPA clarify that closed-vent systems vent emissions to control devices and not to a process. The commenter explained that process piping routes emissions to (or from or within) a process. The commenter further explained that process piping may have equipment subject to equipment leak monitoring requirements that should not be subject to closed-vent system monitoring requirements. Therefore, the commenter suggested that the EPA make the following changes to subparts HH and HHH:

(1) Revise the definition of *closed-vent system* in §63.1271 as shown:

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~~ conveyance system shall not be considered a closed vent system and is not subject to closed vent system standards.

(2) Revise the definition of *control device* as shown:

Control device means any equipment used for recovering or oxidizing hazardous air pollutant (HAP) ~~and volatile organic compound (VOC)~~[8] 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 or closed-vent systems.

(3) Revise §63.1275(c)(1) as shown:

(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 requirement of section 63.1281(c) and (d)~~.

Response: **The definitions of *closed vent system* and *control device* and §63.1275(c)(1) of subpart HHH, and §63.765(c)(1) of subpart HH, have been revised as follows, to clarify that**

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[8]This specific change is unrelated, but important. Subpart HHH is not a VOC rule; it is a HAP rule. Additionally, the way the proposed definition was worded, nothing could be a control device unless it controlled both HAP and VOC. In other words, if a device to control only HAP was installed, that device could not be a control device because it is not also controlling VOC. Such a result would be nonsensical, but it would appear to be compelled by the literal wording of the proposed definition. By eliminating the words "and volatile organic compound (VOC)" from the definition, the EPA can resolve that difficulty.

closed-vent systems vent emissions to control devices and not to a process:

> 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~~ one or more control devices~~-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~~ conveyance system shall not be considered a closed-vent system and is not subject to closed-vent system standards.
>
> > Control device means any equipment used for recovering or oxidizing hazardous air pollutant (HAP) or ~~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 (i.e., injected into the flame zone of a combustion device), 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 or closed-vent systems.

Regarding the removal of "volatile organic compounds" from the definition of *control device*, the EPA does not believe that including VOC suggests that the Agency is regulating VOC.

Compressor Station

Comment: Commenter IV-D-06 stated that the phrase "supplies energy" in the definition of *compressor station* is vague. According to the commenter, under a literal interpretation of subpart HHH, a power plant would be a "compressor station" because it "supplies energy" to run the compressors that move the gas. The commenter contended that the EPA intended that compressor stations would have compressors. The commenter suggested the following language for clarification:

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

The commenter stated that this comment may also apply to subpart HH.

Response: In order to clarify the Agency's intent, the EPA has modified definition of *compressor station* in subpart HHH as suggested by the commenter.

Condensate

Comment: Commenter IV-D-22 recommended the following modification to the definition of *condensate* in subpart HH to specify what the standard conditions are:

> *Condensate* means hydrocarbon liquid that condenses because of changes in temperature, pressure, or both, and remains liquid at standard conditions of 14.7 pounds per square inch, absolute (psia) and 60°F.

Commenter IV-D-02 recommended that the EPA define condensate as MMS does at 30 CFR §206.51 as follows:

> *Condensate* is a mixture of liquid hydrocarbons that result from condensation of petroleum hydrocarbons existing initially in a gaseous phase in the underground reservoir.

Response: The EPA agrees that the definition of condensate needs to refer to liquids produced from natural gas. In addition, the definition of standard conditions (68 °F and 29.92 in Hg) is provided in subpart A (§63.2). Therefore, the revised definition of *condensate* is as follows:

> **Condensate means hydrocarbon liquid separated from natural gas that condenses due to ~~because of~~ changes in the temperature, pressure, or both, and remains liquid at standard conditions, as specified in §63.2 of this part.**

Condenser

Comment: Commenter IV-D-05 recommended that the EPA add a definition for the term *condenser*. The commenter stated that many still column vents have been modified to add tubing to the normal exhaust port. According to the commenter, if an exhaust experiences a temperature decrease because of a modification, then any amount of tubing or apparatus added to decrease the temperature could be classified as a condenser.

Response: **The EPA does not agree that a definition of condenser is necessary. It was not the EPA's intent to allow the kind of scenario described by the commenter as a control technology.**

Continuous Seal

Comment: Commenter IV-D-06 interpreted the definition of *continuous seal* to require a single-piece seal. According to the commenter, some seals, consisting of more than one piece, make a continuous seal. The commenter recommended that the EPA use language similar to that used in the HON, which allows for seals consisting of more than a single piece, for subpart HH.

Response: **The term *continuous seal* is not used in subpart HH and has been removed from §63.761. In addition, the term *fill* or *filling* is not used in subpart HH and has also been deleted.**

Custody Transfer

Comment: Commenter IV-D-05 recommended that the term *custody transfer* in subpart HH be clarified to account for the case where a gas processing plant is incorporated within an oil and gas production facility to process the gas further. The commenter explained that in such cases, the gas does not leave the pad site and does not change ownership.

Response: **The EPA considers the point at which natural gas enters a natural gas processing plant as a point of custody transfer. Therefore, a natural gas processing plant is a facility, despite whether or not the processing plant is incorporated within the production facility. The EPA has not made any changes to subpart HH in response to this comment.**

Comment: Commenter IV-D-16 stated that the definition of custody transfer in subpart HH is not consistent with the definition of custody transfer in other rules. [Note: the commenter did not provide examples of the other rules.] The commenter recommended that the phrase "for this regulation" needs to be added to clarify that this definition is only for subpart HH, so no misunderstandings will occur.

__Response:__ **The EPA has not made the commenter's recommended changes to the definition of custody transfer. The definition of custody transfer was derived from 40 CFR part 60, subpart Kb. Definitions in other rules would apply to those rules regardless of how the EPA defines custody transfer in subpart HH, therefore the commenter's clarification is unnecessary.**

__Comment:__ Commenter IV-D-16 recommended that the definition of custody transfer needs to address that a custody transfer still occurs when a subsidiary or different branch of the same company "sells" or transfers natural gas to another branch of the company.

__Response:__ **According to the proposed definition of custody transfer, the scenario described by the commenter would be considered a custody transfer, if gas was transferred from processing and/or treatment in the producing operations, from storage vessels or automatic transfer facilities, to pipelines or any other forms of transportation or if the gas was transported to a natural gas processing plant. The scenario would not be considered a point of custody transfer if the gas only changes ownership within the company. Therefore, the EPA has not made any changes in response to this comment. The EPA intends to issue implementation guidance on applicability in the future.**

__Comment:__ According to commenter IV-D-22, the definition of custody transfer in subpart HH does not need to include natural gas since applicability for natural gas production is established by the gas entry into the facility subject to the natural gas transmission and storage source category. Therefore, the commenter recommended the following modification to the definition of custody transfer to refer only to hydrocarbon liquids:

> *Custody transfer* means, for purposes of this subpart, the transfer of hydrocarbon liquids after processing and/or treatment in the producing operations, from storage vessels or automatic transfer facilities to pipelines or any other forms of transportation.

However, in their supplemental comments (IV-G-23), commenter IV-D-22 requested that the EPA clarify that the point of custody transfer is beyond such equipment as product loading racks so that this equipment is covered by subpart HH. The commenter stated that their position presented in their original comment letter (i.e., to remove natural gas from the definition of custody transfer) had changed. The commenter stated that they believed that it would be prudent for the EPA to adopt the following definition of custody transfer:

> *Custody transfer* means the transfer of hydrocarbon liquids or natural gas, after processing and/or treatment in the production operations, from storage vessels, automatic transfer facilities, <u>or other such equipment, including product loading racks,</u> to pipelines or any other forms of transportation. <u>For the purposes of this subpart, the EPA considers the point at which such liquids or natural gas are placed into pipelines or other forms of transportation to be a point of custody transfer.</u>

<u>Response:</u> The EPA agrees with the commenter. If the term natural gas were removed from the definition of custody transfer, the definition of *associated equipment* would be extended to the end of the natural gas processing plant. During discussions with industry, the EPA believes that it was clear that aggregating emission points from natural gas processing plants was an acceptable interpretation of section 112(n)(4). The EPA has also made the recommended change to the definition of custody transfer to incorporate loading rack equipment.

<u>Equipment Leaks</u>

Comment: Commenter IV-D-06 stated that the definition of *equipment leak* is inconsistent with the definition of *ancillary equipment*. For example, the commenter stated that product accumulator vessels are not included under the definition of *equipment leak* but they are included under the definition of *ancillary equipment*. The commenter noted that other differences between the two definitions are possible. According to the commenter, §63.769 (equipment leak standards) applies to "ancillary equipment" however, "that does not seem to work," especially for "ancillary equipment" that is not defined as "equipment leaks." The commenter suggested that subpart HH "could get by with" either a definition of "equipment leak" or a definition of "ancillary equipment."

Response: The EPA has modified the definition of equipment leaks as follows to remove inconsistencies between the definitions of *equipment leak* and *ancillary equipment*:

> ***Equipment leaks* means emissions of hazardous air pollutants from ancillary equipment (as defined in this section) and compressors.**

Federally enforceable

Comment: Commenter IV-D-05 stated that the definition of *major source* allows a unit to consider control devices when making major source determinations. According to the commenter, the preamble addresses this and makes it clear that the controls must be federally enforceable. The commenter assumed that *federally enforceable* would apply if it were incorporated as a condition of an operating permit that has gone through the title V process (including the public comment period). If this is not the correct interpretation, the commenter stated that the term *federally enforceable* was vague and should be clarified.

Response: The commenter's interpretation was correct. The definition of the term *federally enforceable*, in §63.2 of the General Provisions, includes a list of federally enforceable

terms and conditions, which includes those contained in a title V permit. The EPA believes that §63.2 is clear about what is considered federally enforceable. Therefore, the EPA has not incorporated a definition of *federally enforceable* that is specific to subparts HH and HHH.

Field Natural Gas

Comment: Commenter IV-D-22 recommended deleting the definition of *field natural gas* from subpart HH. The commenter stated that the term was not sufficiently different from "natural gas" to require a separate listing.

Response: The term *field natural gas* is necessary to distinguish between a natural gas production well and a natural gas storage facility that uses a depleted well for storage. A natural gas production well extracts natural gas that has not been processed (i.e., field natural gas) and a natural gas storage facility extracts natural gas that has been processed. Therefore, the EPA has not removed the definition of *field natural gas* from §63.761.

Flow Indicator

Comment: Commenter IV-D-06 recommended that the EPA clarify that a *flow indicator* can include a device that shows the position of a valve, rather than necessarily requiring a direct reading of "flow." The commenter stated that some EPA inspectors have said that a valve position indicator is not a flow indicator because it does not directly detect "flow." The commenter suggested that the literal language of some rules (before the HON) might support this position. The commenter suggested that the EPA use the current, amended definition of *flow indicator* from §63.111 of subpart G of the HON and use it in subpart HHH, verbatim. The commenter stated that this comment also applies to subpart HH.

Response: **The EPA agrees that a flow indicator should show valve position rather than directly reading the flow. Therefore, the EPA has included the following definition of *flow indicator* in final subparts HH and HHH:**

> **Flow indicator means a device which ~~that~~ indicates whether gas flow is present in a line or whether the valve position would allow gas flow to be present in a line.**

Glycol Dehydration Unit

Comment: Commenter IV-D-06 stated that the definition of *glycol dehydration unit* in subpart HHH has loopholes. According to the commenter, a unit could be reconfigured so the natural gas was not running counter currently to the glycol stream, meaning the unit would not be considered a "glycol dehydration unit" and would not be regulated. The commenter further explained that a unit would not be considered a "glycol dehydration unit" and would not be regulated if it were reconfigured to (1) regenerate glycol by any method other than distillation, or (2) not recycle glycol back to "the absorber." The commenter provided the following language to address these loopholes.

> *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 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~~.

The commenter stated that this comment may also apply to subpart HH.

Commenter IV-D-22 recommended the following addition to the definition of *glycol dehydration unit* to clarify the types of units covered by subpart HH:

> *Glycol dehydration unit* means a device in which liquid glycol (ethylene glycol, diethylene glycol, or

triethylene 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). . . .

Response: The EPA agrees that the definition of *glycol dehydration unit* in subparts HH and HHH has loopholes. Therefore, the EPA has modified the definition to remove any possible loopholes and to add some examples of types of glycol that may be used in the process. Final subparts HH and HHH contain the following revised definition of *glycol dehydration unit*:

> ***Glycol dehydration unit*** **means a device in which a liquid glycol (including, but not limited to, ethylene glycol, diethylene glycol, or triethylene 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 water and other gas stream constituents~~ in the glycol dehydration unit reboiler. The distilled or "lean" glycol is then recycled ~~back to the absorber~~.**

Hydrocarbon Liquid

Comment: Commenter IV-D-22 recommended the following modification to the definition of *hydrocarbon liquid* to clarify that produced water is not a hydrocarbon liquid:

> *Hydrocarbon liquid* means any naturally occurring, unrefined, petroleum liquid; produced water is not a hydrocarbon liquid.

Response: The EPA has not modified the definition of *hydrocarbon liquid* in response to this comment. The statement that produced water is not a hydrocarbon liquid is contained in the definition of *produced water*. The EPA believes that it would be redundant to include it in the definition of *hydrocarbon liquid*.

Hydrocarbon Throughput

Comment: Commenter IV-G-01 stated that *hydrocarbon throughput* should be defined [for the storage tank applicability criteria of 500 barrels per day (BPD)]. According to the commenter, naturally occurring hydrocarbon consists of oil, water, and gas.

Response: The EPA does not believe there is a need to add a definition for *hydrocarbon throughput*. The storage tank applicability criteria in §63.764(c)(2) is based on the "actual throughput of hydrocarbon liquids." Furthermore, the term *hydrocarbon liquids* is defined in §63.761.

In Volatile Organic HAP (VOHAP) Service

Comment: Commenters IV-D-06, IV-D-20, and IV-D-22 requested clarification for the averaging period for the VOHAP concentration trigger, for a stream to be subject to the equipment leak standards. Commenter IV-D-06 asked whether the threshold concentration of 10 percent organic HAP in the definition of *in VOHAP service* in subpart HH means annual average concentration, the normal concentration under standard operating conditions, or the highest concentration ever encountered. The commenter stated that if the 10 percent figure applies to the highest concentration, it will make applicability and enforcement difficult because the highest concentration will probably not be present during inspections. Commenters IV-D-06, IV-D-20, and IV-D-22 recommended an annual average, such as that in subpart H of the HON or 40 CFR part 63, subpart CC.

Response: The MACT floor for equipment leaks at natural gas processing plants was determined to be at the level of control required under the onshore natural gas processing plants NSPS (40 CFR part 60, subpart KKK). The control requirements of 40 CFR part 60, subpart KKK are equivalent to those in 40 CFR part 61, subpart V. Since subpart V is a HAP rule, the oil and natural gas production NESHAP cross references subpart V. The

requirements in subpart V state that, for a piece of equipment to be considered not in volatile HAP (VHAP) service, it must be determined that the percent VHAP can be expected never to exceed 10 percent by weight. Therefore, the EPA has not modified the averaging period for determination for *in VOHAP service*.

However, to be consistent with subpart V, and to avoid confusion between the two rules, the EPA has modified this definition to refer to VHAP, rather than VOHAP. This change will also affect several sections within subpart HH, including, the definition of VOHAP (§63.761), the equipment leaks standards (§63.769), and test methods and procedures (§63.772).

In Wet Gas Service

Comment: Commenter IV-D-01 stated that *in wet gas service* is not defined in §§63.761 or 61.241. The commenter also stated that it is not defined in either the NSPS or the hazardous organic NESHAP (HON) equipment leak provisions.

Response: The EPA agrees that a definition of *in wet gas service* is necessary. Therefore, the EPA has added the following definition of *in wet gas service* to §63.761, based on the one contained in subpart KKK:

> ***In wet gas service* means that a piece of equipment contains or contacts the field gas before the extraction of natural gas liquids.**

Incinerator

Comment: Commenter IV-D-06 noted that the definition of *incinerator* contains the wrong word. The commenter stated that the last sentence mentions energy recovery sections that "permit" the incoming vent stream or combustion air and it should say "preheat." The commenter stated that this comment may also apply to subpart HH.

Response: The definition of *incinerator* in subpart HHH has been revised to change the word "permit" to "preheat." A

definition of *incinerator* was not included in subpart HH. Therefore, the same revised definition has been added to §63.761 of final subpart HH.

Natural Gas

Comment: Commenters IV-D-07 and IV-D-31 requested that the EPA revise the definition of *natural gas* in §63.1271 to state that the primary constituent of natural gas is methane, without reference to any other components. Additionally, according to the commenters, water vapor is essentially removed before transmission. The commenters stated that it appears the definition of *natural gas* used is more appropriate for production gas than transmission and storage gas.

Response: The EPA agrees that the definition of *natural gas* is confusing. Therefore, the EPA has revised the definition of *natural gas* in §§63.761 and 63.1271 based on the definition contained in the Onshore Natural Gas Processing NSPS, 40 CFR part 60, subpart LLL (§60.641):

> ***Natural gas* means a naturally occurring mixture of hydrocarbon and nonhydrocarbon gases found in geologic formations beneath the earth's surface. The principal hydrocarbon constituent is methane.**

Natural Gas Liquids

Comment: Commenter IV-D-22 recommended the following modification to the definition of *natural gas liquids* in subpart HH to distinguish liquid phase hydrocarbons from vapor phase hydrocarbons:

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

Response: The EPA agrees with the commenter and has modified the definition of *natural gas liquids*, as follows:

> ***Natural gas liquids* (NGLs) means the liquid hydrocarbons, such as ethane, propane, butane, pentane,**

natural gasoline, and condensate that are extracted from field natural gas.

Natural Gas Processing Plant

Comment: Commenter IV-D-07 noted that the definition of a *natural gas processing plant* in subpart HH is inconsistent with the background information document (BID)[9]. According to the commenter, "extraction" not "separation and fractionation" is described as occurring at a natural gas processing plant. The commenter stated that a definition of "extraction" or "separation" should be included in the definition. As an alternative, the commenter recommended that the EPA use the BID description. The commenter also stated that the definitions of "field natural gas" and "production well" are inadequate.

Commenter IV-D-11 requested that the EPA clarify the term "extraction" as it is used in the definition of *natural gas processing plant* in subpart HH. The commenter was concerned that the term "extraction" could be misinterpreted to include simple producing field separation of natural gas and liquids that occurs absent of "processing." The commenter stated that the EPA's discussion of its interpretation of the term "extraction" in the proposal and background documents for the NSPS for Natural Gas Processing Plants (subpart KKK) were a correct interpretation for those activities that occur at a natural gas plant versus those that occur at field production facilities. The commenter was concerned that the State employees that interpret the rules for compliance purposes are not always familiar with natural gas processes. The commenter recommended that the EPA include a definition of "extraction" similar to that in the NSPS preamble in the final subpart HH. The commenter stated that if the EPA does not include this definition in the final rule, the EPA

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[9] National Emission Standards for Hazardous Air Pollutants for Source Categories: Oil and Natural Gas Production and Natural Gas Transmission and Storage - Background Information for Proposed Standards. U.S. Environmental Protection Agency. Research Triangle Park, NC. Publication No. EPA-453/R-94-079a. April 1997.

should clarify the intent of the term in the response to comments in the final rule's preamble.

__Response:__ **The EPA does not believe that further clarification is necessary. The EPA has had extensive discussions with industry and trade associations during the development of subpart HH related to the definitions of *field natural gas* and *production well*, and developed these definitions based on this information. Furthermore, the definition of *natural gas processing plant* in §63.761 corresponds to the definition in subpart KKK.**

__Comment:__ Commenter IV-D-16 suggested that tighter language or the addition of exclusionary language should be added to the definition of *natural gas processing plants* to clarify that subpart HH does not cover natural gas liquid (NGL) plants located at refineries. According to the commenter, as defined, NGL plants at refineries which take liquid NGLs into the plant and fractionate them into pure NGL streams would be included.

__Response:__ **It was not the EPA's intent to regulate NGL plants at refineries under the provisions of subpart HH. However, the it was the EPA's intent that *natural gas processing plant* mean any processing site engaged in both of the criteria listed in the proposed definition. Therefore, the EPA has modified the definition of *natural gas processing plant* as follows:**

> ***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__, or a combination of both__.**

__Comment:__ Commenter IV-D-22 recommended the following modification to the definition of *natural gas processing plant* in subpart HH to identify the gas plant according to its primary activities and Standard Industrial Classification (SIC) or North American Industry Classification System (NAICS) code:

> *Natural gas processing plant (gas plant)* means any processing site, ~~engaged in~~ the primary purpose of which is (1) the extraction of natural gas liquids from field gas, (2) the fractionation of natural gas liquids to natural gas products, or both, and which is classified in SIC Code 1321 (NAICS Code 211112). For purposes of subpart HH, a gas plant is considered a facility. A major source determination for a natural gas processing plant will aggregate HAP emissions from the facility, between the inlet scrubber and the plant tailgate or other facility outlet boundary.

Response: **The EPA has not made the recommended modification to the definition of natural gas processing plant. The EPA does not believe that including an SIC code in the definition of *natural gas processing plant* is necessary. Furthermore, the EPA does not believe that the commenters last two suggested sentences (beginning with "For the purposes of subpart HH . . . ") are necessary because the intent contained within these sentences is included in the definition of *facility*.**

No Detectable Emissions

Comment: Commenter IV-D-06 interpreted the definition of "no detectable emissions" to require an instrument reading of zero. The commenter stated that this is incorrect, as other portions of subpart HHH require an instrument reading of 500 parts per million (ppm) or less for "no detectable emissions." The commenter provided the following language for revising the definition of *no detectable emissions* in subpart HHH:

> *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~~ Instrumental monitoring results 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.

The commenter stated that this comment may also apply to subpart HH.

Commenter IV-D-22 recommended the following alternative definition for *no detectable emissions* in subpart HH to conform with the NSPS (subpart KKK):

> *No detectable emissions* means no escape of HAP from a device or system to the atmosphere as determined by: (1) ~~Testing the devices or system in accordance with §63.772(c)~~ the arithmetic difference between the maximum organic concentration indicated by the instrument and the background level that is less than 10,000 parts per million by volume; and (2) No visible openings or defects in the device or system such as rips, tears, or gaps.

Response: **The definition of *no detectable emissions* does not require an instrument reading of zero. Therefore, to clarify the definition of *no detectable emissions* in final subparts HH and HHH, the EPA has revised the definition as follows:**

> ***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~~Instrument monitoring results in accordance with the requirements of §63.1282(b) [§63.772(c) for subpart HH]; and**
>
> **(2) The absence of visible openings or defects in the device or system such as rips, tears, or gaps.**

The EPA believes that restating the requirements of the Test Methods and Procedures sections in subparts HH and HHH [§63.771(c) and §63.1282(d)] within the definition of *no detectable emissions* is redundant. The EPA did not include these requirements in the definition.

Process Heater

Comment: Commenter IV-D-22 recommended the following modification to the definition of *process heater* in subpart HH to conform with the ICCR:

> *Process heater* means ~~a device that transfers heat liberated by burning fuel directly to process streams or to heat transfer liquids other than water~~ an enclosed device using a controlled flame, the primary purpose of which is to transfer heat to a process fluid or process material that is not a fluid, or to a heat

transfer material for use in a process unit (rather than for steam generation).

Response: **Since the definition proposed by the commenter is reasonable, the EPA has modified the definition of *process heater* in subparts HH and HHH, as follows:**

> ***Process heater*** **means an enclosed device using a controlled flame, the primary purpose of which is to transfer heat to a process fluid or process material that is not a fluid, or to a heat transfer material for use in a process (rather than for steam generation)~~that transfers heat liberated by burning fuel directly to process streams or to heat transfer liquids other than water~~.**

Process Unit

Comment: Commenter IV-G-12 noted that the definition of *natural gas processing plant* in subpart HH is identical to that contained in 40 CFR part 60, subpart KKK, but the definition of *process unit* is not included. The commenter was concerned that without this accompanying definition, subpart HH could be interpreted ambiguously with respect to exactly what equipment is, or is not subject to regulatory requirements. The commenter suggested adding the definition of *process unit* from subpart KKK.

Response: **The term *process unit*, as used in 40 CFR part 60, subpart KKK, is necessary to determine the affected sources for that rule. Since the affected sources in subpart HH are listed in §63.760(b), the definition of *process unit* is not necessary.**

Production Field Facilities

Comment: Commenter IV-G-01 requested that the EPA clarify whether outer continental shelf (OSC) platforms are considered *production field facilities*.

Response: **The determination about whether OCS platforms are *production field facilities* is based on existing OCS regulations and the EPA has not added clarifying language to subpart HH. Under the current definition, OCS platforms would be considered**

production field facilities when in waters under EPA control as designated by existing OCS regulations.

Startup and Shutdown

Comment: Commenter IV-D-06 suggested that the EPA have specific definitions of *startup* and *shutdown* in subpart HHH. The commenter remarked that the EPA's apparent use of the General Provisions definition of *startup* and *shutdown* will not work. The commenter stated that the definitions in the General Provisions deal only with startups and shutdowns of a process and do not deal with startups and shutdowns of control devices or monitoring systems. The commenter was concerned that the startup, shutdown, and malfunction plan for a facility would not be applicable for reducing emissions during a control device or monitoring system malfunctions. The commenter recommended that the EPA include specific definitions of *startup* and *shutdown* in subpart HHH, and that those definitions should include control devices and monitoring systems. The commenter stated that this comment also applies to subpart HH.

Response: The purpose of the startup, shutdown, and malfunction plan, as defined in §63.6(e)(3) of the general provisions (subpart A), is to "ensure that, at all times, owners or operators operate and maintain affected sources, including associated air pollution control devices, in a manner consistent with good air pollution control practices for minimizing emissions . . . " The EPA has added definitions for *startup* and *shutdown*, based on the definitions found in §63.101 of subpart F, to §§63.761 and 63.1271. It should be noted that the definitions of startup and shutdown contained in subpart F do not contain language referring to control devices or monitoring equipment.

State Waters

Comment: Commenter IV-D-22 recommended adding the following definition of *state waters* in subpart HH to clarify the scope of coverage of offshore facilities:

> *State waters* means those waters for which States have been granted jurisdiction over offshore lands to a distance of three nautical miles from their coasts by the Submerged Lands Act [43 U.S.C. 1301, et seq.]. In the case of waters offshore from Texas and from Florida in the Gulf of Mexico, State waters are those waters over offshore lands for which these two states have jurisdiction to a distance of three marine leagues [approximately 10.35 statute miles].

Response: The scope of coverage of OCS platforms is based on existing OCS regulations. Therefore, the EPA did not add clarifying language to subpart HH.

Storage vessel

Comment: Commenter IV-D-05 recommended that the EPA define *storage vessel*. The commenter asked if a group of tanks at a facility or each separate tank was considered a storage vessel. The commenter explained that in the case where two tanks process 900 BPD and share a common vent, applicability could be easily avoided with by adding vents to each tank and dividing the flow in half to be below the 500 BPD cutoff.

Response: According to §63.761, a storage vessel is defined as "a tank or other vessel." Therefore, a group of tanks would not be considered a storage vessel. Additionally, storage vessel applicability is on a per vessel basis. In the scenario described by the commenter, applicability would be based on actual tank throughput despite vent configuration. Therefore, the EPA has not made the suggested change.

Storage vessel with the potential for flash emissions

Comment: Commenter IV-D-08 recommended the following new definition for *flash gas* in subpart HH:

> *Flash Gas:* VOC emissions from depressurization of crude oil or condensate when it is transferred from a

higher pressure to a lower pressure tank, reservoir, or other container.

Commenter IV-D-07 recommended that the EPA clarify the definition of *flash emissions*. The commenter stated that at some facilities, a small pressure drop exists between a separator and a storage vessel, so flash emissions are low. The commenter explained that many facilities dump separators straight into a wet header system, and have no flash emissions, while other facilities may only dump low-pressure separators to atmospheric storage tanks.

Response: **The EPA believes that regulating storage vessels based on tank contents rather than operation will prevent the possibility of HAP emissions being emitted to the atmosphere via flashing from uncontrolled tanks. The EPA has added the following language to the definition of *storage vessel with the potential for flash emissions* to clarify what is meant by flash emissions:**

> **. . .Flash emissions occur when dissolved hydrocarbons in the fluid evolve from solution when the fluid pressure is reduced.**

Comment: Commenter IV-D-07 suggested that the EPA delete the requirement for an API gravity of 40° and use the requirement for hydrocarbon liquids with a GOR of 1,750 scf/bbl of condensate in the definition of "flash emissions." The commenter stated that flexibility is added to the definition since if the GOR changes over time, it could be averaged over one year. The commenter also suggested that the specific gravity for an API gravity of 40° is 0.83 which, according to the commenter, seems "excessively low."

Commenter IV-G-02 stated that controlling storage vessels with the potential for flash emissions is an appropriate goal (since most storage tank emissions in oil and gas production are associated with flash emissions). The commenter explained however, that using API gravity as a threshold for determining if flash emissions occur is not appropriate, by itself, as a good indication of flash potential. The commenter suggested that GOR directly measures flash potential and is much more appropriate for use as a control cutoff criterion. The commenter recommended that the EPA delete the API gravity criteria from the proposed definition of "storage vessel with the potential for flash emissions" in §63.761.

Response: The cutoffs included in the definition of *storage vessels with the potential for flash emissions* are intended to identify storage vessels that have the potential for flash emissions. The EPA believes that both the API gravity and stock tank GOR of a liquid are necessary to identify the hydrocarbon liquids that the EPA believes to have the potential for flash emissions. In addition, a throughput cutoff of 500 BPD per tank was added to the definition because the EPA believes that flash emissions are more likely with higher throughputs. Sections 63.760(a)(1)(iii) and 63.1270(a)(4) of the final rules state that other parameters used to calculate emissions (such as API gravity or GOR) must be the maximum for the period over which the maximum natural gas or hydrocarbon liquid throughput is determined, and must be based on highest measured values or annual averages. The EPA has not altered the definition of *storage vessel with the potential for flash emissions* based on this comment.

Comment: Commenter IV-D-07 requested that the definition of *storage vessels with the potential for flash emissions* clarify how emission estimates and seasonal operation should be handled.

Response: Since the hydrocarbon liquid throughput cutoff is based on actual throughput, seasonal fluctuations should not affect applicability. The EPA has not supplied guidance on emission estimations in the promulgated rule. The EPA intends to publish guidance for emission estimations.

Comment: Commenter IV-D-08 recommended the following revisions to the definition for *storage vessel with the potential for flash emissions* in subpart HH:

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

Commenter IV-D-22 recommended the following modification to the definition of *storage vessel with the potential for flash emissions* in subpart HH, to clarify that the GOR is the annual average wellhead GOR and to indicate the point of measurement:

> *Storage vessel with the potential for flash emissions* means any storage vessel that contains hydrocarbon liquids with a GOR equal to or greater than 50 cubic meters (1,750 cubic feet) per barrel determined as an annual weighted average of the wells feeding the storage vessel or an API gravity equal to or greater than 40 degrees measured at the storage tank.

Response: The GOR is a measure of the amount of entrained gas contained in a hydrocarbon liquid. Therefore, the higher the GOR, the higher the potential for flash emissions. The EPA believes that the GOR should be measured as close to the storage vessel as possible, as the stock tank GOR, to obtain a realistic value to determine flash emissions. The EPA has added the phrase "stock tank" before GOR to the definition of *storage vessel with the potential for flash emissions.*

In addition, the EPA has added the throughput cutoff criterion to the storage vessels with the potential for flash emissions definition. The final rule states that a storage vessel with the potential for flash emissions is defined as a storage vessel that contains a hydrocarbon liquid with a stock tank GOR equal to or greater than 1,750 scf/bbl and an API

gravity equal to or greater than 40 degrees, and a hydrocarbon liquid throughput equal to or greater than 500 bpd. By adding the throughput criterion to the definition of storage vessels with the potential for flash emissions, rather than as a cutoff specified in proposed §63.764(c)(2), storage vessels that do not meet the criteria for a storage vessel with the potential for flash emissions are not considered affected sources in the final rule and are not included in a facility's PTE calculation for determining major source status.

Surface Site

Comment: Commenter IV-D-16 requested that the word "platform" be removed from the definition of *surface site* in subpart HH. According to the commenter, when covered with the definition of facility, the definition of *surface site* could be misinterpreted to include offshore platforms. The commenter stated that offshore platforms should not be covered by section 112 since control of emissions offshore will not protect the public as there is no public offshore.

Response: It is not the EPA's intent to exempt offshore platforms. Therefore, the EPA has not removed the term platform from the definition of *surface site*.

Comment: Commenter IV-D-22 recommended the following modification to the definition of *surface site* in subpart HH to clarify that individual surface sites connected by linear installations (e.g., roads, waterways, etc.) are not part of the same facility:

> *Surface site* means the graded pad, gravel pad, foundation, platform, or immediate physical location upon which equipment is physically affixed. Individual surface sites connected solely by a road, waterway, walkway, power line, or pipeline shall not be considered part of the same facility.

Response: The EPA agrees with the commenter and has modified the definition of *facility* by adding language to clarify

that two or more surface sites connected by linear installations are not part of the same facility. The EPA does not believe it is necessary to add the same clarifying language to the definition of *surface site*. However, the surface site definition has been revised as follows to specify that graded pad sites and gravel pad sites are considered surface sites:

> ***Surface site* means any combination of one or more ~~the~~ graded pad sites, gravel pad sites, foundations, platforms, or the immediate physical location upon which equipment is physically affixed.**

Temperature Monitoring Device

Comment: Commenters IV-D-08, IV-D-22, IV-G-02, and IV-G-12 recommended the following modification to the definition of *temperature monitoring device* in subpart HH to allow equipment that uses the Fahrenheit scale, and to remove the accuracy specifications:

> *Temperature monitoring device* means a unit of equipment used to measure ~~monitor~~ temperature at any point in a process in degrees F or C ~~and having an accuracy of ±1 percent of the temperature being monitored expressed in °C, or ± °C, whichever is greater~~.

Response: The EPA has modified the definition of *temperature monitoring device*, as follows, to allow equipment that uses the Fahrenheit scale and to clarify that the accuracy requirements are the minimum allowed to ensure compliance. The EPA believes that the accuracy requirements are necessary to ensure that monitoring equipment is operating to demonstrate ongoing compliance. However, the EPA has modified the level of accuracy to allow the owner or operator more flexibility in choosing a monitoring device.

> ***Temperature monitoring device* means an instrument ~~a unit of equipment~~ used to monitor temperature and having a~~n~~ minimum accuracy of ±2~~1~~ percent of the temperature being monitored expressed in °C, or ±2.5~~0.5~~**

°C, whichever is greater. **The temperature monitoring device may measure temperature in degrees Fahrenheit or degrees Celsius, or both.**

Underground Natural Gas Storage Facilities

Comment: Commenter IV-D-07 stated that the definition for *underground natural gas storage facilities* is inconsistent with the storage process. The commenter stated that the preamble describes underground storage facilities as "typically extending from the natural gas processing plant to the local distribution company." According to the commenter, most storage facilities recover gas from former production wells, separate the liquids in high pressure separators, transfer liquids to a wet header system that transports liquids to a gas processing plant (these liquids are laden with natural gas), and dehydrates the natural gas before transfer to the pipeline network.

Response: The preamble to the proposal describes natural gas transmission and storage facilities as "typically extending from the natural gas processing plant to the local distribution company," and underground storage facilities as "subsurface facilities that store natural gas that has been transferred from its original location for the primary purpose of load balancing." It is not the EPA's intent for the description to be all inclusive of processes at a storage facility and believes that the description of underground storage sufficiently covers the storage process. Therefore the EPA has not made any changes to the regulation in response to this comment.

2.3 ASSOCIATED EQUIPMENT

Several commenters responded to the EPA's request for comments on their interpretation of "associated equipment" in section 112(n)(4) of the Act.

Comment: According to commenters IV-D-02, IV-D-04, IV-D-07, IV-D-08, IV-D-19, IV-D-20, IV-D-22, IV-D-31, IV-D-33, IV-D-38, IV-G-02, and IV-G-03, section 112(n)(4) mandates no aggregation of emissions from individual sources at oil and gas production fields. Commenters IV-D-04 and IV-D-31 stated that the CAA provides a clear intent to not aggregate emissions from small sources (e.g., exploration or production wells and their associated equipment, compressor stations and other similar units) in order to create major sources. Commenters IV-D-02, IV-D-07, IV-D-19, IV-D-20, IV-D-33, and IV-D-38 stated that the EPA exceeded its statutory authority under section 112(n)(4) in its proposed definition of facility, by allowing for the aggregation of emissions from glycol dehydration units and storage vessels with the potential for flash emissions. The commenters requested that the EPA be consistent with the CAA. According to commenter IV-D-20, the EPA did not create a regulatory definition that is true to the statute.

Response: The EPA disagrees that the Agency exceeded its statutory authority for the reasons discussed below. Section 112(a)(1) generally requires HAP emission points within a contiguous area and under common control to be aggregated in a major source determination for the purposes of section 112. While this approach is appropriate for facilities in most industries, it may lead to unreasonable aggregations if strictly applied to oil and natural gas field operations. Given that some oil and natural gas operations (e.g., a production field) may cover several square miles or that leases and mineral rights agreements give some companies control over a large area of contiguous property, determination of major source status

strictly by the language of section 112(a)(1) could mean in this industry that HAP emissions must be aggregated from emissions points separated over large distances.

Congress addressed the unique aspects of the oil and natural gas production industry by providing the special provisions in section 112(n)(4) of the Act referring to the ". . .oil and gas exploration or production well (with its associated equipment). . ." However, Congress did not provide a definition of the term "associated equipment" in the statutory language, leaving its interpretation to the EPA. A definition of this term is important in determining the major source status of facilities in both the oil and natural gas production and the natural gas transmission and storage source categories.

In the absence of clear guidance in the statute, the EPA evaluated various options for defining "associated equipment" prior to proposal and developed the proposed definition. The commenters did not offer substantive new information to support their claim that the EPA had exceeded its authority. The next comment and response provide additional information regarding the development of the definition of associated equipment.

Comment: Commenters IV-D-07, IV-D-19, IV-D-20, IV-D-33, and IV-D-38 did not agree with the EPA's definition of associated equipment, and contended that glycol dehydration units and storage vessels with the potential for flash emissions should be considered "associated equipment."

Although they did not support the EPA's proposed definition of *associated equipment,* commenter IV-D-20 stated their support for the EPA's efforts to control HAP that represent an adverse impact to human health and the environment by focusing on the sources that emit the most HAP from the oil and natural gas production source category.

Commenters IV-D-19 and IV-D-20 were concerned that creating exemptions from the terms of the statute would create a negative precedent for this and future rules and, along with commenter IV-D-38, requested that the EPA modify the definition of major source and associated equipment to comply with the provisions of CAA section 112(n)(4)(A).

Commenter IV-D-29 supported a more narrow definition of "associated equipment" that also excludes glycol dehydration units and storage vessels with flash emissions. The commenter was concerned that many potential major sources in Santa Barbara and Ventura counties would be exempted under the broad definition of associated equipment.

Although commenters IV-D-08, IV-D-22, IV-G-02, and IV-G-03 did not fully support the EPA's interpretation of "associated equipment," they acknowledged that the proposal to limit the aggregation of emissions to HAP from glycol dehydration units and storage vessels with the potential for flash emissions was a workable solution to the aggregation of all HAP sources. The commenters suggested that the aggregation of dehydration units and storage vessels with flash potential would result in the same major source determination as aggregation of all potential sources, but would reduce the burden on the facility operator. In addition, commenter IV-D-05 stated that the rationale and conclusions used to clarify ancillary equipment for aggregating emissions for a major source determination seemed appropriate. [Note: The commenter mentioned "ancillary equipment" but most likely meant "associated equipment," as the comment appears to be directed toward associated equipment.] According to the commenter, the EPA's decision to aggregate glycol units and storage vessels with flash emissions will "give the rule some degree of effectiveness."

Response: **According to the statutory definition of major source in section 112(a)(1) of the Act, HAP emissions from all emission points within a contiguous area and under common control must be counted in a major source determination. By stating that**

emissions from any oil and gas production and exploration well (with its associated equipment) cannot be aggregated for a major source determination, the provisions of section 112(n)(4)(A) mean HAP emissions from each well and each piece of equipment considered to be associated with the well must be evaluated separately in a major source determination. That is, any well or piece of associated equipment would only be determined to be a major source if HAP emissions from that well or piece of associated equipment were major.

Therefore, to implement this special provision of the Act for the oil and natural gas production source category, a definition of "associated equipment" was necessary. The EPA proposed 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 the potential for flash emissions would not be associated equipment. In developing this proposed definition, the Agency evaluated several options. The Agency also sought and received input from industry and other stakeholders.

In the absence of clear guidance in the statute, the EPA evaluated various options for defining "associated equipment" prior to proposal. The EPA's objective was to arrive at a reasonable interpretation that would: (1) provide substantive meaning to the term "associated equipment" consistent with congressional intent; (2) prevent the aggregation of small, scattered HAP emission points in major source determinations; (3) be easily implementable; and (4) not preclude the aggregation of significant HAP emission points in the source category. Due to the lack of clarity in the statute and the potential impact on major source determinations, the Agency worked with industry stakeholders to identify and evaluate options prior to proposal. Industry representatives expressed their goals for the interpretation of associated equipment, and provided information on the magnitude of HAP emissions points and the potential impacts of various options considered by the EPA.

The EPA considered, but rejected a definition based on a narrow interpretation that would include only valves and fittings on a well as being associated equipment primarily because this option would not provide any additional relief to industry beyond what would have been provided had Congress only used the term "well" in section 112(n)(4) of the Act. The EPA also rejected a definition, initially recommended by industry, that was based on a broad interpretation that would include equipment far beyond the well as associated equipment.

In discussions with industry stakeholders over an extended period of time prior to proposal, the Agency sought to reach a workable solution on the definition of associated equipment, one that recognized the need to implement relief for this industry as Congress intended, and that also allowed for the appropriate regulation of significant emission points. In a technical evaluation, the EPA identified glycol dehydration units and storage tanks with flash emission potential as substantial contributors to HAP emissions, particularly relative to sources such as production wells. This conclusion was supported by industry. Under the proposed approach, associated equipment was defined as all equipment up to the point of custody transfer, excluding glycol dehydration units and storage vessels with the potential for flash emissions. This approach also included a definition of facility in the rule that effectively limited the distance over which all emission points (including glycol dehydration units and storage vessels with the potential for flash emissions) may be aggregated. Based on discussions with industry prior to proposal, as well as comments received supporting the proposed definition of associated equipment, the Agency believes that the proposed approach best meets both industry and EPA goals for implementation of the language of section 112(n)(4).

Commenters who argued that the Agency exceeded its authority with the definition of associated equipment offered no substantive new information to support their claim. The EPA could not find support in the statute or in the legislative history[10] that indicated that Congress intended to preclude aggregation of all emission points, including such significant ones as glycol dehydration units and storage tanks with flash emission potential through their inclusion as associated equipment. Rather, there are clear indications, in the EPA's judgement, that Congress' primary intent was to preclude the aggregation of small emitting sources over vast distances. The legislative history of the Act, for example, indicates that Congress believed that oil and natural gas production wells and their "associated equipment" generally have low HAP emissions, and are typically located in widely dispersed geographic areas, rather than being concentrated in a single area. The EPA used this background as a guide in developing an interpretation of "associated equipment" along with available data on HAP emissions from emission points within the oil and natural gas production source category. The EPA believes that glycol dehydration units

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[10] Conference Debates and Report. In: A Legislative History of the Clean Air Act Amendments of 1990. U.S. Government Printing Office. November 1993. P. 1238.

and storage vessels with the potential for flash emissions are not the type of small HAP emission points that Congress intended to be included in the definition of associated equipment.

After the EPA's review and consideration of all comments received on the proposal, the definition of associated equipment promulgated in today's rule is the same as proposed.

Comment: Commenter IV-D-07 remarked that it is arbitrary to include storage vessels in which treating and processing does not take place as associated equipment, because these vessels have the highest potential for flash emissions as compared to storage vessels further downstream.

Response: With regard to including, as associated equipment, storage vessels in which no treating or processing takes place, this statement in the preamble to the proposal referred to an intermediate option that the EPA considered. Under this option, all equipment up to the point where initial processing of an extracted hydrocarbon stream takes place would be considered associated equipment. Thus, only the Christmas tree and storage vessels in which no treating or separation takes place would be considered associated equipment. However, this option was rejected by the EPA as being a definition that was too narrow.

The option selected by the EPA states that storage vessels with the potential for flash emissions are not to be considered associated equipment. Therefore, the EPA has focussed the standards (subpart HH) on those storage vessels with significant emissions.

Comment: Commenter IV-G-01 requested that the EPA clarify whether "all equipment from the wellbore to the point of custody transfer" (as stated in §63.761) includes "ancillary equipment."

<u>Response:</u> *Associated equipment* is defined in §63.761 to include all equipment from the wellbore to the point of custody transfer, except glycol dehydration units and storage vessels with the potential for flash emissions. Therefore, prior to the point of custody transfer, ancillary equipment is considered to be *associated equipment* and cannot be aggregated to determine major source status. Therefore, the EPA has not made any changes to subpart HH in response to this comment.

<u>Comment:</u> Commenter IV-D-07 felt that inserting the statement about custody transfer does not clarify the meaning of associated equipment. The commenter explained that custody transfer usually occurs after a preliminary separation of gas and liquids, which includes the use of storage vessels with flash emissions.

In contrast, commenter IV-D-05 stated that the term *after custody transfer* is "probably the most universal term that can be used in regards to clarity."

<u>Response:</u> As stated in a previous response, the EPA defined *associated equipment* to comply with its interpretation of section 112(n)(4)(A) of the CAA. Although storage vessels with the potential for flash emissions typically occur prior to the point of custody transfer, the EPA specifically excluded these emissions sources from the definition of *associated equipment* in an effort to focus on significant HAP emission points.

The term "custody transfer" is included in the definition of *associated equipment* as the point of delineation for where emission aggregation of all emission points within a facility may occur. It is also used as the basic point to define where the oil and natural gas production source category ends and the natural gas transmission and storage source category begins. The exceptions to this are natural gas processing plants, which are

included in the scope of the oil and natural gas production source category even though they are considered to be after a point of custody transfer. This exception was provided because natural gas processing plants are typically clearly defined facilities within this source category. Furthermore, during the development of the proposed regulations, industry repeatedly stated that the term custody transfer is well understood within the industry and that custody transfer of hydrocarbon streams occurs only once and not multiple times. Therefore, the EPA has not made any changes to the definition of associated equipment in response to this comment.

2.4 HAP EMISSION POINTS

Comment: The EPA specifically requested information and comments, along with supporting documentation, on HAP emissions from several emission points. These emission points included: (1) process vents at amine treating units and sulfur plants, (2) transfer and storage of pipeline pigging wastes, (3) combustion sources located at oil and natural gas production and natural gas storage and transmission facilities, and (4) storage vessels at natural gas transmission and storage facilities.

Amine Treaters and Sulfur Units. Commenters IV-D-07, IV-D-16, IV-D-22, and IV-G-09 responded to the EPA's request for information on amine treaters and sulfur units. The commenters stated that amine treaters are most likely small sources of HAP and there is little available data to estimate HAP emissions from these sources. Commenter IV-D-07 requested clarification on how these emissions should be estimated. Commenter IV-D-16 recommended that if amine units and sulfur recovery units are shown to be significant sources of HAP, they can be controlled during the residual risk review required by section 112(f) of the CAA. Commenter IV-D-22 stated that since there are relatively few units (as compared to glycol dehydration units and storage tanks), the amine treater unit and sulfur recovery unit totals would result in an extremely small percentage of total baseline year HAP for the source category. Commenter IV-G-09 stated that amine plants are designed to remove carbon dioxide, sulfur, and other impurities from the gas. According to the commenter, most aromatic and long chain hydrocarbons are removed from natural gas for their economic value before the gas treatment in amine plants. The commenter further explained that the large amount of non-combustible gases in the vents of amine plants makes flaring impractical and the high flow rate of these non-condensable gases makes condensers technically not feasible. At this time, the commenter stated that they were not able to provide an example of a practical control technology and recommended not regulating amine plants under this standard.

Pipeline Pigging Operations. Commenters IV-D-07, IV-D-08, IV-D-10, IV-D-16, IV-D-17, IV-D-20, IV-D-22, and IV-G-09 responded to the EPA's request for information on pipeline pigging operations. According to the commenters, pipeline pigging activities are performed to remove scale and other accumulations, and occur intermittently and infrequently with insignificant fugitive emissions. Commenter IV-G-09 stated that although there is no set schedule, most transmission lines are pigged less than once per year, and are open to the atmosphere for only the few hours required to discharge the liquids and the solids collected. The commenters stated that pigging wastes are contained in storage tanks and have minimal emissions. The commenters requested that the EPA not regulate these sources. According to commenters IV-D-07, IV-D-08, IV-D-20, IV-D-22, and IV-G-09 the wastes generated from pigging are primarily solids with entrained liquids and contain small amounts of VOC and HAP. The commenters concluded that potential HAP emissions from pipeline pigging operations would be inconsequential in the oil and natural gas production source category.

Commenter IV-D-10 suggested that, until the EPA has developed specific requirements and applicability determinations for HAP emissions from transfer and storage of pipeline pigging wastes and combustion sources, these units should not be covered under the oil and gas MACT. The commenter was mostly concerned with estimating PTE for HAP emissions from transfer and storage of pipeline pigging wastes and combustion sources from the gathering portion of their company. Besides the infrequent occurrence of pigging operations, the commenter stated that there is no testing method available for measuring these emissions from the pigging waste storage tanks. According to the commenter, quantifying emissions from the tanks is difficult. In addition, the flow is difficult to measure given the unsteady flow conditions and the variability of the gas composition over time. The commenter stated that it would be unfair to the industry to assume they are major sources due to emissions from pigging since there is no ability to test for applicability to the requirements.

Combustion sources. Commenters IV-D-20 and IV-D-22 discussed combustion sources. The commenters suggested they were not aware of any existing database that adequately characterizes the populations of equipment, HAP emissions, or risk of exposure to the public for combustion sources at oil and gas production facilities. The commenters also noted that the ICCR had been initiated, by the EPA, to address combustion sources. Commenter IV-D-20 also reminded the EPA that combustion sources in the Appalachian region are unique from those in the Southwest. The commenter explained that in Appalachia, the oil and gas production related combustion sources are generally in non-urban areas, emit small amounts of HAP and pose little if any risk to human health.

Storage vessels at natural gas transmission and storage facilities. Several commenters responded to the EPA's request for information on storage vessels from natural gas transmission and storage facilities. Commenters IV-D-08, IV-D-12, IV-D-16, IV-D-35, and IV-G-12 suggested that there are small amounts of liquids associated with transmission and storage facilities. The commenters also stated that the liquids associated with transmission and storage facilities contain small amounts of HAP, resulting in insignificant emissions. Commenter IV-D-07 stated that at some facilities, a small pressure drop exists between a separator and a storage vessel, so flash emissions are low. According to the commenter, many facilities dump separators straight into a wet header system, and have no flash emissions, while other facilities may only dump low-pressure separators to atmospheric storage tanks. The commenter and commenter IV-D-31 recommended that an annual average be used to evaluate "flash potential" if the EPA decides to regulate storage vessels in the natural gas transmission and storage category. Commenter IV-D-08 explained that by the time natural gas enters the transmission facility, most of the liquid has been removed. The commenter further explained that the entrained liquids are collected in barrels and emptied infrequently. According to the commenter, requiring controls on storage vessels at natural gas transmission and storage facilities would provide negligible HAP emission reduction. Commenter IV-D-12 recommended that these sources not be subject to emission controls unless, and until, the EPA has collected and analyzed adequate information to demonstrate that controls are justified. Commenter IV-D-16 suggested that if the applicability sections of subpart HH and HHH do not overlap, the tanks that need control will be covered under subpart HH. Commenter IV-D-35 stated that very few natural gas transmission and storage facilities in the State of Colorado use storage vessels. Commenter IV-G-12 remarked that storage tanks at their gas storage facilities are used to hold lubricating and fuel oils for internal combustion engines, or fluids with very low vapor pressures such as glycol or produced water. According to the commenter, the calculation of emissions from these tanks for title V permitting purposes showed that they are of a *de minimis* nature.

Response: **Based on the comments received, the EPA believes that process vents at amine treating units and sulfur plants, transfer and storage of pipeline pigging wastes, combustion sources located at oil and natural gas production and natural gas storage and transmission facilities, and storage vessels at natural gas transmission and storage facilities are not significant sources of HAP and do not warrant regulation under subparts HH and HHH. If warranted, combustion sources at natural gas transmission and storage facilities may be regulated under future regulations.**

However, a recently published report from GRI addressed HAP emissions from amine treater and sulfur recovery units. The report indicated that amine treaters and sulfur units are not significant contributors to overall national HAP emissions from

the oil and natural gas production source category. However, the report indicated that amine treaters may be significant contributors to HAP emissions on a site-specific facility basis. It should be noted that emissions from amine treaters and sulfur recovery units must be taken into consideration by a facility's owner or operator in making major source determinations.

2.5 IMPACTS

2.5.1 Cost Impacts Including Production Recovery Credits

Comment: Commenters IV-D-07 and IV-D-12 stated that the cost data are not representative of the true impact of subpart HHH and demonstrates that the data base is inadequate. The commenters referred to the economic analysis which indicated that only five facilities would be affected at a collective capital cost of $57,000. According to the commenters, the size range examined was 20 to 50 MMscf/d, which is not at all representative of the dehydration equipment they operate. Commenter IV-D-12 reviewed the proposal and determined that at least four major sources on their system would be subject to subpart HHH. Additionally, the commenter provided an example of condenser controls equivalent to those proposed in the standard that had been installed on two dehydration units of 300 MMscf/d each, at a single site, at a capital cost greater than $500,000. The commenter remarked that this example demonstrates that the EPA's understanding of the natural gas transmission and storage source category is flawed and deficient. The commenter recommended that the EPA take more time to understand the industry, and to analyze emissions and cost impacts before proceeding further with the rulemaking. Commenter IV-D-07 also mentioned that the recordkeeping costs seem very low.

Commenters IV-D-15 and IV-G-05 stated that based on their experience, the EPA has underestimated the cost of installation of condensers and monitoring equipment. As an example, commenter IV-D-15 stated that a recently purchased natural draft condenser on a 5.0 MMscf/d glycol dehydrator unit cost more than $14,000, not including the cost of installation, tanks, and temperature monitoring equipment. The temperature monitoring equipment (two temperature sensors and a chart recorder) cost $2,000. The cost for an installation using an existing tank was closer to $18,000 and did not include costs for additional controls (e.g., a flare). The commenter, along with commenter IV-G-05, provided another example of a 20.0 MMscf/d unit where the cost of the condenser and connections to allow combustion of the vent offgas in the glycol reboiler was more than $22,000 for the equipment, without installation costs or temperature monitoring equipment costs. The commenters compared their numbers to the costs in the BID of $11,000 (Table 6.1) for a comparable control scheme including a new tank for a comparable unit. Commenter IV-G-05 maintained that the costs of condensers and monitoring equipment may exceed the value of the gas being treated, and some units will probably shut down to avoid the cost of installing and maintaining this equipment.

Response: **The EPA based its cost estimates on published installed control system costs from the Ventura County (California) Air Pollution Control District (APCD). These costs were associated with a glycol dehydration unit regulation issued by the Ventura County APCD (Air Docket A-94-04 number IV-A-07). According to this information, the cost of installing a condenser control system does not vary significantly based on the size (capacity) of a glycol dehydration system.**

However, to address comments received from the natural gas transmission and storage source category, the EPA collected additional data from 83 glycol dehydration units located at natural gas transmission and storage facilities. This additional information, as well as the information on 31 glycol dehydration units collected for the proposal, indicated that 71 glycol dehydration units were controlled. The EPA determined that 59 of the 71 glycol dehydration units were controlled using a combustion device, primarily a flare. Based on this new data, the EPA revised the cost impacts for the natural gas transmission and storage (Air Docket A-94-04 number IV-A-08). The EPA estimated that seven facilities would be affected by subpart HHH. The EPA assumed that six of the facilities would install flares to meet the control requirements, and one facility would install

a condenser. Therefore, based on these control scenarios, the EPA estimated a total capital investment of $280,000 and a total annual cost of $300,000 per year for the natural gas transmission and storage source category. This annual cost estimate includes: (1) the cost of capital, (2) operating and maintenance costs, (3) the cost of monitoring, recordkeeping, and reporting (MRR), and (4) any associated product recovery credits.

Comment: Commenter IV-D-15 stated that, in their experience, the cost for implementing a leak detection and repair (LDAR) program for a natural gas processing plant would cost approximately $6.50 to $7.50 per component monitored for the first year and $5.00 to $6.00 per component monitored for subsequent years. According to the commenter, remote locations will add to such costs, and these costs do not include repair work. The commenter calculated first year costs ranging from $2,600 for the 400 components monitored for the Model "A" Plant up to $17,250 for the 2,300 components for the Model "C" Plant. The commenter compared their costs to the $400 that is provided in the example in the BID.

Response: The EPA estimated that the total annual costs for LDAR programs range from $12,000 (in July 1993 dollars) for model natural gas processing plant "A" to $42,000 for model natural gas processing plant "C." These costs are documented in a memorandum contained in the docket (Docket Item II-A-03).[11] The $400 (as shown in Table C-3 of the Background Information Document) represents additional MRR costs that have not been previously accounted for in the LDAR program costs.

Comment: Commenter IV-D-10 stated that the EPA did not take into account the additional costs to companies to dispose of

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[11]G. Viconovic, EC/R Inc., to M. Smith, EPA:WPCG, and L. Conner, EPA:ISEG. Cost impact estimates for the oil and natural gas production and natural gas transmission and storage national emission standards for hazardous air pollutants. July 9, 1996.

condensed water as exempt waste. According to the commenter, the disposal costs in the San Juan Basin of New Mexico are approximately $1.40 per barrel of water. The commenter stated that condensing will at least double the water disposal amounts from dehydrators because steam currently going to the atmosphere will be condensed.

Response: **Approximately 20 billion barrels per year of produced water are generated by the oil and natural gas production source category.[12] Using GLYCalc to determine the amount of produced water generated by the number of facilities estimated to be affected by subpart HH, the EPA calculated that the oil and natural gas production NESHAP would result in an increase in produced water production by approximately 590,000 barrels per year. According to a GRI report,[13] produced water would be typically handled along with other produced water streams, either by underground injection control, surface impoundment, or other miscellaneous methods. Thus, the EPA believes that the oil and natural gas production NESHAP would have a minimal impact on existing produced water disposal costs and control costs.**

Comment: Commenter IV-D-22 stated that the EPA has substantially understated the cost of subpart HH to industry sources and has underestimated the monitoring, reporting, and recordkeeping burdens associated with the rule. The commenter estimated the capital costs of subpart HH to exceed $25 million

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[12]The Oil and Gas Exploration and Production Industry. Trends: 1985-2000. (Draft Report, April 30, 1993). U.S. EPA, Washington, DC. (Air Docket A-94-04 number IV-A-09).

[13]Rueter, C.O., M.C. Murff, and C.M. Beitler (Radian International LLC). Glycol Dehydration Operations, Environmental Regulations, and Waste Stream Survey. Prepared for the Gas Research Institute. Publication Number GRI-96/0049. June 1996. Page 4-38.

for major sources, as compared to the EPA's estimates of $6.5 million for major sources. The commenter also estimated the annual costs of subpart HH to be $15 million for major sources, as compared to the EPA's estimates of $4 million for major sources. The commenter estimated cost effectiveness to be $3,000/megagram for the EPA's model plant, as compared to the EPA's cost effectiveness of $116/megagram for its model plant.

The commenter mentioned the EPA's request for comments on the production recovery credit assumed to result from installation of control devices. The commenter believes, based on GLYCalc runs, that the EPA has materially overstated the quantity of product recovered that could be sold to offset the capital and annual costs associated with subpart HH.

Response: **The EPA based its national cost estimate impacts on the estimated number of facilities that would be impacted by the regulatory provisions of subparts HH and HHH, along with detailed emission control cost estimates per HAP emission point. In addition, the MRR costs were based on a detailed analysis of the regulatory requirements of subparts HH and HHH. The EPA believes that the MRR cost estimates reflect the estimated effort required to address MRR requirements in the final subparts HH and HHH.**

In reviewing the costs presented by the commenter, the EPA noted that the commenter compared a 10 MMscf/d unit with a 35 MMscf/d unit, which the EPA used as its example cost model plant in Chapter 6.0 of the BID. Thus, the commenter observed a significant difference in product recovered.

Comment: Commenter IV-D-38 made general statements that the proposed regulations will have a profound impact on their operations. This includes a cost of implementation that is enormous compared with environmental benefits and, ultimately, passing these increased costs to consumers.

Response: The EPA also conducted an economic impacts analysis to evaluate the impacts of the regulation of affected producers, consumers, and society (Air Docket A-94-04 numbers II-A-08 and IV-A-13). The EPA estimated that price and output changes as a result of the regulation were less than 0.01 of 1 percent, which is significantly less than observed market trends (based on 1992 and 1993 data). The cost impacts are presented in tables 1 through 3 of the preamble; the development of these costs is documented in the background information document.[14] Through the comment period, the EPA provided the opportunity for the public to submit comments, along with supporting documentation, on all aspects of the proposed NESHAP. Without supporting documentation to address the specific impacts of the proposed NESHAP on the commenter's operations, the EPA is unable to specifically respond to this comment.

Comment: Commenter IV-G-09 estimated the average cost of the condenser and auxiliary equipment it placed on dehydration units, each processing 100 MMscf/d, to be more than $150,000, in contrast to the EPA's preamble statement that the average cost of condenser control devices would be less than $12,000.

Response: As previously stated, the EPA based its cost estimates on published installed control system costs from the Ventura County APCD (Air Docket A-94-04 number IV-A-07). Without substantive supporting documentation to address the specific cost impacts of the NESHAP on the commenter's operations, the EPA is unable to specifically respond to this comment.

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[14] "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.

Comment: Commenter IV-D-11 stated that imposing requirements on sources that are already controlled invalidates the EPA's cost effectiveness analysis. According to the commenter, sources controlled under the Louisiana Department of Environmental Quality (LDEQ) Section 2115 Waste Gas Disposal Rule already meet the MACT floor efficiency requirements. Therefore, the commenter stated that the expenditures for monitoring and recordkeeping requirements will not result in appreciable emissions reductions. The commenter concluded that the cost effectiveness for controlled sources could approach infinity since no additional reductions will be realized. The commenter referred to the State of Louisiana's implementation of significant controls on glycol dehydrators and provided a copy of the pertinent pages of the LDEQ 1995 Annual Report, which shows that toxic air emissions from glycol dehydrators have been reduced from 36,720,000 pounds (lb) to 1,277,608 lb in 1994, representing a reduction greater than 96 percent. According to the commenter, further reductions have occurred since 1994. The commenter explained that the great majority of the emissions reductions are federally enforceable since they were required due to the Louisiana Administrative Code (LAC) 33:III.2115 Waste Gas Disposal Rule and are contained in either State-only or part 70 permit programs in LAC 33:III.Chapter 5. The commenter noted that these rules are incorporated in the EPA-approved State implementation plan (SIP) for Louisiana and that further reductions are being accomplished due to a rule for glycol dehydrators (LAC 33:III.2116) and for flash gas from storage tanks (LAC 33:III.2104, Crude Oil and Condensate rule) which are not included in the EPA-approved SIP.

Response: The commenter seems to imply that the installation and operation of control equipment are all that is necessary to achieve the MACT floor efficiency requirement. The EPA believes that monitoring, recordkeeping, and reporting requirements serve a vital function in ensuring that an emission

limitation is initially, and continues to be, met. Therefore, the EPA maintains that the costs associated with monitoring and recordkeeping are part of the costs that must be incurred to achieve the necessary emission reduction, not additional costs with no appreciable emission reduction.

The monitoring, recordkeeping, and reporting requirements contained in the final rule are the requirements that the EPA believes are necessary to ensure compliance with the emission limitations. If the Louisiana rule referred to by the commenter requires comparable monitoring, recordkeeping, and reporting as that contained in the final rule, then no additional burden would be incurred by affected facilities. In fact, via §63.10(a)(3) of the General Provisions, which is incorporated by reference into the final rule, an owner or operator can simply send the Administrator a copy of any report to the State that contains the same information required by the federal NESHAP. If the monitoring, recordkeeping, and reporting currently being conducted by these Louisiana facilities do not meet the provisions in the final rule, then the EPA believes that these sources would need to upgrade efforts to ensure compliance with the MACT standard.

Further, if the State of Louisiana believes that the rule referenced by the commenter is equivalent to the final standard for Oil and Natural Gas Production facilities, then an application could be made under subpart E of 40 CFR 63. If the EPA agrees that the Louisiana rule is at least as stringent as the federal rule, the State rule would replace the federal NESHAP for source in the State of Louisiana.

2.5.2 Environmental Impacts

Comment: Commenter IV-D-07 stated that the EPA's assumptions made in estimating emissions are not representative of their operations, especially HAP concentrations in natural gas before dehydration. The commenter noted that methane and volatile organic compounds (VOC) emission reductions are included in the preamble even though the standard is designed to reduce HAP emissions. The commenter questioned why methane emissions were included.

Response: The EPA used the best available information to estimate the environmental impacts of subparts HH and HHH. The information represents average facilities and operating practices within the source categories and not any individual facility and facility operations. The EPA included VOC and methane emission reductions for the proposed regulations for informational purposes and to show the overall emission reduction benefits associated with these NESHAP. Methane and VOC reductions were not used to set the standards for subparts HH and HHH. Therefore the EPA has not made any changes to subparts HH and HHH in response to this comment.

Comment: Commenter IV-D-07 stated that the estimates for increases for nitrogen oxides and sulfur dioxide emissions from additional flare operations may be severely underestimated.

Response: The EPA used AP-42 emission factors to estimate the increases in nitrogen oxides and sulfur dioxide emissions associated with the installation of flares at certain remote facilities. The EPA believes these estimates are representative of potential emission increases for this industry. Therefore, the EPA has not made any changes to these estimates.

2.6 ECONOMIC ANALYSIS

<u>Comment:</u> Commenter IV-D-19 was concerned that any analysis of the economic impact of the proposed standard should adequately consider the impact on marginal production operations. Specifically, the commenter mentioned the low crude oil prices and high level of abandonment of marginal oil production operations. The commenter indicated that to meet the requirements of the Regulatory Flexibility Act (RFA), the EPA screened a sample of small entities and determined that minimal impacts from subpart HH would result. The commenter requested assurance or modification of the economic impact analysis to ensure the screening sample contains an appropriate cross section of small entities.

<u>Response:</u> The Agency's economic analysis employed a baseline characterization of the industry that includes marginal production operations. This baseline characterization linked the model plants and units developed by the EPA's engineering analysis with the well groups identified and characterized by the Gruy Engineering Corporation in their 1991 report prepared for API. These well groups are defined by production rates in specified ranges of well depths for both oil and gas wells in each of the 37 different geographic areas across the United States. The Energy Information Administration (EIA) report provides details for oil well groups in Appendix A and for natural gas well groups in Appendix B. Therefore, to the extent that the Gruy Engineering Corporation's database appropriately characterizes marginal production operations, the Agency's economic analysis includes the impacts on these operations.

The Agency expects that the impacts on these marginal operations will be minimal given the size cutoff for glycol dehydration units. Glycol dehydration units that process less than 3 MMscf/d are not affected by the proposed standards. It is

likely that a large share of the marginal operations operates these smaller units and, thus, would not incur compliance costs associated with the proposed standard. Furthermore, it follows that the smaller owners would likely own only units of this type and, thus, would also not be adversely affected by the proposed standard. However, in accordance with the RFA, the Agency still conducted an analysis of the small business impacts of the standards. As noted by the commenter, the Agency employed a sample of companies to evaluate the small business impacts because the necessary financial data were not available for each and every potentially affected company. The sample of 80 companies was determined by data availability and considered a fair representation based on their distribution across the relevant SIC codes. To facilitate evaluation of the appropriateness of the sample, the EIA report provided a list of the companies that were part of the sample as well as their baseline data in Appendix F. Based on Small Business Administration (SBA) size standards, the EPA's sample contained 39 small companies, which were 48.8 percent of all companies. Based on this sample, the Agency determined that the mean cost-to-sales ratio for small companies was 0.1 percent with a maximum of 1.1 percent. This information supports the Agency's finding that there will not be a significant impact on a substantial number of small entities.

Comment: Commenter IV-D-24 stated that the EPA economic analysis appears to significantly underestimate the control costs of the proposed regulation. The commenter estimated that post-regulatory control costs could be $121.2 million/yr as compared to the EPA's estimate of $18.9 million/yr. [Note: These figures include the costs associated with the regulation of area sources, which has been deferred until the development of the Urban Air Toxics Strategy is finalized.]

Furthermore, the commenter estimated that as many as 1,960 wells per year could be abandoned as a result of the increased compliance costs of the proposed regulation and the EPA estimates that no wells would be closed prematurely. The commenter explained that the EPA's determination of abandonment was based on aggregate changes in corporate revenues and profits. However, the commenter stated that production decisions are made on a well-by-well or project basis and if an individual project's profits fall below its break-even point, that well will be abandoned.

The commenter also estimated that an average of 46,000 thousand cubic feet (MCF) of natural gas production could be lost each year as a direct result of the increased costs of the proposed exploration and production (E&P) MACT regulation, compared to the EPA's estimate of 99 thousand cubic feet per year (MCF/yr). The commenter stated that their sophisticated, field-specific benefit-cost model and a detailed gas supply model, to estimate production impacts, provides a more accurate estimate than the EPA's.

The commenter noted that the EPA did not estimate losses of economically producible natural gas reserves. The commenter estimates that reserve losses could average as much as 1,040 billion cubic feet per year (bcf/yr) through 2010. The commenter stated that while employment impacts of the proposed rules are estimated to be minimal in their analysis, the EPA should update its analysis to include this employment loss.

Response: **The Agency's engineering analysis, as summarized in Section 3 of the EIA report, has estimated the annual compliance cost of the proposed standard to be almost $19 million per year, with major sources incurring $7 million annually and area sources incurring $12 million per year. The Agency's economic impact results are based on this estimate of the annual**

compliance cost of the proposed standard. This estimate differs significantly from the commenter's estimate of $121.2 million per year. Therefore, it is not surprising that the commenter's reported economic impacts are much greater than those reported by the Agency. The differences in these economic impacts are attributable to the significant disparity in the cost estimate used in determining these economic impacts as opposed to the economic methodology. The Agency expects that input of these higher compliance costs in its model would likely provide more comparable impacts to the commenter's "sophisticated" economic model. In addition, it is not clear whether the commenter has accounted for the EPA's size cutoff of 3 MMscf/d for TEG dehydration units in computing its economic impact results. The Agency expects that this size cutoff prevents the premature closure of a large number of small and often marginal well operations. Not accounting for this size cutoff would similarly contribute to differences in the estimated reduction in natural gas production and employment losses associated with the proposed standards.

Also, the commenter has misinterpreted the EPA's determination of closure, or abandonment, as based on aggregate changes in corporate revenues and profits. Rather, as described in Section 4 of the EIA report, the EPA's economic model determines production and closure decisions on the basis of a producing field (i.e., a group of similar wells) that is consistent with the commenter's statement that "production decisions are made on a well-by-well or project basis and if an individual project's profits fall below its break-even point, that the well will be abandoned." Furthermore, the commenter is correct in stating that the EPA did not estimate losses of economically producible natural gas reserves. The economic analysis conducted by the Agency is unable to address possible impacts on production from future natural gas reserves. However, based on the negligible impact on current natural gas production associated with the EPA's engineering estimate of compliance cost, it is not expected that these impacts would be as great as indicated by the commenter.

2.7 LEGAL ISSUES [OTHER THAN ISSUES ASSOCIATED WITH THE EPA'S INTERPRETATION OF SECTION 112(n)(4)(A) AND (B)]

Comment: Commenters IV-D-16, IV-D-22, IV-D-23, and IV-D-34 requested that the EPA clarify that subparts HH and HHH do not apply to OCS sources. Commenter IV-D-16 specifically recommended that the definition be modified to clarify that offshore platforms are not covered. The commenters indicated that offshore platforms should not be covered by any section 112 rule. Commenter IV-D-22 stated that they believe that Congress gave the EPA limited authority to regulate air emissions from OCS sources. According to the commenter, most of the authority for controlling these emissions was provided to the Department of the Interior (DOI) and what limited authority was provided to the EPA extends only to emissions of criteria pollutants. Commenter IV-D-23 also indicated that the CAA prevents the EPA from regulating HAP in Federal OCS areas. Commenter IV-D-34 referred to section 328 of the CAA and stated that it does not provide authority to the EPA to regulate air toxics under section 112 in any OCS area.

Response: Section 328 of the CAA requires that the Administrator establish requirements to control air pollution from OCS sources (i.e., sources located offshore of the States along the Pacific, Arctic, and Atlantic coasts and along the U.S. Gulf Coast off the State of Florida eastward of longitude 87 degrees and 30 minutes) to attain and maintain Federal and State ambient air quality standards and to comply with the provisions of part C of title I. For sources located within 25 miles of the seaward boundary of such States, the requirements must be the same as would be applicable if the source were located in the corresponding onshore area. Oil and natural gas production sources emit VOC, which contributes to the formation of ozone, and is regulated by the national ambient air quality standards (NAAQS). The primary HAP of concern for these source categories (benzene, toluene, ethyl benzene, mixed xylenes, and n-hexane)

are also classified as VOC. Therefore, standards for oil and natural gas production sources are applicable to offshore platforms, that are OCS sources, because they are related to the "attainment and maintenance" of ambient air quality standards or the requirements of part C of title I of the Act. Furthermore, section 328 states that the Administrator may exempt an OCS source from a specific requirement "if the Administrator finds that compliance with a pollution control technology requirement is technically infeasible or will cause an unreasonable threat to health and safety." Since offshore platforms typically control process vents by routing them to a flare, the EPA has determined that compliance with the control technology requirements is technically feasible. Therefore, the EPA has not exempted offshore platforms that are OCS sources from subpart HH.

2.8 PERMIT ISSUES

<u>Comment:</u> Commenter IV-D-05 cited a problem with the aggregation of emissions from associated equipment for major source determinations. [Note: the commenter mentioned "ancillary equipment" but most likely meant "associated equipment" as the comment appears to be directed towards associated equipment.] The commenter was concerned that existing facilities that had made applicability determinations in the past (e.g., for title V operating permits), based on not aggregating emissions from glycol units and storage vessels with the potential for flash emissions, had been permitted and operated as minor sources. The commenter asked whether these facilities would be given a "grace period" to pursue title V operating permits if they were classified as major sources given the aggregation of the ancillary equipment. The commenter was concerned that without a grace period, these sites could be subject to enforcement/penalty, etc.

<u>Response:</u> When making past applicability determinations, sources may have interpreted the phrase "associated equipment" in section 112(n)(4) of the Act differently than EPA's final interpretation of that phrase. The EPA acknowledges that such sources may have concluded that they were nonmajor, whereas, under EPA's final subpart HH rule, they could be classified as major. However, the EPA expects the number of sources with this discrepancy is small. The majority of facilities that are major under the EPA's final rule would have applied for title V permits because they have emission points (e.g., glycol dehydration units) that are by themselves major. Of the remaining sources, the EPA expects many to have applied for a title V permit based on the anticipated interpretation of 112(n)(4) described when the proposed rule was published.

For the remaining sources (e.g., those which are major solely because of aggregation of associated equipment, and which have not yet submitted a Title V permit application), the EPA does not agree that a blanket policy granting a "grace period" is appropriate, and EPA encourages major sources subject to subpart HH to apply for a title V permit as expeditiously as possible. The EPA will rely on its enforcement discretion in situations where a source failed to apply for a permit because it determined that it was nonmajor based on section 112(n)(4) of the Act. In most cases the EPA does not expect to undertake enforcement action, so long as the source expeditiously applies for its title V permit. However, the EPA does not believe it is appropriate to give up its ability to enforce part 70 in such instances.

Comment: Commenter IV-D-06 requested that §63.1274(c) mention that sources exempted by §63.1274(b) are not required by this subpart to obtain an operating permit. According to the commenter, sources exempted by §63.1274(b) should not be required to get an operating permit, since subpart HHH has no requirements to put into a permit. The commenter stated that this comment may also apply to subpart HH.

Response: Under proposed §63.1274(b) [now being codified at §63.1274(d)], only individual units are exempt from the requirements of proposed §63.1274(a) [now being codified at §63.1274(c)]. Therefore, major sources would still be required to obtain a title V permit and include the part 63 requirements that these sources keep records to document that the design capacity or benzene emission rate is below the cutoff (§63.1284(d) for subpart HHH and §63.764 for subpart HH). The EPA believes that, when a source is required to obtain a title V permit because it is major, recordkeeping requirements like

§63.1284(d) must be included. Note that in the final rules, neither subpart HH nor subpart HHH regulates nonmajor sources.

Comment: Commenters IV-D-31 and IV-G-02 requested that the sections that require major sources of HAP subject to the proposal to get operating permits [§§63.764(f) and 63.1274(c)], should be eliminated since the requirements are already well documented in parts 70 and 71. The commenters explained that restating these requirements is redundant and can cause confusion in identifying applicable requirements in an operating permit application.

Response: The EPA believes that stating the requirement for a major source to obtain a part 70 or part 71 operating permit identifies the facility's obligation to obtain such permit. The EPA does not see any reason to remove §§63.764(f) and proposed 63.1274(c) [now codified at §63.1274(e)].

Comment: Commenters IV-D-13 and IV-D-37 requested that the NESHAP not affect the monitoring, recordkeeping, and reporting requirements for control devices contained in the title V permit, or other appropriate federal mechanism, at the time the final NESHAP is promulgated. The commenters remarked that if the control device is federally enforceable, the monitoring, recordkeeping, and reporting requirements that have been acknowledged as federally enforceable and quantifiable by the EPA are sufficient to ensure HAP emission reductions.

Response: The final rules impose monitoring, recordkeeping and reporting requirements that are independent from monitoring, recordkeeping, and reporting for any other applicable requirement. The EPA cannot assume that any existing control device requirement, (including monitoring, recordkeeping, or reporting) is adequate to ensure compliance with the particular requirements of a new NESHAP. Ensuring compliance with the NESHAP does not alter existing compliance obligations that are

established for a variety of other reasons. However, the EPA notes that adding the NESHAP to the title V permit may offer opportunities to consolidate and streamline these multiple applicable requirements if they exist. For additional discussion on how this streamlining can occur, see the March 5, 1996 "White Paper Number 2 for Improved Implementation of the Part 70 Operating Permits Program."

Comment: Commenter IV-D-14 asked what the role of State and federal permit limits would be on the major source determinations.

Response: Major source determinations are in part based on a source's PTE. For the purposes of section 112, PTE is defined in §63.2 such that any physical or operational limitation on the capacity of a source to emit a pollutant, including air pollution control equipment and restrictions on hours of operation, shall be treated as part of the unit's design if the restriction is federally enforceable. For additional information on limiting PTE for section 112 purposes and for other reasons, please see the following memoranda: (1) January 25, 1995 Memorandum from John Seitz, Director, OAQPS, entitled "Options for Limiting the Potential to Emit (PTE) of a Stationary Source Under Section 112 and Title V of the Clean Air Act;" (2) August 27, 1996 Memorandum from John Seitz, Director, OAQPS, entitled "Extension of January 25, 1995 Potential to Emit Transition Policy;" and (3) July 10, 1998 Memorandum from John Seitz, Director, OAQPS, entitled "Second Extension of January 25, 1995 Potential to Emit Transition Policy and Clarification of Interim Policy."

2.9 ENFORCEMENT ISSUES

Comment: Commenters IV-D-06, IV-D-07, and IV-D-14 stated that parameter monitoring data do not, by themselves, demonstrate compliance or noncompliance with emission standards. According to these commenters, along with commenter IV-G-09, inability to demonstrate compliance does not prove noncompliance. Commenter IV-D-14 stated that the assumption that an emission limit has been exceeded is not valid and the burden of proof for violation of emission standards should lie on the agency enforcing the rule.

Commenter IV-D-06 referred to the history of the HON and the compromise between industry and the EPA on classifying monitoring excursions as violations. According to the commenter, excursions should not be classified as violations of the emission limit. Instead, they should be classified as violations of an operating requirement (the requirement to keep daily averages within the approved limit). This commenter, along with commenters IV-D-12 and IV-G-09, suggested that is incorrect to define an excursion as a violation of the emission standards. Commenter IV-D-14 asked what the basis was for establishing that a violation of an operating parameter value automatically constitutes a violation of an applicable emission standard.

According to commenter IV-D-06, subpart HHH should be revised to require that industry "operate with the daily averages within the approved limit, except as otherwise provided in this subpart." The commenter further stated that subpart HHH should then require that "excursions violate that paragraph." The commenter requested that the EPA delete all portions of subpart HHH that currently say excursions violate the emission standard. According to the commenter, the EPA can assess the same penalties. The commenter provided the following specific portions of subpart HHH to be amended (Note: the commenter stated that corresponding portions of subpart HH should also be amended, if applicable).

- Section 63.1271 (definition of "operating parameter value"): instead of "determines that an owner or operator has complied with an applicable emission limitation or standard," say "indicates proper operation of the control device."

- <u>Section 63.1274(d)</u>: Delete.
- <u>Section 63.1281(d)(4)(iii):</u> Revise to say that, except as otherwise provided in this subpart, any excursion is a violation of the provisions of section 63.1281(d)(4)(ii).

In addition, commenters IV-D-07 and IV-D-12 recommended that excursions outside the defined operating window should be a notice for corrective or preventive action, instead of a violation of the standard. According to commenter IV-D-12, short-term excursions from the operating window do not result in exceedence of "properly structured emissions limitations." Commenter IV-D-07 claimed that the proposal is inconsistent with other regulatory initiatives, such as the Compliance Assurance Monitoring (CAM) rule.

In contrast, commenter IV-D-35 supported provisions, like those contained in §63.764(h)(2), that plainly state that noncompliance with operating parameters is a violation of the emission limitation or standard.

<u>Response:</u> The EPA's decision to classify a violation of an operating parameter as a violation of the emission standard versus a violation of the operating requirement is based on whether the monitored parameters have a strong correlation to control device operation. In other words, do the monitored parameters accurately predict control device performance? For combustion units to achieve complete combustion, sufficient reactor space, residence time, turbulence, and temperature are necessary. A high combustion temperature must be provided to ignite the vent stream HAP constituents. Therefore, since reactor space, residence time, and turbulence are design parameters, temperature can be used as an accurate prediction of combustion device operation.

For condensers, GRI has published a report entitled "Control Device Monitoring of Glycol Dehydrators: Condenser Efficiency Measurements and Modeling,"[15] in which condenser outlet temperature was evaluated as a sufficient monitoring parameter for glycol dehydrator vent condensers. In the report, GRI concluded that outlet temperature is a sufficient monitoring parameter for indicating control device performance.

Because of these correlations for combustion devices and condensers, the EPA believes that monitoring temperature is strong indication of control device performance. The EPA maintains that a violation of an operating parameter value should be classified as a violation of the emission standard. Therefore, the EPA has not made any changes to subparts HH and HHH in response to this comment.

Comment: Commenter IV-D-06 stated that subpart HHH does not appear to define what constitutes an excursion, although it provides that excursions are violations. The commenter suggested that excursions should be defined by the daily average parameter value, not each monitored data point. The commenter recommended that the EPA modify §63.1281(d)(4)(ii) to clarify that industry is required to keep the daily average parameter value within the limit. The commenter also recommended that the EPA include the definition of an excursion shortly after this paragraph. The commenter stated that this comment also applies to subpart HH.

Commenter IV-D-06 was also concerned that each individual data point might be considered a violation of subpart HHH. The commenter stated that a single missing data point is not an excursion. Instead, a "data quality" excursion should mean that

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[15]Reuter, C.O., et al (Radian International LLC). Control Device Monitoring of Glycol Dehydrators: Condenser Efficiency Measurements and Modeling, Volume 1. Prepared for the Gas Research Institute. Publication Number GRI-97/0005.1 January 1997. 134 pp.

less than 75 percent of the required data were collected. During development of the HON, the industry stated that two types of excursions exist: "parameter" and "data quality." The industry contended that no matter how carefully the monitoring systems are operated, sometimes a data point would not be recorded. The industry stated that if 100 percent of the data were required to be collected, compliance would be impossible. Commenter IV-D-35 was also concerned that the proposed regulations do not contain many quality assurance/quality control provisions or a minimum availability of time for the monitoring equipment. The commenter suggested including a provision requiring 95 percent data availability of continuous monitoring systems on an annual (8,760 hours) basis. The commenters stated that this comment also applies to subpart HH.

Response: **The EPA agrees with the concepts suggested by the commenters and has made several changes to subparts HH and HHH in response with these comments. Section 63.773(d)(4) of final subpart HH and §63.1283(d)(4) of final subpart HHH require the owner or operator to calculate the daily average for each monitored parameter and require that the daily average consist of valid data points for at least 75 percent of the operating hours in an operating day. For condensers, the owner or operator has the option of converting the daily average temperature to an annual average (subpart HH) or a 30-day average (subpart HHH) condenser removal efficiency. In addition, the following requirements have been added to §§63.773(d) and 63.1283(d):**

1. **An excursion for a given control device has occurred when monitoring data or lack of monitoring data result in one of the following:**
    - **The daily average value of a monitored parameter is less than the minimum operating parameter limit (or greater than the maximum operating parameter limit, if applicable) established for that operating parameter.**
    - **If applicable, the 365-day average condenser efficiency is less than 95 percent, unless the owner or operator**

has less than 365 days of data, the average condenser efficiency is less than 90 percent.

- **Monitoring data are not available for at least 75 percent of the operating hours.**
- **The vent stream has been diverted through the bypass device.**

2. **Each excursion is a violation of the operating parameter limit and thus a violation of the standard (either subpart HH or HHH).**
3. **For each control device (or combination of control devices installed on the same HAP emissions unit), one excused excursion is allowed for each semi-annual period (corresponding to the periodic reporting periods specified in §§63.775 and 63.1285).**
4. **Excursions are not considered violations and do not count as excused excursions during the startup, shutdown and malfunction events (provided the facility operates according to the startup, shutdown, or malfunction plan), and during periods of nonoperation of the unit or process that is vented to the control device.**

Comment: Commenter IV-D-06 noted that subpart HHH allows for owner or operator to choose the parameter limits and in some cases may not be restricted to performance tests. The commenter recommended that the EPA use a concept from the HON where the owner or operator establishes the approved parameter limit, which does not necessarily have to be based on a performance test. In cases where the owner or operator is not otherwise required to conduct a performance test, the parameter limit may be based on engineering assessments or manufacturers' data if desired. The commenter suggested that the EPA clarify subpart HHH by borrowing from other MACT standards that explain in greater detail when to use performance test data, and when using other data is permissible, in establishing parameter limits. The commenter suggested that the EPA use the Group I and Group IV Polymers rules as a model. The commenter stated that this comment also applies to subpart HH.

Response: The EPA does not intend to restrict when an owner or operator should use performance test data or design analyses. The owner or operator may decide whether a performance test or a

design analysis will provide accurate data for determining an appropriate minimum or maximum operating parameter value. Proposed §§63.771(d)(3)(iii)(B) and 63.1281(d)(3)(iii)(B) [now codified at §§63.772(e)(4)(ii) and 63.1282(d)(4)(ii)] state that if the owner or operator and the Administrator do not agree on the demonstration of control device performance using a design analysis, then the disagreement shall be resolved using the results of a performance test.

Sections 63.773(d)(5) and 63.1283(d)(5) of the final rules contain the requirements for establishing minimum (or maximum) operating parameter limits. These requirements specify that the owner or operator must establish the appropriate operating parameter limit using performance test data, or a design analysis. Both performance test data and the design analysis may be supplemented using control device manufacturer's information.

Comment: Commenter IV-D-06 noted that subpart HHH does not allow for any excused excursions. The commenter recommended that each monitored control device or recovery device be given a specified number of excused excursions where the number of excused excursions starts larger and becomes smaller with time. The commenter referred to the development of the HON, where the industry raised the concern that no matter how carefully a control device is operated and maintained, sometimes there will be an excursion. The industry maintained that these excursions are most frequent when a control device is new and is being debugged, but they will decrease over time. Therefore, the commenter recommended that the EPA modify §63.1281(d)(4)(ii) by using §63.152(c)(2)(ii)(B) of the HON, which says:

> (B) The number of excused excursions for each control device or recovery device for each semiannual period is specified in paragraphs (c)(2)(ii)(B)(1) through (c)(2)(ii)(B)(6) of this section. This paragraph applies to sources required to submit Periodic Reports semiannually or quarterly. The first

semiannual period is the 6-month period starting the date the Notification of Compliance Status is due.

(1) For the first semiannual period - six excused excursions.

(2) For the second semiannual period - five excused excursions.

(3) For the third semiannual period - four excused excursions.

(4) For the fourth semiannual period - three excused excursions.

(5) For the fifth semiannual period - two excused excursions.

(6) For the sixth and all subsequent semiannual periods - one excused excursion.

The commenter stated that this comment also applies to subpart HH.

Response: The compliance dates for subparts HH and HHH allow owners and operators three years after the effective date of the rule to achieve compliance. The EPA believes that there is sufficient time for an owner or operator to debug control devices and monitors. Furthermore, by allowing for a small amount of missing data, and by specifying that a violation of the operating parameter is defined by the daily average parameter value, the EPA believes that owners and operators have sufficient flexibility to operate and maintain their control devices. Therefore, the EPA maintains that only one "excused excursion" should be allowed per semiannual period [codified at §§63.773(d)(8) and 63.1283(d)(8)].

Sections 63.773(d)(8) and 63.1283(d)(8) also state that during startup, shutdown and malfunction events, as long as the owner or operator complies with the facility's startup, shutdown and malfunction plan, any monitored parameters outside its operating range would not be counted towards the excused excursions. However, simply following a startup, shutdown, and malfunction plan is not necessarily a defense to failure to have taken steps to prevent malfunctions or failure to adequately

minimize emissions during startup, shutdown, and malfunction events (§§63.762 and 63.1272). Also, during periods of nonoperation of the unit or process that is vented to the control device, monitored parameters outside their established operating ranges do not count as excursions.

Comment: Commenter IV-D-06 stated that monitoring data collected during startups, shutdowns, and malfunctions, or periods of non-operation, should be excluded from daily averages. The commenter noted that since daily averages are not mentioned, this concept is also not mentioned in the subpart HHH. The commenter stated that in the General Provisions, normal emissions standards do not apply during startups, shutdowns, and malfunctions. During those periods, compliance is determined based on the facility following the provisions in the startup, shutdown, and malfunction plan. The commenter recommended that the EPA borrow the following concepts from §§63.152(c)(2)(ii)(C) and 63.152(f)(7) of subpart G and incorporate them into §63.1281(d)(4)(ii) (note that wording would have to be changed):

> (C) If a monitored parameter is outside its established range or monitoring data are not collected during periods of startup, shutdown, or malfunction (and the source is operated during such periods in accordance with the source's startup, shutdown, or malfunction plan as required by §63.6(e)(3) of subpart A of this part) or during period of non-operation of the chemical manufacturing process unit or portion thereof (resulting in cessation of the emissions to which the monitoring applies), then the excursion is not a violation and, in cases where continuous monitoring is required, the excursion does not count toward the number of excused excursions for determining compliance.
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> (7) Monitoring data recorded during periods identified in paragraphs (f)(7)(i) through (f)(7)(v) of this section shall not be included in any average computed under this subpart. Records shall be kept of the times and durations of all such periods and any other periods during process or control device operation when monitors are not operating.
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> (i) Monitoring system breakdowns, repairs, calibration checks, and zero (low-level) and high-level adjustments;

(ii) Startups;
(iii) Shutdowns;
(iv) Malfunctions; and
(v) Periods of non-operation of the chemical manufacturing process unit (or portion thereof), resulting in cessation of the emissions to which the monitoring applies.

The commenter stated that this comment also applies to subpart HH.

__Response:__ As stated in a previous comment, the EPA has included provisions for one excused excursion and has incorporated the suggested concepts from §63.152(e)(2)(ii)(C) [codified at §63.773(d)(8) and 63.1283(d)(8) of the final rules]. The EPA also agrees that monitoring data collected during startups, shutdowns, and malfunctions, or periods of non-operation, should be excluded from the daily averages. Therefore, the EPA has incorporated the suggested concepts from 63.152(f)(7) of subpart G and incorporated them into §§63.774(b)(3) and 63.1284(b)(3) of the final rules.

__Comment:__ Commenter IV-D-06 expressed concern that each monitored parameter would be considered a separate violation of subpart HHH. According to the commenter, if a control device has two or more parameters that must be monitored, and more than one parameter has a daily average outside the approved limit on the same day, this should be considered a single excursion. During the development of the HON, the industry explained that operating parameters are generally interrelated, so no matter how many parameters are outside the limit, there is only one opportunity for emissions to be above the standard. The industry felt that it would be unfair to multiply the violations by considering each parameter separately.

__Response:__ The EPA agrees with the commenter. Sections 63.773(d)(6) and 63.1283(d)(6) of the final rules state that for a control device or recovery device where multiple parameters are monitored, if one or more of the parameters meets the criteria

for an excursion, this is considered a single excursion for the control device.

Comment: Commenter IV-D-14 asked how the EPA would initially administer the new program. The commenter also asked what the States' role would be in administering the program and how delegation would be afforded to the States.

Response: Section 112(l) of the Clean Air Act grants the Administrator the authority to approve State programs to implement and enforce section 112 rules. Subpart E of part 63 establishes the procedures for States to follow in obtaining delegated authority as provided in section 112(l). This subpart establishes the procedures for:

- **the approval of State rules or programs to be implemented and enforced in place of section 112 Federal rules, emission standards, or requirements;**
- **the approval of State programs to implement and enforce section 112 Federal rules as promulgated without changes; and**
- **the approval of State rules or programs that adjust a section 112 Federal rule.**

Any request for approval under subpart E must meet all section 112(l) approval criteria specified by the applicable Federal rule, and the approval criteria in §63.91(b) of subpart E. The EPA expects that by the compliance dates of subparts HH and HHH, the States programs to implement and enforce these subparts will have been approved by the Administrator under subpart E. Delegation of authority will be specified in §§63.776 and 63.1286. However, in the case that delegation is not made, then the EPA Regional Administrator for that State would implement the standard.

Comment: Commenters IV-D-07, IV-G-09, and IV-D-31 were concerned with the limitations of GLYCalc and noted that the GLYCalc instruction manual states that it over predicts emissions, usually by at least 20 percent. The commenters recommended GLYCalc not be used for enforcement purposes unless a disclaimer on its use for enforcement purposes is included.

<u>Response:</u> The EPA performed field tests to assess the effectiveness of the GLYCalc emissions model for estimating HAP and VOC emissions.[16] Based on the results of the field test evaluations, and additional glycol dehydrator emissions test sponsored by GRI and API, the EPA has recommended that the GLYCalc model be included in guidance for State and local agency use for the development of emissions inventories to meet CAA requirements. The EPA stated that for sites where source tests have been conducted, the experience was that GLYCalc either estimates emissions accurately or overestimates emissions. According to the EPA's analysis, the likelihood of overestimating emissions may be reduced by obtaining accurate measurements of process variables for as many model inputs as possible. However, since the use of default values for model inputs will occasionally be necessary, some overestimation of emissions is unavoidable.

Therefore, based on the EPA's analysis, the EPA believes that GLYCalc is a reasonable method for estimating benzene emissions from glycol dehydration units for the 1-tpy exemption and for use in conjunction with the Atmospheric Rich/Lean (ARL) method as an alternative to the performance procedures for condensers.

It should be noted that the EPA does not require the use of GLYCalc, but has offered it as an acceptable tool for estimating

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[16]Memorandum from Jones, L.G., U.S. EPA/Emissions Measurement Branch, to J.D. Mobley, U.S. EPA/ Emission Factor and Inventory Group. "Glycol Dehydrator Emissions Test Report and Emissions Estimation Methodology." April 13, 1995.

emissions and demonstrating compliance. However, owners and operators should be aware that it is possible that a performance test could indicate that a glycol dehydration unit is out of compliance. Therefore, the EPA recommends that if GLYCalc predicts that the glycol dehydration unit is operating close to the emission limitations in the NESHAP, then the owner or operator may wish to conduct a performance test.

2.10 CONTROLS

2.10.1 MACT Floor

Comment: Commenter IV-D-07 noted that the EPA assumed an average inlet BTEX concentration of 200 ppmv as the basis for the 95 percent HAP reduction. According to the commenter, if the BTEX concentration is well below 200 ppmv, the required reduction would be much more difficult to obtain for condensers. The commenter stated that they felt the EPA did not consider this scenario or allow for a cost-effective solution. The commenter noted that for a combustion device, the 95 percent reduction should not be a problem.

Response: The commenter's statement that the 95 percent HAP reduction requirement was based on an average inlet BTEX concentration of 200 ppmv is incorrect. Instead, the 95 percent control requirement was developed as the floor level of control (see Air Docket A-94-04, number II-A-07 for further discussion on the MACT floor development).

The national average BTEX concentration was developed to estimate national emissions. The EPA developed three national average BTEX concentrations for natural gas to represent three sectors in the oil and natural gas production and natural gas transmission and storage source categories: (1) 200 ppmv for production; (2) 160 ppmv for processing; and (3) 13 ppmv for transmission and storage.[17] To develop the national emission impacts, the EPA distributed concentrations of BTEX among the TEG unit populations.[18] Therefore, since the 95-percent emission reduction was not based on the average BTEX concentrations, the EPA did not see any reason to modify subpart HH in response to this comment.

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[17]Reference 9, appendix B.

[18]Reference 9. Appendix B.

However, the final rule requires an owner or operator to control process vents on glycol dehydration units to one of the following: (1) 95 percent HAP emission reduction, (2) 20 ppmv control device outlet concentration (for combustion devices), or (3) control device outlet mass emission rate less than 1 tpy of benzene. The benzene limitation was established because the MACT floor for glycol dehydration units with actual benzene emissions less than 1 tpy was determined to be no control (see responses in section 2.10.3 of this document). The EPA believes that the addition of the 1 tpy benzene emission limitation provides additional flexibility for owners or operators of facilities with low BTEX concentrations in the natural gas.

Comment: Commenter IV-D-06 requested that the EPA allow an emission limit of 20 ppmv for non-combustion control devices. The commenter stated that at very low incoming HAP concentrations, recovery devices may be unable to achieve 95 percent HAP reduction, but can probably achieve 20 ppmv HAP at the outlet reliably. The commenter was concerned that they would be forced to use combustion devices rather than recovery devices. The commenter remarked that the combustion device would be allowed to emit the same 20 ppmv that the recovery device was not allowed to emit and that recovery for reuse is environmentally better than destruction. The commenter recommended that the EPA add a 20 ppmv option to §63.1281(d)(1)(ii), using §63.1281(d)(1)(i)(B) as a pattern, without the correction to 3 percent oxygen. The commenter stated that this comment also applies to subpart HH.

Response: In the preamble to the proposed 40 CFR part 60, subpart NNN, NSPS for Air Oxidation Unit Process (48 FR 48932, October 21, 1983), the EPA stated that 20 ppmv is the lowest outlet concentration of total organic compounds achievable by the combustion of low organic concentrations (i.e., inlet

concentrations of 2000 ppmv or less). As stated in the preamble to subpart NNN, the outlet concentration was established based on kinetic calculations of incinerators. It was demonstrated that, at a given temperature and residence time, a stream with a low inlet concentration (approximately 2000 ppmv) could not be controlled in an incinerator to an outlet concentration below 20 ppmv. The commenter did not provide any information indicating that non-combustion control devices could not meet an outlet concentration below 20 ppmv. Therefore, the EPA does not see any reason to modify subparts HH and HHH in response to this comment.

Comment: Commenter IV-D-21 was concerned that documenting 95 percent reduction might be difficult for some dehydrator configurations that have a flash tank. According to the commenter, less than 2 percent of the total uncontrolled HAP emissions from a dehydrator are associated with the flash gas. The commenter explained that for dehydrators that route vent gas to a condenser to recover hydrocarbons, and route flash gas to a combustion device, the compliance determination would depend on defining the emission reduction achieved by both control devices. Based on the small amount of HAP emissions associated with the flash gas, the commenter suggested that testing the combustion device in accordance with proposed §63.772(e) to document control efficiency would significantly increase compliance cost with little environmental benefit.

The commenter also noted that flash gas has a high British thermal unit (Btu) content and is easily burned. The commenter requested that the EPA provide a default reduction efficiency in the final rule that can be used by combustion systems burning flash gas for use in demonstrating compliance with the requirement for a 95-percent reduction efficiency.

Response: The EPA believes that subparts HH and HHH provide sufficient flexibility in demonstrating compliance for owners and

operators that route the glycol dehydration unit reboiler vent gases to a condenser for hydrocarbon recovery and route the flash gas vent to a combustion device. First, final subparts HH and HHH allow combinations of control devices to achieve the 95 percent emission reduction [final §§63.765(b)(1)(i) and (ii) and 63.1275(b)(1)(i) and (ii)]. Second, the final rules do not require control of HAP emissions from flash tanks if the total HAP emissions to the atmosphere from the glycol dehydration unit process vent (i.e., the combined reboiler and flash tank vents) are reduced by 95 percent [§§63.765(c)(3) and 63.1275(c)(3)]. Finally, subparts HH and HHH provide owners and operators the option of demonstrating compliance using either a performance test or a design analysis [§§63.772(e) and 63.1282(d)]. The EPA believes that by providing the option of performing a design analysis rather than a performance test, owners and operators have the flexibility to choose the least expensive option.

As for the commenter's request for a default reduction efficiency for combustion devices burning flash gas, the EPA points to §63.771(d)(1)(i) in final subpart HH and §63.1281(d)(1)(i) in final subpart HHH which state that an owner or operator may install enclosed combustion devices that meet one of the following conditions: (1) reduces HAP emissions by 95 percent or more, (2) reduces the outlet HAP concentration to 20 ppmv or less, (3) operates at a minimum residence time of 0.5 seconds at a minimum temperature of 760°C, or (4) is boiler or process heater that is designed so the vent stream is introduced into the flame zone. If the owner or operator can demonstrate that their combustion device operates according to the minimum residence time and temperature specifications or the vent stream is introduced into the flame zone, then a compliance

demonstration with the 95-percent emission reduction (or the 20 ppmv outlet concentration) is not required. Therefore, the EPA believes that it is not necessary to provide a default reduction efficiency for demonstrating compliance with the 95-percent reduction efficiency.

Comment: Several commenters objected to the 95-percent control requirement. According to commenter IV-D-12, a 90 percent control requirement would provide a more realistically achievable standard. The commenter pointed to a GRI study (Skinner and Rueter, 1998, GRI-98/0073) which shows that condensers at many facilities are unable to achieve 95 percent on a continuous basis. The commenter further stated that applying the control requirement based on the source's choice of either total VOC or HAP is appropriate, but not both.

Commenter IV-D-16 stated that condenser performance is dependent on local climate conditions, and that a 95-percent efficiency cannot be reliably achieved throughout the year in many areas of the United States. The commenter was concerned that requiring efficiencies that could not be met would remove condensers from the potential control list. The commenter further remarked that condensers are a form of recycling and should not be "saddled with an efficiency requirement they cannot meet." The commenter suggested that an efficiency of 85 percent more accurately describes the performance in these devices and should be chosen as the required level of control for subparts HH and HHH. Commenter IV-D-38 also recommended that an emission reduction of 85 percent would be typically achieved for the control devices addressed in section 63.765(c)(2) and (3), as compared with 95 percent in the proposed regulations, and that the cited paragraphs should be changed accordingly.

Commenter IV-G-07 presented HAP efficiency data for twenty condenser-controlled glycol units, each treating between 5 and 55 MMscf/d, and only one of which has no flash tank. According to the commenter, the calculated mean annual control efficiency based on this data is 95.97 percent and the standard deviation error is 2.81 percent. Therefore, the commenter recommended 90 percent as the appropriate lower limit, using this data as representative and taking the common scientific approach of using plus or minus two standard deviations as the proper confidence limit.

Commenter IV-G-02 was concerned about the EPA's setting a MACT floor for dehydration units based on a "control level estimated to be achieved through the use of condensers" (63 FR 6304), rather than on the "emission limitation achieved" as required by the Act. The commenter questioned whether the EPA has considered that many condensers located at an altitude probably cannot meet 95 percent (due to lower atmospheric pressure, substances exhibit a greater partial pressure, and are therefore more difficult to condense). The commenter also questioned whether the EPA has data to show the average of the best performing 12 percent of units achieve a 95 percent reduction. The commenter stated that they believe that the MACT floor is an equipment standard (rather than efficiency, which is appropriate) requiring a condenser, combustion device, or flare for control.

<u>Response:</u> The MACT standard for process vents on new and existing glycol dehydration units was set at the floor level of control. As required under section 112(d) of the Act, the EPA developed the MACT floor based on ". . . the average emission limitation achieved by the best performing 12 percent of the existing sources. . . ." A detailed discussion regarding the development of the MACT floor can be found in the docket (Air Docket A-94-04, number II-A-07). Through section 114 questionnaires, site visits, meetings with stakeholders, and available literature, the EPA obtained information for 200 glycol dehydration units that were considered to be major sources of HAP (prior to control). Of these, 34 percent (67 units) were controlled using a variety of control technologies, including:

condensation, combustion, and a combination of condensation and combustion. The types of control technologies used by the industry have been demonstrated, in other applications, to achieve varying levels of emission reduction (ranging from 95 to 98 percent or better). The EPA could not identify a technical basis for the variation in the performance levels achieved by the controls reported to be used to control process vents on glycol dehydration units. In order to account for the variability in HAP emission reduction efficiencies, the EPA selected 95.0 percent as the required emission reduction (i.e., the MACT floor) for glycol dehydration units in the oil and natural gas production source category. Since the 95-percent emission reduction allows owners and operators to install not only condensers, but also combustion devices, as long as they achieve a 95-percent HAP emission reduction, the EPA does not believe that the MACT floor is an equipment standard.

Although the EPA did not lower the required emission reduction in the final rule, the final rule requires compliance with the 95-percent HAP emission reduction to be demonstrated on a daily basis with an option for compliance using condensers to be demonstrated using a 365-day rolling average for the oil and natural gas production source category, and a 30-day rolling average for the natural gas transmission and storage source category (see section 2.10.2 of this document for further discussion on averaging periods).

Regarding the commenter's concern about condensers located at a high altitude, although differences in altitude do affect condenser performance, the EPA expects the effect to be minimal.

Comment: Commenter IV-D-01 requested that the EPA reevaluate the MACT floor for new sources and require new sources to control HAP emissions by 98%. According to the commenter, Louisiana has many facilities that achieve a 98% or greater control device efficiency by means of a condenser and closed vent system routing non-condensables to the glycol reboiler firebox.

Response: **Based on the available information (i.e., primarily section 114 questionnaire responses), 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. Furthermore, the EPA believes that requiring 98 percent emission reduction for sources in the oil and natural gas production and natural gas transmission and storage source categories would involve the destruction of nonrenewable resources and does not encourage pollution prevention.**

Comment: Commenter IV-D-25 emphasized that catalytic incineration is an effective control option. According to the commenter, minimum temperature and residence time requirements are lower for catalytic oxidation as compared with thermal oxidation, resulting in less expense required for fabrication. The commenter requested that §63.771(d)(1)(i) be modified to include: "(D) For catalytic incineration, operates at a minimum residence time of 0.03 to 0.05 second at a minimum temperature of 340°C." The commenter stated that these requirements would be adequate for more than 95 percent destruction of the HAP.

Response: **The EPA believes that the 0.5 second residence time and 760°C minimum temperature requirements for enclosed combustion devices are sufficient to ensure compliance with the 95-percent HAP emission reduction requirement.[19] The commenter**

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[19] U.S. Environmental Protection Agency. Hazardous Air Pollutant Emissions from Process Units in the Synthetic Organic Chemical Manufacturing Industry - Background Information for Proposed Standards. Volume 1B: Control Technologies. EPA (continued...)

did not provide any data to justify that a 0.03 to 0.05 second minimum residence time and 340°C minimum temperature would be adequate to achieve a 95-percent HAP emission reduction for all catalytic incinerators. Furthermore, the EPA does not have the available data to determine whether catalytic incinerators with these minimum specifications would meet the 95-percent emission reduction requirements. Therefore, the EPA has not modified subparts HH and HHH in response to this comment.

However, owners or operators may use a catalytic incinerator with the parameters specified by the commenter, provided the performance test or design analysis [prepared as specified in §§63.772(e) and 63.1282(d)] shows that the control device meets the required HAP emission reduction efficiency.

2.10.2 Averaging Period

Comment: Commenters IV-D-08 and IV-D-20 noted that §§63.771(d)(1)(i)(A) and 63.771(d)(1)(ii) do not state averaging periods for the 95 percent control efficiency determination. Several commenters were concerned with demonstrating compliance with the 95 percent control efficiency on a continuous basis. Commenter IV-D-12 stated that the proposal for a 15-minute averaging period is inappropriate and could not be consistently achieved due to swings in ambient conditions over which the source has no control. Commenters IV-D-04, IV-D-08, IV-D-12, IV-D-15, IV-G-05, and IV-G-09 requested that the EPA require calculation of control efficiency on a monthly or 30-day basis and commenters IV-D-20, IV-D-22, IV-D-23, IV-D-30, IV-D-34, IV-G-02, requested a 12-month rolling or annual basis for all TEG units subject to a 95 percent control requirement. Commenter IV-D-31 supported either a 30-day or a 12-month averaging period. Commenter IV-G-02 stated that a 12-month rolling average is more

[19](...continued)
Number EPA-453/D-92-016b., November 1992.

appropriate, considering the types of risks involved, still provides the EPA with enforceable numbers, and more appropriately reflects the frequency of the reporting periods required in the proposal. Commenter IV-G-03 stated that continuous compliance could be achieved in the winter months and recommended that continuous compliance determination be based on an annual average, using rolling monthly data. All of the commenters maintained that using a longer averaging period would create no significant change in the emissions to the environment, but would substantially decrease the number of technical violations of the standard, and reduce the administrative burden for the industry and the EPA. Commenter IV-D-04 explained that flow conditions in dehydrators fluctuate over time and a 15-minute compliance period would cause many units to be out of compliance that would be in compliance over a longer period. The commenter suggested that the shorter averaging time would make the control requirement more rigorous than the EPA may have intended. Moreover, commenters IV-D-20 and IV-D-22 stated that they believe longer averaging periods are consistent with the MACT floor.

Commenters IV-D-10, IV-D-20, IV-D-22, IV-D-30, IV-D-34, and IV-G-11 stated that the data collected under section 114 do not support a MACT floor determination of 95 percent on a continuous basis. According to the commenters, the section 114 questionnaire did not ask for the averaging period. Furthermore, commenters IV-D-20, IV-D-22, and IV-G-11 stated that respondents to the EPA's section 114 survey most likely did not provide estimated efficiency on a continuous basis because the data to make that evaluation were not available. According to the commenters, to provide an estimate of condenser efficiency, most respondents would have relied on vendor data or short duration tests and would not have considered seasonal or diurnal variations.

In support of a monthly or annual averaging period, commenters IV-D-07, IV-D-08, IV-D-10, IV-D-15, IV-D-20, IV-D-22, IV-D-23, IV-D-27, and IV-D-31 stated that condensers and flash tanks cannot achieve 95-percent HAP reduction continuously during the hotter months. The commenters referenced a report by GRI,[20] which illustrated that high ambient temperatures cause the control efficiency to drop below 95 percent. However, the report showed that condensers could meet 95-percent control using a longer averaging period. Commenters IV-D-20, IV-D-22, IV-D-31, and IV-G-11 noted that, in the report, three fourths of the TEG units controlled by condensers and flash tanks do not achieve a 95-percent reduction on an hourly basis. Commenters IV-D-27 and IV-D-31 recommended that the EPA review the GRI report and adjust the control efficiency and averaging time as appropriate.

Based on the GRI study[21], commenters IV-D-08, IV-D-10, IV-D-15, IV-D-20, IV-D-22, IV-D-34, and IV-G-11 were concerned that to achieve 95-percent control on a continuous basis, additional combustion controls would be necessary. Commenter IV-D-10 referred to the supplementary information in which the EPA mentions that flares and other combustion devices were not included in the MACT floor analysis because they do not recover hydrocarbons. The commenter agreed that an after condenser combustion device would waste nonrenewable resources for the sake of peaks in ambient temperatures. Commenter IV-G-11 also noted that many operators would install flares or incinerators rather than reroute vapors to the firebox (due to safety issues and State opacity regulations). Furthermore, commenters IV-D-10 and IV-D-15 were concerned that the combustion device would force operators to make tradeoffs among emissions of NO_X, VOC, and HAP. Commenter IV-D-10 stated that combustion devices increase emissions of NO_X and VOC with greater dispersion impacts for only 5 percent additional HAP control on warm days and that the MACT floor is not achievable with the technology envisioned.

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[20]GRI, "Investigation of Condenser Efficiency for HAP Control from Glycol Dehydrator Reboiler Vent Streams: Analysis of Data from the EPA 114 Questionnaire and GRI's Condenser Monitoring Program," Table 3-1 (March 1998).

[21]Reference 20.

Commenter IV-G-12 stated that they collaborated several years ago in an investigation of an evaporatively (water) cooled condenser at one of its facilities that showed the condenser could capture a significant portion (>90%) of the volatile fraction coming from the still vent of a dehydrator. According to the commenter, these condensers are easy to operate, provide significant control, and result in the recovery and conservation of a useful hydrocarbon stream. The commenter was concerned that the proposed rule's presumed short term requirement of 95-percent efficiency will preclude the use of devices of this type. The commenter stated that the makeup of the gas being processed determined the type of control that can be used. The commenter suggested that facilities that can use a condenser should be able to do so at a lower efficiency than required for flares operating on equipment where condensers are not viable.

Commenter IV-D-21 provided emission reduction data resulting from tests on dehydrators equipped with R-BTEX condensers. According to the commenter, the tests showed 96 to 98 percent VOC and HAP emission reductions, at ambient wet bulb temperatures ranging from 65 to 85°F. The commenter stated that while they are confident that these condensers could achieve a 95-percent control efficiency on an annual basis, they were concerned that brief periods of high ambient temperatures would result in lower control efficiencies. To account for the impact of ambient temperature, the commenter requested that the EPA establish an averaging time during which the average condenser outlet temperature must comply with the requirements proposed in §§63.773 and 63.1283.

Commenters IV-D-08 and IV-D-20 objected to the EPA's suggestion that continuous compliance with a standard is necessary to protect human health and the environment from emissions from this source category. Commenter IV-D-20 urged the EPA to retract this statement as unsupported and inconsistent with other regulatory programs. The commenter suggested that the industry is sensitive to unnecessary control costs, and urged the EPA to reconsider this requirement. Commenters IV-D-08 and

IV-D-20 stated that continuous monitoring as required in §63.773(d) is not necessary because a monthly average compliance demonstration does not increase emissions. Commenter IV-D-22 indicated that a rolling 12-month average compliance demonstration would not result in significant increases in annual emissions. Commenter IV-D-22 recommended that periodic monitoring be substituted at an interval appropriate to the condenser averaging period.

Commenter IV-G-07 stated that year-to-year variations in annual temperature histograms are small and that using an annual temperature histogram to calculate annual emissions is an excellent proxy for any year. Furthermore, the commenter maintained that there is not a good proxy for any day. The commenter stated that Congress's focusing on annual emissions in the Clean Air Act Amendments (CAAA) of 1990 set forth a good regulatory policy and asked why should this policy be changed.

Commenters IV-D-08, IV-D-10, IV-D-15, IV-D-20, IV-D-22, IV-D-34, IV-G-03, and IV-G-11 stated that for units with existing condensers that do not quite achieve 95-percent reduction, the incremental cost to remove a small increment of HAP emissions is cost prohibitive. Commenters IV-D-20 and IV-D-22 stated that the marginal cost to remove a small increment of HAP emissions to achieve 95-percent control on a continuous basis would exceed $ 20,000/ton of HAP removed. Commenters IV-D-34 and IV-G-11 estimated this cost to be $ 30,000/ton.

Response: **Based on the information available to the Agency, the EPA believes that the control devices required by the final rule achieve 95-percent HAP emission reduction on a daily basis. However, the EPA has reviewed the GRI reports regarding condenser performance[22] and has considered the commenters concerns regarding averaging periods for condensers. Based on this**

[22]Reference 20.

information, the Agency has included an option for owners and operators that install condensers.

Under the final subpart HH [§63.772(f)], an owner or operator of a glycol dehydration unit subject to the control requirements under final §63.765 must demonstrate compliance with the control device performance requirements on a daily basis. As an alternative, the owner or operator that uses condensers to comply with the requirements of §63.765 has the option of demonstrating compliance with the 95-percent HAP emission reduction on a 365-day rolling average [§63.772(g)]. An owner or operator with less than 120 days of condenser operating data is not required to calculate the average condenser efficiency until after the first 120 days of operation. If this average efficiency is equal to or greater than 90 percent, the owner or operator is in compliance. Owners or operators with 120 days or more, but less than 365 days of condenser operating data, must calculate the average condenser efficiency over the number of days of operation between the current day and the applicable compliance date [specified in §63.760(f)]. The owner or operator is considered to be in compliance with the performance requirements if this average condenser efficiency is equal to or greater than 90 percent. Once the owner or operator has 365 days of condenser operating data, the owner or operator must comply with the 95 percent HAP emission reduction requirement on a 365-day rolling average.

For glycol dehydration units in the natural gas transmission and storage source category, the EPA believes that an averaging period shorter than 365 days is appropriate. To the Agency's knowledge, glycol dehydration units located at storage facilities do not typically operate throughout the year. Additionally, glycol dehydration units located at these sources do not typically operate during the warm summer months when condenser efficiency is lower. The data for the GRI report was based on the operation of production facilities. Although transmission facilities do operate for most of the year, the EPA believes that the HAP emission units in operation at these facilities are primarily compressors and that most glycol dehydration units located at transmission facilities are used for withdrawing natural gas from storage (i.e., are not likely to operate year-round). Therefore, the final subpart HHH specifies that owners or operators that install condensers have the option of complying with the 95-percent HAP emission reduction on a 30-day rolling average [§63.1282(f)]. However, §63.1282(f)(2)(iii)(D) of final subpart HHH provides the owner or operator with the option of complying with the 365-day rolling average procedure specified in §63.772(g) for glycol dehydration units in the natural gas transmission and storage source category that are operated continually.

2.10.3 Process Vent Standards

Comment: Commenter IV-D-08 stated that §63.771(d) should be modified to provide credit for total reductions and cumulative efficiency rather than requiring "control upon control" efficiency. The commenter recommended changes to §63.771(d)(1)(i), (ii), and (iii) to allow cumulative reductions for control devices in series:

> Reduce or contribute to the reduction of the mass content of either Total Organic Compound (TOC) or total HAP by 95 percent, from the point that gases are vented to the first control device until the point that gases are vented to the atmosphere.

Commenter IV-D-06 requested that subpart HHH expressly allow combinations of control devices as a way to achieve the emissions standards. According to the commenter, it may take two or more control devices to achieve the emission limit. For example, some units are controlled by devices that may come close to, but do not meet the requirements. The commenter stated that it is sometimes quicker, easier, and less expensive to add a supplemental device than to remove an existing device and install another. The commenter suggested using HON §§63.113(a)(2)(i), (ii), and (ii)(A), (B), (C), and (D) to address combinations of control and/or recovery devices. The commenter stated that if subpart HH does not expressly allow combinations of control devices, this comment applies to subpart HH.

Response: **The EPA agrees that owners or operators should be able to comply with the requirements of §§63.765 and 63.1275 using combinations of control devices. Therefore, the EPA has modified subparts HH and HHH to allow an owner or operator to connect glycol dehydration unit process vents to a control device or a combination of control devices [§§63.765(b)(1) and 63.1275(b)(1)]. In addition, the EPA has modified §63.772(e)(3) of final subpart HH and §63.1282(d)(3) of final subpart HHH to require the sampling sites to be located at the inlet of the first control device and at the outlet of the final control device.**

Comment: Commenters IV-D-06, IV-D-07, IV-D-08, IV-D-20, IV-D-22, and IV-D-30 requested that the EPA allow any combinations of controls and process modifications to achieve the required control efficiency. Commenters IV-D-08, IV-D-20, IV-D-22, and IV-D-30 recommended that the EPA modify §63.765(c)(2) to add language specifically stating that process modifications and controls are allowed.

In addition, commenter IV-D-30 suggested that the EPA specify in §63.765(c) that the owner or operator may elect to complete a compliance demonstration once for the required process modifications. According to the commenter, no more demonstration should be necessary if the owner or operator made only process modifications (i.e., without emissions controls) to attain the control efficiency and there are no further process modifications.

<u>Response:</u> Proposed subparts HH and HHH contained provisions allowing the owner or operator to demonstrate a 95 percent HAP emission reduction using process modifications. The EPA did not intend to preclude owners or operators from using combinations of process modifications and control devices. Therefore, to clarify that owners or operators have the option of using combinations of process modifications and control devices, §§63.765(c)(2) and 63.1275(c)(2) of the final rules are as follows:

> **(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 process vent are reduced by 95.0 percent through process modifications, or a combination of process modifications and one or more control devices, in accordance with the requirements specified in §63.771(e) [for subpart HH and §63.1281(e) for subpart HHH].**

The EPA does not agree with commenter IV-D-30's recommendation to allow a one-time compliance demonstration. The EPA does not believe that a one-time compliance demonstration would ensure future or continuous compliance. Therefore, the EPA has not included the commenter's suggested language. Instead, the final rules contain provisions that require owners or operators to: (1) establish and document glycol dehydration unit baseline operations; (2) document the conditions for which the glycol dehydration unit baseline operations will be modified to achieve a 95 percent overall HAP emission reduction using process modifications or a combination of process modifications and one or more control device; (3) maintain records demonstrating that the facility operates under the conditions of the process

modification; and (4) if a control device is used in combination with the process modifications, demonstrate that the control device achieves the emission reduction required for an overall emission reduction of 95 percent [§§63.771(e) and 63.1281(e)]. Only modifications in glycol dehydration unit operations directly related to process changes (such as glycol recirculation rate or glycol-HAP absorbency] are allowed. Changes in gas inlet characteristics or natural gas throughput rate are not allowed to be used as process modifications.

Comment: Commenter IV-D-05 stated that the requirement in §63.765(c) to reduce emissions from the reboiler vent and flash tank by 95 percent was ambiguous because the flash tank should not be vented. According to the commenter, all of the offgas from the flash tank should be recovered, and that GLYCalc assumes this. The commenter suggested that §63.765(c) should be clarified to state that ". . . HAP from a glycol process should be reduced to 95 percent as compared with HAP without any process modifications." The commenter noted that the term "process modifications" would have to be defined, and the EPA would have to address whether a flash tank is a process modification.

Commenter IV-D-05 also recommended that the definition of *GCG separator* in subpart HH should state that all off-gas must be recovered. The commenter also stated that the gas-condensate-glycol (GCG) separator should not be called a tank since it is a pressurized vessel.

Response: Although the GCG separator is a pressurized vessel the industry commonly refers to it as a flash tank. For example, the GCG separator is labeled as a flash tank in the TEG dehydration flowsheet presented in GLYCalc. Therefore, the EPA has not modified the definition of GCG separator in subparts HH and HHH.

The EPA does not agree with the commenter's statement that all off-gas must be recovered and that GLYCalc assumes that all off-gas is recovered. According to the GLYCalc Dehydration Handbook, contained electronically within the GLYCalc program, the flash gas from the GCG separator can be used as a supplemental fuel gas or as stripping gas in the reboiler, but may be vented to the atmosphere at some locations. In addition, the emission calculation in GLYCalc plainly separates flash gas emissions from the GCG separator from the reboiler vent emissions.

Although the EPA has not modified the definition of *GCG separator* in response to this comment, the EPA believes that the requirements in §§63.765(c)(3) and 63.1275(c)(3) need to be clarified. As proposed, §§63.765(c)(3) and 63.1275(c)(3) stated that control of HAP emissions from the flash tank ". . . 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) are reduced by 95 percent." These requirements were intended to provide owners and operators the flexibility to install a control device to control emissions from the reboiler vent such that the emission reduction from the glycol dehydration unit process vent (which is defined in §§63.761 and 63.1271 to include the flash tank and the reboiler vent) is equivalent to 95 percent. Thus, the owner or operator would not be required to install separate control devices for the reboiler and flash tank vents. Therefore, the EPA has modified §§63.765(c)(3) and 63.1275(c)(3) to clarify this intent as follows:

(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~~ process vent ~~and GCG separator (flash tank) vent~~ are reduced by ~~95 percent~~ one of the levels specified in paragraphs (c)(3)(i) through (c)(3)(ii) of this section, through controls as specified in paragraph (b)(1) of this section.

(i) HAP emissions are reduced by 95.0 percent or more.

(ii) Benzene emissions are reduced to a level less than 0.90 megagrams per year.

Comment: Commenter IV-G-07 suggested an alternative MACT rule based on air-cooled condensers:

1. Stream exiting an air-cooled glycol dehydrator vent condenser shall be in vapor/liquid equilibrium at or below a temperature of 70°F or within ten Fahrenheit degrees of the then current air temperature, averaged over any 24-hour period.

2. Air emissions shall be less than: 5 tons/yr of benzene, 15 tons per year of HAP, and 50 tons per year of VOC.

3. A rich glycol flash tank must be used in any glycol dehydration system, where its use will cause that system's vent condenser to condense and recover more than an additional 10 tons per year of VOC.

The commenter claimed that the proposed alternative: would eliminate safety hazards associated with forcing operators to burn some vent streams; is technically sound and cost effective; and is good public policy by encouraging hydrocarbon recovery. The commenter claimed that the health risk concerns due to higher emissions on hot days from air cooled condensers are not really the problem, since in reality, hot daytime atmospheres are unstable resulting in vent emissions becoming well mixed. According to the commenter, cool, still nights are a higher potential exposure risk, which is small in any event.

Response: Section 112 of the Act requires the EPA to establish standards no less stringent than the MACT floor. As

stated in the previous response, the EPA determined that a control efficiency of 95 percent represented the MACT floor. The EPA does not believe that the commenter's suggestions represent the MACT floor.

Comment: Commenter IV-D-07 interpreted §§63.765(c)(2) and (3) and §§63.1275 (c)(2) and (3) to mean that emissions from both the reboiler vent and flash tank vent can be used in determining the emission reduction. The commenter supported this option.

Response: The commenter has correctly interpreted the requirements specified in §§63.765(c)(3) and 63.1275(c)(3).

Comment: Commenter IV-D-07 stated that the EPA should consider the fact that still vent and flash gas streams can be laden with water and their use as a fuel source may not be possible. The commenter suggested that burning these streams would not be possible for smaller or unmanned facilities since additional natural gas may need to be added to the stream before flaring. Additionally, according to the commenter, the stream composition may be inconsistent, and its use as a fuel or in a flare may need to be closely monitored.

Response: Combustion of still vent and flash gas streams is not required by subparts HH and HHH. It is up to the owner or operator to decide whether combustion is a viable alternative for control. In the final subparts HH and HHH, an owner or operator has the option of complying with: (1) a HAP emission reduction of 95 percent or more; (2) an outlet HAP concentration of 20 ppmv or less (for combustion devices) or (3) a benzene emission limit of 1 tpy. Therefore, the owner or operator should decide which control device to use to comply with the required reductions depending on individual stream characteristics.

2.10.4 Equipment Leak Standards

Comment: Commenter IV-D-05 requested that §63.769(a) be clarified if the EPA intends to include ancillary equipment at production facilities, and suggested the following wording: "This section applies to: (1) ancillary equipment at natural gas processing plants, and to (2) compressors (as defined in 63.761) at natural gas processing plants that . . . " The commenter also requested that the EPA justify the fact that this program does not afford the same leniency as subpart KKK for plants that process less than 10 MMscf/d regarding routine monitoring.

Response: The commenter is incorrect in stating that subpart HH does not afford the same leniency as subpart KKK for plants that process less than 10 MMscf/d. On the contrary, §63.769(c)(5) exempts equipment located at nonfractionating plants with the capacity to process 10 MMscf/d from routine monitoring requirements, and is consistent with §60.633(d) of subpart KKK. The metric capacity that is equivalent to 10 MMscf/d should be 283,000 standard cubic meters per day (m^3/day), rather than the proposed 283 m^3/day. This has been corrected in the final rule.

With regard to the commenter's first request, the EPA has made the following change to clarify applicability to §63.769(a):

> **(a) This section applies to <u>equipment subject to this subpart located at natural gas processing plants and specified in paragraphs (a)(1) and (a)(2) of this section,</u> ~~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~~<u>VHAP</u> concentration equal to or greater than 10 percent by weight (determined according to the ~~provisions of 40 CFR 61.245(d)~~ <u>procedures specified in §63.772(a)</u>) and that operates <u>in VHAP service</u> equal to or greater than 300 hours per calendar year.**
>
> **<u>(1) Ancillary equipment, as defined in §63.761; and</u>**
>
> **<u>(2) Compressors.</u>**

<u>Comment:</u> Commenter IV-D-06 recommended that the EPA revise §63.769(a) to apply only to equipment operating in <u>VOHAP</u> service for 300 hours or more per year. According to the commenter, if

the equipment is in operation more than 300 hours per year, but is in VOHAP service for only a small part of the time, there would be no need for standards to apply.

Response: **The EPA agrees with the commenter, and has modified §63.769(a) in response to this comment to clarify that equipment operating in VHAP service for more than 300 hours per year is subject to the rule.**

Comment: Commenter IV-D-16 stated that it is confusing to point to 40 CFR part 61, subpart V, which is unfamiliar to gas plant operators, when subpart V is almost the same as 40 CFR part 60, subpart KKK. The commenter recommended that subpart HH point to subpart KKK, since the regulated community and compliance inspectors are familiar with it and will understand it better. The commenter also noted that the MACT floor is subpart KKK.

Response: **The EPA determined that the MACT floor for equipment leaks is subpart KKK and the NSPS level of control in subpart KKK is equal to that of 40 CFR part 61, subpart V. However, subpart KKK is a standard that controls VOC and subpart V controls HAP. Since the pollutants targeted for control under subpart HH are HAP, cross-referencing the requirements from the equipment leaks NESHAP (40 CFR part 61, subpart V) is appropriate.**

Comment: Commenters IV-D-20 and IV-D-22 recommended that it would be less burdensome and would avoid redundancy if provisions were added, for facilities that are subject to other federal, State, and local LDAR programs, to allow control of equipment leaks under similar programs. Commenter IV-D-20 urged the EPA to allow for a process of equivalency and/or stringency demonstration for these other requirements. The commenter also urged the EPA to clarify that facilities have the option of complying with only one rule that will subsume all other LDAR requirements. Furthermore, the commenter requested that §63.769 be expanded to allow for other equivalent, or more stringent

State, and local LDAR programs/rules to be used instead of subpart HH requirements, provided the governing rule is specifically included in the facility's title V permit. Commenter IV-D-22 endorsed the proposed provisions intended to prevent duplication of effort and requirements for facilities subject to LDAR requirements in part 63, subpart H, or subpart KKK NSPS.

Response: The EPA believes that facilities subject to other federal, State and local regulatory programs should be allowed to comply with the requirements those programs, if they are at least as stringent, or equivalent to subparts HH and HHH. Sections 63.777 and 63.1287 already contain provisions for alternative emission limitations that must be at least as equivalent as subpart HH or HHH as appropriate.

2.10.5 Control Device Requirements

Comment: Commenters IV-D-06, IV-G-02 and IV-G-12 stated that §§63.771(d)(5) and 63.1281(d)(5) should only require that spent carbon be managed as a hazardous waste if it is, in fact, a hazardous waste. According to the commenters, it is not a listed waste, so unless it displays a hazardous characteristic, it should not have to be managed as a hazardous waste. Commenter IV-D-06 recommended that the EPA should allow the option of managing the carbon in a combustion device regulated under any subpart of part 60, 61, or 63. The commenter stated that this comment may also apply to subpart HH. Further, regarding acceptable treatment methods, commenters IV-G-02 and IV-G-12 recommended the words "for which the owner or operator" be changed to "whose owner or operator" to make clear that it is the treatment facility, and not the generator, who must obtain the proper RCRA permits or interim status.

Response: The EPA agrees with the commenters and has replaced proposed §§63.771(d)(5) and 63.1281(d)(5) with the following:

(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:~~The spent carbon removed from the carbon adsorption system shall be either regenerated, reactivated, or burned in one of the units specified in paragraphs (d)(5)(ii)(A) through (d)(5)(ii)(G) of this section.

(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~~ that implements the requirements of 40 CFR 264, subpart X~~; or certified compliance with the interim status requirements of 40 CFR 265, subpart P~~.

(B) Regenerated or reactivated in a thermal treatment unit equipped with and operating air emission controls in accordance with this section.

(C) Regenerated or reactivated in a thermal treatment unit equipped with and operating organic air emission controls in accordance with a national emissions standard for hazardous air pollutants under another subpart in 40 CFR part 61 or 40 CFR part 63.

(D) 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~~ that implements the requirements of 40 CFR 264, subpart O.

(E) Burned in a hazardous waste incinerator which the owner or operator has designed and operates in accordance with the requirements of 40 CFR part 265, subpart O.

~~(C)~~(F) 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~~ that implements the requirements of 40 CFR part 266, subpart H.

<u>(G) Burned in a boiler or industrial furnace which the owner or operator has designed and operates in accordance</u>~~, or has certified compliance~~ with the interim status requirements of 40 CFR part 266, subpart H.

2.10.6 <u>Storage Vessel Standards</u>

<u>Comment:</u> Commenter IV-D-16 stated that external floating roofs complying with subpart Kb need to be addressed in the storage vessel standard, if they are allowed. Commenter IV-D-22 stated that the proposed definition of *cover* in §63.761 includes an external floating roof as an example; however, storage vessel standards in §63.766 do not list external floating roofs as an allowed control option. In fact, the commenter noted that §63.766(b)(1) suggests that an external floating roof would need to be connected through a closed-vent system to a *control* device. The commenter stated that they do not believe the EPA intended this result, because other existing standards, such as the subpart Kb New Source Performance Standards (NSPS) (40 CFR Section 60.110b), allow the external floating roof alone. The commenter also stated that they do not endorse the detailed control requirements in subpart Kb (for external or internal floating roofs) for exploration and production (E&P) storage tanks. In particular, the provisions in subpart Kb for the many vents, fittings, lids, and other equipment on both internal and external floating roofs are inappropriate for oil exploration and production tanks. According to the commenter, it is not appropriate to implement controls on E&P tanks that are more stringent than the controls for tanks in a refinery and it is not supported by the MACT floor for production tanks. Additionally, the commenter noted that subpart Kb does not apply to the small vessels typically located at production facilities.

<u>Response:</u> The EPA did not intend to limit the types of covers allowed to only those listed as examples in the definition of *cover* in §63.761. Therefore, the EPA has added language to the definition of *cover* in §63.761 as follows: "...Examples of a

cover include, but are not limited to, 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."

The EPA's data, collected from section 114 questionnaires and site visits indicated that the control technology in use to control existing storage vessels did not include internal or external floating roofs. Therefore, the EPA has removed the requirements for internal floating roofs contained in proposed §63.766(b)(3). However, in order to allow owners or operators the option of complying with the requirements specified in 40 CFR part 60, subpart Kb, 40 CFR part 63, subpart G, or 40 CFR part 63, subpart CC the EPA has added the following paragraph to §63.766:

> (d) This section does not apply to storage vessels for which the owner or operator is meeting the requirements specified in 40 CFR part 60, subpart Kb; or is meeting the requirements specified in 40 CFR part 63, subparts G or CC.

2.11 MONITORING, RECORDKEEPING, AND REPORTING

Comment: Commenters IV-D-08, IV-D-22, and IV-D-34 requested that the EPA allow oversized control devices to be exempt from monitoring, inspection, recordkeeping and reporting requirements other than the initial design analysis. The commenters stated that oversized devices will essentially always meet the regulatory requirements. According to the commenters, if a design analysis shows that the device is oversized so that compliance with the control efficiency requirement will be met even during worst case conditions, the exemption should be allowed. The commenters explained that an exemption would allow the owner or operator to spend more on the device and less on monitoring, inspection, recordkeeping, and reporting over the life of the facility. The commenters further stated that is it not cost-effective to continue monitoring, inspection, recordkeeping, and reporting for a device that will always meet regulatory requirements.

Response: Monitoring, inspection, recordkeeping and reporting requirements ensure continuous compliance with the standards. Over-designing a control device would not ensure proper operation and compliance with the standards. Therefore, the EPA has not modified subparts HH and HHH in response to these comments.

Comment: Commenters IV-D-20 and IV-D-22 urged the EPA to reevaluate how the monitoring, recordkeeping, and reporting requirements can be made clear, nonoverlapping, and implementable in the field. According to the commenters, the "cut and paste" approach apparently used by the EPA to develop the monitoring, recordkeeping, and reporting requirements leads to a burdensome set of confusing, and sometimes unnecessary, requirements. Commenter IV-D-22 stated that they believe the proposed monitoring, recordkeeping, and reporting requirements impose a significant burden on E&P facilities that cannot be justified based on any current monitoring, recordkeeping, and reporting for oil or gas facilities.

Commenter IV-D-09 noted that §§63.10(b)(2) and 63.10(c) require 24 separate record entries for each dehydration unit and control device, as well as up to seven separate reports. The commenter stated that many of these reports are superfluous. As an example, the commenter suggested consolidating all information required to ensure the operational status of the monitoring system into one combined maintenance and operational log. The commenter also requested that the EPA work with operators to explore ways to incorporate the information required for compliance demonstrations into existing recordkeeping and reporting practices realistically.

<u>Response:</u> The EPA recognizes that unnecessary monitoring, recordkeeping, and reporting requirements would burden both the source and enforcement agencies. Prior to proposal, the EPA attempted to reduce the amount of monitoring, recordkeeping, and reporting to only that which is necessary to demonstrate compliance.

In response to the commenters' concerns, the EPA reevaluated whether monitoring, recordkeeping, and reporting requirements could be further reduced while maintaining the enforceability of the rule. Therefore, the EPA has made the following changes in the final rules (subparts HH and HHH) to further reduce the monitoring, recordkeeping, and reporting burden.

(1) Almost all reports have been consolidated into the Notification of Compliance Status Report and the Periodic Reports.

(2) If multiple tests are conducted for the same kind of emission point, using the same test method, only one complete test report is submitted along with the summaries of the results of other tests.

(3) Site-specific test plans describing quality assurance in §63.7(c) of 40 CFR part 63, subpart A are not specifically required in the individual subparts because the test methods

cited in subparts HH and HHH already contain applicable quality assurance protocols. It should be noted that the Administrator would still have the authority to request a test plan.

(4) Periodic reports are required to be submitted semiannually for all facilities (the proposal required quarterly reports if monitored parameters were out of range more than a specified percentage of time).

(4) A reduction in the record retention requirements for monitored parameters. The proposal required values of monitored parameters to be recorded every 15 minutes and all 15-minute records had to be retained. The final rule requires monitored parameters to be recorded every hour and all hourly records to be retained.

Comment: Commenter IV-D-38 suggested that §63.764(c) be modified as follows so that affected sources that are not at major HAP sources do not have to meet stringent control, monitoring, and recordkeeping requirements:

> (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 HAP source shall comply with the standards in this subpart as specified in paragraphs (c)(1) through (c)(3) of this section.

Response: A *major source* is defined in §63.2 as "any stationary source" that "emits, or has the potential to emit, . . . any hazardous air pollutant." Although the EPA believes that specifying that affected sources are located at existing or new major HAP sources would be redundant, the EPA has made the suggested modification.

2.11.1 Monitoring Requirements

Comment: Commenter IV-D-01 questioned the basis for the 10,000 ppm leak definition in §63.769(c)(2) and requested that the 10,000 ppm leak definition for pressure relief devices in gas/vapor service be changed to 500 ppm. The commenter stated that the pressure relief devices in gas/vapor service should have a leak definition of 500 ppm above background in accordance with 40 CFR 61.242-4(a).

Commenter IV-D-01 also requested that the EPA delete the provision for which pressure relief devices, in a nonfractionating facility monitored only by non-facility personnel, may be monitored after a pressure release the next time the monitoring personnel are on-site, instead of within five days (not to exceed 30 days following a pressure release without monitoring). The commenter stated that the owner or operator could make provisions for either company personnel or contract personnel to perform the monitoring. The commenter also stated that pressure release devices should be monitored no later than five calendar days after each pressure release in accordance with 40 CFR 61.242-4(b)(2).

<u>Response:</u> Currently, the oil and natural gas production industry is regulated by the NSPS for equipment leaks of VOC from onshore natural gas processing plants (40 CFR part 60, subpart KKK). The EPA determined that the MACT floor for equipment leaks at natural gas processing plants was the NSPS level of control. Subpart KKK requires owners and operators to monitor pressure relief devices quarterly and within five days after each pressure release to detect leaks [§63.633(b)(3)], with a leak defined as an instrument reading of 10,000 ppm or greater [§60.633(b)(2)]. Section 61.242-4(a) requires pressure relief devices to be operated with no detectable emissions, which is more stringent than subpart KKK. Since the MACT floor was determined to be equivalent to the level of control specified in subpart HHH, the EPA has not changed the leak definition for pressure relief devices, as requested by the commenter.

The requirement allowing the owner and operator of a nonfractionating facility, which are monitored only by non-facility personnel, to monitor after a pressure release the next time the monitoring personnel are on-site is consistent with 40 CFR part 60, subpart KKK [§63.633(b)(4)]. Since the MACT floor was determined to be the level of control required by

subpart KKK, the EPA has not made the change suggested by the commenter.

Comment: Commenter IV-D-22 recommended that the EPA allow for a deviation from a 2 percent leak rate during startup, shutdown, or malfunction, per the facility startup, shutdown and malfunction plan, as specified in §63.10(d)(5), without forgoing the option for skip monitoring. Although subpart HH does not mention skip monitoring directly, the commenter stated that they believe it is invoked through the reference to the leak detection and repair (LDAR) work practice standard in 40 CFR part 60, subpart VV. [Note: The commenter's citation is incorrect. Subpart HH refers to 40 CFR part 61, subpart V.]

Response: The purpose of the startup, shutdown, and malfunction (SSM) plan is to ensure that owners and operators operate and maintain affected sources with good air pollution control practices at all times. The SSM plan also ensures that owners or operators are prepared to correct malfunctions quickly, to minimize excess HAP emissions. The EPA believes that monitoring is warranted during SSM, however, the EPA has modified §63.774(b)(3) to state that the leaks that occur during SSM events do not count toward the percent leak rate, provided the SSM plan is followed.

Comment: Several commenters were concerned with the provisions specifying the accuracy of the measurement devices used to comply with the subpart. Commenter IV-D-06 recommended that the EPA allow measurement devices with better accuracy than what subpart HHH requires. The commenter contended that the way subpart HHH was written, using devices with better accuracy than the rule specifies is forbidden. The commenter suggested that the EPA revise the following sections and paragraphs to allow more accurate measuring devices. The commenter noted that there may also be other paragraphs (in particular, they did not look closely at the compliance demonstration requirements) and if so, the EPA should revise them similarly to the examples shown below.

Section 63.1271:

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

Section 63.1282(a)(1)(i):

> (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 better.

Section 63.1283(d)(3)(i)(A), (B), (D), (E), and (F):

> (A) For a thermal vapor incinerator, a temperature monitoring device equipped with a continuous recorder. The monitoring device shall have an minimum 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 minimum 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.
>
> (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 minimum 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 minimum 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 minimum 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 minimum 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 the regeneration and within 15 minutes of completing the cooling cycle, and over the duration of the carbon bed steaming cycle.

The commenter stated that this comment also applies to subpart HH.

Response: The EPA agrees with the commenter's recommendation to modify the monitoring device accuracy specifications to state that the accuracy requirements are the minimum necessary to demonstrate compliance and has modified the subparts HH and HHH as suggested.

Comment: Commenters IV-D-08 and IV-D-22 requested that the EPA require flow instrumentation with an accuracy of ±2 percent only when the measured values are within 98 percent of the exemption or compliance targets. The commenters stated that while this level of accuracy is available, proving compliance for streams that do not have flows close to the exemption or compliance levels is not necessary. Commenter IV-D-22 stated that throughout §63.773, subpart HH refers to temperature monitoring devices with an accuracy of ± 1 percent of the temperature being monitored in °C, or ±0.5 °C, whichever value is greater. The commenter, along with commenter IV-D-08, stated that they do not believe that the MACT floor for this source category supports the accuracy of 2 percent for measuring flow and 1 percent for measuring temperature, or that they have demonstrated continuous compliance with applicable standards.

Commenter IV-G-12 also stated that the ± 0.5 °C measurement is practically useless for many analog temperature recorders. Commenter IV-D-22 stated that requiring a unit to demonstrate compliance with a temperature requirement is unnecessary and unduly restrictive unless the operator chooses to select a temperature set point within 1 percent of the requirement. The commenter recommended, and commenter IV-D-34 supported, that subpart HH be modified to eliminate specified accuracies for flow and temperature measurement devices and to allow whatever accuracy is necessary to demonstrate compliance with the temperature or flow target.

Response: The average emission limitation achieved by the top 12 percent of the facilities (for source categories with more than 30 facilities) has to be considered for the MACT floor for existing sources. The EPA believes that accuracy requirements are necessary to demonstrate ongoing compliance. The EPA also believes setting site-specific accuracy requirements would be unduly burdensome for the permitting agencies. In addition, a minimum accuracy provides an advantage for the owner or operator because they would not be required to use the same monitor forever. Furthermore, if the accuracy requirements were removed, additional recordkeeping and reporting requirements would be necessary to ensure that less accurate monitors were not installed after the performance tests. However, to provide additional flexibility in selecting monitoring devices, the EPA has changed the accuracy levels from $\pm$ 1 percent of the temperature being monitored, in °C or $\pm$ 0.5 °C, to $\pm$ 2 percent of the temperature being monitored, in °C or $\pm$ 2.5 °C, whichever is greater.

Comment: Commenters IV-D-22 and IV-D-34 recommended that a provision be added to allow design analysis or engineering calculations in place of monitoring if they can demonstrate that limits will not be exceeded.

__Response:__ **Allowing design or engineering calculations would show theoretical compliance, but would not demonstrate continuous compliance with the emission standard. The EPA believes that the monitoring requirements in subparts HH and HHH are the minimum necessary to ensure compliance with the standards. Therefore, the EPA has not added the provisions recommended by the commenters.**

__Comment:__ Commenter IV-D-06 recommended that the EPA clarify the bypass monitoring requirements. The commenter stated that §63.1281(c)(3)(i)(A) says flow indicators must indicate "whether gas, vapor, or fume flow is present" at least once every 15 minutes. The commenter suggested that the wording seems to require a direct indication of "flow." The commenter requested that the definition of "flow indicator" be revised to allow valve position indicators. The commenter stated that valve position indicators will not give a reading of whether flow is present, but they will give a reading of whether a diversion has occurred. In addition, the commenter noted that §63.1281(c)(3)(i)(B) says that car-seals are intended to show that valves are in the "closed" position. The commenter provided an example of a three-way valve that is commonly used in bypass situations. According to the commenter, three-way valves have two "open" positions and one "closed" position. In those cases, the valve should be car-sealed in the open position that goes to the control device. The commenter felt that the literal wording of subpart HHH does not allow that option. The commenter interpreted the wording to read that the "closed" position is required. The commenter suggested the following changes to §63.1281(c)(3)(i)(A) and (B).

> (A) Install, calibrate, maintain, and operate a flow indicator at the inlet to the bypass device that ~~indicates~~ __takes a reading__ 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~~ non-diverting 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~~ non-diverting position.

The commenter stated that this comment also applies to subpart HH.

Response: **The EPA believes that clarifications to the bypass requirements are necessary to allow valve position indicators, and to require that a car-seal be used to secure a valve installed at the inlet to the bypass device in the non-diverting position. The EPA has modified §§63.771(c)(3)(i) and 63.1281(c)(3)(i) as follows:**

> **(A) Properly install, calibrate, maintain, and operate a flow indicator at the inlet to the bypass device that could divert the stream away from the control device to the atmosphere that ~~indicates~~ takes a reading at least once every 15 minutes and sounds an alarm when the bypass device is open such that the stream is being, or could be, diverted away from the control device to the atmosphere~~whether gas, vapor, or fume flow is present in the bypass device~~; or**
>
> **(B) Secure the bypass device valve installed at the inlet to the bypass device in the ~~closed~~ non-diverting 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~~ non-diverting position and the vent stream is not diverted through the bypass device.**

In addition, the final rules contain a definition of *flow indicator* in §§63.761 and 63.1271.

The EPA has also added recordkeeping and reporting requirements for the bypass line requirements. The final rules

contain recordkeeping requirements [§§63.774(b)(4)(iii) and (iv) and 63.1284(b)(4)(iii) and (iv)], which require an owner or operator to maintain records of whether the flow indicator was operating and whether flow was detected at any time during the hour, as well as records of the times and durations of all periods when the vent stream is diverted from the control device or the monitor is not operating. When a seal or closure mechanism is used, hourly records of flow are not required. In such cases, the owner or operator is required to record that the monthly visual inspection of the seals or closure mechanism has been done, and shall record the duration of all periods when the seal mechanism is broken, the bypass line valve position has changed, or the key for a lock-and-key type lock has been checked out, and records of any car-seal that has broken.

The final rule also requires owners or operators to include, in the periodic reports, all periods when the vent stream is diverted from the control device through a bypass line. When a seal or closure mechanism is used, the periodic report must contain all periods in which the seal mechanism was broken, the bypass valve position was changed, or the key to unlock the bypass line valve was checked out.

In addition, periods where the vent stream has been diverted through the bypass line, as indicated by the flow indicator or the closure mechanism or seal, are defined as excursions except when they occur during startup, shutdown, or malfunction events or periods of nonoperation.

Comment: Commenter IV-D-06 requested that the EPA revise Table 2 to say that §63.8(e) does not apply to subpart HHH. The commenter stated that subpart HHH does not require a performance evaluation at a specific time on a continuous monitoring system.

Therefore, according to the commenter, if §63.8(e) applies, nothing is required. The commenter further stated that various other MACT standards have not required performance evaluations on continuous monitoring systems. The commenter suggested that imposing the burden of these performance evaluations is unnecessary. The commenter stated that if subpart HH also incorporates §63.8(e), then this comment also applies to subpart HH.

<u>Response:</u> Although performance evaluations on continuous monitoring systems are not specifically required under subparts HH and HHH, the Administrator retains the authority to request such evaluations. Therefore, the EPA has modified table 2 of subparts HH and HHH to state that the applicable subpart does not specifically require continuous monitoring system performance evaluations but that the Administrator can request the owner or operator to conduct performance evaluations.

<u>Comment:</u> Commenter IV-D-31 requested that if the intent of the monitoring protocol is to ensure that the equipment is operating correctly, then subpart HHH should state that intent. The commenter also requested that the EPA consider the complexity of the control equipment when designing a monitoring period. The commenter suggested that the frequency of monitoring be based on the probability of a device failing to function. The commenter suggested that simple condenser systems cannot vary widely in performance over short periods and have a minimum probability of failure, meaning that recording information at frequent intervals is inefficient and wasteful.

<u>Response:</u> The intent of the monitoring protocol is to ensure compliance with the standards. Based on the comments received on the proposed rules, the EPA reevaluated the monitoring requirements contained in subparts HH and HHH. As stated in section 2.10.2 of this document, the final rule specifies that control devices must determine compliance using

the daily average of the monitored parameters. Owners and operators that install condensers have the option of using a 365-day average under final subpart HH and a 30-day average under final subpart HHH. To reduce the number of data points required to be used in these average calculations, the EPA has modified the monitoring requirements for control devices. The final rule requires continuous monitoring systems to measure data values at least once every hour and record either each measured data value, or each block average for each 1-hour period or shorter periods calculated from all measured data values during each period.

Comment: Commenter IV-D-06 stated that components exempt from instrumental leak detection monitoring in §63.1283(c)(3) (such as components under a vacuum) should also be exempt from the initial monitoring. The commenter stated that this comment may also apply to subpart HH. Commenter IV-D-22 suggested that the type of "no detectable emissions" monitoring required in §§63.771(c)(2) and 63.773(c)(1)(ii) cannot be justified by a MACT floor analysis.

Response: The EPA believes that initial monitoring is necessary to show that the closed-vent system is has been designed to operate with no detectable emissions. However, the EPA believes that once closed-vent system components that are permanently or semi-permanently sealed (e.g., welded joints) have been shown to operate with no detectable emissions, future monitoring is not necessary, unless components are repaired, replaced or unsealed. Therefore, the final rule requires annual visual inspections for these components to detect defects that could result in air emissions. However, the final rule requires closed-vent system components that are not permanently or semi-permanently sealed to be monitored annually to demonstrate

that they are operated with no detectable emissions, in addition to the initial inspection and the annual visual inspections.

Comment: Commenter IV-D-07 supported the EPA's statement that "[t]he CMS that uses gas chromatography to measure individual organic HAP compound chemicals is not practical for applications where multiple organic HAP chemicals are to be monitored . . ." According to the commenter, monitoring of control devices should be flexible to allow for impracticalities in using CMS. Furthermore, the commenter supported the monitoring of control device operating parameters' performance for compliance demonstrations.

Response: The EPA appreciates the commenter's support. As stated in the preamble to the proposed rules (63 FR 6307), the EPA rejected the use of continuous emission monitoring systems (CEMS) for two reasons: (1) CEMS that use gas chromatography to measure individual gaseous organic HAP are not practical for use when multiple HAP are monitored, and (2) CEMS that measure total VOC or total hydrocarbons do not provide a quantified level of the organic species present. Therefore, the EPA selected parameters that would indicate air emission control performance for the monitoring approach. The EPA believes that the selected parameters are good indicators of control device performance and continuous parameter monitoring instrumentation is available at a reasonable cost.

Comment: Several commenters were concerned with the impact of the monitoring requirements on remote and/or unmanned facilities. The commenters suggested that lack of electricity, instrument air, and personnel availability would cause problems complying with the monitoring requirements. Commenter IV-D-08 stated that obtaining electricity for instrumentation necessary to implement continuous monitors is expensive and burdensome for remote facilities. Commenter IV-D-11 stated that their facilities are located in the wetlands or in state waters and pose unique problems. The commenter explained that many of these locations are unmanned or are manned for a few hours per day and access to most of these facilities is by boat and sometimes by helicopter. The commenter also noted that the weather environment is not conducive to maintaining sophisticated electronic equipment that affects the cost of any control strategy imposed. According to the commenter, temperatures range from freezing in the winter to the high 90's in the summer, with high humidity and facilities near the coast experience corrosion problems from the saltwater.

<u>Response:</u> Although the EPA has not removed the monitoring requirements for unmanned or remote facilities, the EPA did evaluate the possibility of reducing the requirements for unmanned facilities.

Several of the facilities visited during the proposal during the development of the proposal were remote and sometimes unmanned facilities that operate through the use of automatic control in monitoring systems. In particular, one site did not have electrical lines to the site (II-B-2). Power was provided by solar panels and associated storage batteries.

The EPA believes that monitoring devices are essential at unmanned sites to ensure that control devices are operating to ensure compliance and are the minimum necessary to ensure that control devices are operating to ensure compliance. Therefore, the EPA has not reduced the monitoring device requirements for unmanned facilities.

<u>Comment:</u> Commenter IV-D-16 noted that most available, reliable, accurate monitoring equipment requires electrical power. The commenter recommended that §63.773(d) be amended to allow for temperature indicators that do not record data. The commenter suggested a compliance determination process: upon inspection of the facility by a regulatory official, the

temperature indicator would be observed and the reading compared with the value chosen for the control device. If this value is unsatisfactory, the facility operator would be required to perform a compliance test per §63.772(e). Compliance with the applicable standard would be based on the result of the compliance test.

Response: **The purpose of a temperature indicator is to ensure compliance with the standard. As stated in a previous response, the EPA considered requiring continuous monitoring systems that measure emissions. However, the EPA determined that parametric monitoring systems would be less burdensome but would be good indicators of control device performance. Furthermore, monitoring device records provide inspectors a means for determining whether or not a control device was operating in compliance. The EPA believes that temperature indicators that do not record data would not give any indication of compliance over the appropriate averaging period. Therefore, the EPA has not modified the monitoring device requirements in response to this comment.**

Comment: Commenters IV-D-20, IV-D-22, and IV-D-34 requested that the EPA amend §63.771(b) and (c) to require periodic visual inspection rather than "no detectable emissions" for covers and closed vent systems. Commenters IV-D-20 and IV-D-22 suggested that repairs would be made if there was visual evidence of a defect that could result in emissions. The commenters explained that many E&P field operations have limited manpower and are remote which prevents them from being attended daily. The commenters stated that a "no detectable emissions" requirement was inappropriate for exploration and production storage vessels and requested that the requirement be dropped. According to the commenters, the requirements would impose significant burdens on the industry. Commenter IV-D-22 suggested that the type of "no detectable emissions" monitoring required in §§63.771(b) and 63.773(b)(3)(ii) cannot be justified by a MACT floor analysis.

In addition, commenters IV-D-20, IV-D-22 and IV-D-34 stated that removing material from a leaking tank until the leak is repaired [as required in §63.771(b)(2)] would result in higher emissions during the transfer operations than would be emitted if the material was left in place. The commenters were concerned that removing the material from the tank would require several wells to be shut in and would risk reservoir damage. Commenters IV-D-20 and IV-D-22 indicated that this requirement is inconsistent with §63.773(b)(3)(vii), which allows the material to remain in the tank if the leak cannot be repaired within 15 calendar days after the leak is detected. The commenters urged the EPA to delete these provisions.

<u>Response:</u> The EPA has evaluated the requirements for storage vessels in subpart HH and determined that the proposed requirements were not appropriate for the oil and natural gas industry. Therefore, the EPA has modified §63.771(b) as follows:

> **(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 <u>form a continuous barrier over the entire surface area of the liquid in the tank</u>~~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~~2) Each cover opening shall be secured in a closed, . . .**

Additionally, the inspection and monitoring requirements contained in proposed §63.773(b) have been combined with the

inspection and monitoring requirements for closed vent systems in §63.773(c). Therefore, §63.773(c) of final subpart HH and §63.1282(c) of final subpart HHH (Cover and closed-vent systems inspection and monitoring requirements) specifies that covers must be visually inspected following the installation of the cover, and annually for defects that could result in air emissions.

In response to the commenters concern about the removal of material from a leaking storage vessel, the EPA has revised the requirements for the repair of leaks. The EPA believes that a 15-day period is sufficient to repair a leak. However, the EPA has provided an option for a delay of repair if a repair is technically infeasible without a shutdown, or if emissions from the immediate repair would be greater than the fugitive emissions resulting from the delay of repair. Therefore, §§63.773(c) and 63.1283(c) of the final rules specify that leaks from covers or closed-vent systems that are detected during the periodic inspections must be repaired no later than 15 days after the leak is detected, unless a delay of repair is requested. In this case, the repair must be completed by the end of the next shutdown.

<u>Comment:</u> Commenter IV-G-02 asked why §§63.771(d)(3)(i)(C) and 63.1281(d)(3)(i)(C) exempt a vent stream introduced with the primary fuel from performance test requirements. The commenter questioned whether the EPA has data showing that, in oil and gas production and natural gas transmission and storage facilities, any boiler or process heater achieves a specific HAP reduction efficiency, or that vent streams introduced with the primary fuel are more likely to achieve reduction and do not need a performance test. The commenter maintained that if the EPA does not have HAP reduction data for boilers and process heaters in

this source category, the control should be a work practice for which a performance test is unnecessary. The commenter cited §63.644 of subpart CC (the petroleum refinery MACT) of 40 CFR part 63 as a precedence for making the control for such vent streams a work practice for which the monitoring requirement is a certification that the stream is introduced into the flame zone of the boiler or process heater.

Commenter IV-D-22 stated that §§63.771(d)(3)(i)(B) and 63.773(d)(2)(ii) exempt boilers or process heaters from performance testing and monitoring if they have an input capacity equal to or greater than 44 megawatts (MW). The commenter was not aware of any fuel gas combustion devices in this source category as large as 44 MW [(150 million British thermal units per hour, (MMBtu/hr)]. The commenter stated that they appreciate the EPA's attempt to reduce the compliance requirements for certain situations, but this heat input threshold designation is virtually meaningless for this source category.

Commenter IV-D-35 referred to §63.771(d)(1)(i)(C), which requires the vent stream to be introduced into the flame zone of a boiler or process heater, and §63.771(d)(3)(i)(C), which exempts boilers or process heaters from performance testing if the vent stream is introduced with the primary fuel. The commenter suggested that the wording in §63.771(d)(1)(i)(C) be modified to require the vent stream to be mixed with the primary fuel prior to introduction to the burner nozzles or injectors. [Note: The reference in this sentence was §63.771(d)(3)(i)(C) but the context indicates that it should be §63.771(d)(1)(i)(C). The commenter stated that boilers and process heaters that introduce the vent stream through their own nozzles or injectors should be subject to performance testing because the degree of combustion being provided by the vent stream would be unknown without performance testing.

<u>Response:</u> The EPA believes that the exemption for boilers with an input capacity greater than 44 MW is important even if

only one boiler in the entire source category meets the exemption. The EPA has not removed this exemption.

The EPA's information shows that boilers or process heaters larger than 44 MW (150 MMBtu/hr) typically operate at temperatures and residence times necessary to achieve 95-percent reduction or greater (usually greater than 98 percent), while boilers and process heaters smaller than 44 MW are frequently not operated to achieve the 95-percent requirement. In addition, analyses also show that when the vent streams are introduced into the flame zone, over 95-percent reduction is achieved. This is because the required residence time is decreased because of the relatively high temperature and turbulence of the flame zone.[23] Additionally, the final rules do not require an initial performance test or monitoring for boilers or process heaters with minimum heat inputs of 44 MW, or boilers and process heaters smaller than 44 MW if the vent stream is introduced with the primary fuel.

<u>Comment:</u> Commenter IV-G-09 disagreed with the requirement in proposed §63.1282(d) that vent streams from dehydration condensers must be measured for HAP even if the vent streams are introduced with combustion air as secondary fuel. The commenter suggested that the operator is being penalized for the environmentally appropriate step of using these streams as secondary fuel and sampling data is meaningless. The commenter requested that this requirement be removed. [Note: this comment also applies to proposed §63.772(e).]

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[23] Hazardous Air Pollutant Emissions from Process Units in the Synthetic Organic Chemical Manufacturing Industry - Background Information for Proposed Standards. Volume 1B: Control Technologies. November 1992. EPA-453/D-92-016b. pg. 2-18.

Response: The EPA does not agree with the commenter. As stated in the previous response, the EPA's information indicates that for combustion units where the vent stream is introduced into the flame zone with the primary fuel achieve at least a 95-percent emission reduction. Although it is possible for an individual enclosed combustion device to achieve a 95-percent emission reduction when the vent stream is introduced with the combustion air as secondary fuel, the EPA does not have the test data to support this and therefore, it is not appropriate to ensure compliance. A design analysis is allowed as an alternative to demonstrate compliance if the owner or operator determines that a performance test is too burdensome. Therefore, the EPA has not modified subparts HH and HHH in response to this comment.

Comment: Commenter IV-D-22 stated that since proposed §63.771(d)(3)(i)(A) exempts flares from performance testing, combustion devices such as heater treaters and glycol reboiler burners should also be exempt from performance testing.

Response: The final rules provide an option for owners and operators to demonstrate compliance with the 95-percent HAP emission reduction using a flare designed and operated according to §63.11(b). Therefore, the final rule clarifies that only flares designed and operated in accordance with §63.11(b) are exempt from the performance test requirements. As stated in the previous response, boilers or process heaters smaller than 44 MW (e.g., heater treaters or glycol reboiler burners) are frequently not operated to achieve a 95-percent emission reduction. Therefore, the EPA has not exempted heater treaters and glycol reboilers from the performance testing requirements.

Comment: Commenter IV-D-22 noted that §63.773(d)(2) exempts control devices from monitoring in which vent streams are introduced with the primary fuel. The commenter suggested that §63.773(d)(2)(i) should be clarified to provide that "introduced with the primary fuel" means "at the same location in the process heater," such as the burner block, and does not require the vent stream to be compressed and introduced into the primary fuel gas line. No combustion or destruction efficiency advantage exists from mixing the vent gas into the primary fuel line versus the burner block because the vent gas undergoes the same residence time and temperature history in either case. However, significant additional cost is incurred to compress the vent gas to introduce it in the primary fuel line instead of at the burner block.

Response: **The performance test and monitoring requirement exemptions for boilers and process heaters for which the vent stream is introduced with the primary fuel or as the primary fuel, are consistent with the EPA's approach for several other rules (e.g., the HON). The commenter did not provide technical information to demonstrate that their recommendation would provide an equivalent level of control warranting an exemption. Therefore, the EPA has not modified subparts HH and HHH in response to this comment.**

Comment: Commenter IV-G-02 noted that in the proposed §63.769 standards for equipment leaks, there is no exemption in paragraphs (c)(1) through (3) from monitoring for pressure relief devices routed through a closed vent system to a control device (such as a flare). According to the commenter, pressure relief devices controlled in this way cannot be monitored as the section requires. The commenter pointed to the equipment leaks NSPS (40 CFR part 60, subpart VV), to which all NSPS for equipment leaks (including subpart KKK) reference, which recognizes this and provides an exemption [the commenter cited §60.482-4(c) and §61.242-4(c)]. Since this proposal recognizes that equipment complying with subpart KKK of part 60 must meet more stringent standards and are exempt from meeting §63.769 requirements, the commenter requested a similar exemption be included for units not required to comply with the subpart KKK standards.

Response: **The commenter's statement that §63.769 does not contain monitoring exemptions for pressure relief devices routed through a closed-vent system to a control device is incorrect. According to §63.769(c), an owner or operator of ancillary equipment and compressors subject to the equipment leak standards of subpart HH must comply with the requirements of 40 CFR 61.241 through 247. Thus, the exemption contained in §61.242-4, for pressure relief devices routed through a closed-vent system to a control device, applies. Therefore, the EPA did not modify subpart HH in response to this comment.**

Comment: Commenter IV-D-14 asked whether the EPA would place additional emphasis on compliance monitoring for "synthetic minor sources" or minor sources near the major source threshold, as has been seen during the implementation of the title V program.

Response: **The EPA is uncertain what the commenter means by "additional emphasis on compliance monitoring for synthetic minors," but notes that the final rules do not alter the part 70 requirements for monitoring of any applicable requirement at title V sources.**

2.11.2 Recordkeeping and Reporting Requirements

Comment: Two commenters were concerned with the relevance of the records required by the standard. Commenter IV-D-05 noted that glycol units that are exempt from the control standards are only required to keep records of gas flow rates. Based on their experience with the results of GLYCalc 3.0, the commenter stated that glycol circulation rates and gas composition are more critical parameters affecting emissions than gas flow rates.

Commenter IV-D-06 suggested that keeping records of glycol dehydration unit design capacity (in terms of natural gas flow rate to the unit per day) is not relevant. According to the commenter, keeping records of the design capacity will not show what the benzene emissions are, and will not really tell anything about whether the unit qualifies for the one tpy exemption. The commenter further stated that if the exemption was claimed based on actual gas throughput being less than 3 MMscf/d, they could understand a requirement to keep records of how actual gas input was determined. However, the commenter stated that keeping records of design capacity would not document whether they qualify for exemption since the exemption is based on actual gas input rather than theoretical gas input.

Response: Maintaining records of glycol dehydration unit natural gas flow rate is required to document that a source meets the criteria for the throughput exemption under §§63.764(e), and proposed 63.1274(b) [now codified under §63.1274(d)]. As proposed, subparts HH and HHH did not require the owner or operator to keep records for the benzene emission criteria for an exemption under §§63.764(e), and 63.1274(b). These criteria are necessary to document that the source qualifies for an exemption from control requirements based on benzene emissions, therefore, §63.774 of final subpart HH and §63.1284(d) of final subpart HHH contain recordkeeping requirements for the benzene emission criteria to document that the affected source qualifies for the exemption. The final rule requires records of benzene emissions determined either by emissions model or direct measurement for these sources.

Comment: Several commenters were interested in reducing the recordkeeping and reporting burden on affected sources. Commenter IV-D-32 recommended streamlining the recordkeeping requirements, but did not provide any specific recommendations. Commenter IV-D-06 requested that the EPA allow a "reduced recordkeeping" option, for monitoring data. The commenter stated that the EPA should not impose a blanket requirement to retain every monitored parameter data point, and that such a requirement would impose a large paperwork burden with no environmental benefit. The commenter stated that a compromise, such as the "reduced recordkeeping" option, which would allow for the storage of less data if the monitoring system has special enhancements would be acceptable. The commenter recommended that the EPA use the HON subpart G, §63.152(g) as a model. The commenter stated that this comment also applies to subpart HH.

Commenter IV-D-06 also stated that they support §63.1285(b)(9) and (c) which say that no paperwork requirements apply to certain exempt sources. The commenter supported the EPA's making steps toward reducing unnecessary paperwork burdens. The commenter stated that the same approach should be implemented in all MACT standards.

Response: **The reduced recordkeeping option recommended by commenter IV-D-06 allows an owner or operator to retain only daily averages of monitored parameter data if certain monitoring device design criteria are met. In addition, these requirements allow an owner or operator to not retain the daily average for any operating day when the daily average is below the maximum parameter limit, or above the minimum parameter limit (as appropriate), provided 6 months have passed without an excursion. The EPA does not believe that the reduced recordkeeping option is appropriate for the oil and natural gas production and natural gas transmission and storage source categories. First, past performance does not prevent future exceedances. Secondly, the 365-day averaging period option for condensers installed to comply with subpart HH and the 30-day averaging period option for condensers installed to comply with subpart HHH require owners or operators to retain the daily average data to calculate the appropriate average. Therefore the EPA has not incorporated the reduced recordkeeping option into subparts HH and HHH.**

However, the EPA did re-evaluate the recordkeeping requirements and has reduced the number of data points required to be measured and recorded for monitoring data. The final rules require continuous monitoring systems to measure and record data at least every hour, rather than every 15 minutes. The EPA believes that this will significantly reduce the amount of data generated by monitoring devices.

Comment: Commenter IV-D-06 stated that they do not support a requirement to keep records proving entitlement to an exemption, which takes away some of the value of the exemption. The commenter stated that since benzene emissions or gas input can change with time, the records of a historic determination may not say anything about current conditions. The commenter maintained that they claim an exemption at their own peril. The commenter contended that if, at any time, the benzene emissions or the annual average gas input exceeds the threshold, the exemption would no longer apply. The commenter stated that this comment may also apply to subpart HH.

Response: The EPA does not agree with the commenter. Since the throughput and benzene emission values are annual averages, some historical data is necessary. Furthermore, the EPA believes that the exemption has significant value to justify keeping records. Therefore, the EPA has not modified subparts HH and HHH in response to this comment.

Comment: Two commenters were particularly concerned with the onsite recordkeeping requirements. Commenters IV-D-06 and IV-D-16 requested that the EPA provide for offsite storage of records and revise Table 2 to say that §63.10(b)(1) does not apply. The commenters stated that the requirement in §63.10(b)(1) to store records on-site is not appropriate, as facilities in remote locations would not have file storage space. Commenter IV-D-06 proposed that the records be collected periodically and taken to a central location (such as the same location where compliance personnel, who review the records and prepare the reports, are located). The commenter recommended that the EPA add a paragraph to the "recordkeeping" section of subpart HHH expressly allowing offsite storage if the records are readily accessible. The commenter stated that if subpart HH also incorporates §63.10(b)(1), this comment also applies to subpart HH. Commenter IV-D-16 suggested that by replacing the records retention requirements with inspection by a regulatory official followed by compliance testing (if necessary), the problem of retaining records at gas production facilities would be avoided.

Response: **The EPA does not believe that replacing the record retention requirements with inspections followed by compliance testing (if necessary) would allow inspectors readily to determine compliance with these standards, at any source. However, the EPA agrees that owners and operators should be allowed to retain some data off-site. Therefore, in response to these comments, the EPA has modified the record retention requirements in §§63.774(b) and 63.1284(b) as follows:**

- **Owner or operator must retain the most recent 12 months of records onsite or the records must be accessible from a central location by computer or other means that provides access within two hours after a request;**
- **Owner or operator may retain the remaining four years of records offsite; and**
- **Owner or operator may maintain records in hard copy or computer-readable form including, but not limited to, on paper, microfilm, computer, floppy disk, magnetic tape, or microfiche.**

Comment: Commenters IV-D-08, IV-D-22, and IV-G-03 requested that the EPA merge several reports into one package to be delivered to the regulatory agency. According to the commenters, the merged reporting approach prevents multiple, staggered reports from being generated and transmitted without providing a comprehensive picture on compliance status. The commenters recommended that the EPA:

- allow for reports to be merged through a title V mechanism for title V facilities;
- merge redundant reports;
- create a unified list of reports; and
- limit frequency to no more than semiannually.

Commenters IV-D-22 and IV-D-34 recommended that the EPA amend §§63.774 and 63.775 to allow operators to maintain annual documentation of State or federally enforceable limits, and to require reports only as necessary based upon the specific device or operating limit relied upon for emission control. The commenters urged the EPA to use the same recordkeeping and reporting requirements as 40 CFR 63 subpart CC (refinery rule) as follows:

- allow semiannual or annual reports rather than reporting events as they occur;
- allow the permitting authority and operator to determine which information will be reported or simply documented; and
- eliminate duplication for facilities subject to multiple requirements.

The commenters suggested that this would ensure compliance while reducing the burden on the operators and permitting agency.

Response: **The EPA recognizes that unnecessary monitoring, recordkeeping, and reporting requirements would burden both the source and the enforcement agencies. As stated in an earlier response at the beginning of section 2.11 of this document, the final rules contain only monitoring, recordkeeping, and reporting requirements that are necessary to demonstrate compliance.**

State and local agencies have the option of enforcing different, but equivalent, monitoring, recordkeeping, and reporting requirements if they submit information on their program to the EPA for approval under the procedures for delegation of NESHAP authority under section 112(l) of the CAA.

Furthermore, in cases where reporting requirements of State or local rules duplicate those of subparts HH or HHH, a source

can work with their State or local title V permit authority to avoid duplicate submittals.

In response to the commenters' request to limit the reporting frequency, table 2 of the final rule has been changed to indicate that the requirement specified in §63.10(e)(3)(i)(C), for quarterly reporting in cases where monitoring parameters are out of range or monitors are not operating more than a specified percent of the time, does not apply. Instead, semiannual reporting is required for all facilities. As proposed, facilities were required to report semiannually, but if the source experienced excess emissions, quarterly reports would be required.

This change was made because the EPA agrees that the quarterly reporting system proposed added complexity to the rule, it may not be helpful for enforcement, and that penalties for noncompliance are a sufficient disincentive for poor performance. Further, semiannual reporting is consistent with title V operating permit reporting requirements. Requiring separate quarterly reports for some facilities adds complexity and increases the reporting burden for both the facility and the enforcement agency. Semiannual reports will provide the regulatory agency information on excess emissions within about six months of the occurrence. This is well within the 1-year period in which the agency can take administrative enforcement actions as specified under section 113(d) of the CAA.

Comment: Commenters IV-D-07 and IV-G-03 requested an adjustment for the reporting requirements for unmanned facilities, as the reporting requirements seemed unnecessarily burdensome. Commenter IV-D-07 requested monthly recordkeeping and annual reporting.

Response: **As stated in the previous response, sources can discuss with the implementing agency the possibility of submitting different reports, providing these reports are equivalent.**

Annual reporting was not selected as requested by the commenters, because it would significantly reduce the EPA's ability to take administrative enforcement actions. Section 113(d) of the CAA limits the assessment of administrative penalties to violations that occur no more than 12 months prior to the initiation of the administrative proceeding. Periodic reports are a primary means of identifying possible violations, and annual submittal would not give the enforcement agency time to review the report and take action on a violation that occurred early in the reporting period within one year after the event.

Comment: Commenters IV-D-08, IV-D-22, and IV-D-26 stated that requiring initial notifications within one year is not realistic. The commenters referred to the Gasoline Distribution Terminals and Pipeline Breakout Stations standard (subpart R) which comprises many different sized facilities. According to the commenters, the initial assessments have taken more than one year and the EPA has had to amend subpart R to allow the facilities more time. Therefore the commenters, along with commenter IV-D-32, recommended the following:

- extend the initial notification period to at least two years;
- create a tiered notification requirements; and
- allow a single notification to cover multiple facilities in the same region.

Response: **The information required in the initial notification includes basic facility information, such as name and address, physical location, identification of the standard that is the basis of the notification, a facility description, and a statement of whether the source is a major or area source.**

The EPA believes that all of this information, except the major or area source determination, should be readily available. Facilities that are potentially subject to subparts HH and HHH have been aware that they might have to perform a major source determination since the date of the proposed rule (February 6, 1998). Furthermore, by the time the initial notification is due (assuming an effective date of May 15, 1999), these facilities will have had more than 27 months from the proposal date to determine their major source status. The EPA believes that there is ample time to make this determination.

However, the EPA has modified §§63.775 and 63.1285 for affected sources that are major on or before the date the initial notification is due (one year after the effective date of the regulation), that plan to become area sources by the compliance date. The final rule states that these affected sources that are major sources but plan to become area sources must include in the initial notification, a brief, nonbinding description of a schedule for the actions that are planned to achieve area source status.

Nothing in subparts HH and HHH prevents single notifications for multiple facilities, provided the required information for all facilities is contained in the notifications.

Comment: Commenters IV-D-08 and IV-D-22 were concerned that the wording in §63.9(h) might be misunderstood, as far as when the notification of compliance status is required, or how soon it has to occur after promulgation. The commenters recommended the following:

- establish a certain time for Notification of Compliance Status -- 180 days after promulgation, as provided for in §63.9(h)(2)(ii); and
- reference specific sections in subpart A for the required contents of this notification (i.e., §63.9(h)(2)(i)).

Response: **The EPA agrees that it would be more clear if the due dates for the notification of compliance status were stated explicitly in the rule. In addition, the EPA has included several sections from the General Provisions (40 CFR part 63, subpart A) directly in subparts HH and HHH. Sections 63.775(d) of final subpart HH and §63.1285(d) of final subpart HHH contain the Notification of Compliance Status Report requirements.**

Comment: Commenter IV-D-01 requested that the reporting of the number of components monitored be a requirement of semiannual reports. The commenter noted that the reporting requirements in §61.247(b), for each piece of ancillary equipment subject to §63.769, do not require the number of components monitored per reporting period to be included in each semiannual report. The commenter stated that the number of components is required in 40 CFR 63 Subpart H. The commenter cited the benefits for including the number of components:

1. Facilitates more rapid review of the report;
2. Provides verification of percent leakers; and
3. Ensures that the facility continues to monitor all components.

Response: **The EPA agrees with the commenter that the number of monitored components is important to verify the calculation of the percent leakers and to ensure that a facility continues to monitor all components. Therefore, §63.775(d)(3) of the final rule contains requirements for owners and operators subject to §63.769 to submit the information required under §61.247(a) (of 40 CFR, part 61, subpart V), except for the following:**

- **The initial report required in §61.247(a) must be submitted as a part of the Notification of Compliance Status Report required under subpart HH.**

- **The number of each equipment (e.g., valves, pumps, etc.) must be included in the Notification of Compliance Status Report.**

- **Changes in the information submitted in the Notification of Compliance Status Report must be submitted in subsequent Periodic Reports.**

Comment: Commenter IV-D-01 requested that the EPA delete the reporting requirement exemption [§63.775(b)(9)] for sources that are not subject to the control requirements for glycol dehydration unit process vents. The commenter stated that these sources may still be subject to the storage vessel and equipment leak provisions and they must also conduct performance tests and develop startup, shutdown and malfunction plans. The commenter further stated that since these facilities are not exempt from recordkeeping requirements, reporting would "hardly constitute an excessive burden."

Response: The intent of the reporting requirements contained in proposed §63.775(b)(9) of subpart HH and §63.1285(b)(9) of subpart HHH was not to exempt entire facilities, but to exempt glycol dehydration units that are not subject to the control requirements, as specified in proposed §§63.764(e) and 63.1274(b) [now codified at §63.764(e)(1) of subpart HH and §63.1274(d) of subpart HHH], from the reporting requirements. To clarify this intent, the final rules specify that only the units exempt from the control requirements are exempt from the reporting requirements in subpart HH and HHH [codified at §63.775(b)(7) of subpart HH and §63.1285(b)(7) of subpart HHH]. Thus, the reporting requirement exemptions do not apply to other units within the facility that are subject to the rule, including glycol dehydration units, storage vessels, and ancillary equipment.

Similarly, §63.764(e)(3) of final subpart HH specifies that ancillary equipment and compressors that contain or contact fluid with a VHAP concentration less than 10 percent and that are in VHAP service less than 300 hours per year are exempted from the

control requirements of §63.769. Therefore, §63.775(b)(8) of the final rule contains an exemption from the reporting requirements for ancillary equipment and compressors that are not subject to §63.769.

Additionally, it should be noted that although storage vessels with the potential for flash emissions (as defined in §63.761) are not subject to the recordkeeping and reporting requirements, an owner or operator would be required to maintain records for these sources under §63.10(b)(3) of 40 CFR part 63, subpart A, which contains recordkeeping requirements for applicability determinations.

Comment: Commenter IV-D-06 stated that §63.1285(b)(7) does not specify a deadline for reports on equipment that was initially exempt, but becomes subject to control requirements due to process changes. The commenter requested reasonable deadlines for these reports. The commenter stated that this comment may also apply to subpart HH.

Response: The EPA agrees that provisions are necessary for area sources that become major sources due to increases in HAP emissions or increases in PTE. Therefore, the final rules specify the following:

- compliance dates for area sources that become major sources [§63.760(f) of subpart HH and §63.1270(d) of subpart HHH],
- initial notification requirements for area sources that become major sources which are correlated to the compliance dates [§63.775(b)(1) of subpart HH and §63.1285(b)(1) of subpart HHH], and
- notifications of process changes due within 180 days after the process change or by the next Periodic Report, whichever is sooner [§63.775(f) of subpart HH and §63.1285(f) of subpart HHH].

Comment: Commenter IV-D-16 recommended that startup, shutdown and malfunction reports as required under §63.10(d)(5) should not be required under subpart HH. The commenter did suggest that if they are required, the startup, shutdown, and malfunction reporting requirements should only apply to gas plants, and should be part of the semiannual reports required by title V rather than a stand alone report.

Response: **The startup, shutdown, and malfunction report enables the EPA to keep track of excess emissions and harm to the environment, and is only required if the owner or operator does not follow their startup, shutdown, and malfunction plan. Therefore, the EPA believes that these reports must be submitted within seven days of the malfunction. If the owner or operator is thorough in developing their facility's startup, shutdown, and malfunction plan, and ensures that the plan is followed during startup, shutdown, and malfunction events, these reports will not be necessary. However, it should be noted that the final rule states that separate startup, shutdown, and malfunction reports are not necessary if the required information is included in the Periodic Report for the facility [codified at §63.775(b)(6) of subpart HH and §63.1285(b)(6) of subpart HHH].**

2.12 TEST METHODS

Comment: Commenter IV-D-06 stated that Methods 1 or 1A will usually not be appropriate as required in §63.1282(d)(1). According to the commenter, Method 1 is only for large stacks and Method 1A is for smaller stacks, and continual references throughout Method 1A say the method is for particulate. The commenter stated that they would not generally be dealing with particulate under subpart HHH. The commenter recommended that §63.1282(d)(1) be revised to say that "if we use Method 1A, any references to particulate do not apply." The commenter stated that this comment may also apply to subpart HH.

Response: The procedures outlined in Methods 1 and 1A are to be used only to select a sampling site. However, to clarify the EPA's intent, the final rules state that Method 1 or 1A of 40 CFR part 60, appendix A must be used to select the sampling site, and any references to particulate mentioned in Methods 1 and 1A do not apply [codified at §63.772(e)(3)(i) of subpart HH and §63.1282(d)(3)(i) of subpart HHH].

Comment: Commenter IV-D-06 stated that the EPA should revise §63.1283(c)(3) to require Method 21 "with the differences specified in §63.1282(b) of this subpart." The commenter stated that it was confusing that §63.1282(b) specified a modified Method 21 and §63.1283(c)(3) specified "straight" Method 21. The commenter stated that according to §63.1282(b), something like modified Method 21 should be used. The commenter stated that this comment may also apply to subpart HH.

Response: The EPA agrees with this recommendation and has modified the closed-vent system requirements [now codified at §63.773(c)(2)(i) and (ii) of subpart HH and §63.1283(c)(2)(i) and (ii) of subpart HHH] to reference the no detectable emissions procedure under §63.772(b) of subpart HH and §63.1282(b) of subpart HHH.

Comment: Commenter IV-D-09 was concerned with the emissions test procedures requirement to use Method 18 to determine concentrations and emissions of HAP and TOC. The commenter stated that although Method 18 is appropriate for speciating organic HAP, it is not appropriate for speciating TOC. The commenter explained that Method 18 uses gas chromatography (GC) to separate a variety of organic compounds. According to the commenter, individual peaks could vary widely in resolution, depending on the complexity of the sample. The commenter further explained that the error associated with determining TOC by GC could be substantial as it would reflect the sum of several errors associated with the separation and detection of individual organic compounds. Furthermore, the commenter expressed doubt that any one chromatographic column and set of operating conditions will cleanly separate the complex organic matrix present in dehydration units.

The commenter recommended that the EPA either require use of Method 25A for determining TOC or allow the use of Method 25A as an alternative means of determining TOC. According to the commenter, the analytical error associated with discrepancies between the response factor of the calibration gases used in Method 25A and the average response factor of the organic gas matrix will not be as significant as the errors associated with Method 18. The commenter further recommended that alternate calibration schemes could be used to ensure safety, if the EPA is concerned with FID response factors. Specifically, the commenter suggested that since the FID response factor in Method 25A is retarded by the presence of oxygenated or chlorinated compounds, the EPA could specify that the FID at the outlet of a combustion control device be calibrated with a mixture of methanol in air. According to the commenter, "since methanol has a relatively high oxygen-to-carbon ratio, it will have among the most markedly dampened response factors of any organic compound likely to be present in the air stream."

The commenter stated that allowing the use of Method 25A would reduce the cost associated with emissions testing.

According to the commenter, Method 18 costs approximately two to three times more than Method 25A because Method 18 requires the use of more sophisticated laboratory techniques. Additionally, the commenter noted that since Method 18 does not result in more accurate TOC emissions estimates, there is not an environmental benefit associated with an increased cost.

Response: **The EPA agrees with the commenter. The aromatic compounds contained in the vent stream make method 25A an appropriate method for measuring TOC. The final rules allow the owner or operator the option of using either method 18 or method 25A [codified at §§63.772(e)(3)(iii) and 63.772(e)(3)(iv) of subpart HH and §§63.1282(d)(3)(iii) and 63.1282(d)(3)(iv) of subpart HHH].**

Comment: Commenter IV-D-07 requested that the EPA specify how emissions from the combustion source should be measured. According to the commenter, Method 25 does not differentiate between methane, ethane, and VOC, and furthermore, testing grab samples with a GC/MS tends to be inaccurate. The commenter also asked whether the 20 ppmv concentration limit is measured "as propane" or "as methane."

Response: **Proposed §§63.772(e)(3) and (4) of subpart HH and §§63.1282(d)(3) and (4) of subpart HHH [now codified at §§63.772(e)(3)(iii) and (iv) of final subpart HH and §§63.1282(d)(3)(iii) and (iv) of final subpart HHH] state that emissions from combustion sources must be measured using Method 18, 40 CFR part 60, appendix A, or any other method or data validated according to the applicable procedures in Method 301, 40 CFR part 63, appendix A. As mentioned in the previous response, the EPA has also modified the test method requirements to allow the owner or operator the option of using Method 25A, instead of Method 18.**

When using Method 18, the 20-ppmv concentration limit is determined as the sum of the compound concentration as measured by Method 18. Individual compounds are presented as the compound (e.g., benzene concentration would be presented as 5 ppmv as benzene). If using Method 25A, the measurement should be presented based on the calibration gas used.

Comment: Commenter IV-G-01 remarked that the proposed NESHAP states that bagging is the only method for measuring fugitive hydrocarbon emissions. The commenter stated that the High Volume Collection System has been demonstrated to be as effective as the bagging method, as shown in EPA-600/R-95-167.

Response: Although the High Volume Collection System could be an alternative method for measuring fugitive HAP emissions, the EPA determined that the MACT floor for equipment leaks from ancillary equipment and compressors in the oil and natural gas production source category was the level of control required under 40 CFR part 60, subpart KKK. Therefore, the equipment leak standards are based on work practices and operational practices equivalent to those required under subpart KKK, rather than emission standards.

Comment: Commenter IV-G-15 provided a letter from a technical consultant to the commenter that describes how EPA Methods 0030/5040 Volatile Organic Sampling Train (VOST) can be used with some modification to characterize accurately emissions from glycol dehydration units. The consultant described the modified method as the new "Bag VOST" technique, similar to California Air Resources Board Method 422.

Commenter IV-G-16 and commenter IV-G-15 provided proposed sampling procedures for glycol dehydration units. According to the commenters, the proposed procedures would be used to estimate uncontrolled emissions and control efficiency for units controlled with condensers, and are based on EPA Methods 1, 2, 3B, 4, and 18 modified. The commenters stated that gas samples are collected over a one hour period. The commenters referred to the method of analysis as GC/FID and GC/TCD.

Commenter IV-D-03 provided for the EPA's information, a copy of the paper entitled *Flash Vaporization Emissions Test Method for Storage Tank VOC & HAP*, which was presented at the October 1997 EPA/A&WMA Emission Inventory Conference in RTP, NC. The commenter stated that the paper describes the EquiVap™ test method and its ability to quantify accurately and speciate storage tank emissions based on fundamental thermodynamic principles using cost effective conventional labware and software analytical tools.

Response: **In order for the EPA to approve alternative test methods, the Agency must receive an analysis according to the procedures in 40 CFR part 60, appendix A, Method 301. Additional guidance for obtaining EPA approval for alternate test methods and procedures may be found on the Internet at: http://www.epa.gov/ttn/emc.**

Comment: Commenter IV-G-02 noted that §63.772(a) appears to be in conflict with §63.769(a). The commenter explained that §63.772(a) sets out a complicated procedure using Method 305 or Method 25D to determine the HAP content of material for applicability of equipment leak standards and §63.769(a) requires the use of the method in §61.245(d) (incorporating ASTM Method D-2267). The commenter requested a clarification that either method can be used to give owners and operators maximum flexibility to choose most economical method available to them.

Response: **The EPA agrees that proposed §63.769(a) and §63.772(a) are inconsistent. The test method specified in §61.245(d), ASTM Method D-2267, is no longer considered by the EPA to be a valid test method. Therefore, the EPA has modified §63.769(a) in the final rule as follows:**

> **". . . that contains or contacts a fluid (liquid or gas) that has a total ~~VOHAP~~VHAP concentration equal to**

> or greater than 10 percent by weight (determined according to the ~~provisions of 40 CFR 61.245(d)~~procedures specified in §63.772(a)) . . . "

In addition, the EPA evaluated the procedures for determining VHAP concentration for the applicability to the equipment leak standards under proposed §63.772(a) and determined that the procedures were not appropriate for the oil and natural gas production source category. The EPA believes that Method 18 of 40 CFR part 60, appendix A and the procedure specified in 40 CFR 63.180(d) of this part are appropriate for determining the VHAP concentration of fluid contained in or in contact with ancillary equipment or compressors. Therefore, §63.772(a) of the final subpart HH reads as follows:

> (a) Determination of material VHAP or HAP concentration to determine the applicability of the equipment leak standards under this subpart (§63.769). Each piece of ancillary equipment and compressors are presumed to be in VHAP service or in wet gas service unless an owner or operator demonstrates that the piece of equipment is not in VHAP service or in wet gas service.
>
> (1) For a piece of ancillary equipment and compressors to be considered not in VHAP service, it must be determined that the percent VHAP content can be reasonably expected never to exceed 10.0 percent by weight. For the purposes of determining the percent VHAP content of the process fluid that is contained in or contacts a piece of ancillary equipment or compressor, Method 18 of 40 CFR part 60, appendix A, shall be used.
>
> (2) For a piece of ancillary equipment and compressors to be considered in wet gas service, it must be determined that it contains or contacts the field gas before the extraction of natural gas liquids.

Comment: Commenter IV-D-06 requested that the EPA clarify "background level" issues, for instrumental leak detection monitoring. The commenter referred to §63.1282(b)(5), which requires that the procedures in Method 21 should be used to determine background levels. However, the commenter stated that Method 21 does not have any procedures to determine background levels. According to the commenter, Method 21 says how to monitor for concentrations of certain substances. Additionally, the commenter recommended that the EPA clarify whether or not there is an option to either determine background level. The commenter stated that the regulatory burden would be reduced and the environment would actually be benefitted by not determining a background level. The commenter suggested that the EPA use the current version of the HON subpart H, §63.180(c) and (c)(2). The commenter stated that this comment also applies to subpart HH.

Response: The EPA does not agree with the commenter's statement that Method 21 does not contain procedures to determine background emission levels. In fact, section 4.3.2 of EPA Method 21 is a section for determining local ambient concentrations (40 CFR part 60, appendix A, Method 21, §4.3.2), which is the methodology for determining background emission concentrations.

The EPA agrees that an option for determining background emissions is appropriate. Therefore, §63.772(c)(5) of final subpart HH and §63.1282(b)(5) of final subpart HHH provide the owner or operator the option of not determining background emissions. However, it should be noted that if an owner or operator chooses not to determine background emissions, and Method 21 shows emissions greater than 500 ppmv, the equipment will not be in compliance.

2.13 COMPLIANCE

2.13.1 Compliance Procedures

Comment: Commenter IV-D-22 recommended that subpart HH include a provision allowing for delay of repair in the event the repairs cannot be made on-line and a unit shutdown will be required. The commenter recommended a provision similar to the provision in 40 CFR §63.171(a), referenced in the Refinery MACT rule [40 CFR §63.648(c)], which allows for delay of repair if the repairs require a shutdown.

Response: Proposed §63.769(c) states that the owner or operator of ancillary equipment must "meet the requirements specified in 40 CFR 61.241 through 61.247 . . . ," including the provisions contained in §61.242-10, allowing for a delay of repair if the repair cannot be made on-line and a unit shutdown would be required. Therefore, the equipment leak standards of subpart HH already contain the provisions requested by the commenter.

Comment: Commenters IV-D-18 and IV-D-25 stated that the procedure specified in §63.772 corrects the measured outlet concentration of HAP to 3 percent oxygen. According to the commenters, many thermal and catalytic oxidizers properly operate with oxygen levels in the exhaust stream near 20 percent and the correction to 3 percent oxygen would make the concentration-based limit unnecessarily restrictive. Therefore, commenter IV-D-25 recommended that §63.772(e)(4) be changed to reflect that the concentration of TOC shall be corrected to the designed oxygen content in the outlet stream and the equation in §63.772(e)(4)(iii)(B) should be modified accordingly.

Response: Section 63.771(d)(1)(i)(B) (control requirements) provides an option requiring combustion devices to reduce "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 . . . ." To make a direct comparison between the enclosed combustion device total HAP concentration limit specified in §63.771(d)(1)(i)(B), and the TOC or total HAP emissions measured using the procedures specified in §63.772(e), a correction to 3 percent oxygen is necessary. Without this correction, a direct comparison of measured emissions to the concentration limit would not be possible. Therefore, the EPA does not see any reason to modify §63.772(e)(4) or the equation contained in proposed §63.772(e)(4)(iii)(B) [now codified at §63.772(e)(3)(iv)(C)(2) of the final rule] in response to this comment.

Comment: Commenter IV-D-35 requested that the alternative condenser evaluation allowed in §63.1282(e) specify that the liquid streams to be sampled are before and after the condenser, to avoid any confusion regarding the testing before and after the still or reboiler. [Note: this comment also applies to §63.772(f)].

Response: The commenter's request that proposed §63.1282(e) specify that the liquid sample streams are "before and after the condenser" is incorrect. The GRI report entitled "Atmospheric Rich/Lean Method for Determining Glycol Dehydrator Emissions" (GRI-95/0368.1) specifies the following sample point locations for collecting rich and lean glycol samples:

1. **Rich Glycol: select a sample point between the glycol pump and the reboiler.**
2. **Lean Glycol: select a sample point between the reboiler and the contactor, if a charcoal filter is not in line between the reboiler and the contactor, OR between the reboiler and the charcoal filter, if a charcoal filter is between the reboiler and the contactor.**

Therefore, the sample locations are required to be before and after the reboiler, not before and after the condenser.

The EPA's intent was for the ARL methodology specified in the GRI report to be used in conjunction with GLYCalc to determine condenser performance. To clarify this intent, proposed §§63.772(f) and 63.1282(e) [now codified at §63.772(e)(5) of final subpart HH and §63.1282(d)(5) of final subpart HHH] have been modified to specify that the ARL method can be used to provide inputs for use in conjunction with GLYCalc.

Comment: Commenter IV-G-07 supplied a detailed "engineering assessment" methodology for calculating annual HAP and VOC emissions from condenser-controlled dehydration units (for possible use in emissions reporting). This method would use: (1) GLYCalc to estimate uncontrolled emissions, (2) a process design model (e.g., Hysim, Aspen, PD+, etc.) to estimate emissions as a function of condenser outlet temperature, (3) a curve of emissions vs. ambient air temperature, constructed based on a condenser design that produces an outlet vapor/liquid stream in equilibrium at least ten degrees Fahrenheit above ambient temperature, and (4) National Climatic Data Center temperature data for the station nearest the site to construct an annual dry bulb temperature histogram. Annual emissions would be calculated by integrating the emissions vs. air temperature curve over the temperature histogram.

Commenters IV-G-15 and IV-D-16 described models that exist for estimating emissions from glycol dehydration units. According to the commenters, GLYCalc, written by Radian Corporation, and PROSIM, written by Bryan Research and Engineering, are approved by the TNRCC. A third model written by OPC DRIZO, is used for design purposes by OPC, but is not available to the public. The consultant made the statement that the emissions models used generally underestimate the actual emissions generated, and that nothing beats a good stack test.

Response: The EPA reviewed the information supplied by the commenters. The EPA evaluated GLYCalc from GRI as a tool for

estimating emissions from glycol dehydration units[24] and the EPA recommends the use of this model for the development of emission inventories to meet Clean Air Act requirements. The EPA understands that the program may overestimate emissions from these units, but believes that the use of accurate input data will reduce this potential.

Proposed §§63.771(d)(3)(iv) and 63.1281(d)(3)(iv) [now codified at §63.772(e)(4) of final subpart HH and §63.1272(d)(4) of final subpart HHH] contain specific requirements for design analyses which may be used to demonstrate compliance with the control device performance requirements. The commenters' suggested approaches are acceptable, provided they comply with the requirements for condenser design analyses as specified in final §63.772(e)(4)(i)(D) or §63.1282(d)(4)(i)(D). It should be noted that any disagreements between the owner or operator and the Administrator would be resolved by conducting a performance test as specified in final §§63.772(e)(4)(ii) or 63.772(d)(4)(ii). The EPA has not added guidance for estimating emissions, for reporting, to the final rules. However, the EPA will publish implementation guidance following promulgation of subparts HH and HHH.

Comment: Commenter IV-D-07 interpreted §63.1282(d)(1)(i)(A) to mean that the sampling site must be located upstream of the control device. The commenter also suggested that the EPA include a definition for the term *final product recovery device*.

Response: The control device inlet sampling site must be located at the inlet of the first control device. To clarify,

[24]Memorandum from Jones, L.G., U.S. EPA/Emissions Measurement Branch, to J.D. Mobely, U.S. EPA/ Emission Factor and Inventory Group. "Glycol Dehydrator Emissions Test Report and Emissions Estimation Methodology." April 13, 1995.

the EPA has modified proposed §§63.772(e)(1)(i)(A) and 63.1282(d)(1)(i)(A) [now codified at §§63.772(e)(3)(i)(A) and 63.1282(d)(3)(i)(A)] as follows:

> **(A) . . . inlet sampling sites shall be located at the inlet of the first control device and at the outlet of the final control device.**

A recovery device is one used for recovering chemicals for fuel value, use, reuse, or for sale for fuel value, use, or reuse, and is not considered a control device. This definition of recovery device is imbedded within the definition of *control device*.

2.13.2 Compliance Determination

Comment: Commenter IV-D-06 recommended that the EPA provide an exemption from performance testing for RCRA-regulated hazardous waste incinerators. According to the commenter, RCRA-regulated hazardous waste incinerators have already had to demonstrate compliance with very stringent emission standards under RCRA, and no further compliance demonstration is needed for MACT standards. The commenter requested that the EPA use the wording in §63.116(b)(5) of subpart G of the HON, verbatim, in §63.1281(d)(3)(i) as a new paragraph (d)(3)(i)(E). The commenter stated that this comment also applies to subpart HH.

Response: The EPA is not aware of any oil and natural gas exploration and production or natural gas transmission and storage facilities that would have RCRA industrial furnaces. However, the EPA has added the recommended language based on §63.116(b)(5) of subpart G of the HON to final subparts HH and HHH [codified at §63.772(e)(1)(v) of final subpart HH and §63.1282(d)(3)(v) of final subpart HHH].

Comment: Commenter IV-D-06 suggested that the EPA include an exemption from performance testing under subpart HHH, for control devices that have already had a performance test under other EPA regulations. The commenter stated that the EPA should use the language in §63.116(b)(3) of the HON, verbatim, and used in subpart HHH as a new paragraph (d)(3)(i)(F). The commenter stated that this comment also applies to subpart HH. [Note: The commenter did not provide section number in subpart HHH, it can be assumed that they were referring to §63.1281.]

Response: The EPA agrees that control devices that have had a performance test under other EPA regulations should be exempt from the performance test requirements under subparts HH and HHH. Therefore, the EPA has added a new paragraph (vi) to §63.772(e)(1) of final subpart HH and §63.1282(d)(1) of final subpart HHH as follows:

> **(vi) A control device for which a performance test was conducted for determining compliance with a regulation promulgated by the EPA and the test was conducted using the same methods specified in this section and either no process changes have been made since the test, or the owner or operator can demonstrate that the results of the performance test, with or without adjustments, reliably demonstrate compliance despite process changes.**

Comment: Commenter IV-D-06 suggested that subpart HHH specify what constitutes a compliance demonstration for flares. According to the commenter, subpart HHH never says whether a compliance demonstration is required for flares, or how to conduct a compliance demonstration. The commenter cited three examples where §63.1281(d)(3)(ii) points to §63.11(b) of subpart A, and does not contain a specific requirement for a compliance demonstration:

- Section 63.11(b) requires the fuel for a flare to have a certain minimum net heating value and how the net heating value would be determined. However, nothing in §63.11(b) says the owner or operator must actually perform the calculations at a certain time, on a certain fuel, to demonstrate compliance.

- Section 63.11(b) requires that flares be designed for, and operated with, no visible emissions and what test method must be used to determine whether there are visible emissions. However, nothing in §63.11(b) says the owner or operator must actually perform the visible emissions test at a certain time, to demonstrate compliance.

- Section 63.11(b) requires that steam-assisted and nonassisted flares be designed for and operated with an exit velocity less than a certain figure, with specified exceptions. Air-assisted flares are given a different limit for the exit velocity. The regulations also provide a method for determining the exit velocity in each case. However, nothing in §63.11(b) says the owner or operator must determine the exit velocity at a certain time, to demonstrate compliance.

The commenter contended that if subpart HHH references §63.11(b) for flares, nothing requires a compliance demonstration for flares. The commenter stated that they believe that enforcement actions have been taken by some EPA personnel, based on the interpretation that §63.11(b) requires a compliance demonstration for flares. However, the commenter does not think that §63.11(b) actually requires a compliance demonstration. Therefore, the commenter requested that subpart HHH specify what elements are included in the compliance demonstration and what the deadline is. The commenter provided the following language that could be inserted to replace §63.1281(d)(3)(ii).

> (ii) Notwithstanding any other provision of this subpart, if an owner or operator uses a flare to comply with any of the requirements of this subpart, the owner or operator shall comply with (ii)(A) through (ii)(C) of this paragraph. The owner or operator is not required to conduct a performance test to determine the percent emission reduction or outlet HAP or TOC concentration. If a compliance demonstration has been conducted previously for a flare, using the techniques specified in (ii)(A) through (ii)(C) of this paragraph, that compliance demonstration may be used to satisfy the requirements of this paragraph if either no deliberate process changes have been made since the compliance demonstration, or the owner or operator can demonstrate that the results of the compliance demonstration reliably demonstrate compliance.
>
> (A) Conduct a visible emissions test using the techniques specified in §63.11(b)(4) of subpart A;
>
> (B) Determine the net heating value of the gas being combusted, using the techniques specified in §63.11(b)(6) of subpart A; and
>
> (C) Determine the exit velocity using the techniques specified in either §63.11(b)(7)(i) and

§63.11(b)(7)(iii) where applicable, or §63.11(b)(8), as appropriate.

The commenter stated that this comment also applies to subpart HH.

<u>Response:</u> The EPA agrees that specific requirements for a flare compliance test are necessary. Therefore, the final rules contains §63.772(e)(2) (for subpart HH) and §63.1282(d)(2) (for subpart HHH) as follows:

> **(2) An owner or operator shall design and operate demonstrate the performance of each flare in accordance with the requirements specified in §63.11(b) and in paragraphs (e)(2)(i) and (ii) [or (d)(2)(i) and (ii) for subpart HHH] of this section.**
>
> **(i) The compliance determination shall be conducted using Method 22 of 40 CFR part 60, appendix A, to determine visible emissions.**
>
> **(ii) An owner or operator is not required to conduct a performance test to determine percent emission reduction or outlet organic HAP or TOC concentration when a flare is used.**

<u>Comment:</u> Regarding the requirement for combustion sources (95-percent emission reduction, or 20-ppmv outlet concentration), commenter IV-D-07 asked how compliance with the requirement is to be demonstrated, and under what operating conditions the requirement is applicable.

<u>Response:</u> Compliance with the requirement for combustion sources (95-percent emission reduction, or 20-ppmv outlet concentration) is demonstrated by monitoring specified operating parameters [see §63.773(d)(3)(i)(A) through (G) of final subpart HH or §63.1283(d)(3)(i)(A) through (G) of final subpart HHH for specific parameters]. For each operating parameter monitored, the owner or operator selects a minimum or maximum operating parameter value (as appropriate) at which the control device must be operated continuously to achieve the applicable performance requirements. The minimum or maximum operating

parameters are established based on the control device manufacturer's recommendation along with either values measured during a performance test or the control device design analysis. For example, §63.773(d)(3)(i)(A) of final subpart HH requires an incinerator to be equipped with a temperature monitoring device. The owner or operator must establish a minimum operating temperature, either by performance test, or design analysis, at which the incinerator must be operated continuously to achieve 95-percent emission reduction. The data collected by the temperature monitoring device must not fall below the minimum operating temperature.

Emissions from a glycol dehydration unit are required to be routed to a control device if the glycol dehydration unit has a natural gas throughput greater than 3 MMscf/d or benzene emissions greater than 1 tpy. If the owner or operator chooses to use a combustion device to comply with the process vent control requirements, the combustion device must achieve 95-percent emission reduction or 20-ppmv outlet concentration. In addition, the final rule allows owners or operators to install control technologies that reduce emissions from glycol dehydration unit process vents to 1 tpy of benzene or less.

Comment: Commenter IV-D-14 asked how operating parameter values used in demonstrating compliance would be assigned and who would be responsible for determining the appropriate values.

Response: The owner or operator is responsible for determining the appropriate operating parameter values (either as a minimum or a maximum) to use to demonstrate compliance [§63.773(d)(5) of final subpart HH and §63.1283(d)(5) of final subpart HHH]. The operating parameter values must be based on either performance testing or design analysis, supplemented with

the manufacturer's recommendations [§63.773(d)(5)(i)(A) and (B) of final subpart HH and §63.1283(d)(5)(i)(A) and (B) of final subpart HHH]. The established operating parameters and the rationale for choosing them, must then be submitted in the Notification of Compliance Status Report [§§63.775(d)(5) and 63.1285(d)(5) of the final rules].

Comment: Commenter IV-D-12 requested that the EPA clarify the methods proposed for demonstrating adequacy of control performance and that the EPA provide examples to show how these methods should be applied.

Response: The EPA agrees that subparts HH and HHH should be clarified to specify when performance tests or design analyses should be conducted. Therefore, the EPA has language to subparts HH and HHH to clarify how compliance is demonstrated using performance tests and design analyses. Section 63.772(f) of final subpart HH and §63.1282(e) of final subpart HHH contain requirements for demonstrating compliance for all control devices. As an alternative, the owner or operator may choose to demonstrate compliance using condensers in accordance with §63.772(g) of final subpart HH or §63.1282(f) of final subpart HHH.

Sections 63.772(e)(4) and 63.1282(d)(4) of the final rules specify that the performance tests must be conducted according to the schedule in §63.7(a)(2) of subpart A and the results must be submitted in the Notification of Compliance Status Report required in the appropriate subpart. Examples of how test methods should be applied will be included in implementation guidance to be published after the promulgation dates for subparts HH and HHH.

Comment: Commenter IV-D-12 stated that a design analysis is the appropriate way to demonstrate control device efficiency because methods to perform emissions performance tests on dehydrator vent streams are unreliable. However, the commenter stated that approval of the design analysis on a case-by-case basis is inappropriate and could result in "an administrative bottleneck to efficient implementation of the standard." The commenter recommended that the EPA define calculations and records to demonstrate control efficiency and that records be kept on file similar to that required by some NSPS.

Response: **The EPA provided the option for an owner or operator to perform design analyses instead of a performance test because design analyses are a generally less expensive option, and simpler to perform than conducting a performance test. However, due to the potential for variability in design analyses, the EPA believes that approval on a case-by-case basis is necessary. Therefore, the EPA has not modified subparts HH and HHH in response to this comment.**

Comment: Commenter IV-D-05 referred to §63.772(f) which allows for an alternative to the documented test procedures of §63.772(e) if the ARL test is performed in accordance with the procedures in GRI-95/0368.1. According to the commenter, this type of test will not give results of how a condensing unit is working because glycol concentrations are not changed just because a condensing unit is added to the still column vent. The commenter recommended that the EPA allow the use of GLYCalc as an alternative since it was designed to model the emission effects of various control devices. In support of this recommendation, the commenter noted that using GLYCalc is allowed to determine exemptions from the control requirements.

Commenter IV-D-22 recommended that the EPA amend Section 63.772(b)(2) by adding subpart (iii) as follows:

> (iii) The owner or operator shall determine an average emissions rate of benzene in tons per year following the procedures specified in GRI Publication 95/0368, March 1996.

The commenter stated that the ARL method has been approved as an accurate method of measuring emissions by the EPA Emission Factor and Inventory Group (memorandum, dated October 26, 1995). The commenter also recommended that the EPA amend §63.772(f) to make it clear that the ARL method can be used to calculate BTEX emissions from a dehydrator in an uncontrolled state. To calculate condenser control efficiency, as intended in §63.772(f), the results of the ARL method must be used in conjunction with GLYCalc to calculate condenser control efficiency. The commenter recommended that the EPA amend §63.772(f) by inserting "in conjunction with GLYCalc to calculate control device performance" at the end of the proposed section.

Response: **The ARL method is intended to be used for determining uncontrolled emissions from the glycol dehydrator. The EPA intended that the ARL method would be used in conjunction with GLYCalc to determine condenser performance. Therefore, proposed §§63.772(f) and 63.1282(e) [now codified at §63.772(e)(5) and 63.1282(d)(5) of the final rules] have been modified to clarify that the results from the ARL method can be used as inputs to GLYCalc (Version 3.0) to estimate condenser control efficiency.**

Additionally, the EPA agrees with the commenter that the ARL method should be allowed as an input to GLYCalc for estimating actual benzene emissions. Therefore, §§63.772(b)(2)(i) and 63.1282(a)(2)(i) of the final rules state that the procedures documented in the GRI report entitled, "Atmospheric Rich/Lean Method for Determining Glycol Dehydrator Emissions" (GRI-95/0368.1), can be used in conjunction with GLYCalc to determine actual benzene emissions.

Comment: Commenter IV-D-07 questioned whether the parameters listed in §63.1281 for the condenser design analysis (i.e., vent stream composition, constituent concentrations, flow rate, relative humidity, and temperature) refer to the natural gas stream entering the contactor tower. For the outlet, the commenter also asked if they need to determine the outlet organic concentration levels or levels of controlled emissions. The commenter noted that not all condensers have a specific coolant fluid for which inlet and outlet temperatures can be measured (e.g., air-cooled vs. glycol-cooled, water-cooled, or forced draft).

Response: The parameters required for the condenser design analysis (i.e., vent stream composition, constituent concentrations, flow rate, relative humidity, and temperature) refer to characteristics of the emission stream to be treated by the condenser, in this case, glycol dehydration unit process vent streams (consisting of reboiler vent emissions, or flash tank vent emissions, or both).

The design analysis was intended to provide some relief from the burden of demonstrating compliance with the control device performance requirements, by giving the owner or operator an alternative to performance testing. The parameters required for the design analysis (i.e., design outlet organic concentration, design average temperature of the condenser exhaust vent stream, and the design average temperatures of the coolant fluid at the condenser inlet and outlet) are required to show that the condenser was designed, based on the process vent stream characteristics, to achieve an emission reduction of 95 percent.

The intent of these design analysis requirements was not to require monitoring of outlet organic concentration level and coolant fluid inlet and outlet temperature. However, the design analysis should show that these factors were considered in the design analysis when establishing the operating temperature of the condenser exhaust stream, which is required to be monitored.

The EPA does not see any reason to modify subparts HH and HHH in response to this comment.

Comment: Commenters IV-D-08, IV-D-22, and IV-D-30 recommended that the EPA specify GLYCalc as an allowed tool to perform the design analysis for a condenser to determine compliance with the control requirements. Commenters IV-D-08 and IV-D-22 suggested that the design condenser exhaust stream temperature should be established as the maximum temperature that allows the condenser to achieve the control required by §63.771(d)(1)(ii). Commenter IV-D-22 stated that if GLYCalc is used to perform the design analysis, the EPA should delete the references to relative humidity, (air) temperature, and the design average temperatures of the coolant fluid at the condenser inlet and outlet, since these parameters are not required by GLYCalc. Commenter IV-D-30 recommended that the EPA add the following language to §63.771(d)(3)(iv)(A)(4): "For example, GLYCalc Version 3.0 or higher is an acceptable design analysis tool for the purposes of this paragraph."

Response: The EPA agrees that it is appropriate to allow an owner or operator to use GLYCalc as an alternative to the design analysis for condensers specified in proposed §§63.771(d)(3)(iv)(A)(4) and 63.1281(d)(3)(iv)(A)(4) [now codified at §§63.772(e)(4)(i)(D) and 63.1281(d)(4)(i)(D) of the final rules] and has modified §§63.772(e)(4)(i)(D) and 63.1282(d)(4)(i)(D) of the final rules accordingly. The requirements for using relative humidity, temperature, and design average temperatures of the coolant fluid at the condenser inlet and outlet in the design analysis are necessary to determine condenser performance when GLYCalc is not used. Therefore, the EPA has retained these requirements.

Comment: Commenter IV-G-09 stated that the direct benzene test in §63.1282(a)(2)(ii) is subject to significant inaccuracy because of the low pressure differential available for sampling dehydration unit vents. Therefore, according to the commenter, the GLYCalc model in §63.1282(a)(2)(i) or some alternative model is critical to demonstrate compliance successfully.

__Response:__ **The EPA agrees with the commenter. As proposed, subparts HH and HHH provide for the use of GLYCalc as an alternative for estimating benzene emissions.**

__Comment:__ Commenter IV-D-35 referred to proposed §63.1282(a)(2)(i) which requires the owner or operator to determine annual benzene emissions using GLYCalc. Inputs to the model are required to be "representative of actual operating conditions." The commenter was concerned that the variation in the ranges of values and the affect on emissions was uncertain. The commenter requested that §63.1282(2)(i) include some guidance on how the "representative" values for use with GLYCalc are to be developed. The commenter stated that they have worked with the industry to develop an approach with no success.

Similarly, the commenter was concerned that proposed §63.1282(a)(2)(ii) does not address how the glycol dehydration unit should be set up for a benzene emission test. According to the commenter, the activity level during a test may not represent yearly operations. The commenter requested guidance to produce meaningful results and stated that the use of the GLYCalc model may become very limited without guidance on input parameters in the proposed regulation.

__Response:__ **Because of the great variability in the operation of glycol dehydration units in the oil and natural gas production and natural gas transmission and storage source categories, the EPA could not develop guidance on what may be considered representative parameters within the final rules. However, the EPA plans to publish implementation guidance for these rules, following promulgation. It is up to the owner/operator to select and document the appropriate values for the parameters that they will be using as representative values.**

Comment: Commenter IV-G-14 requested that GLYCalc not be used to determine BTEX emissions from reboilers. The commenter was concerned that conditions may be altered to slant emissions to the low side. The commenter also stated that some companies are taking gas samples downstream of glycol contact towers, resulting in unrepresentative temperatures of the gas being processed being reported. The commenter stated that the GLYCalc program is not as acceptable as actual testing because of potential inaccuracies. However, the commenter stated that if typical conditions were listed as a guide for the reviewer to go by, then GLYCalc would be an acceptable method for determining emissions. The commenter noted that if the sampling port is downstream of a glycol contact tower the measurement would not be accurate because of glycol's affinity for benzene. The commenter also stated that safety concerns and moisture concerns are not problems for good stack testers.

Response: As stated in a previous response, the EPA reviewed GLYCalc and has determined that the program is an acceptable method for estimating emissions from glycol dehydration units.[25] The EPA also believes that owners/operators who use this program will determine accurate emission estimates due to the documentation required to establish representative parameters. The EPA intends to publish implementation guidance after the promulgation of subparts HH and HHH to aid inspectors in the evaluation of compliance with the regulations.

Sections 63.772(b)(2)(i) and 63.1282(a)(2)(i) of the final rules allow an owner or operator to use the ARL method as an input to GLYCalc. The ARL method specifies where the gas samples must be collected. When not using the ARL method, the GLYCalc

[25] Reference 24.

manual[26] provides guidance for the best locations for collecting gas samples. Therefore, §§63.772(b)(2)(i) and 63.1282(a)(2)(i) of the final rules specify that the owner or operator should use the procedures specified in the GLYCalc Manual for collecting gas samples.[27]

<u>Comment:</u> Commenter IV-G-15 recommended that the Agency require stack testing of controlled and uncontrolled emissions points whenever possible, especially where condensers are used. The commenter submitted examples of testing methods (including proposed sampling procedures for testing glycol dehydrators submitted at the commenter's request by commenters IV-G-16 and IV-G-17), and requested that the test methods in the final rule specify how to test instead of providing general guidance on testing. The commenter noted that LDEQ has conducted emissions tests of compressors and boilers in addition to other emissions points in the source category. The commenter noted that benzene emissions are significant and should be tested rather then modeled.

<u>Response:</u> The EPA provides an owner or operator with the option of conducting an emission source test (i.e., a stack test) or design analysis. The EPA realizes that an emission source test may impose a severe burden on many owners or operators (the costs associated with planning and conducting such a test) in the oil and natural gas production and natural gas transmission and storage source categories. Thus, the EPA included design analyses as an acceptable option for demonstrating compliance to reduce the overall burden. The EPA includes references to

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[26] Radian International LLC. Technical Reference Manual for GRI-GLYCalc™: A Program for Estimating Emissions from Glycol Dehydration of Natural Gas, Version 3.0. Prepared for Gas Research Institute. Chicago, Illinois. GRI-96/0091. March 1996. pp. 7-1 through 7-14.

[27] Reference 26.

appropriate emission measurement methods and does not believe that articulating how to test is necessary. Therefore, the EPA has not modified subparts HH and HHH in response to this comment.

Comment: Commenters IV-D-22 and IV-G-11 requested that the EPA clarify compliance obligations by expressly indicating in §63.760(e) that the facilities failing to meet storage vessel thresholds of §63.764(c)(2) or that meet the glycol unit exemptions of §63.764(e) are not subject to any requirements of subpart HH.

Response: The EPA has determined that for the class of storage vessels that do not have the potential for flash emissions, the MACT floor is no control. Therefore, *storage vessels with the potential for flash emissions* are defined in final subpart HH to mean any storage vessel that contains a hydrocarbon liquid with a stock tank GOR greater than or equal to 1,750 scf/barrel and an API gravity greater than or equal to 40 degrees, and a hydrocarbon liquid throughput greater than or equal to 500 bpd. Since the affected source at an oil and natural gas production facility is defined, in §63.760(b) of the final rule, as each storage vessel with the potential for flash emissions, owners or operators of storage vessels that do not meet the definition of *storage vessels with the potential for flash emissions,* have no further obligations for those storage vessels under subpart HH. However, it should be noted that the owner or operator is subject to §63.10(b)(3) of subpart A and must maintain records of applicability determinations.

Each glycol dehydration unit with an actual annual average natural gas throughput less than 3 MMscf/d or with actual average benzene emissions less than 1 tpy are not exempt from the subpart, but are subject to recordkeeping and reporting requirements. In addition, these units must be included in the

calculation of PTE for major source applicability determinations. Furthermore, the exemptions provided in §63.764(e) do not apply to entire facilities, but to each individual glycol dehydration unit. Therefore, providing a general exemption for a facility in §63.760(e) would not be applicable.

As proposed, ancillary equipment and compressors located at natural gas processing plants with a VHAP concentration less than 10 percent and in VHAP service for less than 300 hours per year were not subject to the recordkeeping and reporting requirements. However, the EPA believes that recordkeeping requirements for these equipment are appropriate. Therefore, §63.755(d)(2) of final subpart HH contains recordkeeping requirements for the documentation of the information and data used to determine which ancillary equipment and compressors are exempt from the control requirements of §63.769 of subpart HH.

2.13.3 Compliance Dates

Comment: Commenter IV-D-38 suggested that §63.760(f)(2) be modified so that the effective date for new construction and reconstruction be six (6) months after the final rules are promulgated. The commenter was concerned that if the final rule is much less stringent than the proposed rule, operators would unnecessarily incur significant expenses to install controls that comply with the proposed rule.

Response: Sections 63.760(f)(2) and 63.1270(d)(2) of the final rules specify that the compliance date for new and reconstructed sources (i.e., sources that commence construction or reconstruction on or after February 6, 1998) is the date of initial startup, or the effective date of the rule, whichever is later. Therefore, the EPA believes that new or reconstructed sources have adequate time to comply with the final rule. Furthermore, since the final rule is not significantly less

stringent than the proposed rule (i.e., 95 percent control is required in the final rule), the EPA believes that owners or operators should not unnecessarily incur significant expenses to install controls that comply with the proposed rule.

2.14 WORDING OF REGULATIONS (OTHER THAN APPLICABILITY AND DEFINITIONS)

Comment: Commenter IV-D-16 recommended that the EPA delete the phrase "as expeditiously as practical" in proposed §63.760(f)(1) as it "is open to interpretation and disagreement by all." As an alternative, the commenter recommended that compliance should be by three years after the date of final rulemaking in the Federal Register. The commenter noted that this had been done by other MACT standards.

Response: The EPA intends for existing sources to achieve compliance no fewer than three years after the final rule is published. It is a benefit to the environment for sources to achieve compliance in less than three years. However, the EPA understands that the commenter is concerned about enforcement actions based on the phrase "as expeditiously as practical." The EPA does not feel that this phrase adds anything to subparts HH and HHH and has removed it from §§63.760(f)(1) and 63.1270(d)(1) of the final rules.

Comment: Commenter IV-D-06 requested that the EPA clarify the difference between "initial startup" and "startup." According to the commenter, these two terms do not have the same meaning. The commenter explained that the time between the completion of construction and the day of initial startup is used to try out and debug the equipment. The commenter stated that these trial runs are not initial startups and should not trigger the compliance date. The commenter suggested the following language for §63.1270(d)(2) to clarify and stated that any other sections in the rule that say "startup" should be changed as well.

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

The commenter stated that this comment may also apply to subpart HH.

<u>**Response:**</u> **The EPA agrees that only initial startups should trigger the compliance dates. Sections 63.760(f)(2) and 63.1270(d)(2) of the final rules have been modified to include the term "initial startup." Additionally, a definition for *initial startup* has also been added to §§63.761 and 63.1271 of the final rules, as follows:**

> ***Initial startup*** **means the first time a new or reconstructed source begins production. For the purposes of this subpart, initial startup does not include subsequent startups (as defined in this section) of equipment, for example, following malfunctions or shutdowns.**

<u>Comment:</u> Commenter IV-D-06 stated that subpart HHH is a HAP rule and not a VOC rule. The commenter recommended that references to VOC in the rule should be corrected. The commenter presented the following changes to §63.1271, and requested that any other paragraphs with references to VOC also be changed:

> *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~~ <u>HAP</u> vapors.

The commenter stated that this comment may also apply to subpart HH.

Commenter IV-D-07 questioned whether the EPA was suggesting a need to look at either TOC or HAP, or both TOC and HAP. According to the commenter, before §63.1281, only HAP is referred to, while §63.1281 refers to a 95-percent reduction of either TOC or total HAP.

<u>**Response:**</u> **In response to commenter IV-D-06, and to be consistent with the definition of *combustion device* in other rules, the EPA has made the following change to §§63.761 and 63.1271.**

> ***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.**

The EPA does not intend to regulate VOC or TOC under subparts HH and HHH, however, TOC has been included as a surrogate for HAP in determining control device efficiency. The EPA believes that allowing the owner/operator to measure TOC rather than HAP provides some flexibility for the owners and operators and still achieves the objective of reducing HAP emissions by the specified emission reduction.

Comment: Commenter IV-D-06 stated that §63.1281(c) should say "that closed-vent system must route all HAP gases, vapors and fumes emitted from the reboiler vent to a control device." The commenter explained that non-HAP gases and emissions from "the unit," but not from the reboiler vent (such as fugitive emissions) should not count.

Response: The EPA agrees that the requirement in §§63.771(c) and 63.1281(c) should specify that closed-vent systems should route HAP emissions from an affected source, and has made the recommended changes to subparts HH and HHH. However, the EPA does not agree the commenter's recommendation that §§63.771(c) and 63.1281(c) should specify that the emissions from the reboiler vent be routed to the control device through a closed vent system. In subparts HH and HHH the standards require closed-vent systems for more emissions points than just the glycol dehydration unit reboiler vent. Therefore, the EPA has not made this recommended change.

Comment: Commenter IV-D-06 pointed out several typographical errors.

(1) Remove the word "a" from the phrase ". . . either TOC or a total HAP in the exhaust gases," in §63.1281(d)(1)(i)(B).

(2) In Table 1, "Ethylene glycol" should be "Ethylene glycol"

(3) In Table 1, "p-Xylenea" should be "p-Xylene."

The commenter stated that this comment may also apply to subpart HH.

<u>Response:</u> **The EPA has made the recommended corrections.**

<u>Comment:</u> Commenter IV-D-06 requested that the word "practicable" in §63.1283(c)(4) be changed to the word "practical." According to the commenter, courts have interpreted "practicable" to mean "capable of being done," with little regard to the cost or other difficulties. The commenter was concerned that no matter how quickly they fixed a leak, it would have been "practicable" to fix it sooner. The commenter stated that they doubted the EPA intended to impose such a severe requirement. The commenter also stated that this comment may also apply to subpart HH.

<u>Response:</u> **The word "practicable" has been used in several regulations in the past (e.g., subpart H of the HON). The commenter did not cite, and the EPA is unaware of any instances where this language has been interpreted incorrectly. Therefore, the EPA does not see any reason to modify subparts HH and HHH based on this comment.**

<u>Comment:</u> Commenter IV-D-06 requested that the EPA revise the last sentence of §63.1283(d)(4)(ii) to read ". . . based on the control device design analysis <u>and/or</u> the control device manufacturer's recommendations." The commenter stated that this change would allow the possibility of not following the manufacturer's recommendations, which is important for the following reasons:

1. The EPA cannot lawfully delegate rulemaking power to manufacturers. The commenter felt that the manufacturers would be given the power to create binding law (without public notice, or an opportunity to comment) because whatever they wrote into their instructions would become mandatory.

2. Sometimes there will not be any single manufacturer to provide instructions.

3. Sometimes the manufacturer's instructions will not be appropriate for the use of the equipment. The commenter explained that the manufacturer may have never considered the intended use, or the environment in which the component would be placed.

The commenter stated that this comment may also apply to subpart HH.

Response: The EPA agrees with the commenter. Sections 63.773(d)(5) and 63.1283(d)(5) of the final rules specify that the minimum or maximum operating parameters should be set based on: (1) a performance test, supplemented by a control device design analysis or the control device manufacturer's recommendation or a combination of both [§§ 63.773(d)(5)(i)(A) and 63.1283(d)(5)(i)(A)], or (2) the control device design analysis, supplemented by the control device manufacturer's recommendation [§§ 63.773(d)(5)(i)(B) and 63.1283(d)(5)(i)(B)].

Comment: Commenter IV-D-07 stated that no graphic was shown for Figure 1 (Section III.A.2, page 6294).

Response: The figure is in the *Federal Register* version of the regulation (63 FR 6294).

Comment: Commenter IV-D-07 stated that the referenced equations are missing in the following sections: 63.772(a)(4)(iii)(D), 63.772(a)(4)(iv)(E), 63.1282(d)(3)(ii), 63.1282(d)(3)(iii), 63.1282(d)(4)(ii)(A), and 63.1282(d)(4)(iii)(B).

Response: The equations are in the *Federal Register* version of the regulation (63 FR 6318 and 6331).

2.15 GENERAL PROVISIONS

Comment: Commenter IV-D-13 stated that additional rulemaking or preamble language is needed to clarify the applicability of the General Provisions (40 CFR part 63, subpart A) to subpart HH. Commenter IV-D-06 stated that subpart HHH should not defer to subpart A, because according to the commenter, the General Provisions have significant flaws and should not be used as the basis for compliance in the MACT standard. The commenter provided four examples of flaws in the General Provisions.

1. Section 63.6(e)(3)(i)(A) says that the startup, shutdown, and malfunction plan must ensure that sources are operated in a manner that will minimize emissions "at least to the levels required by all relevant standards." The commenter remarked that this provision could be interpreted two ways, and neither one will work. According to the commenter, one interpretation could mean that emissions have to be minimized "as much as the relevant standards require during startup, shutdown, and malfunctions." The commenter stated that this will not work because the relevant standards refer to §63.6 for the requirements, resulting in an endless loop, with neither standard stating the requirements. The second interpretation could mean that emissions have to be minimized "as much as the relevant standards require during normal operation when there is not any startup, shutdown, or malfunction." The commenter noted that this is impossible, and would eliminate the reason for having special provisions for startups, shutdowns, and malfunctions.

2. The general provisions do not specifically address shutdowns of compliance equipment such as control devices. According to the commenter, under a literal reading of a MACT standard, the owner or operator might simply elect to shut down all the control devices and assert that no further emission standards apply because this is a "shutdown."

3. The General Provisions do not specifically address that some startups, shutdowns, and malfunctions affect only a portion of the process. According to the commenter, an owner or operator might assert that a malfunction in one small, localized portion of a process justifies shutting down the controls throughout the entire process, even though the malfunction does not impair the ability of other portions of the process to comply with the emission standards.

4. The General Provisions do not say how to deal with periods of non-operation when the relevant emissions have ceased. According to the commenter, a shutdown is a transitional state between operation and non-operation. The commenter stated that once the shutdown is complete, the process is idle and is not producing emissions. The commenter contended that it doesn't make sense to impose control requirements when there are no emissions. The commenter further explained that some inspectors have interpreted standards such that control devices must be monitored even when there is nothing for them to control. The commenter stated that the HON and other rules clarify that when there is nothing to monitor (i.e., when the process is not operating and there are no emissions), parameter monitoring of control devices is not required and sometimes a failure to monitor may be excused during startups, shutdowns, and malfunctions. The commenter explained that there are instances where imposing a requirement to continue monitoring would be inappropriate. For example, monitoring cannot be continued if the monitoring device has a malfunction or it might be necessary to "valve off" the monitoring device to keep the device from being damaged.

Because of the problems with the General Provisions, the commenter recommended that the EPA should not use the General Provisions as a basis for handling startups, shutdowns, and malfunctions. The commenter suggested that the EPA put provisions equivalent to the HON into §63.1272, which is currently reserved. The commenter provided the following language for the new §63.1272:

(a) The provisions set forth and in this subpart shall apply at all times except during startups or shutdowns, during malfunctions, and during periods of non-operation of the affected sources (or specific portion thereof) resulting in cessation of the emissions to which this subpart applies. However, if a startup, shutdown, malfunction, or period of non-operation of one portion of an affected source does not affect the ability of a particular emission point to comply with the specific provisions to which it is subject, then that emission point shall still be required to comply with the applicable provisions of this subpart during the startup, shutdown, malfunction, or period of non-operation.

(b) The owner or operator shall not shut down items of equipment that are required or utilized for compliance with the provisions of this subpart during

> times when emissions are being routed to such items of equipment, if the shutdown would contravene requirements of this subpart applicable to such items of equipment. This paragraph does not apply if the item of equipment is malfunctioning, or if the owner or operator must shut down the equipment to avoid damage due to a contemporaneous startup, shutdown, or malfunction of the affected source or portion thereof.
>
> (c) During startups, shutdowns, and malfunctions when the requirements of this subpart do no apply pursuant to paragraphs (a) and (b) of this section, the owner or operator shall implement, to the extent reasonably available, measures to prevent or minimize excess emissions to the extent practical. For purposes of this paragraph, the term "excess emissions" means emissions in excess of those that would have occurred if there were no startup, shutdown, or malfunction, and the owner or operator complied with the relevant provisions of this subpart. The measures to be taken shall be identified in the applicable startup, shutdown, and malfunction plan, and may include, but are not limited to, air pollution control technologies, recovery technologies, work practices, pollution prevention, monitoring, and/or changes in the manner of operation of the source. Back-up control devices are not required, but may be used if available.

The commenter also suggested adding the words "Except as otherwise provided in this subpart" to start §63.1281(d)(2). The commenter stated that this comment may also apply to subpart HH. Additionally, the commenter requested that the EPA modify Table 2 to list paragraph-by-paragraph the applicability of §63.6(e) to subpart HHH. The commenter stated that this comment also applies to subpart HH.

Response: **The EPA disagrees with the commenters that there are significant "flaws" in the existing subpart A General Provisions. However, the General Provisions are designed to be general in nature, and individual NESHAP may have reasons to override them to implement the intent of the General Provisions in a standard-specific setting. Consequently, the EPA has considered the commenters' concerns related to the startup, shutdown, and malfunction (SSM) provisions in §63.6(e) and has added the language suggested by commenter IV-D-06 to §§63.762 and**

63.1272 of the final rules. In addition, §§63.762 and 63.1272 of the final rule specify that an owner or operator must prepare a startup, shutdown, or malfunction plan as required in §63.6(e)(3), except that the plan is not required to be incorporated by reference into the title V permit.

The commenter is concerned that the requirement for the SSM plan to ensure that sources are operated in a way that will minimize emissions "at least to the levels required by all relevant standards" may result in unclear requirements or will be impossibly stringent by requiring sources to meet the NESHAP requirements during all SSM events. The intent of the requirements in §63.6(e) is that sources do their best to minimize emissions to the levels of the required standards (i.e., the individual subpart). This does not mean, however, that the source would be required to operate better than the standards or even to meet the standards during the SSM period, if the source is in compliance with the SSM plan. Because no plan can cover every conceivable situation, the duty of the owner or operator is to do the best he or she can to minimize emissions during all events, even those not specifically addressed by the plan, based on good engineering judgement, expertise, and familiarity with the equipment, as well as following protocols for similar events that are in the SSM plan, if any.

Commenter IV-D-06 suggested that the General Provisions could be interpreted to allow a source to shut down control devices to "eliminate" emissions or to shut down controls for an entire process if only a portion of that process has a SSM event. Section 63.2 of the General Provisions defines shutdown as the "cessation of operation of an affected source for any purpose." The EPA believes that the general duty to operate and maintain at

all times, including periods of SSM, "any affected source, including associated air pollution control equipment, in a manner consistent with good air pollution control practices for minimizing emissions" [§63.6(e)(1)(i)] precludes the possibility of sources invoking the commenter's interpretation. In fact, such actions would be considered a violation of the requirements.

The EPA agrees that there are limited cases where continued monitoring of air pollution control devices during periods of SSM serves no useful function. These cases should be addressed in the source's SSM plan, which the State has the authority to review and approve. However, to address the commenter's concern, §§63.773(d)(8) and 63.1283(d)(8) of the final rule specify that emissions during SSM events when the facility is operated in accordance with the SSM plan, and periods of non-operation of the unit or process that is vented to the control device (which result in cessation of emissions), are not considered excursions.

Although the HON requirements do not specifically require monitoring during periods of SSM, EPA policy is that, unpromulgated rules should incorporate requirements for monitoring to be continued at all times. This includes monitoring during periods of SSM, since these records will provide the Agency valuable information on the adequacy of the source's SSM plan and also adherence to the requirement that emissions are minimized.

Comment: Commenter IV-D-06 requested that the EPA revise Table 2 to say that §63.7(c) does not apply to subpart HHH. According to the commenter, the requirement in §63.7(c) of the General Provisions for a site-specific test plan is "unduly burdensome" and has not been required in various other MACT standards. The commenter stated that if subpart HH also incorporates §63.7(c), then this comment also applies to subpart HH.

Response: **Site-specific test plans must be developed, but only need to be submitted to the Administrator for approval upon request of the Administrator. Subparts HH and HHH do not specifically require a site specific test plan. Therefore, to provide State and local permitting authorities the authority to request site-specific test plans, the EPA has not changed the applicability of §63.7(c) to subparts HH and HHH.**

Comment: Commenter IV-D-16 stated that the requirements of §63.6(e)(3) to prepare and follow a startup, shutdown, and malfunction plan should not be applicable to sites in subpart HH, since they are likely to be unmanned. The commenter did suggest that manned gas plants could be required to develop a plan, but other sources subject to subpart HH should not be subject to §63.6(e)(3).

Response: **The EPA disagrees that unmanned sites should not have SSM plans. Such plans are perhaps even more essential at unmanned sites to ensure that emissions are minimized and problems addressed as soon as possible. Plans at these sites may include alarm systems and computerized protocols and other measures to ensure that appropriate steps are taken to notify operators of problems and to initiate steps to minimize emissions. Automated process shutdowns may be required when certain events occur.**

2.16 MISCELLANEOUS

2.16.1 Health Effects

Comment: Commenter IV-D-28 stated that the EPA should qualify its statement regarding ethyl benzene's potential inhalation effects, and reference the many assumptions and uncertainty factors required in extrapolating from experimental results in animal studies to potential human effects at actual concentrations found in the environment.

Response: The proposed rule is technology-based rather than risk-based, so the summary of toxic effects for ethyl benzene has no influence on the proposed NESHAP. The EPA included health effects summaries for ethyl benzene and the other hazardous air pollutants emitted by this source category to provide the public with background information about possible effects of overexposure. The EPA agrees that there are substantial uncertainties associated with interspecies extrapolation, and has established national risk assessment guidelines to incorporate these uncertainties into risk assessments. However, no risk assessment has been performed in support of the proposed rule. Thus, the requested explanation of how these uncertainties are considered, which would necessarily be detailed and long, would serve no useful purpose.

Comment: Commenter IV-D-28 stated that while the EPA does not identify the studies on which the conclusions on ethyl benzene inhalation effects are based, it appears to be relying principally on adverse effects observed in animal studies.

Response: Given the brevity of the summary, the EPA believes it has clearly and fairly represented where animal and human studies have been considered. The use of animal data in this context is not unusual. Lack of adequate human data for long-term exposures often makes it necessary to rely on animal data to predict potential health effects.

Comment: Commenter IV-D-28 stated that the EPA has frequently used qualifying language in describing the health effects associated with chemicals . . . for purposes of other NESHAP. The commenter suggested that the EPA should include similar [qualifying] language in this preamble.

Response: The EPA agrees that the suggested qualifying text, excerpted from the NESHAP for the printing and publishing industry, accurately reflects the EPA's current thinking on hazard identification, as expressed in the Agency's guidance on risk assessment. However, although the EPA believes that the lack of such qualifying text in this proposal does not necessarily mislead the public about the purpose of the proposed rule, this language has been included in the preamble to the final rule.

Comment: Commenter IV-D-28 stated that the EPA also should state that its summary is not intended to be relied on to characterize ethyl benzene's potential inhalation toxicity.

Response: The EPA has not suggested anywhere in the proposed rule that this brief paragraph should serve as a risk characterization. The section presents only a qualitative description of effects that may result from overexposure, and does not suggest where, when, or if such overexposure may occur.

Comment: Commenter IV-D-28 stated that the preamble fails to include any review of the scientific database on ethyl benzene's toxicological effects, or reference any animal or human inhalation studies of ethyl benzene. According to the commenter, absent such a review the EPA should not publish, in a Federal Register notice, findings regarding a chemical's health risks.

Response: The EPA agrees with the commenters' point that risk assessment findings should be fully supported by a review of the toxicological database. However, the 5-sentence summary of toxic effects cannot be construed as a risk assessment for ethyl

benzene. It contains only qualitative descriptions of potential effects of overexposure, and presents no findings regarding risks from ethyl benzene exposure (or any information at all about exposure). This paragraph does not need to be, and makes no pretense of being, a fully-referenced review of the scientific database.

<u>Comment:</u> Commenter IV-D-28 stated that the EPA states that "short-term inhalation of high levels of ethyl benzene in humans may cause throat and eye irritation, chest constriction, and dizziness." The commenter requested that the EPA delete this statement from the preamble to the final rule. The commenter further stated that if the EPA does not delete the discussion entirely, the EPA should, at a minimum, acknowledge the substantial database demonstrating the absence of acute effects following inhalation exposure to ethyl benzene.

<u>**Response:**</u> **The EPA based its description of short-term respiratory and ocular effects on a review of the toxicological literature by the U.S. Agency for Toxic Substance and Disease Registry (ATSDR).[28] ATSDR's supported its description of throat irritation, chest constriction, and burning eyes accompanied by profuse lacrimation at ethyl benzene levels above 1000 parts per million with numerous literature citations. The commenters' citation of other studies that failed to show such effects, while potentially interesting, does not change the results of studies that did report these effects.**

<u>Comment:</u> Commenter IV-D-28 stated that the EPA also should acknowledge that levels of ethyl benzene in the ambient air are well below those at which adverse health effects have been observed.

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[28] Agency for Toxic Substance and Disease Registry , 1997. Toxicological Profile for Ethyl benzene. Public Comment Draft. Toxicology Information Branch, Atlanta, GA

Response: **The EPA's preamble to the proposed rule (paragraph 1, last sentence) states, "In general, these findings have only been shown with concentrations higher than those in the ambient air." This statement applies to ethyl benzene as well as the other hazardous air pollutants for which the preamble describes health effects. The EPA believes that this statement already addresses the commenter's concerns in a manner that is more than fair. Because the EPA lacks positive evidence that all locations in the United States are free from hazardous ambient concentrations of ethyl benzene, it is impossible to further strengthen this statement.**

Comment: Commenter IV-D-28 requested that the EPA delete, or qualify substantially, its statement regarding ethyl benzene's teratogenic effects in animals to reflect the toxicological database accurately.

Response: **ATSDR's 1997 review of the health effects of ethyl benzene,[29] describes several animal inhalation studies that reported delayed skeletal development, increased incidence of extra ribs, and renal malformation. The EPA believes that the sentence currently in the preamble, "Birth defects have been reported in animals exposed via inhalation; whether these effects may occur in humans in not known," is a fair condensation of ATSDR's review. As with the acute effects above, the commenter's citation of a study for which no teratogenic effects were found does not change the conclusion, based on positive data, that such effects are possible.**

Comment: Commenter IV-D-28 requested that the EPA delete, or revise substantially, its discussion of ethyl benzene's potential chronic health effects. According to the commenter, the

[29] Reference 28.

EPA's statement does not accurately describe ethyl benzene's potential hematological effects and may potentially mislead users, consumers, and regulatory bodies about the health risks associated with repeated exposure to ethyl benzene. Additionally, the EPA's statement is inconsistent with the relatively low toxicity assigned to ethyl benzene under the EPA's Sector Facility Indexing Program (SFIP).

Response: **The EPA agrees that the language in the current preamble does not describe ethyl benzene's chronic effects well, or in fact at all. Reported effects to the rodent kidney include increased kidney weight and increased activity of several kidney enzymes. Hepatic effects reported in animal studies include increased liver weight, altered enzyme activity, and degenerative changes in liver cells. Hematologic effect reported in workers occupationally exposed to ethyl benzene include decreased hemoglobin levels and increased lymphocyte count. The EPA believes the current brief description, "Animal studies have reported blood, liver, and kidney effects associated with ethyl benzene inhalation." is consistent with these findings and does not think additional background detail is needed to support the proposed rule.**

The EPA also agrees that ethyl benzene has relatively low toxic potential when compared with many other substances listed as hazardous air pollutants under section 112 of the Clean Air Act. However, the proposed action is not based on a risk assessment, and the preamble language therefore does not intend, or need, to convey information about risk. The one-sentence listing of chronic health effects refers only to adverse effects that may occur if the dose of ethyl benzene is high enough. Any further discussion of relatively low toxicity would need to be accompanied by information about the large amounts of ethyl

benzene emitted relative to other, more toxic, pollutants, none of which would be germane to the proposed rule.

Comment: Commenter IV-D-28 requested that the EPA clarify that adverse health effects have been observed only at ethyl benzene levels substantially higher than those found in the ambient air.

Response: The commenters' data on ethyl benzene concentrations is generally consistent with the EPA's data. The EPA agrees that our current understanding, based on these air monitoring data and on modeled concentrations, suggests that ethyl benzene does not currently pose a national threat. However, measured concentration data are sparse, and detailed modeling has not been conducted for many areas. These very substantial data gaps prevent the EPA from conclusively stating that no location in the United States experiences ethyl benzene levels above the reference concentration.

Furthermore, the National Toxicology Program (NTP) recently released data that suggest ethyl benzene may be carcinogenic in animals. If further studies bear this out, perceived "safe" levels of ethyl benzene may change substantially. This uncertainty about carcinogenicity also prevents any categorical guarantee of safety from health effects of ethyl benzene. The EPA believes the current statement, "In general, these findings have only been shown with concentrations higher than those in the ambient air," is the strongest that can accurately be made.

2.16.2 Other Miscellaneous Comments

Comment: Commenter IV-D-06 supported semiannual reporting of actions inconsistent with the startup, shutdown, and malfunction plan instead of immediate reporting and suggested that the EPA apply the concept to all MACT standards (including standards that have already been promulgated). The commenter cited three reasons that immediate reporting has been an unnecessary burden. First, the commenter contended that just because actions are inconsistent with the startup, shutdown and malfunction plan, does not mean that excess emissions have occurred. Second, even if excess emissions have occurred, they are not necessarily an immediate health threat (most HAP concerns are related to long-term, rather than short-term, exposure). Third, in any case where short-term emissions may be a concern, there are better ways to address those concerns (including immediate reporting under CERCLA section 103 or SARA section 304, or emergency response actions under EPA's Risk Management Programs rule implementing section 112(r) of the Act). The commenter stated that retrofitting semiannual reporting into existing MACT standards should not be a major burden on the EPA as it is a minor change and would not likely be controversial.

Response: While the EPA is continually reviewing the burdens imposed by its regulations in an attempt to reduce these burdens, no changes have been identified at this time.

Comment: Commenter IV-D-38 stated that the proposed rules exceed the EPA's authority under section 112 of the CAAA and the intent of Congress in promulgating the CAA.

Response: The EPA is required to develop NESHAP under section 112(d) of the CAA for listed source categories and has not exceeded its authority.

Comment: Commenter IV-D-04 stated that based on the data presented by the EPA, there are many small natural gas production, transmission and storage facilities that are small sources of HAP. According to the commenter, these sources are already regulated under State rules and the commenter requested that the EPA not regulate these sources further.

Response: When developing the MACT floor for production and transmission and storage facilities, the EPA made several distinctions between sizes of emissions units. For example, the EPA developed a MACT floor for large glycol dehydration units

(natural gas flowrate greater than or equal to 3 MMscf/d or benzene emissions greater than or equal to 1 tpy) and one for small glycol dehydration units (natural gas flowrate less than 3 MMscf/d or benzene emission less than 1 tpy). In this case, the MACT floor for small glycol dehydration units was determined to be no control and these units are not required, in the final rules, to be controlled. Therefore, the NESHAP are focussed on facilities with significant HAP emissions. These criteria will exempt a large number of facilities in the oil and natural gas production and natural gas transmission and storage source categories from regulatory requirements and installation of controls due to their small size and low emissions. These applicability criteria include benzene emission rate, natural gas throughput, storage tank throughput, and hours of operation and apply only to major sources.

2.17 GENERAL COMMENTS SPECIFIC TO SUBPART HHH (NOT OTHERWISE ADDRESSED)

Comment: Several commenters were concerned with the EPA's proposed standard for the natural gas transmission and storage source category and the EPA's apparent lack of information used to develop the standard. Commenter IV-D-31 stated that the inclusion of natural gas transmission and storage in the oil and natural gas production rulemaking has compromised the regulatory process and denied affected stakeholders equal opportunity for input. Although the commenter was pleased that the EPA created a separate source category for the transmission and storage industry, they suggested that the EPA did not truly develop separate MACT standards for the two source categories. Furthermore, the commenter stated that including the transmission and storage source category in this proposal is inconsistent with the procedures of the CAA of 1990. According to the commenter, the EPA extended the oil and natural gas production source category, without adequate notice and opportunity to comment to include the natural gas transmission and storage sources.

The commenter stated that the EPA is obligated to provide equal opportunity for the natural gas transmission and storage industry to work with the EPA during the rulemaking process. The commenter further stated that regulating both sources simultaneously, to save limited resources, does not justify "abandoning well-established procedures for developing a MACT that is achievable." The commenter stressed that in raising these issues they are not attempting to avoid or delay regulation but insisting on the right to the benefit of the full MACT development process, including source category listing, data gathering, determination of a MACT floor, and source category-specific standards.

Commenters IV-D-07, IV-D-12, IV-D-31, IV-G-09 stated that the EPA has insufficient data to develop a standard for the transmission and storage source category. The commenters requested that the EPA delay the transmission and storage portion of the rulemaking to properly survey the industry for more meaningful data, and assess whether a standard for the natural gas transmission and storage source category is necessary or achievable. According to commenter IV-D-07, the EPA would create confusion "by leaving numerous questions unanswered and terms undefined or interrelated with the proposed oil and gas production standard" in its haste to develop a standard for the natural gas transmission and storage source category simultaneously with that of the production source category. Additionally, commenters IV-D-07 and IV-D-31 stated that the EPA has proven a lack of information on this source category by asking for emission point comments on reboiler vents, flash tanks (GCG separators), storage vessels with flash potential, pipeline pigging and storage of pipeline pigging wastes, and equipment leaks.

Response: The EPA contacted potential stakeholders in the initial phase of the development process for this NESHAP to identify a list of interested stakeholders. The public record, contained in EPA Air Docket A-94-04, has correspondence and meeting summaries that show that the EPA had continual contact with interested stakeholders, including representatives of the natural gas transmission and storage source category. However, to address industry concerns on the adequacy of the database used in the development of proposed subpart HHH for natural gas transmission and storage facilities, the EPA has collected additional information on glycol dehydration units in the natural gas transmission and storage source category. The EPA conducted site visits to five natural gas transmission and storage facilities to gain additional first-hand knowledge of the processes and operations at existing facilities in this source category. The EPA also met with stakeholders from the natural gas transmission and storage industry to understand their concerns. The EPA developed a questionnaire for distribution to eight natural gas transmission and storage companies under the authority of section 114 of the CAA. In the questionnaire, the EPA requested data on the processes, operations, and control technologies in use at existing natural gas transmission and storage facilities and relevant to the development of HAP emissions standards for glycol dehydration units.

Through the questionnaire and site visits, the EPA collected additional information on approximately 83 glycol dehydration units in the natural gas transmission and storage source category. The EPA considered this new information, along with the previously collected information on the natural gas transmission and storage source category, to develop a MACT floor for process vents on glycol dehydration units located at existing and new facilities in this source category.

On January 15, 1999, the EPA published a supplemental notice announcing the availability of and to discuss the consideration of, the additional information on the natural gas transmission and storage source category collected by the EPA since proposal (64 FR 2612). The additional data announced in the January 15, supplemental notice included the following items located in Air Docket A-94-04: (1) completed responses to the EPA's section 114 survey questionnaire, items IV-G-24, and IV-G-26 through IV-G-32; (2) site visit information, items IV-G-21, IV-G-22, and IV-G-25; and (3) meeting summary of the meeting with representatives of the Interstate Natural Gas Association of America, the Gas Research Institute, and industry, item IV-E-02. The EPA has also prepared analyses of these data, items IV-A-01, IV-A-02 and IV-A-08.

Comment: Commenter IV-D-31 stated that the EPA underestimated the impact of the proposed regulation on the natural gas transmission and storage source category, due to the EPA's lack of sufficient and representative information to develop a MACT standard. The commenter contended that the EPA underestimated the number of transmission and storage facilities that would be affected by subpart HHH (five out of 2,000) resulting in an underestimation of the cost impact. The commenter suggested that the EPA postpone the natural gas transmission and storage NESHAP (subpart HHH) to evaluate the industry properly and to develop a better estimate of what the MACT floor should be. The commenter offered to work with the EPA on the development of a separate proposal.

Response: As stated in the previous response, in response to comments on proposed subpart HHH, the EPA surveyed eight natural gas transmission and storage companies under the authority of section 114, conducted five site visits to transmission and storage facilities, and received additional information on 83 glycol dehydration units. In addition, the EPA had data on 31 glycol dehydration units that was collected during the development of the proposed NESHAP. According to the Oil and Gas Journal,[30] the total natural gas throughput handled by the companies for which the Agency had information represented approximately 14 percent of the total natural throughput for the entire industry. Of the 114 glycol dehydration units for which information was submitted, the EPA determined that one unit had the potential to be an affected source under subpart HHH.

Based on this information, the EPA projected the number of affected sources to a nationwide value. Since the available data represented approximately one seventh of the industry, the EPA estimated that seven glycol dehydration units would be affected

[30] True, W.R. Weather, Construction Inflation Could Squeeze North American Pipelines. Oil & Gas Journal. pp. 33-56. August 31, 1998.

sources. Although the MACT floor indicated that the best performing 12 percent of the existing sources used combustion (primarily flares) to control HAP emissions from the glycol dehydration units, the EPA assumed that at least one of the affected facilities would install a condensation unit to control HAP emissions. Thus, the environmental and cost impacts were based on six of the facilities installing a flare to meet the requirements of subpart HHH and one would install a condenser.

Table 2.17-1 presents a summary of estimated environmental, energy, and cost impacts for the natural gas transmission and storage standards for existing major sources. The impacts were revised using the same approach that was used for the proposed NESHAP. A detailed analysis regarding the estimated impacts of

TABLE 2.17-1
SUMMARY OF REVISED ESTIMATED ENVIRONMENTAL, ENERGY, AND COST IMPACTS FOR THE NATURAL GAS TRANSMISSION AND STORAGE STANDARDS FOR EXISTING MAJOR SOURCES*

Impact category	Existing Natural Gas Transmission and Storage*
Estimated number of impacted facilities	7
Emission reductions (Mg/yr)	
HAP	390
VOC	610
Methane	230
Secondary environmental emission increases (Mg/yr)	
Sulfur oxides	<1
Nitrogen oxides	<1
Carbon monoxide	<1
Energy (Kilowatt hours per year)	None
Implementation costs (Million of July 1993 $)	
Total installed capital	0.28
Total annual	0.3

* - 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 rule.

the NESHAP is presented in the docket (Air Docket A-94-04, number IV-A-08).

Comment: Commenter IV-D-31 was concerned that the EPA is regulating the natural gas transmission and storage industry similarly to the oil and natural gas production industry. According to the commenter, the EPA's "skewed data collection effort" resulted in a failure to make important distinctions between the transmission and storage and the production segments of the industry. The commenter was especially concerned about the potential impact of subpart HHH on underground storage facilities, as they are used to offset fluctuations in gas flow, reduce natural gas costs, and improve reliability. Commenters IV-D-07, IV-D-12, and IV-D-31 explained that a review of the background information for this standard showed that the database consisted of information on the methods used in natural gas transmission from only two companies and no underground storage facilities. The commenters noted that the companies surveyed were oil production facilities that handled gas as a by-product of oil production that have higher HAP emissions because they handle more liquids with higher concentrations of HAP. Furthermore, commenters IV-D-31 and IV-G-12 also noted that once the gas reaches the transmission and storage facilities, it has been dehydrated at least once, further lowering the concentrations of HAP. Commenter IV-G-12 also mentioned that exposing processed gas to ground water in a storage facility can increase the moisture content and require additional dehydration, but it does not necessary increase BTEX in the gas. The commenter referred to the GLYCalc manual for discussion of impact of BTEX concentration in the gas on dehydrator emissions.

Commenters IV-D-10 and IV-G-12 recommended changes in the exemptions for transmission and storage facilities. Commenter IV-D-10 requested that the size cutoff for transmission and storage be higher than that for production, since HAP emissions at transmission and storage facilities are generally much lower than production facilities. Commenter IV-G-12 recommended that the subpart HHH provide an exemption for transmission and storage facilities where the BTEX concentrations of the stored gas fall below a minimum threshold and it can be shown that the act of storing the gas does not cause an increase in the concentration of the BTEX in the gas when it is retrieved from storage. The commenter further explained that dehydrators serving transmission and storage facilities are fundamentally different from those located at production wells.

<u>Response:</u> In the proposal, glycol dehydration units operating at an actual annual average natural gas throughput less than 3 MMscf/d or having actual average benzene emissions less than 1 tpy were exempt from the control requirements. The EPA evaluated the data collected for 114 glycol dehydration units in the natural gas transmission and storage source category to determine whether there was a natural gas throughput level, or a benzene emission level for which glycol dehydration units operating below this level were not controlled.

In the new data, the Agency did not identify evidence to suggest that glycol dehydration units operating with actual annual average natural gas throughput rates less than 10 MMscf/d or having actual benzene emissions less than 1 tpy are controlled at the MACT floor and it was not cost effective to go beyond the floor for these glycol dehydration units.

In addition, the Agency does not have any information indicating that there are any sources in the natural gas transmission and storage source category operating below 10 MMscf/d or having benzene emissions less than 1 tpy that have emissions greater than the major source thresholds of 10 tpy for individual HAP or 25 tpy for any combination of HAP.

Therefore, the final subpart HHH exempts each glycol dehydration unit with an annual actual average natural gas

throughput less than 10 MMscf/d or actual average benzene emissions less than 1 tpy from the control requirements.

Comment: Commenter IV-D-31 stated that they believe that the EPA lacks sufficient and representative information on the natural gas transmission and storage source category to determine a MACT floor. The commenter noted that only one transmission facility, and no underground storage facilities, was surveyed. The commenter recommended that the EPA revise its MACT floor determination for transmission and storage dehydration units. The commenter suggested that the EPA did not include the additional cost that would be required to send personnel to remote, unmanned transmission and storage facilities to demonstrate compliance based on short averaging periods. The commenter stated that a longer averaging period would also be more practical and cost-effective, and more likely to be achievable by the best performing sources. The commenter asked the EPA to take the time to gather the information required to properly evaluate what is actually achieved by emission points in the natural gas transmission and storage source category.

Response: According to the information collected from 114 glycol dehydration units through the section 114 questionnaire, site visits, and data previously collected during the development of the proposed standards, 71 glycol dehydration units are controlled. Fifty-nine of these units utilize combustion as the control technology for process vents on glycol dehydration units. Of these, 51 utilize flares, seven utilize enclosed combustion devices, and one uses an in-stack flare system. Seven units utilize a combination of condensation and combustion to control glycol dehydration unit process vents and five utilize condensation.

The MACT floor analysis for the natural gas transmission and storage source category was based on information available on the

top 14 performing glycol dehydration units, which corresponds to 12 percent of 114 glycol dehydration units.

The EPA compared the control level data for the top 14 performing units to the proposed control level of 95 percent for process vents on glycol dehydration units at existing and new natural gas transmission and storage facilities. The available information indicates that the best performing 12 percent of the facilities, i.e., 14 units, utilize some form of combustion and achieve a HAP emission reduction of at least 98 percent. However, among all sources that apply combustion, the reported control efficiency ranged from 95 to 98 percent. The EPA was unable to determine the technical basis for the reported differences in the control efficiencies for these combustion devices. Therefore, in order to account for the observed variability in HAP emission reduction efficiency, the final rule requires 95 percent as the HAP emission reduction for this source category associated with this technology.

Under the proposed standards, the MACT floor for new sources was the same as the MACT floor for existing sources (i.e., 95-percent control). In the review of the new additional 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, as with the proposal, the EPA determined that the MACT floor for new sources in the natural gas transmission and storage source category was the same as the MACT floor for existing sources.

Comment: Commenter IV-D-31 supported the aggregation of equipment at compressor stations and single wells, with their associated equipment, for major source determinations. However, the commenter explained that natural gas storage fields cover large areas and operations are based on depleted production fields with the same surface separation of facilities as existing production fields. Therefore, the commenter, along with commenter IV-D-04, stated that aggregating emission sources at natural gas storage facilities for major source determinations is inconsistent with the meaning of section 112(n)(4)(A) of the CAA and that aggregating emission sources at these facilities suggests that the EPA has insufficient data regarding natural gas storage facilities. The commenters explained that glycol dehydrators at storage facilities do not emit significant quantities of HAP because the natural gas has been processed or dehydrated before it is injected into the storage fields, and has small amounts of HAP and VOC. According to the commenters, aggregating affected sources over large gas storage fields could result in major source determinations and the controls on each contributing affected source would be more expensive than the EPA has estimated, for small amounts of HAP reduction. The commenters recommended that the EPA collect data to characterize natural gas storage operations better.

Response: **Section 112(n)(4)(A) of the Act states that**

> **". . .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 . . .."**

The EPA has interpreted this provision to mean that individual pipeline compressor or pump stations shall not be aggregated with emissions from other stations. Nothing in the section 112(n)(4)(A) provisions refers to natural gas storage facilities as those facilities for which emission aggregation is not allowed. Additionally, the definition of *major source* in §63.1271 states that emissions from processes, operations, or equipment that are not part of the same facility shall not be

aggregated. Based on the EPA's knowledge of the industry, storage fields should have well-defined surface sites, preventing large areas from being considered part of the same facility.

Comment: Commenters IV-D-10 and IV-D-31 requested that the deadline for promulgation of the transmission and storage standard be changed from November 15, 1997 to November 15, 2000. The commenters noted that transmission and storage is a new source category.

Response: The EPA amended the source category list to add the natural gas transmission and storage source category as a major source category and proposed a regulation that would apply to major sources in this source category. As stated in section 112(c)(5) of the Clean Air Act as Amended in 1990 on the addition of source categories

> **". . .emission standards under subsection (d) for the category or subcategory shall be shall be promulgated within 10 years after enactment of the Clean Air Act Amendments of 1990, or within 2 years after the date on which such category or subcategory is listed, whichever is later."**

Although the natural gas transmission and storage source category is in the 10-year bin of source categories, by promulgating the proposed regulation on the current schedule, the EPA is complying with the requirements of the CAA.

Comment: Commenters IV-D-07 and IV-D-31 stated that the definition of *natural gas transmission* is misleading and mixes production terms with natural gas transmission terms. For example, "boosters" are only used on production lines. The commenters further remarked they did not understand the phrase "used for long distance transport" since "long distance" is not defined. The commenters recommended that the EPA use the Department of Transportation's definitions (49 CFR 192.3) for such terms as pipeline, transmission line, and transportation of natural gas.

Response: The EPA does not believe that further clarification of the definition for *natural gas transmission* is necessary. The definition of natural gas transmission in §63.1271 of subpart HHH was developed in consultation with stakeholders in the natural gas transmission and storage source category (Air Docket A-94-04 Numbers II-C-4, II-C-5, and II-D-53). As requested by the stakeholders, this definition is consistent with the definition used by the Federal Energy Regulatory Commission and adequately reflects the actual workings of the industry.

In addition, the EPA's understanding is that natural gas transmission pipelines differ from natural gas mains in that they typically operate at higher pressure, are longer, and the distance between connections is greater. Therefore, the EPA has retained the phrase "long distance transport" to maintain this distinction.

Comment: Commenter IV-D-16 stated that the term *associated equipment* does not need to be defined in subpart HHH since production sources are not covered. Commenter IV-D-35 agreed with proposed definition of associated equipment.

Response: The EPA agrees that the term associated equipment is unnecessary and has removed this term from §63.1271 of subpart HHH. In addition, the EPA has revised the definition of *major source* in §63.1271 as follows:

> *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 stations~~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.**

Comment: Commenter IV-D-16 stated that a *compressor station* is defined in §63.1271 as equipment that "...supplies energy to move natural gas at increased pressure from fields. . . ." The commenter requested that the reference to fields be deleted since subpart HHH does not cover production sites (i.e., fields).

Response: As suggested by the commenter, subpart HHH does not encompass production sites. However, it is possible for compressors, located in the transmission and storage source category, to move natural gas from production fields. Furthermore, the EPA developed this definition based on standard industry nomenclature. Therefore, the EPA does not believe that the change recommended by the commenter is warranted.

2.18 COMMENTS RECEIVED ON THE JANUARY 15, 1999 SUPPLEMENTAL NOTICE (64 FR 2611)

Comment: Commenters IV-G-38 and IV-G-37 indicated that they did not agree with a MACT floor of 95 percent for the transmission and storage source category. The commenters stated that capital expenditures had been made to control some existing dehydrators with condensers and that it would be unreasonable to require these sources to meet a MACT floor based on a different technology.

The commenters requested that the final rule should either exempt existing sources controlled by condensers, or require that existing sources controlled with condensers be controlled to a different level (i.e., 70 percent) than the combustion technology-based MACT floor. The commenters stated that the data show that condensers could consistently achieve a 75-percent emission reduction and that requiring an additional 20-percentage points of emission reduction in HAP would be inconsistent with the cost-to-benefit analysis in the February 6, 1998 proposal. In addition, commenter IV-G-36 stated that the 95 percent control level cannot be continuously achieved by the use of condensers alone.

Response: The EPA does not believe that it is appropriate to provide exemptions or alternative levels of control for existing glycol dehydration units that are controlled by condensers. The EPA believes that this would not be consistent with the Act, which specifies in section 112(d)(3) that for a source category with 30 or more sources (such as the transmission and storage source category), the MACT floor for existing sources shall not be less stringent than the " . . . the average limitation achieved by the best performing 12 percent of the existing sources. . . ." The data collected by the EPA indicated that the average limitation achieved by the top 12 percent of the existing glycol dehydration units located at natural gas

transmission and storage facilities was 95 percent. Furthermore, the data indicated that the top 12 percent of the existing glycol dehydration units were controlled using combustion or a combination of combustion and condensation. Therefore, in accordance with the statute, the EPA established the MACT floor to be 95 percent for glycol dehydration units located at natural gas transmission and storage facilities, which corresponds to combustion.

With regard to the comment regarding continuous compliance, in the supplemental notice the EPA did not address the issue of averaging period for condensers in use at transmission and storage facilities. The final subpart HHH allows an owner or operator that installs a condenser for control of HAP from glycol dehydration unit process vents to establish compliance with the 95-percent HAP emission reduction on a 30-day rolling average. In addition, the final subpart HHH allows the owner or operator to comply with: (1) 95 percent HAP emission reduction, (2) 20 ppmv outlet HAP concentration for combustion devices, or (3) outlet emissions of 1 tpy of benzene. The EPA believes that the 1 tpy benzene emission limit and the 30-day averaging period for condensers provides sufficient flexibility for owners and operators of existing controlled glycol dehydration units.

Comment: Commenters IV-G-37 and IV-G-38 referred to the proposed rule (63 FR 6288), which provided a 20 ppmv outlet HAP concentration limit for combustion devices. The commenters stated that the EPA did not provide rationale for dropping this limitation and requested that it be retained.

Response: The EPA did not drop the 20 ppmv requirement for combustion devices. The final rule requires owners or operators to meet: (1) a 95-percent HAP emission reduction, (2) a 20 ppmv

outlet HAP concentration limit for combustion devices, or (3) a 1 tpy outlet benzene emission limit.

Comment: Commenters IV-G-37, IV-G-38 ,and IV-G-39 agreed that exempting glycol dehydration units with actual annual average natural gas throughputs less than 283 thousand m^3/day from the control requirements under subpart HHH was appropriate. Commenters IV-G-37 and IV-G-38 stated that they were unaware of any dehydration units that operate at the higher flow rate that would exceed the HAP emission cut-off. In contrast, commenter IV-G-36 stated that a cutoff level of 10 MMscf/d would provide no significant relief to the majority of companies in the transmission and storage segment of the industry. Although they supported the change in the level for the cutoff, the commenter stated that dehydration units of this size would probably be exempt from the controls based on the criteria for major sources.

Response: **The EPA appreciates the commenters' support and the EPA believes that the cutoff level of 10 MMscf/d, which is based on the MACT floor determination, is appropriate for this industry. However, commenter IV-G-36 was incorrect in stating that dehydration units with natural gas throughput less than 10 MMscf/d would be exempt from controls based on the criteria for major source. This statement is true if the glycol dehydration unit is the only HAP emission source located at the facility. However, if the facility is determined to be major source due to the aggregation of all HAP emission sources located at the facility, then the owner or operator must comply with the control requirements for each glycol dehydration unit at that facility. Thus, only glycol dehydration units that have natural gas throughput less than 10 MMscf/d are exempt from control requirements at the major source.**

Commenter: Commenter IV-G-36 referred to Section I (Background) of the supplemental notice, which indicated that the original data included a questionnaire to one company with 31 glycol dehydration units. The commenter stated that they had assumed that this corresponds to the September 15, 1993 entry noted in table A-1 of the BID, Questionnaire to CNG Transmission Corporation.

__**Response:**__ **The commenter's assumption is correct. The EPA surveyed CNG Transmission Corporation and received information for 31 glycol dehydration units.**

__Comment:__ Commenter IV-G-36 reviewed the docket items listed in the supplemental notice as containing the information used by the Agency to evaluate the transmission and storage source category (Air Docket A-94-04 Numbers IV-E-02, IV-G-21, IV-G-22, and IV-G-24 through 32). The information contained in item IV-G-26 was deemed to be confidential. The commenter stated that the data they were able to review indicated that there were 89 additional glycol dehydration units, 14 of which were noted as having emission controls. The commenter stated that it was unclear how the EPA derived the numbers presented in Section III (MACT Floor for Existing Sources) regarding the total number of units and the number of controlled units. According to the commenter, the data they were able to review indicated that there are a minimum of 120 dehydration units (instead of the 112 reported by the EPA) of which 14 have been identified as having controls (instead of 69 as reported by the EPA). Furthermore, the commenter indicated that there was a discrepancy in the types of controls being utilized. However, the commenter also noted that the data on the original 31 units and the confidential information contained in docket number IV-G-26 were not reviewed.

__**Response:**__ **The discrepancy in the number of units that the commenter identified and the number of units reported in the supplemental notice resulted from the information not reviewed by the commenter including: the confidential information (i.e., information contained in site visit reports, and the information collected from one company under the authority of section 114),** the information collected during the development of the proposal, as well as the number of units for which no information was submitted as instructed in the section 114 questionnaire. Table 2.18-1 presents a summary of the information collected to identify the number of existing glycol dehydration units and the types of controls in use. As shown in the table, the EPA used three sources of information: section 114 questionnaire (data received 12/93), site visits (conducted in 10/98), and section 114 questionnaires (data received 10/98).

The number of glycol dehydration units identified in the response to the section 114 questionnaire in December 1993 is contained in the docket (Air Docket A-94-04 number II-D-26).

The data collected under the October 1998 section 114 questionnaire is also contained in the docket (Air Docket A-94-04

TABLE 2.18-1 SUMMARY OF THE INFORMATION COLLECTED FOR GLYCOL DEHYDRATION UNITS IN THE NATURAL GAS TRANSMISSION AND STORAGE SOURCE CATEGORY

Source of Information	Total Number of Dehydration Units Identified	Number of Dehydration Units for Which Information was Provided	Number of Dehydration Units that are Controlled (by Control Technology)				Number of Dehydration Units that are Uncontrolled
			Flares	Enclosed Combustion	Combustion and Condensation	Condensation	
Response to Section 114 questionnaire (data received 12/93)	31	31	21	0	0	0	10
Site Visits[a]	7	7	1	0	1	5	0
Response to Section 114 questionnaire (data received 10/98)[b,c]	106	76	30	7	6	0	33
Total	144	114	52	7	7	5	43

[a] Five facilities were visited, seven glycol dehydration units were identified. Site visit reports are contained in Air Docket A-94-04, numbers IV-B-01 through IV-B-05.

[b] Respondents were required to identify all dehydration units and submit information for dehydration units whose natural gas throughput was greater than 15 MMscf/d. Two respondents reported information for their dehydration units whose natural gas throughput was less than 15 MMscf/d. There were 30 dehydration units identified for which no information was provided.

[c] Information contained in docket A-94-04, item IV-G-26 represents 61 glycol dehydration units, of which information was provided for 46 units and 34 of these are controlled.

numbers IV-G-24 and IV-G-26 through 32). Respondents to the October 1998 section 114 questionnaire were instructed to submit all information on glycol dehydration units that have natural gas throughputs greater than 15 MMscf/d. Respondents were also instructed that the requested information was not required for each glycol dehydration unit where the natural gas throughput was less than 15 MMscf/d, but could be submitted if available. The respondents identified 30 glycol dehydration units that had natural gas throughputs less than 15 MMscf/d, and no information was submitted for these units (it should be noted that information was provided for three glycol dehydration units for which the natural gas throughput was less than 15 MMscf/d).

In addition, while reviewing the number of dehydration units for which the EPA had information, the EPA identified two additional glycol dehydration units, both of which were controlled (Air Docket A-94-04 numbers IV-G-21, IV-G-22, and IV-G-25). Therefore, the total number of glycol dehydration units for which the EPA has information is 114 (compared to 112 as stated in the January 15 supplemental notice).

Comment: Commenters IV-G-36, IV-G-37, and IV-G-38 referred to a GRI report[31] which stated that condensers could not consistently achieve a 95-percent reduction of HAP. The commenters indicated that this report had been submitted to the EPA and was included in the regulatory record. Commenters IV-G-37 and IV-G-38 stated that in the supplemental notice, the EPA did not present information refuting that condensers may not

[31] The commenters referred to the following draft report: "BTEX Emission from T&S Industry Segment Glycol Dehydrator." July 27, 1998, by Radian International LLC. Conversations with the commenters (Air Docket A-94-04 numbers IV-A-10 and IV-A-11) indicated that the final report title is "Glycol Dehydrator Emissions when Treating Low-BTEX Gas." November 5, 1998.

achieve the proposed HAP emission reduction, but had instead chosen to change the technological basis for the MACT floor for existing and new sources.

Commenter IV-G-36 was concerned that the EPA did not consider all of the information when evaluating the proposed standards. The commenter stated the information, compiled by GRI regarding emission levels as functions of gas throughput, gas temperature, gas pressure, water content, and BTEX concentration, was not contained in the docket and should be included and considered by the EPA. The commenter indicated that since this information was not referenced in the supplemental notice, it is likely that the EPA did not give this data due consideration. The commenter stated that the EPA needs to consider all available data when establishing industry standards.

Response: The GRI report referred to by the commenters was not submitted to the EPA, and therefore was not included in the docket prior to the supplemental notice. However, since the publication of the supplemental notice, the EPA has obtained a copy of this report, and has reviewed its content (the report is available on the Internet at the following address: http://www.gri.org/pub/content/nov/19981105/115012/low-btex_dehys.html).

As stated in previous responses, the MACT floor for the transmission and storage source category was developed based on data collected in response to comments on the proposed subpart HHH, as well as data collected prior to proposal. The EPA determined the MACT floor for this source category to be 95-percent emission reduction. Furthermore, at least 93 percent of the existing glycol dehydration units that are controlled, for which the EPA had data (66 dehydration units out of 71 controlled units) employed combustion in some form (i.e., flares, enclosed combustion, or a combination of combustion and condensation) and

achieve at least a 95-percent emission reduction (see table 2.18 1) .

Since most existing sources are controlled using combustion, and by providing a 30-day averaging period and a 1-tpy benzene emission limitation, the EPA believes that the commenter's concerns about condenser performance have been addressed. Therefore, the EPA has not made any modifications to subpart HHH in response to these comments.

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(Please read Instructions on reverse before completing)

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16 ABSTRACT

This document contains a summary of public comments received on the NESHAP for Oil and Natural Gas Production and Natural Gas Transmission and Storage (40 CFR 63, subparts HH and HHH), which were proposed on February 6, 1998 (63 FR 6288). This document also provides the EPA's response to each comment, and outlines the changes made to the regulation in response to public comments.

17 KEY WORDS AND DOCUMENT ANALYSIS

a. DESCRIPTORS	b. IDENTIFIERS/OPEN ENDED TERMS	c. COSATI Field/Group
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 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	Hazardous air pollutants	
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