

# ADEQ

A R K A N S A S  
Department of Environmental Quality

APR 14 2010

Peter Henige, Site EHS  
BASF Corporation  
100 Bridgeport Road  
West Memphis, AR 72301

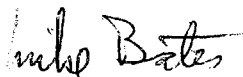
Dear Mr. Henige:

The enclosed Permit No. 0860-AR-4 is your authority to construct, operate, and maintain the equipment and/or control apparatus as set forth in your application initially received on 7/21/2009.

After considering the facts and requirements of A.C.A. §8-4-101 et seq., and implementing regulations, I have determined that Permit No. 0860-AR-4 for the construction, operation and maintenance of an air pollution control system for BASF Corporation to be issued and effective on the date specified in the permit, unless a Commission review has been properly requested under Arkansas Department of Pollution Control & Ecology Commission's Administrative Procedures, Regulation 8.603, within thirty (30) days after service of this decision.

All persons submitting written comments during this thirty (30) day period, and all other persons entitled to do so, may request an adjudicatory hearing and Commission review on whether the decision of the Director should be reversed or modified. Such a request shall be in the form and manner required by Regulation 8.603, including filing a written Request for Hearing with the APC&E Commission Secretary at 101 E. Capitol Ave., Suite 205, Little Rock, Arkansas 72201. If you have any questions about filing the request, please call the Commission at 501-682-7890.

Sincerely,



Mike Bates  
Chief, Air Division

# ADEQ MINOR SOURCE AIR PERMIT

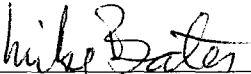
Permit No. : 0860-AR-4

IS ISSUED TO:

BASF Corporation  
100 Bridgeport Road  
West Memphis, AR 72301  
Crittenden County  
AFIN: 18-00081

THIS PERMIT IS THE ABOVE REFERENCED PERMITTEE'S AUTHORITY TO CONSTRUCT, MODIFY, OPERATE, AND/OR MAINTAIN THE EQUIPMENT AND/OR FACILITY IN THE MANNER AS SET FORTH IN THE DEPARTMENT'S MINOR SOURCE AIR PERMIT AND THE APPLICATION. THIS PERMIT IS ISSUED PURSUANT TO THE PROVISIONS OF THE ARKANSAS WATER AND AIR POLLUTION CONTROL ACT (ARK. CODE ANN. SEC. 8-4-101 *ET SEQ.*) AND THE REGULATIONS PROMULGATED THEREUNDER, AND IS SUBJECT TO ALL LIMITS AND CONDITIONS CONTAINED HEREIN.

Signed:

  
\_\_\_\_\_  
Mike Bates  
Chief, Air Division

**APR 14 2010**  
\_\_\_\_\_  
Date

BASF Corporation  
Permit #: 0860-AR-4  
AFIN: 18-00081

Table of Contents

Section I: FACILITY INFORMATION.....	4
Section II: INTRODUCTION .....	5
Summary of Permit Activity .....	5
Process Description.....	6
Regulations .....	13
Total Allowable Emissions.....	13
Section III: PERMIT HISTORY .....	15
Section IV: EMISSION UNIT INFORMATION.....	19
Section V: INSIGNIFICANT ACTIVITIES .....	39
Section VI: GENERAL CONDITIONS .....	40
Appendix A - 40 CFR 60 Subpart Dc	
Appendix B - 40 CFR 60 Subpart Kb	
Appendix C - 40 CFR 60 Subpart NNN	
Appendix D - 40 CFR 60 Subpart RRR	

BASF Corporation  
Permit #: 0860-AR-4  
AFIN: 18-00081

#### List of Acronyms and Abbreviations

A.C.A.	Arkansas Code Annotated
AFIN	ADEQ Facility Identification Number
CFR	Code of Federal Regulations
CO	Carbon Monoxide
HAP	Hazardous Air Pollutant
lb/hr	Pound Per Hour
No.	Number
NO <sub>x</sub>	Nitrogen Oxide
PM	Particulate Matter
PM <sub>10</sub>	Particulate Matter Smaller Than Ten Microns
SO <sub>2</sub>	Sulfur Dioxide
Tpy	Tons Per Year
UTM	Universal Transverse Mercator
VOC	Volatile Organic Compound

BASF Corporation  
Permit #: 0860-AR-4  
AFIN: 18-00081

Section I: FACILITY INFORMATION

PERMITTEE:	BASF Corporation
AFIN:	18-00081
PERMIT NUMBER:	0860-AR-4
FACILITY ADDRESS:	100 Bridgeport Road West Memphis, AR 72301
MAILING ADDRESS:	100 Bridgeport Road West Memphis, AR 72301
COUNTY:	Crittenden County
CONTACT NAME:	Peter Henige
CONTACT POSITION:	Site EHS
TELEPHONE NUMBER:	870-702-5386
REVIEWING ENGINEER:	Travis Porter
UTM NorthSouth (Y): Zone	15: 3891990.12 m
UTM EastWest (X):Zone:	15: 764512.58 m

BASF Corporation  
Permit #: 0860-AR-4  
AFIN: 18-00081

## Section II: INTRODUCTION

### Summary of Permit Activity

BASF Corporation (AFIN# 18-00081), located at 100 Bridgeport Road in West Memphis, AR, owns and operates a facility which manufactures intermediate synthetic organic chemicals used in water treatment applications. The intermediate chemicals produced at BASF include crude glycidyl ethers and (meth) acrylic esters. This modification combines an Administrative Amendment received on May 9, 2009 with a DeMinimis/Modification request received on July 21, 2009.

This permit activity adds the following as Insignificant Activities:

1. Heated raw material tanks (V-1212 & V-1213)
2. T-400 Tank Farm methanol cleanout
3. T-600 Tank Farm Methanol Cleanout
4. Quat inhibitor dosing
5. Mercaptan addition for T-125
6. R-105 use to hold mDADMAC tank & reactor cleanout water
7. Centrifuges C3 & C4 in the P1 mDADMAC process
8. T902 Poly Epamine dilution

This permit action makes the following other changes:

1. Updates emissions for Tank Farm 600 that vent to the PC Scrubber System, SN-P3-1, based on revised composition.
2. Changes the process description for Pour Point Depressant on p.7 of 860-AR-3 to read: "R-108 (SN-P2-4). VII and pour point depressants are produced in a batch reaction combining monomers and a carrier oil in the presence of a peroxide initiator. The final products are used as an additive in petroleum to help prevent freezing of oil at low temperatures."
3. Corrects the tanks in Tank Farm 100. T-108 was inadvertently left out of the description in the previous permit. The tank's inclusion does not affect emissions.
4. Connects Tank 407 to the P3 Scrubber, SN-P3-1, for odor control. This tank is now physically located in Tank Farm 400, but will be vented to SN-P3-1.
5. Connects the wastewater neutralization vents, SN-FS-4, to the P1 Scrubber, SN-P1-9, for odor control.

Emission changes from these modifications occur in the P3 Building. Permitted emissions are increasing as follows: VOCs by 0.5 tpy; Methanol by 0.05 tpy; Methyl Methacrylate by 0.05 tpy.

BASF Corporation  
Permit #: 0860-AR-4  
AFIN: 18-00081

## Process Description

### P-1 Process Building

#### TAAC Process R-104 (P1-1)

Reactor 104 is used to produce tetraallyl ammonium chloride (TAAC). This emission source consists of a reactor vessel, a water cooled condenser, and a continuously circulated caustic packed scrubber.

The crude TAAC is produced by reacting triallylamine (TAA) with allyl chloride. The unit is vented to a caustic scrubber during the vent down cycle following the reaction. The crude aqueous product is cut to storage and fresh TAA is charged into the remaining unreacted raw materials, followed by feeding allyl chloride to complete the next batch. The process continues, charging on the remaining unreacted raw materials. After crude production is complete, the crude is charged back to the reactor where it is heated and stripped under vacuum with caustic addition. Once the product meets specifications, it is collected and transferred to storage.

#### Poly Epiamine Process R-106 (SN-P1-3) and R-114 (SN-P1-4)

Reactor 106 and Reactor 114 are uncontrolled emission sources consisting each of a reactor vessel. This process reacts dimethylamine (DMA) with epichlorohydrin in the presence of water in a closed reactor. The system is closed during the charging and reaction. This process produces poly epiamines for use as a flocculent. The process is only vented to atmosphere before charging and again at the end of the batch run.

#### Tank Farm #500 (SN-P1-5)

The majority of these tanks contain water based products. Emissions are assumed to be essentially negligible for all tanks except T-520. Tanks V1212 and V1213 are physically located in the P-3 unit and are included in the Insignificant Activities section of the permit.

#### Crude mDMDAC Process Reactor R-107 for mDMDAC Service (SN-P1-9)

Crude dimethyl diallyl ammonium chloride (mDMDAC) is produced by reacting dimethylamine (DMA) with allyl chloride and sodium hydroxide. The initial charging step and subsequent reaction occur in a closed system. The reactors are not vented, and no emissions occur. Following this reaction, the reactors contain the product mDMDAC in an aqueous phase, as well as a small organic phase consisting of unreacted allyl chloride and byproduct allyl alcohol. The units enter a vent down cycle, in which the unreacted contents of each reactor's vapor space are

BASF Corporation  
Permit #: 0860-AR-4  
AFIN: 18-00081

vented through the water/glycol condenser, and then through a new packed-column caustic (NaOH) scrubber to the atmosphere. Once the reactors are vented, a water strip and allyl alcohol strip are performed. Uncondensed organics from the strip processes are also routed through the condenser and caustic scrubber. When product specifications are achieved, the product is pumped to storage.

## P-2 Process Building

### Quat Process

R-101 (SN-P2-1) and R-109 (SN-P2-5)

Reactor 101 and 109 are used to produce methyl chloride quat. These emission sources consist of a reactor vessel and an amine scrubber.

The Quat Process involves an initial charging step, in which a heel of quat is charged and heated. Then, an initial quantity of methyl chloride is fed into a closed reactor vessel and a continuous flow of methyl chloride and (meth)acrylate ester is co-fed into the reactor to begin the reaction. There is no venting during the reaction, and the vessel pressure increases as unreacted methyl chloride and air accumulates in the vapor space. As the reaction proceeds, water is also fed into the reaction.

When the reaction is completed, the unreacted methyl chloride and air in the vapor space is vented to the scrubber. Remaining methyl chloride is stripped from the reactor contents under vacuum. With the exception of unreacted methyl chloride, the contents of the reactor during the time the unit is vented to the scrubber are non-volatile. In the scrubber, a single-stage venturi contacts the vented methyl chloride with a circulating stream of (meth)acrylate ester. A majority of the methyl chloride reacts with the (meth)acrylate ester to produce quat, which is recycled back to the reactor in a subsequent batch.

### DMDAC Polymer, Copolymer, and Terpolymer Process

R-102 (SN-P2-2) and R-103 (SN-P2-3)

Reactors 102 and 103 are used to produce diallyldimethylammonium chloride homopolymers and copolymers by polymerizing an aqueous solution of monomer DADMAC with or without aqueous acrylamide. These emission sources consist of a reactor vessel and a water-cooled overhead condenser. The reactors are vented to the atmosphere during the entire production process.

DMDAC copolymers are produced by reacting an aqueous solution of mDMDAC with aqueous acrylamide as a second monomer. Therefore, this reaction will produce the acrylamide copolymer.

DMDAC polymers are produced by reacting an aqueous solution of mDMDAC. This reaction produces a DMDAC homopolymer. The reactor is vented to the atmosphere during the entire process, which includes an initial charging step and reaction. Some products require a nitrogen



BASF Corporation  
Permit #: 0860-AR-4  
AFIN: 18-00081

sparge before or after the reaction. The batch is diluted with water to fulfill customer specifications.

Reactors 102 and 103 yield three products, a DADMAC polymer, a DADMAC acrylamide copolymer, and a DADMAC terpolymer, that are made in a similar process.

Pour Point Depressant  
R-101 (SN-P2-4)

VII and pour point depressants are produced in a batch reaction combining monomers and a carrier oil in the presence of a peroxide initiator. The final products are used as an additive in petroleum to help prevent freezing of oil at low temperatures.

Tank Farm #100  
(SN-P2-6)

Tank Farm #100 is located in the P2 processing area.

### P-3 Process Building

There are five similar reactor units in P-3. Five types of operations are run in this equipment. Process equipment in this section consists of reactors, fractionation column, main and vent condensers, and a two-stage caustic scrubber.

Tank Farm 600 Control

Several storage tanks, located at Tank Farm 600, are routed to the P3-1 scrubber.

Trans Esterification  
R-110, R-112, R-113, R-115, and R-116 (all under Source SN-P3-1)

Methyl (meth)acrylate reacts with alcohol in the presence of a catalyst. This reaction yields the (meth)acrylate ester and methanol. The reaction takes place in a solvent media of cyclohexane and/or heptane. P-3 also has the capability to react ethyl acrylate with an alcohol. This produces an acrylate ester and a side product of ethanol. (Meth)acrylate esters are produced in all P-3 reactors.

Direct Esterification  
R-112 and R-113 (SN-P3-1)

(Meth)acrylic acid reacts with alcohol in the presence of a catalyst. This reaction yields (meth)acrylate ester and water. The reaction takes place in a solvent media of cyclohexane and/or heptane. (Meth)acrylate esters may be produced by the direct esterification route in R-112 and R-113.

R-110, R-112, and R-113 (SN-P3-1)

BASF Corporation  
Permit #: 0860-AR-4  
AFIN: 18-00081

Alcohol is reacted with epichlorohydrin in the presence of a catalyst to produce monochlorohydrin. The monochlorohydrin is reacted with caustic in a wash tank before final distillation in a reactor.

#### Ether Distillation

R-110, R-112, R-113, R-115, and R-116 (SN-P3-1)

After the production of the crude monochlorohydrin, the material is transferred to a wash tank and reacted with caustic to produce crude glycidyl ether. The ether is then distilled in the reactors to specification.

#### Solvent Recovery

R-110, R-112, R-113, R-115, and R-116 (SN-P3-1)

Solvents from esterification are distilled in these reactors for reuse in future reactions.

#### Tank Farm 600 (SN-P3-2)

The tank farm consists of several vessels of varying capacities which are used to store components or products of reactions. Several storage tanks are routed to the P3-1 scrubber. Emissions for a 500 gallon ester wash tank are also included at this source.

#### Tank Farm 400 (SN-P3-3)

Tank Farm #400 is located in the P3 Processing Area. Some tanks are under pressure and equipped with vapor recovery/recirculation or contain water based products. These tank farms consist of several vessels of varying capacities which are used to store components or products of reactions.

#### Boiler #1 (SN-P3-4) and Boiler #3 (SN-P3-6)

Boiler #1 and Boiler #3 are used to supply steam for facility processes (Boiler #2 has been removed from service). Boiler #1 is natural gas-fired with a design heat input of 33.5 MMBTU/hr. Boiler #3 is allowed to use natural gas, by-product methanol, or byproduct isopropanol on a continuous basis. The methanol may be either from the P3 or P4 plants. The design heat input of Boiler #3 is 29.4 MMBTU/hr. Boiler emission estimates have been calculated at maximum capacity, assuming year-round operation at worst-case scenario. Boiler #1 and Boiler #3 are subject to the requirements of 40 CFR Part 60, Subpart Dc (Standards for Small Industrial-Commercial-Institutional Steam Generating Units). Both boilers in this process area are allowed to use No. 2 fuel oil for a period of 30 days.

#### Fire Emergency Pump SN-P3-7

BASF Corporation  
Permit #: 0860-AR-4  
AFIN: 18-00081

A 300-horsepower diesel-fired power the fire water pumps, if necessary, to provide copious amounts of water in case of a plant fire or other emergency event. The fire pump is tested on a weekly basis to ensure operability. This source is limited to 200 hours of operation per year.

Aboveground 500 gallon Storage Tanks.  
SN-P3-8 and SN-P3-9

SN-P3-8 is used to store gasoline for plant vehicles. SN-P3-9 stores diesel fuel used for the Fire Water Pump, SN-P3-7.

Wash Tanks  
SN-P3-10

The esters produced in the reactors are washed in the wash tanks, V-643, V-644, B-645, and V-646, with water, dilute caustic, and/or brine (sodium chloride) to remove excess acid, catalyst, and impurities. On occasion, the wash tanks can be used for a process rework. Emissions from the wash tanks are controlled by the SN-P3-1 scrubber/condenser system. The tanks are, on occasion, rinsed with methanol.

Methanol Recovery  
SN-P3-11

The by-product methanol/water streams from the trans-esterification processes are mixed with caustic to saponify residual (meth)acrylate. A portion of the methanol/water solution is then distilled in R-112, R-110, R-113, R-115, R-116 (SN-P3-1) or the methanol recovery still for recovery. The remaining portion is shipped off-site for recovery. Emissions from the methanol recovery still are controlled by the SN-P3-1 scrubber/condenser system.

Tank Farm #700  
SN-P3-12

Tank Farm #700 is located in the P-3 processing area. All of its vessels are under pressure and equipped with vapor recovery/recirculation. Emissions from these sources are negligible.

#### P4 Building

Catationic Monomer Process  
SN-P4-1

The Catationic Monomer Plant (P-4 Process) is dedicated to the production of Dimethyl Amino Ethyl Acrylate (FA-1) and  $Ti(DME)_4$ .

The reaction section of the process consists of two (2) continuous stirred tank reactors. Methyl acrylate (MAC), catalyst, and other reactants are fed into the primary reactor, which will operate

BASF Corporation  
Permit #: 0860-AR-4  
AFIN: 18-00081

in series with the remaining reactor. Reactor contents are then sent through several separation steps; some streams are collected as product, while others will be reused in later reactions.

Off-gases are scrubbed before being passed through a carbon absorber and being vented to the atmosphere. The off-gases are scrubbed with sodium hydroxide solution followed by sulfuric acid solution before being passed through a carbon adsorber. The adsorber gases are vented to the atmosphere.

The caustic scrubbers, consisting of two random packed towers, operate in series but have the ability to be bypassed to allow for recharging. The sulfuric acid scrubbers consist of two random packed towers. The plant control system automatically shuts down the process plant unless a minimum circulation flow on one caustic and one acid scrubber is being measured.

P4 Tank Farm  
SN-P4-2

The P4 unit at BASF is dedicated to the production of Dimethyl Amino Ethyl Acrylate (FA-1) and catalyst. This unit has a dedicated tank farm area for raw materials and products/byproducts.

Rail/Truck/Drum Stations in P4  
SN-P4-3

Loading/unloading losses are the sources of evaporative emissions from rail tank cars, tank trucks, and drumming operations.

P4 Equipment Leaks  
SN-P4-4

Fugitive emissions from processes and equipment from the P4 section comprise this source. The facility has a leak detection and repair program for the P4 plant.

Boiler #4 (SN-P4-5)

Boiler #4 (SN-P4-5) operates to generate steam, which is used in various chemical processing operations. The boiler is equipped to burn either natural gas, methanol/isopropanol byproduct or, No. 2 fuel oil (10,000 gallon oil tank, SN-P4-6). Boiler emission estimates have been calculated at maximum capacity, assuming year-round operation. Boiler #4 is subject to the requirements of 40 CFR Part 60, Subpart Dc (*Standards for Small Industrial-Commercial-Institutional Steam Generating Units*).

Fuel Oil Tanks (2)  
SN-P4-6 and SN-P4-2

These 25,000 gallon aboveground storage tanks are used to store fuel for the boilers. The tanks are usually filled once a year.

BASF Corporation  
Permit #: 0860-AR-4  
AFIN: 18-00081

### Non-Point Sources

Loading/Unloading for Plants P1, P2, and P3  
SN-FS-1

Loading and unloading losses in P1, P2, and P3 occur through evaporation at drums, rail tank cars, and tank trucks.

Equipment Leaks for Plants P1, P2, and P3  
SN-FS-2

Fugitive emissions from processes and equipment from the P1, P2, and P3 sections comprise this source. The facility has a leak detection and repair program for these plants.

Wastewater Fugitives  
SN-FS-3

The new plant is designed to process approximately 150 gallons per minute of raw effluent water. The plant design consists of five treatment sections. The raw process wastewater from the four site production units will be: 1) pH-adjusted; 2) equalized; 3) subjected to aerobic biological treatment; 4) clarified by ultra-filtration; and 5) thicken and mechanically dewater excess biological sludge before disposal. The wastewater treatment plant also has two closed tanks of 5,000 gallons each.

### Miscellaneous Sources

Emergency Electrical Generator (for lab)  
SN-MI-1

The 180 hp diesel-fired generator, SN-MI-1, will be used to generate emergency power for the lab and is limited to 200 hours of maintenance and testing operation, annually.

Emergency Electrical Generator (By P-2)  
SN-MI-2

A 1500 hp diesel fired generator provides electrical generation in the event of a power outage or other emergency event. The generator is tested on a weekly basis to ensure operability.

Fire Protection Generator (WWTP/Instrumentation)  
SN-MI-3

A 1500 hp diesel fired generator provides electrical generation in the event of a power outage or other emergency event to the water pumps and to the plant instrumentation. The generator is tested on a weekly basis to ensure operability.

BASF Corporation  
 Permit #: 0860-AR-4  
 AFIN: 18-00081

Electrical Generator (400 kW/600 HP – P4)  
 SN-MI-4

A 600 hp diesel fired generator provides electrical generation in the event of a power outage or other emergency event to the water pumps and to the plant instrumentation. The generator is tested on a weekly basis to ensure operability.

Electrical Generator (80kW/108HP – Control Room)  
 SN-MI-5

108 hp, diesel fired generator to provide emergency power to the central control room. The source operates 100 hours per year.

Regulations

The following table contains the regulations applicable to this permit.

Source No.	Regulation
All Sources	Arkansas Air Pollution Code (Regulation 18) effective January 25, 2009
All Sources	Regulations of the Arkansas Plan of Implementation for Air Pollution Control (Regulation 19) effective July 18, 2009
SN-P4-2	NSPS Subpart Kb
SN-P3-4 SN-P3-6 SN-P4-5	NSPS Subpart Dc
SN-P4-1	NSPS Subpart NNN
	NSPS Subpart RRR

Total Allowable Emissions

The following table is a summary of emissions from the facility. This table, in itself, is not an enforceable condition of the permit.

TOTAL ALLOWABLE EMISSIONS		
Pollutant	Emission Rates	
	lb/hr	tpy
PM	11.1	4.2
PM <sub>10</sub>	11.1	4.2
SO <sub>2</sub>	58.0	18.6
VOC	62.7	89.2

BASF Corporation  
 Permit #: 0860-AR-4  
 AFIN: 18-00081

TOTAL ALLOWABLE EMISSIONS		
Pollutant	Emission Rates	
	lb/hr	tpy
CO	38.1	37.9
NO <sub>x</sub>	154.3	75.3
Acetone	34.2	1.9
Acrylamide <sup>HAP</sup>	0.02	0.02
Acrylic Acid <sup>HAP</sup>	0.10	0.42
Allyl Chloride <sup>HAP</sup>	1.48	0.87
Epichlorohydrin <sup>HAP</sup>	0.10	0.28
Methanol <sup>HAP</sup>	3.66	6.85
Methyl Methacrylate <sup>HAP</sup>	8.59	5.85
Methyl Chloride <sup>HAP</sup>	1.13	4.96
Total HAP	15.08	19.25

BASF Corporation  
Permit #: 0860-AR-4  
AFIN: 18-00081

### Section III: PERMIT HISTORY

860-A - Initial permit issued on 03/26/90 which consolidated air permit issued to CPS Chemical, encompassing all existing sources.

860-AR-1 - Permit issued on 04/28/92. This permit acknowledged the applicability of NSPS Subpart Kb in relation to tanks T-400 and T-401. Also the tank farm emissions were bubbled into a single source designation.

860-AR-2 - A new reactor, R-107, into building P-1 was permitted and sources were organized into three main process areas, P-1, P-2, and P-3. Permit was issued on 08/12/96.

860-AOP-R0 - Initial Title V permit assigned to the facility on 07/10/00. Due to the installation of two unpermitted sources, the facility was required to submit a PSD application. After reviewing the PSD application, the Department accepted the facility's proposal for BACT. The Department incorporated the proposed controls as a requirement of Operating Air Permit 860-AOP-R0. In requiring the control as a federally enforceable limit, the issuance of a PSD air permit was not required. The applicability of major source status under PSD first became clear in early 1997, when the facility and its consultant performed a comprehensive re-analysis of existing emissions generated by the facility. During this inventory, it was discovered that existing but newly quantified fugitive emissions brought the VOC emission total to a level beyond 100 tons per year, the major source threshold for the chemical plant category under PSD.

At the time of Title V permit application submittal in March of 1998, the facility (then CPS Chemical) reported to the Department that two wash tanks (V1212 and V1213, SN-P3-10a) had been installed in 1991 without authorization. In addition to violating the terms of Air Permit 860-A, the facility stated that the combined potential emissions from these tanks may have exceeded the significant increase threshold for VOC under the regulations of PSD. The Department responded by issuing Consent Administrative Order LIS: 98-073. One of the Order's conditions required the facility to submit a historical PSD permit application. In September of 1998, the facility submitted the PSD application, which included an applicability review, a Best Available Control Technology (BACT) analysis, and an air quality analysis. After reviewing the PSD application, the Department accepted the facility's proposal for BACT: the installation of chilled vent condensers as control equipment for the wash tanks. Additionally, the Department approved the facility's plan to implement a leak detection and repair (LDAR) program for the P-3 plant, which houses the tanks. The condenser efficiency was estimated at 90% for VOC reduction, and the LDAR program at 95% for fugitive VOC.

The application of the chilled vent condenser systems to the wash tanks reduced their potential to emit from 58 to 5.8 tons per year, below the PSD significant increase threshold. The Department has incorporated this proposed control as a requirement of Operating Air Permit 860-AOP-R0. In requiring the control as a federally enforceable limit, the issuance of a PSD air permit was not required for the tanks.



BASF Corporation  
Permit #: 0860-AR-4  
AFIN: 18-00081

In addition to the previously installed wash tanks, VOC increases from new process modifications were also examined for PSD applicability during the application review. The units in the P3 process contributed 14.1 ton/yr in VOC emissions, while the P4 process line resulted in a total of 38.3 ton/yr of VOC. Since the P3 and P4 processes were not related (they share no common equipment or materials, and neither process depends upon the other), their combined emission increases did not constitute a PSD review for this permitting action.

860-AOP-R1 - This minor modification, issued 04/18/01, was concerned with the usage of two reactors, 106 and 114, in the P1 manufacturing section. In addition to their current use, they were allowed to produce DMDAC polymers in a similar fashion as in the P2 section.

860-AOP-R2 - Three modifications were incorporated in this permit. One entailed additional service to the T-600 tank farm (SN-P3-2), involving an allowance for cyclohexane/methyl methacrylate processing at tanks T-606, T-620, T-623, and T-627. Secondly, Boiler #3 (SN-P3-6) was allowed to utilize by-product methanol as a fuel source under the EPA's guidelines for alternative fuels. Third, an emission limit for Reactor 108 (R-108) in source P2-4 was corrected. Permit was issued 09/18/01.

860-AOP-R3 - The minor modification allowed the manufacture of additional water treatment chemicals in its P-3 process unit. Reactors in the P3-1 process unit were permitted for additional service. Five tanks were installed, two in the 600 Tank Farm (SN-P3-2) and three tanks in the 400 Tank Farm (SN-P3-3). Permit issued on 4/26/02.

860-AOP-R4 - The permit was issued on 10/29/02. The minor modification affected sources P2-4 (Reactor 108), P3-1 (the P3 reactors), and P3-10a & b (Wash Tanks). Changes were made to the permit limits for these sources to more accurately reflect calculations for the transesterification process. Changes were also made at these sources to reflect an increase in sparge rates due to safety considerations, the main focus being to prevent an explosive atmosphere. A typographical correction was also made to include fugitive HAP emissions previously quantified for SN-FS-3 in the emission summary table and in Plantwide Condition 7.

860-AOP-R5 - The permit was issued on 5/11/2004. The facility made the following changes to the permit: added a new product, TAAC (tetraallylammonium chloride), for the R-104 reactor (SN-P1-1); added isopropanol as a recovered solvent under R-110, 112, 113, 115, and 116 (SN-P3-1); revised the testing requirements for methanol by-product fuel at Boiler #3 (SN-P3-6); allowed an annual 4-hour testing and maintenance event at the Emergency Electrical Generator, Fire Protection Generator, and Electrical Generator (SN-P4-9, SN-P4-10, and SN-P4-11); added methanol rinsing allowances to the Wash Tanks (SN-P3-10); revised emission calculations for the Inhibitor Vats (SN-P3-13); revised emission calculations for loading at FS-1; added a 180 hp diesel-fired electrical emergency generator (SN-MI-1); and allowed combustion of an isopropanol by-product in Boiler #3. Additionally, the process descriptions for the P1 and P2 buildings were corrected, as well as several other typographical errors.

860-AOP-R6 - The permit was issued on 11/18/2004. This modification authorized the facility to perform the following: to manufacture a new product, a terpolymer compound, in the R-102 and

BASF Corporation  
Permit #: 0860-AR-4  
AFIN: 18-00081

R-103 (SN-P2-2 and SN-P2-3) reactors; to manufacture NNDMA (N,N-dimethylacrylamide), in the R-108 reactor (SN-P2-4); to install a 20,000 gallon tank in the P4 unit; to replace the existing open neutralization basin with two closed tanks of approximately 5,000 gallons each (SN-FS-4); and to add methanol loading at FS-1 (which was previously removed), along with loading of methyl methacrylate, cyclohexane, heptane, and NNMDA.

860-AOP-R7 - Issued on 07/12/2005, the permit modification incorporated the following changes to their permit: to revise allyl chloride emissions at Reactors 104, 105, and 107 for mDMDAC (SN-P1-9) on the basis of testing; to allow sampling at the start and at the end of venting operations of the scrubbers at Reactors 101 and 109 (SN-P2-1 and SN-P2-5); to allow manufacture of FA-1 in the R-108 reactor (SN-P2-4) and P3 reactors (SN-P3-1) using ethyl acrylate; to revise NO<sub>x</sub> emission estimates at Boiler #3 (SN-P3-6) for combustion of isopropanol or methanol fuels; to revise the sampling requirements of the P4 Cationic Monomer Reactors (SN-P4-1); to recalculate emission estimates of Tank Farm 100 (SN-P2-6), Tank Farm 600 (SN-P3-2) P4 Loading/Unloading (SN-P4-3), and Loading/Unloading P1, P2, P3 (SN-FS-1); and the addition of a new wastewater treatment plant (SN-FS-3A).

860-AOP-R8 - Issued on 01/04/2006, this permit renewal encompassed the following changes: SN-P1-6 (Tank Farm 300) was removed; short term emissions from SN-P3-4 (Boiler #1), P3-6 (Boiler #3), and P4-5 (Boiler #4) were changed to reflect No. 2 fuel oil use during natural gas curtailment situations; annual emissions from SN-P3-4 (Boiler #1), P3-6 (Boiler #3), and P4-5 (Boiler #4) were recalculated with current AP-42 factors; FS-2 (Equipment Leaks for the P1, P2, and P3 Processes) were recalculated; CAM requirements have added for several sources; SN-P3-14 and P3-15 (10,000 gallon diesel tanks) were removed; NSPS Kb and NNN requirements have been updated; and the Emergency Electrical Generator (by P-2), Fire Protection Generator (WWTP/Instrumentation) and Electrical Generator (SN-P4-9, 10, and 11) have been renamed to SN-MI-2, MI-3, and MI-4 in the Miscellaneous Sources section. A period of 30-days of fuel oil usage during natural gas curtailment situations was added to the permit along with a commensurate increase in criteria pollutants. This change affected SN-P3-4, SN-P3-6, and SN-P4-5.

860-AOP-R9 - The permit revision, issued 3/29/06, increased the allowable allyl chloride at SN-P1-9 from 1.00 lb/hr to 4.03 lb/hr with a commensurate increase in annual emissions of allyl chloride due to the variability of hourly emissions. The facility has also requested a minor modification to their permit in order to allow for No. 2 fuel oil usage at any time for SNP3-1, SN-P3-6, and SN-P4-5. The permit had previously specified fuel oil usage only during periods of natural gas curtailment. Emissions for these sources take into account a 30-day period of fuel oil usage, and therefore, there are no permitted emission increases.

860-AOP-R10 - The permit was issued on 07/27/2006. The facility requested a minor modification to their current permit in order to incorporate the following changes: To recalculate epichlorohydrin emissions from the P1 Building, involving Reactors 104, 105, 106, 114, and 107; To allow for the production of biodiesel at Reactor 104; To increase plantwide HAP from FS-3A so that emissions reflect total annual operation; and to correct a citation error of Specific Condition 56.

BASF Corporation  
Permit #: 0860-AR-4  
AFIN: 18-00081

860-AOP-R11 - The permit was issued on 02/20/2007. The facility requested several modifications to perform the following: to install a 108 hp, diesel fired generator, SN-MI-5, to provide emergency power; to burn byproduct methanol/isopropanol in Boiler #4, SN-P4-5; to produce XPDL 649, a pour point depressant, and to add two insignificant activities; and to add Wastewater Sludge Dewatering and Quat Scrubber Feed Tank Charge as A-13 insignificant activities.

860-AOP-R12 - The permit was issued on 10/17/2007. The facility moved production of a recently permitted product XPDL 649 from R-101 (SN-P2-1) to R-108 (SN-P2-4). Second, the facility will burn part of the P3 plant's methanol byproduct in both Boilers No. 3 and No. 4.

860-AR-3 - This permit was issued on 12/15/2008. As a result of this permit modification, the facility became a minor source. The facility took limits and revised processes in order to reduce emissions below Title V thresholds. Furthermore, due to their status as a minor source, the facility is not subject to NESHAP FFFF. Permitted criteria pollutants are decreased by 0.6 PM/PM<sub>10</sub>, 0.3 tpy SO<sub>2</sub>, 448.1 tpy VOC, 0.2 tpy CO, and 1.6 tpy NO<sub>x</sub>. Permitted total HAP emissions decreased by 91.50 tpy.

BASF Corporation  
 Permit #: 0860-AR-4  
 AFIN: 18-00081

Section IV: EMISSION UNIT INFORMATION

Specific Conditions

- The permittee shall not exceed the emission rates set forth in the following table.  
 [Regulation No. 19 §19.501 et seq. and 40 CFR Part 52, Subpart E]

SN	Description	Pollutant	lb/hr	tpy
P1 Building				
P1-1	Reactor 104	VOC	4.3	*
P1-3	Reactor 106			
P1-4	Reactor 114			
P1-5	Tank Farm 500			
P1-8	Tank Farm 200			
P1-9	Reactor 107 for mDMDAC			
P2 Building				
P2-1	Reactor 101	VOC	2.9	*
P2-2	Reactor 102			
P2-3	Reactor 103			
P2-4	Reactor 108			
P2-5	Reactor 109			
P2-6	Tank Farm 100			
P3 Building				
P3-1	Reactors 110, 112, 113, 115, 116, P3 Wash System, Methanol Recovery, and some Tanks from Tank Farm 600	PM <sub>10</sub>	1.7	2.3
P3-2	Tank Farm 600	SO <sub>2</sub>	32.7	11.7
P3-3	Tank Farm 400	VOC	10.4	*
P3-4	Boiler #1	CO	7.5	23.6
P3-6	Boiler #3	NO <sub>x</sub>	21.6	48.6
P3-7	Fire Emergency Pump			
P3-8	500 Gallon Gasoline Tank			
P3-9	500 Gallon Gasoline Tank			
P3-12	Tank Farm 700			
P4 Building				
P4-1	P4 Cationic Monomer Reactors	PM <sub>10</sub>	0.5	1.2
		SO <sub>2</sub>	17.0	6.2
P4-2	P4 Tank Farm	VOC	6.7	*
P4-3	P4 Loading/Unloading	CO	2.9	12.4
P4-4	P4 Equipment Leaks	NO <sub>x</sub>	8.6	19.9

BASF Corporation  
 Permit #: 0860-AR-4  
 AFIN: 18-00081

SN	Description	Pollutant	lb/hr	tpy
P4-5	Boiler #4			
P4-6	25,000 Gallon Diesel Storage Tank			
P4-8	25,000 Gallon Diesel Storage Tank			
Non-Point Sources				
FS-1	Loading/Unloading/Drumming	VOC	21.0	1.9
FS-2	Equipment Leaks (P1, P2, P3)	VOC	4.8	20.7
FS-3	Wastewater Fugitives	VOC	2.5	10.5
Miscellaneous Sources				
MI-1	Lab Emergency Electrical Generator, 180 hp	PM <sub>10</sub>	0.4	0.1
		SO <sub>2</sub>	0.4	0.1
		VOC	0.5	0.1
		CO	1.3	0.2
		NO <sub>x</sub>	5.6	0.6
MI-2	Emergency Electrical Generator (by P-2), 1500 hp	PM <sub>10</sub>	3.3	0.2
		SO <sub>2</sub>	3.1	0.2
		VOC	3.8	0.2
		CO	10.1	0.6
		NO <sub>x</sub>	46.5	2.4
MI-3	Fire Protection Generator (WWTP/Instrumentation), 1500 hp	PM <sub>10</sub>	3.3	0.2
		SO <sub>2</sub>	3.1	0.2
		VOC	3.8	0.2
		CO	10.1	0.6
		NO <sub>x</sub>	46.5	2.4
MI-4	Electrical Generator (400 kW/600 Hp-P4)	PM <sub>10</sub>	1.4	0.1
		SO <sub>2</sub>	1.3	0.1
		VOC	1.5	0.1
		CO	4.1	0.3
		NO <sub>x</sub>	18.6	1.0
MI-5	Electrical Generator (80kW/108HP – Control Room)	PM <sub>10</sub>	0.5	0.1
		SO <sub>2</sub>	0.3	0.1
		VOC	0.3	0.1
		CO	2.1	0.2
		NO <sub>x</sub>	6.9	0.4

\*Subject to a combined limit for annual VOC emissions. See Specific Condition #42.

- The permittee shall not exceed the emission rates set forth in the following table. [Regulation No. 18 §18.801 and A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311]

BASF Corporation  
 Permit #: 0860-AR-4  
 AFIN: 18-00081

SN	Description	Pollutant	lb/hr	tpy
P1 Building				
P1-1	Reactor 104	Epichlorohydrin <sup>HAP</sup> Allyl Chloride <sup>HAP</sup>	0.04	*
P1-3	Reactor 106			
P1-4	Reactor 114			
P1-5	Tank Farm 500			
P1-8	Tank Farm 200			
P1-9	Reactor 107 for mDMDAC			
P2 Building				
P2-1	Reactor 101	Acrylamide <sup>HAP</sup> Acrylic Acid <sup>HAP</sup> Methyl Methacrylate <sup>HAP</sup> Methyl Chloride <sup>HAP</sup>	0.02	*
P2-2	Reactor 102			
P2-3	Reactor 103			
P2-4	Reactor 108			
P2-5	Reactor 109			
P2-6	Tank Farm 100			
P3 Building				
P3-1	Reactors 110, 112, 113, 115, 116, P3 Wash System, and Methanol Recovery	PM Acetone Methanol <sup>HAP</sup> Methyl Methacrylate <sup>HAP</sup>	1.70	2.3
P3-2	Tank Farm 600			
P3-3	Tank Farm 400			
P3-4	Boiler #1			
P3-6	Boiler #3			
P3-7	Fire Emergency Pump			
P3-12	Tank Farm 700			
P4 Building				
P4-1	P4 Cationic Monomer Reactors	PM Methanol <sup>HAP</sup>	0.5	1.2
P4-2	P4 Tank Farm			
P4-3	P4 Loading/Unloading			
P4-4	P4 Equipment Leaks			
P4-5	Boiler #4			
Non-Point Sources				
FS-1	Loading/Unloading/Drumming	Acetone	33.6	0.2
		Methanol <sup>HAP</sup>	0.90	0.28
		Methyl Methacrylate <sup>HAP</sup>	7.20	0.16
FS-2	Equipment Leaks (P1, P2, P3)	Allyl Chloride <sup>HAP</sup>	0.02	0.04
		Methyl Methacrylate <sup>HAP</sup>	0.22	0.99
		Epichlorohydrin <sup>HAP</sup>	0.06	0.24
		Methanol <sup>HAP</sup>	0.48	2.09

BASF Corporation  
 Permit #: 0860-AR-4  
 AFIN: 18-00081

SN	Description	Pollutant	lb/hr	tpy
		Methyl Chloride <sup>HAP</sup>	0.08	0.36
FS-3	Wastewater Fugitives	Allyl Chloride <sup>HAP</sup>	0.12	0.53
		Methanol <sup>HAP</sup>	0.48	2.20
		Methyl Methacrylate <sup>HAP</sup>	0.16	0.71
Miscellaneous Sources				
MI-1	Lab Emergency Electrical Generator, 180 hp	PM	0.4	0.1
MI-2	Emergency Electrical Generator (by P-2), 1500 hp	PM	3.3	0.2
MI-3	Fire Protection Generator (WWTP/Instrumentation), 1500 hp	PM	3.3	0.2
MI-4	Electrical Generator (400 kW/600 Hp-P4)	PM	1.4	0.1
MI-5	Electrical Generator (80kW/108HP – Control Room)	PM	0.5	0.1

\*Subject to a combined limit for annual HAP emissions. See Specific Condition #42

3. Visible emissions may not exceed the limits specified in the following table of this permit as measured by EPA Reference Method 9. [A.C.A. §8-4-203 as referenced by A.C.A. §8-4-304 and §8-4-311]

SN	Limit	Regulatory Citation
SN-P3-7, MI-1, MI-2, MI-3, MI-4, and MI-5	20%	§19.503
SN-P3-4, P3-6, P4-5	5% and 20%	§18.501 and §19.503

4. The permittee shall not cause or permit the emission of air contaminants, including odors or water vapor and including an air contaminant whose emission is not otherwise prohibited by Regulation #18, if the emission of the air contaminant constitutes air pollution within the meaning of A.C.A. §8-4-303. [Regulation 18, §18.801 and A.C.A. §8-4-203 as referenced by A.C.A. §8-4-304 and §8-4-311]
5. The permittee shall not conduct operations in such a manner as to unnecessarily cause air contaminants and other pollutants to become airborne. [Regulation 18, §18.901 and A.C.A. §8-4-203 as referenced by A.C.A. §8-4-304 and §8-4-311]

P1 Building Section

6. The permittee shall maintain the following control device parameters and operations at SN-P1-1 when SN-P1-1 is in operation. [§19.303 of Regulation 19 and A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311]
  - a. The permittee shall maintain a liquid flow rate of at least 20 gallons per minute at the scrubber.
  - b. The permittee shall maintain a minimum of 10% (weight %) caustic strength at the scrubber.
  - c. The permittee shall measure scrubbing fluid flow at SN-P1-1 once every three hours of operation. Flow rates shall be measured by a flow meter. In the event that the permittee must perform maintenance on the flow meter, scrubbing fluid flow may be derived and recorded from a pump curve performance chart.
  - d. Confirmation sampling of the caustic strength of SN-P1-1 shall be performed on a weekly basis. Sampling and analysis of the scrubber fluid shall be conducted prior to discharge operations. Records shall be maintained of the date and time of measurements and the caustic strength of the fluid.
  - e. The sampled values shall be kept in a log at the source in order to verify compliance. These records shall be made available to Department personnel upon request.
  
7. The SN-P1-1 scrubber shall be charged in accordance with the equipment Standard Operating Procedure (SOP) prior to initiation of a vent down sequence of operation. A record of the vent down operations to the scrubber shall be maintained and shall include a) date and time of vent down operation and b) batch number(s) vented to the scrubber.

At the conclusion of a reactor vent down cycle, which shall not exceed two batches, the contents of the scrubber will be discharged and the scrubber recharged prior to resumption of reactor vent down operations. A record of the discharge and recharge of each scrubber shall be maintained and shall include a) date and time of recharge and b) batch number(s) vented to the scrubber. [§19.703 of Regulation 19 and A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311]
  
8. The permittee shall maintain the following control device parameters and operations at SN-P1-9. [§19.303 of Regulation 19 and A.C.A. §8 4 203 as referenced by A.C.A. §8 4 304 and §8 4 311].
  - a. The permittee shall maintain a liquid flow rate of at least 17 gallons per minute at the caustic and acid scrubber columns, and a liquid flow rate of at least 30 gallons per minute at the acid scrubber eductor during vent and strip operations.



- b. The permittee shall maintain a minimum of 10% (weight %) caustic strength at the caustic scrubber and a maximum pH of 5.5 at the acid scrubber.
  - c. The permittee shall not exceed 35°F at the condenser's chilled water inlet. The inlet temperature may be measured at the recirculation loop located at the chilled water tank.
  - d. The permittee shall maintain interlocks on the P1-9 scrubber and vent condenser system that prevent venting of the reaction process if scrubber flows, caustic concentration, acid scrubber pH, and vent condenser temperature do not meet the minimum requirements set out in this plan.
  - e. The permittee must conduct documented checks of interlock operation at least annually.
9. The permittee shall maintain records of hourly VOC emissions within the P1 Process Building area and associated storage tanks on a monthly basis. For compliance purposes, the monthly VOC total divided by the monthly operating hours shall be compared to the hourly VOC emission rate in Specific Condition 1. The records and calculations shall be kept on site and made available to Department personnel upon request. [§19.705 of Regulation 19 and A.C.A. §8-4-203 as referenced by A.C.A. §8-4-304 and §8-4-311]
10. The permittee shall maintain records of hourly HAP emissions within the P1 Process Building area and associated storage tanks on a monthly basis. For compliance purposes, the monthly HAP total divided by the monthly operating hours shall be compared to the hourly emission rate for that pollutant in Specific Condition 2. The records and calculations shall be kept on site and made available to Department personnel upon request. [§18.1004 of Regulation 19 and A.C.A. §8-4-203 as referenced by A.C.A. §8-4-304 and §8-4-311]

#### P2 Building Section

11. The SN-P2-1 and SN-P2-5 scrubbers shall be charged prior to initiation of each batch of product to be manufactured. A record of each charge shall be maintained and shall include: a) date and time of the charge, b) quantity of amine charged, and, c) quantity of water charged. Records to demonstrate amine concentration (wt%) shall be maintained and made available to Department personnel upon request.

To perform maintenance or to shutdown one of the quat reactors, two reactor batches may be vented to one scrubber charge, as long as the permittee confirms that the amine concentration of the scrubber is a minimum of 95%.

At the conclusion of each batch cycle, the contents of the scrubber shall be discharged for use in the next batch of product to be manufactured. A record of the discharge of the scrubber shall be maintained and shall include: a) date and time of the discharge, and b)

BASF Corporation  
Permit #: 0860-AR-4  
AFIN: 18-00081

subsequent batch number manufactured. [§19.303 of Regulation 19 and A.C.A. §8-4-203 as referenced by A.C.A. §8-4-304 and §8-4-311]

12. The permittee shall maintain the following control device parameters and operations at SN-P2-1 and SN-P2-5. [§19.303 of Regulation 19 and A.C.A. §8-4-203 as referenced by A.C.A. §8-4-304 and §8-4-311]
  - a. The permittee shall maintain a liquid flow rate of at least 15 gallons per minute at the scrubber eductors and a flow rate of at least 17 gallons per minute at the scrubber columns for SN-P2-1 and SN-P2-5 during reactor venting and stripping operations.
  - b. The permittee shall maintain a minimum of 95% (weight %) amine at the scrubber. Amine concentration shall be verified by the water and amine charge weights as required by Specific Condition #11.
  - c. The permittee shall maintain interlocks on the P2 scrubbers at SN-P2-1 and SN-P2-5 that prevent venting of the reaction process if scrubber flows do not meet the minimum requirements set out in this plan.
  - d. The permittee must conduct documented checks of interlock operation at least annually.
13. The permittee shall maintain records of hourly VOC emissions within the P2 Process Building area and associated storage tanks on a monthly basis. For compliance purposes, the monthly VOC total divided by the monthly operating hours shall be compared to the hourly VOC emission rate in Specific Condition #1. The records and calculations shall be kept on site and made available to Department personnel upon request. [§19.705 of Regulation 19 and A.C.A. §8-4-203 as referenced by A.C.A. §8-4-304 and §8-4-311]
14. The permittee shall maintain records of hourly HAP emissions within the P2 Process Building area and associated storage tanks on a monthly basis. For compliance purposes, the monthly HAP total divided by the monthly operating hours shall be compared to the hourly emission rate for that pollutant in Specific Condition #2. The records and calculations shall be kept on site and made available to Department personnel upon request. [§18.1004 of Regulation 19 and A.C.A. §8-4-203 as referenced by A.C.A. §8-4-304 and §8-4-311]

### P3 Building Section

15. The permittee shall maintain the following control device parameters and operations at SN-P3-1. [§19.303 of Regulation 19 and A.C.A. §8-4-203 as referenced by A.C.A. §8-4-304 and §8-4-311]

BASF Corporation  
Permit #: 0860-AR-4  
AFIN: 18-00081

- a. The permittee shall maintain a liquid flow rate of at least 17 gallons per minute at the caustic and water scrubber columns, and a liquid flow rate of at least 30 gallons per minute at the caustic and water scrubber eductors during operation.
  - b. The permittee shall maintain a minimum of 10% (weight %) caustic strength at the caustic scrubber during operation. Caustic strength will be monitored at least every three hours by an inline autotitrator. During periods of maintenance on the titrator, titration can be carried out manually.
  - c. The permittee shall measure scrubbing fluid flows every four hours by means of a flow meter. During required flow meter maintenance, scrubbing fluid flow may be derived from a pump curve performance chart. Measurement and logging of flow may be accomplished by use of a computerized flow monitoring and data logging system.
  - d. The permittee shall not exceed 35°F at the vent condenser's chilled water inlet for the wash tanks, reactors, and methanol still. The inlet temperature may be measured at the recirculation loop located at the chilled water tank.
  - e. The permittee shall record chilled water temperature every three hours of operation. Measurement and logging of temperature may be accomplished by use of a computerized flow monitoring and data logging system.
  - f. Electronic flow, caustic concentration, and temperature data will be maintained and made available to Department personnel upon request.
  - g. Periods of scrubber maintenance during which flow and/or caustic concentration cannot be maintained must be logged at the site. During these periods of maintenance, no reaction processes or material transfers controlled by the scrubbers may occur.
16. The Boiler #1 and Boiler #3 (SN-P3-4 and SN-P3-6) shall fully comply with all applicable requirements of the 40 CFR 60 Subpart Dc - *Standards for Small Industrial-Commercial-Institutional Steam Generating Units* (see Appendix). These requirements include, but are not limited to, the following. [Regulation No. 19 §19.304 and 40 CFR Part 60 Subpart Dc]
- a. For natural gas combustion:  
  
*Recordkeeping* [from 60.48c(g), (i)]. Amounts of each fuel combusted shall be recorded on a monthly basis. The records shall be maintained by the facility for a period of two years following the date of recording.
  - b. For by-product methanol and/or isopropanol combustion at Boiler #3 (SN-P3-6) only.

*Recordkeeping* [from 60.48c(g), (i)]. Amounts of each fuel combusted shall be recorded on a daily basis. The records shall be maintained by the facility for a period of two years following the date of recording.

- c. For No. 2 fuel oil:

*Sulfur Standards* [60.42c(d)]. Sulfur content shall be limited to 0.5 or less weight percent.

*Sulfur Limit Compliance* [from 60.46(e)] Compliance with the sulfur content limits shall be demonstrated by certification from the fuel supplier as described under 60.48c(f).

*Recordkeeping* [from 60.48c(g), (i)]. Amounts of each fuel combusted shall be recorded on a monthly basis. The records shall be maintained by the facility for a period of two years following the date of recording.

*Quarterly Reporting* [from 60.48c(d), (e), (e)(1), (e)(5)-(6), (e)(11), (f)] Submit quarterly reports of 30-day average SO<sub>2</sub> emission rate (ng/J or lb/million Btu) or 30-day average sulfur content, records of fuel supplier certification as described under paragraph (f), and a certified statement signed by the owner or operator that the records of fuel supplier certifications submitted represent all of the fuel combusted during the reporting period.

- 17. The permittee shall not use more than 4,600,000 gallons of by-product methanol and isopropanol, combined, as fuel at SN-P3-6 (Boiler #3) per rolling 12-month period. The methanol may be either from the P3 or P4 plants. Compliance with this condition shall be verified by maintaining daily records of the amount of fuel used. These records shall be kept onsite and made available to Department personnel upon request. [§19.705 of Regulation 19, A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311]
- 18. The permittee will sample and analyze the methanol by-product combusted at SN-P3-6 semi-annually in accordance with the methanol by-product analysis plan and the provisions of 40 CFR 261.38 to ensure the constituents listed in this subpart are not present over RCRA threshold amounts. These threshold values, which are to be normalized to 10,000 BTU/lb, are listed below. This condition only applies to methanol by-product from the P4 area. This information shall be kept on site and made available to Department personnel upon request. [§19.304 of Regulation 19 and 40 CFR Subpart 261.38]

Value	Limit
BTU	>5,000 BTU/lb
Total Nitrogen	≤ 4,900

BASF Corporation  
 Permit #: 0860-AR-4  
 AFIN: 18-00081

Value	Limit
Viscosity	≤ 50 centipoise

19. The permittee will sample and analyze the isopropanol by-product combusted at SN-P3-6 semi-annually in accordance with the by-product analysis plan and the provisions of 40 CFR 261.38 to ensure the constituents listed in this subpart are not present over RCRA threshold amounts. These threshold values, which are to be normalized to 10,000 BTU/lb, are listed below. This information shall be kept on site and made available to Department personnel upon request. [§19.304 of Regulation 19 and 40 CFR Subpart 261.38]

Value	Limit
BTU	> 5,000 BTU/lb
Total Nitrogen	≤ 4,900 mg/kg
Total Chloride	≤ 540 mg/kg
Acrolein	≤ 37 mg/kg
Viscosity	≤ 50 centipoise

20. The permittee shall not operate the Fire Emergency Pumps (SN-P3-7) more than 200 hours combined per rolling 12-month period for testing and maintenance purposes. The permittee may not operate both pumps simultaneously. Records of testing/maintenance operation time shall be maintained on site, updated on a per-event basis, and made available to Department personnel upon request. Operation time required for actual emergency use is not restricted by this permit. [§19.705 of Regulation 19, A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311]
21. The permittee shall maintain records of hourly VOC emissions within the P3 Process Building area and associated storage tanks on a monthly basis. For compliance purposes, the monthly VOC total divided by the monthly operating hours shall be compared to the hourly VOC emission rate in Specific Condition #1. The records and calculations shall be kept on site and made available to Department personnel upon request. [§19.705 of Regulation 19 and A.C.A. §8-4-203 as referenced by A.C.A. §8-4-304 and §8-4-311]
22. The permittee shall maintain records of hourly HAP and acetone emissions within the P3 Process Building area and associated storage tanks on a monthly basis. For compliance purposes, the monthly HAP or acetone total divided by the monthly operating hours shall be compared to the hourly emission rate for that pollutant in Specific Condition 2. The records and calculations shall be kept on site and made available to Department personnel upon request. [§18.1004 of Regulation 18 and A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311]

P4 Building Section

23. The permittee shall maintain the following control device parameters at SN-P4-1 (P4 Cationic Monomer Reactors). The permittee shall operate at least one caustic scrubber, one acid scrubber, and one carbon absorber at all times at SN-P4-1. [§19.303 of Regulation 19 and A.C.A. §8-4-203 as referenced by A.C.A. §8-4-304 and §8-4-311]
- a. The permittee shall maintain a caustic scrubber liquid flow rate of at least 40 gallons per minute.
  - b. The permittee shall maintain a concentration minimum of 3%, for both caustic and acid media.
  - c. The permittee shall measure scrubbing fluid flow at the SN-P4-1 scrubbers once every three hours of operation with a flow meter. In the event that the permittee must perform maintenance on the flow meter, scrubbing fluid flow may be derived and recorded from a pump curve performance chart.
  - d. The caustic and acid concentrations at the SN-P4-1 scrubbers shall be sampled once every seven days of operation. If sampling shows that an SN-P4-1 scrubber concentration has fallen below 3%, the scrubber shall be regenerated in order to maintain the scrubbing system at a minimum of 3%, for both caustic and acid media.
  - e. The sampled flow values and the sampled caustic and acid concentrations shall be kept in a log at the source. These records shall be made available to Department personnel upon request.
24. Boiler #4 (SN-P4-5) shall fully comply with all applicable requirements of the *Standards for Small Industrial-Commercial-Institutional Steam Generating Units* (see Appendix A). These requirements include, but are not limited to, the following. [§19.304 of the Regulation 19 and 40 CFR Part 60 Subpart Dc]
- a. For natural gas combustion:  
  
*Recordkeeping* [from 60.48c(g), (i)]. Amounts of each fuel combusted shall be recorded on a monthly basis. The records shall be maintained by the facility for a period of two years following the date of recording.
  - b. For by-product methanol and/or isopropanol combustion at Boiler #4 (SN-P4-5) only.  
  
*Recordkeeping* [from 60.48c(g), (i)]. Amounts of each fuel combusted shall be recorded on a monthly basis. The records shall be maintained by the facility for a period of two years following the date of recording.

- c. For No. 2 fuel oil (see the regulation in Appendix A for details):

*Sulfur Standards* [60.42c(d)]. Sulfur content shall be limited to 0.5 or less weight percent.

*Sulfur Limit Compliance* [from 60.46(e)] Compliance with the sulfur content limits shall be demonstrated by certification from the fuel supplier as described under 60.48c(f).

*Recordkeeping* [from 60.48c(g), (i)]. Amounts of each fuel combusted shall be recorded on a monthly basis. The records shall be maintained by the facility for a period of two years following the date of recording.

*Quarterly Reporting* [from 60.48c(d), (e), (e)(1), (e)(5)-(6), (e)(11), (f)] Submit quarterly reports of 30-day average SO<sub>2</sub> emission rate (ng/J or lb/million Btu) or 30-day average sulfur content, records of fuel supplier certification as described under paragraph (f), and a certified statement signed by the owner or operator that the records of fuel supplier certifications submitted represent all of the fuel combusted during the reporting period.

25. The permittee shall not use more than 2,440,000 gallons of by-product methanol and isopropanol, combined, as fuel at SN-P4-5 (Boiler #4) per rolling 12-month period. The methanol may be either from the P3 or P4 plants. Compliance with this condition shall be verified by maintaining daily records of the amount of fuel used. These records shall be kept on site and made available to Department personnel upon request. [§19.705 of Regulation 19, A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311]
26. The permittee will sample and analyze the methanol by-product combusted at SN-P4-5 semi-annually in accordance with the methanol by-product analysis plan and the provisions of 40 CFR 261.38 to ensure the constituents listed in this subpart are not present over RCRA threshold amounts. This condition only applies to methanol by-product from the P4 area. These threshold values, which are to be normalized to 10,000 BTU/lb, are listed below. This information shall be kept on site and made available to Department personnel upon request. [§19.304 of Regulation 19 and 40 CFR Subpart 261.38]

Value	Limit
BTU	>5,000 BTU/lb
Total Nitrogen	≤ 4,900
Viscosity	≤ 50 centipoise

27. The permittee will sample and analyze the isopropanol by-product semi-annually combusted at SN-P4-5 in accordance with the by-product analysis plan and the provisions of 40 CFR 261.38 to ensure the constituents listed in this subpart are not present over

BASF Corporation  
 Permit #: 0860-AR-4  
 AFIN: 18-00081

RCRA threshold amounts. These threshold values, which are to be normalized to 10,000 BTU/lb, are listed below. This information shall be kept on site and made available to Department personnel upon request. [§19.304 of Regulation 19 and 40 CFR Subpart 261.38]

Value	Limit
BTU	> 5,000 BTU/lb
Total Nitrogen	≤ 4,900 mg/kg
Total Chloride	≤ 540 mg/kg
Acrolein	≤ 37 mg/kg
Viscosity	≤ 50 centipoise

28. The permittee shall fully comply with all applicable requirements of the *Standards of Performance for Volatile Organic Liquid Storage Vessels* (see Appendix) for the following tanks at SN-P4-2. Applicable requirements include, but are not limited to, the items outlined in Specific Condition #45. [§19.304 of Regulation 19 and 40 CFR Part 60 Subpart Kb]

# Tanks	Capacity	Contents
2	32,120 gallon	Byproduct Methanol

29. The Cationic Monomer Plant (SN-P4-1) shall fully comply with all applicable requirements of NSPS Subpart NNN - Standards of Performance for Volatile Organic Compound (VOC) Emissions from Synthetic Organic Chemical Manufacturing Industry (SOCMI) Distillation Operations. Applicable requirements include, but are not limited to, the items outlined below. [§19.304 of Regulation 19 and 40 CFR Part 60 Subpart NNN]

Subpart NNN: VOC Emissions for SOCMI Distillation Operations	
Emission Unit(s)	<ul style="list-style-type: none"> <li>•Distillation units not discharging vent stream into recovery system.</li> <li>•Combinations of distillation unit(s) and recovery system into which its vent stream(s) is discharged.</li> </ul>
Pollutant(s)	VOC
Emission Standard/Avg Time	<ul style="list-style-type: none"> <li>•98% reduction efficiency or reduce concentration to 20 ppmv (dry basis) corrected to 3% O<sub>2</sub>, whichever is less stringent/3-hr avg.</li> <li>•Note: If boiler or process heater used to comply, vent stream must be introduced into flame zone.</li> </ul>



Subpart NNN: VOC Emissions for SOCM Distillation Operations		
Monitoring  PS/QA  Exceedance Level	<b>Incinerator Units:</b> <ul style="list-style-type: none"> <li>•Continuous monitoring and recording of temperature: -in firebox (thermal).- before and after bed (catalytic).</li> <li>•At least hourly measurement using flow indicator of vent stream flow to incinerator.</li> </ul> <b>Monitor Accuracy:</b> <ul style="list-style-type: none"> <li>•Temperature: Greater of <math>\pm 1\%</math> or <math>\pm 0.5^\circ\text{C}</math>.</li> <li>•Flow: Location specifications.</li> <li>•Any 3-hr period in which temperature <math>&gt;28^\circ\text{C}</math> below baseline (thermal and pre-bed temperature monitor for catalytic).</li> <li>•Any period in which temperature difference across catalytic bed <math>&lt;80\%</math> of baseline.</li> </ul>	<b>Boiler/Process Heater Units:</b> <ul style="list-style-type: none"> <li>•Continuous monitoring and recording of temperature in firebox</li> <li>•Monitoring and recording of periods of operation (if boiler process heater <math>\geq 44</math> MW heat input capacity).</li> <li>•At least hourly measurement using flow indicator of vent stream flow to boiler/process heater.</li> </ul> <b>Monitor Accuracy:</b> <ul style="list-style-type: none"> <li>•Temperature: Greater of <math>\pm 1\%</math> or <math>\pm 0.5^\circ\text{C}</math>.</li> <li>•Boiler/process heater records of operation readily available for inspection.</li> <li>•Flow indicator: Location specifications.</li> <li>•Any 3-hr period in which temperature <math>&gt;28^\circ\text{C}</math> below baseline.</li> <li>•Boilers/Process Heaters: Change in location of where vent stream introduced into flame zone.</li> </ul>
Performance Testing (PT) Test Method When Conducted	<ul style="list-style-type: none"> <li>•RM's 1, 2 (2A, 2C, 2D), 3 and 18, as applicable.</li> <li>•Initial, except waived if boiler/process heater <math>\geq 44</math> MW heat input capacity.</li> </ul>	
Specific Reporting	<ul style="list-style-type: none"> <li>•PT data and results.</li> <li>•Semiannual reports of exceedance, including periods when vent stream diverted from controls or when no flow rate, and any periods in which an applicable boiler or process heater not operating.</li> </ul>	
Specific Recordkeeping	<ul style="list-style-type: none"> <li>•Detailed requirements similar to data required for reporting.</li> </ul>	
Emission Unit(s)	<ul style="list-style-type: none"> <li>•Distillation units not discharging vent stream into recovery system.</li> <li>•Combinations of distillation unit(s) and recovery system into which its vent stream(s) is discharged.</li> </ul>	
Pollutant(s)	VOC	
Emission Standard/Avg Time	Combust emissions in a flare meeting §60.18/None.	
Monitoring System/Procedure  PS/QA  Exceedance Level	<ul style="list-style-type: none"> <li>•Heat sensing device, such as a thermocouple or ultra-violet beam sensor at pilot light to indicate continuous presence of flame.</li> <li>•At least hourly measurement using flow indicator of vent stream flow to flare.</li> <li>•Flow indicator: Location specifications.</li> <li>•None.</li> </ul>	
Performance Testing (PT) Test Method When Conducted	<ul style="list-style-type: none"> <li>•§60.18 requirements apply:-RM 22 for VE. -Procedures for determining net heating value (RM 18 and ASTM Methods). -Exit velocity using RM 2 (or 2A, 2C, 2D).</li> <li>•Initial.</li> </ul>	
Specific Reporting	<ul style="list-style-type: none"> <li>•PT data and results</li> <li>•Semiannual report of periods when pilot flame absent and when vent stream diverted from flare or has no flow rate.</li> </ul>	

Subpart NNN: VOC Emissions for SOCOMI Distillation Operations				
Specific Recordkeeping	<ul style="list-style-type: none"> <li>Detailed requirements similar to data required for reporting.</li> <li>Includes all data records from pilot flame monitor.</li> </ul>			
Emission Unit(s)	<ul style="list-style-type: none"> <li>Distillation units not discharging vent stream into recovery system.</li> <li>Combinations of distillation unit(s) and recovery system into which its vent control stream(s) is discharged.</li> </ul>			
Pollutant(s)	VOC			
Emission Standard/Avg Time	Maintain TRE index value greater than 1.0 without use of VOC emission control devices/Not specified.			
Monitoring System/Procedure  PS/QA	<b>Absorber Units:</b> <ul style="list-style-type: none"> <li>Continuous monitoring and recording of:- Scrubbing liquid temperature.- Specific gravity.</li> <li>Monitor accuracy: - Temperature: Greater of <math>\pm 1\%</math> or <math>\pm 0.5^\circ\text{C}</math>. -Specific Gravity: <math>\pm 0.02</math> units.</li> </ul>	<b>Condenser Units</b> <ul style="list-style-type: none"> <li>Continuous monitoring and recording of: - Temperature.</li> <li>Monitor accuracy: - Temperature: Greater of <math>\pm 1\%</math> or <math>\pm 0.5^\circ\text{C}</math>.</li> </ul>	<b>Carbon Adsorber Units:</b> <ul style="list-style-type: none"> <li>Continuous monitoring and recording of: - Steam flow.- Carbon bed temperature.</li> <li>Monitor accuracy: Steam flow: <math>\pm 10\%</math>. - Temperature: Greater of <math>\pm 1\%</math> or <math>\pm 0.5^\circ\text{C}</math>.</li> </ul>	<b>Alternative for any Recovery Device:</b> <ul style="list-style-type: none"> <li>VOC CEMS at exit.</li> <li>None.</li> </ul>
Exceedance Level	<ul style="list-style-type: none"> <li>Any 3-hr period in which temperature <math>&gt;11^\circ\text{C}</math> above baseline.</li> <li>Any 3-hr period in which specific gravity <math>&gt;\pm 0.1</math> unit from baseline.</li> </ul>	<ul style="list-style-type: none"> <li>Any 3-hr period in which temperature <math>&gt;6^\circ\text{C}</math> below baseline.</li> </ul>	<ul style="list-style-type: none"> <li>Any period in which mass steam flow for regeneration cycle <math>&gt;10\%</math> below baseline.</li> <li>Any 3-hr period in which temperature <math>&gt;28^\circ\text{C}</math> below baseline.</li> </ul>	<ul style="list-style-type: none"> <li>Any 3-hr period in which concentration level <math>&gt;20\%</math> above baseline.</li> </ul>
Performance Testing (PT) Test Method  When Conducted	<ul style="list-style-type: none"> <li>Determine net heating value of gas combusted and calculate TRE using specified calculations and RM's 1 (1A), 2 (2A, 2C, 2D), 4 and 18 and other procedures, as applicable.</li> <li>Initial and whenever process changes conducted.</li> </ul>			
Specific Reporting	<ul style="list-style-type: none"> <li>PT data and results</li> <li>Semiannual report of exceedance and any recalculation of TRE index.</li> </ul>			
Specific Recordkeeping	<ul style="list-style-type: none"> <li>Detailed requirements similar to data required for semiannual reports.</li> </ul>			

30. The Cationic Monomer Plant (SN-P4-1) shall fully comply with all applicable requirements of NSPS Subpart RRR - Standards of Performance for Volatile Organic

Compound (VOC) Emissions from Synthetic Organic Chemical Manufacturing Industry (SOCMI) Reactor Processes.

In keeping with the exemption provided by 60.700(c)(5), the facility is only required to comply with 60.705(r). The permittee must submit a process design description as part of the initial report which must be retained for the life of the process. [§19.304 of Regulation 19 and 40 CFR Part 60 Subpart RRR]

31. The permittee shall perform an annual audit to determine the number of valves, pumps, relief valves, flanges, and compressors at the P4 unit. The audit shall identify the number of valves, pumps, relief valves, flanges, and compressors as being part of these units. The numbers resulting from this audit shall be used to calculate emissions at SN-P4-4. A copy of the results of this audit and accompanying annual calculations shall be kept on site and made available to Department personnel upon request. [§19.705 of Regulation 19 and A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311]
32. The permittee shall maintain records of hourly VOC emissions within the P4 Process Building area and associated storage tanks on a monthly basis. For compliance purposes, the monthly VOC total divided by the monthly operating hours shall be compared to the hourly VOC emission rate in Specific Condition #1. The records and calculations shall be kept on site and made available to Department personnel upon request. [§19.705 of Regulation 19 and A.C.A. §8-4-203 as referenced by A.C.A. §8-4-304 and §8-4-311]
33. The permittee shall maintain records of hourly HAP emissions within the P4 Process Building area and associated storage tanks on a monthly basis. For compliance purposes, the monthly HAP total divided by the monthly operating hours shall be compared to the hourly emission rate for that pollutant in Specific Condition 2. The records and calculations shall be kept on site and made available to Department personnel upon request. [§18.1004 of Regulation 19 and A.C.A. §8-4-203 as referenced by A.C.A. §8-4-304 and §8-4-311]

Non-Stack Sources

34. The permittee shall maintain monthly records of VOC emissions at FS-1. These records must be kept on site and made available to Department personnel upon request. Compliance shall be based upon a 12-month rolling total. [§19.705 of Regulation 19 and A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311]
35. The permittee shall maintain monthly records of HAP emissions at FS-1. These records must be kept on site and made available to Department personnel upon request. Compliance shall be based upon a 12-month rolling total. [§18.1004 of Regulation 18 and A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311]
36. The permittee shall perform an annual audit to determine the number of valves, pumps, relief valves, flanges, and compressors at the P1, P2, and P3 units. The audit shall

BASF Corporation  
Permit #: 0860-AR-4  
AFIN: 18-00081

identify the number of valves, pumps, relief valves, flanges, and compressors as being part of these units. The numbers resulting from this audit shall be used to calculate emissions of FS-2. A copy of the results of this audit and accompanying annual calculations shall be kept on site and made available to Department personnel upon request. [§19.705 of Regulation 19 and A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311]

37. The permittee shall perform an annual evaluation of VOC, HAP, and acetone emissions from the wastewater treatment operations at SN-FS-3. The evaluation shall be based upon data from sampling of these pollutants in the wastewater, estimations from the TANKS program, WATER9 or similar wastewater treatment modeling software. The permittee, if necessary to correct permitted emissions, shall submit an application to modify their minor source permit within 30 days of the assessment. [§18.1004 of Regulation 18, §19.705 of Regulation 19 and A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311]

#### Miscellaneous Sources Section

38. The permittee shall not operate the Lab Emergency Electrical Generator (SN-MI-1) more than 200 hours per rolling 12-month period for testing and maintenance purposes. Records of testing/maintenance operation time shall be maintained on site, updated on a per-event basis, and made available to Department personnel upon request. Operation time required for actual emergency use is not restricted by this permit. [§19.705 of Regulation 19, A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311]
39. The permittee shall be limited to 2 hours per week and 100 hours per year of diesel generator testing and maintenance operating time, each for SN-MI-2, SN-MI-3, and SN-MI-4, except that a 4-hour testing and maintenance event may be conducted once per year. Records of generator use for testing/maintenance shall be maintained on site, updated on a per-event basis, and made available to Department personnel upon request. Operation time required for actual emergency use is not restricted by this permit. [§19.705 of Regulation 19, A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311]
40. The permittee shall not operate the Electrical Generator (SN-MI-5) more than 100 hours per rolling 12-month period for testing and maintenance purposes. Records of testing/maintenance operation time shall be maintained on site, updated on a per-event basis, and made available to Department personnel upon request. Operation time required for actual emergency use is not restricted by this permit. [§19.705 of Regulation 19, A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311]
41. The permittee shall maintain a copy of the manufacturer's specification sheet for the Lab Emergency Electrical Generator (SN-MI-1), Emergency Electrical Generator (SN-MI-2), the Fire Protection Generator (SN-MI-3), the Electrical Generator (SN-MI-4), and Electrical Generator (SN-MI-5). This information shall be kept on site and made

available to Department personnel upon request. [§19.705 of Regulation 19, A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311]

Plantwide Conditions

- 42. The permittee will implement a Leak Detection and Repair (LDAR) Program at the facility. The LDAR procedure and inspection logs will be kept on site at all times and will be made available to Department personnel upon request. [§19.705 of Regulation 19 and A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311]
- 43. The permittee is limited to the following VOC, HAP, and acetone 12-month rolling total limits from the P1, P2, P3, and P4 sources. [§18.801 et seq of Regulation 18, §19.501 et seq of Regulation 19 and A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311]

Pollutant	12-month rolling limit
VOC	55.4
Acetone	1.7
Acrylamide <sup>HAP</sup>	0.02
Acrylic Acid <sup>HAP</sup>	0.42
Allyl Chloride <sup>HAP</sup>	0.30
Epichlorohydrin <sup>HAP</sup>	0.04
Methanol <sup>HAP</sup>	2.28
Methyl Methacrylate <sup>HAP</sup>	3.99
Methyl Chloride <sup>HAP</sup>	4.60

- 44. The permittee shall maintain records of VOC emissions at the P1, P2, P3, and P4 source groups on a monthly basis. These records must be kept on site and made available to Department personnel upon request. Compliance shall be based upon a 12-month rolling total. Calculations shall be based on boiler fuel usage, diesel combustion, reactor kinetic equations, estimations from the TANKS program, and fugitive emissions caused by unloading and equipment leaks. The calculated value shall be compared to the limit contained within Specific Condition 43 for compliance purposes. [§19.705 of Regulation 19 and A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311]
- 45. The permittee shall maintain records of HAP and acetone emissions at the P1, P2, P3, and P4 source groups on a monthly basis. These records must be kept on site and made available to Department personnel upon request. Compliance shall be based upon a 12-month rolling total. Calculations shall be based on boiler fuel usage, diesel combustion, reactor kinetic equations, estimations from the TANKS program, and fugitive emissions caused by unloading and equipment leaks. The calculated value shall be compared to the limit contained within Specific Condition 42 for compliance purposes. [§18.1004 of Regulation 18 and A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311]

BASF Corporation  
 Permit #: 0860-AR-4  
 AFIN: 18-00081

46. The permittee may maintain their compliance logs in a spreadsheet, database, or other well organized format. [§19.705 of Regulation 19 and A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311]
47. The permittee shall be responsible for complying with all applicable requirements of NSPS-Kb at any tank at the facility if a volatile organic liquid meeting the vapor pressure and quantity thresholds outlined in NSPS-Kb is stored in the tank. These vapor pressure and quantity thresholds are presented in the following NSPS Kb Summary of Requirements for reference. [§19.304 of Regulation 19 and 40 CFR Part 60 Subpart Kb]

Vessel Capacity (gallons)	VOL Pressure Limit	Required Control Device	Summary of Testing & Procedures	Recordkeeping & Reporting	Monitoring of Operations
>=19,813 but <39,889 60.116(b)(c)	>=2.18 psia but < 4.00 psia	None	None	None	Items A, B, C, & D
>=19,813 but <39,889	>=2.18 psia	None	None	None	Items A & B
>=19,813 but <39,890 60.112b(a)	>= 4.00 psia but < 11.11 psia	IFR, EFR, or Closed Vent System, or EPA Alternative	See Below	See Below	Items A, B, & C
>=19,813 60.112(b)(b)	>= 11.11 psia	Closed Vent System or EPA Alternative	See Below	See Below	Items A & B
>=39,890 60.116(b)(c)	>=0.5 psia	None	None	None	Items A & B
>=39,890	>=0.5 psia but < 0.75 psia	None	None	None	Items A, B, C, & D
>=39,890 60.112b(a)	>= 0.75 psia but <11.11 psia	IFR, EFR, or Closed Vent System, or EPA Alternative	See Below	See Below	Items A, B, & C

**DESCRIPTION OF CONTROL DEVICE**

**IFR:** Internal Floating Roof, in conjunction with a fixed roof. The IFR is equipped with a liquid-mounted or mechanical shoe primary seal, either flexible fabric sleeve seals on pipe columns or gasketed sliding covers on built-up or pipe columns, slit fabric membranes or sample wells, and gasketed covers on roof fittings.

**EFR:** External Floating Roof, equipped with mechanical shoe primary seals and a continuous rim-mounted secondary seal, with both seals meeting certain minimum gap requirements, and gasketed covers on roof fittings.

**Closed Vent System and Control Device:** 95% effective control device

**Alternative means of emission limitation:** May be approved by EPA after notice and an opportunity for public hearing.

**SUMMARY OF TESTING AND PROCEDURES**

BASF Corporation  
Permit #: 0860-AR-4  
AFIN: 18-00081

**Closed Vent System:** Submit a design specification and operation and maintenance plan, which specifies maintenance and operating practices.

**Alternate Means Approved by EPA:** Specified by EPA when approved.

**External Floating Roof:** Inspect seals prior to filling. Also, gap measurements between the seal and vessel wall are required to ensure equipment is properly maintained and operated. Gap measurements of primary and secondary seals are required within 60 days of introducing liquid to the vessel. Every 12 months, secondary gap measurements must be conducted. Every five years, primary seal gap measurements must be conducted. Measured gaps that exceed limitations must be repaired within 45 days, or the vessel must be emptied. Notify EPA 30 days prior to gap measurements being conducted and also prior to filling and refilling of vessel.

**Fixed Roof with IFR:** Required to inspect to ensure that equipment is maintained and properly operated. Floating roof and seals are to be inspected prior to filling the vessel to ensure there are no holes in the IFR and that there are no holes, tears, or other openings in the seal from the fixed roof. If there are holes in the IFR or if liquid has accumulated on the roof, then repairs can be made within 45 days or the vessel can be emptied within 45 days. Every ten years, the vessel must be emptied to inspect the IFR and primary and secondary seals. All defects must be repaired before the vessel is refilled. Notify EPA 30 days prior to filling and refilling the vessel.

#### **SUMMARY OF MONITORING OPERATIONS**

**Item A:** Requirement to keep copies of all records required by Items C and D for two years. The record required by Item B is to be kept for the life of the source.

**Item B:** Record showing the dimension of the storage vessel and an analysis showing the capacity of the vessel.

**Item C:** Maintain a record of the VOL stored, the period of storage and the maximum true vapor pressure of that VOL during the respective storage period. Vessels with closed vent systems and control device are exempt.

**Item D:** Notify EPA within 30 days when the maximum true vapor pressure of the liquid exceeds the respective maximum true vapor pressure values for each volume range. Vessels with Closed Vent System and Control Device are EXEMPT.

#### **AFFECTED FACILITY DEFINED**

The affected facility to which this subpart applies is each storage vessel with a capacity greater than or equal to 19,813 gallons that is used to store volatile organic liquids (VOLs) for which construction, reconstruction, or modification is commenced after July 23, 1984.

#### **EXCEPTIONS**

1. Vessels at coke oven by-product plants.
2. Pressure vessels designed to operate in excess of 204.9 kPa (29.69 psia) and without emissions to the atmosphere.
3. Vessels permanently attached to mobile vehicles such as trucks, railcars, barges, or ships.
4. Vessels with a design capacity less than or equal to 420,000 gal. Used for petroleum or condensate stored, processed, or treated prior to custody transfer.
5. Vessels located at bulk gasoline plants.
6. Storage vessels located at gasoline service stations.
7. Vessels used to store beverage alcohol.

BASF Corporation  
Permit #: 0860-AR-4  
AFIN: 18-00081

Section V: INSIGNIFICANT ACTIVITIES

The Department deems the following types of activities or emissions as insignificant on the basis of size, emission rate, production rate, or activity in accordance with Group A of the Insignificant Activities list found in Regulation 18 and 19 Appendix A. Insignificant activity emission determinations rely upon the information submitted by the permittee in applications dated July 2007, May 2009, and July 2009.

<b>Description</b>	<b>Category</b>
Final Product Drumming and Shipping	A-13
P3 Acetone Boilouts	A-13
Wastewater Sludge Dewatering	A-13
Quat Scrubber and Feed Tank Charge	A-13
Heated Raw Materials Tanks (V-1212, V-1213)	A-13
T-400 Tank Farm Methanol Cleanout	A-13
T-600 Tank Farm Methanol Cleanout	A-13
Quat Inhibitor Dosing	A-13
Mercaptan Addition for T-125	A-13
R-105 Use to Hold mDADMAC Tank & Reactor Cleanout Water	A-13
Centrifuges C3 & C4 in the P1 mDADMAC Process	A-13
T902 Poly Epiamine Dilution	A-13



Section VI: GENERAL CONDITIONS

1. Any terms or conditions included in this permit that specify and reference Arkansas Pollution Control & Ecology Commission Regulation 18 or the Arkansas Water and Air Pollution Control Act (A.C.A. §8-4-101 et seq.) as the sole origin of and authority for the terms or conditions are not required under the Clean Air Act or any of its applicable requirements, and are not federally enforceable under the Clean Air Act. Arkansas Pollution Control & Ecology Commission Regulation 18 was adopted pursuant to the Arkansas Water and Air Pollution Control Act (A.C.A. §8-4-101 et seq.). Any terms or conditions included in this permit that specify and reference Arkansas Pollution Control & Ecology Commission Regulation 18 or the Arkansas Water and Air Pollution Control Act (A.C.A. §8-4-101 et seq.) as the origin of and authority for the terms or conditions are enforceable under this Arkansas statute.
2. This permit does not relieve the owner or operator of the equipment and/or the facility from compliance with all applicable provisions of the Arkansas Water and Air Pollution Control Act and the regulations promulgated under the Act. [A.C.A. §8-4-203 as referenced by A.C.A. §8-4-304 and §8-4-311]
3. The permittee shall notify the Department in writing within thirty (30) days after commencement of construction, completion of construction, first operation of equipment and/or facility, and first attainment of the equipment and/or facility target production rate. [Regulation 19, §19.704 and/or A.C.A. §8-4-203 as referenced by A.C.A. §8-4-304 and §8-4-311]
4. Construction or modification must commence within eighteen (18) months from the date of permit issuance. [Regulation 19, §19.410(B) and/or Regulation 18, §18.309(B) and A.C.A. §8-4-203 as referenced by A.C.A. §8-4-304 and §8-4-311]
5. The permittee must keep records for five years to enable the Department to determine compliance with the terms of this permit such as hours of operation, throughput, upset conditions, and continuous monitoring data. The Department may use the records, at the discretion of the Department, to determine compliance with the conditions of the permit. [Regulation 19, §19.705 and/or Regulation 18, §18.1004 and A.C.A. §8-4-203 as referenced by A.C.A. §8-4-304 and §8-4-311]
6. A responsible official must certify any reports required by any condition contained in this permit and submit any reports to the Department at the address below. [Regulation 19, §19.705 and/or Regulation 18, §18.1004 and A.C.A. §8-4-203 as referenced by A.C.A. §8-4-304 and §8-4-311]

Arkansas Department of Environmental Quality  
Air Division  
ATTN: Compliance Inspector Supervisor

BASF Corporation  
Permit #: 0860-AR-4  
AFIN: 18-00081

5301 Northshore Drive  
North Little Rock, AR 72118-5317

7. The permittee shall test any equipment scheduled for testing, unless stated in the Specific Conditions of this permit or by any federally regulated requirements, within the following time frames: (1) newly constructed or modified equipment within sixty (60) days of achieving the maximum production rate, but no later than 180 days after initial start up of the permitted source or (2) existing equipment already operating according to the time frames set forth by the Department. The permittee must notify the Department of the scheduled date of compliance testing at least fifteen (15) days in advance of such test. The permittee must submit compliance test results to the Department within thirty (30) days after the completion of testing. [Regulation 19, §19.702 and/or Regulation 18, §18.1002 and A.C.A. §8-4-203 as referenced by A.C.A. §8-4-304 and §8-4-311]
8. The permittee shall provide: [Regulation 19, §19.702 and/or Regulation 18, §18.1002 and A.C.A. §8-4-203 as referenced by A.C.A. §8-4-304 and §8-4-311]
  - a. Sampling ports adequate for applicable test methods;
  - b. Safe sampling platforms;
  - c. Safe access to sampling platforms; and
  - d. Utilities for sampling and testing equipment
9. The permittee shall operate equipment, control apparatus and emission monitoring equipment within their design limitations. The permittee shall maintain in good condition at all times equipment, control apparatus and emission monitoring equipment. [Regulation 19, §19.303 and/or Regulation 18, §18.1104 and A.C.A. §8-4-203 as referenced by A.C.A. §8-4-304 and §8-4-311]
10. If the permittee exceeds an emission limit established by this permit, the permittee will be deemed in violation of said permit and will be subject to enforcement action. The Department may forego enforcement action for emissions exceeding any limits established by this permit provided the following requirements are met: [Regulation 19, §19.601 and/or Regulation 18, §18.1101 and A.C.A. §8-4-203 as referenced by A.C.A. §8-4-304 and §8-4-311]
  - a. The permittee demonstrates to the satisfaction of the Department that the emissions resulted from an equipment malfunction or upset and are not the result of negligence or improper maintenance, and the permittee took all reasonable measures to immediately minimize or eliminate the excess emissions.
  - b. The permittee reports the occurrence or upset or breakdown of equipment (by telephone, facsimile, or overnight delivery) to the Department by the end of the next business day after the occurrence or the discovery of the occurrence.
  - c. The permittee must submit to the Department, within five business days after the occurrence or the discovery of the occurrence, a full, written report of such occurrence, including a statement of all known causes and of the scheduling and

BASF Corporation  
Permit #: 0860-AR-4  
AFIN: 18-00081

nature of the actions to be taken to minimize or eliminate future occurrences, including, but not limited to, action to reduce the frequency of occurrence of such conditions, to minimize the amount by which said limits are exceeded, and to reduce the length of time for which said limits are exceeded. If the information is included in the initial report, the information need not be submitted again.

11. The permittee shall allow representatives of the Department upon the presentation of credentials: [A.C.A. §8-4-203 as referenced by A.C.A. §8-4-304 and §8-4-311]
  - a. To enter upon the permittee's premises, or other premises under the control of the permittee, where an air pollutant source is located or in which any records are required to be kept under the terms and conditions of this permit;
  - b. To have access to and copy any records required to be kept under the terms and conditions of this permit, or the Act;
  - c. To inspect any monitoring equipment or monitoring method required in this permit;
  - d. To sample any emission of pollutants; and
  - e. To perform an operation and maintenance inspection of the permitted source.
12. The Department issued this permit in reliance upon the statements and presentations made in the permit application. The Department has no responsibility for the adequacy or proper functioning of the equipment or control apparatus. [A.C.A. §8-4-203 as referenced by A.C.A. §8-4-304 and §8-4-311]
13. The Department may revoke or modify this permit when, in the judgment of the Department, such revocation or modification is necessary to comply with the applicable provisions of the Arkansas Water and Air Pollution Control Act and the regulations promulgated the Arkansas Water and Air Pollution Control Act. [Regulation 19, §19.410(A) and/or Regulation 18, §18.309(A) and A.C.A. §8-4-203 as referenced by A.C.A. §8-4-304 and §8-4-311]
14. This permit may be transferred. An applicant for a transfer must submit a written request for transfer of the permit on a form provided by the Department and submit the disclosure statement required by Arkansas Code Annotated §8-1-106 at least thirty (30) days in advance of the proposed transfer date. The permit will be automatically transferred to the new permittee unless the Department denies the request to transfer within thirty (30) days of the receipt of the disclosure statement. The Department may deny a transfer on the basis of the information revealed in the disclosure statement or other investigation or, deliberate falsification or omission of relevant information. [Regulation 19, §19.407(B) and/or Regulation 18, §18.307(B) and A.C.A. §8-4-203 as referenced by A.C.A. §8-4-304 and §8-4-311]
15. This permit shall be available for inspection on the premises where the control apparatus is located. [A.C.A. §8-4-203 as referenced by A.C.A. §8-4-304 and §8-4-311]

BASF Corporation  
Permit #: 0860-AR-4  
AFIN: 18-00081

16. This permit authorizes only those pollutant emitting activities addressed herein. [A.C.A. §8-4-203 as referenced by A.C.A. §8-4-304 and §8-4-311]
17. This permit supersedes and voids all previously issued air permits for this facility. [Regulation 18 and 19 and A.C.A. §8-4-203 as referenced by A.C.A. §8-4-304 and §8-4-311]
18. The permittee must pay all permit fees in accordance with the procedures established in Regulation No. 9. [A.C.A §8-1-105(c)]
19. The permittee may request in writing and at least 15 days in advance of the deadline, an extension to any testing, compliance or other dates in this permit. No such extensions are authorized until the permittee receives written Department approval. The Department may grant such a request, at its discretion in the following circumstances:
  - a. Such an extension does not violate a federal requirement;
  - b. The permittee demonstrates the need for the extension; and
  - c. The permittee documents that all reasonable measures have been taken to meet the current deadline and documents reasons it cannot be met.

[Regulation 18, §18.314(A), Regulation 19, §19.416(A), A.C.A. §8-4-203 as referenced by A.C.A. §8-4-304 and §8-4-311, and 40 CFR Part 52, Subpart E]

20. The permittee may request in writing and at least 30 days in advance, temporary emissions and/or testing that would otherwise exceed an emission rate, throughput requirement, or other limit in this permit. No such activities are authorized until the permittee receives written Department approval. Any such emissions shall be included in the facilities total emissions and reported as such. The Department may grant such a request, at its discretion under the following conditions:
  - a. Such a request does not violate a federal requirement;
  - b. Such a request is temporary in nature;
  - c. Such a request will not result in a condition of air pollution;
  - d. The request contains such information necessary for the Department to evaluate the request, including but not limited to, quantification of such emissions and the date/time such emission will occur;
  - e. Such a request will result in increased emissions less than five tons of any individual criteria pollutant, one ton of any single HAP and 2.5 tons of total HAPs; and
  - f. The permittee maintains records of the dates and results of such temporary emissions/testing.

[Regulation 18, §18.314(B), Regulation 19, §19.416(B), A.C.A. §8-4-203 as referenced by A.C.A. §8-4-304 and §8-4-311, and 40 CFR Part 52, Subpart E]

BASF Corporation  
Permit #: 0860-AR-4  
AFIN: 18-00081

21. The permittee may request in writing and at least 30 days in advance, an alternative to the specified monitoring in this permit. No such alternatives are authorized until the permittee receives written Department approval. The Department may grant such a request, at its discretion under the following conditions:
  - a. The request does not violate a federal requirement;
  - b. The request provides an equivalent or greater degree of actual monitoring to the current requirements; and
  - c. Any such request, if approved, is incorporated in the next permit modification application by the permittee.

[Regulation 18, §18.314(C), Regulation 19, §19.416(C), A.C.A. §8-4-203 as referenced by A.C.A. §8-4-304 and §8-4-311, and 40 CFR Part 52, Subpart E]

Appendix A—40 CFR 60 Subpart Dc: *Standards of Performance for Small Industrial-  
Commercial-Institutional Steam Generating Units*

[Home Page](#) > [Executive Branch](#) > [Code of Federal Regulations](#) > [Electronic Code of Federal Regulations](#)

Electronic Code of Federal Regulations  
**e-CFR**<sup>TM</sup>

**e-CFR Data is current as of April 2, 2010**

**Title 40: Protection of Environment**

**PART 60—STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES**

[Browse Previous](#) | [Browse Next](#)

**Subpart Dc—Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units**

**Source:** 72 FR 32759, June 13, 2007, unless otherwise noted.

**§ 60.40c Applicability and delegation of authority.**

(a) Except as provided in paragraphs (d), (e), (f), and (g) of this section, the affected facility to which this subpart applies is each steam generating unit for which construction, modification, or reconstruction is commenced after June 9, 1989 and that has a maximum design heat input capacity of 29 megawatts (MW) (100 million British thermal units per hour (MMBtu/hr)) or less, but greater than or equal to 2.9 MW (10 MMBtu/hr).

(b) In delegating implementation and enforcement authority to a State under section 111(c) of the Clean Air Act, §60.48c(a)(4) shall be retained by the Administrator and not transferred to a State.

(c) Steam generating units that meet the applicability requirements in paragraph (a) of this section are not subject to the sulfur dioxide (SO<sub>2</sub>) or particulate matter (PM) emission limits, performance testing requirements, or monitoring requirements under this subpart (§§60.42c, 60.43c, 60.44c, 60.45c, 60.46c, or 60.47c) during periods of combustion research, as defined in §60.41c.

(d) Any temporary change to an existing steam generating unit for the purpose of conducting combustion research is not considered a modification under §60.14.

(e) Heat recovery steam generators that are associated with combined cycle gas turbines and meet the applicability requirements of subpart KKKK of this part are not subject to this subpart. This subpart will continue to apply to all other heat recovery steam generators that are capable of combusting more than or equal to 2.9 MW (10 MMBtu/hr) heat input of fossil fuel but less than or equal to 29 MW (100 MMBtu/hr) heat input of fossil fuel. If the heat recovery steam generator is subject to this subpart, only emissions resulting from combustion of fuels in the steam generating unit are subject to this subpart. (The gas turbine emissions are subject to subpart GG or KKKK, as applicable, of this part).

(f) Any facility covered by subpart AAAA of this part is not subject by this subpart.

(g) Any facility covered by an EPA approved State or Federal section 111(d)/129 plan implementing subpart BBBB of this part is not subject by this subpart.

[72 FR 32759, June 13, 2007, as amended at 74 FR 5090, Jan. 28, 2009]

**§ 60.41c Definitions.**

As used in this subpart, all terms not defined herein shall have the meaning given them in the Clean Air Act and in subpart A of this part.

*Annual capacity factor* means the ratio between the actual heat input to a steam generating unit from an individual fuel or

combination of fuels during a period of 12 consecutive calendar months and the potential heat input to the steam generating unit from all fuels had the steam generating unit been operated for 8,760 hours during that 12-month period at the maximum design heat input capacity. In the case of steam generating units that are rented or leased, the actual heat input shall be determined based on the combined heat input from all operations of the affected facility during a period of 12 consecutive calendar months.

*Coal* means all solid fuels classified as anthracite, bituminous, subbituminous, or lignite by the American Society of Testing and Materials in ASTM D388 (incorporated by reference, see §60.17), coal refuse, and petroleum coke. Coal-derived synthetic fuels derived from coal for the purposes of creating useful heat, including but not limited to solvent refined coal, gasified coal not meeting the definition of natural gas, coal-oil mixtures, and coal-water mixtures, are also included in this definition for the purposes of this subpart.

*Coal refuse* means any by-product of coal mining or coal cleaning operations with an ash content greater than 50 percent (by weight) and a heating value less than 13,900 kilojoules per kilogram (kJ/kg) (6,000 Btu per pound (Btu/lb) on a dry basis.

*Cogeneration steam generating unit* means a steam generating unit that simultaneously produces both electrical (or mechanical) and thermal energy from the same primary energy source.

*Combined cycle system* means a system in which a separate source (such as a stationary gas turbine, internal combustion engine, or kiln) provides exhaust gas to a steam generating unit.

*Combustion research* means the experimental firing of any fuel or combination of fuels in a steam generating unit for the purpose of conducting research and development of more efficient combustion or more effective prevention or control of air pollutant emissions from combustion, provided that, during these periods of research and development, the heat generated is not used for any purpose other than preheating combustion air for use by that steam generating unit (i.e., the heat generated is released to the atmosphere without being used for space heating, process heating, driving pumps, preheating combustion air for other units, generating electricity, or any other purpose).

*Conventional technology* means wet flue gas desulfurization technology, dry flue gas desulfurization technology, atmospheric fluidized bed combustion technology, and oil hydrosulfurization technology.

*Distillate oil* means fuel oil that complies with the specifications for fuel oil numbers 1 or 2, as defined by the American Society for Testing and Materials in ASTM D396 (incorporated by reference, see §60.17) or diesel fuel oil numbers 1 or 2, as defined by the American Society for Testing and Materials in ASTM D975 (incorporated by reference, see §60.17).

*Dry flue gas desulfurization technology* means a SO<sub>2</sub>-control system that is located between the steam generating unit and the exhaust vent or stack, and that removes sulfur oxides from the combustion gases of the steam generating unit by contacting the combustion gases with an alkaline reagent and water, whether introduced separately or as a premixed slurry or solution and forming a dry powder material. This definition includes devices where the dry powder material is subsequently converted to another form. Alkaline reagents used in dry flue gas desulfurization systems include, but are not limited to, lime and sodium compounds.

*Duct burner* means a device that combusts fuel and that is placed in the exhaust duct from another source (such as a stationary gas turbine, internal combustion engine, kiln, etc.) to allow the firing of additional fuel to heat the exhaust gases before the exhaust gases enter a steam generating unit.

*Emerging technology* means any SO<sub>2</sub>-control system that is not defined as a conventional technology under this section, and for which the owner or operator of the affected facility has received approval from the Administrator to operate as an emerging technology under §60.48c(a)(4).

*Federally enforceable* means all limitations and conditions that are enforceable by the Administrator, including the requirements of 40 CFR parts 60 and 61, requirements within any applicable State implementation plan, and any permit requirements established under 40 CFR 52.21 or under 40 CFR 51.18 and 51.24.

*Fluidized bed combustion technology* means a device wherein fuel is distributed onto a bed (or series of beds) of limestone aggregate (or other sorbent materials) for combustion; and these materials are forced upward in the device by the flow of combustion air and the gaseous products of combustion. Fluidized bed combustion technology includes, but is not limited to, bubbling bed units and circulating bed units.

*Fuel pretreatment* means a process that removes a portion of the sulfur in a fuel before combustion of the fuel in a steam generating unit.

*Heat input* means heat derived from combustion of fuel in a steam generating unit and does not include the heat derived from preheated combustion air, recirculated flue gases, or exhaust gases from other sources (such as stationary gas turbines, internal combustion engines, and kilns).

*Heat transfer medium* means any material that is used to transfer heat from one point to another point.



*Maximum design heat input capacity* means the ability of a steam generating unit to combust a stated maximum amount of fuel (or combination of fuels) on a steady state basis as determined by the physical design and characteristics of the steam generating unit.

*Natural gas* means:

- (1) A naturally occurring mixture of hydrocarbon and nonhydrocarbon gases found in geologic formations beneath the earth's surface, of which the principal constituent is methane; or
- (2) Liquefied petroleum (LP) gas, as defined by the American Society for Testing and Materials in ASTM D1835 (incorporated by reference, see §60.17); or
- (3) A mixture of hydrocarbons that maintains a gaseous state at ISO conditions. Additionally, natural gas must either be composed of at least 70 percent methane by volume or have a gross calorific value between 34 and 43 megajoules (MJ) per dry standard cubic meter (910 and 1,150 Btu per dry standard cubic foot).

*Noncontinental area* means the State of Hawaii, the Virgin Islands, Guam, American Samoa, the Commonwealth of Puerto Rico, or the Northern Mariana Islands.

*Oil* means crude oil or petroleum, or a liquid fuel derived from crude oil or petroleum, including distillate oil and residual oil.

*Potential sulfur dioxide emission rate* means the theoretical SO<sub>2</sub> emissions (nanograms per joule (ng/J) or lb/MMBtu heat input) that would result from combusting fuel in an uncleaned state and without using emission control systems.

*Process heater* means a device that is primarily used to heat a material to initiate or promote a chemical reaction in which the material participates as a reactant or catalyst.

*Residual oil* means crude oil, fuel oil that does not comply with the specifications under the definition of distillate oil, and all fuel oil numbers 4, 5, and 6, as defined by the American Society for Testing and Materials in ASTM D396 (incorporated by reference, see §60.17).

*Steam generating unit* means a device that combusts any fuel and produces steam or heats water or heats any heat transfer medium. This term includes any duct burner that combusts fuel and is part of a combined cycle system. This term does not include process heaters as defined in this subpart.

*Steam generating unit operating day* means a 24-hour period between 12:00 midnight and the following midnight during which any fuel is combusted at any time in the steam generating unit. It is not necessary for fuel to be combusted continuously for the entire 24-hour period.

*Wet flue gas desulfurization technology* means an SO<sub>2</sub> control system that is located between the steam generating unit and the exhaust vent or stack, and that removes sulfur oxides from the combustion gases of the steam generating unit by contacting the combustion gases with an alkaline slurry or solution and forming a liquid material. This definition includes devices where the liquid material is subsequently converted to another form. Alkaline reagents used in wet flue gas desulfurization systems include, but are not limited to, lime, limestone, and sodium compounds.

*Wet scrubber system* means any emission control device that mixes an aqueous stream or slurry with the exhaust gases from a steam generating unit to control emissions of PM or SO<sub>2</sub>.

*Wood* means wood, wood residue, bark, or any derivative fuel or residue thereof, in any form, including but not limited to sawdust, sander dust, wood chips, scraps, slabs, millings, shavings, and processed pellets made from wood or other forest residues.

[72 FR 32759, June 13, 2007, as amended at 74 FR 5090, Jan. 28, 2009]

### § 60.42c Standard for sulfur dioxide (SO<sub>2</sub>).

(a) Except as provided in paragraphs (b), (c), and (e) of this section, on and after the date on which the performance test is completed or required to be completed under §60.8, whichever date comes first, the owner or operator of an affected facility that combusts only coal shall neither: cause to be discharged into the atmosphere from the affected facility any gases that contain SO<sub>2</sub> in excess of 87 ng/J (0.20 lb/MMBtu) heat input or 10 percent (0.10) of the potential SO<sub>2</sub> emission rate (90 percent reduction), nor cause to be discharged into the atmosphere from the affected facility any gases that contain SO<sub>2</sub> in excess of 520 ng/J (1.2 lb/MMBtu) heat input. If coal is combusted with other fuels, the affected facility shall neither: cause to be discharged into the atmosphere from the affected facility any gases that contain SO<sub>2</sub> in excess of 87 ng/J (0.20 lb/MMBtu) heat input or 10 percent (0.10) of the potential SO<sub>2</sub> emission rate (90 percent reduction), nor cause to be discharged into the atmosphere from the affected

facility any gases that contain SO<sub>2</sub> in excess of the emission limit is determined pursuant to paragraph (e)(2) of this section.

(b) Except as provided in paragraphs (c) and (e) of this section, on and after the date on which the performance test is completed or required to be completed under §60.8, whichever date comes first, the owner or operator of an affected facility that:

(1) Combusts only coal refuse alone in a fluidized bed combustion steam generating unit shall neither:

(i) Cause to be discharged into the atmosphere from that affected facility any gases that contain SO<sub>2</sub> in excess of 87 ng/J (0.20 lb/MMBtu) heat input or 20 percent (0.20) of the potential SO<sub>2</sub> emission rate (80 percent reduction); nor

(ii) Cause to be discharged into the atmosphere from that affected facility any gases that contain SO<sub>2</sub> in excess of SO<sub>2</sub> in excess of 520 ng/J (1.2 lb/MMBtu) heat input. If coal is fired with coal refuse, the affected facility subject to paragraph (a) of this section. If oil or any other fuel (except coal) is fired with coal refuse, the affected facility is subject to the 87 ng/J (0.20 lb/MMBtu) heat input SO<sub>2</sub> emissions limit or the 90 percent SO<sub>2</sub> reduction requirement specified in paragraph (a) of this section and the emission limit is determined pursuant to paragraph (e) (2) of this section.

(2) Combusts only coal and that uses an emerging technology for the control of SO<sub>2</sub> emissions shall neither:

(i) Cause to be discharged into the atmosphere from that affected facility any gases that contain SO<sub>2</sub> in excess of 50 percent (0.50) of the potential SO<sub>2</sub> emission rate (50 percent reduction); nor

(ii) Cause to be discharged into the atmosphere from that affected facility any gases that contain SO<sub>2</sub> in excess of 260 ng/J (0.60 lb/MMBtu) heat input. If coal is combusted with other fuels, the affected facility is subject to the 50 percent SO<sub>2</sub> reduction requirement specified in this paragraph and the emission limit determined pursuant to paragraph (e) (2) of this section.

(c) On and after the date on which the initial performance test is completed or required to be completed under §60.8, whichever date comes first, no owner or operator of an affected facility that combusts coal, alone or in combination with any other fuel, and is listed in paragraphs (c)(1), (2), (3), or (4) of this section shall cause to be discharged into the atmosphere from that affected facility any gases that contain SO<sub>2</sub> in excess of the emission limit determined pursuant to paragraph (e)(2) of this section. Percent reduction requirements are not applicable to affected facilities under paragraphs (c)(1), (2), (3), or (4).

(1) Affected facilities that have a heat input capacity of 22 MW (75 MMBtu/hr) or less.

(2) Affected facilities that have an annual capacity for coal of 55 percent (0.55) or less and are subject to a federally enforceable requirement limiting operation of the affected facility to an annual capacity factor for coal of 55 percent (0.55) or less.

(3) Affected facilities located in a noncontinental area.

(4) Affected facilities that combust coal in a duct burner as part of a combined cycle system where 30 percent (0.30) or less of the heat entering the steam generating unit is from combustion of coal in the duct burner and 70 percent (0.70) or more of the heat entering the steam generating unit is from exhaust gases entering the duct burner.

(d) On and after the date on which the initial performance test is completed or required to be completed under §60.8, whichever date comes first, no owner or operator of an affected facility that combusts oil shall cause to be discharged into the atmosphere from that affected facility any gases that contain SO<sub>2</sub> in excess of 215 ng/J (0.50 lb/MMBtu) heat input; or, as an alternative, no owner or operator of an affected facility that combusts oil shall combust oil in the affected facility that contains greater than 0.5 weight percent sulfur. The percent reduction requirements are not applicable to affected facilities under this paragraph.

(e) On and after the date on which the initial performance test is completed or required to be completed under §60.8, whichever date comes first, no owner or operator of an affected facility that combusts coal, oil, or coal and oil with any other fuel shall cause to be discharged into the atmosphere from that affected facility any gases that contain SO<sub>2</sub> in excess of the following:

(1) The percent of potential SO<sub>2</sub> emission rate or numerical SO<sub>2</sub> emission rate required under paragraph (a) or (b)(2) of this section, as applicable, for any affected facility that

(i) Combusts coal in combination with any other fuel;

(ii) Has a heat input capacity greater than 22 MW (75 MMBtu/hr); and

(iii) Has an annual capacity factor for coal greater than 55 percent (0.55); and

(2) The emission limit determined according to the following formula for any affected facility that combusts coal, oil, or coal and oil with any other fuel:

$$E_s = \frac{(K_a H_a + K_b H_b + K_c H_c)}{(H_a + H_b + H_c)}$$

Where:

$E_s$  = SO<sub>2</sub> emission limit, expressed in ng/J or lb/MMBtu heat input;

$K_a$  = 520 ng/J (1.2 lb/MMBtu);

$K_b$  = 260 ng/J (0.60 lb/MMBtu);

$K_c$  = 215 ng/J (0.50 lb/MMBtu);

$H_a$  = Heat input from the combustion of coal, except coal combusted in an affected facility subject to paragraph (b)(2) of this section, in Joules (J) [MMBtu];

$H_b$  = Heat input from the combustion of coal in an affected facility subject to paragraph (b)(2) of this section, in J (MMBtu); and

$H_c$  = Heat input from the combustion of oil, in J (MMBtu).

(f) Reduction in the potential SO<sub>2</sub> emission rate through fuel pretreatment is not credited toward the percent reduction requirement under paragraph (b) (2) of this section unless:

(1) Fuel pretreatment results in a 50 percent (0.50) or greater reduction in the potential SO<sub>2</sub> emission rate; and

(2) Emissions from the pretreated fuel (without either combustion or post-combustion SO<sub>2</sub> control) are equal to or less than the emission limits specified under paragraph (b)(2) of this section.

(g) Except as provided in paragraph (h) of this section, compliance with the percent reduction requirements, fuel oil sulfur limits, and emission limits of this section shall be determined on a 30-day rolling average basis.

(h) For affected facilities listed under paragraphs (h)(1), (2), or (3) of this section, compliance with the emission limits or fuel oil sulfur limits under this section may be determined based on a certification from the fuel supplier, as described under §60.48c(f), as applicable.

(1) Distillate oil-fired affected facilities with heat input capacities between 2.9 and 29 MW (10 and 100 MMBtu/hr).

(2) Residual oil-fired affected facilities with heat input capacities between 2.9 and 8.7 MW (10 and 30 MMBtu/hr).

(3) Coal-fired facilities with heat input capacities between 2.9 and 8.7 MW (10 and 30 MMBtu/hr).

(i) The SO<sub>2</sub> emission limits, fuel oil sulfur limits, and percent reduction requirements under this section apply at all times, including periods of startup, shutdown, and malfunction.

(j) For affected facilities located in noncontinental areas and affected facilities complying with the percent reduction standard, only the heat input supplied to the affected facility from the combustion of coal and oil is counted under this section. No credit is provided for the heat input to the affected facility from wood or other fuels or for heat derived from exhaust gases from other sources, such as stationary gas turbines, internal combustion engines, and kilns.

[72 FR 32759, June 13, 2007, as amended at 74 FR 5090, Jan. 28, 2009]

**§ 60.43c Standard for particulate matter (PM).**

(a) On and after the date on which the initial performance test is completed or required to be completed under §60.8, whichever date comes first, no owner or operator of an affected facility that commenced construction, reconstruction, or modification on or before February 28, 2005, that combusts coal or combusts mixtures of coal with other fuels and has a heat input capacity of 8.7 MW (30 MMBtu/hr) or greater, shall cause to be discharged into the atmosphere from that affected facility any gases that contain PM in excess of the following emission limits:

(1) 22 ng/J (0.051 lb/M MBtu) heat input if the affected facility combusts only coal, or combusts coal with other fuels and has an annual capacity factor for the other fuels of 10 percent (0.10) or less.

(2) 43 ng/J (0.10 lb/M MBtu) heat input if the affected facility combusts coal with other fuels, has an annual capacity factor for the other fuels greater than 10 percent (0.10), and is subject to a federally enforceable requirement limiting operation of the affected facility to an annual capacity factor greater than 10 percent (0.10) for fuels other than coal.

(b) On and after the date on which the initial performance test is completed or required to be completed under §60.8, whichever date comes first, no owner or operator of an affected facility that commenced construction, reconstruction, or modification on or before February 28, 2005, that combusts wood or combusts mixtures of wood with other fuels (except coal) and has a heat input capacity of 8.7 MW (30 MMBtu/hr) or greater, shall cause to be discharged into the atmosphere from that affected facility any gases that contain PM in excess of the following emissions limits:

(1) 43 ng/J (0.10 lb/M MBtu) heat input if the affected facility has an annual capacity factor for wood greater than 30 percent (0.30); or

(2) 130 ng/J (0.30 lb/M MBtu) heat input if the affected facility has an annual capacity factor for wood of 30 percent (0.30) or less and is subject to a federally enforceable requirement limiting operation of the affected facility to an annual capacity factor for wood of 30 percent (0.30) or less.

(c) On and after the date on which the initial performance test is completed or required to be completed under §60.8, whichever date comes first, no owner or operator of an affected facility that combusts coal, wood, or oil and has a heat input capacity of 8.7 MW (30 MMBtu/hr) or greater shall cause to be discharged into the atmosphere from that affected facility any gases that exhibit greater than 20 percent opacity (6-minute average), except for one 6-minute period per hour of not more than 27 percent opacity. Owners and operators of an affected facility that elect to install, calibrate, maintain, and operate a continuous emissions monitoring system (CEMS) for measuring PM emissions according to the requirements of this subpart and are subject to a federally enforceable PM limit of 0.030 lb/M MBtu or less are exempt from the opacity standard specified in this paragraph.

(d) The PM and opacity standards under this section apply at all times, except during periods of startup, shutdown, or malfunction.

(e)(1) On and after the date on which the initial performance test is completed or is required to be completed under §60.8, whichever date comes first, no owner or operator of an affected facility that commences construction, reconstruction, or modification after February 28, 2005, and that combusts coal, oil, wood, a mixture of these fuels, or a mixture of these fuels with any other fuels and has a heat input capacity of 8.7 MW (30 MMBtu/hr) or greater shall cause to be discharged into the atmosphere from that affected facility any gases that contain PM in excess of 13 ng/J (0.030 lb/M MBtu) heat input, except as provided in paragraphs (e)(2), (e)(3), and (e)(4) of this section.

(2) As an alternative to meeting the requirements of paragraph (e)(1) of this section, the owner or operator of an affected facility for which modification commenced after February 28, 2005, may elect to meet the requirements of this paragraph. On and after the date on which the initial performance test is completed or required to be completed under §60.8, whichever date comes first, no owner or operator of an affected facility that commences modification after February 28, 2005 shall cause to be discharged into the atmosphere from that affected facility any gases that contain PM in excess of both:

(i) 22 ng/J (0.051 lb/M MBtu) heat input derived from the combustion of coal, oil, wood, a mixture of these fuels, or a mixture of these fuels with any other fuels; and

(ii) 0.2 percent of the combustion concentration (99.8 percent reduction) when combusting coal, oil, wood, a mixture of these fuels, or a mixture of these fuels with any other fuels.

(3) On and after the date on which the initial performance test is completed or is required to be completed under §60.8, whichever date comes first, no owner or operator of an affected facility that commences modification after February 28, 2005, and that combusts over 30 percent wood (by heat input) on an annual basis and has a heat input capacity of 8.7 MW (30 MMBtu/hr) or greater shall cause to be discharged into the atmosphere from that affected facility any gases that contain PM in excess of 43 ng/J (0.10 lb/M MBtu) heat input.

(4) On and after the date on which the initial performance test is completed or is required to be completed under §60.8, whichever date comes first, no owner or operator of an affected facility that commences construction, reconstruction, or modification after February 28, 2005, and that combusts only oil that contains no more than 0.50 weight percent sulfur or a mixture of 0.50 weight percent sulfur oil with other fuels not subject to a PM standard under §60.43c and not using a post-combustion technology (except a wet scrubber) to reduce PM or SO<sub>2</sub> emissions is not subject to the PM limit in this section.

[72 FR 32759, June 13, 2007, as amended at 74 FR 5091, Jan. 28, 2009]

### § 60.44c Compliance and performance test methods and procedures for sulfur dioxide.

(a) Except as provided in paragraphs (g) and (h) of this section and §60.8(b), performance tests required under §60.8 shall be conducted following the procedures specified in paragraphs (b), (c), (d), (e), and (f) of this section, as applicable. Section 60.8(f) does not apply to this section. The 30-day notice required in §60.8(d) applies only to the initial performance test unless otherwise specified by the Administrator.

(b) The initial performance test required under §60.8 shall be conducted over 30 consecutive operating days of the steam generating unit. Compliance with the percent reduction requirements and SO<sub>2</sub> emission limits under §60.42c shall be determined using a 30-day average. The first operating day included in the initial performance test shall be scheduled within 30 days after achieving the maximum production rate at which the affected facility will be operated, but not later than 180 days after the initial startup of the facility. The steam generating unit load during the 30-day period does not have to be the maximum design heat input capacity, but must be representative of future operating conditions.

(c) After the initial performance test required under paragraph (b) of this section and §60.8, compliance with the percent reduction requirements and SO<sub>2</sub> emission limits under §60.42c is based on the average percent reduction and the average SO<sub>2</sub> emission rates for 30 consecutive steam generating unit operating days. A separate performance test is completed at the end of each steam generating unit operating day, and a new 30-day average percent reduction and SO<sub>2</sub> emission rate are calculated to show compliance with the standard.

(d) If only coal, only oil, or a mixture of coal and oil is combusted in an affected facility, the procedures in Method 19 of appendix A of this part are used to determine the hourly SO<sub>2</sub> emission rate (E<sub>ho</sub>) and the 30-day average SO<sub>2</sub> emission rate (E<sub>ao</sub>). The hourly averages used to compute the 30-day averages are obtained from the CEMS. Method 19 of appendix A of this part shall be used to calculate E<sub>ao</sub> when using daily fuel sampling or Method 6B of appendix A of this part.

(e) If coal, oil, or coal and oil are combusted with other fuels:

(1) An adjusted E<sub>ho</sub> (E<sub>ho</sub>o) is used in Equation 19-19 of Method 19 of appendix A of this part to compute the adjusted E<sub>ao</sub> (E<sub>ao</sub>o). The E<sub>ho</sub>o is computed using the following formula:

$$E_{ho\ o} = \frac{E_{ho} - E_w(1 - X_k)}{X_k}$$

Where:

E<sub>ho</sub>o = Adjusted E<sub>ho</sub>, ng/J (lb/MMBtu);

E<sub>ho</sub> = Hourly SO<sub>2</sub> emission rate, ng/J (lb/MMBtu);

E<sub>w</sub> = SO<sub>2</sub> concentration in fuels other than coal and oil combusted in the affected facility, as determined by fuel sampling and analysis procedures in Method 9 of appendix A of this part, ng/J (lb/MMBtu). The value E<sub>w</sub> for each fuel lot is used for each hourly average during the time that the lot is being combusted. The owner or operator does not have to measure E<sub>w</sub> if the owner or operator elects to assume E<sub>w</sub> = 0.

X<sub>k</sub> = Fraction of the total heat input from fuel combustion derived from coal and oil, as determined by applicable procedures in Method 19 of appendix A of this part.

(2) The owner or operator of an affected facility that qualifies under the provisions of §60.42c(c) or (d) (where percent reduction is not required) does not have to measure the parameters E<sub>w</sub> or X<sub>k</sub> if the owner or operator of the affected facility elects to measure emission rates of the coal or oil using the fuel sampling and analysis procedures under Method 19 of appendix A of this part.

(f) Affected facilities subject to the percent reduction requirements under §60.42c(a) or (b) shall determine compliance with the

SO<sub>2</sub> emission limits under §60.42c pursuant to paragraphs (d) or (e) of this section, and shall determine compliance with the percent reduction requirements using the following procedures:

(1) If only coal is combusted, the percent of potential SO<sub>2</sub> emission rate is computed using the following formula:

$$\%P_s = 100 \left( 1 - \frac{\%R_g}{100} \right) \left( 1 - \frac{\%R_f}{100} \right)$$

Where:

%P<sub>s</sub> = Potential SO<sub>2</sub> emission rate, in percent;

%R<sub>g</sub> = SO<sub>2</sub> removal efficiency of the control device as determined by Method 19 of appendix A of this part, in percent; and

%R<sub>f</sub> = SO<sub>2</sub> removal efficiency of fuel pretreatment as determined by Method 19 of appendix A of this part, in percent.

(2) If coal, oil, or coal and oil are combusted with other fuels, the same procedures required in paragraph (f) (1) of this section are used, except as provided for in the following:

(i) To compute the %P<sub>s</sub>, an adjusted %R<sub>g</sub> (%R<sub>g</sub><sub>o</sub>) is computed from E<sub>ao</sub> from paragraph (e) (1) of this section and an adjusted average SO<sub>2</sub> inlet rate (E<sub>ai</sub><sub>o</sub>) using the following formula:

$$\%R_{g,o} = 100 \left( 1 - \frac{E_w}{E_{ai,o}} \right)$$

Where:

%R<sub>g</sub><sub>o</sub> = Adjusted %R<sub>g</sub>, in percent;

E<sub>ao</sub> = Adjusted E<sub>ao</sub>, ng/J (lb/MMBtu); and

E<sub>ai</sub><sub>o</sub> = Adjusted average SO<sub>2</sub> inlet rate, ng/J (lb/MMBtu).

(ii) To compute E<sub>ai</sub><sub>o</sub>, an adjusted hourly SO<sub>2</sub> inlet rate (E<sub>hi</sub><sub>o</sub>) is used. The E<sub>hi</sub><sub>o</sub> is computed using the following formula:

$$E_{hi,o} = \frac{E_{hi} - E_w(1 - X_1)}{X_1}$$

Where:

E<sub>hi</sub><sub>o</sub> = Adjusted E<sub>hi</sub>, ng/J (lb/MMBtu);

E<sub>hi</sub> = Hourly SO<sub>2</sub> inlet rate, ng/J (lb/MMBtu);

E<sub>w</sub> = SO<sub>2</sub> concentration in fuels other than coal and oil combusted in the affected facility, as determined by fuel sampling and analysis procedures in Method 19 of appendix A of this part,

ng/J (lb/MMBtu). The value  $E_w$  for each fuel lot is used for each hourly average during the time that the lot is being combusted. The owner or operator does not have to measure  $E_w$  if the owner or operator elects to assume  $E_w = 0$ ; and

$X_k$  = Fraction of the total heat input from fuel combustion derived from coal and oil, as determined by applicable procedures in Method 19 of appendix A of this part.

(g) For oil-fired affected facilities where the owner or operator seeks to demonstrate compliance with the fuel oil sulfur limits under §60.42c based on shipment fuel sampling, the initial performance test shall consist of sampling and analyzing the oil in the initial tank of oil to be fired in the steam generating unit to demonstrate that the oil contains 0.5 weight percent sulfur or less. Thereafter, the owner or operator of the affected facility shall sample the oil in the fuel tank after each new shipment of oil is received, as described under §60.46c(d)(2).

(h) For affected facilities subject to §60.42c(h)(1), (2), or (3) where the owner or operator seeks to demonstrate compliance with the  $SO_2$  standards based on fuel supplier certification, the performance test shall consist of the certification from the fuel supplier, as described in §60.48c(f), as applicable.

(i) The owner or operator of an affected facility seeking to demonstrate compliance with the  $SO_2$  standards under §60.42c(c)(2) shall demonstrate the maximum design heat input capacity of the steam generating unit by operating the steam generating unit at this capacity for 24 hours. This demonstration shall be made during the initial performance test, and a subsequent demonstration may be requested at any other time. If the demonstrated 24-hour average firing rate for the affected facility is less than the maximum design heat input capacity stated by the manufacturer of the affected facility, the demonstrated 24-hour average firing rate shall be used to determine the annual capacity factor for the affected facility; otherwise, the maximum design heat input capacity provided by the manufacturer shall be used.

(j) The owner or operator of an affected facility shall use all valid  $SO_2$  emissions data in calculating  $\%P_s$  and  $E_{ho}$  under paragraphs (d), (e), or (f) of this section, as applicable, whether or not the minimum emissions data requirements under §60.46c(f) are achieved. All valid emissions data, including valid data collected during periods of startup, shutdown, and malfunction, shall be used in calculating  $\%P_s$  or  $E_{ho}$  pursuant to paragraphs (d), (e), or (f) of this section, as applicable.

[72 FR 32759, June 13, 2007, as amended at 74 FR 5091, Jan. 28, 2009]

### **§ 60.45c Compliance and performance test methods and procedures for particulate matter.**

(a) The owner or operator of an affected facility subject to the PM and/or opacity standards under §60.43c shall conduct an initial performance test as required under §60.8, and shall conduct subsequent performance tests as requested by the Administrator, to determine compliance with the standards using the following procedures and reference methods, except as specified in paragraph (c) of this section.

(1) Method 1 of appendix A of this part shall be used to select the sampling site and the number of traverse sampling points.

(2) Method 3A or 3B of appendix A-2 of this part shall be used for gas analysis when applying Method 5 or 5B of appendix A-3 of this part or 17 of appendix A-6 of this part.

(3) Method 5, 5B, or 17 of appendix A of this part shall be used to measure the concentration of PM as follows:

(i) Method 5 of appendix A of this part may be used only at affected facilities without wet scrubber systems.

(ii) Method 17 of appendix A of this part may be used at affected facilities with or without wet scrubber systems provided the stack gas temperature does not exceed a temperature of 160 °C (320 °F). The procedures of Sections 8.1 and 11.1 of Method 5B of appendix A of this part may be used in Method 17 of appendix A of this part only if Method 17 of appendix A of this part is used in conjunction with a wet scrubber system. Method 17 of appendix A of this part shall not be used in conjunction with a wet scrubber system if the effluent is saturated or laden with water droplets.

(iii) Method 5B of appendix A of this part may be used in conjunction with a wet scrubber system.

(4) The sampling time for each run shall be at least 120 minutes and the minimum sampling volume shall be 1.7 dry standard cubic meters (dscm) [60 dry standard cubic feet (dscf)] except that smaller sampling times or volumes may be approved by the Administrator when necessitated by process variables or other factors.

(5) For Method 5 or 5B of appendix A of this part, the temperature of the sample gas in the probe and filter holder shall be

monitored and maintained at  $160 \pm 14$  °C ( $320 \pm 25$  °F).

(6) For determination of PM emissions, an oxygen (O<sub>2</sub>) or carbon dioxide (CO<sub>2</sub>) measurement shall be obtained simultaneously with each run of Method 5, 5B, or 17 of appendix A of this part by traversing the duct at the same sampling location.

(7) For each run using Method 5, 5B, or 17 of appendix A of this part, the emission rates expressed in ng/J (lb/MMBtu) heat input shall be determined using:

(i) The O<sub>2</sub> or CO<sub>2</sub> measurements and PM measurements obtained under this section, (ii) The dry basis F factor, and

(iii) The dry basis emission rate calculation procedure contained in Method 19 of appendix A of this part.

(8) Method 9 of appendix A-4 of this part shall be used for determining the opacity of stack emissions.

(b) The owner or operator of an affected facility seeking to demonstrate compliance with the PM standards under §60.43c(b) (2) shall demonstrate the maximum design heat input capacity of the steam generating unit by operating the steam generating unit at this capacity for 24 hours. This demonstration shall be made during the initial performance test, and a subsequent demonstration may be requested at any other time. If the demonstrated 24-hour average firing rate for the affected facility is less than the maximum design heat input capacity stated by the manufacturer of the affected facility, the demonstrated 24-hour average firing rate shall be used to determine the annual capacity factor for the affected facility; otherwise, the maximum design heat input capacity provided by the manufacturer shall be used.

(c) In place of PM testing with Method 5 or 5B of appendix A-3 of this part or Method 17 of appendix A-6 of this part, an owner or operator may elect to install, calibrate, maintain, and operate a CEMS for monitoring PM emissions discharged to the atmosphere and record the output of the system. The owner or operator of an affected facility who elects to continuously monitor PM emissions instead of conducting performance testing using Method 5 or 5B of appendix A-3 of this part or Method 17 of appendix A-6 of this part shall install, calibrate, maintain, and operate a CEMS and shall comply with the requirements specified in paragraphs (c)(1) through (c)(14) of this section.

(1) Notify the Administrator 1 month before starting use of the system.

(2) Notify the Administrator 1 month before stopping use of the system.

(3) The monitor shall be installed, evaluated, and operated in accordance with §60.13 of subpart A of this part.

(4) The initial performance evaluation shall be completed no later than 180 days after the date of initial startup of the affected facility, as specified under §60.8 of subpart A of this part or within 180 days of notification to the Administrator of use of CEMS if the owner or operator was previously determining compliance by Method 5, 5B, or 17 of appendix A of this part performance tests, whichever is later.

(5) The owner or operator of an affected facility shall conduct an initial performance test for PM emissions as required under §60.8 of subpart A of this part. Compliance with the PM emission limit shall be determined by using the CEMS specified in paragraph (d) of this section to measure PM and calculating a 24-hour block arithmetic average emission concentration using EPA Reference Method 19 of appendix A of this part, section 4.1.

(6) Compliance with the PM emission limit shall be determined based on the 24-hour daily (block) average of the hourly arithmetic average emission concentrations using CEMS outlet data.

(7) At a minimum, valid CEMS hourly averages shall be obtained as specified in paragraph (c)(7) (i) of this section for 75 percent of the total operating hours per 30-day rolling average.

(i) At least two data points per hour shall be used to calculate each 1-hour arithmetic average.

(ii) [Reserved]

(8) The 1-hour arithmetic averages required under paragraph (c)(7) of this section shall be expressed in ng/J or lb/MMBtu heat input and shall be used to calculate the boiler operating day daily arithmetic average emission concentrations. The 1-hour arithmetic averages shall be calculated using the data points required under §60.13(e)(2) of subpart A of this part.

(9) All valid CEMS data shall be used in calculating average emission concentrations even if the minimum CEMS data requirements of paragraph (c)(7) of this section are not met.

(10) The CEMS shall be operated according to Performance Specification 11 in appendix B of this part.



(11) During the correlation testing runs of the CEMS required by Performance Specification 11 in appendix B of this part, PM and O<sub>2</sub> (or CO<sub>2</sub>) data shall be collected concurrently (or within a 30- to 60-minute period) by both the continuous emission monitors and performance tests conducted using the following test methods.

(i) For PM, Method 5 or 5B of appendix A-3 of this part or Method 17 of appendix A-6 of this part shall be used; and

(ii) After July 1, 2010 or after Method 202 of appendix M of part 51 has been revised to minimize artifact measurement and notice of that change has been published in the Federal Register, whichever is later, for condensable PM emissions, Method 202 of appendix M of part 51 shall be used; and

(iii) For O<sub>2</sub> (or CO<sub>2</sub>), Method 3A or 3B of appendix A-2 of this part, as applicable shall be used.

(12) Quarterly accuracy determinations and daily calibration drift tests shall be performed in accordance with procedure 2 in appendix F of this part. Relative Response Audits must be performed annually and Response Correlation Audits must be performed every 3 years.

(13) When PM emissions data are not obtained because of CEMS breakdowns, repairs, calibration checks, and zero and span adjustments, emissions data shall be obtained by using other monitoring systems as approved by the Administrator or EPA Reference Method 19 of appendix A of this part to provide, as necessary, valid emissions data for a minimum of 75 percent of total operating hours on a 30-day rolling average.

(14) After July 1, 2011, within 90 days after the date of completing each performance evaluation required by paragraph (c)(11) of this section, the owner or operator of the affected facility must either submit the test data to EPA by successfully entering the data electronically into EPA's WebFIRE data base available at <http://cfpub.epa.gov/oarweb/index.cfm?action=fire.main> or mail a copy to: United States Environmental Protection Agency; Energy Strategies Group; 109 TW Alexander DR; Mail Code: D243-01; RTP, NC 27711.

(d) The owner or operator of an affected facility seeking to demonstrate compliance under §60.43c(e)(4) shall follow the applicable procedures under §60.48c(f). For residual oil-fired affected facilities, fuel supplier certifications are only allowed for facilities with heat input capacities between 2.9 and 8.7 M W (10 to 30 MMBtu/hr).

[72 FR 32759, June 13, 2007, as amended at 74 FR 5091, Jan. 28, 2009]

### § 60.46c Emission monitoring for sulfur dioxide.

(a) Except as provided in paragraphs (d) and (e) of this section, the owner or operator of an affected facility subject to the SO<sub>2</sub> emission limits under §60.42c shall install, calibrate, maintain, and operate a CEMS for measuring SO<sub>2</sub> concentrations and either O<sub>2</sub> or CO<sub>2</sub> concentrations at the outlet of the SO<sub>2</sub> control device (or the outlet of the steam generating unit if no SO<sub>2</sub> control device is used), and shall record the output of the system. The owner or operator of an affected facility subject to the percent reduction requirements under §60.42c shall measure SO<sub>2</sub> concentrations and either O<sub>2</sub> or CO<sub>2</sub> concentrations at both the inlet and outlet of the SO<sub>2</sub> control device.

(b) The 1-hour average SO<sub>2</sub> emission rates measured by a CEMS shall be expressed in ng/J or lb/M MBtu heat input and shall be used to calculate the average emission rates under §60.42c. Each 1-hour average SO<sub>2</sub> emission rate must be based on at least 30 minutes of operation, and shall be calculated using the data points required under §60.13(h)(2). Hourly SO<sub>2</sub> emission rates are not calculated if the affected facility is operated less than 30 minutes in a 1-hour period and are not counted toward determination of a steam generating unit operating day.

(c) The procedures under §60.13 shall be followed for installation, evaluation, and operation of the CEMS.

(1) All CEMS shall be operated in accordance with the applicable procedures under Performance Specifications 1, 2, and 3 of appendix B of this part.

(2) Quarterly accuracy determinations and daily calibration drift tests shall be performed in accordance with Procedure 1 of appendix F of this part.

(3) For affected facilities subject to the percent reduction requirements under §60.42c, the span value of the SO<sub>2</sub> CEMS at the inlet to the SO<sub>2</sub> control device shall be 125 percent of the maximum estimated hourly potential SO<sub>2</sub> emission rate of the fuel combusted, and the span value of the SO<sub>2</sub> CEMS at the outlet from the SO<sub>2</sub> control device shall be 50 percent of the maximum estimated hourly potential SO<sub>2</sub> emission rate of the fuel combusted.

(4) For affected facilities that are not subject to the percent reduction requirements of §60.42c, the span value of the SO<sub>2</sub> CEMS at

the outlet from the SO<sub>2</sub> control device (or outlet of the steam generating unit if no SO<sub>2</sub> control device is used) shall be 125 percent of the maximum estimated hourly potential SO<sub>2</sub> emission rate of the fuel combusted.

(d) As an alternative to operating a CEMS at the inlet to the SO<sub>2</sub> control device (or outlet of the steam generating unit if no SO<sub>2</sub> control device is used) as required under paragraph (a) of this section, an owner or operator may elect to determine the average SO<sub>2</sub> emission rate by sampling the fuel prior to combustion. As an alternative to operating a CEMS at the outlet from the SO<sub>2</sub> control device (or outlet of the steam generating unit if no SO<sub>2</sub> control device is used) as required under paragraph (a) of this section, an owner or operator may elect to determine the average SO<sub>2</sub> emission rate by using Method 6B of appendix A of this part. Fuel sampling shall be conducted pursuant to either paragraph (d)(1) or (d)(2) of this section. Method 6B of appendix A of this part shall be conducted pursuant to paragraph (d)(3) of this section.

(1) For affected facilities combusting coal or oil, coal or oil samples shall be collected daily in an as-fired condition at the inlet to the steam generating unit and analyzed for sulfur content and heat content according to the Method 19 of appendix A of this part. Method 19 of appendix A of this part provides procedures for converting these measurements into the format to be used in calculating the average SO<sub>2</sub> input rate.

(2) As an alternative fuel sampling procedure for affected facilities combusting oil, oil samples may be collected from the fuel tank for each steam generating unit immediately after the fuel tank is filled and before any oil is combusted. The owner or operator of the affected facility shall analyze the oil sample to determine the sulfur content of the oil. If a partially empty fuel tank is refilled, a new sample and analysis of the fuel in the tank would be required upon filling. Results of the fuel analysis taken after each new shipment of oil is received shall be used as the daily value when calculating the 30-day rolling average until the next shipment is received. If the fuel analysis shows that the sulfur content in the fuel tank is greater than 0.5 weight percent sulfur, the owner or operator shall ensure that the sulfur content of subsequent oil shipments is low enough to cause the 30-day rolling average sulfur content to be 0.5 weight percent sulfur or less.

(3) Method 6B of appendix A of this part may be used in lieu of CEMS to measure SO<sub>2</sub> at the inlet or outlet of the SO<sub>2</sub> control system. An initial stratification test is required to verify the adequacy of the Method 6B of appendix A of this part sampling location. The stratification test shall consist of three paired runs of a suitable SO<sub>2</sub> and CO<sub>2</sub> measurement train operated at the candidate location and a second similar train operated according to the procedures in §3.2 and the applicable procedures in section 7 of Performance Specification 2 of appendix B of this part. Method 6B of appendix A of this part, Method 6A of appendix A of this part, or a combination of Methods 6 and 3 of appendix A of this part or Methods 6C and 3A of appendix A of this part are suitable measurement techniques. If Method 6B of appendix A of this part is used for the second train, sampling time and timer operation may be adjusted for the stratification test as long as an adequate sample volume is collected; however, both sampling trains are to be operated similarly. For the location to be adequate for Method 6B of appendix A of this part 24-hour tests, the mean of the absolute difference between the three paired runs must be less than 10 percent (0.10).

(e) The monitoring requirements of paragraphs (a) and (d) of this section shall not apply to affected facilities subject to §60.42c(h)(1), (2), or (3) where the owner or operator of the affected facility seeks to demonstrate compliance with the SO<sub>2</sub> standards based on fuel supplier certification, as described under §60.48c(f), as applicable.

(f) The owner or operator of an affected facility operating a CEMS pursuant to paragraph (a) of this section, or conducting as-fired fuel sampling pursuant to paragraph (d)(1) of this section, shall obtain emission data for at least 75 percent of the operating hours in at least 22 out of 30 successive steam generating unit operating days. If this minimum data requirement is not met with a single monitoring system, the owner or operator of the affected facility shall supplement the emission data with data collected with other monitoring systems as approved by the Administrator.

### § 60.47c Emission monitoring for particulate matter.

(a) Except as provided in paragraphs (c), (d), (e), (f), and (g) of this section, the owner or operator of an affected facility combusting coal, oil, or wood that is subject to the opacity standards under §60.43c shall install, calibrate, maintain, and operate a continuous opacity monitoring system (COMS) for measuring the opacity of the emissions discharged to the atmosphere and record the output of the system. The owner or operator of an affected facility subject to an opacity standard in §60.43c(c) and that is not required to install a COMS due to paragraphs (c), (d), (e), or (f) of this section that elects not to install a COMS shall conduct a performance test using Method 9 of appendix A-4 of this part and the procedures in §60.11 to demonstrate compliance with the applicable limit in §60.43c and shall comply with either paragraphs (a)(1), (a)(2), or (a)(3) of this section. If during the initial 60 minutes of observation all 6-minute averages are less than 10 percent and all individual 15-second observations are less than or equal to 20 percent, the observation period may be reduced from 3 hours to 60 minutes.

(1) Except as provided in paragraph (a)(2) and (a)(3) of this section, the owner or operator shall conduct subsequent Method 9 of appendix A-4 of this part performance tests using the procedures in paragraph (a) of this section according to the applicable schedule in paragraphs (a)(1)(i) through (a)(1)(iv) of this section, as determined by the most recent Method 9 of appendix A-4 of this part performance test results.

(i) If no visible emissions are observed, a subsequent Method 9 of appendix A-4 of this part performance test must be completed within 12 calendar months from the date that the most recent performance test was conducted;

(ii) If visible emissions are observed but the maximum 6-minute average opacity is less than or equal to 5 percent, a subsequent

Method 9 of appendix A-4 of this part performance test must be completed within 6 calendar months from the date that the most recent performance test was conducted;

(iii) If the maximum 6-minute average opacity is greater than 5 percent but less than or equal to 10 percent, a subsequent Method 9 of appendix A-4 of this part performance test must be completed within 3 calendar months from the date that the most recent performance test was conducted; or

(iv) If the maximum 6-minute average opacity is greater than 10 percent, a subsequent Method 9 of appendix A-4 of this part performance test must be completed within 30 calendar days from the date that the most recent performance test was conducted.

(2) If the maximum 6-minute opacity is less than 10 percent during the most recent Method 9 of appendix A-4 of this part performance test, the owner or operator may, as an alternative to performing subsequent Method 9 of appendix A-4 of this part performance tests, elect to perform subsequent monitoring using Method 22 of appendix A-7 of this part according to the procedures specified in paragraphs (a)(2)(i) and (ii) of this section.

(i) The owner or operator shall conduct 10 minute observations (during normal operation) each operating day the affected facility fires fuel for which an opacity standard is applicable using Method 22 of appendix A-7 of this part and demonstrate that the sum of the occurrences of any visible emissions is not in excess of 5 percent of the observation period (i.e., 30 seconds per 10 minute period). If the sum of the occurrence of any visible emissions is greater than 30 seconds during the initial 10 minute observation, immediately conduct a 30 minute observation. If the sum of the occurrence of visible emissions is greater than 5 percent of the observation period (i.e., 90 seconds per 30 minute period) the owner or operator shall either document and adjust the operation of the facility and demonstrate within 24 hours that the sum of the occurrence of visible emissions is equal to or less than 5 percent during a 30 minute observation (i.e., 90 seconds) or conduct a new Method 9 of appendix A-4 of this part performance test using the procedures in paragraph (a) of this section within 30 calendar days according to the requirements in §60.45c(a)(8).

(ii) If no visible emissions are observed for 30 operating days during which an opacity standard is applicable, observations can be reduced to once every 7 operating days during which an opacity standard is applicable. If any visible emissions are observed, daily observations shall be resumed.

(3) If the maximum 6-minute opacity is less than 10 percent during the most recent Method 9 of appendix A-4 of this part performance test, the owner or operator may, as an alternative to performing subsequent Method 9 of appendix A-4 performance tests, elect to perform subsequent monitoring using a digital opacity compliance system according to a site-specific monitoring plan approved by the Administrator. The observations shall be similar, but not necessarily identical, to the requirements in paragraph (a)(2) of this section. For reference purposes in preparing the monitoring plan, see OAQPS "Determination of Visible Emission Opacity from Stationary Sources Using Computer-Based Photographic Analysis Systems." This document is available from the U.S. Environmental Protection Agency (U.S. EPA); Office of Air Quality and Planning Standards; Sector Policies and Programs Division; Measurement Policy Group (D243-02), Research Triangle Park, NC 27711. This document is also available on the Technology Transfer Network (TTN) under Emission Measurement Center Preliminary Methods.

(b) All COMS shall be operated in accordance with the applicable procedures under Performance Specification 1 of appendix B of this part. The span value of the opacity COMS shall be between 60 and 80 percent.

(c) Owners and operators of an affected facilities that burn only distillate oil that contains no more than 0.5 weight percent sulfur and/or liquid or gaseous fuels with potential sulfur dioxide emission rates of 26 ng/J (0.060 lb/MMBtu) heat input or less and that do not use a post-combustion technology to reduce SO<sub>2</sub> or PM emissions and that are subject to an opacity standard in §60.43c (c) are not required to operate a COMS if they follow the applicable procedures in §60.48c(f).

(d) Owners or operators complying with the PM emission limit by using a PM CEMS must calibrate, maintain, operate, and record the output of the system for PM emissions discharged to the atmosphere as specified in §60.45c(c). The CEMS specified in paragraph §60.45c(c) shall be operated and data recorded during all periods of operation of the affected facility except for CEMS breakdowns and repairs. Data is recorded during calibration checks, and zero and span adjustments.

(e) Owners and operators of an affected facility that is subject to an opacity standard in §60.43c(c) and that does not use post-combustion technology (except a wet scrubber) for reducing PM, SO<sub>2</sub>, or carbon monoxide (CO) emissions, burns only gaseous fuels or fuel oils that contain less than or equal to 0.5 weight percent sulfur, and is operated such that emissions of CO discharged to the atmosphere from the affected facility are maintained at levels less than or equal to 0.15 lb/MMBtu on a boiler operating day average basis is not required to operate a COMS. Owners and operators of affected facilities electing to comply with this paragraph must demonstrate compliance according to the procedures specified in paragraphs (e)(1) through (4) of this section; or

(1) You must monitor CO emissions using a CEMS according to the procedures specified in paragraphs (e)(1)(i) through (iv) of this section.

(i) The CO CEMS must be installed, certified, maintained, and operated according to the provisions in §60.58b(1)(3) of subpart Eb of this part.

(ii) Each 1-hour CO emissions average is calculated using the data points generated by the CO CEMS expressed in parts per million by volume corrected to 3 percent oxygen (dry basis).

(iii) At a minimum, valid 1-hour CO emissions averages must be obtained for at least 90 percent of the operating hours on a 30 -

day rolling average basis. The 1-hour averages are calculated using the data points required in §60.13(h)(2).

(iv) Quarterly accuracy determinations and daily calibration drift tests for the CO CEMS must be performed in accordance with procedure 1 in appendix F of this part.

(2) You must calculate the 1-hour average CO emissions levels for each steam generating unit operating day by multiplying the average hourly CO output concentration measured by the CO CEMS times the corresponding average hourly flue gas flow rate and divided by the corresponding average hourly heat input to the affected source. The 24-hour average CO emission level is determined by calculating the arithmetic average of the hourly CO emission levels computed for each steam generating unit operating day.

(3) You must evaluate the preceding 24-hour average CO emission level each steam generating unit operating day excluding periods of affected source startup, shutdown, or malfunction. If the 24-hour average CO emission level is greater than 0.15 lb/MMBtu, you must initiate investigation of the relevant equipment and control systems within 24 hours of the first discovery of the high emission incident and, take the appropriate corrective action as soon as practicable to adjust control settings or repair equipment to reduce the 24-hour average CO emission level to 0.15 lb/MMBtu or less.

(4) You must record the CO measurements and calculations performed according to paragraph (e) of this section and any corrective actions taken. The record of corrective action taken must include the date and time during which the 24-hour average CO emission level was greater than 0.15 lb/MMBtu, and the date, time, and description of the corrective action.

(f) Owners and operators of an affected facility that is subject to an opacity standard in §60.43c(c) and that uses a bag leak detection system to monitor the performance of a fabric filter (baghouse) according to the most recent requirements in section §60.48Da of this part is not required to operate a CEMS.

(g) Owners and operators of an affected facility that is subject to an opacity standard in §60.43c(c) and that burns only gaseous fuels or fuel oils that contain less than or equal to 0.5 weight percent sulfur and operates according to a written site-specific monitoring plan approved by the permitting authority is not required to operate a CEMS. This monitoring plan must include procedures and criteria for establishing and monitoring specific parameters for the affected facility indicative of compliance with the opacity standard.

[72 FR 32759, June 13, 2007, as amended at 74 FR 5091, Jan. 28, 2009]

### **§ 60.48c Reporting and recordkeeping requirements.**

(a) The owner or operator of each affected facility shall submit notification of the date of construction or reconstruction and actual startup, as provided by §60.7 of this part. This notification shall include:

(1) The design heat input capacity of the affected facility and identification of fuels to be combusted in the affected facility.

(2) If applicable, a copy of any federally enforceable requirement that limits the annual capacity factor for any fuel or mixture of fuels under §60.42c, or §60.43c.

(3) The annual capacity factor at which the owner or operator anticipates operating the affected facility based on all fuels fired and based on each individual fuel fired.

(4) Notification if an emerging technology will be used for controlling SO<sub>2</sub> emissions. The Administrator will examine the description of the control device and will determine whether the technology qualifies as an emerging technology. In making this determination, the Administrator may require the owner or operator of the affected facility to submit additional information concerning the control device. The affected facility is subject to the provisions of §60.42c(a) or (b)(1), unless and until this determination is made by the Administrator.

(b) The owner or operator of each affected facility subject to the SO<sub>2</sub> emission limits of §60.42c, or the PM or opacity limits of §60.43c, shall submit to the Administrator the performance test data from the initial and any subsequent performance tests and, if applicable, the performance evaluation of the CEMS and/or COMS using the applicable performance specifications in appendix B of this part.

(c) In addition to the applicable requirements in §60.7, the owner or operator of an affected facility subject to the opacity limits in §60.43c(c) shall submit excess emission reports for any excess emissions from the affected facility that occur during the reporting period and maintain records according to the requirements specified in paragraphs (c)(1) through (3) of this section, as applicable to the visible emissions monitoring method used.

(1) For each performance test conducted using Method 9 of appendix A-4 of this part, the owner or operator shall keep the records including the information specified in paragraphs (c)(1) (i) through (iii) of this section.

(i) Dates and time intervals of all opacity observation periods;

(ii) Name, affiliation, and copy of current visible emission reading certification for each visible emission observer participating in the performance test; and

(iii) Copies of all visible emission observer opacity field data sheets;

(2) For each performance test conducted using Method 22 of appendix A-4 of this part, the owner or operator shall keep the records including the information specified in paragraphs (c)(2)(i) through (iv) of this section.

(i) Dates and time intervals of all visible emissions observation periods;

(ii) Name and affiliation for each visible emission observer participating in the performance test;

(iii) Copies of all visible emission observer opacity field data sheets; and

(iv) Documentation of any adjustments made and the time the adjustments were completed to the affected facility operation by the owner or operator to demonstrate compliance with the applicable monitoring requirements.

(3) For each digital opacity compliance system, the owner or operator shall maintain records and submit reports according to the requirements specified in the site-specific monitoring plan approved by the Administrator

(d) The owner or operator of each affected facility subject to the SO<sub>2</sub> emission limits, fuel oil sulfur limits, or percent reduction requirements under §60.42c shall submit reports to the Administrator.

(e) The owner or operator of each affected facility subject to the SO<sub>2</sub> emission limits, fuel oil sulfur limits, or percent reduction requirements under §60.42c shall keep records and submit reports as required under paragraph (d) of this section, including the following information, as applicable.

(1) Calendar dates covered in the reporting period.

(2) Each 30-day average SO<sub>2</sub> emission rate (ng/J or lb/M MBtu), or 30-day average sulfur content (weight percent), calculated during the reporting period, ending with the last 30-day period; reasons for any noncompliance with the emission standards; and a description of corrective actions taken.

(3) Each 30-day average percent of potential SO<sub>2</sub> emission rate calculated during the reporting period, ending with the last 30-day period; reasons for any noncompliance with the emission standards; and a description of the corrective actions taken.

(4) Identification of any steam generating unit operating days for which SO<sub>2</sub> or diluent (O<sub>2</sub> or CO<sub>2</sub>) data have not been obtained by an approved method for at least 75 percent of the operating hours; justification for not obtaining sufficient data; and a description of corrective actions taken.

(5) Identification of any times when emissions data have been excluded from the calculation of average emission rates; justification for excluding data; and a description of corrective actions taken if data have been excluded for periods other than those during which coal or oil were not combusted in the steam generating unit.

(6) Identification of the F factor used in calculations, method of determination, and type of fuel combusted.

(7) Identification of whether averages have been obtained based on CEMS rather than manual sampling methods.

(8) If a CEMS is used, identification of any times when the pollutant concentration exceeded the full span of the CEMS.

(9) If a CEMS is used, description of any modifications to the CEMS that could affect the ability of the CEMS to comply with Performance Specifications 2 or 3 of appendix B of this part.

(10) If a CEMS is used, results of daily CEMS drift tests and quarterly accuracy assessments as required under appendix F, Procedure 1 of this part.

(11) If fuel supplier certification is used to demonstrate compliance, records of fuel supplier certification as described under paragraph (f)(1), (2), (3), or (4) of this section, as applicable. In addition to records of fuel supplier certifications, the report shall include a certified statement signed by the owner or operator of the affected facility that the records of fuel supplier certifications submitted represent all of the fuel combusted during the reporting period.

(f) Fuel supplier certification shall include the following information:

(1) For distillate oil:

(i) The name of the oil supplier;

(ii) A statement from the oil supplier that the oil complies with the specifications under the definition of distillate oil in §60.41c; and

(iii) The sulfur content or maximum sulfur content of the oil.

(2) For residual oil:

(i) The name of the oil supplier;

(ii) The location of the oil when the sample was drawn for analysis to determine the sulfur content of the oil, specifically including whether the oil was sampled as delivered to the affected facility, or whether the sample was drawn from oil in storage at the oil supplier's or oil refiner's facility, or other location;

(iii) The sulfur content of the oil from which the shipment came (or of the shipment itself); and

(iv) The method used to determine the sulfur content of the oil.

(3) For coal:

(i) The name of the coal supplier;

(ii) The location of the coal when the sample was collected for analysis to determine the properties of the coal, specifically including whether the coal was sampled as delivered to the affected facility or whether the sample was collected from coal in storage at the mine, at a coal preparation plant, at a coal supplier's facility, or at another location. The certification shall include the name of the coal mine (and coal seam), coal storage facility, or coal preparation plant (where the sample was collected);

(iii) The results of the analysis of the coal from which the shipment came (or of the shipment itself) including the sulfur content, moisture content, ash content, and heat content; and

(iv) The methods used to determine the properties of the coal.

(4) For other fuels:

(i) The name of the supplier of the fuel;

(ii) The potential sulfur emissions rate or maximum potential sulfur emissions rate of the fuel in ng/J heat input; and

(iii) The method used to determine the potential sulfur emissions rate of the fuel.

(g)(1) Except as provided under paragraphs (g)(2) and (g)(3) of this section, the owner or operator of each affected facility shall record and maintain records of the amount of each fuel combusted during each operating day.

(2) As an alternative to meeting the requirements of paragraph (g)(1) of this section, the owner or operator of an affected facility that combusts only natural gas, wood, fuels using fuel certification in §60.48c(f) to demonstrate compliance with the SO<sub>2</sub> standard, fuels not subject to an emissions standard (excluding opacity), or a mixture of these fuels may elect to record and maintain records of the amount of each fuel combusted during each calendar month.

(3) As an alternative to meeting the requirements of paragraph (g)(1) of this section, the owner or operator of an affected facility or multiple affected facilities located on a contiguous property unit where the only fuels combusted in any steam generating unit (including steam generating units not subject to this subpart) at that property are natural gas, wood, distillate oil meeting the most current requirements in §60.42C to use fuel certification to demonstrate compliance with the SO<sub>2</sub> standard, and/or fuels, excluding coal and residual oil, not subject to an emissions standard (excluding opacity) may elect to record and maintain records of the total amount of each steam generating unit fuel delivered to that property during each calendar month.

(h) The owner or operator of each affected facility subject to a federally enforceable requirement limiting the annual capacity factor for any fuel or mixture of fuels under §60.42c or §60.43c shall calculate the annual capacity factor individually for each fuel combusted. The annual capacity factor is determined on a 12-month rolling average basis with a new annual capacity factor calculated at the end of the calendar month.

(i) All records required under this section shall be maintained by the owner or operator of the affected facility for a period of two years following the date of such record.

(j) The reporting period for the reports required under this subpart is each six-month period. All reports shall be submitted to the Administrator and shall be postmarked by the 30th day following the end of the reporting period.

[72 FR 32759, June 13, 2007, as amended at 74 FR 5091, Jan. 28, 2009]

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*Appendix B--40 CFR 60 Subpart Kb: Standards of Performance for Volatile Organic Storage Vessels (including Petroleum Liquid Storage Vessels) for Which Construction, Reconstruction, or Modification Commenced After July 23, 1984*



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#### Title 40: Protection of Environment

##### PART 60—STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES

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#### Subpart Kb—Standards of Performance for Volatile Organic Liquid Storage Vessels (Including Petroleum Liquid Storage Vessels) for Which Construction, Reconstruction, or Modification Commenced After July 23, 1984

Source: 52 FR 11429, Apr. 8, 1987, unless otherwise noted.

#### § 60.110b Applicability and designation of affected facility.

(a) Except as provided in paragraph (b) of this section, the affected facility to which this subpart applies is each storage vessel with a capacity greater than or equal to 75 cubic meters ( $m^3$ ) that is used to store volatile organic liquids (VOL) for which construction, reconstruction, or modification is commenced after July 23, 1984.

(b) This subpart does not apply to storage vessels with a capacity greater than or equal to  $151 m^3$  storing a liquid with a maximum true vapor pressure less than 3.5 kilopascals (kPa) or with a capacity greater than or equal to  $75 m^3$  but less than  $151 m^3$  storing a liquid with a maximum true vapor pressure less than 15.0 kPa.

(c) [Reserved]

(d) This subpart does not apply to the following:

- (1) Vessels at coke oven by-product plants.
- (2) Pressure vessels designed to operate in excess of 204.9 kPa and without emissions to the atmosphere.
- (3) Vessels permanently attached to mobile vehicles such as trucks, railcars, barges, or ships.
- (4) Vessels with a design capacity less than or equal to  $1,589.874 m^3$  used for petroleum or condensate stored, processed, or treated prior to custody transfer.
- (5) Vessels located at bulk gasoline plants.
- (6) Storage vessels located at gasoline service stations.
- (7) Vessels used to store beverage alcohol.
- (8) Vessels subject to subpart G GGG of 40 CFR part 63.

(e) *Alternative means of compliance* —(1) *Option to comply with part 65.* Owners or operators may choose to comply with 40 CFR part 65, subpart C, to satisfy the requirements of §§60.112b through 60.117b for storage vessels that are subject to this subpart that meet the specifications in paragraphs (e)(1)(i) and (ii) of this section. When choosing to comply with 40 CFR part 65, subpart

C, the monitoring requirements of §60.116b(c), (e), (f)(1), and (g) still apply. Other provisions applying to owners or operators who choose to comply with 40 CFR part 65 are provided in 40 CFR 65.1.

(i) A storage vessel with a design capacity greater than or equal to 151 m<sup>3</sup> containing a VOL that, as stored, has a maximum true vapor pressure equal to or greater than 5.2 kPa; or

(ii) A storage vessel with a design capacity greater than 75 m<sup>3</sup> but less than 151 m<sup>3</sup> containing a VOL that, as stored, has a maximum true vapor pressure equal to or greater than 27.6 kPa.

(2) *Part 60, subpart A.* Owners or operators who choose to comply with 40 CFR part 65, subpart C, must also comply with §§60.1, 60.2, 60.5, 60.6, 60.7(a)(1) and (4), 60.14, 60.15, and 60.16 for those storage vessels. All sections and paragraphs of subpart A of this part that are not mentioned in this paragraph (e)(2) do not apply to owners or operators of storage vessels complying with 40 CFR part 65, subpart C, except that provisions required to be met prior to implementing 40 CFR part 65 still apply. Owners and operators who choose to comply with 40 CFR part 65, subpart C, must comply with 40 CFR part 65, subpart A.

(3) *Internal floating roof report.* If an owner or operator installs an internal floating roof and, at initial startup, chooses to comply with 40 CFR part 65, subpart C, a report shall be furnished to the Administrator stating that the control equipment meets the specifications of 40 CFR 65.43. This report shall be an attachment to the notification required by 40 CFR 65.5(b).

(4) *External floating roof report.* If an owner or operator installs an external floating roof and, at initial startup, chooses to comply with 40 CFR part 65, subpart C, a report shall be furnished to the Administrator stating that the control equipment meets the specifications of 40 CFR 65.44. This report shall be an attachment to the notification required by 40 CFR 65.5(b).

[52 FR 11429, Apr. 8, 1987, as amended at 54 FR 32973, Aug. 11, 1989; 65 FR 78275, Dec. 14, 2000; 68 FR 59332, Oct. 15, 2003]

## § 60.111b Definitions.

Terms used in this subpart are defined in the Act, in subpart A of this part, or in this subpart as follows:

*Bulk gasoline plant* means any gasoline distribution facility that has a gasoline throughput less than or equal to 75,700 liters per day. Gasoline throughput shall be the maximum calculated design throughput as may be limited by compliance with an enforceable condition under Federal requirement or Federal, State or local law, and discoverable by the Administrator and any other person.

*Condensate* means hydrocarbon liquid separated from natural gas that condenses due to changes in the temperature or pressure, or both, and remains liquid at standard conditions.

*Custody transfer* means the transfer of produced petroleum and/or condensate, after processing and/or treatment in the producing operations, from storage vessels or automatic transfer facilities to pipelines or any other forms of transportation.

*Fill* means the introduction of VOL into a storage vessel but not necessarily to complete capacity.

*Gasoline service station* means any site where gasoline is dispensed to motor vehicle fuel tanks from stationary storage tanks.

*Maximum true vapor pressure* means the equilibrium partial pressure exerted by the volatile organic compounds (as defined in 40 CFR 51.100) in the stored VOL at the temperature equal to the highest calendar-month average of the VOL storage temperature for VOL's stored above or below the ambient temperature or at the local maximum monthly average temperature as reported by the National Weather Service for VOL's stored at the ambient temperature, as determined:

(1) In accordance with methods described in American Petroleum Institute Bulletin 2517, Evaporation Loss From External Floating Roof Tanks, (incorporated by reference—see §60.17); or

(2) As obtained from standard reference texts; or

(3) As determined by ASTM D2879–83, 96, or 97 (incorporated by reference—see §60.17);

(4) Any other method approved by the Administrator.

*Petroleum* means the crude oil removed from the earth and the oils derived from tar sands, shale, and coal.

*Petroleum liquids* means petroleum, condensate, and any finished or intermediate products manufactured in a petroleum refinery.

*Process tank* means a tank that is used within a process (including a solvent or raw material recovery process) to collect material discharged from a feedstock storage vessel or equipment within the process before the material is transferred to other equipment within the process, to a product or by-product storage vessel, or to a vessel used to store recovered solvent or raw material. In many process tanks, unit operations such as reactions and blending are conducted. Other process tanks, such as surge control vessels and bottoms receivers, however, may not involve unit operations.

*Reid vapor pressure*  means the absolute vapor pressure of volatile crude oil and volatile nonviscous petroleum liquids except liquefied petroleum gases, as determined by ASTM D323-82 or 94 (incorporated by reference—see §60.17).

*Storage vessel* means each tank, reservoir, or container used for the storage of volatile organic liquids but does not include:

- (1) Frames, housing, auxiliary supports, or other components that are not directly involved in the containment of liquids or vapors;
- (2) Subsurface caverns or porous rock reservoirs; or
- (3) Process tanks.

*Volatile organic liquid (VOL)* means any organic liquid which can emit volatile organic compounds (as defined in 40 CFR 51.100) into the atmosphere.

*Waste* means any liquid resulting from industrial, commercial, mining or agricultural operations, or from community activities that is discarded or is being accumulated, stored, or physically, chemically, or biologically treated prior to being discarded or recycled.

[52 FR 11429, Apr. 8, 1987, as amended at 54 FR 32973, Aug. 11, 1989; 65 FR 61756, Oct. 17, 2000; 68 FR 59333, Oct. 15, 2003]

### § 60.112b Standard for volatile organic compounds (VOC).

(a) The owner or operator of each storage vessel either with a design capacity greater than or equal to 151 m<sup>3</sup> containing a VOL that, as stored, has a maximum true vapor pressure equal to or greater than 5.2 kPa but less than 76.6 kPa or with a design capacity greater than or equal to 75 m<sup>3</sup> but less than 151 m<sup>3</sup> containing a VOL that, as stored, has a maximum true vapor pressure equal to or greater than 27.6 kPa but less than 76.6 kPa, shall equip each storage vessel with one of the following:

(1) A fixed roof in combination with an internal floating roof meeting the following specifications:

(i) The internal floating roof shall rest or float on the liquid surface (but not necessarily in complete contact with it) inside a storage vessel that has a fixed roof. The internal floating roof shall be floating on the liquid surface at all times, except during initial fill and during those intervals when the storage vessel is completely emptied or subsequently emptied and refilled. When the roof is resting on the leg supports, the process of filling, emptying, or refilling shall be continuous and shall be accomplished as rapidly as possible.

(ii) Each internal floating roof shall be equipped with one of the following closure devices between the wall of the storage vessel and the edge of the internal floating roof:

(A) A foam- or liquid-filled seal mounted in contact with the liquid (liquid-mounted seal). A liquid-mounted seal means a foam- or liquid-filled seal mounted in contact with the liquid between the wall of the storage vessel and the floating roof continuously around the circumference of the tank.

(B) Two seals mounted one above the other so that each forms a continuous closure that completely covers the space between the wall of the storage vessel and the edge of the internal floating roof. The lower seal may be vapor-mounted, but both must be continuous.

(C) A mechanical shoe seal. A mechanical shoe seal is a metal sheet held vertically against the wall of the storage vessel by springs or weighted levers and is connected by braces to the floating roof. A flexible coated fabric (envelope) spans the annular space between the metal sheet and the floating roof.

(iii) Each opening in a noncontact internal floating roof except for automatic bleeder vents (vacuum breaker vents) and the rim space vents is to provide a projection below the liquid surface.

(iv) Each opening in the internal floating roof except for leg sleeves, automatic bleeder vents, rim space vents, column wells, ladder wells, sample wells, and stub drains is to be equipped with a cover or lid which is to be maintained in a closed position at all times (i.e., no visible gap) except when the device is in actual use. The cover or lid shall be equipped with a gasket. Covers on each access hatch and automatic gauge float well shall be bolted except when they are in use.

(v) Automatic bleeder vents shall be equipped with a gasket and are to be closed at all times when the roof is floating except when the roof is being floated off or is being landed on the roof leg supports.

(vi) Rim space vents shall be equipped with a gasket and are to be set to open only when the internal floating roof is not floating or at the manufacturer's recommended setting.

(vii) Each penetration of the internal floating roof for the purpose of sampling shall be a sample well. The sample well shall have a slit fabric cover that covers at least 90 percent of the opening.

(viii) Each penetration of the internal floating roof that allows for passage of a column supporting the fixed roof shall have a flexible fabric sleeve seal or a gasketed sliding cover.

(ix) Each penetration of the internal floating roof that allows for passage of a ladder shall have a gasketed sliding cover.

(2) An external floating roof. An external floating roof means a pontoon-type or double-deck type cover that rests on the liquid surface in a vessel with no fixed roof. Each external floating roof must meet the following specifications:

(i) Each external floating roof shall be equipped with a closure device between the wall of the storage vessel and the roof edge. The closure device is to consist of two seals, one above the other. The lower seal is referred to as the primary seal, and the upper seal is referred to as the secondary seal.

(A) The primary seal shall be either a mechanical shoe seal or a liquid-mounted seal. Except as provided in §60.113b(b)(4), the seal shall completely cover the annular space between the edge of the floating roof and tank wall.

(B) The secondary seal shall completely cover the annular space between the external floating roof and the wall of the storage vessel in a continuous fashion except as allowed in §60.113b(b)(4).

(ii) Except for automatic bleeder vents and rim space vents, each opening in a noncontact external floating roof shall provide a projection below the liquid surface. Except for automatic bleeder vents, rim space vents, roof drains, and leg sills, each opening in the roof is to be equipped with a gasketed cover, seal, or lid that is to be maintained in a closed position at all times (i.e., no visible gap) except when the device is in actual use. Automatic bleeder vents are to be closed at all times when the roof is floating except when the roof is being floated off or is being landed on the roof leg supports. Rim vents are to be set to open when the roof is being floated off the roof legs supports or at the manufacturer's recommended setting. Automatic bleeder vents and rim space vents are to be gasketed. Each emergency roof drain is to be provided with a slotted membrane fabric cover that covers at least 90 percent of the area of the opening.

(iii) The roof shall be floating on the liquid at all times (i.e., off the roof leg supports) except during initial fill until the roof is lifted off leg supports and when the tank is completely emptied and subsequently refilled. The process of filling, emptying, or refilling when the roof is resting on the leg supports shall be continuous and shall be accomplished as rapidly as possible.

(3) A closed vent system and control device meeting the following specifications:

(i) The closed vent system shall be designed to collect all VOC vapors and gases discharged from the storage vessel and operated with no detectable emissions as indicated by an instrument reading of less than 500 ppm above background and visual inspections, as determined in part 60, subpart VV, §60.485(b).

(ii) The control device shall be designed and operated to reduce inlet VOC emissions by 95 percent or greater. If a flare is used as the control device, it shall meet the specifications described in the general control device requirements (§60.18) of the General Provisions.

(4) A system equivalent to those described in paragraphs (a)(1), (a)(2), or (a)(3) of this section as provided in §60.114b of this subpart.

(b) The owner or operator of each storage vessel with a design capacity greater than or equal to 75 m<sup>3</sup> which contains a VOL that, as stored, has a maximum true vapor pressure greater than or equal to 76.6 kPa shall equip each storage vessel with one of the following:

(1) A closed vent system and control device as specified in §60.112b(a)(3).

(2) A system equivalent to that described in paragraph (b)(1) as provided in §60.114b of this subpart.

(c) *Site-specific standard for Merck & Co., Inc.'s Stonewall Plant in Elkton, Virginia.* This paragraph applies only to the pharmaceutical manufacturing facility, commonly referred to as the Stonewall Plant, located at Route 340 South, in Elkton, Virginia ("site").

(1) For any storage vessel that otherwise would be subject to the control technology requirements of paragraphs (a) or (b) of this section, the site shall have the option of either complying directly with the requirements of this subpart, or reducing the site-wide total criteria pollutant emissions cap (total emissions cap) in accordance with the procedures set forth in a permit issued pursuant to 40 CFR 52.2454. If the site chooses the option of reducing the total emissions cap in accordance with the procedures set forth in such permit, the requirements of such permit shall apply in lieu of the otherwise applicable requirements of this subpart for such storage vessel.

(2) For any storage vessel at the site not subject to the requirements of 40 CFR 60.112b (a) or (b), the requirements of 40 CFR 60.116b (b) and (c) and the General Provisions (subpart A of this part) shall not apply.

[52 FR 11429, Apr. 8, 1987, as amended at 62 FR 52641, Oct. 8, 1997]

### § 60.113b Testing and procedures.

The owner or operator of each storage vessel as specified in §60.112b(a) shall meet the requirements of paragraph (a), (b), or (c) of this section. The applicable paragraph for a particular storage vessel depends on the control equipment installed to meet the requirements of §60.112b.

(a) After installing the control equipment required to meet §60.112b(a)(1) (permanently affixed roof and internal floating roof), each owner or operator shall:

(1) Visually inspect the internal floating roof, the primary seal, and the secondary seal (if one is in service), prior to filling the storage vessel with VOL. If there are holes, tears, or other openings in the primary seal, the secondary seal, or the seal fabric or defects in the internal floating roof, or both, the owner or operator shall repair the items before filling the storage vessel.

(2) For vessels equipped with a liquid-mounted or mechanical shoe primary seal, visually inspect the internal floating roof and the primary seal or the secondary seal (if one is in service) through manholes and roof hatches on the fixed roof at least once every 12 months after initial fill. If the internal floating roof is not resting on the surface of the VOL inside the storage vessel, or there is liquid accumulated on the roof, or the seal is detached, or there are holes or tears in the seal fabric, the owner or operator shall repair the items or empty and remove the storage vessel from service within 45 days. If a failure that is detected during inspections required in this paragraph cannot be repaired within 45 days and if the vessel cannot be emptied within 45 days, a 30-day extension may be requested from the Administrator in the inspection report required in §60.115b(a)(3). Such a request for an extension must document that alternate storage capacity is unavailable and specify a schedule of actions the company will take that will assure that the control equipment will be repaired or the vessel will be emptied as soon as possible.

(3) For vessels equipped with a double-seal system as specified in §60.112b(a)(1)(ii)(B):

(i) Visually inspect the vessel as specified in paragraph (a)(4) of this section at least every 5 years; or

(ii) Visually inspect the vessel as specified in paragraph (a)(2) of this section.

(4) Visually inspect the internal floating roof, the primary seal, the secondary seal (if one is in service), gaskets, slotted membranes and sleeve seals (if any) each time the storage vessel is emptied and degassed. If the internal floating roof has defects, the primary seal has holes, tears, or other openings in the seal or the seal fabric, or the secondary seal has holes, tears, or other openings in the seal or the seal fabric, or the gaskets no longer close off the liquid surfaces from the atmosphere, or the slotted membrane has more than 10 percent open area, the owner or operator shall repair the items as necessary so that none of the conditions specified in this paragraph exist before refilling the storage vessel with VOL. In no event shall inspections conducted in accordance with this provision occur at intervals greater than 10 years in the case of vessels conducting the annual visual inspection as specified in paragraphs (a)(2) and (a)(3)(ii) of this section and at intervals no greater than 5 years in the case of vessels specified in paragraph (a)(3)(i) of this section.

(5) Notify the Administrator in writing at least 30 days prior to the filling or refilling of each storage vessel for which an inspection is required by paragraphs (a)(1) and (a)(4) of this section to afford the Administrator the opportunity to have an observer present. If the inspection required by paragraph (a)(4) of this section is not planned and the owner or operator could not have known about the inspection 30 days in advance or refilling the tank, the owner or operator shall notify the Administrator at least 7 days prior to the refilling of the storage vessel. Notification shall be made by telephone immediately followed by written documentation demonstrating why the inspection was unplanned. Alternatively, this notification including the written documentation may be made in writing and sent by express mail so that it is received by the Administrator at least 7 days prior to the refilling.

(b) After installing the control equipment required to meet §60.112b(a)(2) (external floating roof), the owner or operator shall:

(1) Determine the gap areas and maximum gap widths, between the primary seal and the wall of the storage vessel and between the secondary seal and the wall of the storage vessel according to the following frequency.

(i) Measurements of gaps between the tank wall and the primary seal (seal gaps) shall be performed during the hydrostatic testing of the vessel or within 60 days of the initial fill with VOL and at least once every 5 years thereafter.

(ii) Measurements of gaps between the tank wall and the secondary seal shall be performed within 60 days of the initial fill with VOL and at least once per year thereafter.

(iii) If any source ceases to store VOL for a period of 1 year or more, subsequent introduction of VOL into the vessel shall be considered an initial fill for the purposes of paragraphs (b)(1)(i) and (b)(1)(ii) of this section.

(2) Determine gap widths and areas in the primary and secondary seals individually by the following procedures:

(i) Measure seal gaps, if any, at one or more floating roof levels when the roof is floating off the roof leg supports.

(ii) Measure seal gaps around the entire circumference of the tank in each place where a 0.32-cm diameter uniform probe passes freely (without forcing or binding against seal) between the seal and the wall of the storage vessel and measure the circumferential distance of each such location.

(iii) The total surface area of each gap described in paragraph (b)(2)(ii) of this section shall be determined by using probes of various widths to measure accurately the actual distance from the tank wall to the seal and multiplying each such width by its respective circumferential distance.

(3) Add the gap surface area of each gap location for the primary seal and the secondary seal individually and divide the sum for each seal by the nominal diameter of the tank and compare each ratio to the respective standards in paragraph (b)(4) of this section.

(4) Make necessary repairs or empty the storage vessel within 45 days of identification in any inspection for seals not meeting the requirements listed in (b)(4)(i) and (ii) of this section:

(i) The accumulated area of gaps between the tank wall and the mechanical shoe or liquid-mounted primary seal shall not exceed 212  $\text{Cm}^2$  per meter of tank diameter, and the width of any portion of any gap shall not exceed 3.81 cm.

(A) One end of the mechanical shoe is to extend into the stored liquid, and the other end is to extend a minimum vertical distance of 61 cm above the stored liquid surface.

(B) There are to be no holes, tears, or other openings in the shoe, seal fabric, or seal envelope.

(ii) The secondary seal is to meet the following requirements:

(A) The secondary seal is to be installed above the primary seal so that it completely covers the space between the roof edge and the tank wall except as provided in paragraph (b)(2)(iii) of this section.

(B) The accumulated area of gaps between the tank wall and the secondary seal shall not exceed 21.2  $\text{cm}^2$  per meter of tank diameter, and the width of any portion of any gap shall not exceed 1.27 cm.

(C) There are to be no holes, tears, or other openings in the seal or seal fabric.

(iii) If a failure that is detected during inspections required in paragraph (b)(1) of §60.113(b) cannot be repaired within 45 days and if the vessel cannot be emptied within 45 days, a 30-day extension may be requested from the Administrator in the inspection report required in §60.115(b)(4). Such extension request must include a demonstration of unavailability of alternate storage capacity and a specification of a schedule that will assure that the control equipment will be repaired or the vessel will be emptied as soon as possible.

(5) Notify the Administrator 30 days in advance of any gap measurements required by paragraph (b)(1) of this section to afford the Administrator the opportunity to have an observer present.

(6) Visually inspect the external floating roof, the primary seal, secondary seal, and fittings each time the vessel is emptied and degassed.

(i) If the external floating roof has defects, the primary seal has holes, tears, or other openings in the seal or the seal fabric, or the secondary seal has holes, tears, or other openings in the seal or the seal fabric, the owner or operator shall repair the items as necessary so that none of the conditions specified in this paragraph exist before filling or refilling the storage vessel with VOL.

(ii) For all the inspections required by paragraph (b)(6) of this section, the owner or operator shall notify the Administrator in writing at least 30 days prior to the filling or refilling of each storage vessel to afford the Administrator the opportunity to inspect the storage vessel prior to refilling. If the inspection required by paragraph (b)(6) of this section is not planned and the owner or operator could not have known about the inspection 30 days in advance of refilling the tank, the owner or operator shall notify the Administrator at least 7 days prior to the refilling of the storage vessel. Notification shall be made by telephone immediately followed by written documentation demonstrating why the inspection was unplanned. Alternatively, this notification including the

written documentation may be made in writing and sent by express mail so that it is received by the Administrator at least 7 days prior to the refilling.

(c) The owner or operator of each source that is equipped with a closed vent system and control device as required in §60.112b (a)(3) or (b)(2) (other than a flare) is exempt from §60.8 of the General Provisions and shall meet the following requirements.

(1) Submit for approval by the Administrator as an attachment to the notification required by §60.7(a)(1) or, if the facility is exempt from §60.7(a)(1), as an attachment to the notification required by §60.7(a)(2), an operating plan containing the information listed below.

(i) Documentation demonstrating that the control device will achieve the required control efficiency during maximum loading conditions. This documentation is to include a description of the gas stream which enters the control device, including flow and VOC content under varying liquid level conditions (dynamic and static) and manufacturer's design specifications for the control device. If the control device or the closed vent capture system receives vapors, gases, or liquids other than fuels from sources that are not designated sources under this subpart, the efficiency demonstration is to include consideration of all vapors, gases, and liquids received by the closed vent capture system and control device. If an enclosed combustion device with a minimum residence time of 0.75 seconds and a minimum temperature of 816 °C is used to meet the 95 percent requirement, documentation that those conditions will exist is sufficient to meet the requirements of this paragraph.

(ii) A description of the parameter or parameters to be monitored to ensure that the control device will be operated in accordance with its design and an explanation of the criteria used for selection of that parameter (or parameters).

(2) Operate the closed vent system and control device and monitor the parameters of the closed vent system and control device in accordance with the operating plans submitted to the Administrator in accordance with paragraph (c)(1) of this section, unless the plan was modified by the Administrator during the review process. In this case, the modified plan applies.

(d) The owner or operator of each source that is equipped with a closed vent system and a flare to meet the requirements in §60.112b (a)(3) or (b)(2) shall meet the requirements as specified in the general control device requirements, §60.18 (e) and (f).

[52 FR 11429, Apr. 8, 1987, as amended at 54 FR 32973, Aug. 11, 1989]

### § 60.114b Alternative means of emission limitation.

(a) If, in the Administrator's judgment, an alternative means of emission limitation will achieve a reduction in emissions at least equivalent to the reduction in emissions achieved by any requirement in §60.112b, the Administrator will publish in the Federal Register a notice permitting the use of the alternative means for purposes of compliance with that requirement.

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

(c) Any person seeking permission under this section shall submit to the Administrator a written application including:

(1) An actual emissions test that uses a full-sized or scale-model storage vessel that accurately collects and measures all VOC emissions from a given control device and that accurately simulates wind and accounts for other emission variables such as temperature and barometric pressure.

(2) An engineering evaluation that the Administrator determines is an accurate method of determining equivalence.

(d) The Administrator may condition the permission on requirements that may be necessary to ensure operation and maintenance to achieve the same emissions reduction as specified in §60.112b.

### § 60.115b Reporting and recordkeeping requirements.

The owner or operator of each storage vessel as specified in §60.112b (a) shall keep records and furnish reports as required by paragraphs (a), (b), or (c) of this section depending upon the control equipment installed to meet the requirements of §60.112b. The owner or operator shall keep copies of all reports and records required by this section, except for the record required by (c)(1), for at least 2 years. The record required by (c)(1) will be kept for the life of the control equipment.

(a) After installing control equipment in accordance with §60.112b (a)(1) (fixed roof and internal floating roof), the owner or operator shall meet the following requirements.

(1) Furnish the Administrator with a report that describes the control equipment and certifies that the control equipment meets the specifications of §60.112b (a)(1) and §60.113b (a)(1). This report shall be an attachment to the notification required by §60.7(a)(3).

(2) Keep a record of each inspection performed as required by §60.113b (a)(1), (a)(2), (a)(3), and (a)(4). Each record shall identify

the storage vessel on which the inspection was performed and shall contain the date the vessel was inspected and the observed condition of each component of the control equipment (seals, internal floating roof, and fittings).

(3) If any of the conditions described in §60.113b(a)(2) are detected during the annual visual inspection required by §60.113b(a)(2), a report shall be furnished to the Administrator within 30 days of the inspection. Each report shall identify the storage vessel, the nature of the defects, and the date the storage vessel was emptied or the nature of and date the repair was made.

(4) After each inspection required by §60.113b(a)(3) that finds holes or tears in the seal or seal fabric, or defects in the internal floating roof, or other control equipment defects listed in §60.113b(a)(3)(ii), a report shall be furnished to the Administrator within 30 days of the inspection. The report shall identify the storage vessel and the reason it did not meet the specifications of §61.112b(a)(1) or §60.113b(a)(3) and list each repair made.

(b) After installing control equipment in accordance with §61.112b(a)(2) (external floating roof), the owner or operator shall meet the following requirements.

(1) Furnish the Administrator with a report that describes the control equipment and certifies that the control equipment meets the specifications of §60.112b(a)(2) and §60.113b(b)(2), (b)(3), and (b)(4). This report shall be an attachment to the notification required by §60.7(a)(3).

(2) Within 60 days of performing the seal gap measurements required by §60.113b(b)(1), furnish the Administrator with a report that contains:

(i) The date of measurement.

(ii) The raw data obtained in the measurement.

(iii) The calculations described in §60.113b(b)(2) and (b)(3).

(3) Keep a record of each gap measurement performed as required by §60.113b(b). Each record shall identify the storage vessel in which the measurement was performed and shall contain:

(i) The date of measurement.

(ii) The raw data obtained in the measurement.

(iii) The calculations described in §60.113b(b)(2) and (b)(3).

(4) After each seal gap measurement that detects gaps exceeding the limitations specified by §60.113b(b)(4), submit a report to the Administrator within 30 days of the inspection. The report will identify the vessel and contain the information specified in paragraph (b)(2) of this section and the date the vessel was emptied or the repairs made and date of repair.

(c) After installing control equipment in accordance with §60.112b(a)(3) or (b)(1) (closed vent system and control device other than a flare), the owner or operator shall keep the following records.

(1) A copy of the operating plan.

(2) A record of the measured values of the parameters monitored in accordance with §60.113b(c)(2).

(d) After installing a closed vent system and flare to comply with §60.112b, the owner or operator shall meet the following requirements.

(1) A report containing the measurements required by §60.18(f)(1), (2), (3), (4), (5), and (6) shall be furnished to the Administrator as required by §60.8 of the General Provisions. This report shall be submitted within 6 months of the initial start-up date.

(2) Records shall be kept of all periods of operation during which the flare pilot flame is absent.

(3) Semiannual reports of all periods recorded under §60.115b(d)(2) in which the pilot flame was absent shall be furnished to the Administrator.

### **§ 60.116b Monitoring of operations.**

(a) The owner or operator shall keep copies of all records required by this section, except for the record required by paragraph (b)



of this section, for at least 2 years. The record required by paragraph (b) of this section will be kept for the life of the source.

(b) The owner or operator of each storage vessel as specified in §60.110b(a) shall keep readily accessible records showing the dimension of the storage vessel and an analysis showing the capacity of the storage vessel.

(c) Except as provided in paragraphs (f) and (g) of this section, the owner or operator of each storage vessel either with a design capacity greater than or equal to 151 m<sup>3</sup> storing a liquid with a maximum true vapor pressure greater than or equal to 3.5 kPa or with a design capacity greater than or equal to 75 m<sup>3</sup> but less than 151 m<sup>3</sup> storing a liquid with a maximum true vapor pressure greater than or equal to 15.0 kPa shall maintain a record of the VOL stored, the period of storage, and the maximum true vapor pressure of that VOL during the respective storage period.

(d) Except as provided in paragraph (g) of this section, the owner or operator of each storage vessel either with a design capacity greater than or equal to 151 m<sup>3</sup> storing a liquid with a maximum true vapor pressure that is normally less than 5.2 kPa or with a design capacity greater than or equal to 75 m<sup>3</sup> but less than 151 m<sup>3</sup> storing a liquid with a maximum true vapor pressure that is normally less than 27.6 kPa shall notify the Administrator within 30 days when the maximum true vapor pressure of the liquid exceeds the respective maximum true vapor pressure values for each volume range.

(e) Available data on the storage temperature may be used to determine the maximum true vapor pressure as determined below.

(1) For vessels operated above or below ambient temperatures, the maximum true vapor pressure is calculated based upon the highest expected calendar-month average of the storage temperature. For vessels operated at ambient temperatures, the maximum true vapor pressure is calculated based upon the maximum local monthly average ambient temperature as reported by the National Weather Service.

(2) For crude oil or refined petroleum products the vapor pressure may be obtained by the following:

(i) Available data on the Reid vapor pressure and the maximum expected storage temperature based on the highest expected calendar-month average temperature of the stored product may be used to determine the maximum true vapor pressure from nomographs contained in API Bulletin 2517 (incorporated by reference—see §60.17), unless the Administrator specifically requests that the liquid be sampled, the actual storage temperature determined, and the Reid vapor pressure determined from the sample(s).

(ii) The true vapor pressure of each type of crude oil with a Reid vapor pressure less than 13.8 kPa or with physical properties that preclude determination by the recommended method is to be determined from available data and recorded if the estimated maximum true vapor pressure is greater than 3.5 kPa.

(3) For other liquids, the vapor pressure:

(i) May be obtained from standard reference texts, or

(ii) Determined by ASTM D2879–83, 96, or 97 (incorporated by reference—see §60.17); or

(iii) Measured by an appropriate method approved by the Administrator; or

(iv) Calculated by an appropriate method approved by the Administrator.

(f) The owner or operator of each vessel storing a waste mixture of indeterminate or variable composition shall be subject to the following requirements.

(1) Prior to the initial filling of the vessel, the highest maximum true vapor pressure for the range of anticipated liquid compositions to be stored will be determined using the methods described in paragraph (e) of this section.

(2) For vessels in which the vapor pressure of the anticipated liquid composition is above the cutoff for monitoring but below the cutoff for controls as defined in §60.112b(a), an initial physical test of the vapor pressure is required; and a physical test at least once every 6 months thereafter is required as determined by the following methods:

(i) ASTM D2879–83, 96, or 97 (incorporated by reference—see §60.17); or

(ii) ASTM D323–82 or 94 (incorporated by reference—see §60.17); or

(iii) As measured by an appropriate method as approved by the Administrator.

(g) The owner or operator of each vessel equipped with a closed vent system and control device meeting the specification of

§60.112b or with emissions reductions equipment as specified in 40 CFR 65.42(b)(4), (b)(5), (b)(6), or (c) is exempt from the requirements of paragraphs (c) and (d) of this section.

[52 FR 11429, Apr. 8, 1987, as amended at 65 FR 61756, Oct. 17, 2000; 65 FR 78276, Dec. 14, 2000; 68 FR 59333, Oct. 15, 2003]

**§ 60.117b Delegation of authority.**

(a) In delegating implementation and enforcement authority to a State under section 111(c) of the Act, the authorities contained in paragraph (b) of this section shall be retained by the Administrator and not transferred to a State.

(b) Authorities which will not be delegated to States: §§60.111b(f)(4), 60.114b, 60.116b(e)(3)(iii), 60.116b(e)(3)(iv), and 60.116b(f)(2)(iii).

[52 FR 11429, Apr. 8, 1987, as amended at 52 FR 22780, June 16, 1987]

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Appendix C—40 CFR 60 Subpart NNN: *Standards of Performance for Volatile Organic Compound (VOC) Emissions From Synthetic Organic Chemical Manufacturing Industry (SOCMI) Distillation Operations*

[Home Page](#) > [Executive Branch](#) > [Code of Federal Regulations](#) > [Electronic Code of Federal Regulations](#)

## Electronic Code of Federal Regulations

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### **Title 40: Protection of Environment**

**PART 60—STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES**

[Browse Previous](#) | [Browse Next](#)

### **Subpart NNN—Standards of Performance for Volatile Organic Compound (VOC) Emissions From Synthetic Organic Chemical Manufacturing Industry (SOCMI) Distillation Operations**

**Source:** 55 FR 26942, June 29, 1990, unless otherwise noted.

#### **§ 60.660 Applicability and designation of affected facility.**

(a) The provisions of this subpart apply to each affected facility designated in paragraph (b) of this section that is part of a process unit that produces any of the chemicals listed in §60.667 as a product, co-product, by-product, or intermediate, except as provided in paragraph (c).

(b) The affected facility is any of the following for which construction, modification, or reconstruction commenced after December 30, 1983:

(1) Each distillation unit not discharging its vent stream into a recovery system.

(2) Each combination of a distillation unit and the recovery system into which its vent stream is discharged.

(3) Each combination of two or more distillation units and the common recovery system into which their vent streams are discharged.

(c) Exemptions from the provisions of paragraph (a) of this section are as follows:

(1) Any distillation unit operating as part of a process unit which produces coal tar or beverage alcohols, or which uses, contains, and produces no VOC is not an affected facility.

(2) Any distillation unit that is subject to the provisions of subpart DDD is not an affected facility.

(3) Any distillation unit that is designed and operated as a batch operation is not an affected facility.

(4) Each affected facility that has a total resource effectiveness (TRE) index value greater than 8.0 is exempt from all provisions of this subpart except for §§60.662; 60.664 (d), (e), and (f); and 60.665 (h) and (l).

(5) Each affected facility in a process unit with a total design capacity for all chemicals produced within that unit of less than one gigagram per year is exempt from all provisions of this subpart except for the recordkeeping and reporting requirements in paragraphs (j), (l)(6), and (n) of §60.665.

(6) Each affected facility operated with a vent stream flow rate less than 0.008 sc m/min is exempt from all provisions of this subpart except for the test method and procedure and the recordkeeping and reporting requirements in §60.664(g) and paragraphs (i), (l)(5), and (o) of §60.665.

(d) *Alternative means of compliance* —(1) *Option to comply with part 65.* Owners or operators of process vents that are subject to this subpart may choose to comply with the provisions of 40 CFR part 65, subpart D, to satisfy the requirements of §§60.662 through 60.665 and 60.668. The provisions of 40 CFR part 65 also satisfy the criteria of paragraphs (c)(4) and (6) of this section. Other provisions applying to an owner or operator who chooses to comply with 40 CFR part 65 are provided in 40 CFR 65.1.

(2) *Part 60, subpart A.* Owners or operators who choose to comply with 40 CFR part 65, subpart D, must also comply with §§60.1, 60.2, 60.5, 60.6, 60.7(a)(1) and (4), 60.14, 60.15, and 60.16 for those process vents. All sections and paragraphs of subpart A of this part that are not mentioned in this paragraph (d)(2) do not apply to owners or operators of process vents complying with 40 CFR part 65, subpart D, except that provisions required to be met prior to implementing 40 CFR part 65 still apply. Owners and operators who choose to comply with 40 CFR part 65, subpart D, must comply with 40 CFR part 65, subpart A.

(3) *Compliance date.* Owners or operators who choose to comply with 40 CFR part 65, subpart D, at initial startup shall comply with paragraphs (d) (1) and (2) of this section for each vent stream on and after the date on which the initial performance test is completed, but not later than 60 days after achieving the maximum production rate at which the affected facility will be operated, or 180 days after the initial startup, whichever date comes first.

(4) *Initial startup notification.* Each owner or operator subject to the provisions of this subpart that chooses to comply with 40 CFR part 65, subpart D, at initial startup shall notify the Administrator of the specific provisions of 40 CFR 65.63(a)(1), (2), or (3), with which the owner or operator has elected to comply. Notification shall be submitted with the notifications of initial startup required by 40 CFR 65.5(b).

[Note: The intent of these standards is to minimize the emissions of VOC through the application of best demonstrated technology (BDT). The numerical emission limits in these standards are expressed in terms of total organic compounds (TOC), measured as TOC less methane and ethane. This emission limit reflects the performance of BDT.]

[55 FR 26942, June 29, 2000, as amended at 65 FR 78279, Dec. 14, 2000]

## § 60.661 Definitions.

As used in this subpart, all terms not defined here shall have the meaning given them in the Act and in subpart A of part 60, and the following terms shall have the specific meanings given them.

*Batch distillation operation* means a noncontinuous distillation operation in which a discrete quantity or batch of liquid feed is charged into a distillation unit and distilled at one time. After the initial charging of the liquid feed, no additional liquid is added during the distillation operation.

*Boiler* means any enclosed combustion device that extracts useful energy in the form of steam.

*By compound* means by individual stream components, not carbon equivalents.

*Continuous recorder* means a data recording device recording an instantaneous data value at least once every 15 minutes.

*Distillation operation* means an operation separating one or more feed stream(s) into two or more exit stream(s), each exit stream having component concentrations different from those in the feed stream(s). The separation is achieved by the redistribution of the components between the liquid and vapor-phase as they approach equilibrium within the distillation unit.

*Distillation unit* means a device or vessel in which distillation operations occur, including all associated internals (such as trays or packing) and accessories (such as reboiler, condenser, vacuum pump, steam jet, etc.), plus any associated recovery system.

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

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

*Halogenated vent stream* means any vent stream determined to have a total concentration (by volume) of compounds containing halogens of 20 ppm v (by compound) or greater.

*Incinerator* means any enclosed combustion device that is used for destroying organic compounds and does not extract energy in the form of steam or process heat.

*Process heater* means a device that transfers heat liberated by burning fuel to fluids contained in tubes, including all fluids except water that is heated to produce steam.

*Process unit* means equipment assembled and connected by pipes or ducts to produce, as intermediates or final products, one or more of the chemicals in §60.667. A process unit can operate independently if supplied with sufficient fuel or raw materials and sufficient product storage facilities.

*Product* means any compound or chemical listed in §60.667 that is produced for sale as a final product as that chemical, or for use in the production of other chemicals or compounds. By-products, co-products, and intermediates are considered to be products.

*Recovery device* means an individual unit of equipment, such as an absorber, carbon adsorber, or condenser, capable of and used for the purpose of recovering chemicals for use, reuse, or sale.

*Recovery system* means an individual recovery device or series of such devices applied to the same vent stream.

*Total organic compounds (TOC)* means those compounds measured according to the procedures in §60.664(b)(4). For the purposes of measuring molar composition as required in §60.664(d)(2)(i); hourly emissions rate as required in §60.664(d)(5) and §60.664(e); and TOC concentration as required in §60.665(b)(4) and §60.665(g)(4), those compounds which the Administrator has determined do not contribute appreciably to the formation of ozone are to be excluded. The compounds to be excluded are identified in Environmental Protection Agency's statements on ozone abatement policy for State Implementation Plans (SIP) revisions (42 FR 35314; 44 FR 32042; 45 FR 32424; 45 FR 48942).

*TRE index value* means a measure of the supplemental total resource requirement per unit reduction of TOC associated with an individual distillation vent stream, based on vent stream flow rate, emission rate of TOC net heating value, and corrosion properties (whether or not the vent stream is halogenated), as quantified by the equation given under §60.664(e).

*Vent stream* means any gas stream discharged directly from a distillation facility to the atmosphere or indirectly to the atmosphere after diversion through other process equipment. The vent stream excludes relief valve discharges and equipment leaks including, but not limited to, pumps, compressors, and valves.

## § 60.662 Standards.

Each owner or operator of any affected facility shall comply with paragraph (a), (b), or (c) of this section for each vent stream on and after the date on which the initial performance test required by §60.8 and §60.664 is completed, but not later than 60 days after achieving the maximum production rate at which the affected facility will be operated, or 180 days after the initial start-up, whichever date comes first. Each owner or operator shall either:

- (a) Reduce emissions of TOC (less methane and ethane) by 98 weight-percent, or to a TOC (less methane and ethane) concentration of 20 ppm v, on a dry basis corrected to 3 percent oxygen, whichever is less stringent. If a boiler or process heater is used to comply with this paragraph, then the vent stream shall be introduced into the flame zone of the boiler or process heater; or
- (b) Combust the emissions in a flare that meets the requirements of §60.18; or
- (c) Maintain a TRE index value greater than 1.0 without use of VOC emission control devices.

## § 60.663 Monitoring of emissions and operations.

(a) The owner or operator of an affected facility that uses an incinerator to seek to comply with the TOC emission limit specified under §60.662(a) shall install, calibrate, maintain, and operate according to manufacturer's specifications the following equipment:

- (1) A temperature monitoring device equipped with a continuous recorder and having an accuracy of  $\pm 1$  percent of the temperature being monitored expressed in degrees Celsius or  $\pm 0.5$  °C, whichever is greater.
  - (i) Where an incinerator other than a catalytic incinerator is used, a temperature monitoring device shall be installed in the firebox.
  - (ii) Where a catalytic incinerator is used, temperature monitoring devices shall be installed in the gas stream immediately before and after the catalyst bed.
- (2) A flow indicator that provides a record of vent stream flow to the incinerator at least once every hour for each affected facility. The flow indicator shall be installed in the vent stream from each affected facility at a point closest to the inlet of each incinerator and before being joined with any other vent stream.

(b) The owner or operator of an affected facility that uses a flare to seek to comply with §60.662(b) shall install, calibrate, maintain and operate according to manufacturer's specifications the following equipment:

- (1) A heat sensing device, such as an ultra-violet beam sensor or thermocouple, at the pilot light to indicate the continuous presence of a flame.

(2) A flow indicator that provides a record of vent stream flow to the flare at least once every hour for each affected facility. The flow indicator shall be installed in the vent stream from each affected facility at a point closest to the flare and before being joined with any other vent stream.

(c) The owner or operator of an affected facility that uses a boiler or process heater to seek to comply with §60.662(a) shall install, calibrate, maintain and operate according to the manufacturer's specifications the following equipment:

(1) A flow indicator that provides a record of vent stream flow to the boiler or process heater at least once every hour for each affected facility. The flow indicator shall be installed in the vent stream from each distillation unit within an affected facility at a point closest to the inlet of each boiler or process heater and before being joined with any other vent stream.

(2) A temperature monitoring device in the firebox equipped with a continuous recorder and having an accuracy of  $\pm 1$  percent of the temperature being measured expressed in degrees Celsius or  $\pm 0.5$  °C, whichever is greater, for boilers or process heaters of less than 44 MW (150 million Btu/hr) heat input design capacity.

(d) Monitor and record the periods of operation of the boiler or process heater if the design heat input capacity of the boiler or process heater is 44 MW (150 million Btu/hr) or greater. The records must be readily available for inspection.

(e) The owner or operator of an affected facility that seeks to comply with the TRE index value limit specified under §60.662(c) shall install, calibrate, maintain, and operate according to manufacturer's specifications the following equipment, unless alternative monitoring procedures or requirements are approved for that facility by the Administrator:

(1) Where an absorber is the final recovery device in the recovery system:

(i) A scrubbing liquid temperature monitoring device having an accuracy of  $\pm 1$  percent of the temperature being monitored expressed in degrees Celsius or  $\pm 0.5$  °C, whichever is greater, and a specific gravity monitoring device having an accuracy of  $\pm 0.02$  specific gravity units, each equipped with a continuous recorder, or

(ii) An organic monitoring device used to indicate the concentration level of organic compounds exiting the recovery device based on a detection principle such as infrared, photoionization, or thermal conductivity, each equipped with a continuous recorder.

(2) Where a condenser is the final recovery device in the recovery system:

(i) A condenser exit (product side) temperature monitoring device equipped with a continuous recorder and having an accuracy of  $\pm 1$  percent of the temperature being monitored expressed in degrees Celsius or  $\pm 0.5$  °C, whichever is greater, or

(ii) An organic monitoring device used to monitor organic compounds exiting the recovery device based on a detection principle such as infra-red, photoionization, or thermal conductivity, each equipped with a continuous recorder.

(3) Where a carbon adsorber is the final recovery device unit in the recovery system:

(i) An integrating steam flow monitoring device having an accuracy of  $\pm 10$  percent, and a carbon bed temperature monitoring device having an accuracy of  $\pm 1$  percent of the temperature being monitored expressed in degrees Celsius or  $\pm 0.5$  °C, whichever is greater, both equipped with a continuous recorder, or

(ii) An organic monitoring device used to indicate the concentration level of organic compounds exiting the recovery device based on a detection principle such as infra-red, photoionization, or thermal conductivity, each equipped with a continuous recorder.

(f) An owner or operator of an affected facility seeking to demonstrate compliance with the standards specified under §60.662 with control devices other than incinerator, boiler, process heater, or flare; or recovery device other than an absorber, condenser, or carbon adsorber shall provide to the Administrator information describing the operation of the control device or recovery device and the process parameter(s) which would indicate proper operation and maintenance of the device. The Administrator may request further information and will specify appropriate monitoring procedures or requirements.

[55 FR 26942, June 29, 1990, as amended at 65 FR 61774, Oct. 17, 2000]

## § 60.664 Test methods and procedures.

(a) For the purpose of demonstrating compliance with §60.662, all affected facilities shall be run at full operating conditions and flow rates during any performance test.

(b) The following methods in appendix A to this part, except as provided under §60.8(b), shall be used as reference methods to determine compliance with the emission limit or percent reduction efficiency specified under §60.662(a).

(1) Method 1 or 1A, as appropriate, for selection of the sampling sites. The control device inlet sampling site for determination of vent stream molar composition or TOC (less methane and ethane) reduction efficiency shall be prior to the inlet of the control device and after the recovery system.

(2) Method 2, 2A, 2C, or 2D, as appropriate, for determination of the gas volumetric flow rates.

(3) The emission rate correction factor, integrated sampling and analysis procedure of Method 3 shall be used to determine the oxygen concentration (%O<sub>2d</sub>) for the purposes of determining compliance with the 20 ppm v limit. The sampling site shall be the same as that of the TOC samples, and the samples shall be taken during the same time that the TOC samples are taken.

The TOC concentration corrected to 3 percent O<sub>2</sub> (C<sub>c</sub>) shall be computed using the following equation:

$$C_c = C_{TOC} \frac{17.9}{20.9 - \%O_{2d}}$$

where:

C<sub>c</sub>=Concentration of TOC corrected to 3 percent O<sub>2</sub>, dry basis, ppm by volume.

C<sub>TOC</sub>=Concentration of TOC (minus methane and ethane), dry basis, ppm by volume.

%O<sub>2d</sub>=Concentration of O<sub>2</sub>, dry basis, percent by volume.

(4) Method 18 to determine the concentration of TOC in the control device outlet and the concentration of TOC in the inlet when the reduction efficiency of the control device is to be determined.

(i) The sampling time for each run shall be 1 hour in which either an integrated sample or four grab samples shall be taken. If grab sampling is used then the samples shall be taken at 15-minute intervals.

(ii) The emission reduction (R) of TOC (minus methane and ethane) shall be determined using the following equation:

$$R = \frac{E_i - E_o}{E_i} \times 100$$

where:

R=Emission reduction, percent by weight.

E<sub>i</sub>=Mass rate of TOC entering the control device, kg/hr (lb/hr).

E<sub>o</sub>=Mass rate of TOC discharged to the atmosphere, kg/hr (lb/hr).

(iii) The mass rates of TOC (E<sub>i</sub>, E<sub>o</sub>) shall be computed using the following equations:

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

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



where:

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

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

$Q_i$ ,  $Q_o$ =Flow rate of gas stream at the inlet and outlet of the control device, respectively, dscm/min (dscf/min).

$K_2 = 2.494 \times 10^{-6} (1/\text{ppm})(\text{g-mole}/\text{scm}) (\text{kg}/\text{g}) (\text{min}/\text{hr})$  (metric units), where standard temperature for (g-mole/scm) is 20 °C.

$= 1.557 \times 10^{-7} (1/\text{ppm}) (\text{lb-mole}/\text{scf}) (\text{min}/\text{hr})$  (English units), where standard temperature for (lb-mole/scf) is 68 °F.

(iv) The TOC concentration ( $C_{\text{TOC}}$ ) is the sum of the individual components and shall be computed for each run using the following equation:

$$C_{\text{TOC}} = \sum_{j=1}^n C_j$$

where:

$C_{\text{TOC}}$ =Concentration of TOC (minus methane and ethane), dry basis, ppm by volume.

$C_j$ =Concentration of sample components "j", dry basis, ppm by volume.

n=Number of components in the sample.

(c) When a boiler or process heater with a design heat input capacity of 44 MW (150 million Btu/hour) or greater is used to seek to comply with §60.662(a), the requirement for an initial performance test is waived, in accordance with §60.8(b). However, the Administrator reserves the option to require testing at such other times as may be required, as provided for in section 114 of the Act.

(d) When a flare is used to seek to comply with §60.662(b), the flare shall comply with the requirements of §60.18.

(e) The following test methods in appendix A to this part, except as provided under §60.8(b), shall be used for determining the net heating value of the gas combusted to determine compliance under §60.662(b) and for determining the process vent stream TRE index value to determine compliance under §60.662(c).

(1)(i) Method 1 or 1A, as appropriate, for selection of the sampling site. The sampling site for the vent stream flow rate and molar composition determination prescribed in §60.664(e)(2) and (3) shall be, except for the situations outlined in paragraph (e)(1)(ii) of this section, prior to the inlet of any control device, prior to any post-distillation dilution of the stream with air, and prior to any post-distillation introduction of halogenated compounds into the process vent stream. No transverse site selection method is needed for vents smaller than 10 centimeters (4 inches) in diameter.

(ii) If any gas stream other than the distillation vent stream from the affected facility is normally conducted through the final recovery device.

(A) The sampling site for vent stream flow rate and molar composition shall be prior to the final recovery device and prior to the point at which the nondistillation stream is introduced.

(B) The efficiency of the final recovery device is determined by measuring the TOC concentration using Method 18 at the inlet to

the final recovery device after the introduction of any nondistillation vent stream and at the outlet of the final recovery device.

(C) This efficiency is applied to the TOC concentration measured prior to the final recovery device and prior to the introduction of the nondistillation stream to determine the concentration of TOC in the distillation vent stream from the final recovery device. This concentration of TOC is then used to perform the calculations outlined in §60.664(e)(4) and (5).

(2) The molar composition of the process vent stream shall be determined as follows:

(i) Method 18 to measure the concentration of TOC including those containing halogens.

(ii) ASTM D1946-77 or 90 (Reapproved 1994) (incorporation by reference as specified in §60.17 of this part) to measure the concentration of carbon monoxide and hydrogen.

(iii) Method 4 to measure the content of water vapor.

(3) The volumetric flow rate shall be determined using Method 2, 2A, 2C, or 2D, as appropriate.

(4) The net heating value of the vent stream shall be calculated using the following equation:

$$H_T = K_1 \left( \sum_{j=1}^n C_j H_j \right)$$

where:

$H_T$  = Net heating value of the sample, MJ/scm (Btu/scf), where the net enthalpy per mole of vent stream is based on combustion at 25 °C and 760 mm Hg (77 °F and 30 in. Hg), but the standard temperature for determining the volume corresponding to one mole is 20 °C (68 °F).

$K_1 = 1.74 \times 10^{-7}$  (1/ppm) (g-mole/scm) (MJ/kcal) (metric units), where standard temperature for (g-mole/scm) is 20 °C.

$= 1.03 \times 10^{-11}$  (1/ppm) (lb-mole/scf) (Btu/kcal) (English units) where standard temperature for (lb-mole/scf) is 68 °F.

$C_j$  = Concentration on a wet basis of compound j in ppm, as measured for organics by Method 18 and measured for hydrogen and carbon monoxide by ASTM D1946-77 or 90 (Reapproved 1994) (incorporation by reference as specified in §60.17 of this part) as indicated in §60.664(e)(2).

$H_j$  = Net heat of combustion of compound j, kcal/(g-mole) [kcal/(lb-mole)], based on combustion at 25 °C and 760 mm Hg (77 °F and 30 in. Hg).

The heats of combustion of vent stream components would be required to be determined using ASTM D2382-76 (incorporation by reference as specified in §60.17 of this part) if published values are not available or cannot be calculated.

(5) The emission rate of TOC in the vent stream shall be calculated using the following equation:

$$E_{TOC} = K_2 \left[ \sum_{j=1}^n C_j M_j \right] Q_s$$

where:

$E_{TOC}$  = Measured emission rate of TOC, kg/hr (lb/hr).

$K_2 = 2.494 \times 10^{-6}$  (1/ppm) (g-mole/scm) (kg/g) (min/hr) (metric units), where standard temperature for (g-mole/scm) is 20 °C.

$= 1.557 \times 10^{-7}$  (1/ppm) (lb-mole/scf) (min/hr) (English units), where standard temperature for (lb-mole/scf) is 68 °F.

$C_j$  = Concentration on a wet basis of compound j in ppm, as measured by Method 18 as indicated in §60.664(e)(2).

$M_j$  = Molecular weight of sample j, g/g-mole (lb/lb-mole).

$Q_s$  = Vent stream flow rate, scm/min (scf/min), at a temperature of 20 °C (68 °F).

(6) The total process vent stream concentration (by volume) of compounds containing halogens (ppm v, by compound) shall be summed from the individual concentrations of compounds containing halogens which were measured by Method 18.

(f) For purposes of complying with §60.662(c) the owner or operator of a facility affected by this subpart shall calculate the TRE index value of the vent stream using the equation for incineration in paragraph (e)(1) of this section for halogenated vent streams. The owner or operator of an affected facility with a nonhalogenated vent stream shall determine the TRE index value by calculating values using both the incinerator equation in (e)(1) and the flare equation in (e)(2) of this section and selecting the lower of the two values.

(1) The equation for calculating the TRE index value of a vent stream controlled by an incinerator is as follows:

$$TRE = \frac{1}{E_{TOC}} \left[ a + b(Q_s) + c(Q_s)^{0.88} + d(Q_s)(H_T) + e(Q_s)^{0.88}(H_T)^{0.88} + f(Y_s)^{0.5} \right]$$

(i) Where for a vent stream flow rate that is greater than or equal to 14.2 scm/min (501 scf/min) at a standard temperature of 20 °C (68 °F):

TRE = TRE index value.

$Q_s$  = Vent stream flow rate, scm/min (scf/min), at a temperature of 20 °C (68 °F).

$H_T$  = Vent stream net heating value, MJ/scm (Btu/scf), where the net enthalpy per mole of vent stream is based on combustion at 25 °C and 760 mm Hg (68 °F and 30 in. Hg), but the standard temperature for determining the volume corresponding to one mole is 20 °C (68 °F) as in the definition of  $Q_s$ .

$Y_s = Q_s$  for all vent stream categories listed in table 1 except for Category E vent streams where  $Y_s = Q_s H_T / 3.6$ .

$E_{TOC}$  = Hourly emissions of TOC, kg/hr (lb/hr).

a, b, c, d, e, and f are coefficients.

The set of coefficients that apply to a vent stream can be obtained from table 1.

TABLE 1. DISTILLATION NSPS TRE COEFFICIENTS FOR VENT STREAMS  
CONTROLLED BY AN INCINERATOR

DESIGN CATEGORY A1. FOR HALOGENATED PROCESS VENT STREAMS, IF  $D \leq$  NET HEATING VALUE (MJ/scm)  $\leq$  3.5 OR IF  
 $D \leq$  NET HEATING VALUE (Btu/scf)  $\leq$  94:

$Q_v$ = Vent Stream Flow rate scm/min (scf/min)	a	b	c	d	e	f
$14.2 \leq Q_v \leq 18.8$	18.84468	0.26742	-0.20044	0	0	0.01025
$(501 \leq Q_v \leq 664)$	(41.54494)	(0.016696)	(-0.019194)	(0)	(0)	(0.003803)
$18.8 < Q_v \leq 669$	19.66658	0.26742	-0.25332	0	0	0.01025
$(664 < Q_v \leq 24,700)$	(43.35694)	(0.016696)	(-0.024258)	(0)	(0)	(0.003803)
$669 < Q_v \leq 1400$	39.19213	0.29062	-0.25332	0	0	0.01449
$(24,700 < Q_v \leq 49,000)$	(86.40297)	(0.018145)	(-0.024258)	(0)	(0)	(0.005376)
$1400 < Q_v \leq 2100$	58.71768	0.30511	-0.25332	0	0	0.01775
$(49,000 < Q_v \leq 74,000)$	(129.4490)	(0.019050)	(-0.024258)	(0)	(0)	(0.006585)
$2100 < Q_v \leq 2800$	78.24323	0.31582	-0.25332	0	0	0.02049
$(74,000 < Q_v \leq 99,000)$	(172.4950)	(0.019718)	(-0.024258)	(0)	(0)	(0.007607)
$2800 < Q_v \leq 3500$	97.76879	0.32439	-0.25332	0	0	0.02291
$(99,000 < Q_v \leq 120,000)$	(215.5411)	(0.020253)	(-0.024258)	(0)	(0)	(0.008500)

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DESIGN CATEGORY A2. FOR HALOGENATED PROCESS VENT STREAMS, IF NET HEATING VALUE  $<$  3.5 (MJ/scm)  
OR IF NET HEATING VALUE  $<$  94 (Btu/scf):

$Q_v$ = Vent Stream Flow rate scm/min (scf/min)	a	b	c	d	e	f
$14.2 \leq Q_v \leq 18.8$	18.84468	0.26742	-0.20044	0	0	0.01025
$(501 \leq Q_v \leq 664)$	(41.54494)	(0.016696)	(-0.019194)	(0)	(0)	(0.003803)
$18.8 < Q_v \leq 669$	19.66658	0.26742	-0.25332	0	0	0.01025
$(664 < Q_v \leq 24,700)$	(43.35694)	(0.016696)	(-0.024258)	(0)	(0)	(0.003803)
$669 < Q_v \leq 1400$	39.19213	0.29082	-0.25332	0	0	0.01449
$(24,700 < Q_v \leq 49,000)$	(86.40297)	(0.018145)	(-0.024258)	(0)	(0)	(0.005376)
$1400 < Q_v \leq 2100$	58.71768	0.30511	-0.25332	0	0	0.01775
$(49,000 < Q_v \leq 74,000)$	(129.4490)	(0.019050)	(-0.024258)	(0)	(0)	(0.006585)
$2100 < Q_v \leq 2800$	78.24323	0.31582	-0.25332	0	0	0.02049
$(74,000 < Q_v \leq 99,000)$	(172.4950)	(0.019718)	(-0.024258)	(0)	(0)	(0.007607)
$2800 < Q_v \leq 3500$	97.76879	0.32439	-0.25332	0	0	0.02291
$(99,000 < Q_v \leq 120,000)$	(215.5411)	(0.020253)	(-0.024258)	(0)	(0)	(0.008500)

DESIGN CATEGORY B. FOR NONHALOGENATED PROCESS VENT STREAMS, IF  $D \leq$  NET HEATING VALUE (MJ/scm)  $\leq$  0.48  
OR IF  $D \leq$  NET HEATING VALUE (Btu/scf)  $\leq$  13:

$Q_v$ = Vent Stream Flow rate scm/min (scf/min)	a	b	c	d	e	f
$14.2 \leq Q_v \leq 1340$	8.34243	0.10555	0.09030	-0.17109	0	0.01025
$(501 \leq Q_v \leq 47,300)$	(18.83268)	(0.0065801)	(0.008647)	(-0.00039782)	(0)	(0.003803)
$1340 < Q_v \leq 2090$	16.94386	0.11470	0.09030	-0.17109	0	0.01449
$(47,300 < Q_v \leq 85,000)$	(37.35443)	(0.0071814)	(0.008647)	(-0.00039782)	(0)	(0.005376)
$2090 < Q_v \leq 4040$	25.34526	0.12042	0.09030	-0.17109	0	0.01775
$(85,000 < Q_v \leq 143,000)$	(55.87620)	(0.0075185)	(0.008647)	(-0.00039782)	(0)	(0.006585)

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DESIGN CATEGORY C. FOR NONHALOGENATED PROCESS VENT STREAMS, IF  $0.48 < \text{NET HEATING VALUE (MJ/scm)} \leq 1.9$   
OR IF  $13 < \text{NET HEATING VALUE (Btu/scf)} \leq 51$ :

$Q_g$ = Vent Stream Flow rate scm/min(scf/min)	a	b	c	d	e	f
$14.2 < Q_g < 1340$ ( $501 < Q_g < 47,300$ )	9.25233 (20.39769)	0.05105 (0.003812)	0.31937 (0.030582)	-0.16181 (-0.00037605)	0 (0)	0.01025 (0.003803)
$1340 < Q_g < 2680$ ( $47,300 < Q_g < 95,000$ )	18.36353 (40.48446)	0.06635 (0.004143)	0.31937 (0.030582)	-0.16181 (-0.00037605)	0 (0)	0.01449 (0.005376)
$2680 < Q_g < 4040$ ( $95,000 < Q_g < 143,000$ )	27.47492 (60.57121)	0.06965 (0.004349)	0.31937 (0.030582)	-0.16181 (-0.00037605)	0 (0)	0.01775 (0.006585)

DESIGN CATEGORY D. FOR NONHALOGENATED PROCESS VENT STREAMS, IF  $1.9 < \text{NET HEATING VALUE (MJ/scm)} \leq 3.6$   
OR IF  $51 < \text{NET HEATING VALUE (Btu/scf)} \leq 97$ :

$Q_g$ = Vent Stream Flow rate scm/min(scf/min)	a	b	c	d	e	f
$14.2 < Q_g < 1180$ ( $501 < Q_g < 41,700$ )	6.67868 (14.72382)	0.06943 (0.004335)	0.02582 (0.002472)	0 (0)	0 (0)	0.01025 (0.003803)
$1180 < Q_g < 2370$ ( $41,700 < Q_g < 83,700$ )	13.21633 (29.13672)	0.07546 (0.004711)	0.02582 (0.002472)	0 (0)	0 (0)	0.01449 (0.005376)
$2370 < Q_g < 3550$ ( $83,700 < Q_g < 125,000$ )	19.75398 (43.54962)	0.07922 (0.004946)	0.02582 (0.002472)	0 (0)	0 (0)	0.01775 (0.006585)

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DESIGN CATEGORY E. FOR NONHALOGENATED PROCESS VENT STREAMS, IF NET HEATING VALUE  $> 3.6 \text{ MJ/scm}$   
OR IF NET HEATING VALUE  $> 97 \text{ (Btu/scf)}$ :

$Q_g$ = Vent Stream Flow rate scm/min(scf/min)	a	b	c	d	e	f
$14.2 < Y_g < 1180$ ( $501 < Y_g < 41,700$ )	6.67868 (14.72382)	0 (0)	0 (0)	-0.00707 (-0.000164)	0.02220 (0.0001174)	0.01025 (0.003803)
$1180 < Y_g < 2370$ ( $41,700 < Y_g < 83,700$ )	13.21633 (29.13672)	0 (0)	0 (0)	-0.00707 (-0.000164)	0.02412 (0.0001276)	0.01449 (0.005376)
$2370 < Y_g < 3550$ ( $83,700 < Y_g < 125,000$ )	19.75398 (43.54962)	0 (0)	0 (0)	-0.00707 (-0.000164)	0.02533 (0.0001340)	0.01775 (0.006585)

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(ii) Where for a vent stream flow rate that is less than 14.2 scm/min (501 scf/min) at a standard temperature of 20 °C (68 °F):

TRE = TRE index value.

$Q_g = 14.2 \text{ scm/min (501 scf/min)}$ .

$H_T = (\text{FLOW}) (\text{HVAL}) / Q_g$ .

Where the following inputs are used:

FLOW = Vent stream flow rate, scm/min (scf/min), at a temperature of 20 °C (68 °F).

HVAL = Vent stream net heating value, MJ/scm (Btu/scf), where the net enthalpy per mole of vent stream is based on combustion at 25 °C and 760 mm Hg (68 °F and 30 in. Hg), but the standard temperature for determining the volume corresponding to one mole is 20 °C (68 °F) as in the definition of  $Q_s$ .

$Y_s = Q_s$  for all vent stream categories listed in table 1 except for Category E vent streams where  $Y_s = Q_s H_T / 3.6$ .

$E_{TOC}$  = Hourly emissions of TOC, kg/hr (lb/hr).

a, b, c, d, e, and f are coefficients

The set of coefficients that apply to a vent stream can be obtained from table 1.

(2) The equation for calculating the TRE index value of a vent stream controlled by a flare is as follows:

$$TRE = \frac{1}{E_{TOC}} \left[ a(Q_s) + b(Q_s)^{0.8} + c(Q_s)(H_T) + d(E_{TOC}) + e \right]$$

where:

TRE = TRE index value.

$E_{TOC}$  = Hourly emissions of TOC, kg/hr (lb/hr).

$Q_s$  = Vent stream flow rate, scm/min (scf/min), at a standard temperature of 20 °C (68 °F).

$H_T$  = Vent stream net heating value, MJ/scm (Btu/scf), where the net enthalpy per mole of vent stream is based on combustion at 25 °C and 760 mm Hg (68 °F and 30 in. Hg), but the standard temperature for determining the volume corresponding to one mole is 20 °C (68 °F) as in the definition of  $Q_s$ .

a, b, c, d, and e are coefficients.

The set of coefficients that apply to a vent stream shall be obtained from table 2.

Table 2—Distillation NSPS TRE Coefficients for Vent Streams Controlled By a Flare

	a	b	c	d	e
$H_T < 11.2$ MJ/scm	2.25	0.288	-0.193	-0.0051	2.08
( $H_T < 301$ Btu/scf)	(0.140)	(0.0367)	(-0.000448)	(-0.0051)	(4.59)
$H_T \geq 11.2$ MJ/scm	0.309	0.0619	-0.0043	-0.0034	2.08
( $H_T \geq 301$ Btu/scf)	(0.0193)	(0.00788)	(-0.000010)	(-0.0034)	(4.59)

(g) Each owner or operator of an affected facility seeking to comply with §60.660(c)(4) or §60.662(c) shall recalculate the TRE index value for that affected facility whenever process changes are made. Examples of process changes include changes in production capacity, feedstock type, or catalyst type, or whenever there is replacement, removal, or addition of recovery

equipment. The TRE index value shall be recalculated based on test data, or on best engineering estimates of the effects of the change to the recovery system.

(1) Where the recalculated TRE index value is less than or equal to 1.0, the owner or operator shall notify the Administrator within 1 week of the recalculation and shall conduct a performance test according to the methods and procedures required by §60.664 in order to determine compliance with §60.662(a). Performance tests must be conducted as soon as possible after the process change but no later than 180 days from the time of the process change.

(2) Where the initial TRE index value is greater than 8.0 and the recalculated TRE index value is less than or equal to 8.0 but greater than 1.0, the owner or operator shall conduct a performance test in accordance with §§60.8 and 60.664 and shall comply with §§60.663, 60.664 and 60.665. Performance tests must be conducted as soon as possible after the process change but no later than 180 days from the time of the process change.

(h) Any owner or operator subject to the provisions of this subpart seeking to demonstrate compliance with §60.660(c)(6) shall use Method 2, 2A, 2C, or 2D as appropriate, for determination of volumetric flow rate.

[55 FR 26942, June 29, 1990, as amended at 65 FR 61774, Oct. 17, 2000]

### § 60.665 Reporting and recordkeeping requirements.

(a) Each owner or operator subject to §60.662 shall notify the Administrator of the specific provisions of §60.662 (§60.662(a), (b), or (c)) with which the owner or operator has elected to comply. Notification shall be submitted with the notification of initial start-up required by §60.7(a)(3). If an owner or operator elects at a later date to use an alternative provision of §60.662 with which he or she will comply, then the Administrator shall be notified by the owner or operator 90 days before implementing a change and, upon implementing the change, a performance test shall be performed as specified by §60.664 within 180 days.

(b) Each owner or operator subject to the provisions of this subpart shall keep an up-to-date, readily accessible record of the following data measured during each performance test, and also include the following data in the report of the initial performance test required under §60.8. Where a boiler or process heater with a design heat input capacity of 44 MW (150 million Btu/hour) or greater is used to comply with §60.662(a), a report containing performance test data need not be submitted, but a report containing the information in §60.665(b)(2)(i) is required. The same data specified in this section shall be submitted in the reports of all subsequently required performance tests where either the emission control efficiency of a control device, outlet concentration of TOC, or the TRE index value of a vent stream from a recovery system is determined.

(1) Where an owner or operator subject to the provisions of this subpart seeks to demonstrate compliance with §60.662(a) through use of either a thermal or catalytic incinerator:

(i) The average firebox temperature of the incinerator (or the average temperature upstream and downstream of the catalyst bed for a catalytic incinerator), measured at least every 15 minutes and averaged over the same time period of the performance testing, and

(ii) The percent reduction of TOC determined as specified in §60.664(b) achieved by the incinerator, or the concentration of TOC (ppmv, by compound) determined as specified in §60.664(b) at the outlet of the control device on a dry basis corrected to 3 percent oxygen.

(2) Where an owner or operator subject to the provisions of this subpart seeks to demonstrate compliance with §60.662(a) through use of a boiler or process heater:

(i) A description of the location at which the vent stream is introduced into the boiler or process heater, and

(ii) The average combustion temperature of the boiler or process heater with a design heat input capacity of less than 44 MW (150 million Btu/hr) measured at least every 15 minutes and averaged over the same time period of the performance testing.

(3) Where an owner or operator subject to the provisions of this subpart seeks to demonstrate compliance with §60.662(b) through use of a smokeless flare, flare design (i.e., steam-assisted, air-assisted or nonassisted), all visible emission readings, heat content determinations, flow rate measurements, and exit velocity determinations made during the performance test, continuous records of the flare pilot flame monitoring, and records of all periods of operations during which the pilot flame is absent.

(4) Where an owner or operator subject to the provisions of this subpart seeks to demonstrate compliance with §60.662(c):

(i) Where an absorber is the final recovery device in the recovery system, the exit specific gravity (or alternative parameter which is a measure of the degree of absorbing liquid saturation, if approved by the Administrator), and average exit temperature, of the absorbing liquid measured at least every 15 minutes and averaged over the same time period of the performance testing (both measured while the vent stream is normally routed and constituted), or

(ii) Where a condenser is the final recovery device in the recovery system, the average exit (product side) temperature measured

at least every 15 minutes and averaged over the same time period of the performance testing while the vent stream is routed and constituted normally, or

(iii) Where a carbon adsorber is the final recovery device in the recovery system, the total steam mass flow measured at least every 15 minutes and averaged over the same time period of the performance test (full carbon bed cycle), temperature of the carbon bed after regeneration (and within 15 minutes of completion of any cooling cycle(s)), and duration of the carbon bed steaming cycle (all measured while the vent stream is routed and constituted normally), or

(iv) As an alternative to §60.665(b)(4) ((i), (ii) or (iii)), the concentration level or reading indicated by the organics monitoring device at the outlet of the absorber, condenser, or carbon adsorber, measured at least every 15 minutes and averaged over the same time period of the performance testing while the vent stream is normally routed and constituted.

(v) All measurements and calculations performed to determine the TRE index value of the vent stream.

(c) Each owner or operator subject to the provisions of this subpart shall keep up-to-date, readily accessible continuous records of the equipment operating parameters specified to be monitored under §60.663(a) and (c) as well as up-to-date, readily accessible records of periods of operation during which the parameter boundaries established during the most recent performance test are exceeded. The Administrator may at any time require a report of these data. Where a combustion device is used to comply with §60.662(a), periods of operation during which the parameter boundaries established during the most recent performance tests are exceeded are defined as follows:

(1) For thermal incinerators, all 3-hour periods of operation during which the average combustion temperature was more than 28 °C (50 °F) below the average combustion temperature during the most recent performance test at which compliance with §60.662(a) was determined.

(2) For catalytic incinerators, all 3-hour periods of operation during which the average temperature of the vent stream immediately before the catalyst bed is more than 28 °C (50 °F) below the average temperature of the vent stream during the most recent performance test at which compliance with §60.662(a) was determined. The owner or operator also shall record all 3-hour periods of operation during which the average temperature difference across the catalyst bed is less than 80 per cent of the average temperature difference of the device during the most recent performance test at which compliance with §60.662(a) was determined.

(3) All 3-hour periods of operation during which the average combustion temperature was more than 28 °C (50 °F) below the average combustion temperature during the most recent performance test at which compliance with §60.662(a) was determined for boilers or process heaters with a design heat input capacity of less than 44 MW (150 million Btu/hr).

(4) For boilers or process heaters, whenever there is a change in the location at which the vent stream is introduced into the flame zone as required under §60.662(a).

(d) Each owner or operator subject to the provisions of this subpart shall keep up to date, readily accessible continuous records of the flow indication specified under §60.663(a)(2), §60.663(b)(2) and §60.663(c)(1), as well as up-to-date, readily accessible records of all periods when the vent stream is diverted from the control device or has no flow rate.

(e) Each owner or operator subject to the provisions of this subpart who uses a boiler or process heater with a design heat input capacity of 44 MW (150 million Btu/hour) or greater to comply with §60.662(a) shall keep an up-to-date, readily accessible record of all periods of operation of the boiler or process heater. (Examples of such records could include records of steam use, fuel use, or monitoring data collected pursuant to other State or Federal regulatory requirements.)

(f) Each owner or operator subject to the provisions of this subpart shall keep up-to-date, readily accessible continuous records of the flare pilot flame monitoring specified under §60.663(b), as well as up-to-date, readily accessible records of all periods of operations in which the pilot flame is absent.

(g) Each owner or operator subject to the provisions of this subpart shall keep up-to-date, readily accessible continuous records of the equipment operating parameters specified to be monitored under §60.663(e), as well as up-to-date, readily accessible records of periods of operation during which the parameter boundaries established during the most recent performance test are exceeded. The Administrator may at any time require a report of these data. Where an owner or operator seeks to comply with §60.662(c), periods of operation during which the parameter boundaries established during the most recent performance tests are exceeded are defined as follows:

(1) Where an absorber is the final recovery device in a recovery system, and where an organic compound monitoring device is not used:

(i) All 3-hour periods of operation during which the average absorbing liquid temperature was more than 11 °C (20 °F) above the average absorbing liquid temperature during the most recent performance test, or

(ii) All 3-hour periods of operation during which the average absorbing liquid specific gravity was more than 0.1 unit above, or more than 0.1 unit below, the average absorbing liquid specific gravity during the most recent performance test (unless monitoring of an alternative parameter, which is a measure of the degree of absorbing liquid saturation, is approved by the Administrator, in which



case he will define appropriate parameter boundaries and periods of operation during which they are exceeded).

(2) Where a condenser is the final recovery device in a system, and where an organic compound monitoring device is not used, all 3-hour periods of operation during which the average exit (product side) condenser operating temperature was more than 6 °C (11 °F) above the average exit (product side) operating temperature during the most recent performance test.

(3) Where a carbon adsorber is the final recovery device in a system, and where an organic compound monitoring device is not used:

(i) All carbon bed regeneration cycles during which the total mass steam flow was more than 10 percent below the total mass steam flow during the most recent performance test, or

(ii) All carbon bed regeneration cycles during which the temperature of the carbon bed after regeneration (and after completion of any cooling cycle(s)) was more than 10 percent greater than the carbon bed temperature (in degrees Celsius) during the most recent performance test.

(4) Where an adsorber, condenser, or carbon adsorber is the final recovery device in the recovery system and where an organic compound monitoring device is used, all 3-hour periods of operation during which the average organic compound concentration level or reading of organic compounds in the exhaust gases is more than 20 percent greater than the exhaust gas organic compound concentration level or reading measured by the monitoring device during the most recent performance test.

(h) Each owner or operator of an affected facility subject to the provisions of this subpart and seeking to demonstrate compliance with §60.662(c) shall keep up-to-date, readily accessible records of:

(1) Any changes in production capacity, feedstock type, or catalyst type, or of any replacement, removal or addition of recovery equipment or a distillation unit;

(2) Any recalculation of the TRE index value performed pursuant to §60.664(f); and

(3) The results of any performance test performed pursuant to the methods and procedures required by §60.664(d).

(i) Each owner or operator of an affected facility that seeks to comply with the requirements of this subpart by complying with the flow rate cutoff in §60.660(c)(6) shall keep up-to-date, readily accessible records to indicate that the vent stream flow rate is less than 0.008 scm/min (0.3 scf/min) and of any change in equipment or process operation that increases the operating vent stream flow rate, including a measurement of the new vent stream flow rate.

(j) Each owner or operator of an affected facility that seeks to comply with the requirements of this subpart by complying with the design production capacity provision in §60.660(c)(5) shall keep up-to-date, readily accessible records of any change in equipment or process operation that increases the design production capacity of the process unit in which the affected facility is located.

(k) Each owner and operator subject to the provisions of this subpart is exempt from the quarterly reporting requirements contained in §60.7(c) of the General Provisions.

(l) Each owner or operator that seeks to comply with the requirements of this subpart by complying with the requirements of §60.660 (c)(4), (c)(5), or (c)(6) or §60.662 shall submit to the Administrator semiannual reports of the following recorded information. The initial report shall be submitted within 6 months after the initial start-up date.

(1) Exceedances of monitored parameters recorded under §60.665 (c) and (g).

(2) All periods recorded under §60.665( d) when the vent stream is diverted from the control device or has no flow rate.

(3) All periods recorded under §60.665( e) when the boiler or process heater was not operating.

(4) All periods recorded under §60.665( f) in which the pilot flame of the flare was absent.

(5) Any change in equipment or process operation that increases the operating vent stream flow rate above the low flow exemption level in §60.660(c)(6), including a measurement of the new vent stream flow rate, as recorded under §60.665(i). These must be reported as soon as possible after the change and no later than 180 days after the change. These reports may be submitted either in conjunction with semiannual reports or as a single separate report. A performance test must be completed with the same time period to verify the recalculated flow value and to obtain the vent stream characteristics of heating value and E<sub>TOC</sub>. The performance test is subject to the requirements of §60.8 of the General Provisions. Unless the facility qualifies for an exemption under the low capacity exemption status in §60.660(c)(5), the facility must begin compliance with the requirements set forth in §60.662.

(6) Any change in equipment or process operation, as recorded under paragraph (j) of this section, that increases the design

production capacity above the low capacity exemption level in §60.660(c)(5) and the new capacity resulting from the change for the distillation process unit containing the affected facility. These must be reported as soon as possible after the change and no later than 180 days after the change. These reports may be submitted either in conjunction with semiannual reports or as a single separate report. A performance test must be completed within the same time period to obtain the vent stream flow rate, heating value, and  $E_{TOC}$ . The performance test is subject to the requirements of §60.8. The facility must begin compliance with the requirements set forth in §60.660(d) or §60.662. If the facility chooses to comply with §60.662, the facility may qualify for an exemption in §60.660(c)(4) or (6).

(7) Any recalculation of the TRE index value, as recorded under §60.665(h).

(m) The requirements of §60.665(l) remain in force until and unless EPA, in delegating enforcement authority to a State under section 111(c) of the Act, approves reporting requirements or an alternative means of compliance surveillance adopted by such State. In that event, affected sources within the State will be relieved of the obligation to comply with §60.665(l), provided that they comply with the requirements established by the State.

(n) Each owner or operator that seeks to demonstrate compliance with §60.660(c)(5) must submit to the Administrator an initial report detailing the design production capacity of the process unit.

(o) Each owner or operator that seeks to demonstrate compliance with §60.660(c)(6) must submit to the Administrator an initial report including a flow rate measurement using the test methods specified in §60.664.

(p) The Administrator will specify appropriate reporting and recordkeeping requirements where the owner or operator of an affected facility complies with the standards specified under §60.662 other than as provided under §60.663(a), (b), (c) and (d).

[55 FR 26922, June 29, 1990; 55 FR 36932, Sept. 7, 1990, as amended at 60 FR 58237, Nov. 27, 1995; 65 FR 61778, Oct. 17, 2000; 65 FR 78279, Dec. 14, 2000]

### § 60.666 Reconstruction.

For purposes of this subpart "fixed capital cost of the new components," as used in §60.15, includes the fixed capital cost of all depreciable components which are or will be replaced pursuant to all continuous programs of component replacement which are commenced within any 2-year period following December 30, 1983. For purposes of this paragraph, "commenced" means that an owner or operator has undertaken a continuous program of component replacement or that an owner or operator has entered into a contractual obligation to undertake and complete, within a reasonable time, a continuous program of component replacement.

### § 60.667 Chemicals affected by subpart NNN.

Chemical name	CAS No.*
Acetaldehyde	75-07-0
Acetaldol	107-89-1
Acetic acid	64-19-7
Acetic anhydride	108-24-7
Acetone	67-64-1
Acetone cyanohydrin	75-86-5
Acetylene	74-86-2
Acrylic acid	79-10-7
Acrylonitrile	107-13-1
Adipic acid	124-04-9
Adiponitrile	111-69-3
Alcohols, C-11 or lower, mixtures	
Alcohols, C-12 or higher, mixtures	
Allyl chloride	107-05-1
Amylene	513-35-9

Amylenes, mixed	
Aniline	62-53-3
Benzene	71-43-2
Benzenesulfonic acid	98-11-3
Benzenesulfonic acid C <sub>10-16</sub> -alkyl derivatives, sodium salts	68081-81-2
Benzoic acid, tech	65-85-0
Benzyl chloride	100-44-7
Biphenyl	92-52-4
Bisphenol A	80-05-7
Brometone	76-08-4
1,3-Butadiene	106-99-0
Butadiene and butene fractions	
n-Butane	106-97-8
1,4-Butanediol	110-63-4
Butanes, mixed	
1-Butene	106-98-9
2-Butene	25167-67-3
Butenes, mixed	
n-Butyl acetate	123-86-4
Butyl acrylate	141-32-2
n-Butyl alcohol	71-36-3
sec-Butyl alcohol	78-92-2
tert-Butyl alcohol	75-65-0
Butylbenzyl phthalate	85-68-7
Butylene glycol	107-88-0
tert-Butyl hydroperoxide	75-91-2
2-Butyne-1,4-diol	110-65-6
Butyraldehyde	123-72-8
Butyric anhydride	106-31-0
Caprolactam	105-60-2
Carbon disulfide	75-15-0
Carbon tetrabromide	558-13-4
Carbon tetrachloride	56-23-5
Chlorobenzene	108-90-7
2-Chloro-4-(ethylamino)-6-(isopropylamino)-s-triazine	1912-24-9
Chloroform	67-66-3
p-Chloronitrobenzene	100-00-5
Chloroprene	126-99-8

Citric acid	77-92-9
Crotonaldehyde	4170-30-0
Crotonic acid	3724-65-0
Cumene	98-82-8
Cumene hydroperoxide	80-15-9
Cyanuric chloride	108-77-0
Cyclohexane	110-82-7
Cyclohexane, oxidized	68512-15-2
Cyclohexanol	108-93-0
Cyclohexanone	108-94-1
Cyclohexanone oxime	100-64-1
Cyclohexene	110-83-8
1,3-Cyclopentadiene	542-92-7
Cyclopropane	75-19-4
Diacetone alcohol	123-42-2
Dibutanized aromatic concentrate	
1,4-Dichlorobutene	110-57-6
3,4-Dichloro-1-butene	64037-54-3
Dichlorodifluoromethane	75-71-8
Dichlorodimethylsilane	75-78-5
Dichlorofluoromethane	75-43-4
-Dichlorohydrin	96-23-1
Diethanolamine	111-42-2
Diethylbenzene	25340-17-4
Diethylene glycol	111-46-6
Di-n-heptyl-n-nonyl undecyl phthalate	85-68-7
Di-isodecyl phthalate	26761-40-0
Diisononyl phthalate	28553-12-0
Dimethylamine	124-40-3
Dimethyl terephthalate	120-61-6
2,4-Dinitrotoluene	121-14-2
2,4-(and 2,6)-dinitrotoluene	121-14-2
	606-20-2
Dioctyl phthalate	117-81-7
Dodecene	25378-22-7
Dodecylbenzene, non linear	
Dodecylbenzenesulfonic acid	27176-87-0
Dodecylbenzenesulfonic acid, sodium salt	25155-30-0
Epichlorohydrin	106-89-8

Ethanol	64-17-5
Ethanolamine	141-43-5
Ethyl acetate	141-78-6
Ethyl acrylate	140-88-5
Ethylbenzene	100-41-4
Ethyl chloride	75-00-3
Ethyl cyanide	107-12-0
Ethylene	74-85-1
Ethylene dibromide	106-93-4
Ethylene dichloride	107-06-2
Ethylene glycol	107-21-1
Ethylene glycol monobutyl	111-76-2
Ethylene glycol monoethyl ether	110-80-5
Ethylene glycol monoethyl ether acetate	111-15-9
Ethylene glycol monomethyl ether	109-86-4
Ethylene oxide	75-21-8
2-Ethylhexanal	26266-68-2
2-Ethylhexyl alcohol	104-76-7
(2-Ethylhexyl) amine	104-75-6
Ethylmethylbenzene	25550-14-5
6-Ethyl-1,2,3,4-tetrahydro 9,10-anthracenedione	15547-17-8
Formaldehyde	50-00-0
Glycerol	56-81-5
n-Heptane	142-82-5
Heptenes (mixed)	
Hexadecyl chloride	
Hexamethylene diamine	124-09-4
Hexamethylene diamine adipate	3323-53-3
Hexamethylenetetramine	100-97-0
Hexane	110-54-3
2-Hexenedinitrile	13042-02-9
3-Hexenedinitrile	1119-85-3
Hydrogen cyanide	74-90-8
Isobutane	75-28-5
Isobutanol	78-83-1
Isobutylene	115-11-7
Isobutyraldehyde	78-84-2
Isodecyl alcohol	25339-17-7
Isooctyl alcohol	26952-21-6

Isopentane	78-78-4
Isophthalic acid	121-91-5
Isoprene	78-79-5
Isopropanol	67-63-0
Ketene	463-51-4
Linear alcohols, ethoxylated, mixed	
Linear alcohols, ethoxylated, and sulfated, sodium salt, mixed	
Linear alcohols, sulfated, sodium salt, mixed	
Linear alkylbenzene	123-01-3
Magnesium acetate	142-72-3
Maleic anhydride	108-31-6
Melamine	108-78-1
Mesityl oxide	141-79-7
Methacrylonitrile	126-98-7
Methanol	67-56-1
Methylamine	74-89-5
ar-Methylbenzenediamine	25376-45-8
Methyl chloride	74-87-3
Methylene chloride	75-09-2
Methyl ethyl ketone	78-93-3
Methyl iodide	74-88-4
Methyl isobutyl ketone	108-10-1
Methyl methacrylate	80-62-6
2-Methylpentane	107-83-5
1-Methyl-2-pyrrolidone	872-50-4
Methyl tert-butyl ether	
Naphthalene	91-20-3
Nitrobenzene	98-95-3
1-Nonene	27215-95-8
Nonyl alcohol	143-08-8
Nonylphenol	25154-52-3
Nonylphenol, ethoxylated	9016-45-9
Octene	25377-83-7
Oil-soluble petroleum sulfonate, calcium salt	
Oil-soluble petroleum sulfonate, sodium salt	
Pentaerythritol	115-77-5
n-Pentane	109-66-0
3-Pentenenitrile	4635-87-4
Pentenes, mixed	109-67-1

Perchloroethylene	127-18-4
Phenol	108-95-2
1-Phenylethyl hydroperoxide	3071-32-7
Phenylpropane	103-65-1
Phosgene	75-44-5
Phthalic anhydride	85-44-9
Propane	74-98-6
Propionaldehyde	123-38-6
Propionic acid	79-09-4
Propyl alcohol	71-23-8
Propylene	115-07-1
Propylene chlorohydrin	78-89-7
Propylene glycol	57-55-6
Propylene oxide	75-56-9
Sodium cyanide	143-33-9
Sorbitol	50-70-4
Styrene	100-42-5
Terephthalic acid	100-21-0
1,1,2,2-Tetrachloroethane	79-34-5
Tetraethyl lead	78-00-2
Tetrahydrofuran	109-99-9
Tetra (methyl-ethyl) lead	
Tetramethyl lead	75-74-1
Toluene	108-88-3
Toluene-2,4-diamine	95-80-7
Toluene-2,4-(and, 2,6)-diisocyanate (80/20 mixture)	26471-62-5
Tribromomethane	75-25-2
1,1,1-Trichloroethane	71-55-6
1,1,2-Trichloroethane	79-00-5
Trichloroethylene	79-01-6
Trichlorofluoromethane	75-69-4
1,1,2-Trichloro-1,2,2-trifluoroethane	76-13-1
Triethanolamine	102-71-6
Triethylene glycol	112-27-6
Vinyl acetate	108-05-4
Vinyl chloride	75-01-4
Vinylidene chloride	75-35-4
m-Xylene	108-38-3
o-Xylene	95-47-6

p-Xylene	106-42-3
Xylenes (mixed)	1330-20-7
m-Xylenol	576-26-1

\*CAS numbers refer to the Chemical Abstracts Registry numbers assigned to specific chemicals, isomers, or mixtures of chemicals. Some isomers or mixtures that are covered by the standards do not have CAS numbers assigned to them. The standards apply to all of the chemicals listed, whether CAS numbers have been assigned or not.

[55 FR 26942, June 29, 1990, as amended at 60 FR 58237, 58238, Nov. 27, 1995]

### § 60.668 Delegation of authority.

(a) In delegating implementation and enforcement authority to a State under §111(c) of the Act, the authorities contained in paragraph (b) of this section shall be retained by the Administrator and not transferred to a State.

(b) Authorities which will not be delegated to States: §60.663(e).

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Appendix D—40 CFR 60 Subpart RRR: *Standards of Performance for Volatile Organic  
Compound Emissions From Synthetic Organic Chemical Manufacturing Industry (SOCMI)  
Reactor Processes*



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### **Title 40: Protection of Environment**

#### **PART 60—STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES**

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### **Subpart RRR—Standards of Performance for Volatile Organic Compound Emissions From Synthetic Organic Chemical Manufacturing Industry (SOCMI) Reactor Processes**

**Source:** 58 FR 45962, Aug. 31, 1993, unless otherwise noted.

#### **§ 60.700 Applicability and designation of affected facility.**

(a) The provisions of this subpart apply to each affected facility designated in paragraph (b) of this section that is part of a process unit that produces any of the chemicals listed in §60.707 as a product, co-product, by-product, or intermediate, except as provided in paragraph (c) of this section.

(b) The affected facility is any of the following for which construction, modification, or reconstruction commenced after June 29, 1990:

(1) Each reactor process not discharging its vent stream into a recovery system.

(2) Each combination of a reactor process and the recovery system into which its vent stream is discharged.

(3) Each combination of two or more reactor processes and the common recovery system into which their vent streams are discharged.

(c) Exemptions from the provisions of paragraph (a) of this section are as follows:

(1) Any reactor process that is designed and operated as a batch operation is not an affected facility.

(2) Each affected facility that has a total resource effectiveness (TRE) index value greater than 8.0 is exempt from all provisions of this subpart except for §§60.702(c); 60.704 (d), (e), and (f); and 60.705 (g), (l)(1), (l)(6), and (t).

(3) Each affected facility in a process unit with a total design capacity for all chemicals produced within that unit of less than 1 gigagram per year (1,100 tons per year) is exempt from all provisions of this subpart except for the recordkeeping and reporting requirements in §60.705 (i), (l)(5), and (n).

(4) Each affected facility operated with a vent stream flow rate less than 0.011 sc m/min is exempt from all provisions of this subpart except for the test method and procedure and the recordkeeping and reporting requirements in §60.704(g) and §70.705 (h), (l)(4), and (o).

(5) If the vent stream from an affected facility is routed to a distillation unit subject to subpart NNN and has no other releases to the air except for a pressure relief valve, the facility is exempt from all provisions of this subpart except for §60.705(r).

(6) Any reactor process operating as part of a process unit which produces beverage alcohols, or which uses, contains, and produces no VOC is not an affected facility.

(7) Any reactor process that is subject to the provisions of subpart D DD is not an affected facility.

(8) Each affected facility operated with a concentration of total organic compounds (TOC) (less methane and ethane) in the vent stream less than 300 ppm v as measured by Method 18 or a concentration of TOC in the vent stream less than 150 ppm v as measured by Method 25A is exempt from all provisions of this subpart except for the test method and procedure and the reporting and recordkeeping requirements in §60.704(h) and paragraphs (j), (l)(8), and (p) of §60.705.

(d) *Alternative means of compliance* —(1) *Option to comply with part 65.* Owners or operators of process vents that are subject to this subpart may choose to comply with the provisions of 40 CFR part 65, subpart D, to satisfy the requirements of §§60.702 through 60.705 and 60.708. The provisions of 40 CFR part 65 also satisfy the criteria of paragraphs (c)(2), (4), and (8) of this section. Other provisions applying to an owner or operator who chooses to comply with 40 CFR part 65 are provided in 40 CFR 65.1.

(2) *Part 60, subpart A.* Owners or operators who choose to comply with 40 CFR part 65, subpart D, must also comply with §§60.1, 60.2, 60.5, 60.6, 60.7(a)(1) and (4), 60.14, 60.15, and 60.16 for those process vents. All sections and paragraphs of subpart A of this part that are not mentioned in this paragraph (d)(2) do not apply to owners or operators of process vents complying with 40 CFR part 65, subpart D, except that provisions required to be met prior to implementing 40 CFR part 65 still apply. Owners and operators who choose to comply with 40 CFR part 65, subpart D, must comply with 40 CFR part 65, subpart A.

(3) *Compliance date.* Owners or operators who choose to comply with 40 CFR part 65, subpart D at initial startup shall comply with paragraphs (d)(1) and (2) of this section for each vent stream on and after the date on which the initial performance test is completed, but not later than 60 days after achieving the maximum production rate at which the affected facility will be operated, or 180 days after the initial startup, whichever date comes first.

(4) *Initial startup notification.* Each owner or operator subject to the provisions of this subpart that chooses to comply with 40 CFR part 65, subpart D, at initial startup shall notify the Administrator of the specific provisions of 40 CFR 65.63(a)(1), (2), or (3), with which the owner or operator has elected to comply. Notification shall be submitted with the notifications of initial startup required by 40 CFR 65.5(b).

(Note: The intent of these standards is to minimize emissions of VOC through the application of best demonstrated technology (BDT). The numerical emission limits in these standards are expressed in terms of TOC, measured as TOC less methane and ethane. This emission limit reflects the performance of BDT.)

[58 FR 45962, Aug. 31, 1993, as amended at 60 FR 58238, Nov. 27, 1995; 65 FR 78279, Dec. 14, 2000]

## § 60.701 Definitions.

As used in this subpart, all terms not defined here shall have the meaning given them in the Act and in subpart A of part 60, and the following terms shall have the specific meanings given them.

*Batch operation* means any noncontinuous reactor process that is not characterized by steady-state conditions and in which reactants are not added and products are not removed simultaneously.

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

*By compound* means by individual stream components, not carbon equivalents.

*Car-seal* means a seal that is placed on a device that is used to change the position of a valve (e.g., from opened to closed) in such a way that the position of the valve cannot be changed without breaking the seal.

*Combustion device* means an individual unit of equipment, such as an incinerator, flare, boiler, or process heater, used for combustion of a vent stream discharged from the process vent.

*Continuous recorder* means a data recording device recording an instantaneous data value at least once every 15 minutes.

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

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

*Halogenated vent stream* means any vent stream determined to have a total concentration (by volume) of compounds containing halogens of 20 ppm v (by compound) or greater.

*Incinerator* means an enclosed combustion device that is used for destroying organic compounds. If there is energy recovery, the energy recovery section and the combustion chambers are not of integral design. That is, the energy recovery section and the combustion section are not physically formed into one manufactured or assembled unit but are joined by ducts or connections carrying flue gas.

*Primary fuel* means the fuel fired through a burner or a number of similar burners. The primary fuel provides the principal heat input to the device, and the amount of fuel is sufficient to sustain operation without the addition of other fuels.

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

*Process unit* means equipment assembled and connected by pipes or ducts to produce, as intermediates or final products, one or more of the chemicals in §60.707. A process unit can operate independently if supplied with sufficient feed or raw materials and sufficient product storage facilities.

*Product* means any compound or chemical listed in §60.707 which is produced for sale as a final product as that chemical, or for use in the production of other chemicals or compounds. By-products, co-products, and intermediates are considered to be products.

*Reactor processes* are unit operations in which one or more chemicals, or reactants other than air, are combined or decomposed in such a way that their molecular structures are altered and one or more new organic compounds are formed.

*Recovery device* means an individual unit of equipment, such as an absorber, carbon adsorber, or condenser, capable of and used for the purpose of recovering chemicals for use, reuse, or sale.

*Recovery system* means an individual recovery device or series of such devices applied to the same vent stream.

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

*Secondary fuel* means a fuel fired through a burner other than a primary fuel burner. The secondary fuel may provide supplementary heat in addition to the heat provided by the primary fuel.

*Total organic compounds or TOC* means those compounds measured according to the procedures in §60.704(b)(4). For the purposes of measuring molar composition as required in §60.704(d)(2)(i) and §60.704(d)(2)(ii), hourly emission rate as required in §60.704(d)(5) and §60.704(e), and TOC concentration as required in §60.705(b)(4) and §60.705(f)(4), those compounds which the Administrator has determined do not contribute appreciably to the formation of ozone are to be excluded.

*Total resource effectiveness or TRE index value* means a measure of the supplemental total resource requirement per unit reduction of TOC associated with a vent stream from an affected reactor process facility, based on vent stream flow rate, emission rate of TOC, net heating value, and corrosion properties (whether or not the vent stream contains halogenated compounds), as quantified by the equation given under §60.704(e).

*Vent stream* means any gas stream discharged directly from a reactor process to the atmosphere or indirectly to the atmosphere after diversion through other process equipment. The vent stream excludes relief valve discharges and equipment leaks.

## § 60.702 Standards.

Each owner or operator of any affected facility shall comply with paragraph (a), (b), or (c) of this section for each vent stream on and after the date on which the initial performance test required by §60.8 and §60.704 is completed, but not later than 60 days after achieving the maximum production rate at which the affected facility will be operated, or 180 days after the initial start-up, whichever date comes first. Each owner or operator shall either:

(a) Reduce emissions of TOC (less methane and ethane) by 98 weight-percent, or to a TOC (less methane and ethane) concentration of 20 ppm v, on a dry basis corrected to 3 percent oxygen, whichever is less stringent. If a boiler or process heater is used to comply with this paragraph, then the vent stream shall be introduced into the flame zone of the boiler or process heater; or

(b) Combust the emissions in a flare that meets the requirements of §60.18; or

(c) Maintain a TRE index value greater than 1.0 without use of a VOC emission control device.

## § 60.703 Monitoring of emissions and operations.

(a) The owner or operator of an affected facility that uses an incinerator to seek to comply with the TOC emission limit specified under §60.702(a) shall install, calibrate, maintain, and operate according to manufacturer's specifications the following equipment:

(1) A temperature monitoring device equipped with a continuous recorder and having an accuracy of  $\pm 1$  percent of the temperature being monitored expressed in degrees Celsius or  $\pm 0.5$  °C, whichever is greater.

(i) Where an incinerator other than a catalytic incinerator is used, a temperature monitoring device shall be installed in the firebox or in the ductwork immediately downstream of the firebox in a position before any substantial heat exchange is encountered.

(ii) Where a catalytic incinerator is used, temperature monitoring devices shall be installed in the gas stream immediately before and after the catalyst bed.

(2) A flow indicator that provides a record of vent stream flow diverted from being routed to the incinerator at least once every 15 minutes for each affected facility, except as provided in paragraph (a)(2)(ii) of this section.

(i) The flow indicator shall be installed at the entrance to any bypass line that could divert the vent stream from being routed to the incinerator, resulting in its emission to the atmosphere.

(ii) Where the bypass line valve is secured in the closed position with a car-seal or a lock-and-key type configuration, a flow indicator is not required. A visual inspection of the seal or closure mechanism shall be performed at least once every month to ensure that the valve is maintained in the closed position and the vent stream is not diverted through the bypass line.

(b) The owner or operator of an affected facility that uses a flare to seek to comply with §60.702(b) shall install, calibrate, maintain, and operate according to manufacturer's specifications the following equipment:

(1) A heat sensing device, such as an ultraviolet beam sensor or thermocouple, at the pilot light to indicate the continuous presence of a flame.

(2) A flow indicator that provides a record of vent stream flow diverted from being routed to the flare at least once every 15 minutes for each affected facility, except as provided in paragraph (b)(2)(ii) of this section.

(i) The flow indicator shall be installed at the entrance to any bypass line that could divert the vent stream from being routed to the flare, resulting in its emission to the atmosphere.

(ii) Where the bypass line valve is secured in the closed position with a car-seal or a lock-and-key type configuration, a flow indicator is not required. A visual inspection of the seal or closure mechanism shall be performed at least once every month to ensure that the valve is maintained in the closed position and the vent stream is not diverted through the bypass line.

(c) The owner or operator of an affected facility that uses a boiler or process heater to seek to comply with §60.702(a) shall install, calibrate, maintain and operate according to the manufacturer's specifications the following equipment:

(1) A flow indicator that provides a record of vent stream flow diverted from being routed to the boiler or process heater at least once every 15 minutes for each affected facility, except as provided in paragraph (c)(1)(ii) of this section.

(i) The flow indicator shall be installed at the entrance to any bypass line that could divert the vent stream from being routed to the boiler or process heater, resulting in its emission to the atmosphere.

(ii) Where the bypass line valve is secured in the closed position with a car-seal or a lock-and-key type configuration, a flow indicator is not required. A visual inspection of the seal or closure mechanism shall be performed at least once every month to ensure that the valve is maintained in the closed position and the vent stream is not diverted through the bypass line.

(2) A temperature monitoring device in the firebox equipped with a continuous recorder and having an accuracy of  $\pm 1$  percent of the temperature being monitored expressed in degrees Celsius or  $\pm 0.5$  °C, whichever is greater, for boilers or process heaters of less than 44 MW (150 million Btu/hr) design heat input capacity. Any vent stream introduced with primary fuel into a boiler or process heater is exempt from this requirement.

(d) The owner or operator of an affected facility that seeks to demonstrate compliance with the TRE index value limit specified under §60.702(c) shall install, calibrate, maintain, and operate according to manufacturer's specifications the following equipment, unless alternative monitoring procedures or requirements are approved for that facility by the Administrator:

(1) Where an absorber is the final recovery device in the recovery system:

(i) A scrubbing liquid temperature monitoring device having an accuracy of  $\pm 1$  percent of the temperature being monitored expressed in degrees Celsius or  $\pm 0.5$  °C, whichever is greater, and a specific gravity monitoring device having an accuracy of  $\pm 0.02$  specific gravity units, each equipped with a continuous recorder; or

(ii) An organic monitoring device used to indicate the concentration level of organic compounds exiting the recovery device based on a detection principle such as infra-red, photoionization, or thermal conductivity, each equipped with a continuous recorder.

(2) Where a condenser is the final recovery device in the recovery system:

(i) A condenser exit (product side) temperature monitoring device equipped with a continuous recorder and having an accuracy of  $\pm 1$  percent of the temperature being monitored expressed in degrees Celsius or  $\pm 0.5$  °C, whichever is greater; or

(ii) An organic monitoring device used to indicate the concentration level of organic compounds exiting the recovery device based on a detection principle such as infra-red, photoionization, or thermal conductivity, each equipped with a continuous recorder.

(3) Where a carbon adsorber is the final recovery device unit in the recovery system:

(i) An integrating steam flow monitoring device having an accuracy of  $\pm 10$  percent, and a carbon bed temperature monitoring device having an accuracy of  $\pm 1$  percent of the temperature being monitored expressed in degrees Celsius or  $\pm 0.5$  °C, whichever is greater, both equipped with a continuous recorder; or

(ii) An organic monitoring device used to indicate the concentration level of organic compounds exiting the recovery device based on a detection principle such as infra-red, photoionization, or thermal conductivity, each equipped with a continuous recorder.

(e) An owner or operator of an affected facility seeking to demonstrate compliance with the standards specified under §60.702 with a control device other than an incinerator, boiler, process heater, or flare; or a recovery device other than an absorber, condenser, or carbon adsorber, shall provide to the Administrator information describing the operation of the control device or recovery device and the process parameter(s) which would indicate proper operation and maintenance of the device. The Administrator may request further information and will specify appropriate monitoring procedures or requirements.

### § 60.704 Test methods and procedures.

(a) For the purpose of demonstrating compliance with §60.702, all affected facilities shall be run at full operating conditions and flow rates during any performance test.

(b) The following methods in appendix A to this part, except as provided under §60.8(b), shall be used as reference methods to determine compliance with the emission limit or percent reduction efficiency specified under §60.702(a).

(1) Method 1 or 1A, as appropriate, for selection of the sampling sites. The control device inlet sampling site for determination of vent stream molar composition or TOC (less methane and ethane) reduction efficiency shall be prior to the inlet of the control device and after the recovery system.

(2) Method 2, 2A, 2C, or 2D, as appropriate, for determination of the gas volumetric flow rates.

(3) The emission rate correction factor, integrated sampling and analysis procedure of Method 3B shall be used to determine the oxygen concentration (%O<sub>2d</sub>) for the purposes of determining compliance with the 20 ppmv limit. The sampling site shall be the same as that of the TOC samples, and the samples shall be taken during the same time that the TOC samples are taken. The TOC concentration corrected to 3 percent O<sub>2</sub>(C<sub>c</sub>) shall be computed using the following equation:

$$C_c = C_{TOC} \frac{17.9}{20.9 - \%O_{2d}}$$

where:

C<sub>c</sub>=Concentration of TOC corrected to 3 percent O<sub>2</sub>, dry basis, ppm by volume.

C<sub>TOC</sub>=Concentration of TOC (minus methane and ethane), dry basis, ppm by volume.

%O<sub>2d</sub>=Concentration of O<sub>2</sub>, dry basis, percent by volume.

(4) Method 18 to determine the concentration of TOC in the control device outlet and the concentration of TOC in the inlet when the reduction efficiency of the control device is to be determined.

(i) The minimum sampling time for each run shall be 1 hour in which either an integrated sample or four grab samples shall be taken. If grab sampling is used, then the samples shall be taken at approximately 15-minute intervals.

(ii) The emission reduction (R) of TOC (minus methane and ethane) shall be determined using the following equation:

$$R = \frac{E_i - E_o}{E_i} \times 100$$

where:

R=Emission reduction, percent by weight.

$E_i$ =Mass rate of TOC entering the control device, kg TOC/hr.

$E_o$ =Mass rate of TOC discharged to the atmosphere, kg TOC/hr.

(iii) The mass rates of TOC ( $E_i$ ,  $E_o$ ) shall be computed using the following equations:

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

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

where:

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

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

$Q_i$ ,  $Q_o$ =Flow rate of gas stream at the inlet and outlet of the control device, respectively, dscm/min (dscf/hr).

$K_2$ =Constant,  $2.494 \times 10^{-6}$  (l/ppm) (g-mole/scm) (kg/g) (min/hr), where standard temperature for (g-mole/scm) is 20 °C.

(iv) The TOC concentration ( $C_{TOC}$ ) is the sum of the individual components and shall be computed for each run using the following equation:

$$C_{TOC} = \sum_{j=1}^n C_j$$

where:

$C_{TOC}$ =Concentration of TOC (minus methane and ethane), dry basis, ppm by volume.



$C_j$ =Concentration of sample components "j", dry basis, ppm by volume.

n=Number of components in the sample.

(5) The requirement for an initial performance test is waived, in accordance with §60.8(b), for the following:

(i) When a boiler or process heater with a design heat input capacity of 44 MW (150 million Btu/hour) or greater is used to seek compliance with §60.702(a).

(ii) When a vent stream is introduced into a boiler or process heater with the primary fuel.

(iii) The Administrator reserves the option to require testing at such other times as may be required, as provided for in section 114 of the Act.

(6) For purposes of complying with the 98 weight-percent reduction in §60.702(a), if the vent stream entering a boiler or process heater with a design capacity less than 44 MW (150 million Btu/hour) is introduced with the combustion air or as secondary fuel, the weight-percent reduction of TOC (minus methane and ethane) across the combustion device shall be determined by comparing the TOC (minus methane and ethane) in all combusted vent streams, primary fuels, and secondary fuels with the TOC (minus methane and ethane) exiting the combustion device.

(c) When a flare is used to seek to comply with §60.702(b), the flare shall comply with the requirements of §60.18.

(d) The following test methods in appendix A to this part, except as provided under §60.8(b), shall be used for determining the net heating value of the gas combusted to determine compliance under §60.702(b) and for determining the process vent stream TRE index value to determine compliance under §60.700(c)(2) and §60.702(c).

(1)(i) Method 1 or 1A, as appropriate, for selection of the sampling site. The sampling site for the vent stream flow rate and molar composition determination prescribed in §60.704(d)(2) and (d)(3) shall be, except for the situations outlined in paragraph (d)(1)(ii) of this section, prior to the inlet of any control device, prior to any postreactor dilution of the stream with air, and prior to any postreactor introduction of halogenated compounds into the process vent stream. No traverse site selection method is needed for vents smaller than 4 inches in diameter.

(ii) If any gas stream other than the reactor vent stream is normally conducted through the final recovery device:

(A) The sampling site for vent stream flow rate and molar composition shall be prior to the final recovery device and prior to the point at which any nonreactor stream or stream from a nonaffected reactor process is introduced.

(B) The efficiency of the final recovery device is determined by measuring the TOC concentration using Method 18 at the inlet to the final recovery device after the introduction of any vent stream and at the outlet of the final recovery device.

(C) This efficiency of the final recovery device shall be applied to the TOC concentration measured prior to the final recovery device and prior to the introduction of any nonreactor stream or stream from a nonaffected reactor process to determine the concentration of TOC in the reactor process vent stream from the final recovery device. This concentration of TOC is then used to perform the calculations outlined in §60.704(d)(4) and (5).

(2) The molar composition of the process vent stream shall be determined as follows:

(i) Method 18 to measure the concentration of TOC including those containing halogens.

(ii) ASTM D1946-77 or 90 (Reapproved 1994) (incorporation by reference as specified in §60.17 of this part) to measure the concentration of carbon monoxide and hydrogen.

(iii) Method 4 to measure the content of water vapor.

(3) The volumetric flow rate shall be determined using Method 2, 2A, 2C, or 2D, as appropriate.

(4) The net heating value of the vent stream shall be calculated using the following equation:

$$H_T = K_1 \sum_{j=1}^n C_j H_j - B_w$$

where:

$H_T$  = Net heating value of the sample, MJ/scm, where the net enthalpy per mole of vent stream is based on combustion at 25 °C and 760 mm Hg, but the standard temperature for determining the volume corresponding to one mole is 20 °C, as in the definition of  $Q_s$  (vent stream flow rate).

$K_1$  = Constant,  $1.740 \times 10^{-7}$  (l/ppm) (g-mole/scm) (MJ/kcal), where standard temperature for (g-mole/scm) is 20 °C.

$C_j$  = Concentration on a dry basis of compound j in ppm, as measured for organics by Method 18 and measured for hydrogen and carbon monoxide by ASTM D1946–77 or 90 (Reapproved 1994) (incorporation by reference as specified in §60.17 of this part) as indicated in §60.704 (d)(2).

$H_j$  = Net heat of combustion of compound j, kcal/g-mole, based on combustion at 25 °C and 760 mm Hg. The heats of combustion of vent stream components would be required to be determined using ASTM D2382–76 or 88 or D4809–95 (incorporation by reference as specified in §60.17 of this part) if published values are not available or cannot be calculated.

$B_{ws}$  = Water vapor content of the vent stream, proportion by volume.

(5) The emission rate of TOC in the vent stream shall be calculated using the following equation:

$$E_{TOC} = K_2 \sum_{j=1}^n C_j M_j Q_s$$

where:

$E_{TOC}$  = Emission rate of TOC in the sample, kg/hr.

$K_2$  = Constant,  $2.494 \times 10^{-6}$  (l/ppm) (g-mole/scm) (kg/g) (min/hr), where standard temperature for (g-mole/scm) is 20 °C.

$C_j$  = Concentration on a dry basis of compound j in ppm as measured by Method 18 as indicated in §60.704(d)(2).

$M_j$  = Molecular weight of sample j, g/g-mole.

$Q_s$  = Vent stream flow rate (dscm/min) at a temperature of 20 °C.

(6) The total vent stream concentration (by volume) of compounds containing halogens (ppm v, by compound) shall be summed from the individual concentrations of compounds containing halogens which were measured by Method 18.

(e) For purposes of complying with §60.700(c)(2) and §60.702(c), the owner or operator of a facility affected by this subpart shall calculate the TRE index value of the vent stream using the equation for incineration in paragraph (e)(1) of this section for halogenated vent streams. The owner or operator of an affected facility with a nonhalogenated vent stream shall determine the TRE index value by calculating values using both the incinerator equation in (e)(1) of this section and the flare equation in (e)(2) of this section and selecting the lower of the two values.

(1) The equation for calculating the TRE index value of a vent stream controlled by an incinerator is as follows:

$$TRE = \frac{1}{E_{TOC}} \left[ a + b(Q_s)^{0.88} + c(Q_s) + d(Q_s)(H_T) + e(Q_s)^{0.88}(H_T)^{0.88} + f(Y_s)^{0.5} \right]$$

(i) Where for a vent stream flow rate (scm/min) at a standard temperature of 20 °C that is greater than or equal to 14.2 scm /min:

TRE=TRE index value.

Q<sub>s</sub>=Vent stream flow rate (scm/min) at a standard temperature of 20 °C.

H<sub>T</sub>=Vent stream net heating value (MJ/scm), where the net enthalpy per mole of vent stream is based on combustion at 25 °C and 760 mm Hg, but the standard temperature for determining the volume corresponding to one mole is 20 °C as in the definition of Q<sub>s</sub>.

Y<sub>s</sub>=Q<sub>s</sub> for all vent stream categories listed in table 1 except for Category E vent streams where Y<sub>s</sub>=(Q<sub>s</sub>)(H<sub>T</sub>)/3.6.

E<sub>TOC</sub>=Hourly emissions of TOC reported in kg/hr.

a, b, c, d, e, and f are coefficients. The set of coefficients that apply to a vent stream can be obtained from table 1.

Table 1—Total Resource Effectiveness Coefficients for Vent Streams Controlled by an Incinerator Subject to the New Source Performance Standards for Reactor Processes

	a	b	c	d	e	f
<b>DESIGN CATEGORY A1. FOR HALOGENATED PROCESS VENT STREAMS, IF 0≤NET HEATING VALUE (MJ/scm)≤3.5: Q<sub>s</sub> = Vent Stream Flow Rate (scm/min)</b>						
14.2≤Q <sub>s</sub> ≤18.8	19.18370	0.27580	0.75762	-0.13064	0	0.01025
18.8<Q <sub>s</sub> ≤699	20.00563	0.27580	0.30387	-0.13064	0	0.01025
699<Q <sub>s</sub> ≤1,400	39.87022	0.29973	0.30387	-0.13064	0	0.01449
1,400<Q <sub>s</sub> ≤2,100	59.73481	0.31467	0.30387	-0.13064	0	0.01775
2,100<Q <sub>s</sub> ≤2,800	79.59941	0.32572	0.30387	-0.13064	0	0.02049
2,800<Q <sub>s</sub> ≤3,500	99.46400	0.33456	0.30387	-0.13064	0	0.02291
<b>DESIGN CATEGORY A2. FOR HALOGENATED PROCESS VENT STREAMS, IF NET HEATING VALUE (MJ/scm)&gt;3.5: Q<sub>s</sub> = Vent Stream Flow Rate (scm/min)</b>						
14.2<Q <sub>s</sub> ≤18.8	18.84466	0.26742	-0.20044	0	0	0.01025
18.8<Q <sub>s</sub> ≤699	19.66658	0.26742	-0.25332	0	0	0.01025
699<Q <sub>s</sub> ≤1,400	39.19213	0.29062	-0.25332	0	0	0.01449
1,400<Q <sub>s</sub> ≤2,100	58.71768	0.30511	-0.25332	0	0	0.01775
2,100<Q <sub>s</sub> ≤2,800	78.24323	0.31582	-0.25332	0	0	0.02049

2,800<Q <sub>s</sub> ≤3,500	97.76879	0.32439	-0.25332	0	0	0.02291
DESIGN CATEGORY B. FOR NONHALOGENATED PROCESS VENT STREAMS, IF 0≤NET HEATING VALUE (MJ/scm)≤0.48: Q <sub>s</sub> = Vent Stream						
<i>Flow Rate (scm/min)</i>						
14.2≤Q <sub>s</sub> ≤1,340	8.54245	0.10555	0.09030	-0.17109	0	0.01025
1,340<Q <sub>s</sub> ≤2,690	16.94386	0.11470	0.09030	-0.17109	0	0.01449
2,690<Q <sub>s</sub> ≤4,040	25.34528	0.12042	0.09030	-0.17109	0	0.01775
DESIGN CATEGORY C. FOR NONHALOGENATED PROCESS VENT STREAMS, IF 0.48<NET HEATING VALUE (MJ/scm)≤1.9: Q <sub>s</sub> = Vent Stream						
<i>Flow Rate (scm/min)</i>						
14.2≤Q <sub>s</sub> ≤1,340	9.25233	0.06105	0.31937	-0.16181	0	0.01025
1,340<Q <sub>s</sub> ≤2,690	18.36363	0.06635	0.31937	-0.16181	0	0.01449
2,690<Q <sub>s</sub> ≤4,040	27.47492	0.06965	0.31937	-0.16181	0	0.01775
DESIGN CATEGORY D. FOR NONHALOGENATED PROCESS VENT STREAMS, IF 1.9<NET HEATING VALUE (MJ/scm)≤3.6: Q <sub>s</sub> = Vent Stream						
<i>Flow Rate (scm/min)</i>						
14.2≤Q <sub>s</sub> ≤1,180	6.67868	0.06943	0.02582	0	0	0.01025
1,180<Q <sub>s</sub> ≤2,370	13.21633	0.07546	0.02582	0	0	0.01449
2,370<Q <sub>s</sub> ≤3,550	19.75398	0.07922	0.02582	0	0	0.01755
DESIGN CATEGORY E. FOR NONHALOGENATED PROCESS VENT STREAMS, IF NET HEATING VALUE (MJ/scm)>3.6: Y <sub>s</sub> = Dilution Flow Rate						
<i>(scm/min)=(Q<sub>s</sub>) (H<sub>T</sub>)/3.6</i>						
14.2≤Y <sub>s</sub> ≤1,180	6.67868	0	0	-0.00707	0.02220	0.01025
1,180<Y <sub>s</sub> ≤2,370	13.21633	0	0	-0.00707	0.02412	0.01449
2,370<Y <sub>s</sub> ≤3,550	19.75398	0	0	-0.00707	0.02533	0.01755

(ii) For a vent stream flow rate (scm/min) at a standard temperature of 20 °C that is less than 14.2 scm/min:

TRE=TRE index value.

Q<sub>s</sub>=14.2 scm/min.

H<sub>T</sub>=(FLOW)(HVAL)/14.2

where the following inputs are used:

FLOW=Vent stream flow rate (scm/min), at a standard temperature of 20 °C.

HVAL=Vent stream net heating value (MJ/scm), where the net enthalpy per mole of vent

stream is based on combustion at 25 °C and 760 mm Hg, but the standard temperature for determining the volume corresponding to one mole is 20 °C as in definition of Q<sub>s</sub>.

Y<sub>s</sub>=14.2 scm/min for all vent streams except for Category E vent streams, where Y<sub>s</sub>=(14.2)(H<sub>T</sub>)/3.6.

E<sub>TOC</sub>=Hourly emissions of TOC reported in kg/hr.

a, b, c, d, e, and f are coefficients. The set of coefficients that apply to a vent stream can be obtained from table 1.

(2) The equation for calculating the TRE index value of a vent stream controlled by a flare is as follows:

$$TRE = \frac{1}{E_{TOC}} \left[ a(Q_s) + b(Q_s)^{0.8} + c(Q_s)(H_T) + d(E_{TOC}) + e \right]$$

where:

TRE=TRE index value.

E<sub>TOC</sub>=Hourly emission rate of TOC reported in kg/hr.

Q<sub>s</sub>=Vent stream flow rate (scm/min) at a standard temperature of 20 °C.

H<sub>T</sub>=Vent stream net heating value (MJ/scm) where the net enthalpy per mole of offgas is based on combustion at 25 °C and 760 mm Hg, but the standard temperature for determining the volume corresponding to one mole is 20 °C as in the definition of Q<sub>s</sub>.

a, b, c, d, and e are coefficients. The set of coefficients that apply to a vent stream can be obtained from table 2.

**Table 2—Total Resource Effectiveness Coefficients for Vent Streams Controlled by a Flare Subject to the New Source Performance Standards for Reactor Processes**

	a	b	c	d	e
H <sub>T</sub> <11.2 MJ/scm	2.25	0.288	-0.193	-0.0051	2.08
H <sub>T</sub> ≥11.2 MJ/scm	0.309	0.0619	-0.0043	-0.0034	2.08

(f) Each owner or operator of an affected facility seeking to comply with §60.700(c)(2) or §60.702(c) shall recalculate the TRE index value for that affected facility whenever process changes are made. Examples of process changes include changes in production capacity, feedstock type, or catalyst type, or whenever there is replacement, removal, or addition of recovery equipment. The TRE index value shall be recalculated based on test data, or on best engineering estimates of the effects of the change on the recovery system.

(1) Where the recalculated TRE index value is less than or equal to 1.0, the owner or operator shall notify the Administrator within 1 week of the recalculation and shall conduct a performance test according to the methods and procedures required by §60.704 in order to determine compliance with §60.702 (a) or (b). Performance tests must be conducted as soon as possible after the process change but no later than 180 days from the time of the process change.

(2) Where the recalculated TRE index value is less than or equal to 8.0 but greater than 1.0, the owner or operator shall conduct a performance test in accordance with §60.8 and §60.704 and shall comply with §60.703, §60.704 and § 60.705. Performance tests must be conducted as soon as possible after the process change but no later than 180 days from the time of the process change.

(g) Any owner or operator subject to the provisions of this subpart seeking to demonstrate compliance with §60.700(c)(4) shall use

Method 2, 2A, 2C, or 2D of appendix A to 40 CFR part 60, as appropriate, for determination of volumetric flow rate.

(h) Each owner or operator seeking to demonstrate that a reactor process vent stream has a TOC concentration for compliance with the low concentration exemption in §60.700(c)(8) shall conduct an initial test to measure TOC concentration.

(1) The sampling site shall be selected as specified in paragraph (d)(1)(i) of this section.

(2) Method 18 or Method 25A of part 60, appendix A shall be used to measure concentration.

(3) Where Method 18 is used to qualify for the low concentration exclusion in §60.700(c)(8), the procedures in §60.704(b)(4)(i) and (iv) shall be used to measure TOC concentration, and the procedures of §60.704(b)(3) shall be used to correct the TOC concentration to 3 percent oxygen. To qualify for the exclusion, the results must demonstrate that the concentration of TOC, corrected to 3 percent oxygen, is below 300 ppm by volume.

(4) Where Method 25A is used, the following procedures shall be used to calculate ppm by volume TOC concentration, corrected to 3 percent oxygen:

(i) Method 25A shall be used only if a single organic compound is greater than 50 percent of total TOC, by volume, in the reactor process vent stream. This compound shall be the principal organic compound.

(ii) The principal organic compound may be determined by either process knowledge or test data collected using an appropriate EPA Reference Method. Examples of information that could constitute process knowledge include calculations based on material balances, process stoichiometry, or previous test results provided the results are still relevant to the current reactor process vent stream conditions.

(iii) The principal organic compound shall be used as the calibration gas for Method 25A.

(iv) The span value for Method 25A shall be 300 ppmv.

(v) Use of Method 25A is acceptable if the response from the high-level calibration gas is at least 20 times the standard deviation of the response from the zero calibration gas when the instrument is zeroed on the most sensitive scale.

(vi) The owner or operator shall demonstrate that the concentration of TOC including methane and ethane measured by Method 25A, corrected to 3 percent oxygen, is below 150 ppm by volume to qualify for the low concentration exclusion in §60.700(c)(8).

(vii) The concentration of TOC shall be corrected to 3 percent oxygen using the procedures and equation in paragraph (b)(3) of this section.

[58 FR 45962, Aug. 31, 1993, as amended at 60 FR 58238, Nov. 27, 1995; 65 FR 61778, Oct. 17, 2000]

## § 60.705 Reporting and recordkeeping requirements.

(a) Each owner or operator subject to §60.702 shall notify the Administrator of the specific provisions of §60.702 (§60.702(a), (b), or (c)) with which the owner or operator has elected to comply. Notification shall be submitted with the notification of initial start-up required by §60.7(a)(3). If an owner or operator elects at a later date to use an alternative provision of §60.702 with which he or she will comply, then the Administrator shall be notified by the owner or operator 90 days before implementing a change and, upon implementing the change, a performance test shall be performed as specified by §60.704 no later than 180 days from initial start-up.

(b) Each owner or operator subject to the provisions of this subpart shall keep an up-to-date, readily accessible record of the following data measured during each performance test, and also include the following data in the report of the initial performance test required under §60.8. Where a boiler or process heater with a design heat input capacity of 44 MW (150 million Btu/hour) or greater is used or where the reactor process vent stream is introduced as the primary fuel to any size boiler or process heater to comply with §60.702(a), a report containing performance test data need not be submitted, but a report containing the information in §60.705(b)(2)(i) is required. The same data specified in this section shall be submitted in the reports of all subsequently required performance tests where either the emission control efficiency of a combustion device, outlet concentration of TOC, or the TRE index value of a vent stream from a recovery system is determined.

(1) Where an owner or operator subject to the provisions of this subpart seeks to demonstrate compliance with §60.702(a) through use of either a thermal or catalytic incinerator:

(i) The average firebox temperature of the incinerator (or the average temperature upstream and downstream of the catalyst bed for a catalytic incinerator), measured at least every 15 minutes and averaged over the same time period of the performance testing, and

(ii) The percent reduction of TOC determined as specified in §60.704(b) achieved by the incinerator, or the concentration of TOC (ppmv, by compound) determined as specified in §60.704(b) at the outlet of the control device on a dry basis corrected to 3 percent oxygen.

(2) Where an owner or operator subject to the provisions of this subpart seeks to demonstrate compliance with §60.702(a) through use of a boiler or process heater:

(i) A description of the location at which the vent stream is introduced into the boiler or process heater, and

(ii) The average combustion temperature of the boiler or process heater with a design heat input capacity of less than 44 MW (150 million Btu/hr) measured at least every 15 minutes and averaged over the same time period of the performance testing.

(3) Where an owner or operator subject to the provisions of this subpart seeks to demonstrate compliance with §60.702(b) through use of a smokeless flare, flare design (i.e., steam-assisted, air-assisted or nonassisted), all visible emission readings, heat content determinations, flow rate measurements, and exit velocity determinations made during the performance test, continuous records of the flare pilot flame monitoring, and records of all periods of operations during which the pilot flame is absent.

(4) Where an owner or operator subject to the provisions of this subpart seeks to demonstrate compliance with §60.702(c):

(i) Where an absorber is the final recovery device in the recovery system, the exit specific gravity (or alternative parameter which is a measure of the degree of absorbing liquid saturation, if approved by the Administrator), and average exit temperature, of the absorbing liquid measured at least every 15 minutes and averaged over the same time period of the performance testing (both measured while the vent stream is normally routed and constituted); or

(ii) Where a condenser is the final recovery device in the recovery system, the average exit (product side) temperature measured at least every 15 minutes and averaged over the same time period of the performance testing while the vent stream is routed and constituted normally; or

(iii) Where a carbon adsorber is the final recovery device in the recovery system, the total steam mass flow measured at least every 15 minutes and averaged over the same time period of the performance test (full carbon bed cycle), temperature of the carbon bed after regeneration [and within 15 minutes of completion of any cooling cycle(s)], and duration of the carbon bed steaming cycle (all measured while the vent stream is routed and constituted normally); or

(iv) As an alternative to §60.705(b)(4) (i), (ii) or (iii), the concentration level or reading indicated by the organics monitoring device at the outlet of the absorber, condenser, or carbon adsorber, measured at least every 15 minutes and averaged over the same time period of the performance testing while the vent stream is normally routed and constituted.

(v) All measurements and calculations performed to determine the TRE index value of the vent stream.

(c) Each owner or operator subject to the provisions of this subpart shall keep up-to-date, readily accessible continuous records of the equipment operating parameters specified to be monitored under §60.703(a) and (c) as well as up-to-date, readily accessible records of periods of operation during which the parameter boundaries established during the most recent performance test are exceeded. The Administrator may at any time require a report of these data. Where a combustion device is used to comply with §60.702(a), periods of operation during which the parameter boundaries established during the most recent performance tests are exceeded are defined as follows:

(1) For thermal incinerators, all 3-hour periods of operation during which the average combustion temperature was more than 28 °C (50 °F) below the average combustion temperature during the most recent performance test at which compliance with §60.702(a) was determined.

(2) For catalytic incinerators, all 3-hour periods of operation during which the average temperature of the vent stream immediately before the catalyst bed is more than 28 °C (50 °F) below the average temperature of the vent stream during the most recent performance test at which compliance with §60.702(a) was determined. The owner or operator also shall record all 3-hour periods of operation during which the average temperature difference across the catalyst bed is less than 80 percent of the average temperature difference of the bed during the most recent performance test at which compliance with §60.702(a) was determined.

(3) All 3-hour periods of operation during which the average combustion temperature was more than 28 °C (50 °F) below the average combustion temperature during the most recent performance test at which compliance with §60.702(a) was determined for boilers or process heaters with a design heat input capacity of less than 44 MW (150 million Btu/hr) where the vent stream is introduced with the combustion air or as a secondary fuel.

(4) For boilers or process heaters, whenever there is a change in the location at which the vent stream is introduced into the flame zone as required under §60.702(a).

(d) Each owner or operator subject to the provisions of this subpart shall keep records of the following:

(1) Up-to-date, readily accessible continuous records of the flow indication specified under §60.703(a)(2)(i), §60.703(b)(2)(i) and

§60.703(c)(1)(i), as well as up-to-date, readily accessible records of all periods and the duration when the vent stream is diverted from the control device.

(2) Where a seal mechanism is used to comply with §60.703(a)(2)(ii), §60.703(b)(2)(ii), and §60.703(c)(1)(ii), a record of continuous flow is not required. In such cases, the owner or operator shall keep up-to-date, readily accessible records of all monthly visual inspections of the seals as well as readily accessible records of all periods and the duration when the seal mechanism is broken, the bypass line valve position has changed, the serial number of the broken car-seal has changed, or when the key for a lock-and-key type configuration has been checked out.

(e) Each owner or operator subject to the provisions of this subpart shall keep up-to-date, readily accessible continuous records of the flare pilot flame monitoring specified under §60.703(b), as well as up-to-date, readily accessible records of all periods of operations in which the pilot flame is absent.

(f) Each owner or operator subject to the provisions of this subpart shall keep up-to-date, readily accessible continuous records of the equipment operating parameters specified to be monitored under §60.703(d), as well as up-to-date, readily accessible records of periods of operation during which the parameter boundaries established during the most recent performance test are exceeded. The Administrator may at any time require a report of these data. Where an owner or operator seeks to comply with §60.702(c), periods of operation during which the parameter boundaries established during the most recent performance tests are exceeded are defined as follows:

(1) Where an absorber is the final recovery device in a recovery system, and where an organic compound monitoring device is not used:

(i) All 3-hour periods of operation during which the average absorbing liquid temperature was more than 11 °C (20 °F) above the average absorbing liquid temperature during the most recent performance test, or

(ii) All 3-hour periods of operation during which the average absorbing liquid specific gravity was more than 0.1 unit above, or more than 0.1 unit below, the average absorbing liquid specific gravity during the most recent performance test (unless monitoring of an alternative parameter, which is a measure of the degree of absorbing liquid saturation, is approved by the Administrator, in which case he will define appropriate parameter boundaries and periods of operation during which they are exceeded).

(2) Where a condenser is the final recovery device in a system, and where an organic compound monitoring device is not used, all 3-hour periods of operation during which the average exit (product side) condenser operating temperature was more than 6 °C (11 °F) above the average exit (product side) operating temperature during the most recent performance test.

(3) Where a carbon adsorber is the final recovery device in a system, and where an organic compound monitoring device is not used:

(i) All carbon bed regeneration cycles during which the total mass steam flow was more than 10 percent below the total mass steam flow during the most recent performance test, or

(ii) All carbon bed regeneration cycles during which the temperature of the carbon bed after regeneration (and after completion of any cooling cycle(s)) was more than 10 percent or 5 °C greater, whichever is less stringent, than the carbon bed temperature (in degrees Celsius) during the most recent performance test.

(4) Where an absorber, condenser, or carbon adsorber is the final recovery device in the recovery system and where an organic compound monitoring device is used, all 3-hour periods of operation during which the average organic compound concentration level or reading of organic compounds in the exhaust gases is more than 20 percent greater than the exhaust gas organic compound concentration level or reading measured by the monitoring device during the most recent performance test.

(g) Each owner or operator of an affected facility subject to the provisions of this subpart and seeking to demonstrate compliance with §60.702(c) shall keep up-to-date, readily accessible records of:

(1) Any changes in production capacity, feedstock type, or catalyst type, or of any replacement, removal or addition of recovery equipment or reactors;

(2) Any recalculation of the TRE index value performed pursuant to §60.704(f); and

(3) The results of any performance test performed pursuant to the methods and procedures required by §60.704(d).

(h) Each owner or operator of an affected facility that seeks to comply with the requirements of this subpart by complying with the flow rate cutoff in §60.700(c)(4) shall keep up-to-date, readily accessible records to indicate that the vent stream flow rate is less than 0.011 scm/min and of any change in equipment or process operation that increases the operating vent stream flow rate, including a measurement of the new vent stream flow rate.

(i) Each owner or operator of an affected facility that seeks to comply with the requirements of this subpart by complying with the design production capacity provision in §60.700(c)(3) shall keep up-to-date, readily accessible records of any change in equipment



or process operation that increases the design production capacity of the process unit in which the affected facility is located.

(j) Each owner or operator of an affected facility that seeks to comply with the requirements of this subpart by complying with the low concentration exemption in §60.700(c)(8) shall keep up-to-date, readily accessible records of any change in equipment or process operation that increases the concentration of the vent stream of the affected facility.

(k) Each owner or operator subject to the provisions of this subpart is exempt from the quarterly reporting requirements contained in §60.7(c) of the General Provisions.

(l) Each owner or operator that seeks to comply with the requirements of this subpart by complying with the requirements of §60.700(c)(2), (c)(3), or (c)(4) or §60.702 shall submit to the Administrator semiannual reports of the following recorded information. The initial report shall be submitted within 6 months after the initial start-up date.

(1) Exceedances of monitored parameters recorded under §60.705(c), (f), and (g).

(2) All periods and duration recorded under §60.705(d) when the vent stream is diverted from the control device to the atmosphere.

(3) All periods recorded under §60.705(f) in which the pilot flame of the flare was absent.

(4) Any change in equipment or process operation that increases the operating vent stream flow rate above the low flow exemption level in §60.700(c)(4), including a measurement of the new vent stream flow rate, as recorded under §60.705(i). These must be reported as soon as possible after the change and no later than 180 days after the change. These reports may be submitted either in conjunction with semiannual reports or as a single separate report. A performance test must be completed within the same time period to verify the recalculated flow value and to obtain the vent stream characteristics of heating value and  $E_{TOC}$ . The performance test is subject to the requirements of §60.8 of the General Provisions. Unless the facility qualifies for an exemption under any of the exemption provisions listed in §60.700(c), except for the total resource effectiveness index greater than 8.0 exemption in §60.700(c)(2), the facility must begin compliance with the requirements set forth in §60.702.

(5) Any change in equipment or process operation, as recorded under paragraph (i) of this section, that increases the design production capacity above the low capacity exemption level in §60.700(c)(3) and the new capacity resulting from the change for the reactor process unit containing the affected facility. These must be reported as soon as possible after the change and no later than 180 days after the change. These reports may be submitted either in conjunction with semiannual reports or as a single separate report. A performance test must be completed within the same time period to obtain the vent stream flow rate, heating value, and  $E_{TOC}$ . The performance test is subject to the requirements of §60.8. The facility must begin compliance with the requirements set forth in §60.702 or §60.700(d). If the facility chooses to comply with §60.702, the facility may qualify for an exemption under §60.700(c)(2), (4), or (8).

(6) Any recalculation of the TRE index value, as recorded under §60.705(g).

(7) All periods recorded under §60.705(d) in which the seal mechanism is broken or the by-pass line valve position has changed. A record of the serial number of the car-seal or a record to show that the key to unlock the bypass line valve was checked out must be maintained to demonstrate the period, the duration, and frequency in which the bypass line was operated.

(8) Any change in equipment or process operation that increases the vent stream concentration above the low concentration exemption level in §60.700(c)(8), including a measurement of the new vent stream concentration, as recorded under §60.705(j). These must be reported as soon as possible after the change and no later than 180 days after the change. These reports may be submitted either in conjunction with semiannual reports or as a single separate report. If the vent stream concentration is above 300 ppmv as measured using Method 18 or above 150 ppmv as measured using Method 25A, a performance test must be completed within the same time period to obtain the vent stream flow rate, heating value, and  $E_{TOC}$ . The performance test is subject to the requirements of §60.8 of the General Provisions. Unless the facility qualifies for an exemption under any of the exemption provisions listed in §60.700(c), except for the TRE index greater than 8.0 exemption in §60.700(c)(2), the facility must begin compliance with the requirements set forth in §60.702.

(m) The requirements of §60.705(l) remain in force until and unless EPA, in delegating enforcement authority to a State under section 111(c) of the Act, approves reporting requirements or an alternative means of compliance surveillance adopted by such State. In that event, affected sources within the State will be relieved of the obligation to comply with §60.705(l), provided that they comply with the requirements established by the State.

(n) Each owner or operator that seeks to demonstrate compliance with §60.700(c)(3) must submit to the Administrator an initial report detailing the design production capacity of the process unit.

(o) Each owner or operator that seeks to demonstrate compliance with §60.700(c)(4) must submit to the Administrator an initial report including a flow rate measurement using the test methods specified in §60.704.

(p) Each owner or operator that seeks to demonstrate compliance with §60.700(c)(8) must submit to the Administrator an initial report including a concentration measurement using the test method specified in §60.704.

(q) The Administrator will specify appropriate reporting and recordkeeping requirements where the owner or operator of an affected facility complies with the standards specified under §60.702 other than as provided under §60.703 (a), (b), (c), and (d).

(r) Each owner or operator whose reactor process vent stream is routed to a distillation unit subject to subpart NNN and who seeks to demonstrate compliance with §60.700(c)(5) shall submit to the Administrator a process design description as part of the initial report. This process design description must be retained for the life of the process. No other records or reports would be required unless process changes are made.

(s) Each owner or operator who seeks to demonstrate compliance with §60.702 (a) or (b) using a control device must maintain on file a schematic diagram of the affected vent streams, collection system(s), fuel systems, control devices, and bypass systems as part of the initial report. This schematic diagram must be retained for the life of the system.

(t) Each owner or operator that seeks to demonstrate compliance with §60.700(c)(2) must maintain a record of the initial test for determining the total resource effectiveness index and the results of the initial total resource effectiveness index calculation.

[58 FR 45962, Aug. 31, 1993, as amended at 60 FR 58238, Nov. 27, 1995; 65 FR 78279, Dec. 14, 2000]

**§ 60.706 Reconstruction.**

(a) For purposes of this subpart "fixed capital cost of the new components," as used in §60.15, includes the fixed capital cost of all depreciable components which are or will be replaced pursuant to all continuous programs of component replacement which are commenced within any 2-year period following June 29, 1990. For purposes of this paragraph, "commenced" means that an owner or operator has undertaken a continuous program of component replacement or that an owner or operator has entered into a contractual obligation to undertake and complete, within a reasonable time, a continuous program of component replacement.

(b) [Reserved]

**§ 60.707 Chemicals affected by subpart RRR.**

Chemical	CAS No. <sup>1</sup>
Acetaldehyde	75-07-0
Acetic acid	64-19-7
Acetic anhydride	108-24-7
Acetone	67-64-1
Acetone cyanohydrin	75-86-5
Acetylene	74-86-2
Acrylic acid	79-10-7
Acrylonitrile	107-13-1
Adipic acid	124-04-9
Adiponitrile	111-69-3
Alcohols, C-11 or lower, mixtures	
Alcohols, C-12 or higher, mixtures	
Alcohols, C-12 or higher, unmixed	
Allyl chloride	107-05-1
Amylene	513-35-9
Amylenes, mixed	
Aniline	62-53-3
Benzene	71-43-2
Benzenesulfonic acid	98-11-3
	68081-81-2

Benzenesulfonic acid C <sub>10-16</sub> -alkyl derivatives, sodium salts	
Benzyl chloride	100-44-7
Bisphenol A	80-05-7
Brometone	76-08-4
1,3-Butadiene	106-99-0
Butadiene and butene fractions	
n-Butane	106-97-8
1,4-Butanediol	110-63-4
Butanes, mixed	
1-Butene	106-98-9
2-Butene	25167-67-3
Butenes, mixed	
n-Butyl acetate	123-86-4
Butyl acrylate	141-32-2
n-Butyl alcohol	71-36-3
sec-Butyl alcohol	78-92-2
tert-Butyl alcohol	75-65-0
Butylbenzyl phthalate	85-68-7
tert-Butyl hydroperoxide	75-91-2
2-Butyne-1,4-diol	110-65-6
Butyraldehyde	123-72-8
Butyric anhydride	106-31-0
Caprolactam	105-60-2
Carbon disulfide	75-15-0
Carbon tetrachloride	56-23-5
Chloroacetic acid	79-11-8
Chlorobenzene	108-90-7
Chlorodifluoromethane	75-45-6
Chloroform	67-66-3
p-Chloronitrobenzene	100-00-5
Citric acid	77-92-9
Cumene	98-82-8
Cumene hydroperoxide	80-15-9
Cyanuric chloride	108-77-0
Cyclohexane	110-82-7
Cyclohexane, oxidized	68512-15-2
Cyclohexanol	108-93-0
Cyclohexanone	108-94-1

Cyclohexanone oxime	100-64-1
Cyclohexene	110-83-8
Cyclopropane	75-19-4
Diacetone alcohol	123-42-2
1,4-Dichlorobutene	110-57-6
3,4-Dichloro-1-butene	64037-54-3
Dichlorodifluoromethane	75-71-8
Dichlorodimethylsilane	75-78-5
Dichlorofluoromethane	75-43-4
Diethanolamine	111-42-2
Diethylbenzene	25340-17-4
Diethylene glycol	111-46-6
Di-isodecyl phthalate	26761-40-0
Dimethyl terephthalate	120-61-6
2,4-(and 2,6)-dinitrotoluene	121-14-2
	606-20-2
Dioctyl phthalate	117-81-7
Dodecene	25378-22-7
Dodecylbenzene, nonlinear	
Dodecylbenzenesulfonic acid	27176-87-0
Dodecylbenzenesulfonic acid, sodium salt	25155-30-0
Epichlorohydrin	106-89-8
Ethanol	64-17-5
Ethanolamine	141-43-5
Ethyl acetate	141-78-6
Ethyl acrylate	140-88-5
Ethylbenzene	100-41-4
Ethyl chloride	75-00-3
Ethylene	74-85-1
Ethylene dibromide	106-93-4
Ethylene dichloride	107-06-2
Ethylene glycol	107-21-1
Ethylene glycol monobutyl ether	111-76-2
Ethylene glycol monoethyl ether acetate	111-15-9
Ethylene glycol monomethyl ether	109-86-4
Ethylene oxide	75-21-8
2-Ethylhexyl alcohol	104-76-7
(2-Ethylhexyl) amine	104-75-6
6-Ethyl-1,2,3,4-tetrahydro 9,10-anthracenedione	15547-17-8

Formaldehyde	50-00-0
Glycerol	56-81-5
n-Heptane	142-82-5
Heptenes (mixed)	
Hexamethylene diamine	124-09-4
Hexamethylene diamine adipate	3323-53-3
Hexamethylenetetramine	100-97-0
Hexane	110-54-3
Isobutane	75-28-5
Isobutanol	78-83-1
Isobutylene	115-11-7
Isobutyraldehyde	78-84-2
Isopentane	78-78-4
Isoprene	78-79-5
Isopropanol	67-63-0
Ketene	463-51-4
Linear alcohols, ethoxylated, mixed	
Linear alcohols, ethoxylated, and sulfated, sodium salt, mixed	
Linear alcohols, sulfated, sodium salt, mixed	
Linear alkylbenzene	123-01-3
Maleic anhydride	108-31-6
Mesityl oxide	141-79-7
Methanol	67-56-1
Methylamine	74-39-5
ar-Methylbenzenediamine	25376-45-8
Methyl chloride	74-87-3
Methylene chloride	75-09-2
Methyl ethyl ketone	78-93-3
Methyl isobutyl ketone	108-10-1
Methyl methacrylate	80-62-6
1-Methyl-2-pyrrolidone	872-50-4
Methyl tert-butyl ether	
Naphthalene	91-20-3
Nitrobenzene	98-95-3
1-Nonene	27215-95-8
Nonyl alcohol	143-08-8
Nonylphenol	25154-52-3
Nonylphenol, ethoxylated	9016-45-9
Octene	25377-83-7

Oil-soluble petroleum sulfonate, calcium salt	
Pentaerythritol	115-77-5
3-Pentenenitrile	4635-87-4
Pentenes, mixed	109-67-1
Perchloroethylene	127-18-4
Phenol	108-95-2
1-Phenylethyl hydroperoxide	3071-32-7
Phenylpropane	103-65-1
Phosgene	75-44-5
Phthalic anhydride	85-44-9
Propane	74-98-6
Propionaldehyde	123-38-6
Propyl alcohol	71-23-8
Propylene	115-07-1
Propylene glycol	57-55-6
Propylene oxide	75-56-9
Sorbitol	50-70-4
Styrene	100-42-5
Terephthalic acid	100-21-0
Tetraethyl lead	78-00-2
Tetrahydrofuran	109-99-9
Tetra (methyl-ethyl) lead	
Tetramethyl lead	75-74-1
Toluene	108-88-3
Toluene-2,4-diamine	95-80-7
Toluene-2,4-(and, 2,6)-diisocyanate (80/20 mixture)	26471-62-5
1,1,1-Trichloroethane	71-55-6
1,1,2-Trichloroethane	79-00-5
Trichloroethylene	79-01-6
Trichlorofluoromethane	75-69-4
1,1,2-Trichloro-1,2,2-trifluoroethane	76-13-1
Triethanolamine	102-71-6
Triethylene glycol	112-27-6
Vinyl acetate	108-05-4
Vinyl chloride	75-01-4
Vinylidene chloride	75-35-4
m-Xylene	108-38-3
o-Xylene	95-47-6
p-Xylene	106-42-3

Xylenes (mixed)	1330-20-7
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<sup>1</sup>CAS numbers refer to the Chemical Abstracts Registry numbers assigned to specific chemicals, isomers, or mixtures of chemicals. Some isomers or mixtures that are covered by the standards do not have CAS numbers assigned to them. The standards apply to all of the chemicals listed, whether CAS numbers have been assigned or not.

[58 FR 45962, Aug. 31, 1993, as amended at 60 FR 58238, Nov. 27, 1995]

### § 60.708 Delegation of authority.

(a) In delegating implementation and enforcement authority to a State under section 111(c) of the Act, the authorities contained in paragraph (b) of this section shall be retained by the Administrator and not transferred to a State.

(b) Authorities which will not be delegated to States: §60.703(e).

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**CERTIFICATE OF SERVICE**

I, Cynthia Hook, hereby certify that a copy of this permit has been mailed by first class mail to BASF Corporation, 100 Bridgeport Road, West Memphis, AR, 72301, on this 14<sup>th</sup> day of April, 2010.

A handwritten signature in cursive script, appearing to read 'C. Hook', written over a horizontal line.

Cynthia Hook, AAIL, Air Division