

3. 40 CFR part 52 is amended by adding a new § 52.742 to subpart O to read as follows:

§ 52.742 Incorporation by reference.

The materials listed below are incorporated by reference in the corresponding sections noted. The incorporation by reference was approved by the Director of the Office of Federal Register in accordance with 5 U.S.C. 552(a) and 1 CFR part 51. These materials are incorporated as they exist on the date of approval, and a notice of any change in these materials will be published in the *Federal Register*. The materials are available from the sources listed below.

(a) The following material is available for purchase from the American Society for Testing and Materials (ASTM), 1916 Race Street, Philadelphia, Pennsylvania, 19103.

(1) ASTM D1475-85, Standard Test Method for Density of Paint, Varnish, Lacquer, and Related Products, for § 52.741(a)(4)(i)(B)(3)(i).

(2) ASTM D2369-87, Standard Test Method for Volatile Content of Coatings, for § 52.741(a)(4)(i)(B)(3)(ii).

(3) ASTM D3792-86, Standard Test Method for Water Content of Water-Reducible Paints by Direct Injection into a Gas Chromatograph, for § 52.741(a)(4)(i)(B)(3)(iii).

(4) ASTM D4017-81 (Reapproved 1987), Standard Test Method for Water in Paints and Paint Materials by Karl Fischer Method, for § 52.741(a)(4)(i)(B)(3)(iv).

(5) ASTM D4457-85, Standard Test Method for Determination of Dichloromethane and 1,1,1-Trichloroethane in Paints and Coatings by Direct Injection into a Gas Chromatograph, for § 52.741(a)(4)(i)(B)(3)(v).

(6) ASTM D2697-86, Standard Test Method for Volume Nonvolatile Matter in Clear or Pigmented Coatings, for § 52.741(a)(4)(i)(B)(3)(vi).

(7) ASTM D3980-87, Standard Practice for Interlaboratory Testing of Paint and Related Materials, for § 52.741(a)(4)(i)(B)(3)(vii).

(8) ASTM E180-85, Standard Practice for Determining the Precision of ASTM Methods for Analysis and Testing of Industrial Chemicals, for § 52.741(a)(4)(i)(B)(3)(viii).

(9) ASTM D2372-85, Standard Method of Separation of Vehicle from Solvent-Reducible Paints, for § 52.741(a)(4)(i)(B)(3)(ix).

(10) ASTM D2879-86, Standard Test Method for Vapor Pressure-Temperature Relationship and Initial Decomposition Temperature of Liquids by Isotenoscope, for § 52.741(a)(3), (a)(8)(iii), (a)(9)(iii), and (a)(10)(iii).

(11) ASTM D323-82, Standard Test Method for Vapor Pressure of Petroleum Products (Reid Method), for § 52.741(a)(3).

(12) ASTM D86-82, Standard Method for Distillation of Petroleum Products, for § 52.741(a)(3).

(13) ASTM D3925-81 (Reapproved 1985), Standard Practice for Sampling Liquid Paints and Related Pigment Coatings, for § 52.741(a)(4)(i)(A)(i).

(14) ASTM E300-86, Standard Practice for Sampling Industrial Chemicals, for § 52.741(a)(4)(i)(A)(2).

(b) The Evaporation Loss From External Floating-Roof Tanks, Publication 2517, second edition, February 1980, for § 52.741(a)(3) is available for purchase from the American Petroleum Institute, 2101 L Street, NW., Washington, DC, 20037.

(c) The Standard Industrial Classification Manual, 1987, for § 52.741(a)(3) is available for purchase from the Superintendent of Documents, U.S. Government Printing Office, Washington, DC, 20402.

(d) 35 Illinois Administrative Code 215, June 1989, subparts (B), (E) (sections 215.182, 215.183, and 215.184), (K) (sections 215.301 and 215.302), (Q) (excluding sections 215.432 and 215.436), (R) (excluding sections 215.447, 215.450, and 215.452), (S), (V), (X), (Y) (sections 215.582, 215.583, and 215.584), and (Z) of 35 Ill. Adm. Code 215 for § 52.741 (d)(1)-(d)(3); (e)(3), (e)(4); (h)(2); (i)(1), (i)(2); (j)(1)-(j)(3); (q)(1); (s)(1); (u)(1), (3); (v)(1); (w)(1); and (x)(1), (x)(3) is available from the United States Environmental Protection Agency, Air and Radiation Division, Region V, 230 S. Dearborn, Chicago, IL, 60604.

4. Section 52.726 is further amended by adding paragraph (e) to read as follows:

§ 52.726 Control strategy—ozone

(e) Disapproval—The Administrator finds that the following State rules have not been demonstrated to be consistent with the reasonably available control technology requirements of section 172 of the Clean Air Act, as amended in 1977, and thus, are disapproved: subpart F, section 215.204(c); subpart F, section 215.206(b); subpart F, section 215.204(j)(4); subpart I; subpart AA; subpart PP; subpart QQ; subpart RR; subpart A, section 215.102; subpart T; subpart H, section 215.245; subpart F, section 215.207; and subpart A, section 215.107, all of title 35; Environmental Protection; subtitle B: Air Pollution;

Chapter 1: Pollution Control Board of the Illinois Administrative Code (June 1989).

5. Section 52.720 is amended by adding paragraph (c)(78) to read as follows:

§ 52.720 Identification of plan.

(c) * * *

(78) On January 28, 1983, June 25, 1987, August 21, 1987, September 28, 1987, October 2, 1987, December 22, 1987, January 8, 1988, March 29, 1988, and May 2, 1988 the State submitted stationary source control measures for incorporation in the ozone plan.

(i) *Incorporation by reference.* (A) The following sections of title 35, Environmental Protection; subtitle B: Air Pollution; Chapter 1: Pollution Control Board of the Illinois Administrative Code, (June 1989): section 211.122 (definitions of bead-dipping; component; dry cleaning facility; external floating roof; gas service; green tire spraying; green tires; heavy liquid; liquid mounted seal; liquid service; pneumatic rubber tire manufacture; refinery unit, process unit, or unit; tread end cementing; undertread cementing; valves not externally regulated; vapor collection system; vapor mounted primary seal; volatile organic liquid; and volatile organic material) of subpart B (part 211); section 215.104 (definitions of continuous process; in vacuum service; material recovery section; open-ended valve; polystyrene plant; polystyrene resin; repaired; styrene devolatilizer unit; and styrene recovery unit) of subpart A (part 215); sections 215.124, 215.125, and 215.126 of subpart B (part 215); section 215.205 of subpart F (part 215); sections 215.240, 215.241, and 215.249 of subpart H (part 215); section 215.408 of subpart P (part 215); sections 215.420 through 215.431, 215.433, 215.434, 215.435, 215.437, and 215.438, all of subpart Q (part 215); section 215.453 of subpart R (part 215); sections 215.465 and 215.466 of subpart S (part 215); sections 215.520, 215.521, 215.525, 215.526, and 215.527 all of subpart V (part 215); sections 215.582, 215.583, and 215.584 of subpart Y (part 215); sections 215.607 through 215.613 of subpart Z (part 215); and sections 215.875, 215.877, 215.879, 215.881, 215.883, and 215.886 all of subpart BB (part 215) are approved.

(ii) *Additional material.*

[FR Doc. 90-13929 Filed 6-28-90; 8:45 am]

BILLING CODE 6560-50-M

1. The first part of the document is a letter from the President of the United States to the Congress, dated January 3, 1862. It is a long and detailed letter, covering many topics, including the state of the Union, the progress of the war, and the administration of the government. The letter is written in a formal and dignified style, and is signed by Abraham Lincoln.

2. The second part of the document is a report from the Secretary of the War Department, dated January 10, 1862. It is a long and detailed report, covering many topics, including the state of the war, the progress of the army, and the administration of the department. The report is written in a formal and dignified style, and is signed by Edwin M. Stanton.

3. The third part of the document is a report from the Secretary of the Navy Department, dated January 10, 1862. It is a long and detailed report, covering many topics, including the state of the navy, the progress of the fleet, and the administration of the department. The report is written in a formal and dignified style, and is signed by Gideon Welles.

4. The fourth part of the document is a report from the Secretary of the Treasury Department, dated January 10, 1862. It is a long and detailed report, covering many topics, including the state of the treasury, the progress of the revenue, and the administration of the department. The report is written in a formal and dignified style, and is signed by Charles A. Smith.

5. The fifth part of the document is a report from the Secretary of the Interior Department, dated January 10, 1862. It is a long and detailed report, covering many topics, including the state of the interior, the progress of the land office, and the administration of the department. The report is written in a formal and dignified style, and is signed by Caleb B. Smith.

6. The sixth part of the document is a report from the Secretary of the War Department, dated January 10, 1862. It is a long and detailed report, covering many topics, including the state of the war, the progress of the army, and the administration of the department. The report is written in a formal and dignified style, and is signed by Edwin M. Stanton.

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Environmental Protection Agency

Friday
June 29, 1990

Part III

Environmental Protection Agency

40 CFR Part 60

Standards of Performance for New
Stationary Sources; Rules and Proposed
Rule

ENVIRONMENTAL PROTECTION AGENCY

40 CFR Part 60

[AD-FRL-2960-5]

RIN 2060-AA30

Standards of Performance for New Stationary Sources; Volatile Organic Compound (VOC) Emissions From the Synthetic Organic Chemical Manufacturing Industry (SOCMI) Air Oxidation Processes

AGENCY: Environmental Protection Agency (EPA).

ACTION: Final rule.

SUMMARY: Standards of performance for air oxidation unit processes in the SOCMI were proposed in the Federal Register on October 21, 1983 (48 FR 48932). On May 16, 1985, the public comment period was reopened (50 FR 20446) for the purpose of allowing public comment on the results of a reanalysis of the costing procedures, the total resource effectiveness (TRE) equation and coefficients, and the designation of affected facility. This action promulgates standards of performance for SOCMI air oxidation unit processes. These standards implement section 111 of the Clean Air Act (CAA) and are based on the Administrator's determination that VOC emissions from air oxidation processes in the SOCMI cause or contribute significantly to air pollution which may reasonably be anticipated to endanger public health or welfare. The intended effect of these standards is to require all new, modified, and reconstructed air oxidation facilities to achieve an emission reduction that reflects the capabilities of the best demonstrated system of continuous emission reduction, considering costs, nonair quality health, and environmental and energy impacts.

EFFECTIVE DATE: June 29, 1990.

Under section 307(b)(1) of the CAA, judicial review of this new source performance standard (NSPS) is available only by the filing of a petition for review in the U.S. Court of Appeals for the District of Columbia Circuit within 60 days of today's publication of this rule. Under section 307(b)(2) of the CAA, the requirements that are the subject of today's notice may not be challenged later in civil or criminal proceedings brought by EPA to enforce these requirements.

INCORPORATION BY REFERENCE: The incorporation by reference of certain publications in these standards is

approved by the Director of the Office of the Federal Register as of June 29, 1990.

ADDRESSES: *Background Information Document.* The background information document (BID) for the promulgated standards may be obtained from the U.S. EPA Library (MD-35), Research Triangle Park, North Carolina 27711, telephone number (919) 541-2777. Please refer to "Air Oxidation Processes in Synthetic Organic Chemical Manufacturing Industry—Background Information for Promulgated Standards," EPA-450/3-82-001b. The BID contains: (1) A summary of all the public comments made on the proposed standards and the Administrator's response to the comments, (2) a summary of the changes made to the regulation since proposal, and (3) the final Environmental Impact Statement which summarizes the impacts of the standards.

Docket. A docket, number A-81-22, containing information considered by EPA in development of the promulgated standards, is available for public inspection between 8 a.m. and 4 p.m., Monday through Friday, at EPA's Central Docket Section (LE-131), South Conference Center, 401 M Street SW., Washington, DC 20460. A reasonable fee may be charged for copying.

FOR FURTHER INFORMATION CONTACT:

Mr. Doug Bell or Ms. Debbie Stackhouse, telephone (919) 541-5568 and 5258, respectively, concerning regulatory decisions. Mr. Robert E. Rosensteel or Mr. Leslie B. Evans, telephone (919) 541-5608 and 5410, respectively, concerning technical aspects of the industry and control technologies. The address for the above contacts is Emission Standards Division (MD-13), U.S. Environmental Protection Agency, Research Triangle Park, North Carolina 27711.

SUPPLEMENTARY INFORMATION:

The Standards

Standards of performance for new sources established under section 111 of the CAA reflect:

... application of the best technological system of continuous emission reduction which (taking into consideration the cost of achieving such emission reduction, any nonair quality health and environmental impact and energy requirements) the Administrator determines has been adequately demonstrated [section 111(a)(1)].

For convenience, this will be referred to as "best demonstrated technology" or "BDT."

The promulgated standards apply to new, modified, and reconstructed air oxidation facilities within the SOCMI. This includes any reactors that use air

as an oxidizing agent to produce one or more of the chemicals listed in § 60.617 of the regulation. The affected facility is designated as a single air oxidation reactor with its own individual recovery system (if any) or the combination of two or more air oxidation reactors and the common recovery system they share. A recovery system consists of any device, or devices, capable of and used for the purpose of recovering chemicals for use, reuse, or sale and may include both primary and secondary recovery devices. Some examples of recovery devices are absorbers, adsorbers, and condensers as well as certain devices that recover non-VOC's, such as ammonia and hydrogen chloride recovery units. Construction, reconstruction, or modification of the facility must have begun after October 21, 1983, for the standard to be applicable. Existing facilities are not subject to the standard unless modified or reconstructed as defined in 40 CFR 60.14 or 60.15.

The standards include emission reduction requirements and/or emission limits which are based on the emission reduction capabilities of BDT. However, the standards do not require that a specific device or technology be used for those facilities that must comply with the emission reduction requirements, although the Agency expects that those facilities required to reduce their VOC emissions by 98 weight-percent or to 20 parts per million by volume (ppmv) will use combustion devices (e.g., incinerators, flares, etc.). Rather, any control technology other than recovery devices as defined in the standards can be used as long as it can be demonstrated that it is at least as effective as BDT at reducing VOC emissions.

Due to variations in factors such as flow rate, heat content, and concentration of organic compounds, the total cost of control per unit of total organic compound (TOC) emission reduction would vary considerably among the different types of air oxidation facilities. The Administrator has determined that for some air oxidation facilities, the cost of control per unit of VOC reduced is unreasonably high. Thus, the designation of BDT by the Administrator has two aspects. First, for facilities that can reduce VOC emissions at a reasonable cost, BDT is the reduction of VOC emissions by 98 weight-percent or to 20 ppmv through the use of thermal incineration. For facilities that cannot reduce VOC emissions at a reasonable cost, BDT is no additional control.

To identify those facilities for which implementation of the emission reduction requirements would be too costly, a means of measuring the total cost to control VOC emissions from air oxidation facilities was developed. This means of measuring the cost to control is called the TRE index. Using the TRE index approach, the standards would require each owner or operator of an affected facility with a TRE less than 1.0 to either reduce process vent stream VOC emissions by 98 weight-percent or to 20 ppmv, whichever is less stringent, or for facilities with a TRE index value greater than 1.0 to consistently maintain a value greater than 1.0.

An equation is included in the regulation for determining the TRE index value of each vent stream from an affected facility. The process vent stream flow rate, TOC emission rate, net heating value and corrosion properties (whether or not halogenated compounds are present) must be determined according to the specified Reference Methods in order to calculate the TRE index value. These vent stream characteristics would be measured following the last product recovery device (e.g., condensers, absorbers, carbon adsorbers).

The structure of the standards allows an affected facility with a TRE index value of less than 1.0 to add a recovery device; improve the existing recovery system efficiency; or alter the process operation so that the TRE value would increase above 1.0 and; therefore, VOC emissions would not have to be reduced by 98 weight-percent or to 20 ppmv. Increased recovery efficiency would have the advantage of achieving additional emission reduction, less energy usage, lower costs, and increased recovery of compounds or increased retention of products. The additional emission reduction could be as much as 30 percent more than current industry practice.

If a boiler or process heater were used to comply with the percent reduction or emission limit, the standards would also require that the air oxidation vent stream be introduced in the flame zone of the boiler or process heater. If a boiler or process heater were used to comply with the standards, the owner or operator would be required to monitor and record continuously the vent stream flow (using a flow indicator as described later) to the device and the firebox operating temperature. For boilers or process heaters of 44 MW (150 million/Btu) design heat input capacity or greater, no temperature monitoring is required but records (such as steam production records) would be required

which would verify the periods of operation of the heat generating unit.

A steam-assisted flare, an air-assisted flare, and a flare with no assist are considered to be capable of achieving 98 weight-percent emission reduction and may be used to meet the standards, provided that the flares are operated in accordance with the requirements in 40 CFR 60.18. Each owner or operator complying with the standards by using a smokeless flare would be required to monitor continuously the presence of the pilot flame. Ultra-violet beam sensors or thermocouples are acceptable for this purpose. A flow indicator would also be required that provides a record of vent stream flow to the flare.

Each owner or operator complying with the standards by using an incinerator would be required to monitor continuously and record the firebox operating temperature or, if a catalytic oxidizer were used, the temperature before and after the catalyst bed. A vent stream flow indicator is also required for each affected facility and must be installed as close to the combustion device as possible but immediately before the vent stream is joined with any vent stream not part of the affected facility. Records of vent stream flow must be maintained. If the emission reduction requirements were achieved by other means, the owner or operator would be required to provide information describing the operation of the control device and the parameter(s) that indicate proper operation and maintenance of the device so that the enforcing agency could specify appropriate monitoring requirements.

Each owner or operator who complies with the standards by maintaining a vent stream TRE index value above 1.0 would be required to monitor and record specified operating parameters of the final recovery device, or, if there are no recovery devices, at the point where the vent stream is discharged from the reactor to ensure that the TRE is consistently maintained. Operating parameters are established during the initial (or most recent) performance test. Subsequent monitoring of these parameters is done to determine whether their values have deviated from the values measured during the performance test. Depending on what the final recovery device is, the specified operating parameters are condenser exit (product side) operating temperature; absorber liquid temperature; specific gravity (or an alternative measure of absorbing liquid saturation, if approved by the enforcing agency); carbon adsorption bed temperature (after regeneration and

completion of any cooling cycles); and the mass flow rate of carbon bed regeneration steam. The owner or operator would also be required to maintain records of any change in the design or operation of the facility which could affect the TRE index value. Such records would include changes in the production capacity, feedstock type, or catalyst type, as well as the replacement, removal, or addition of recovery equipment. When any such change takes place, the owner or operator of the facility is required to recalculate the TRE index value to document that the facility continues to have a TRE index value above 1.0. Such recalculation can be based on test data reflecting the changes in the system, or best engineering estimates of the effects of the changes. If the recalculated TRE index value for the facility is less than 1.0, the owner or operator shall demonstrate compliance with the 98 weight-percent reduction requirement or 20 ppmv emission limit within 180 days of the process change. Prior notice of any performance testing shall be given to EPA as required by the General Provisions of 40 CFR part 60. Performance testing may also be required on a case-by-case basis by the Administrator following any change to the recovery system in order to verify the TRE index value for the facility.

The standards require that records of the operating parameters discussed above be maintained to ensure the proper operation and maintenance of combustion control equipment and recovery equipment used to reduce VOC emissions. Furthermore, records of instances where these monitored values exceed allowable limitations established during the most recent performance test must be maintained. In addition to maintaining these records, an owner or operator must submit a semiannual report of the recorded exceedances. The requirement of semiannual reporting may be waived for affected facilities in States that have been delegated authority for enforcement provided EPA approves the reporting requirements or alternative means of compliance surveillance adopted by the State and the affected facilities comply with the requirements established by the State. For facilities with TRE index values greater than 4.0, there are no monitoring and reporting requirements unless there is a change to the process operation.

In addition to this promulgated standard, Reference Methods 1A, 2C, and 2D are being promulgated in today's Federal Register.

Summary of Environmental, Energy, and Economic Impacts

The environmental, energy, and economic impacts associated with the standards were projected by using a statistical representation of the industry's vent stream characteristics at existing plants. These characteristics included vent stream flow rate, net heating value, TOC emission rate, and corrosion properties (presence or absence of halogenated compounds). It was assumed that the national distribution of these characteristics for new sources would be the same as the distribution for existing sources. In the determination of these impacts it was assumed that all new, modified, and reconstructed facilities with a TRE index value less than 1.0 would use thermal incineration to meet the 98 weight-percent emission reduction requirement or the 20 ppmv emission limit. Thermal oxidation is the only VOC control technique determined to be universally applicable to all SOCM air oxidation processes.

The actual energy, environmental, and economic impacts associated with the air oxidation NSPS are expected to be less than the impacts estimated here. One reason why these impacts would be lessened is that some facilities would upgrade existing recovery equipment to achieve a TRE index value higher than the cutoff, and, in fact, the standards structured in such a way that encourages this. Such equipment generally has lower associated costs and energy use. Secondly, some facilities would use other combustion devices, such as boilers, or process heaters which may be less expensive to apply and have a lower net energy consumption than incineration. A third reason is that some facilities could use existing devices to control emissions and not have to build new devices. The impacts estimated here assumed that new control devices would be built as a result of the standards. Although these factors contribute to the overstatement of the energy and economic impacts associated with the standards, the degree of overstatement of the impacts cannot be quantified.

Under the standards, it is estimated that 19 percent of all new, modified, or reconstructed air oxidation facilities would have vent streams with TRE index values under the TRE cutoff of 1.0. If all of these facilities were controlled to 98 weight-percent, the projected national VOC emissions from all new, modified and reconstructed air oxidation processes would be reduced by an estimated 10,700 megagrams per year (Mg/yr). This national VOC

reduction would be approximately 46 percent beyond the 23,500 Mg/yr level that would be expected under typical State implementation plans (SIP's).

It is projected that in the absence of the standards, uncontrolled VOC emissions would be reduced an average of 72 percent by State regulations. Seventy-two percent represents a weighted average of the regulations in States where new sources are projected to be built. The actual control required would vary considerably from State to State. Therefore, the impacts for individual plants would vary depending on the State where the affected facility is located.

Any increase in emissions of other air pollutants as a result of controlling VOC emissions would be negligible. There would be no direct solid waste impacts under the standards, and impacts on noise, space requirements, and availability of resources would be negligible.

No significant increase in total plant wastewater is projected under the standard. There is no organic wastewater effluent associated with combustion devices themselves. Some facilities which could have an associated water pollution impact are those which might choose to upgrade or add recovery devices to achieve a TRE index value above the 1.0 cutoff. Carbon adsorption is the only product recovery technique currently in use in the industry which has an associated organic wastewater effluent. Based on available data, only a small percentage of air oxidation chemical manufacturing processes are expected to employ carbon adsorption.

The fifth year energy requirements of the standards would be 0.69 billion megajoules per year (MJ/yr) (320 bbl fuel oil equivalent/day). The projected national energy impacts are considered reasonable.

The fifth year cost impacts of the standards are also considered reasonable. The fifth year national annualized cost for VOC control would be \$8.9 million (\$1978). The fifth year national capital cost for VOC control would be \$14.4 million (\$1978).

An economic analysis indicated that the costs associated with the standards could be passed on with little or no effect on the profitability of the industry. Projections made by employing process-specific assumptions indicate that the standards would not trigger product price increases in excess of 5 percent of the product price. Potential price increases for the 36 chemicals that are currently produced using the air oxidation process, assuming control

costs would be passed through totally and using conservative control cost estimates (high cost projections), would range from 0 to a 3.1 percent increase. Finally, there would be no adverse effects on employment because the standards would not appreciably affect demand for the air oxidation chemicals.

The environmental, energy, and cost impacts are discussed in greater detail in the two BID's for the standards: "Air Oxidation Processes in Synthetic Organic Chemical Manufacturing Industry—Background Information for Proposed Standards" and "Air Oxidation Processes in Synthetic Organic Chemical Manufacturing Industry—Background Information for Promulgated Standards" (EPA-450/3-82-001a and EPA-450/3-82-001b).

Public Participation

Prior to proposal of the standards, interested parties were advised by public notice in the *Federal Register* (46 FR 42910) of a meeting of the National Air Pollution Control Techniques Advisory Committee to discuss the air oxidation VOC standard recommended for proposal. This meeting was held on September 22, 1981. The meeting was open to the public and each attendee was given an opportunity to comment on the standards recommended for proposal. The standards were proposed and published in the *Federal Register* on October 21, 1983 (48 FR 48932). The preamble to the proposed standards discussed the availability of the BID "Air Oxidation Processes in Synthetic Organic Chemical Manufacturing Industry" (EPA-450/3-82-001a) which described in detail the regulatory alternatives considered and the impacts of those alternatives. Public comments were solicited at the time of proposal and, when requested, copies of the BID were distributed to interested parties. The proposal notice stated that a public hearing would be held, if requested, to provide interested persons the opportunity for oral presentation of data, views, or arguments concerning the proposed standards. The public hearing was held on December 1, 1983. One speaker appeared at the public hearing to comment on the proposed standards. The public comment period ended on December 31, 1983.

On May 16, 1985, the public comment period was reopened (50 FR 20446) for the purpose of allowing public comment on the results of a reanalysis of the costing procedures, the TRE equation and coefficients, and the designation of affected facility. The reanalysis resulted from the acquisition of new information

received in public comments and collected since proposal.

Twelve comment letters were received concerning issues relative to the proposed standards of performance for air oxidation processes in the SOCMI. Eleven of these were in response to the proposed publication and one was in response to the reopening of the public comment period. The comments have been carefully considered and, where determined to be appropriate by the Administrator, changes have been made in the standards.

Significant Comments and Changes to the Proposed Standards

Comments on the proposed standards were received from nine chemical companies, one manufacturer of control equipment, and one environmental group. A detailed discussion of these comments and responses can be found in the BID for the promulgated standards which is referred to in the ADDRESSES section of this preamble. The summary of comments and responses in the BID serves as the basis for the revisions which have been made to the standards between proposal and promulgation.

The major comments and responses are summarized in this preamble. The comments have been divided into the following areas: Designation of Affected Facility; Applicability of the Standards; Selection of BDT; Selection of the TRE Cutoff; and Costing Revisions.

All comments discussed here have been entered into Docket Number A-81-22. Access to this docket is described in the ADDRESSES section of this preamble.

Designation of Affected Facility

One commenter objected to the designation of affected facility in the proposed standards. The standards designated the affected facility as the recovery system and all associated air oxidation reactors or each air oxidation reactor that vents directly to the atmosphere. The commenter stated that this designation does not conform to the requirements of the CAA as outlined in *ASARCO v. EPA*, 578 F.2d 319 (D.C. Cir. 1978). The commenter stated that this designation in effect legislates a mechanism that may enable certain facilities to avoid the reconstruction and modification provisions of the standards. As an example, the commenter indicated that if an existing facility consists of a single reactor, any changes in that reactor which would result in cumulative costs of over 50 percent of the capital cost of a new reactor would make it an affected facility. However, if two or more reactors are joined in an existing

facility, similar changes in one reactor may not make that facility subject to the standards because the capital costs are not likely to exceed 50 percent of the capital cost of the entire facility (both reactors and the associated recovery system). Thus, the commenter concluded that under the Agency's proposed designation the changed reactor may go unaffected by the standards. The commenter recommended that the designation be changed to each individual reactor and its associated recovery system to ensure that the standards achieve the maximum possible VOC emission reductions.

The Agency has reviewed the commenter's recommended affected facility designation and has found it to be inappropriate for use in these standards. The choice of the affected facility for these standards is based on the Agency's interpretation of section 111 of the CAA and on the judicial construction of its meaning (*ASARCO v. EPA*, 578 F.2d 319 (D.C. Cir. 1978)). Under section 111, the standards of performance for new stationary sources must apply to "new sources." "Source" is defined as "any building, structure, facility, or installation which emits or may emit any air pollutant" (section 111(a)(3)). Most industrial plants, however, consist of numerous pieces or groups of equipment that emit air pollutants and that may be viewed as "sources." The Agency, therefore, uses the term "affected facility" to designate the equipment within a particular kind of plant that is chosen as the "source" covered by a given standard.

As the commenter notes, the Court in *ASARCO* discussed the scope of EPA's discretion in choosing the affected facility. The Court stated:

The EPA's definition of a "facility", which this court accepts, is "any apparatus to which a standard of performance is specifically applicable." [Citation omitted.] This definition is clearly designed to designate as "facilities" those units of equipment—be they individual machines, combinations of machines, or even entire plants—that the Agency finds to be appropriate units for separate emission standards. A cursory review of EPA's regulations indicates that the units designated as "facilities" under this definition are usually larger than individual machines or single pieces of equipment, and are sometimes whole plants. [Citation omitted.] In designating what will constitute a facility in each particular industrial context, EPA is guided by a reasoned application of the terms of the statute it is charged to enforce, not by an abstract "dictionary" definition. This court would not remove this appropriate exercise of the Agency's discretion. [Citation omitted.] 578 F.2d at 324 n. 17.

Consistent with this statement, EPA has selected the affected facility in the air oxidation standards by looking at the terms and purposes of section 111, as well as the characteristics of air oxidation plants. As EPA stated at proposal, the main purpose of section 111 is to minimize emissions by requiring the application of BDT at all new, modified, and reconstructed sources (considering cost, nonair quality health and environmental effects, and energy impacts). The EPA believes that in most cases a narrow affected facility designation will best further this purpose, because in most cases a narrow designation ensures that all new emission units will be brought under the coverage of the standards. If, for example, an entire plant is designated as the affected facility, no part of the plant would be covered by the standard unless a replacement caused the plant as a whole to be "modified" or "reconstructed." If each piece of equipment is designated as a separate affected facility, then as each piece is replaced, the replacement piece would be a new source subject to the standards. For this reason, EPA generally presumes that the narrow designation is appropriate.

The EPA treats the narrow designation only as a presumption, however, because in some cases a broader affected facility designation may be more consistent with the purposes of section 111. For example, the Agency might choose a broader designation if it concludes that either: (a) It would result in greater emissions reduction than would a narrow designation; or (b) the other relevant statutory factors (technical feasibility, energy, cost, and nonair quality health and environmental impacts) point to a broader designation.

The EPA analyzed several alternative affected facility designations for the air oxidation standards, including: (1) Each individual reactor with its recovery system, (2) the group of reactors whose vent streams are ducted together through a single recovery system, and (3) the entire plant. Using the presumption mentioned above, EPA examined as a single affected facility each individual reactor whose vent stream is sent to its own recovery system. The EPA concluded, however, that when reactor vent streams are joined and sent through a single recovery system the group of reactors and their recovery system, rather than each reactor, should be a single affected facility.

The EPA estimates a greater reduction in national VOC emissions using the

broad designation of affected facility. Greater reduction in emissions will occur with the broader designation because for facilities where the TRE index is less than 1.0, emissions from existing air oxidation reactors will also be controlled when new reactors are combined with existing reactors sharing a common recovery system. Under a narrow designation, when a new reactor is combined with existing reactors, the new reactor is treated separately. Thus, only emissions from the new reactor could potentially be controlled.

The commenter did not comment on this reasoning. Instead, the commenter contended that when more than one reactor is vented to the same recovery device, EPA's designation will permit reactor replacements to avoid coverage under the standards and will therefore result in less emission reduction than would occur if the commenter's affected facility designation were used. The EPA disagrees with the commenter's analysis and conclusion. The replacement of air oxidation reactors or pieces of recovery equipment is rare within the industry. This is because reactors are expensive pieces of equipment which are designed to last a long time. Moreover, the Agency has concluded that those few replacements which do occur often result from process changes (e.g., from chlorination to hydrochlorination) or catastrophic events that would probably require replacement of most of the group of reactors joined to a single recovery system. These changes would likely amount to a "reconstruction" of the facility as it is defined in these standards. Thus, in the small percentage of cases where reactor replacements occur, the facility would most likely fall under the coverage of the standards.

Furthermore, as EPA stated at proposal, the other types of reactor changes that source owners would most likely consider are substantial changes in catalysts, reactor conditions, or product separation purification equipment. The cost of these changes is so great, however, that most owners would choose to build new groups of reactors rather than radically modify individual existing reactors. Thus, few air oxidation reactors would undergo process changes that would subject them to the standards under either the commenter's or EPA's designation. Moreover, under EPA's designation, in the event an owner added a reactor to an existing group of reactors ducted to the same recovery system, it is unlikely the facility could avoid being considered a modification by offsetting the new reactor emissions somewhere else within the reactor group. This is because

it would likely be technologically infeasible to reduce emissions sufficiently or at all from the other reactors. Although some VOC reductions could occur through upgrading recovery equipment, it is unlikely that this reduction would result in a full offset of the new reactor emissions because the increased load on the recovery device (i.e., increased flow and VOC) would make the needed increase in VOC removal efficiency difficult to achieve. Thus, the likely result is that addition of a reactor to a group of joined reactors would bring the entire set under the coverage of the standards as a modified facility.

In short, the broad evasion of the modification and reconstruction provisions that might generally occur under broad affected facility designations would not occur under EPA's designation for the air oxidation standards. As discussed above, under EPA's designation, the inability of owners to offset emissions from new reactors added to a set of existing reactors would likely cause the entire set of new and existing reactors to come under the standards as a modified facility. This results in a greater emission reduction potential than would be the case for these reactors under a narrow designation. For these reasons, EPA disagrees with the commenter's premise that the affected facility designation in these standards would result in foregone emission reductions and would, therefore, be inconsistent with section 111. Rather, EPA's selection of the affected facility represents a reasoned application of section 111, consistent with ASARCO, because it couples consideration of both the need to secure the greatest emissions reductions from new and modified emission units with the technological realities of the air oxidation process.

An incidental effect of selecting the broader designation of affected facility is that implementation of the standards would be made significantly easier. When several reactors feed process vent streams into a common recovery system, the characteristics of the emissions vented into the atmosphere from the recovery system are determined by both the process vent streams from each of the reactors and the efficiency of the recovery system. Determining accurately the contribution of each individual reactor to these emissions (i.e., each reactor's TRE index value) can be complex and, therefore, costly. It requires a mass balance calculation using three sampling sites: two which are located upstream and downstream

of the recovery system and one located just downstream of the reactor.

Under the broader designation EPA is promulgating, however, only one sampling site located after the last recovery device is needed to yield an accurate determination of the facility's TRE index value. No estimation of the recovery device efficiency on individual reactors is required, because the standards cover the entire vent stream. Therefore there is no need to determine which portion of the final vent stream from a group of reactors is attributable to new, modified, and reconstructed reactors and which portion is attributable to reactors that have not been changed or added. This results in a decrease in both the cost and complexity of performance testing because fewer sampling sites and a simpler analysis are needed.

Applicability of the Standards

Four commenters requested clarification on the applicability of the standards. These commenters indicated that the standards are not explicitly limited to air oxidation processes in the SOCMI. Further, the commenters stated that, consequently, the standards could be interpreted as applying to air oxidation reactors in other industries, such as asphalt roofing, kraft pulp mills, and fertilizer plants. The commenters recommended that the applicability provisions of the regulation be amended to specify that the standards are applicable only to air oxidation processes used in the manufacture of certain listed chemicals.

Upon considering this comment, the Agency decided to clarify the applicability of the standards by adding a list of affected SOCMI air oxidation chemicals to the regulation. Based on information available to the Agency, this list includes all SOCMI air oxidation chemicals produced and; thus, the list includes all chemicals and processes intended to be covered under these standards. The list is contained in § 60.617 and consists of the 36 chemicals identified in the BID as being entirely or partially produced by air oxidation processes. To accommodate this change § 60.610(a) of the regulation has been amended to limit the coverage of the standards to air oxidation processes that are used to produce one of the listed chemicals.

Selection of BDT

Several commenters objected to the Agency's selection of BDT. The objections raised by the commenters focused on two main areas. First, two commenters implied that the 98 percent

emission reduction specified in the regulation should be lowered to allow for the use of catalytic oxidation. These commenters stated that catalytic oxidation could achieve VOC destruction efficiencies comparable to those achievable by thermal incineration. One commenter stated that it would be necessary to add a thermal incinerator after the catalytic oxidizer in order to comply with the standards. Another commenter mentioned that compared to catalytic oxidation, the slightly higher efficiency typical of thermal incineration would not result in a measurable improvement in the environment. The commenter added that the use of thermal incineration instead of catalytic oxidation could possibly entail detrimental effects such as increased NO_x emission, energy use, cost, and domestic chemical prices relative to foreign chemical prices. A second concern related to one commenter's perception that technologies which involve lower costs and energy requirements than thermal incineration be evaluated for application to facilities which have too high a cost per megagram of VOC destroyed (i.e., over \$1,900/Mg). The commenter suggested that recovery devices and combustion devices such as catalytic oxidation be evaluated for such applications. It was pointed out that although the emission reduction capabilities of recovery devices are not as great as combustion, further emissions reductions could be achieved using these relatively low cost devices.

The Agency evaluated the commenters' concerns and has decided to make no changes in the emission reduction requirements of the standards. The standards do not prohibit the application of any devices, including catalytic oxidizers, which are used to comply with the emission reduction requirements and/or emission limits. The Agency believes, based on available data, the catalytic oxidizers are capable of achieving 98 weight-percent destruction efficiency in all cases where they are applicable. Since both thermal incinerators and catalytic oxidizers can meet the 98 weight-percent reduction or 20 ppmv limit, the owner or operator has the flexibility to choose the device which he believes is best for the facility in terms of cost or other technical considerations.

Catalytic oxidizers do not, however, necessarily have the advantages over thermal incinerators named by the commenters. Because of the potential for greater heat recovery associated with recuperative heat exchangers used in conjunction with thermal incinerators,

thermal incinerators may in many cases be less expensive and use less energy than catalytic oxidation units. This has to be examined on a case-by-case basis by owners or operators with facilities which can use catalytic oxidation. For these reasons, catalytic oxidation does not necessarily have an advantage over thermal incineration in terms of price impacts or competitive position of domestic producers relative to foreign competition, as suggested by the commenters. The potential impacts of domestic price increases associated with thermal incineration were investigated and are not considered to be large enough to significantly affect the competitive position of domestic producers relative to foreign competition. Using conservative (high) control cost estimates, chemical price increases are estimated to range from 0 to about 3 percent. Further, the potential for increased NO_x emissions associated with thermal incineration was also examined, but the rate of NO_x formation is estimated to be low due the relatively low combustion temperatures and relatively short residence times.

With respect to the second major concern raised by one commenter, the Agency maintains that it is appropriate to not require additional control for facilities with control costs per unit of VOC removed greater than \$1,900/Mg. It was determined to be infeasible to consider catalytic oxidizers and recovery devices (e.g., adsorbers, absorbers, and condensers) for application to individual facilities with cost-effectiveness values above the cutoff. These devices were not considered because the Agency was unable to identify subcategories for which a particular control device would apply in all cases. The applicability and effectiveness of these devices may be greatly affected by the vent stream flow rate, water content, temperature, VOC concentration, and VOC properties such as solubility, molecular weight, and liquid/vapor equilibrium. Since these characteristics vary widely within the air oxidation industry, it is not possible with available information and resources to identify categories or subcategories of air oxidation processes for which these devices would always apply and to specify control efficiencies under an industry-wide standards development approach. Therefore, application of these devices in analyzing regulatory options is not feasible. Even with greater resources, this analysis would be infeasible because it would require a stream-by-stream characterization, ultimately resulting in the need to create a separate standard

for each process used to produce a listed chemical. The number of standards required to regulate the same number of sources would increase significantly. The Agency believes that such an approach to regulating the air oxidation industry would be administratively infeasible and, therefore, environmentally counterproductive. In any event, as the commenter recognizes, proceeding now with this generic regulation based on thermal incineration at least represents an important first step in regulating air oxidation emissions and does not preclude later regulation of subcategories of air oxidation facilities should that become feasible. The EPA believes it has the authority to take this step-by-step approach under section 111. See, e.g., *Group Against Smog and Pollution v. EPA*, 665 F.2d (D.C. Cir. 1981).

Selection of the TRE Cutoff

Three commenters indicated that the \$1,900/Mg (1978\$) cost-effectiveness cutoff is unreasonable. One commenter recommended that the cutoff be raised to a level higher than \$1,900/Mg so that the standards cover a greater number of emission sources and, thus, a greater amount of emissions. This recommendation is based on the commenter's perception that the inclusion of a greater number of sources would reduce public exposure to pollutants emitted by air oxidation reactors, including potentially hazardous pollutants. This commenter also stated that cost effectiveness is inappropriate as the sole determinant for excluding certain air oxidation reactors from the application of the proposed standards. The commenter stated that cost effectiveness is an invalid basis for deciding not to set standards on processes for which no perceptible economic impacts have been shown. Two commenters stated that the cost-effectiveness cutoff should be reduced to a lower level which is more typical of VOC standards. Both commenters stated that the Agency has not presented adequate justification for concluding that a \$1,900/Mg cost-effectiveness cutoff is a reasonable upper limit for application of the standards. Specifically, these commenters assert that this higher figure cannot be justified based on the presence of toxic constituents in the discharge streams from air oxidation reactors. They point out that the control of toxic pollutants is the objective of standards developed under section 112 of the CAA (national emission standards for hazardous air pollutants (NESHAP)) and not standards such as

these which are being proposed pursuant to section 111 of the Act (NSPS). The first commenter stated that the Agency: (1) Has not presented data which quantify the presence of toxic pollutants in the emissions from air oxidation processes, (2) has made no effort to correlate the costs of control with the degree to which toxic pollutants are eliminated, and (3) has not shown that toxic pollutants will be controlled to the same degree as other pollutants under the proposed standards. The second commenter contended that the preamble does not adequately demonstrate that the presence of toxic pollutants in the emissions from air oxidation reactors are sufficiently different from the emissions from other VOC sources to justify a special consideration of their hazards. Both commenters also state that although the cost of controlling VOC emissions is analyzed as a "worst-case" situation, there are facilities which will have to incur costs as high as \$1,900/Mg. They contend that the Agency has not justified costs this high as being either reasonable or appropriate for these facilities.

The EPA believes that its decision to consider cost effectiveness as one indication of cost when determining the cutoff for applying the standards reflects a reasonable interpretation of section 111 of the CAA. In analyzing the question whether the consideration of cost effectiveness is appropriate, EPA looked to see whether Congress had "directly spoken to the precise question." *Chevron, U.S.A., Inc. v. NRDC*, 467 U.S. 837, 104 S.Ct. 2778, 2782 (1984). Section 111 requires EPA to promulgate NSPS limiting emissions to the level that reflects the best system of emission reduction "which (taking into consideration the cost of achieving such emission reduction, any nonair quality health and environmental impact and energy requirements) the Administrator determines has been adequately demonstrated." Section 111(a)(1). Nothing in either section 111 or elsewhere in the Act defines "the cost of achieving such emission reduction." The plain meaning of the phrase, however, is quite broad. This indicates that Congress implicitly delegated to EPA the authority to interpret the phrase to encompass a range of impacts, including costs of control in relation to the emission reduction achieved. Further, Congress did not specify any particular manner in which EPA was to take these costs "into consideration." Thus, absent a clear Congressional direction to the contrary discernible from the Act's history, *Chevron*, 104 S.Ct. at 2783,

section 111 gives EPA authority to reject NSPS control options on the ground that their costs are unreasonably high in light of the emission reductions they achieve.

The EPA has reviewed the legislative history of Section 111 and concluded that no contrary intent is discernible. Most important, the history contains no express repudiation of the use of cost effectiveness as one mechanism in considering cost when setting an NSPS.

For these reasons, EPA believes that Congress implicitly delegated the Agency the authority to decide how best to "take into consideration * * * cost" in setting NSPS and, if the Agency concluded it was appropriate, to consider cost effectiveness.

Further, in *Portland Cement Association v. Train*, 513 F.2d 506, 508 (D.C. Cir. 1975), *cert. denied*, 416 U.S. 1025 (1975) ("Portland II"), the Court stated that EPA may reject control options that result in a "gross disproportion between achievable reduction in emissions and cost of the control technique." Since the purpose of cost effectiveness analysis is to highlight such disproportion, this passage supports EPA's approach.

In selecting cutoffs related to applicability of NSPS, EPA looks at a variety of factors including: (1) The technical feasibility of additional control; (2) the economic feasibility associated with different control alternatives; (3) the magnitude of emission reductions associated with a control alternative (e.g., a slightly higher cutoff could be selected if it led to a substantial increase in the emission reduction achieved by the NSPS); (4) the cost effectiveness (C/E) of the control alternative in terms of annual cost per megagram (\$/Mg) of emissions reduced; (5) the quality of the cost estimates (e.g., worst case versus realistic estimates); (6) potential reductions in other air pollutants not specifically regulated by the NSPS resulting from a control alternative; and (7) the location of the sources (e.g., urban versus rural). Because these factors vary from industry to industry and, in some cases, within the same industry, decisions on the appropriate level of control are made on a category by category basis.

In evaluating the above factors, EPA found that the following considerations were key to the selection of the appropriate cutoff for SOCOMI air oxidation processes: (1) The cost effectiveness of NSPS for VOC emissions previously promulgated by EPA; (2) the fact that air oxidation vent streams contain compounds that are considered potentially toxic by EPA and that many of the facilities are located in

urban areas; and (3) the likelihood that these maximum costs will not be incurred by industry.

A survey of the VOC standards for other source categories shows that the cost effectiveness of those control requirements has sometimes ranged as high as \$2,000/Mg. (See Docket Item No. IV-B-14.) The Agency's experience in implementing these standards reveals that NSPS requiring this level of control have proved a useful tool in bringing about the installation of much emissions control technology, significant reductions in emissions, and corresponding improvements in air quality, yet have not imposed costs that appear "grossly disproportionate" to the emission reduction achieved. *Portland II*, 513 F.2d at 508. Such an approach simply makes this NSPS consistent (as to dollars spent per metric ton of VOC removed) with the existing body of NSPS regulations, all of which have either been promulgated without legal challenge or have been judicially upheld.

EPA also considered evidence that air oxidation streams include compounds that may be toxic.¹ Although that evidence has not yet resulted in a determination that those compounds should be listed as hazardous under section 112, EPA considered this potential toxicity along with other relevant factors when choosing the cutoff. As stated in EPA's Air Toxics Strategy published in July 1985, the Agency will consider the likely toxic pollutant control benefits in the course of carrying out its responsibilities under section 111. This strategy reduces emissions of potentially toxic compounds from new sources and from industries as their facilities are reconstructed or modified. This approach achieves significant reductions in these compounds of concern while the Agency evaluates them for regulation under section 112. The Agency disagrees with the argument that EPA has no authority to do this. The EPA is not attempting here to regulate streams based on a decision that they contain hazardous air pollutants within the meaning of section 112. Rather, the Agency is simply considering all available evidence within the

¹ The Agency has adequately documented that this is the case. (See Wehrum, W. et al., "Air Toxics Emission Patterns and Trends," Docket Item No. IV-A-3, and Registry of Toxic Effects of Chemical Substances, Docket Item No. IV-J-9.) Moreover, it is apparent that combustion of those streams will reduce those compounds proportionately. (See, e.g., "Thermal Incinerator Performance for NSPS," Docket Item No. II-B-3.) The Agency received no comment questioning this documentation.

framework of section 111. Section 111 does not attempt to restrict EPA's discretion to consider all relevant factors in making that decision, and certainly the potential toxicity of a stream is relevant to the control requirement selected. Many SOCM facilities are located in urban areas and, as a result, many people will be exposed to any hazardous air pollutants emitted from these facilities.

A third consideration in setting the cutoff at \$1,900/Mg is the likelihood that no facility will actually have to incur the costs implied by that cutoff. The reasons are: (a) Less expensive control systems may be used, thus reducing the costs and cost effectiveness incurred by individual facilities; (b) the cost estimates for thermal incinerators and natural gas prices are overstated; and (c) the inherent flexibility within the regulation encourages the use of product recovery modifications that will significantly reduce the cost incurred by individual facilities that may have otherwise had to add a combustion device. The regulatory analysis assumes that each air oxidation process vent would have its own combustion device and would need separate ducting and support structures. It is expected, however, that some air oxidation processes will share control systems with other process vents. The analysis also assumes that thermal incinerators or flares will be used to reduce VOC emissions by 98 weight-percent. Data on current capital costs of thermal incinerators indicate that units are now available at substantially reduced costs compared to the costs used in developing these standards. Lower capital costs would reduce the annualized costs estimates, also, but not as significantly. This is an important consideration in selecting the appropriate cost-effectiveness cutoff. Another consideration is the fact that natural gas prices used to calculate the cost effectiveness for each stream are overstated by about 40 percent, even though they were updated after proposal (see following section on "Costing Revisions"). These conservative assumptions have resulted in higher cost and cost-effectiveness estimates than will actually occur. Finally, the standard encourages pollution prevention by not requiring 98 weight-percent reduction if a TRE index greater than 1.0 is maintained. The EPA believes that many facilities having a TRE index just below the 1.0 cutoff (equivalent to \$1,900/Mg) will upgrade product recovery to reduce VOC and raise their TRE index above 1.0. This will significantly reduce the cost of control incurred by the industry

while reducing emissions and will also minimize the national energy impacts. A preliminary examination of the national statistical profile shows that because many facilities have the potential to reduce VOC emissions sufficiently to raise their TRE values above 1.0, the highest cost effectiveness that a facility will actually incur as a result of installing a combustion device is estimated to be approximately \$1,400/Mg.

The EPA believes that this process reflects a reasoned interpretation of the phrase "taking into consideration the cost of achieving such emission reduction," especially given the lack of clear Congressional guidance. The commenters' arguments that EPA should have selected either a higher cutoff to provide for a greater degree of protection of the public health, or a lower cutoff because most VOC standards have lower costs in relation to the resulting emission reduction, fail to provide a more reasoned methodology for selecting the appropriate level. Instead, they merely reflected each of the competing goals reflected in section 111's history, as described above.

Consideration of all of the above factors confirmed EPA's belief that a TRE value of 1.0 (i.e., \$1,900/Mg) represents an appropriate cutoff for determining which facilities must reduce VOC emissions by 98 weight-percent or to 20 ppmv. The cutoff is specific to the SOCM air oxidation processes source category and would not necessarily be appropriate for other source categories; therefore, it should not be viewed as a benchmark for other standards.

Costing Revisions

Several commenters indicated that several oversights and flawed assumptions exist in the cost estimation procedure. The commenters mentioned that the following capital cost items were either ignored or treated inadequately in the costing procedures: Ductwork length between the emission source and the incinerator, siting, bringing utilities to the site, and piping and instrumentation connections. In addition, both commenters mentioned that the following operating costs were ignored: maintenance-related labor costs, operating supplies, and laboratory costs. The commenters requested that the cost estimation procedure contain factors to account for these capital and operating cost items.

In response to these statements claiming that the costing procedures contain flawed assumptions, the Agency reviewed the procedures in great detail. Revisions were made where determined

to be appropriate for ensuring that the costing procedures result in representative costs. Throughout the development of the air oxidation NSPS, the Agency has made efforts to ensure that the costing procedures result in estimates that adequately represent control costs anticipated to be incurred by the majority of facilities in the industry. Prior to proposal, industry members were given the opportunity to provide substantial input into the development of the costing procedures. Preliminary costing assumptions were reviewed by industry and subsequently revised based upon industry input. After proposal, costing assumption revisions were prepared and presented in a supplemental Federal Register notice (50 FR 20446) on May 16, 1985. This notice solicited further comments on costing procedures. The bases for these revisions are documented in Docket Item No. IV-B-8. As a result of the initial industry involvement and the recent revisions based on industry public comments, the Agency feels confident that the costing procedures result in accurate estimates for typical air oxidation facilities. The specific assumptions that are key for ensuring representative cost estimates are discussed below.

Certain assumptions were included in the procedures to avoid underestimating costs incurred by facilities using combustion to control VOC. These assumptions were made to ensure that control equipment sizes and supplemental gas requirements were not underestimated. First, vent streams were assumed to contain no oxygen to maximize estimated combustion air requirements. Most streams, while not containing 21 percent oxygen, have some smaller percentage of oxygen present. The assumption of no oxygen ensures that no underestimate will occur for the equipment size, the combustion air flow rate, and the amount of supplemental natural gas needed. Second, actual offgas flow rate was increased by 5 percent in calculating costs, which inflated gas consumption and equipment size by 5 percent. Third, the temperatures and residence times assumed for cost estimation purposes (1,600 °F/75 sec for non-halogenated streams, 2,000 °F/1 sec for halogenated streams) are the highest temperature and residence time conditions generally necessary to achieve a 98 percent VOC destruction efficiency, as discussed in appendix A of the proposal BID. These higher temperatures and residence times would result in a larger equipment size and higher gas consumption than the majority of air oxidation facilities

require. Fourth, the overall installation factors assumed for new sources were 4.0, 2.5, and 3.5 for the combustion chamber, heat exchanger, and waste heat boiler, respectively. These factors were all higher than the EPA GARD Manual recommended factor of 2.17 (EPA-450/5-80-002) because they incorporate contingencies recommended by industry representatives to account for equipment that was not originally specified in the costing procedures.

Revisions were made where appropriate in the capital cost and the annual operating cost assumptions used in the procedures. For example, in the capital cost component of the procedures, the ductwork length was changed from 150 feet to 300 feet. The ductwork length increase is based on specifications provided by the Industrial Risk Insurers (IRI) and the National Fire Protection Association (NFPA). These organizations present recommended distances for safely locating combustion sources from process units in chemical plants. The recommended distance for locating a closed combustion source such as an incinerator from a process unit is 200 feet. An additional 100 feet was added to the IRI and NFPA recommendation to account for routing the stream around process equipment before routing it away from the process unit. The 300-foot figure is believed to be more representative of industry conditions and is within the range recommended by the commenter.

In addition to the ductwork length change, the capital cost component of the procedures also was modified to include 250 feet of pipe rack. The Agency judged that since the standards will probably require the use of new rather than existing incinerators and since newly constructed incinerators would require about 300 feet of ductwork, it is reasonable to assume that existing structures may not be available to support the piping. However, the 250 feet of pipe rack assumes that 50 feet of the 300 feet of ductwork would be supported by existing structures.

Several revisions were also made in the annual operating cost component of the procedures. These were revisions in the labor rate, in the calculation of total labor cost, and in the gas and electricity prices used. All these annual operating cost revisions were discussed below and are explained in more detail in a memorandum to the SOCOMI air oxidation NSPS files (Docket Item No. IV-B-8). The labor rate was changed to reflect more accurately the actual value for 1978. The original incinerator labor costing was based on a labor rate

(including overhead) in 1979 dollars that was deescalated to 1978 dollars. The new labor rate is based on actual U.S. Bureau of Labor Statistics for 1978 and does not include overhead and fringe benefits.

The revisions in the calculation of total labor cost were made to calculate explicitly the cost attributable to overhead and fringe benefits. The overall changes in the total labor cost calculation included: (1) Calculation of the supervisory labor cost as 15 percent of the operating labor cost; (2) calculation of the overhead cost as 80 percent of the sum of operating, supervisory, and maintenance labor costs; and (3) calculation of total labor cost as the sum of operating, supervisory, maintenance, and overhead labor costs.

The natural gas price used in the costing procedures was revised to represent more accurately the projected effects of natural gas deregulation and account for regional variations in gas price. The previous estimate of natural gas was based on prices projected through the first 5 years of the regulation and then was deflated to 1978 dollars. This was done to reflect the fact that gas prices have been rising more rapidly than inflation. The previous estimate was made during a period of rapidly increasing energy prices. However, the actual rate of increase has slowed since that original estimate was made. Thus, to improve the accuracy and representativeness of the gas price, a new projection was made. The gas price was derived by projecting regional gas prices to 1990, taking a nationwide 1990 gas price that was weighted geographically, and then deflating to 1978 dollars. Since that projection was made, the rate of increase continued to slow. Therefore, the revised gas price is still overstated but is more realistic than the original estimate.

The price for electricity was modified to provide for a more accurate estimate of 1978 costs. Although the electricity was originally based on 1978 costs, further examination showed that a more representative price could be used.

Several of the commenters' suggestions were not incorporated in the procedures because they were not justified. The recommended capital cost items that were judged to be inappropriate included the costs for siting, bringing utilities to the site, and piping and instrumentation connections. The cost associated with bringing utilities to the site was not included because the control device will be located in the proximity of the process units where utilities are readily

accessible. It was not necessary to include the cost for siting because this has already been included. An equipment cost installation factor of 1.35, which increased equipment purchase price by 35 percent, was used to account for site development, fees, and general contingencies. Neither was it necessary to include the cost associated with piping and instrumentation connections, because these were already incorporated. An equipment cost installation factor of 1.20 was used to increase the equipment purchase price by 20 percent to account for unspecified equipment. Also, an overall correction factor of 1.33 was used to increase equipment purchase price by 33 percent to account for any miscellaneous items associated with purchasing and installing control equipment that may have been overlooked.

Some annual operating cost items recommended by the commenters were also judged to be inappropriate. The items identified by the commenters included maintenance-related labor costs, operating supplies, and laboratory costs. It was not necessary to include maintenance-related labor costs because these are already incorporated in the maintenance labor factor, which is calculated as 3 percent of the total installed capital cost. Similarly, the cost associated with operating supplies was not a missing item but was already incorporated in the maintenance materials factor, which is calculated as 3 percent of the installed capital cost. Finally, it was determined that laboratory expenses, such as those involved with testing scrubbing wastewater effluent, are part of the normal operating and maintenance cost for an incinerator/scrubber system that would be used to control vent streams with halogenated compounds. Thus, factors for maintenance labor and maintenance materials associated with such a system would incorporate laboratory expenses.

In summary, the revised costing procedures do not result in annualized costs that are significantly different from the costs estimated using the procedures at proposal. An examination of the data showed that depending on the vent stream characteristics of a facility, the annualized cost increased for some facilities and decreased for others. For the most common type of air oxidation vent stream (Category B—nonhalogenated stream with net heating value below 0.48 MJ/m³), the annualized cost increased by about 3 percent.

Paperwork Reduction Act

The reporting and recordkeeping requirements of the regulation are assessed in Standard Form 83 and an accompanying supporting statement which are included in Docket Item No. IV-H-1 for public review. This documentation contains: (1) A description of the reporting and recordkeeping required by the regulation and the 40 CFR part 60 General Provisions, (2) the reasons for the requirements, (3) and evaluation of the major alternatives considered (including the use of existing sources of information), and (4) an estimate of the labor-hour burden of the requirements.

The General Provisions of 40 CFR part 60 and the standards would require three types of reports: (1) Notification requirements which enable the Agency to keep abreast of facilities subject to the standards, (2) reporting of initial performance test results and continuous monitoring system performance evaluations, and (3) semiannual reporting of exceedances or deviations from the monitored parameters from recovery of combustion control devices. Analysis of these reporting requirements (Docket Item No. IV-H-1) indicates that they are both necessary and reasonable considering the savings in Agency time and resources required for effective enforcement.

The resources needed by the industry to maintain records and to prepare the reports for the first 3 years average about 3.5 person-years per year. The resources required by EPA and State and local agencies to process the reports and to maintain records for the first 3 years would average about 0.2 person-years per year.

Information collection requirements associated with this regulation have been approved by the Office of Management and Budget (OMB) under the provisions of the Paperwork Reduction Act of 1980, 44 U.S.C. 3501 *et seq.*, and have been assigned OMB control number 2060-0053.

Public reporting burden for this collection of information is estimated to be 7,150 hours per year, with an average of 715 hours per response, including time for reviewing instructions, searching existing data sources, gathering and maintaining the data needed, and completing and reviewing the collection of information. Send comments regarding the burden estimate or any other aspect of this collection of information, including suggestions for reducing this burden, to Chief, Information Policy Branch, PM-223, U.S. Environmental Protection Agency, 401 M Street SW., Washington, DC 20460; and

to the Office of Information and Regulatory Affairs, Office of Management and Budget, Washington, DC 20503.

There are no reporting requirements by other governmental agencies for the information required by these standards which would result in overlapping requirements. In particular, there is no overlap with the reporting requirements of the Superfund program. The Superfund program was established in 1980 by the Comprehensive Environmental Response, Compensation, and Liability Act (CERCLA, Pub. L. 96-510) and authorizes the Federal government to respond directly to releases (or threatened releases) of hazardous substances and pollutants or contaminants to any media that may endanger public health or welfare. Under the notification and liability provisions of section 103 (see 48 FR 23552, May 25, 1983), CERCLA requires that persons in charge of vessels or facilities from which hazardous substances have been released in quantities that are equal to or greater than the reportable quantities immediately notify the National Response Center (NRC) of the release (800-424-6802; in Washington, DC, metropolitan area 202-426-2675). However, air releases which qualify as Federally permitted releases, such as VOC emissions that are regulated under section 111 of the CAA, are not subject to the notification or liability provisions of CERCLA unless the air releases are in excess of the allowable NSPS emissions by an amount equal to or greater than the reportable quantity; in this case, persons in charge must report the excess air release to the NRC. (Reporting under CERCLA does not excuse the persons in charge from any responsibility, including reporting, or liability under the NSPS program.)

Docket

The docket is an organized and complete file of all the information considered by EPA in the development of this rulemaking. The docket is a dynamic file, since material is added throughout the rulemaking development. The docketing system is intended to allow members of the public and industries involved to readily identify and locate documents so that they can intelligently and effectively participate in the rulemaking process. Along with the statement of basis and purpose of the proposed and promulgated standards and EPA responses to significant comments, the contents of the docket will serve as the record in

case of judicial review (except as noted in section 307(d)(7)(A)).

Miscellaneous

The effective date of this regulation is June 29, 1990. Section 111 of the CAA provides that standards of performance or revisions thereof become effective upon promulgation and apply to affected facilities, construction, reconstruction, or modification of which commenced after October 21, 1983.

As prescribed by section 111, the promulgation of these standards was preceded by the Administrator's determination (40 CFR 60.16, 44 FR 49222, dated August 21, 1979) that these sources contribute significantly to air pollution which may reasonably be anticipated to endanger public health or welfare. In accordance with section 117 of the Act, publication of these promulgated standards was preceded by consultation with appropriate advisory committees, independent experts, and Federal departments and agencies.

This regulation will be reviewed 4 years from the date of promulgation as required by the CAA. This review will include an assessment of such factors as the need for integration with other programs, the existence of alternative methods, enforceability, improvements in emission control technology, and reporting requirements.

Section 317 of the CAA requires the Administrator to prepare an economic impact assessment for any NSPS under section 111(b) of the Act. An economic impact assessment was prepared for this regulation and for other regulatory alternatives. All aspects of the assessment were considered in the formulation of the standards to ensure that cost was carefully considered in determining BDT. The economic impact assessment is included in the BID for the proposed standards (EPA-450/3-82-001a).

Under Executive Order 12291, EPA must judge whether a regulation is "major" and therefore subject to the requirement of a Regulatory Impact Analysis. This regulation is not major because: (1) The national annualized compliance costs, including capital charges resulting from the standards total less than \$100 million; (2) the standards do not cause a major increase in prices or production costs; and (3) the standards do not cause significant adverse effects on domestic competition, employment, investment, productivity, innovation or competition in foreign markets. This regulation was submitted to OMB for review as required by Executive Order 12291. Any written communication between OMB and EPA

pertaining to the standards has been put in the docket (A-81-22).

Regulatory Flexibility Analysis

The Regulatory Flexibility Act of 1980 requires that adverse effects of all Federal regulations upon small businesses be identified. According to current Small Business Administration guidelines, a small business in the air oxidation industry is one that has 1,000 employees or less. Currently only 4 percent of existing air oxidation companies (three companies) employ less than 1,000 people. No new, modified, or reconstructed small air oxidation facilities will be adversely affected by the standards. This conclusion is based on the fact that in doing the economic analysis for this standard, the price increase and profitability impacts have been estimated from the perspective of the smaller air oxidation facilities in operation. The findings of this analysis that producers of air oxidation chemicals, under a worst-case scenario, would be able to pass through NSPS compliance costs to their customers while keeping the price increase of their product under 5 percent accurately reflects the impacts for small air oxidation companies.

The economies of scale that exist in this industry hinder the entrance of small businesses. Furthermore, if a company has the capital available to enter the industry, the NSPS will require only a small percentage increase in the capital required for the project.

Pursuant to the provisions of 5 U.S.C. 605(b), I hereby certify that this rule will not have a significant economic impact on a substantial number of small entities.

List of Subjects in 40 CFR Part 60

Air pollution control, Incorporation by reference, SOCMCI air oxidation processes.

Dated: June 1, 1990.

William K. Reilly,
Administrator.

PART 60—[AMENDED]

40 CFR part 60 is amended as follows:

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

Authority: Secs. 101, 111, 114, 116, and 301 of the Clean Air Act (CAA) as amended (42 U.S.C. 7401, 7411, 7414, 7416, 7601).

2. Section 60.17 is amended by revising (a)(6) and (a)(38), removing (a)(46), and redesignating (a)(47) through (a)(55) as (a)(46) through (a)(54) to read as follows:

§ 60.17 Incorporation by reference.

* * *

(a) * * *
(6) ASTM D1946-77, Standard Method for Analysis of Reformed Gas by Gas Chromatography, IBR approved for §§ 60.45(f)(5)(i), 60.18(f), 60.614(d)(2)(ii), 60.614(d)(4).

* * *
(38) ASTM D2382-76, Heat of Combustion of Hydrocarbon Fuels by Bomb Calorimeter [High-Precision Method], IBR approved for § 60.18(f), 60.485(g), 60.614(d)(4).

* * *

3. By adding subpart III to read as follows:

Subpart III—Standards of Performance for Volatile Organic Compound Emissions From the Synthetic Organic Chemical Manufacturing Industry (SOCMI) Air Oxidation Unit Processes

Sec.

- 60.610 Applicability and designation of affected facility.
- 60.611 Definitions.
- 60.612 Standards.
- 60.613 Monitoring of emissions and operations.
- 60.614 Test methods and procedures.
- 60.615 Reporting and recordkeeping requirements.
- 60.616 Reconstruction.
- 60.617 Chemicals affected by subpart III.
- 60.618 Delegation of Authority.

Subpart III—Standards of Performance for Volatile Organic Compound (VOC) Emissions From the Synthetic Organic Chemical Manufacturing Industry (SOCMI) Air Oxidation Unit Processes

§ 60.610 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 produces any of the chemicals listed in § 60.617 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 October 21, 1983:

(1) Each air oxidation reactor not discharging its vent stream into a recovery system.

(2) Each combination of an air oxidation reactor and the recovery system into which its vent stream is discharged.

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

(c) Each affected facility that has a total resource effectiveness (TRE) index

value greater than 4.0 is exempt from all provisions of this subpart except for §§ 60.612, 60.614(f), 60.615(h), and 60.615(l).

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

§ 60.611 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.

Air Oxidation Reactor means any device or process vessel in which one or more organic reactants are combine with air, or a combination of air and oxygen, to produce one or more organic compounds. Ammoxidation and oxychlorination reactions are included in this definition.

Air Oxidation Reactor Recovery Train means an individual recovery system receiving the vent stream from at least one air oxidation reactor, along with all air oxidation reactors feeding vent streams into this system.

Air Oxidation Unit Process means a unit process, including ammoxidation and oxychlorination unit process, that uses air, or a combination of air and oxygen, as an oxygen source in combination with one or more organic reactants to produce one or more organic compounds.

Boilers 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.

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 ppmv (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 § 60.617. 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 § 60.617 that is produced for sale as a final product as that chemical or is produced for use in a process that needs that chemical for the production of other chemicals in another facility. By-products, co-products, and intermediates are considered to be products.

Recovery Device means an individual unit of equipment, such as an absorber, condenser, and carbon adsorber, capable of and used to recover chemicals for use, reuse or sale.

Recovery System means an individual recovery device or series of such devices applied to the same process stream.

Total organic compounds (TOC) means those compounds measured according to the procedures in § 60.614(b)(4). For the purposes of measuring molar composition as required in § 60.614(d)(2)(i), hourly emissions rate as required in § 60.614(d)(5) and § 60.614(e) and TOC concentration as required in § 60.615(b)(4) and § 60.615(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 SIP revisions (42 FR 35314; 44 FR 32042; 45 FR 32424; 45 FR 48942).

Total resource effectiveness (TRE) Index Value means a measure of the supplemental total resource requirement per unit reduction of TOC associated with an individual air oxidation 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 § 60.614(e).

Vent Stream means any gas stream, containing nitrogen which was introduced as air to the air oxidation reactor, released to the atmosphere directly from any air oxidation reactor recovery train or indirectly, after diversion through other process equipment. The vent stream excludes

equipment leaks and relief valve discharges including, but not limited to, pumps, compressors, and valves.

§ 60.612 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 § 60.614 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 (minus methane and ethane) by 98 weight-percent, or to a TOC (minus methane and ethane) concentration of 20 ppmv 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.

§ 60.613 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 § 60.612(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 ± 1 percent of the temperature being monitored expressed in degrees Celsius or ± 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 § 60.612(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 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 § 60.612(a) shall install, calibrate, maintain and operate according to the manufacturer's specifications in 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 air oxidation reactor 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 ± 1 percent of the temperature being measured expressed in degrees Celsius or ± 0.5 °C, whichever is greater, for boilers or process heaters of less than 44 MW (150 million Btu/hr) heat input design capacity.

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

(d) The owner or operator of an affected facility that seeks to demonstrate compliance with the TRE index value limit specified under § 60.612(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 a recovery system:

(i) A scrubbing liquid temperature monitoring device having an accuracy of ± 1 percent of the temperature being monitored expressed in degrees Celsius

or 0.5 °C, whichever is greater, and a specific gravity monitoring device having an accuracy of 0.02 specific gravity units, each equipped with a continuous recorder;

(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 a recovery system:

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

(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 in a recovery system:

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

(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 § 60.612 with control devices other than an incinerator, boiler, process heater, or flare; or recovery devices 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.

§ 60.614 Test methods and procedures.

(a) For the purpose of demonstrating compliance with § 60.612, 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 § 60.612(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 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_{2d}) 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 O₂ (C_c) shall be computed using the following equation:

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

where:

C_c = Concentration of TOC corrected to 3 percent O₂, dry basis, ppm by volume.

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

%O_{2d} = Concentration of O₂, dry basis, percent by volume.

(4) Method 18 to determine 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_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:

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

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

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/hr).

K₂ = Constant, 2.494 × 10⁻⁶ (1/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 in the sample.

n = Number of components in the sample.

(5) 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 § 60.612(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.

(c) When a flare is used to seek to comply with § 60.612(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 § 60.612(b) and for determining the process vent stream TRE index value to determine compliance under § 60.612(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 § 60.614(d) (2) and (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 post-reactor dilution of the stream with air, and prior to any post-reactor introduction of halogenated compounds into the vent stream. No transverse site selection method is needed for vents smaller than 4 inches in diameter.

(ii) If any gas stream other than the air oxidation 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 nonair oxidation 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 nonair oxidation 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 nonair oxidation stream to determine the concentration of TOC in the air oxidation stream from the final recovery device. This concentration of TOC is then used to perform the calculations outlined in § 60.614(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 (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, 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_s (offgas flow rate).

K_1 = Constant, 1.740×10^{-7}

(1)	(g mole)	(MJ)
ppm	scm	kcal

where standard temperature for

(g-mole)
scm

is 20 °C.

C_j = Concentration of compound j in ppm, as measured for organics by Method 18 and measured for hydrogen and carbon monoxide by ASTM D1946-77 (incorporated by reference as specified in § 60.17 of this part) as indicated in § 60.614(d)(2).

H_j = Net heat of combustion 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 (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 process 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} = Emission rate of TOC in the sample, kg/hr

K_2 = Constant, 2.494×10^{-6} (1/ppm) (g-mole/scm) (kg/g) (min/hr), where standard temperature for (g-mole/scm) is 20 °C

C_j = Concentration on a basis of compound j in ppm as measured by Method 18 as indicated in § 60.614(d)(2)

M_j = Molecular weight of sample j, g/g-mole

Q_s = Vent stream flow rate (scm/min) at a standard temperature of 20 °C

(6) The total process vent stream concentration (by volume) of compounds containing halogens (ppmv, 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 § 60.612(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 paragraph (e)(1) of this section and the flare equation in paragraph (e)(2) of this section and selecting the lower of the two values.

(1) The TRE index value of the vent stream controlled by an incinerator shall be calculated using the following equation:

$$TRE = \frac{1}{E_{TOC}} \left[a + b (Q_s)^{0.55} + c (Q_s) + d (Q_s) (H_T) + e (Q_s)^{0.55} (H_T)^{0.55} + f (Y_s)^{0.5} \right]$$

(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_v = Vent stream flow rate (scm/min), at a standard temperature of 20 °C.

H_T = Vent stream net heating value (MJ/scm), where the net enthalpy of combustion 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_v .

$Y_v = Q_v$ for all vent stream categories listed in Table 1 except for Category E vent streams where $Y_v = (Q_v)(H_T)/3.6$.

E_{TOC} = Hourly emissions of TOC reported in kg/hr.

a, b, c, d, e, and f are coefficients.

The set of coefficients which apply to a vent stream shall be obtained from Table 1.

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TABLE 1. AIR OXIDATION NSPS TRE COEFFICIENTS FOR VENT STREAMS CONTROLLED BY AN INCINERATOR

DESIGN CATEGORY A1. FOR HALOGENATED PROCESS VENT STREAMS, IF $0 \leq \text{NET HEATING VALUE (MJ/scm)} \leq 3.5$:

Q_s = Vent Stream Flow rate (scm/min)	a	b	c	d	e	f
$14.2 < Q_s \leq 18.8$	19.18370	0.27580	0.75762	-0.13064	0	0.01025
$18.8 < Q_s \leq 699$	20.00563	0.27580	0.30387	-0.13064	0	0.01025
$699 < Q_s \leq 1400$	39.87022	0.29973	0.30387	-0.13064	0	0.01449
$1400 < Q_s \leq 2100$	59.73481	0.31467	0.30387	-0.13064	0	0.01775
$2100 < Q_s \leq 2800$	79.59941	0.32572	0.30387	-0.13064	0	0.02049
$2800 < Q_s \leq 3500$	99.46400	0.33456	0.30387	-0.13064	0	0.02291

DESIGN CATEGORY A2. FOR HALOGENATED PROCESS VENT STREAMS, IF NET HEATING VALUE > 3.5 MJ/scm:

Q_s = Vent Stream Flow rate (scm/min)	a	b	c	d	e	f
$14.2 < Q_s \leq 18.8$	18.84466	0.26742	-0.20044	0	0	0.01025
$18.8 < Q_s \leq 699$	19.66658	0.26742	-0.25332	0	0	0.01025
$699 < Q_s \leq 1400$	39.19213	0.29062	-0.25332	0	0	0.01449
$1400 < Q_s \leq 2100$	58.71768	0.30511	-0.25332	0	0	0.01775
$2100 < Q_s \leq 2800$	78.24323	0.31582	-0.25332	0	0	0.02049
$2800 < Q_s \leq 3500$	97.76879	0.32439	-0.25332	0	0	0.02291

DESIGN CATEGORY B. FOR NONHALOGENATED PROCESS VENT STREAMS, IF $0 \leq \text{NET HEATING VALUE (MJ/scm)} \leq 0.48$:

Q_s = Vent Stream Flow rate (scm/min)	a	b	c	d	e	f
$14.2 < Q_s \leq 1340$	8.54245	0.10555	0.09030	-0.17109	0	0.01025
$1340 < Q_s \leq 2690$	16.94386	0.11470	0.09030	-0.17109	0	0.01449
$2690 < Q_s \leq 4040$	25.34528	0.12042	0.09030	-0.17109	0	0.01775

DESIGN CATEGORY C. FOR NONHALOGENATED PROCESS VENT STREAMS, IF $0.48 < \text{NET HEATING VALUE (MJ/scm)} \leq 1.9$:

Q_s = Vent Stream Flow rate (scm/min)	a	b	c	d	e	f
$14.2 < Q_s \leq 1340$	9.25233	0.06105	0.31937	-0.16181	0	0.01025
$1340 < Q_s \leq 2690$	18.36363	0.06635	0.31937	-0.16181	0	0.01449
$2690 < Q_s \leq 4040$	27.47492	0.06965	0.31937	-0.16181	0	0.01775

DESIGN CATEGORY D. FOR NONHALOGENATED PROCESS VENT STREAMS, IF $1.9 < \text{NET HEATING VALUE (MJ/scm)} \leq 3.6$:

Q_s = Vent Stream Flow rate (scm/min)	a	b	c	d	e	f
$14.2 < Q_s \leq 1180$	6.67868	0.06943	0.02582	0	0	0.01025
$1180 < Q_s \leq 2370$	13.21633	0.07546	0.02582	0	0	0.01449
$2370 < Q_s \leq 3550$	19.75398	0.07922	0.02582	0	0	0.01775

DESIGN CATEGORY E. FOR NONHALOGENATED PROCESS VENT STREAMS, IF NET HEATING VALUE > 3.6 MJ/scm:

Y_s = Dilution Flow rate (scm/min) = $(Q_s)(H_T)/3.6$	a	b	c	d	e	f
$14.2 < Y_s \leq 1180$	6.67868	0	0	-0.00707	0.02220	0.01025
$1180 < Y_s \leq 2370$	13.21633	0	0	-0.00707	0.02412	0.01449
$2370 < Y_s \leq 3550$	19.75398	0	0	-0.00707	0.02533	0.01775

(ii) Where 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.

$Q_v = 14.2$ scm/min.

$H_T = (FLOW)(HVAL)/14.2$.

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 1 mole is 20 °C as in the definition of Q_v .

$Y_v = 14.2$ scm/min for all vent stream categories listed in Table 1 except for Category E vent streams, where

$Y_v = (14.2)(H_T)/3.6$.

E_{TOC} = 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:

$$TRE = \frac{1}{E_{TOC}} \left[a(Q_v) + b(Q_v)^{a_s} + c(Q_v)(H_T) + d(E_{TOC}) + e \right]$$

where:

TRE = TRE index value.

E_{TOC} = Hourly emission rate of TOC reported in kg/hr.

Q_v = Vent stream flow rate (scm/min) at a standard temperature of 20 °C.

H_T = 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 1 mole is 20 °C as in the definition of Q_v .

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.—AIR OXIDATION PROCESSES 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
$H_T > 11.2$ MJ/scm.....	0.309	0.619	-0.0043	-0.0034	2.08

(f) Each owner or operator of an affected facility seeking to comply with § 60.610(c) or § 60.612(c) shall recalculate the TRE index value for that affected facility whenever process changes are made. Some examples of process changes are 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 § 60.614 to determine compliance with § 60.612(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 4.0 and the recalculated TRE index value is less than or equal to 4.0, but greater than 1.0, the owner or operator shall conduct a performance

test in accordance with § 60.8 and § 60.614 and shall comply with § 60.613, § 60.614, and § 60.615. 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.

§ 60.615 Reporting and recordkeeping requirements.

(a) Each owner or operator subject to § 60.612 shall notify the Administrator of the specific provisions of § 60.612 (§ 60.612 (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 § 60.612 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 § 60.614 within 180 days.

(b) Each owner or operator subject to the provisions of this subpart shall keep up-to-date, readily accessible records 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 § 60.612(a), a report containing performance test data need not be submitted, but a report containing the information of § 60.615(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 this subpart seeks to demonstrate compliance with § 60.612(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 § 60.614(b) achieved by the incinerator, or the concentration of TOC (ppmv, by

compound) determined as specified in § 60.614(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 § 60.612(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 comply with § 60.612(b) through the 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 seeks to demonstrate compliance with § 60.612(c):

(i) Where an absorber is the final recovery device in a 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 a recovery system, the average exit (product side) temperature, measured at least every 15 minutes and average over the same time period of the performance testing while the vent stream is normally routed and constituted.

(iii) Where a carbon adsorber is the final recovery device in a 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 normally routed and constituted), or

(iv) As an alternative to § 60.615(b)(4)(i), (ii) or (iii), the concentration level or reading indicated by the organic 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 § 60.613(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 by an owner or operator seeking to demonstrate compliance with § 60.612(a) or (c), 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 § 60.612(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 § 60.612(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 device during the most recent performance test at which compliance with § 60.612(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 § 60.612(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 § 60.612(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 § 60.613(a)(2), § 60.613(b)(2), and § 60.613(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 or greater to comply with § 60.612(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 in § 60.613(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 § 60.613(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 the owner or operator seeks to demonstrate compliance with § 60.612(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 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 or she will define appropriate parameter boundaries and periods of operation during which they are exceeded).

(2) When a condenser is the final recovery device in a recovery system, and where an organic 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 recovery system and where an organic 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 absorber, condenser, or carbon adsorber is the final recovery device in the recovery system and an organic monitoring device approved by the Administrator is used, all 3-hour periods of operation during which the average 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 subject to the provisions of this subpart and seeking to demonstrate compliance with § 60.612(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 air oxidation reactors;

(2) Any recalculation of the TRE index value performed pursuant to § 60.614(f);

(3) The results of any performance test performed pursuant to the methods and

procedures required by § 60.614(d).

(i) 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.

(j) Each owner or operator that seeks to comply with the requirements of this subpart by complying with the requirements of § 60.612 shall submit to the Administrator semiannual reports of the following information. The initial report shall be submitted within 6 months after the initial start-up-date.

(1) Exceedances of monitored parameters recorded under § 60.615(c) and (g).

(2) All periods recorded under § 60.615(d) when the vent stream is diverted from the control device or has no flow rate.

(3) All periods recorded under § 60.615(e) when the boiler or process heater was not operating.

(4) All periods recorded under § 60.615(f) in which the pilot flame of the flare was absent.

(5) Any recalculation of the TRE index value, as recorded under § 60.615(h).

(k) The requirements of § 60.615(j) 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 § 60.615(j), provided that they comply with the requirements established by the State.

(l) The Administrator will specify appropriate reporting and recordkeeping requirements where the owner or operator of an affected facility seeks to demonstrate compliance with the standards specified under § 60.612 other than as provided under § 60.613 (a), (b), (c), and (d).

§ 60.616 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 October 21, 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.

(Approved by OMB under the control number 2060-0053)

§ 60.617 Chemicals affected by subpart III.

Chemical name	CAS No.*
Acetaldehyde.....	75-07-0
Acetic acid.....	64-19-7
Acetone.....	67-64-1
Acetonitrile.....	75-05-8
Acetophenone.....	98-86-2
Acrolein.....	107-02-8
Acrylic acid.....	79-10-7
Acrylonitrile.....	107-13-1
Anthraquinone.....	84-65-1
Benzaldehyde.....	100-52-7
Benzoic acid, tech.....	65-85-0
1,3-Butadiene.....	106-99-0
p-t-Butyl benzoic acid.....	98-73-7
N-Butyric acid.....	107-82-6
Crotonic acid.....	3724-65-0
Cumene hydroperoxide.....	80-15-8
Cyclohexanol.....	108-93-0
Cyclohexanone.....	108-94-1
Dimethyl terephthalate.....	120-61-6
Ethylene dichloride.....	107-06-2
Ethylene oxide.....	75-21-8
Formaldehyde.....	50-00-0
Formic acid.....	64-18-6
Glyoxal.....	107-22-2
Hydrogen cyanide.....	74-90-8
Isobutyric acid.....	79-31-2
Isophthalic acid.....	121-91-5
Maleic anhydride.....	108-31-6
Methyl ethyl ketone.....	78-93-3
o-Methyl styrene.....	98-83-9
Phenol.....	108-95-2
Phthalic anhydride.....	85-44-9
Propionic acid.....	79-09-4
Propylene oxide.....	75-56-9
Styrene.....	100-42-5
Terephthalic acid.....	100-21-0

*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.

§ 60.618 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: § 60.613(e).

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40 CFR Part 60

[AD-FRL-2960-6]

RIN 2060-AA35

Standards of Performance for New Stationary Sources; Volatile Organic Compound (VOC) Emissions From the Synthetic Organic Chemical Manufacturing Industry (SOCMI) Distillation Operations**AGENCY:** Environmental Protection Agency (EPA).**ACTION:** Final rule.

SUMMARY: Standards of performance for distillation unit operations in the SOCMI were proposed in the Federal Register on December 30, 1983 (48 FR 57538). On May 16, 1985, the public comment period was reopened (50 FR 20446) for the purpose of allowing public comment on revisions to the affected facility designation and the costing procedures. Today's action promulgates standards of performance for SOCMI distillation unit operations. These standards implement section 111 of the Clean Air Act (CAA) and are based on the Administrator's determination that VOC emissions from SOCMI cause or contribute significantly to air pollution which may reasonably be anticipated to endanger public health or welfare. The intended effect of these standards is to require all new, modified, and reconstructed distillation facilities to achieve an emission reduction that reflects the capabilities of the best demonstrated system of continuous emission reduction, considering costs, nonair quality health, and environmental and energy impacts.

EFFECTIVE DATE: June 29, 1990. Under section 307(b)(1) of the CAA, judicial review of the actions taken by this notice is available only by the filing of a petition for review in the U.S. Court of Appeals for the District of Columbia Circuit within 60 days of today's publication of this rule. Under section 307(b)(2) of the CAA, the requirements that are the subject of today's notice may not be challenged later in civil or criminal proceedings brought by EPA to enforce these requirements.

Incorporation by Reference: The incorporation by reference of certain publications in these standards is approved by the Director of the Office of the Federal Register as of June 29, 1990.

ADDRESSES: Background Information Document. The background information document (BID) for the promulgated standards may be obtained from the U.S. EPA Library (MD-35), Research Triangle Park, North Carolina 27711, telephone number (919) 541-2777. Please refer to "Distillation Operations in Synthetic Organic Chemical

Manufacturing Industry—Background Information for Promulgated Standards," EPA-450/3-83-005b. The BID contains: (1) A summary of all the public comments made on the proposed standards and the Administrator's response to the comments, (2) a summary of the changes made to the regulation since proposal, and (3) the final Environmental Impact Statement which summarizes the impacts of the standards.

Docket. A docket, number A-80-25, containing information considered by EPA in development of the promulgated standards, is available for public inspection between 8 a.m. and 4 p.m., Monday through Friday, at EPA's Central Docket Section (LE-131), South Conference Center, room 4, 401 M Street SW., Washington, DC 20460. A reasonable fee may be charged for copying.

FOR FURTHER INFORMATION CONTACT: Mr. Doug Bell or Ms. Debbie Stackhouse, telephone (919) 541-5568 and 5258, respectively, concerning regulatory decisions. Mr. Robert E. Rosensteel or Mr. David A. Beck, telephone (919) 541-5608 and 5421, respectively, concerning technical aspects of the industry and control technologies. The address for the above contacts is Emission Standards Division (MD-13), U.S. Environmental Protection Agency, Research Triangle Park, North Carolina 27711.

SUPPLEMENTARY INFORMATION:**The Standards**

Standards of performance for new sources established under section 111 of the CAA reflect:

* * * application of the best technological system of continuous emission reduction which (taking into consideration the cost of achieving such emission reduction, any nonair quality health and environmental impact and energy requirements) the Administrator determines has been adequately demonstrated [section 111(a)(1)].

For convenience, this will be referred to as "best demonstrated technology" or "BDT."

The promulgated standards apply to new, modified, and reconstructed distillation facilities within the SOCMI. The standards apply to distillation facilities operating as part of a process unit which produces any of the chemicals listed in section 60.667 as a product. The definition of "process unit" and "product" is discussed below in the section entitled: *Significant Comments and Changes to the Proposed Standards*. The affected facility is designated as a single distillation column with its own individual recovery system (if any) or the combination of two or more

distillation columns and the common recovery system they share. A recovery system consists of any device, or devices, capable of and used for the purpose of recovering chemicals for use, reuse, or sale and may include both primary and secondary recovery devices. Some examples of recovery devices are absorbers, adsorbers, and condensers as well as certain devices that recover non-VOC's, such as ammonia and hydrogen chloride recovery units. The designation of affected facility has been changed since the proposed regulation, where an affected facility was designated as a single distillation unit and associated recovery system. Reasons for the change are given in the section below entitled: *Significant Comments and Changes to the Proposed Standards*.

Construction, reconstruction or modification of the affected facility must have begun after December 30, 1983, for the standards to be applicable. Existing facilities are not subject to the standards unless modified or reconstructed as defined in 40 CFR 60.14 or 60.15.

Distillation facilities operating as part of a process unit which produces coal tar or beverage alcohols, or which uses, contains, or produces no VOC are not affected facilities. Any distillation facility that is part of a process unit that has a total design production capacity less than one Gg/yr for the entire process unit has to meet the requirements in paragraphs (j), (l)(6), and (n) of § 60.665 only. Any distillation facility operated with a maximum vent stream flow rate less than 0.008 m³/min has to meet the requirements in § 60.664(g) and paragraphs (i), (l)(5), and (o) of § 60.665 only. Any distillation facility operating as part of a polymer manufacturing process that is subject to the provisions of the polymer manufacturing new source performance standards (NSPS) (subpart DDD) is not subject to these standards. Any distillation facility that is designed and operated as a batch operation is exempt from the distillation operation NSPS.

The standards include emission reduction requirements and/or emission limits which are based on the emission reduction capabilities of the BDT. However, the standards do not require that a specific device or technology be used for those facilities that must comply with the emission reduction requirements. Rather, any control technology other than recovery devices as defined in the standards can be used as long as it can be demonstrated that it is at least as effective as BDT at reducing VOC emissions.

Due to variations in the vent stream characteristics of flow rate, heat content, and concentration of organic compounds, the total cost of control per unit of VOC removed would vary considerably among the different types of distillation facilities. The Administrator has determined that for some distillation facilities, the cost of control per unit of VOC reduced is unreasonably high. Thus, the designation of BDT by the Administrator has two aspects. First, for facilities that can reduce VOC emissions at a reasonable cost, BDT is the reduction of VOC emissions by 98 weight-percent or to 20 ppmv through the use of a thermal incinerator or a flare. For facilities that cannot reduce VOC emissions at a reasonable cost, BDT is no additional control.

To identify those facilities for which implementation of the emission reduction requirements would be unreasonably costly, a means of measuring the total cost to control VOC emissions from distillation facilities was developed. This means of measuring the cost to control is called the total resource effectiveness (TRE) index. Using the TRE approach, the standards would require each owner or operator of an affected facility with a TRE less than 1.0 to either reduce process vent stream VOC emissions by 98 weight-percent or to 20 ppmv by a method other than additional product recovery, whichever is less stringent, or for facilities with a TRE index greater than 1.0 to consistently maintain a value greater than 1.0.

Equations are included in the regulation for determining the TRE index of a vent stream from an affected facility. The process vent stream flow rate, total organic compound emission rate, net heating value, and corrosion properties (whether or not halogenated compounds are present) must be determined according to the specified Reference Methods in order to calculate the TRE index. These vent stream characteristics would be determined for the vent stream following the last recovery device (e.g., condenser, absorber, carbon adsorber).

The structure of the standards allows an affected facility with a TRE index value of less than 1.0 to add a recovery device or improve the existing recovery system efficiency so that the TRE value would increase above 1.0 and, therefore, emissions would not have to be reduced by 98 weight-percent or to 20 ppmv. Increased recovery efficiency for this purpose would have the advantages of achieving additional emission reductions, less energy usage, lower

costs and increased recovery of compounds or increased retention of products. The additional emission reduction could be as much as 30 percent more than current industry practice.

If a boiler or process heater were used to comply with the percent reduction or emission limit, the standards also would require that the distillation vent stream be introduced in the flame zone of the boiler or process heater. If a boiler or process heater were used to comply with the standards, the owner or operator would be required to monitor and record continuously the vent stream flow (using a flow indicator as described later) to the device and the firebox operating temperature. For boilers or process heaters of 44 MW (150 million Btu/hr) design heat input capacity or greater, no temperature monitoring is required but records (such as steam production records) would be required which would verify the periods of operation of the heat generating unit.

A steam-assisted flare, an air-assisted flare, and a flare with no assist are considered to be capable of achieving 98 weight-percent emission reduction and may be used to meet the standards, provided that the flares are operated in accordance with the requirements in 40 CFR 60.18. Each owner or operator complying with the standards by using a smokeless flare would be required to monitor continuously the presence of the pilot flame. Ultra-violet beam sensors or thermocouples are acceptable for this purpose. A flow indicator would also be required that provides a record of vent stream flow to the flare.

Each owner or operator complying with the standards by using an incinerator would be required to monitor continuously and record the firebox operating temperature or, if a catalytic oxidizer were used, the temperature before and after the catalyst bed. A vent stream flow indicator is also required for each affected facility and must be installed as close to the combustion device as possible but immediately before that vent stream is joined with any vent stream not part of the affected facility. Records of vent stream flow must be maintained. If the emission reduction requirements were achieved by other means, the owner or operator would be required to provide information describing the operation of the control device and the parameter(s) that indicate proper operation and maintenance of the device so that the enforcing agency could specify appropriate monitoring requirements.

Each owner or operator who complies with the standards by maintaining a

vent stream TRE index value above 1.0 would be required to monitor continuously and record specified operating parameters of the final piece of recovery equipment to ensure this TRE is consistently maintained.

Operating parameters are established during the initial (or most recent) performance test when VOC concentration is measured. Subsequent monitoring of these parameters is done to determine if their values have deviated from the values measured during the performance test. Depending on what the final recovery device is, the specified operating parameters are condenser exit (product side) operating temperature; absorber liquid temperature; specific gravity (or an alternative measure of absorbing liquid saturation, if approved by the enforcing agency); carbon adsorption bed temperature (after regeneration and completion of any cooling cycle(s)); and the mass flow rate of carbon bed regeneration steam. The owner or operator would also be required to maintain records of changes in production capacity; feedstock identity, catalyst identity; or of replacement, removal, or addition of recovery equipment. When any such change takes place, the owner or operator of the facility is required to recalculate the TRE index value to document that the facility continues to have a TRE index value above 1.0. Such recalculation can be based on test data reflecting the changes in the system, or best engineering estimates of the effects of the changes. If the recalculated TRE index for the facility is less than 1.0, the owner or operator would have to demonstrate compliance with the 98 weight-percent reduction or 20 ppmv emission limit within 180 days from the time of process change. Prior notice of any performance testing shall be given to EPA as required by the General Provisions of 40 CFR part 60. Performance testing may also be required on a case-by-case basis by the Administrator following any change to the recovery system in order to verify the status of the TRE index value for the facility.

The standards require that records of the operating parameters discussed above be maintained to ensure the proper operation and maintenance of combustion control equipment and recovery equipment used to reduce VOC emissions. Furthermore, records of instances where these monitored values exceed allowable limitations established during the most recent performance test must be maintained. In addition to maintaining these records,

an owner or operator must submit a semiannual report of the recorded exceedances. The requirement of semiannual reporting may be waived for affected facilities in States that have been delegated authority for enforcement provided EPA approves the reporting requirements or alternative means of compliance surveillance adopted by the State and the affected facilities comply with the requirements established by the State.

Summary of Environmental, Energy, and Economic Impacts

The environmental, energy, and economic impacts associated with the standards were projected by using a statistical representation of the industry's vent stream characteristics at existing plants. These characteristics include process vent stream flow rate, net heating value, total organic compound emission rate, and corrosion properties (presence or absence of halogenated compounds). It was assumed that the national distribution of these characteristics for new sources would be the same as the distribution for existing sources. In analyzing regulatory alternatives it was assumed that for all new, modified, and reconstructed facilities with a TRE index less than 1.0 either a flare or an incinerator would be applied to all nonhalogenated vent streams to meet the 98 weight-percent emission reduction requirement or 20 ppmv emission limit. Flaring and incineration were determined to be effective control devices that are universally applicable to all SOGMI distillation vent streams that do not contain halogenated compounds. In estimating the impacts of each alternative for nonhalogenated streams it was assumed that the least expensive of these two devices would be applied to individual vent streams. For distillation vent streams containing halogenated compounds, incineration was determined to be most widely applicable due primarily to the corrosion related problems that may occur if flares were used.

The actual energy, environmental, and economic impacts associated with the distillation NSPS are expected to be less than the impacts estimated here. One reason why these impacts would be lessened is that some facilities would upgrade existing recovery equipment to achieve a TRE index value higher than the cutoff, and, in fact, the standards are structured in such a way that encourages this. Such equipment generally has lower associated costs and energy use. Secondly, some facilities would use other combustion devices, such as boilers, or process

heaters which may be less expensive to apply and have a lower net energy consumption than flaring or incineration. A third reason is that some facilities could use existing devices to control emissions and not have to build new devices. The impacts estimated here assumed that new control devices would be built as a result of the standards. Although these factors contribute to the overstatement of the energy, and economic impacts associated with the standards, the degree of overstatement of the impacts cannot be quantified.

Under the standards, it is estimated that 32 percent of all new, modified, or reconstructed distillation facilities would have vent streams with TRE index values under the TRE cutoff of 1.0. If all of these facilities were controlled to 98 weight-percent, the projected national VOC emissions from all new, modified and reconstructed distillation operations would be reduced by an estimated 42,200 Mg/yr. This national VOC reduction would be approximately 82 percent beyond the emission level projected to occur under typical State Implementation Plans (SIP's).

It is projected that in the absence of the standards, uncontrolled VOC emissions would be reduced an average of 81 percent by State regulations. Eighty-one percent represents a weighted average of the regulations in States where new sources are projected to be built. The actual control required would vary considerably from State to State. Therefore, the impacts for individual plants would vary depending on the State where the affected facility is located.

Any increase in emissions of other air pollutants as a result of controlling VOC emissions would be negligible. There would be no direct solid waste impacts under the standards, and impacts on noise, space requirements, and availability of resources would be negligible.

No significant increase in total plant wastewater effluent is projected under the standard. There is no organic wastewater effluent associated with combustion devices themselves. Some facilities which may have a slight increase in wastewater are those which might choose to upgrade or add recovery devices to achieve a TRE above the 1.0 cutoff. Absorption and carbon adsorption are the only recovery techniques currently in use in the industry which have an associated organic wastewater effluent. Based on the available data, only a small percentage of distillation chemical

manufacturing operations are expected to employ these recovery techniques.

The fifth year energy requirements of the standards would be 600 terajoules per year (TJ/yr), (268 bbl of fuel oil equivalent/day), which are considered reasonable. The fifth year cost impacts of the standards are also considered reasonable. The fifth year national annualized cost for VOC control would be \$9.0 million (1978). The fifth year national capital cost for VOC control would be \$15.5 million (1978). As mentioned above, these impacts may be overstated because less costly and less energy intensive VOC reduction methods are likely to be used.

An economic analysis indicated that the costs associated with the standards could be passed on with little or no effect on the profitability of the industry. Projections made by employing process-specific assumptions indicate that the standards would not trigger product price increases in excess of 5 percent of the product price. Most of the chemicals screened (87 percent) would have a maximum price increase of 2 percent or less and 95 percent would have a maximum price increase of 3 percent or less. Finally, there would be no adverse effects on employment because the standards would not appreciably affect the sale or use of chemicals covered by these standards.

The environmental, energy, and cost impacts are discussed in greater detail in the two background information documents for the standards: "Distillation Operations in Synthetic Organic Chemical Manufacturing—Background Information for Proposed Standards" and "Distillation Operations in Synthetic Organic Chemical Manufacturing—Background Information for Promulgated Standards." (EPA-450/3-83-005a and EPA-450/3-83-005b).

Public Participation

Prior to proposal of the standards, interested parties were advised by public notice in the Federal Register (47 FR 26453) of a meeting of the National Air Pollution Control Techniques Advisory Committee to discuss the distillation VOC standards recommended for proposal. This meeting was held on July 21-22, 1982. The meeting was open to the public and each attendee was given an opportunity to comment on the standards recommended for proposal. The standards were proposed and published in the Federal Register on December 30, 1983 (48 FR 57538). The preamble to the proposed standards discussed the availability of the BID "Distillation

Operations in Synthetic Organic Chemical Manufacturing" (EPA-450/3-83-005a) which described in detail the regulatory alternatives considered and the impacts of those alternatives. Public comments were solicited at the time of proposal and, when requested, copies of the BID were distributed to interested parties. The proposal notice stated that a public hearing would be held, if requested, to provide interested persons the opportunity for oral presentation of data, views, or arguments concerning the proposed standards. No public hearing was requested. On May 16, 1985, the public comment period was reopened (50 FR 20446) for the purpose of allowing public comment on the results of a reanalysis of the costing procedures, the TRE equations and coefficients which are derived from these costing procedures, and the designation of affected facility. The reanalysis resulted from the acquisition of new information received in public comments and collected since proposal.

Thirty-five comment letters were received concerning issues relative to the proposed standards of performance for distillation operations in the SOCM. Thirty-four of these were in response to the proposed standards and one was in response to the revisions being considered to the costing procedures, TRE equations, and designation of affected facility. The comments have been carefully considered and, where determined to be appropriate by the Administrator, changes have been made in the standards.

Significant Comments and Changes to the Proposed Standards

Comments on the proposed standards were received from 25 industry representatives, one manufacturer of control equipment, one environmental group, and two State and Federal agencies. A detailed discussion of these comments and responses can be found in the BID for the promulgated standards which is referred to in the ADDRESSES section of this preamble. The summary of comments and responses in the BID serve as the basis for the revisions which have been made to the standards between proposal and promulgation.

The major comments and responses are summarized in this preamble. The comments have been divided into the following areas: Designation of Affected Facility; Applicability of the Standards; Selection of Best Demonstrated Technology; Selection of the TRE Cutoff; Costing Revisions; Change in Flare Specifications; and Exemptions.

All comments discussed here have been entered into Docket Number A-80-

25. Access to this docket is described in the ADDRESSES section of this preamble.

Designation of Affected Facility

At proposal, the affected facility was designated to be any single distillation unit with its associated recovery system that produces any of the chemicals listed in § 80.667. Other possible designations were identified at proposal and EPA specifically solicited comments concerning the proposed designation of affected facility. A number of commenters from the chemical industry disagreed with the proposed designation of affected facility. The commenters indicated that this designation is unrealistic and not representative of the way distillation units are operated within the industry. According to the commenters, distillation units are often physically linked together and to artificially separate them would be inappropriate. The commenters pointed out that some processes include a series of distillation units that can use a common recovery device. They concluded that in these cases, application of VOC reduction requirements and monitoring methods under the proposed designation of affected facility would be potentially confusing and costly.

The commenters prefer that an affected facility be designated as the recovery system with all associated distillation units. The commenters indicated that this designation would best reflect the way distillation units are used within the industry. Also, ambiguities in monitoring and testing requirements would be minimized when more than one distillation unit is tied to a common recovery system. The commenters stated that this designation would also allow a facility the flexibility to change operating conditions or equipment within a process unit in lieu of adding combustion devices. It was also stated that the flexibility associated with the recommended designation would not result in less environmental benefits compared to the proposed designation. Overall, the commenters felt that this designation would reduce monitoring, control, and hardware costs incurred by affected distillation facilities.

A comment from an environmental group indicated that the designation of affected facility contained in the proposed regulation conforms with the requirements of the CAA in so far as it does not allow two or more distillation units which are joined to a common recovery system to be interpreted as one facility. One commenter from industry is in favor of the designation of affected facility selected by EPA at proposal

because the commenter believes the approach will allow for continuous improvement of the air quality.

Based on these comments, the Agency reevaluated the designation of affected facility and presented the results of this reevaluation in the Federal Register on May 16, 1985 (50 FR 20446). Based on those results and the lack of adverse comment on that reevaluation, the designation of affected facility used in the standards has been changed to a single distillation unit that does not vent to a recovery device, a combination of a single unit with its associated recovery system, or the combination of two or more distillation units and the common recovery system to which their vent streams are discharged. For the majority of the industry, this change will have no effect because approximately 80 to 90 percent of the industry's distillation units exist as individual units. However, the effect of the designation change will be seen for the remaining 10 to 20 percent of the distillation units that share recovery devices. This change was not made to provide industry with operating flexibility; rather the new designation is estimated to result in greater emissions reduction. Also, as discussed below, the new designation would facilitate the implementation of the standards because, in some cases, the cost and complexity associated with determining a TRE index value will decrease.

The EPA estimates a greater reduction in national VOC emissions because of the change in the designation of affected facility. Greater reduction in emissions will occur with the new designation because for facilities where the TRE is less than 1.0, emissions from existing distillation units will also be controlled when new units are combined with existing units sharing a common recovery system. The Agency believes that a widespread evasion of the modification provisions would not occur under this designation. For example, a change that would be considered a modification is made to one distillation unit within a group of existing units. In order to avoid a modification, the common recovery system is upgraded so that no emissions increase results. However, operational or physical changes that would be considered modifications are rarely made to individual existing distillation units sharing a recovery device. Instead, it is more likely that new distillation units would be added to an existing group of units resulting in increased emissions.

In the event an owner added a distillation unit to an existing group of units ducted to the same recovery

system, it is unlikely the facility could avoid being considered a modification by offsetting the new distillation unit emissions somewhere else within the distillation group. This is because it would likely be technologically infeasible to reduce emissions sufficiently from other distillation units. Although some VOC reductions could occur through upgrading recovery equipment, it is unlikely that this reduction would result in a full offset of the new distillation unit emissions because the increased load on the recovery device (i.e., increase flow and VOC) would make the needed increase in VOC removal efficiency difficult to achieve. Thus, the likely result is that addition of a distillation unit to a group of joined units would bring the entire set under the coverage of the standards as a modified facility. Even though it is unlikely to occur, if the owners or operators of the facility could completely offset emissions from a new distillation unit by upgrading the recovery system, it would be the equivalent of 100 percent VOC control for that new distillation unit. This is 2 percent more than would be necessary if the individual units were designated as affected facilities and 98 weight-percent control were applied to the new unit.

The EPA believes the reconstruction provisions will not be avoided under the broad designation because major physical changes (i.e., reconstruction) to individual distillation units within a group of units rarely occurs within the industry. It is not likely that an owner or operator of an affected facility made up of a group of distillation units could replace one of the units and avoid being considered a reconstruction. Available data show this situation would not arise because the replacement of individual distillation units or pieces of recovery equipment is rare within the industry. This is because distillation units are expensive pieces of equipment which are designed to last a long time (Docket Item No. II-B-13). Moreover, the Agency has concluded that those few replacements which do occur often result from process changes or catastrophic events that would probably require replacement of most of the group of distillation units joined to a single recovery system. These changes would likely amount to a "reconstruction" of the facility as it is defined in these standards. Thus, in the small percentage of cases where distillation unit replacements occur, the facility would most likely fall under the coverage of the standards.

An incidental effect of this change in the affected facility designation is that

implementation of the standards would be made significantly easier. When two or more distillation units are joined to a common recovery system, determining a TRE index value is less complex and less costly than under the designation at proposal because fewer test sites are required to measure the vent stream characteristics needed to calculate a TRE index value. Under the designation set forth at proposal of these standards, it was required only that the portion of the combined vent stream contributed by the new, modified, or reconstructed distillation unit comply with the standards when it shares a recovery system with existing units. Therefore, the TRE index value was determined for the portion of the stream contributed by that unit only. This determination was complex and costly and was based upon an apportioning method using sampling sites located just downstream of the new unit and sampling sites located upstream and downstream of the common recovery system. These sampling data were to have been used to determine the overall efficiency of the common recovery system. This efficiency was then to have been applied to the vent stream from the new unit to determine its contribution to the total emissions from the common recovery system.

Under the final designation, the standards require only one sampling site located after the last recovery device to determine a TRE index value. No determination of recovery efficiency is needed because the entire vent stream is covered. Therefore, there is no need to determine which portion of the final vent stream from a group of distillation units is attributable to new, modified, or reconstructed distillation units and which portion is attributable to distillation units that have not been changed or added. This results in a performance test requirement that is less costly and less complex because fewer sampling sites and subsequent analyses are needed.

Applicability of Standards

Several commenters stated that three fertilizer chemicals, urea, urea ammonium nitrate (UAN), and ammonium carbamate should not be covered by the standards. They stated that the production of two of these chemicals does not involve the use of a distillation operation, while urea production uses flash evaporation which may be considered a distillation operation. It was also stated that production of these three chemicals does not result in significant VOC emissions. It was pointed out because of insignificant VOC emissions all affected

facilities that produce urea, UAN, or ammonium carbamate would probably comply with the standards by maintaining a TRE index value much greater than 1.0. The reasons given for the expected high TRE index value for all affected facilities producing these chemicals are the current and extensive use of very efficient recovery equipment and the large amounts of fuel enrichment needed for the low heating value vent streams. The commenters stated that compliance based on maintaining a TRE index value above the cutoff would still be costly because of the required monitoring, recordkeeping, reporting, and performance testing. The commenters felt it was unjustified that these compounds be on the SOCOMI list only because they are organic chemicals produced in large volume.

Based upon available information, EPA has decided to remove three fertilizer chemicals from the list in § 60.667. Urea, ammonium carbamate, and UAN are no longer listed in the distillation regulation. The distillation NSPS is not applicable to the production of UAN and ammonium carbamate because according to the information available to the Agency, no distillation operations are used to produce these chemicals. Although distillation operations are involved in the production of urea, EPA has removed urea from the list because no VOC emissions are expected to occur during distillation operations involved with urea production. The vent streams from these distillation units consist almost entirely of inert gases (e.g., nitrogen), water, ammonia, and urea particulate. The potential for VOC emissions would exist when formaldehyde based additives (FBA) and/or methanol are added before or during the distillation operation. However, available information indicates that at the majority of urea production facilities, FBA is injected into the product stream after the distillation operation. Therefore, there is no potential for formaldehyde emissions from distillation units within this type of production process. For process units where FBA are injected prior to or during distillation, the only organic emissions expected from the distillation unit would be particulate urea. Any formaldehyde should be completely reacted with urea to form methylenediurea. (Docket Item No. IV-E-14).

No information was available that indicates methanol is added before or during distillation. For these reasons, the Agency has decided to remove urea

from the list of chemicals covered by the final standards.

Several organic chemical and petroleum producers believe the standards should not apply to distillation facilities that do not produce any of the chemicals listed in the regulation as the main product. They said that only listed chemicals produced as products should be covered, while contaminants, by-products, and intermediates should not be included. It was also suggested that the standards should not apply to the recovery of waste or feedstock components. There was a request that EPA clarify whether a facility would be an affected facility if its process stream contains listed chemicals that are either sold, disposed of, used in the production of other chemicals, or recycled. Furthermore, it was suggested that the standards specify a minimum level for quantities of listed chemicals in a process stream that would cause the proposed regulation not to be applicable to distillation facilities that contain listed chemicals only as impurities in a process stream.

The EPA considers it appropriate for the standards to apply to any distillation facility within a process unit producing any of the listed chemicals as a product, by-product, co-product, or intermediate. The standards were developed from data on distillation facilities within process units that produce the chemicals listed in § 60.667 in any of the forms listed above. The cost of controlling emissions from the production of a listed chemical as a by-product, co-product, or intermediate is similar to the cost of controlling emissions from the production of that chemical as a product. Furthermore, the application of the standards to facilities producing any of the listed chemicals was found to be reasonable. Therefore, EPA considers the word product to also represent by-products, co-products, and intermediates. The standards are also applicable to distillation facilities that are used to recover waste or feedstock components as long as the facility is within a process unit producing any of the listed chemicals as a product. The main factor in determining if a listed chemical is produced as a product is the use of the chemical after the process unit. The EPA considers either of the following downstream uses as indicative of the production of a listed chemical as a product: (1) Produced for sale as that listed chemical, or (2) used in another process where that listed chemical is needed. However, if a listed chemical is only part of a mixed stream exiting a process unit and cannot be sold or used in another process as the listed

chemical, then that chemical is not considered to be produced as a product.

The EPA has decided that for the purposes of these standards it is more appropriate to determine applicability according to whether a listed chemical is intended to be produced as a product instead of setting a minimum concentration level of a listed chemical as a means of defining what may constitute production as a "product". It is not feasible to set any one concentration limit for listed chemicals below which the chemical is always an impurity or waste. It is not feasible because the necessary concentration or purity for a listed chemical to be considered a product can vary from site to site. For example, a chemical that is produced as 90 percent pure from one process may only be 80 percent pure to be considered as a product for another process. Therefore, resource requirements for establishing different concentration limits for all of the processes covered by the standards would be prohibitive because of the diversity and complexity of the SOCMI.

Selection of BDT

One commenter stated that catalytic oxidation can be an attractive alternative to thermal incineration. He indicated that although catalytic oxidation can be designed for high VOC reduction efficiencies, economic factors dictate whether these levels are practical. The commenter added that the 98 percent reduction efficiencies associated with the proposed standards would possibly require the use of uneconomically large catalyst volumes in catalytic incinerators or require the use of thermal incinerators. The commenter pointed out that 98 percent reduction efficiency may not result in a measurable improvement in the environment over the case of catalytic oxidation at an efficiency slightly lower than 98 percent. Furthermore, the use of thermal incineration may potentially entail the following detrimental effects: (a) A higher energy usage by the affected facilities; (b) an increase in NO_x emissions from the affected facilities using thermal incineration; and (c) a decrease in the international competitive position of domestic chemical producers with respect to foreign competition.

Another commenter suggested that those distillation facilities with vent streams above the TRE cutoff be considered for the applicability of emission reduction techniques other than flaring or incineration. A suggestion was made that technologies such as catalytic oxidation and carbon adsorption which involve lower costs

and energy requirements than flaring or incineration be evaluated for application to distillation facilities determined to have cost-effectiveness values above the cutoff. It was pointed out that although the emission reduction capabilities of catalytic oxidizers and recovery devices are not consistently as great as combustion, further emissions reductions could be achieved using these relatively low cost devices.

The EPA has determined that where catalytic oxidation units are applicable, they are capable of achieving 98 weight-percent reduction efficiency. However, catalytic oxidation for VOC emissions reduction has not been demonstrated to be universally applicable for all distillation process vent streams, and we cannot subcategorize facilities that can use catalytic oxidation on the basis of available information. Therefore, the costs of catalytic oxidation were not evaluated by the Agency. Catalytic oxidizers are limited by their inability to handle streams with high heating values because deactivation of the catalyst occurs at high temperatures. Catalysts can also be deactivated by compounds present in some waste streams, such as arsenic, sulfur, mercury, lead, zinc or tin.

The Agency did evaluate two control techniques universally applicable within the industry, thermal incineration and flaring. The Agency examined emissions data from incinerators already operating within the industry, as well as incinerator and flare tests conducted by the Agency and by chemical companies. All the new, well-operated incinerators and flares were found to achieve 98 percent reduction efficiency. From the available data the Agency determined many facilities could achieve 98 percent reduction efficiency at a reasonable cost using thermal incineration and flaring. The Agency has bounded the cost impacts associated with combustion devices by costing the most expensive devices: thermal incinerators and flares. Costs associated with these devices were found to be reasonable for facilities with TRE index values less than 1.0. Therefore, if a stream does exist whose constituents are such that a catalytic oxidizer is not applicable or not economical, a flare or thermal incinerator can be used.

The commenter is particularly concerned that EPA, by not allowing catalytic incinerators to substitute for thermal incinerators, will create a competitive disadvantage for U.S. plants vis-a-vis foreign competition. However, the Agency is not preventing the use of catalytic incinerators. They may be used if the emission reduction requirements are satisfied. Furthermore, if an owner

or operator chooses to use a thermal incinerator, no economic disadvantage should be created vis-a-vis foreign competition. Using reasonable control estimates, chemical price increases are expected to range from about 0 to about 4 percent.

The energy and environmental effects mentioned were considered in selecting thermal incineration as one of the control techniques upon which the impacts of the standards are based. The energy consumption and cost associated with thermal incineration were considered and found to be reasonable because these can be offset by the use of recuperative heat exchangers. The potential for increased NO_x emissions was also examined, but the rate of NO_x formation is expected to be low due to relatively low combustion temperatures and relatively short residence times associated with thermal incineration.

With respect to the suggestion of evaluating other techniques for use on facilities above the TRE cutoff, EPA is unable with available information to identify subcategories of distillation operations for which other VOC control techniques, such as catalytic oxidation and carbon adsorption, have been demonstrated to always apply. The applicability and effectiveness of these devices may be affected greatly by the vent stream flow rate, water content, temperature, VOC concentration, and VOC properties such as solubility, molecular weight, and liquid/vapor equilibrium. These characteristics vary widely within the SOCMI. Therefore, consideration of these devices in developing regulatory options was not feasible. Even with greater resources, this analysis would be infeasible because it would require a stream-by-stream characterization, ultimately resulting in the need to create a separate standard for each distillation facility within a process unit used to produce a listed chemical. The number of standards required to regulate the same number of sources would increase significantly. The Agency believes that such an approach to regulating the SOCMI distillation industry would be administratively infeasible and therefore environmentally counterproductive. In any event, as the commenter recognizes, proceeding now with this generic regulation based on thermal incineration and flaring at least represents an important first step in regulating distillation emissions and does not preclude later regulation of subcategories of distillation facilities should that become feasible. The EPA believes it has the authority to take this step by step approach under section 111.

See, e.g., Group Against Smog and Pollution v. EPA, 665 F.2d 1284. (D.C. Cir 1981).

Selection of the TRE Cutoff

Both an environmental group and industry commenters indicated that the \$1,900/Mg (1978\$) cutoff is unreasonable. The environmental group requested that the cutoff level be raised in order to cover a greater number of sources and a greater quantity of emissions. This recommendation is based on the commenter's perception that the inclusion of a greater number of sources would reduce public exposure to pollutants emitted by distillation facilities, including potentially hazardous pollutants. The environmental group requested that the cutoff be set at the point of diminishing returns, i.e., where cost effectiveness at individual facilities starts to sharply increase in relation to the amount of reduction in national emissions. The commenter stated that this rationale has not been applied for this NSPS in selecting the cutoff.

An industry representative considers the cutoff too high and stated that it is not adequately justified by the Agency. The commenter stated because EPA has greatly underestimated the total installed capital cost and the annual operating costs of control devices, the cutoff of \$1,900/Mg for VOC abatement is understated. The commenter also contended that the cutoff exceeds the \$1,000/Mg limit used in most other NSPS and suggested that a \$500/Mg cutoff is more than adequate to secure all meaningful reductions. The commenter stated that a plot of the data from the proposed regulation shows a point of sharply diminished national VOC emission reduction in the \$200 to \$600/Mg range with essentially no additional reduction in emissions achieved at any cost above that range.

The same commenter asserted that the \$1,900/Mg cutoff cannot be justified based on the presence of toxic constituents in the vent streams from distillation facilities. The commenter pointed out that control of toxic pollutants is the objective of standards developed under section 112 of the CAA (national emission standards for hazardous air pollutants (NESHAP)) and not standards such as these which are being proposed pursuant to section 111 of the Act (NSPS). The commenter also stated that the Agency has not adequately demonstrated that the presence of toxic pollutants in the emissions from distillation facilities are sufficiently different from the emissions from other VOC sources to justify a special consideration of their hazards.

Several commenters indicated that EPA had used the same \$1,900/Mg cutoff in the recently proposed air oxidation NSPS. They suggested this figure results from an EPA policy decision, not from a specific evaluation of the costs and impacts associated with the distillation NSPS.

The EPA believes that its decision to consider cost effectiveness as one indication of cost when determining the cutoff for applying the percent reduction standards reflects a reasonable interpretation of section 111 of the CAA. In analyzing the question of whether the consideration of cost effectiveness is appropriate, EPA looked to see whether Congress had "directly spoken to the precise question." *Chevron, U.S.A., Inc. v. NRDC*, 467 U.S. 837, 104 S.Ct. 2778, 2782 (1984). Section 111 requires EPA to promulgate NSPS limiting emissions to the level that reflects the best system of emission reduction "which (taking into consideration the cost of achieving such emission reduction, any nonair quality health and environmental impact and energy requirements) the Administrator determines has been adequately demonstrated." Section 111(a)(1). Nothing in either section 111 or elsewhere in the Act defines "the cost of achieving such emission reduction." The plain meaning of the phrase, however, is quite broad. This indicates that Congress implicitly delegated to EPA the authority to interpret the phrase to encompass a range of impacts, including costs of control in relation to the emission reductions achieved. Further, Congress did not specify any particular manner in which EPA was to take these costs "into consideration." Thus, absent a clear Congressional direction to the contrary discernible from the Act's history, *Chevron*, 104 S.Ct. at 2783, section 111 gives EPA authority to reject NSPS control options on the ground that their costs are unreasonably high in light of the emission reductions they achieve.

The EPA has reviewed the legislative history of section 111 and concluded that no contrary intent is discernible. Most important, the history contains no express repudiation of the use of cost effectiveness as one mechanism in considering costs when setting an NSPS.

For these reasons, EPA believes that Congress implicitly delegated the Agency the authority to decide how best to "take into consideration . . . cost" in setting NSPS and, if the Agency concluded it was appropriate, to consider cost effectiveness.

Further, in *Portland Cement Association v. Train*, 513 F.2d 506, 508 (D.C. Cir 1975), *cert. denied*, 416 U.S. 1025 (1975) ("Portland II"), the Court

stated that EPA may reject control options that result in a "gross disproportion between achievable reduction in emissions and cost of the control technique." Since the purpose of cost effectiveness analysis is to highlight such disproportion, this passage supports EPA's approach.

In selecting cutoffs related to applicability of NSPS, EPA looks at a variety of factors including: (1) The technical feasibility of additional control; (2) the economic feasibility associated with different control alternatives; (3) the magnitude of emission reductions associated with a control alternative (e.g., a slightly higher cutoff could be selected if it led to a substantial increase in the emission reduction achieved by the NSPS); (4) the cost effectiveness (C/E) of the control alternative in terms of annual cost per megagram (\$/Mg) of emissions reduced; (5) the quality of the cost estimates (e.g., worst case versus realistic estimates); (6) potential reductions in other air pollutants not specifically regulated by the NSPS resulting from a control alternative; and (7) the location of the sources (e.g., urban versus rural). Because these factors vary from industry to industry and, in some cases, within the same industry, decisions on the appropriate level of control are made on a category by category basis.

In evaluating the above factors, EPA found that the following considerations were key to the selection of the appropriate cutoff for SOCM distillation operations: (1) The cost effectiveness of NSPS for VOC emissions previously promulgated by EPA; (2) the fact that distillation vent streams contain compounds that are considered potentially toxic by EPA and that many of the facilities are located in urban areas; and (3) the likelihood that these maximum costs will not be incurred by industry.

A survey of the VOC standards for other source categories shows that the cost effectiveness of those control requirements has sometimes ranged as high as \$2,000/Mg. (See Docket Item No. IV-B-17.) The Agency's experience in implementing these standards reveals that NSPS requiring this level of control have proved a useful tool in bringing about the installation of much emissions control technology, significant reductions in emissions, and corresponding improvements in air quality, yet have not imposed costs that appear "grossly disproportionate" to the emission reduction achieved. *Portland II*, 513 F.2d at 508. Such an approach simply makes this NSPS consistent (as to dollars spent per metric ton of VOC

removed) with the existing body of NSPS regulations, all of which have either been promulgated without legal challenge or have been judicially upheld.

EPA also considered evidence that distillation streams include compounds that may be toxic.¹ Although that evidence has not yet resulted in a determination that those compounds should be listed as hazardous under Section 112, EPA considered this potential toxicity along with other relevant factors when choosing the cutoff. As stated in EPA's Air Toxics Strategy published in July 1985, the Agency will consider the likely toxic pollutant control benefits in the course of carrying out its responsibilities under Section 111. This strategy reduces emissions of potentially toxic compounds from new sources and from industries as their facilities are reconstructed or modified. This approach achieves significant reductions in these compounds of concern while the Agency evaluates them for regulation under section 112. The Agency disagrees with the argument that EPA has no authority to do this. The EPA is not attempting here to regulate streams based on a decision that they contain hazardous air pollutants within the meaning of section 112. Rather, the Agency is simply considering all available evidence within the framework of section 111. Section 111 does not attempt to restrict EPA's discretion to consider all relevant factors in making that decision, and certainly the potential toxicity of a stream is relevant to the control requirement selected. Many SOCM facilities are located in urban areas and, as a result, many people will be exposed to any hazardous air pollutants emitted from these facilities.

A third consideration in setting the cutoff at \$1,900/Mg is the likelihood that no facility will actually have to incur the costs implied by that cutoff. The reasons are: (a) Less expensive control systems may be used, thus reducing the costs and cost effectiveness incurred by individual facilities; (b) the cost estimates for thermal incinerators and natural gas prices are overstated; and (c) the inherent flexibility within the regulation encourages the use of product

recovery modifications that will significantly reduce the cost incurred by individual facilities that may have otherwise had to add a combustion device. The regulatory analysis assumes that each distillation operation process vent would have its own combustion device and would need separate ducting and support structures. It is expected, however, that some operations will share control systems with other process vents. The analysis also assumes that incinerators or flares will be used to reduce VOC emissions by 98 weight-percent. However, many facilities will opt to use boilers, process heaters or catalytic oxidizers. When these devices are used, the cost of control will be significantly reduced over the cost of thermal incineration. Data on current capital costs of thermal incinerators indicate that units are now available at substantially reduced costs compared to the costs used in developing these standards. Lower capital costs would reduce the annualized costs estimates, also, but not as significantly. This is an important consideration in selecting the appropriate cost-effectiveness cutoff. Another consideration is the fact that natural gas prices used to calculate the cost effectiveness for each stream are overstated by about 40 percent, even though they were updated after proposal (see following section on "Costing Revisions"). These conservative assumptions have resulted in higher cost and cost-effectiveness estimates than will actually occur. Finally, the standard encourages pollution prevention by not requiring 98 weight-percent reduction if a TRE index greater than 1.0 is maintained. The EPA believes that many facilities having a TRE index just below the 1.0 cutoff (equivalent to \$1,900/Mg) will upgrade product recovery to reduce VOC and raise their TRE index above 1.0. This will significantly reduce the cost of control incurred by the industry while reducing emissions and will also minimize the national energy impacts. A preliminary examination of the national statistical profile shows that because many facilities have the potential to reduce VOC emissions sufficiently to raise their TRE values above 1.0, the highest cost effectiveness that a facility will actually incur as a result of installing a combustion device is estimated to be approximately \$1,400/Mg.

The EPA believes that this process reflects a reasoned interpretation of the phrase "taking into consideration the cost of achieving such emission reduction," especially given the lack of clear Congressional guidance. The

¹ The agency has adequately documented that this is the case. (See Wehrum, W. et al., "Air Toxics Emission Patterns and Trends," Docket Item No. IV-A-3, and Registry of Toxic Effects of Chemical Substances, Docket Item No. IV-J-8.) Moreover, it is apparent that combustion of those streams will reduce those compounds proportionately. (See, e.g., "Thermal Incinerator Performance for NSPS," Docket Item No. II-B-3.) The Agency received no comment questioning this documentation.

commenters' arguments that EPA should have selected either a higher cutoff to provide for a greater degree of protection of the public health, or a lower cutoff because most VOC standards have lower costs in relation to the resulting emission reduction, fail to provide a more reasoned methodology for selecting the appropriate level. Instead, they merely reflect each of the competing goals reflected in Section 111's history, as described above.

Consideration of all of the above factors confirmed EPA's belief that a TRE value of 1.0 (i.e., \$1,900/Mg) represents an appropriate cutoff for determining which facilities must reduce VOC emissions by 98 weight-percent or to 20 ppmv. The cutoff is specific to the SOCM distillation operations source category and would not necessarily be appropriate for other source categories; therefore, it should not be viewed as a benchmark for other standards. It is not surprising, however, that the cost-effectiveness cutoff for distillation would be the same as for the air oxidation NSPS for a number of reasons. First, the same pollutant, (i.e., VOC) is being regulated. Second, the same general class of VOC emitters (i.e., SOCM) and similar types of process equipment (e.g., recovery equipment) are affected. Third, the same types of control techniques are applicable.

Costing Revisions

Several commenters from industry objected to the costing assumptions used in development of the standards. They stated that both the total installed capital cost and annualized costs for combusting VOC were greatly underestimated thus causing the TRE cutoff to be understated. Most comments pertained to flares. The following are some of the major equipment cost items identified as being either overlooked or not adequately treated by EPA: (a) A new pipe support system (pipe rack); (b) provision of steam, natural gas, and electrical services to the flares; (c) a TV camera and monitor to observe flare operations for smoke; and (d) an inadequate design basis for the flare height (maximum ground level heat intensity). Some of the major operating and maintenance components that industry identified as being either overlooked or not adequately treated by EPA included the following: (a) General plant overhead; (b) engineering and environmental costs; and (c) labor, supervision, and maintenance related costs.

The EPA reevaluated all costing assumptions (see Docket Items IV-B-7 and IV-B-8) and revised them where it

was justified. For example, the cost of a new pipe rack was added that is appropriate for use in routing flare services (e.g., electrical, gas and steam services) and the vent stream to the base of the control device. However, the pipe bridge cost recommended by industry was not used because it was found to be unrealistically high for servicing a single affected facility. The pipe bridge cost recommended by industry corresponded to a heavy-duty system capable of supporting many pipes from many process units and not just those pipes associated with the affected facility. In addition to the pipe rack, other costs such as those associated with bringing services such as gas and steam up to the flare were added. Based on recommendations from industry, the maximum ground level heat intensity for flares was adjusted from the original value used. This change had little effect on costs and resulted in increased flare heights in some cases; but in most cases, the flare height did not change from the height determined with the original heat intensity.

Some equipment additions recommended by industry were not included. For example, a TV camera and monitor were not included in the flare costing algorithms because they were judged to be unnecessary for ensuring the proper operation and maintenance of a flare. The EPA determined that the monitoring requirements in the regulation can be satisfied without the use of a TV camera and ancillary equipment. Constant temperature readings of a flare thermocouple are acceptable for monitoring the flare.

In reviewing costs, several equipment cost assumptions were changed that were not requested by industry. For example, changes were made in the length of duct needed to route a vent stream from the facility to a flare or incinerator. The original estimates of duct lengths were derived from information received from the chemical industry and were based on distances from existing distillation units to the nearest combustion devices. However, EPA determined that a new combustion device dedicated to a continuous flow vent stream at new plants would be necessary for some facilities covered by the standard. Since use of a new combustion device at a new plant should be the basis of costing, duct length criteria should be based on the most probable location of a new combustion device. This device is expected to be located as close to the process unit as possible but far enough away to provide safety. The length of

ducting included in the revised design criteria (200 feet for an incinerator and 300 feet for a flare) is based on insurance underwriter recommendations for locating open and enclosed combustion sources at a safe distance from process equipment.

The Agency also reviewed, and where appropriate, revised the operating and maintenance costs for flaring and incineration. The cost for labor involved with operation and maintenance was adjusted along with the cost for supervisory labor. Changes were also made in the overhead costs and engineering costs. The net heating value of natural gas used as a supplemental fuel was also modified and the new flare specifications, as discussed below, were incorporated into the costing algorithms. The cost of natural gas was also revised to take into account: (1) Regional variations in gas price, and (2) the projected effects of natural gas deregulation. However, due to a slower than anticipated rate of price increase the revised cost of natural gas is overstated by about 40 percent.

Change in Flare Specifications

A number of commenters from industry consider the flare specifications at proposal to be too restrictive. Commenters indicated that the proposed flare specifications would have a severe economic impact on some existing facilities that would be covered by these standards. This is because these plants already use flares designed and operated at velocities considerably higher than 60 ft/sec maximum exit velocity specification. The commenters stated that the exit velocity limitation of 60 ft/sec when the gas stream heating value is less than 1,000 Btu/scf could necessitate the replacement of existing flares designed and operated with velocities greater than 60 ft/sec. Commenters also mentioned that the construction of new flares to meet the velocity restrictions will be costly and in many cases completely infeasible. Furthermore, the commenters mentioned that not enough data were collected and not a broad enough range in test conditions was used by EPA in setting the specifications.

Because of the technical infeasibility of testing for the VOC reduction efficiency of flares, EPA determined it necessary to set operational specifications to ensure 98 weight-percent reduction efficiency. The original specifications were based upon the best data available at the time of proposal. Since proposal, operating specifications for flares used to comply with requirements in NSPS were added

to the General Provisions (51 FR 2701, January 21, 1986). The regulation has been revised to refer all owners or operators of affected facilities which use flares to comply with this NSPS to those requirements. These new specifications resolve the commenters' concerns about the specifications in the standards at proposal.

Other types of flares not demonstrated by EPA to have a 98 weight-percent reduction efficiency could be used in complying with the standards. As stated in the General Provisions, data can be submitted to the Agency to demonstrate 98 weight-percent reduction efficiency. If this were done, that flare could be allowed as a suitable control device.

The commenters were concerned that the exit velocity limitation of 60 ft/sec when the gas stream heating value is less than 1,000 Btu/scf could necessitate the replacement of existing flares designed and operated with velocities greater than 60 ft/sec. However, EPA's analysis shows the cost of constructing a complete new flare system to be reasonable. The EPA believes existing facilities coming under the standards would not have to completely replace these existing flares designed and operated with velocities greater than 60 ft/sec. Instead of building a new flare, only the existing flare tip and some auxiliary equipment would have to be changed to accommodate the 60 ft/sec limitation. Considering that many components of the existing flare could still be used, EPA has judged the cost of modifying and existing flare to be well below the cost estimated to construct an entirely new flare.

Exemptions

A suggestion was made to allow distillation facilities operated with a vent stream flow rate of less than 0.008 m³/min (0.3 scfm) to be exempt from coverage by the standards. The proposed regulation contained an exemption for any distillation facility which is designed with a maximum vent stream flow rate of less than 0.008 m³/min. The proposed provision constituted an exemption from meeting the specifications of the standards except for recordkeeping and reporting requirements. The commenters indicated the designed vent stream flow rate is usually different from the operated flow rate. Since vents are typically designed to accommodate the highest flow rate that might be experienced under typical operating conditions, operating flow rates are usually lower than design flow rates. The commenter pointed out that the suggested change would also clarify any ambiguity over vents that were

designed for 0.008 m³/min but are operated at higher flow rates.

The Agency recognizes that some distillation facilities may operate with vent stream flow rates above or below their designed level. Therefore, EPA has decided to exempt from coverage by the standards, except for recordkeeping and reporting requirements, those distillation facilities that operate with a vent stream flow rate less than 0.008 m³/min. The Agency will not exempt distillation facilities only because they were designed for a vent stream flow rate below 0.008 m³/min. The owner or operator of an affected facility that operates with a vent stream flow rate below 0.008 m³/min must notify EPA and demonstrate, with a performance tests, that the operating flow rate is less than 0.008 m³/min. Furthermore, any operational changes in the facility that may cause the operating vent stream flow rate to no longer be below the exemption level must be recorded along with a new flow rate measurement after the change has been made. No reporting to EPA is required until the low flow level has been exceeded and the report must contain the new flow rate measurement. If the vent stream flow rate exceeds the exemption level, the owner or operator must comply with the provisions of Section 60.662.

Several commenters requested more consideration be given to the complex nature of batch operations. They suggested the standards be applied on a case-by-case basis for batch distillation systems because the vent streams from these operations often have variable characteristics. For example, batch vacuum distillation may have an initially high vent stream flow rate as noncondensibles are removed from the products being purified followed by very low emissions for the rest of the cycle. The commenter stated that application of a recovery system for compliance with a TRE greater than 1.0 is likely to represent greater difficulty and cost impact on batch distillation facilities than anticipated by the Agency.

The EPA has decided to exclude batch distillation operations from this NSPS because BDT was evaluated with respect to continuous operations which have relatively constant vent stream flow rates and compositions within a process unit. Batch distillation typically emits a vent stream of variable flow rate and composition during its operation. As a result, BDT may not be applicable to vent streams from batch processes. The Agency is currently investigating the need for a separate NSPS for batch processes within the SOCMI.

One commenter suggested that an exemption from monitoring or recordkeeping requirements should be allowed for facilities showing a TRE index greater than a specified value. The Agency has decided that facilities with TRE index values greater than 8.0 would not fall below the cutoff without a process change. Thus, the Agency believes that the monitoring and recordkeeping requirements should not be imposed on such facilities. However, a process change in that facility would warrant a recalculation of the TRE index value to determine whether the value is still greater than 8.0 and the facility still qualifies for the exemption.

Paperwork Reduction Act

The reporting and recordkeeping requirements of the regulation are assessed in Standard Form 83 and an accompanying supporting statement which are included in the docket for public review. This documentation contains (1) A description of the reporting and recordkeeping required by the regulation and the 40 CFR Part 60 General Provisions, (2) the reasons for the requirements, (3) an evaluation of the major alternatives considered (including the use of existing sources of information), and (4) an estimate of the labor-hour burden of the requirements.

The General Provisions of 40 CFR part 60 and the standards would require three types of reports: (1) Notification requirements which enable the Agency to keep abreast of facilities subject to the standards, (2) reporting of initial performance test results and continuous monitoring system performance evaluations, and (3) semiannual reporting of exceedances or deviations from the monitored parameters from recovery equipment or combustion control devices. Analysis of these reporting requirements (II-F-2) indicates that they are both necessary and reasonable considering the savings in Agency time and resources required for effective enforcement.

The resources needed by the industry to maintain records and to prepare the reports for the first 3 years average about 82.7 person-years per year. The resources required by EPA and State and local agencies to process the reports and to maintain records for the first 3 years would average about 5.2 person-years per year.

Information collection requirements associated with this regulation have been approved by the Office of Management and Budget (OMB) under the provisions of the Paperwork Reduction Act of 1980, 44 U.S.C. 3501 et

seq., and have been assigned OMB control number 2060-0055.

Public reporting burden for this collection of information is estimated to be 168,668 hours per year, with an average of 715 hours per response, including time for reviewing instructions, searching existing data sources, gathering and maintaining the data needed, and completing and reviewing the collection of information. Send comments regarding the burden estimate or any other aspect of this collection of information, including suggestions for reducing this burden, to Chief, Information Policy Branch, PM-223, U.S. Environmental Protection Agency, 401 M St., SW., Washington, DC 20460; and to the Office of Information and Regulatory Affairs, Office of Management and Budget, Washington, DC 20503.

There are no reporting requirements by other governmental agencies for the information required by these standards which would result in overlapping requirements. In particular, there is no overlap with the reporting requirements of the Superfund program. The Superfund program was established in 1980 by the Comprehensive Environmental Response, Compensation, and Liability Act (CERCLA, Pub. L. 96-510) and authorizes the Federal government to respond directly to releases (or threatened releases) of hazardous substances and pollutants or contaminants to any media that may endanger public health or welfare. Under the notification and liability provisions of section 103 (see 40 FR 23552, May 25, 1983), CERCLA requires that persons in charge of vessels or facilities from which hazardous substances have been released in quantities that are equal to or greater than the reportable quantities immediately notify the National Response Center of the release (800-424-8802; in Washington, DC, metropolitan area 202-426-2675). However, air releases which qualify as Federally-permitted releases such as VOC emissions that are regulated under section 111 of the CAA, are not subject to the notification or liability provisions of CERCLA unless the air releases are in excess of the allowable NSPS emissions by an amount equal to or greater than the reportable quantity; in this case, persons in charge must report the excess air releases to the National Response Center. (Reporting under CERCLA does not excuse the persons in charge from any responsibility, including reporting, or liability under the NSPS program).

Docket

The docket is an organized and complete file of all the information considered by EPA in the development of this rulemaking. The docket is a dynamic file, since material is added throughout the rulemaking development. The docketing system is intended to allow members of the public and industries involved to readily identify and locate documents so that they can intelligently and effectively participate in the rulemaking process. Along with the statement of basis and purpose of the proposed and promulgated standards and EPA responses to significant comments, the contents of the docket will serve as the record in case of judicial review except as noted in (Section 307(d)(7)(A)).

Miscellaneous

The effective date of this regulation is June 29, 1990. Section 111 of the Clean Air Act provides that standards of performance or revisions thereof become effective upon promulgation and apply to affected facilities, where construction, reconstruction, or modification commenced after December 30, 1983.

As prescribed by section 111, the promulgation of these standards was preceded by the Administrator's determination (40 CFR 60.16, 44 FR 49222, dated August 21, 1979) that these sources contribute significantly to air pollution which may reasonably be anticipated to endanger public health or welfare. In accordance with section 117 of the Act, publication of these promulgated standards was preceded by consultation with appropriate advisory committees, independent experts, and Federal departments and agencies.

This regulation will be reviewed 4 years from the date of promulgation as required by the CAA. This review will include an assessment of such factors as the need for integration with other programs, the existence of alternative methods, enforceability, improvements in emission control technology, and reporting requirements.

Section 317 of the CAA requires the Administrator to prepare an economic impact assessment for any new source standard of performance under section 111(b) of the Act. An economic impact assessment was prepared for this regulation and for other regulatory alternatives. All aspects of the assessment were considered in the formulation of the standards to ensure that cost was carefully considered in determining BDT. The economic impact

assessment is included in the BID for the proposed standards (EPA-450/3-83-005a). As explained in the section entitled *Selection of the TRE Cutoff* in the preamble to the proposed standards (48 FR 57538), cost per megagram of emission reduction was an important factor considered in selecting the proposed standards.

Under Executive Order 12291, EPA must judge whether a regulation is "major" and therefore subject to the requirement of a Regulatory Impact Analysis. This regulation is not major because: (1) The national annualized compliance costs, including capital charges resulting from the standards total less than \$100 million; (2) the standards do not cause a major increase in prices or production costs; and (3) the standards do not cause significant adverse effects on domestic competition, employment, investment, productivity, innovation or competition in foreign markets. This regulation was submitted to the OMB for review as required by Executive Order 12291. Any written communication between OMB and EPA pertaining to the standards has been put in Docket A-80-25. This docket is available for public inspection at the EPA's Central Docket Section, which is listed under the "ADDRESSES" section of this notice.

Regulatory Flexibility Analysis

The Regulatory Flexibility Act of 1980 requires that adverse effects of all Federal regulations upon small businesses be identified. According to the current guidelines of the Small Business Administration, a small business that uses distillation operations in the manufacture of synthetic organic chemicals is one that has 750 employees or less. Currently, about 24 percent of the existing producers of the 211 affected chemicals (41 of 169 producers) are estimated to be small by this definition. Since it is estimated that about 600 plants would be affected by the standards in the first 5 years, all 41 small producers could potentially be affected by the NSPS.

Based upon an economic screening of the 211 chemicals, the control costs associated with the standards would be small since no chemical that is covered by these standards would have a cost increase of 5 percent or greater of the projected chemical price in 1987. Even under the conservative costing assumptions used in the economic screening analysis, 95 percent of the chemicals screened would have price increases less than 3 percent. Therefore,

no plants either large or small, would suffer significant economic impact under this NSPS.

It is difficult to estimate the specific effects of the NSPS on new businesses entering the industry. In general, however, if a company has the capital available to enter the industry, the NSPS will require only a small percentage increase in the capital needed for the project.

Pursuant to the provisions of 5 U.S.C.A. 605(b), I hereby certify that this rule will not have a significant economic impact on a substantial number of small entities.

List of Subjects in 40 CFR Part 60

Air pollution control, Incorporation by reference, SOCMCI distillation unit operations, Reporting and recordkeeping requirements, Intergovernmental relations.

Dated: June 13, 1990.

William K. Reilly,
Administrator.

PART 60—[AMENDED]

40 CFR part 60 is amended as follows:

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

Authority: Secs. 101, 111, 114, 116, and 301 of the Clean Air Act (CAA) as amended (42 U.S.C. 7401, 7411, 7414, 7416, 7601).

§ 60.17 [Amended]

2. Section 60.17 is amended in paragraph (a)(8) by removing the period at the end of the paragraph and adding the phrase "60.664(d)(2)(ii) and 60.664(d)(4)" and in paragraph (a)(38) by removing the period at the end of the paragraph and adding the phrase "and 60.664(d)(4)".

3. By adding subpart NNN as follows:

Subpart NNN—Standards of Performance for Volatile Organic Compound Emissions From Synthetic Organic Chemical Manufacturing Industry Distillation Operations

Sec.

60.660 Applicability and designation of affected facility.

60.661 Definitions.

60.662 Standards.

60.663 Monitoring of emissions and operations.

60.664 Test methods and procedures.

60.665 Reporting and recordkeeping requirements.

60.666 Reconstruction.

60.667 Chemicals affected by Subpart NNN.

60.668 Delegation of Authority.

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

§ 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 scm/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.

[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.]

§ 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 ppmv (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 ppmv, 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 ± 1 percent of the temperature being monitored expressed in degrees Celsius or ± 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 a 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 in 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 ± 1 percent of the temperature being measured expressed in degrees Celsius or ± 0.5 °C, whichever is greater, for boilers or process heaters of less than 44 MW (150 million Btu/hr) heat input design capacity.

(3) 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.

(d) 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 ± 1 percent of the temperature being monitored expressed in degrees Celsius or ± 0.5 °C, whichever is greater, and a specific gravity monitoring device having an accuracy of ± 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 ± 1 percent of the temperature being monitored expressed in degrees Celsius or ± 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 ± 10 percent, and a carbon bed temperature monitoring device having an accuracy of ± 1 percent of the temperature being monitored expressed in degrees Celsius or ± 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 § 60.662 with control devices other than incinerator, boiler, process heater, or flare; or recovery device other than an absorber, condenser, or carbon absorber 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.

§ 60.664 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 (%O₂) 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 O₂ (C_c) shall be computed using the following equation:

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

where:

C_c = Concentration of TOC corrected to 3 percent O₂, dry basis, ppm by volume.
C_{TOC} = Concentration of TOC (minus methane and ethane), dry basis, ppm by volume.
%O_{2d} = Concentration of O₂, 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_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:

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

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

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/hr).
K₂ = Constant, 2.494 × 10⁻⁶ (1/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) 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.

(c) When a flare is used to seek to comply with § 60.662(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 § 60.662(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(d) (2) and (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 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 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(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 (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, 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, 1.740×10^{-7}

(1)	(g-mole)	(MJ),
ppm	scm	kcal

where standard temperature for

(g-mole)
scm

is 20 °C.

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 (incorporation by reference as specified in § 60.17 of this part) as indicated in § 60.664(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 (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} = Emission rate of TOC in the sample, kg/hr.

K_2 = Constant, 2.494×10^{-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 basis of compound j in ppm as measured by Method 18 as indicated in § 60.664(d)(2).

M_j = Molecular weight of sample j, g/g-mole.

Q_s = Vent stream flow rate (scm/min) at a temperature of 20 °C.

(6) The total process vent stream concentration (by volume) of compounds containing halogens (ppmv, 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 § 60.662(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:

$$TRE = \frac{1}{E_{TOC}} [a + b(Q_s)^{0.88} + c(Q_s) + d(Q_s)(H_T) + e(Q_s)^{0.88}(H_T)^{0.88} + f(Y_s)^{0.5}]$$

(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_s = Vent stream flow rate (scm/min) at a standard temperature of 20 °C.

H_T = 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_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 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.

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TABLE 1. DISTILLATION NSPS TRE COEFFICIENTS FOR VENT STREAMS CONTROLLED BY AN INCINERATOR

DESIGN CATEGORY A1. FOR HALOGENATED PROCESS VENT STREAMS, IF $0 \leq \text{NET HEATING VALUE (MJ/scm)} \leq 3.5$:

Q_s = Vent Stream Flow rate (scm/min)	a	b	c	d	e	f
$14.2 < Q_s \leq 18.8$	19.18370	0.27580	0.75762	-0.13064	0	0.01025
$18.8 < Q_s \leq 699$	20.00563	0.27580	0.30387	-0.13064	0	0.01025
$699 < Q_s \leq 1400$	39.87022	0.29973	0.30387	-0.13064	0	0.01449
$1400 < Q_s \leq 2100$	59.73481	0.31467	0.30387	-0.13064	0	0.01775
$2100 < Q_s \leq 2800$	79.59941	0.32572	0.30387	-0.13064	0	0.02049
$2800 < Q_s \leq 3500$	99.46400	0.33456	0.30387	-0.13064	0	0.02291

DESIGN CATEGORY A2. FOR HALOGENATED PROCESS VENT STREAMS, IF NET HEATING VALUE > 3.5 MJ/scm:

Q_s = Vent Stream Flow rate (scm/min)	a	b	c	d	e	f
$14.2 < Q_s \leq 18.8$	18.84466	0.26742	-0.20044	0	0	0.01025
$18.8 < Q_s \leq 699$	19.66658	0.26742	-0.25332	0	0	0.01025
$699 < Q_s \leq 1400$	39.19213	0.29062	-0.25332	0	0	0.01449
$1400 < Q_s \leq 2100$	58.71768	0.30511	-0.25332	0	0	0.01775
$2100 < Q_s \leq 2800$	78.24323	0.31582	-0.25332	0	0	0.02049
$2800 < Q_s \leq 3500$	97.76879	0.32439	-0.25332	0	0	0.02291

DESIGN CATEGORY B. FOR NONHALOGENATED PROCESS VENT STREAMS, IF $0 \leq \text{NET HEATING VALUE (MJ/scm)} \leq 0.48$:

Q_s = Vent Stream Flow rate (scm/min)	a	b	c	d	e	f
$14.2 < Q_s \leq 1340$	8.54245	0.10555	0.09030	-0.17109	0	0.01025
$1340 < Q_s \leq 2690$	16.94386	0.11470	0.09030	-0.17109	0	0.01449
$2690 < Q_s \leq 4040$	25.34528	0.12042	0.09030	-0.17109	0	0.01775

DESIGN CATEGORY C. FOR NONHALOGENATED PROCESS VENT STREAMS, IF $0.48 < \text{NET HEATING VALUE (MJ/scm)} \leq 1.9$:

Q_s = Vent Stream Flow rate (scm/min)	a	b	c	d	e	f
$14.2 < Q_s \leq 1340$	9.25233	0.06105	0.31937	-0.16181	0	0.01025
$1340 < Q_s \leq 2690$	18.36363	0.06635	0.31937	-0.16181	0	0.01449
$2690 < Q_s \leq 4040$	27.47492	0.06965	0.31937	-0.16181	0	0.01775

DESIGN CATEGORY D. FOR NONHALOGENATED PROCESS VENT STREAMS, IF $1.9 < \text{NET HEATING VALUE (MJ/scm)} \leq 3.6$:

Q_s = Vent Stream Flow rate (scm/min)	a	b	c	d	e	f
$14.2 < Q_s \leq 1180$	6.67868	0.06943	0.02582	0	0	0.01025
$1180 < Q_s \leq 2370$	13.21633	0.07546	0.02582	0	0	0.01449
$2370 < Q_s \leq 3550$	19.75398	0.07922	0.02582	0	0	0.01775

DESIGN CATEGORY E. FOR NONHALOGENATED PROCESS VENT STREAMS, IF NET HEATING VALUE > 3.6 MJ/scm:

Y_s = Dilution Flow rate (scm/min) = $(Q_s)(H_T)/3.6$	a	b	c	d	e	f
$14.2 < Y_s \leq 1180$	6.67868	0	0	-0.00707	0.02220	0.01025
$1180 < Y_s \leq 2370$	13.21633	0	0	-0.00707	0.02412	0.01449
$2370 < Y_s \leq 3550$	19.75398	0	0	-0.00707	0.02533	0.01775

(ii) where 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.

$Q_s = 14.2$ scm/min.

$H_T = (\text{FLOW})(\text{HVAL})/14.2$.

where by 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_s .

$Y_s = 14.2$ scm/min for all vent stream categories listed in Table 1 except for Category E vent streams, where $Y_s = (14.2)(H_T)/3.6$.

E_{TOC} = 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:

$$\text{TRE} = \frac{1}{E_{\text{TOC}}} \left[a(Q_s) + b(Q_s)^a + c(Q_s)(H_T) + d(E_{\text{TOC}}) + e \right]$$

where:

TRE = TRE index value.

E_{TOC} = Hourly emission rate of TOC reported in kg/hr.

Q_s = Vent stream flow rate (scm/min) at a standard temperature of 20 °C.

H_T = 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_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
$H_T > 11.2$ 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 § 60.660(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.

(g) 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.

§ 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 adsorbing 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 percent 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 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(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 § 60.662(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 absorber 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 m³/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. 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_{TOC}. 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 § 60.665(j), 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. A performance test must be completed within the same time period to obtain the vent stream flow rate, heating value, 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 the low flow exemption in § 60.660(c)(6), the facility must begin compliance with the requirements set forth in § 60.662.

(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).

§ 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.

(Approved by the Office of Management and Budget under the control number 2080-0055)

§ 60.667 Chemicals affected by Subpart NNN.

Chemical name	CAS No.*
Acetaldehyde	75-07-0
Acetaldehyde, tech	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 ₁₀₋₁₈ -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
Bromotone	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	75-85-0
Butylbenzyl phthalate	85-88-7
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	96-82-8
Cumene hydroperoxide	80-15-9

Chemical name	CAS No.*
Cyanuric chloride	108-77-0
Cyclohexane	110-82-7
Cyclohexane, oxidized	68512-15-2
Cyclohexanol	108-93-0
Cyclohexanone	108-94-1
Cyclohexanone oxime	100-84-1
Cyclohexene	110-83-8
1,3-Cyclopentadiene	542-92-7
Cyclopropane	75-19-4
Diacetone alcohol	123-42-2
Dibutylated 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
Diethyl 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	104-78-7
(2-Ethylhexyl) amine	104-75-6
Ethylmethylbenzene	25550-14-5
6-Ethyl-1,2,3,4-tetrahydro 9,10-antra-cenedione	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	

Chemical name	CAS No.*
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	143-08-08
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-Pentenitrile	4635-87-4
Pentenenes, 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	75-58-9
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	112-27-8
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.

§ 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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BILLING CODE 6560-50-M

ENVIRONMENTAL PROTECTION AGENCY**40 CFR Part 60****[AD-FRL-2823-6]****RIN 2060-AB55****Standards of Performance for New Stationary Sources; Volatile Organic Compound (VOC) Emissions From the Synthetic Organic Chemical Manufacturing Industry (SOCMI) Reactor Processes****AGENCY:** Environmental Protection Agency (EPA).**ACTION:** Proposed rule and notice of public hearing.

SUMMARY: The proposed standards would limit the emissions of VOC from new, modified, and reconstructed SOCMI reactor process facilities. The proposed standards implement section 111 of the Clean Air Act (CAA) and are based on the Administrator's determination that emissions from the SOCMI cause or contribute significantly to air pollution which may reasonably be anticipated to endanger public health or welfare. The intent is to require new, modified, and reconstructed SOCMI reactor process facilities to control emissions to the level achievable by the best demonstrated system of continuous emission reduction, considering costs, nonair quality health and environmental impacts, and energy requirements.

A public hearing will be held, if requested, to provide interested parties an opportunity for oral presentation of data, views, or arguments concerning the proposed standards.

DATES: *Comments.* Comments must be received on or before September 12, 1990.

Public Hearing. If anyone contacts EPA requesting to speak at a public hearing by July 20, 1990, a public hearing will be held on August 7, 1990 beginning at 10:00 a.m. Persons interested in attending the hearing should call Ms. Ann Eleanor at (919) 541-5578 to verify that a hearing will be held.

Request to Speak at Public Hearing. Persons wishing to present oral testimony must contact EPA by July 20, 1990.

Incorporated by Reference. The incorporation by reference of certain publications in these standards will be approved by the Director of the Federal Register as of the date of publication of the final rule.

ADDRESSES: *Comments.* Comments should be submitted (in duplicate if possible) to: Central Docket Section (LE-131), Attention: Docket Number A-

63-29, U.S. Environmental Protection Agency, 401 M Street, SW., Washington, DC 20460.

Public Hearing. If anyone contacts EPA requesting a public hearing, it will be held at the EPA's Office of Administration Auditorium, Research Triangle Park, North Carolina. Persons interested in attending the hearing or wishing to present oral testimony should notify Ms. Julia Stevens, Standards Development Branch (MD-13), U.S. Environmental Protection Agency, Research Triangle Park, North Carolina 27711, telephone number (919) 541-5578.

Background Information Document. The background information document (BID) for the proposed standards may be obtained from the U.S. EPA Library (MD-35), Research Triangle Park, North Carolina 27711, telephone number (919) 541-2777. Please refer to "Reactor Processes in Synthetic Organic Chemical Manufacturing Industry—Background Information for Proposed Standards," EPA/450-3/85-005a.

Docket. Docket Number A-63-29, containing supporting information used in developing the proposed standards, is available for public inspection and copying between 8 a.m. and 4 p.m., Monday through Friday, at EPA's Central Docket Section, South Conference Center, room 4, 401 M Street, SW., Washington, DC 20460. A reasonable fee may be charged for copying.

FOR FURTHER INFORMATION CONTACT:

Mr. Doug Bell or Ms. Debbie Stackhouse, telephone (919) 541-5568 and 5258, respectively, concerning regulatory decisions. Mr. Robert E. Rosensteel or Mr. Leslie B. Evans, telephone (919) 541-5608 and 5410, respectively, concerning technical aspects of the industry and control technologies. The address for the above contacts is Emission Standards Division (MD-13), U.S. Environmental Protection Agency, Research Triangle Park, North Carolina 27711.

SUPPLEMENTARY INFORMATION:**I. Introduction****A. New Source Performance Standards—General**

New source performance standards (NSPS or "standards") implement section 111 of the CAA. The NSPS are issued for categories of sources which cause, or contribute significantly to, air pollution which may reasonably be anticipated to endanger public health or welfare. They apply to new stationary sources of emissions, i.e., sources whose construction, reconstruction, or modification begins after a standard for them is proposed.

The NSPS require these sources to control emissions to the level achievable by "best demonstrated technology" or "BDT," which is defined in item B.6 below.

B. The NSPS Decision Scheme

An NSPS is the product of a series of decisions related to certain key elements for the source category being considered for regulation. The elements identified in this "decision scheme" are generally the following:

1. Source category to be regulated—usually an entire industry but can be a process or group of processes within an industry.
2. Pollutant(s) to be regulated—the particular substance(s) emitted by the source that the standard will control.
3. Regulatory approach—the general strategy for regulating sources.
4. Affected facility—the pieces or groups of equipment that comprise the sources to which the standards will apply.

5. Emission points to be regulated—within the affected facility, the specific physical location emitting pollutants (e.g., vents, stacks, and equipment leaks).

6. Best demonstrated technology—the technology on which the Agency will base the standards, i.e.,

* * * application of the best technological system of continuous emission reduction which (taking into consideration the cost of achieving such emission reduction, and any nonair quality health and environmental impact and energy requirements) the Administrator determines has been adequately demonstrated. [Section 111(a)(1)].

7. Format for the standards—the form in which the standards are expressed, i.e., as a percent reduction in emissions, as pollutant concentrations or as equipment standards.

8. Actual standards—based on what BDT can achieve, the maximum permissible emissions.

Note: In general, standards do not require that a specific technology be used to achieve them. The source owner/operator may select the method for achieving the pollution control required.)

9. Other considerations—in addition, this NSPS includes: modification/reconstruction considerations, performance test methods, monitoring requirements, and reporting and recordkeeping requirements.

C. Overview of This Preamble

This preamble will:

1. Summarize the important features of this NSPS by discussing the conclusions reached with respect to

each of the elements in the decision scheme.

2. Describe the estimated environmental, energy, and economic impacts of this NSPS.

3. Present a rationale for each of the decisions in the decision scheme.

4. Discuss administrative requirements relevant to this action.

II. Summary of the NSPS

A. Source Category to be Regulated

The source category to be regulated is the SOCMI. These standards affect the reactor process subcategory of the SOCMI. A reactor process is the means by which one or more synthetic organic chemicals are produced by the reaction of feedstocks or chemical intermediates other than air. (Processes using air are covered in a separate NSPS.)

B. Pollutant to be Regulated

The proposed standards would control emissions of VOC from reactor process vent streams.

C. Regulatory Approach

Rather than develop a separate standard for each chemical produced in reactor processes, this proposal is a single standard covering all reactor processes producing one or more designated high production volume chemicals. These 173 high production volume chemicals account for about 90 percent of total chemical production from the SOCMI and are estimated to account for the majority of the emissions from reactor processes as well. This same approach was used in the two previous process vent standards for the SOCMI (distillation, 48 FR 57538, and air oxidation, 48 FR 48932).

D. Affected Facility

The facility affected by the proposed standards is designated as a single reactor with its own recovery system (if any) or the combination of two or more reactors and the common recovery system they share.

E. Emission Points to be Regulated

The emission points to be regulated include VOC discharged from chemical reactors either directly from a reactor or indirectly after passing from one or more reactors through one or more product recovery devices.

F. Best Demonstrated Technology

A variety of control techniques are capable of reducing VOC from reactor process vent stream by 98 weight-percent or to 20 parts per million by volume (ppmv). However, certain combustion controls (thermal incinerators and flares) are the only

devices that are applicable to all reactor process vent streams. The selection of the best device for an individual stream depends on the process vent stream characteristics and other site-specific considerations. Each of these two devices, however, is capable of achieving 98 weight-percent VOC destruction or 20 ppmv.

For facilities where the costs of combustion control by thermal incinerators or flares are reasonable, BDT is 98 weight-percent control or reduction to 20 ppmv, whichever is less stringent. For facilities where the costs to control VOC by combustion are not reasonable, BDT is no additional control. The standards do not require that a specific device or technology be used to comply with the emission reduction requirements. Rather, any control can be used as long as it can be demonstrated that it is at least as effective as BDT at reducing VOC emissions. The EPA is unable, with available information, to identify subcategories of reactor processes for which VOC control techniques other than incineration or flaring (e.g., catalytic oxidation and carbon adsorption) have been demonstrated to always apply. The applicability of these devices may be greatly affected by the vent stream flow rate, water content, temperature, VOC concentration and VOC properties such as solubility, molecular weight, and liquid/vapor equilibrium. These characteristics vary widely within the SOCMI. Therefore, consideration of these devices in developing regulatory options was not feasible. Even with greater resources, this analysis would be infeasible because it would require a stream-by-stream characterization, ultimately resulting in the need to create a separate standard for each reactor process facility. The number of standards required to regulate the same number of sources would increase significantly. The Agency believes that such an approach to regulating SOCMI reactor processes would be administratively infeasible and therefore environmentally counter-productive. This approach does not preclude later regulation of subcategories of reactor process facilities should that become feasible.

G. Format of the Standards

The format of the proposed standards would allow owners and operators of affected facilities to comply with the standards by controlling emissions or by maintaining or adding product recovery devices. Where the cost effectiveness of controls is reasonable, a percentage reduction or concentration limit,

whichever is less stringent, would apply. Where the costs of control are unreasonably high, no additional emission reduction would be required. The cutoff is calculated by using a set of equations and coefficients in the regulation that produce a total resource effectiveness (TRE) index value. A TRE index value of 1.0 or less indicates the need to control. This format permits owners and operators of facilities near, but below, the 1.0 cutoff to change the process operation or equipment in order to reduce emissions and, thereby, raise the TRE index value to a point above the cutoff.

H. Actual Standards

Sources with TRE values of 1.0 or below would be subject to the following: (1) A 98 weight-percent reduction of the total organic compounds (minus methane and ethane) in the reactor vent stream, or a reduction to 20 ppmv, whichever is less stringent; (2) if a boiler or process heater is used to comply with the standards, the reactor vent stream must be introduced into the flame zone; (3) if a flare is used to comply with the standards, it must comply with the requirements set forth in 40 CFR 60.18.

For sources where the costs of combustion control result in a TRE index value greater than 1.0, no additional VOC control is required.

Facilities with low flow rates (less than or equal to 0.011 scm/min) and facilities which are in process units with low production capacities (less than or equal to 1 gigagram per year for all chemicals produced) would be exempt from the standards except for certain recordkeeping and reporting requirements. Batch processes would also be exempt from the standards.

I. Modification/Reconstruction Considerations

An existing facility would be required to meet these standards if it is modified or reconstructed as determined under the General Provisions of 40 CFR part 60. With some specific exceptions, an existing facility is considered to be modified if a physical or operational change results in an increase in VOC emissions. For example, if a reactor is added to a group of existing reactors and if an increase in VOC emissions results, all reactors—existing and new—would be subject to the standards because the facility had been modified. A reconstruction occurs when components of an existing facility are replaced to such an extent that the fixed capital costs of the new components exceed 50 percent of the fixed capital costs that would be required to

construct an entirely new facility comparable to the existing facility. A facility will be considered to have been reconstructed only if it is technologically and economically feasible for the facility to meet the standards.

J. Compliance Testing

Initial performance testing is required to demonstrate that a facility complies with the TRE provisions of the standard or, for facilities complying with the emission reduction requirements, that control devices achieve 98 weight-percent control of VOC emissions or 20 ppmv. Facility owners or operators seeking to demonstrate compliance with the TRE index provisions must determine vent stream flow rate, heating value, VOC emissions, and the presence or absence of halogenated compounds. The vent stream heating value and flow rate are used to select the appropriate TRE index coefficients for calculating the TRE index value. For facilities that seek to comply with the 98 weight-percent reduction requirement, an initial performance test is required if an incinerator, a small boiler or small process heater (less than 150 million Btu/hr) is used. The initial performance test for a flare includes a measurement of exit velocity and stream heat content to verify that the operating specifications are met. The initial performance test has been waived for large boilers and large process heaters (greater than 150 million Btu/hr).

K. Monitoring Requirements

For facilities using any combustion device to comply with the emission reduction requirements, vent stream flow to the combustion device would be monitored by use of flow indicators. For facilities using thermal incinerators, small boilers or small process heaters, continuous measurements of firebox temperatures are also required. For facilities using large boilers or large process heaters, records indicating when the device is being operated are also required. For facilities using a flare, the regulation requires continuous monitoring of the presence of a flame. For facilities using catalytic incinerators, the regulation requires continuous monitoring of the gas stream temperature immediately before and after the catalyst bed.

For facilities using product recovery devices to maintain a TRE index value greater than 1.0, the following parameters are required to be continuously monitored: The temperature and specific gravity of the absorbing liquid where an absorber is the final product recovery device; the exit temperature of the vent stream

where a condenser is the final product recovery device; and the carbon bed temperature and regeneration stream flow where a carbon adsorber is the final product recovery device.

L. Reporting and Recordkeeping Requirements

As required under the General Provisions of 40 CFR part 60, the recommended standards require three types of reports. First, there are notification requirements under the General Provisions, which would enable the Agency to keep abreast of facilities subject to the standards of performance. Second, there is the reporting of performance test results, which would show that a facility is meeting the standards initially. Third, there is the semiannual reporting of exceedances of certain monitored parameters and any change in equipment or process operation that could affect compliance with the TRE or emission reduction requirements or with the low flow and low capacity exemptions. The proposed standards would require records indicating proper operation and maintenance of the control device or product recovery equipment. First, specific operating parameters would be monitored and the results recorded. Second, records of periods when the measured values of these parameters significantly deviated from the values measured in the most recent performance test would be maintained. Third, there would be recordkeeping of major changes that could affect the TRE index value or the low flow and low capacity exemption status. Finally, records and reporting of periods when control device are not operating or when the vent stream is not routed to the control device would be required.

III. Impacts of the NSPS

A. Air

In the fifth year after this NSPS is proposed, it is estimated that nationwide emissions of VOC will be decreased by 2,100 megagrams per year compared with projected emissions calculated to occur in the absence of the standards (baseline). During the first 5 years of the standards' applicability, an estimated 56 facilities would be candidates for the control attributable solely to the requirements of this NSPS. It is estimated that 7 of the 56 facilities are anticipated to be required to meet the 98 weight-percent reduction requirements. However, the VOC emissions from the 7 facilities account for about 90 percent of the total from all 56 facilities. Any increase in emissions of other air pollutants as a result of

controlling VOC emissions will be negligible.

B. Water

A Negligible increase in total plant wastewater is projected under this NSPS.

C. Solid Waste, Noise and Radiation

No solid waste, noise, or radiation impacts are expected under this NSPS.

D. Energy

In the fifth year after this NSPS would become applicable, energy consumption in the SOCMI nationwide would be increased by as much as the equivalent of about 141 barrels of crude oil per day if incinerators and flares are used to comply with the proposed standards when compared with the existing energy consumption associated with the baseline level.

E. Control Costs

During the fifth year of applicability of the proposed standards, the nationwide annualized costs of control at facilities covered by the standards would amount to \$3.7 million (1982 dollars) per year. The nationwide cumulative 5-year capital costs for control under the proposed standards would be \$5.9 million (1982 dollars). These costs are based on the assumption that flares or incinerators would be used to comply with the proposed standards. If less expensive control devices such as boilers and process heaters are used, the costs would be significantly lower.

F. Economic Effects

No chemical that is projected both to have new, modified, or reconstructed facilities built in the first 5 years of the standards and to be required to control emissions beyond current State requirements is projected to have a price increase greater than 5 percent. Furthermore, chemicals that are produced downstream of the listed chemicals will not have price increases over 5 percent. Most of the projected price increases for the listed chemicals and chemicals produced downstream are small: 81 percent are under 2 percent. Impacts on industry structure, industry growth, inflation, foreign trade, and capital formation are projected to be insignificant.

IV. Rationale for the Proposed Standards

A. Selection of Source Category

The EPA priority list, 40 CFR 60.16 (44 FR 49222, August 21, 1979), ranks major source categories for which NSPS are to be promulgated. This list implements

section 111(b) of the Clean Air Act and reflects the Administrator's determination that emissions from the listed source categories contribute significantly to air pollution that endangers health or welfare. The SOCM was ranked highest priority for NSPS development on the final priority list of 59 major source categories. Organic chemical plants are a major source of VOC emissions that contribute to ozone formation.

The VOC's are emitted from four main subcategories of sources within the SOCM: Losses from storage and handling of volatile organic liquids, fugitive leaks from valves and process equipment, evaporative losses from liquid and solid wastes (secondary sources), and emissions from process vents. A breakdown by source type indicates that over half of the VOC emitted from the SOCM are from process vents.

Process vent emission sources are typically associated with product recovery systems in a SOCM chemical manufacturing facility. Process vent emission sources consist primarily of the venting of VOC-containing inert gases and evacuation of equipment for vacuum processing. For purposes of developing an NSPS for the SOCM, EPA has divided process vents into two categories: Continuous and batch processes. Batch process vents are currently being evaluated by the Agency. Continuous process vents include distillation unit operations, air oxidation processes, and reactor process. Standards for distillation unit operations were proposed on December 30, 1983 (48 FR 57538). Standards for air oxidation processes were proposed on October 21, 1983 (48 FR 48932). The standards being proposed today address the third type of process vents: Reactor processes. A reactor process is the means by which one or more substances or reactants, other than air, are chemically altered such that one or more new organic chemicals are formed. The VOC's are emitted from reactor process vents in one of two ways: (1) Indirectly from the reactor following product recovery (e.g., through condensation, absorption, or adsorption), or (2) directly from the reactor to the atmosphere. An estimated 6 percent of the total VOC emitted by the SOCM source category are from reactor processes.

In developing standards, environmental, cost, economics, small business, and other impacts are examined. It would be very resource intensive and time consuming to analyze all of these impacts for each of the many chemicals produced. The result of

following such an approach would be to delay developing standards significantly, resulting in turn in a significant loss in emission reduction. Therefore, EPA has decided to limit the scope of these standards initially to a relatively small number of high production chemicals. The Agency performed an analysis to determine the probable effects of such a limitation. Two alternatives were considered for limiting the scope to high production volume synthetic organic chemicals. The first involved limiting the scope of the standards to about 870 organic chemicals produced in quantities greater than 4,500 Mg/yr (10 million lb/yr). This would cover roughly 97 percent of organic chemical production but would result in an unworkable number of chemicals for the impact analyses. The second alternative would limit the scope of the standards to 173 organic chemicals generally produced in quantities greater than 45,000 Mg/yr (100 million lb/yr). The chemicals covered under this second alternative would account for about 90 percent of total U.S. production of organic chemicals. Therefore, the Administrator concluded that limiting the scope of the standards to the 173 chemicals generally produced in quantities greater than 45,000 Mg/yr would provide a workable scope while covering the great majority of organic chemical production. A list of the affected chemicals is included in the regulation.

B. Pollutant to be Regulated

In addition to VOC emissions, other pollutants are emitted from reactor process sources in much smaller quantities. These include carbon monoxide (CO), Nitrogen oxides (NO_x) sulfur oxides (SO_x) and hydrochloric acid (HCl). The VOC is by far the primary pollutant emitted from reactor processes. Due to the size and complexity of this source category, acquiring the information to determine the applicable technology for the other pollutants that have low emissions at the same time the Agency analyzes the pollutant covered by these standards would have been an unmanageable task. Therefore, the pollutant to be regulated by these standards is VOC.

C. Selection of Regulatory Approach

Two general regulatory approaches were considered for use in developing standards for reactor processes. The first approach would involve establishing standards for each of the 173 specific chemicals included under these proposed standards. It would be very difficult to develop standards using this approach due to the large number of

chemical reactions and chemical products that are produced by reactor processes and the variable emission characteristics associated with each. There are about 35 separate types of chemical reactions used to produce the 173 chemicals that account for the great majority of the emissions from reactor processes.

The second approach involves the development of standards on the basis of similar types of emission sources and applicable emission control techniques. This approach would allow a timely and resource-efficient regulatory development because a large number of specific chemicals can be covered by only one regulation. Using this approach would mean that an NSPS for the SOCM reactor processes could be developed in a relatively short period of time at much less public cost, compared to the chemical-by-chemical approach.

Despite the large number of reaction types and chemicals produced by reactor processes, VOC emissions from reactor process units can be controlled by commonly used combustion and noncombustion control techniques. Because regulating the entire group would be more resource-efficient and the chemical-by-chemical approach is for practical purposes infeasible and lacks any clear advantage, the Administrator has determined that a single regulation should be proposed for all reactor processes in the SOCM. This approach is consistent with the approach taken for the SOCM distillation and air oxidation standards.

D. Selection of Affected Facility

The choice of the affected facility for these standards is based on the Agency's interpretation of section 111 of the Clean Air Act and on the judicial construction of its meaning (*ASARCO, Inc., v. EPA*, 578 F.2d 319 (D.C. Cir. 1978)). Under Section 111, the standards of performance for new stationary sources must apply to "new sources." "Source" is defined as "any building, structure, facility, or installation which emits or may emit any air pollutant" (section 111(a)(3)). Most industrial plants, however, consist of numerous pieces or groups of equipment that emit air pollutants and that may be viewed as "sources." The EPA, therefore, uses the term "affected facility" to designate the equipment within a particular kind of plant that is chosen as the "source" covered by a given standard.

In designating the affected facility, EPA must decide which piece or group of equipment is the appropriate unit (the source) for emission standards in the particular industrial context. The

Agency must do this by examining the situation in light of the terms and purpose of section 111 of the Clean Air Act. The main purpose of section 111 is to minimize emissions by requiring the application of BDT at all new, modified, and reconstructed sources (considering cost, nonair quality health and environmental effects, and energy impacts). The EPA believes that in most cases a narrow affected facility designation will best further this purpose, because in most cases a narrow designation ensures that new emission units will be brought under the coverage of the standards. If, for example, an entire plant is designated as the affected facility, no part of an existing plant would be covered by the standard unless the replacement caused the plant as a whole to be "modified" or "reconstructed." If each piece of equipment is designated as a separate affected facility, then as each piece is replaced, the replacement piece would be a new source subject to the standards. For this reason, EPA generally presumes that the narrow designation is appropriate.

The EPA treats the narrow designation only as a presumption, however, because in some cases a broader affected facility designation may be more consistent with the purposes of section 111. For example, the Agency might choose a broader designation if it concluded that either (a) it would result in greater emissions reduction than would a narrow designation; or (b) the other relevant statutory factors (technical feasibility, economic cost, energy, and nonair quality health and environmental impacts) point to a broader designation.

The EPA analyzed several alternative affected facility designations for the reactor process standards, including (1) each individual reactor with its recovery system; (2) the group of reactors whose vent streams flow together through a single recovery system; and (3) the entire plant. Using the presumption mentioned above, EPA examined as a single affected facility each individual reactor whose vent stream is sent to its own recovery system. The EPA concluded, however, that when reactor vent streams are joined and sent through a single recovery system, the group of reactors and their recovery system, rather than each reactor, should be a single affected facility.

The EPA estimates that a greater reduction in national VOC emissions would likely result under the broader designation of affected facility. This conclusion is based upon the behavior of the industry with regard to the

expansion of reactor capacity and replacement, reconstruction or modification of existing reactors.

Capacity expansions will occur either as a result of new facilities being built or existing ones being expanded. When expanding production capacity at an existing reactor facility, it is common industry practice to add new reactors to existing sets of reactors and recovery systems. When this occurs, there are two possible outcomes under the broader affected facility designation—both of which will result in a greater emissions reduction than would occur under a more narrow designation of affected facility. One possibility is that the total emissions from the group of reactors will increase. In this case, it would bring all (new plus existing) reactors discharging into a common recovery system under the standard by virtue of the NSPS General Provisions regarding "modifications." The second possibility is that the owners or operators of the plant could completely offset the increased emissions from the new reactors by increasing recovery. Although this outcome is unlikely, the result is that a greater emissions reduction will occur under the broad rather than the narrow designation of affected facility. The reason is that by completely offsetting the increased emissions from the new reactors through additional recovery, the emissions from the new reactors have been controlled at 100 weight-percent effectiveness. This exceeds the control effectiveness (i.e., 98 weight-percent) required under this standard.

Replacement of existing reactors rarely occurs within the industry because reactors are expensive pieces of equipment designed and usually built to last the lifetime of the plant. Reactor replacements usually occur as a result of process changes (e.g., from chlorination to hydrochlorination) or as a result of fires or explosions. Whether in multireactor or single reactor facilities, the replacements of individual reactors (as opposed to replacement of entire facilities) are rare. When reactor replacements do occur, however, all reactors tend to be replaced, and, therefore, the reactor replacements would bring the entire facility under the standards under the broader affected facility designation.

Reactor changes that source owners could make that might be considered modifications are substantial changes in catalysts, reactor conditions, or product separation purification equipment. The cost of these changes is so great, however, that most owners would choose to build a new group of reactors

rather than radically modify individual existing reactors. Therefore, few reactors would undergo process changes that might be considered a modification under any designation of affected facility.

Thus, greater emissions reductions are likely to occur under this broader designation. For that reason, the Administrator has determined that the appropriate affected facility designation is an individual reactor with its own individual recovery system (if any) or the combination of two or more reactors and the common recovery system they share.

When several reactors feed vent streams into a common recovery system, the characteristics of the emissions vented into the atmosphere from the recovery system are determined by both the vent streams from each of the reactors and the efficiency of the recovery system. Under the narrow designation, it would have been required that only that portion of the combined vent stream contributed by any new, modified or reconstructed reactor unit comply with the standards when the unit shares a recovery system with existing units. Therefore, the TRE index value would have been determined for the portion of the stream contributed by that unit only. At least three sampling locations would be used in this case. Two of the locations (i.e., before and after the common recovery system) would be used to determine the overall efficiency of the common recovery system. This efficiency would then be applied to the emissions measurement taken at the third sample location which is just prior to the new or changed unit being joined with any other vent stream. Thus, three sample locations would be needed to determine the contribution by the new or changed unit to the total emissions from the common recovery system.

However, under the broader affected facility option selected above, only one sampling site is necessary to determine the facility's TRE index value. No estimation of the recovery system's efficiency on individual reactors is required, because the standards cover the entire vent stream. Therefore, there is no need to determine which portion of the final vent stream from a group of reactors is attributable to new, modified, and reconstructed reactors and which portion is attributable to reactors that have not been changed or added. This results in performance testing that is simpler and cheaper because fewer sampling sites and simpler analyses are needed.

The Administrator has decided to exclude from these standards reactors that are operated in a batch mode rather than operated continuously. The data upon which the standards are based (including the cost and control device performance) assume a continuous or near continuous type of operation.

Also excluded from these standards are facilities in plants with very low capacities or with very low vent stream flows. Most research and development or laboratory scale facilities are not designed to produce more than one gigagram (Gg) per year. It is not the intent of the standards to cover such facilities because they are generally intermittent operations. Moreover, the control techniques that are applicable to industry-scale production facilities would not necessarily be appropriate for these operations. For these reasons, EPA has decided to exempt facilities which are part of process units with one Gg production capacity per year or less of all chemicals produced within the process unit. Similarly, facilities with vent stream flows below 0.011 standard cubic meters per minute (scm/min) are excluded from the standards. No facility with flows below this cutoff are anticipated to have TRE index value less than 1.0, and thus to include them under the standards would impose unnecessary reporting and recordkeeping requirements on these facilities. For the low flow facilities, only an initial measurement and report is required to verify entitlement to the exclusion. In addition, owners and operators of both low capacity and low flow facilities are required to notify EPA if a change occurs that would result in production capacities or flows above the respective cutoff levels.

E. Selection of Control Techniques

The Clean Air Act requires that standards of performance be based on the best system of continuous emission reduction, considering costs, energy usage and nonair health and environmental impacts ("best demonstrated technology" or BDT). As discussed in the BID, one or more combustion techniques (boiler, process heater, incinerator, or flares) are applicable to any reactor process vent stream and can achieve at least 98 weight-percent control or 20 ppmv in the outlet gas.

However, combustion control devices are the only types of control devices which are applicable to reactor processes. The EPA examined several VOC control technologies that achieve the same or less emission reduction, such as absorption, adsorption, condenser devices, and catalytic

oxidation, but found that these control technologies are not applicable to all reactor process vent streams. Moreover, EPA is unable, with available information, to identify subcategories of reactor processes for which the above mentioned control technologies have been demonstrated to always apply. The applicability and effectiveness of these devices may be greatly affected by the vent stream flow rate, water content, temperature, VOC concentration, and VOC properties such as solubility, molecular weight, and liquid/vapor equilibrium. These characteristics vary widely within the SOCMI. Therefore, there is no way to evaluate technologies for application to reactor process units for which thermal incineration and flaring have been determined to be too costly. Even with greater resources, this approach would be infeasible because it would require a stream-by-stream characterization, ultimately resulting in the need for a separate standard for each vent stream from a process used to produce a reactor chemical.

Combustion devices were found to be applicable to any nonhalogenated vent stream. For incinerators, operating conditions can be identified that will ensure 98 weight-percent reduction or 20 ppmv total organics (minus methane and ethane) in the outlet gas, whichever is less stringent. Boilers and process heaters were found to be capable of achieving 98 weight-percent reduction if the organic-laden stream is used as a fuel and is put into the flame zone. In recent tests, smokeless steam-assisted, air-assisted and nonassisted flares were also found to be as efficient as these other combustion devices in achieving 98 weight-percent reduction of VOC if they were operated as specified in 40 CFR 60.18. In terms of cost, boilers and process heaters are generally the least expensive combustion devices, because these units are already in place in SOCMI plants and because of heat recovery from the VOC-containing vent streams. Flares can control most nonhalogenated VOC-containing streams for less cost than incinerators. Incinerators were found to be the only devices applicable to halogenated streams because incinerators can accept a wide variety of stream types and can be constructed to tolerate the corrosive effects of halogenated streams. Furthermore, an absorber can be used to remove halogens from the offgases exiting the incinerator.

In summary, 98 weight-percent control or reduction to 20 ppmv is achievable for all halogenated and nonhalogenated reactor process vent streams using one of the combustion devices discussed

above. Thus, these four combustion devices are candidates for BDT for the emission source category of organic chemical reactor processes.

Since vent stream characteristics within this category vary widely, it is to be expected that the cost per unit of emission reduction among streams will also vary. The potential environmental impacts of using a combustion device to control VOC emissions vary from vent stream to vent stream. The Administrator, therefore, has analyzed the environmental, economic, and energy impacts and the cost per unit of emission reduction for reactor processes vent streams included in the scope of these standards to determine if, due to adverse impacts associated with the use of the most applicable combustion devices, BDT for certain classes, types, or sizes of reactor processes might be no additional control. The following sections discuss these additional impacts.

Consideration of Environmental Impacts

The potential adverse environmental impacts that could result from reactor process standards were assessed. The generation of NO_x by the combustion process was examined as a possible native impact on ambient air quality. The principal factors affecting the rate of NO_x formation during combustion are the amount of excess air available, the peak temperature, and the rate of cooling of the combustion products. Relatively low combustion temperatures of approximately 870 °C (1,600 °F) are associated with control of VOC using thermal incinerators, and residence times are generally too short to be conducive to NO_x formation. Therefore, the rate of NO_x formation is expected to be low if incinerators are used.

Introduction of a reactor process vent stream as a supplement to the fuel and combustion air normally introduced into a boiler or process heater could, in some cases, result in increases in NO_x emissions. The combustion temperatures in these devices are well in excess of 2,000 °F and are therefore conducive to NO_x formation, and some reactor process vents being controlled would contain nitrogenous organic compounds or nitrogen from air in the vent stream. However, reactor process vent streams would represent only a small part of the total input to the boiler or heater. Also, in many cases, introduction of the reactor process vent stream would result in lowered fuel requirements and could result in lower NO_x emissions if the nitrogen from nitrogenous organic compounds is less than the fuel-bound nitrogen of the fuel being replaced. In

addition, measures to minimize NO_x formation could be implemented due to NO_x standards under development for industrial boilers. Any increase or decrease in NO_x emissions due to introduction of the reactor process stream would be slight.

Only limited data are available for NO_x emissions from flares. In a recent study of steam-assisted and air-assisted flares, the highest estimated NO_x emissions were well below the reported NO_x emissions tabulated for industrial boilers and process heaters firing gas or oil. Because NO_x emissions from flares are less than the NO_x emissions from boilers and process heaters (which are themselves slight), NO_x emissions from flares are considered to be insignificant. Therefore, any increase in NO_x emissions resulting from the combustion of a reactor process vent stream is expected to be relatively small.

In additions to generation of NO_x , the control of VOC emissions from halogenated vent streams by thermal incinerators may result in the release of halogenated combustion products to the environment. However, flue gas quenching and scrubbing could be used to remove these compounds from the incinerator outlet stream. State or local regulations may require use of these scrubbers if the halogenated combustion products are in high enough concentrations. Current industry practice among reactor process facilities with halogenated vent streams that employ combustion devices is to use flue gas scrubbing to reduce plant maintenance costs by preventing corrosion of equipment. The capital cost and operating costs associated with flue gas quenching and scrubbing were taken into account in projecting the cost impacts for the standards.

Control of VOC emissions using combustion devices would not result in any significant increase in wastewater discharge by reactor processes. No water effluents are generated by the combustion devices themselves.

Use of an incinerator/scrubber system for control of VOC emissions from halogenated streams would result in increased water consumption. The increase in total plant wastewater would be relatively small and would not affect plant waste treatment capacity or sewer capacity. However, if the scrubber effluent is not recovered, it may be necessary to adjust the pH of the scrubber effluent by treatment with caustic (NaOH) before it is released into the plant wastewater system. The salt (NaCl) formed by the caustic treatment must be purged from the system and properly disposed. Brine solutions are currently disposed of in a variety of

ways depending on site-specific conditions. These include direct discharge to sewer systems and surface waters (fresh and salt water bodies or rivers), discharge to evaporative lagoons, and injection into a disposal well. Because it is not possible to determine which options will be selected by the individual facilities analyzed, it would be impractical to represent all of these types of brine disposal in the cost analysis. Therefore, the costs most likely to occur at affected facilities, handling halogenated compounds, were considered instead.

The Agency has investigated brine disposal costs and has found that the deep well injection cost represents the cost associated with the most expensive disposal option available. In addition, available data indicate that this cost is appropriate for disposal of hazardous wastes in deep wells, not nonhazardous brine solutions. Furthermore, the cost associated with this option is not applicable to the majority of facilities generating brine.

For the reactor processes NSPS, the cost for brine disposal was considered to be negligible and not included in the TRE equation because the disposal options most likely to be used by affected facilities are of a relatively low cost. These include ocean dumping; direct discharge to fresh water, brackish water, and sewer systems were permitted; and injection into existing oil or gas wells that are located on-site. The Agency sees no reason why any facility would have to choose the most expensive option of deep well injection; therefore, these costs were not included in the TRE equation.

For each of the 173 chemicals under consideration, the adverse environmental impacts of VOC control using combustion devices would not be significant. Therefore, these impacts do not provide a basis for exempting any of the chemicals from the proposed standards or affecting the selection of BDT.

Consideration of Economic Impacts

An economic analysis was performed to determine if the price of any of the 173 chemicals or chemicals produced from the listed chemicals would be adversely affected by control at the 98 weight-percent reduction level. Assumptions that tend to maximize projected price increases were used in the analysis.

Some of the 173 chemicals are basic chemicals produced directly from the petroleum, while others are intermediates or end-use chemicals produced from the basic chemicals. The price increase caused by the use of a

combustion device for a particular chemical was assumed to be reflected also in the price of all chemicals produced from that chemical. The projected price increase was calculated assuming that all control costs would be reflected as price increase, and that none would be absorbed. The price increase was calculated by dividing the estimated annualized control costs by the annual production of a facility. The price increase was then rolled into the price of chemicals that are produced downstream of the listed chemicals.

No chemical that is projected both to have new, modified, or reconstructed facilities built in the first 5 years of the standards and to be required to control emissions beyond current State requirements is projected to have a price increase greater than 5 percent. Furthermore, chemicals that are produced downstream of the listed chemicals will not have price increases over 5 percent. Most of the projected price increases for listed and downstream chemicals are small: 81 percent are under 2 percent while 90 percent are under 3 percent; any actual price increases are expected to be less than these projections. Impacts on industry structure, industry growth, inflation, foreign trade, and capital formation are projected to be insignificant.

Consideration of Cost and Energy Impacts

After it had been determined that the 98 weight-percent VOC emission reduction could be achieved from a variety of combustion controls without significant adverse environmental or economic impacts, the Administrator next examined the cost, energy, and costs per unit of VOC reduced (i.e., cost effectiveness) of these controls on the projected new, modified, or reconstructed reactor process units. Based on EPA's previous experience in developing an NSPS for SOCM process vents, the Agency anticipated that the cost of removing VOC from the vent streams of some of the process units would be unreasonably high and therefore, conducted additional analysis.

The analysis required to determine costs, energy requirements, and costs per unit of VOC reduced included the following steps. First, the total number of new, modified, and reconstructed process units with vent streams which would be affected by the standard during the first 5 years was estimated. These include all process units with vent streams projected to not use combustion in the absence of an NSPS.

The process units with these uncontrolled streams are assumed to be those that would incur the cost and energy impacts resulting from the control requirements of the standards. The costs of controlling the emissions from these process units were then developed for each. These process units were then ranked according to costs of control per Mg of VOC reduced. From this ranking, a set of regulatory alternatives consisting of increasingly large numbers of controlled process units was developed. The remainder of this section provides a discussion of the approach and results of this regulatory analysis.

In order to project the number of process units that would be affected by the standards during the first 5 years of its applicability, estimates of SOGMI growth and replacement capacity were determined for each of the 173 chemicals. This step identified all of the chemicals which may have new, modified or reconstructed process units built between 1985 and 1990. The next step was to identify which of these chemicals would likely have units built where combustion devices would be applied in the absence of an NSPS. A total of 22 chemicals were identified as where combustion would be applied as a result of existing regulations or industry practices. Any impacts associated with process units making these chemicals would not be attributed to the NSPS and, therefore, these chemicals were eliminated from the analysis of impacts. The next step was to estimate the number and size of new, modified, and reconstructed process units producing chemicals which would likely not use a combustion device in the absence of an NSPS. A total of 56 such units were projected to come on-line and these were the facilities included in the analysis of impacts.

To determine the emission characteristics of these 56 process units, an extensive data base on existing reactor processes was developed. This data base or Emissions Data Profile

(EDP) covers 127 reactor process units and is discussed in detail in the BID. The emission characteristics contained in the EDP were used to represent the emission characteristics of the 56 process units. It was assumed the EDP was representative of units making all of the chemicals associated with the 56 units. The EDP is based upon reactor process units rather than affected facilities. A process unit is defined in the BID as one or more combinations of reactor(s) and recovery system(s) located at a common site and producing the same chemical. Therefore, it should be noted that this regulatory analysis is based upon an industry unit which, in some cases, may include more than one affected facility. The EPA does not believe that this difference will affect the validity of the conclusions of this regulatory analysis because where a process unit contains more than one affected facility it is likely that emissions from both facilities will be ducted to a common control device. This is the situation represented in the regulatory analysis.

As previously stated, the 56 process units projected to come on-line between 1985 and 1990 are estimated to have vent streams that would not be controlled in the absence of an NSPS. The VOC emissions from these 56 process units are estimated to be about 2,400 Mg/yr. Total emissions from the 77 process units making the 22 chemicals anticipated to use combustion in the absence of an NSPS are estimated to be 910 Mg/yr. Therefore, the baseline emissions for all new, modified, and reconstructed reactor process units projected to come on-line between 1985 and 1990 are estimated to be 3,310 Mg/yr (the sum of 2,400 and 910). Baseline represents conditions that would exist in the absence of a standard. The proposed standards would affect the 2,400 Mg/yr from the 56 process units with uncontrolled vent streams.

In order to rank the 56 process units and to conduct the regulatory analysis, the cost for controlling each of the

process units was determined. Estimating the cost of controlling VOC emissions from reactor process units consists of first designing the control system and then costing the system. The general approach used consists of determining the design parameters for a control system applied to a particular reactor process that emits VOC. The system was costed based upon these design parameters and by using cost equations developed from data supplied by vendors and industry. It was not possible with available data to identify those reactor process vent streams for which the use of catalytic incinerators, process heaters, and boilers would be applicable. Therefore, only thermal incinerators and flares were used to develop these cost data. Flares or incinerators (whichever were determined to be less costly) were applied to nonhalogenated streams. Incinerators are applied to vent streams containing halogenated VOC because flare tip corrosion may prohibit use of flares and because halogenated streams may create secondary emissions that require flue gas scrubbing (which is not possible from flared emission). Because this regulatory analysis is based upon the assumption that facilities will use flares and incinerators, when in fact, the less expensive boilers and process heaters (because they are already in place and they accrue heat recovery credits) will be used in some plants, the cost impacts are overstated.

Once the cost and emissions reductions for each of the 56 process units were estimated, the cost per Mg of VOC reduction for each process unit was determined. Then, each of the 56 units was ranked by cost effectiveness (i.e., from the lowest to the highest cost per Mg of VOC). To illustrate how impacts change as a result of increasing the number of units controlled, nine regulatory alternatives were developed based on discrete cost-effectiveness cutoffs from a continuum of all possible cost-effectiveness values. These alternatives are presented in Table 1.

TABLE 1.—SUMMARY OF ENVIRONMENTAL, COST, AND ENERGY IMPACTS OF NINE REGULATORY ALTERNATIVES *

[All Costs are in Third Quarter 1982 Dollars]

Regulatory alternatives	Theoretical ^b worst case cost-effectiveness cutoff value (\$/Mg)	Average cost per Mg of VOC removed (\$/Mg)	Costs per Mg of VOC removed (\$/Mg)	Number of units controlled	Emission reduction from baseline (Mg/yr)	Percent "controllable" emissions reduced ^c	National annualized costs (million \$/yr)	National energy requirements (TJ/yr) ^d
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
I ^e				0	0	0	0	0
II	1,200	500	250-760	4	300	13	0.15	3
III	2,500	1,700	2,000	7	2,100	90	3.7	320
IV	5,500	1,800	5,400	9	2,300	91	3.9	340
V	20,000	2,100	5,600-14,000	21	2,300	97	4.7	390
VI	50,000	2,900	21,000-43,000	33	2,300	100	6.7	430

TABLE 1.—SUMMARY OF ENVIRONMENTAL, COST, AND ENERGY IMPACTS OF NINE REGULATORY ALTERNATIVES *—Continued

[All Costs are in Third Quarter 1982 Dollars]

Regulatory alternatives	Theoretical ^b worst case cost-effectiveness cutoff value (\$/Mg)	Average cost per Mg of VOC removed (\$/Mg)	Costs per Mg of VOC removed (\$/Mg)	Number of units controlled	Emission reduction from baseline (Mg/yr)	Percent "controllable" emissions reduced ^c	National annualized costs (million \$/yr)	National energy requirements (TJ/yr) ^d
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
VII.....	200,000	3,200	64,000-110,000	42	2,300	100	7.4	440
VIII.....	500,000	3,500	280,000-450,000	46	2,300	100	8.2	450
IX.....	> 500,000	4,000	> 4,000,000	56	2,300	100	9.3	520

* Calculated for the fifth year of the NSPS.

^b This is a theoretical cost effectiveness. As explained elsewhere in this document, all the units with calculated costs per Mg which approach the indicated value are expected to make process adjustments and thus not experience control costs as high as indicated by this theoretical worst case.^c Controllable emissions are the 2,400 Mg/yr that would be controlled if all 56 units were controlled at 98-weight-percent VOC destruction efficiency (i.e., at the most stringent possible alternative, Alternative IX).^d Expressed in Terajoules per year.^e Baseline, or conditions that would exist in the absence of the standards.

Column 1 in Table 1 identifies each of the nine alternatives. Regulatory Alternative I represents baseline or the conditions which would exist in the absence of a standard. At the other extreme is Alternative IX, which would control all 56 units. The number of units controlled above baseline for each alternative is presented in Column 5. The ranges of costs per Mg of VOC removed within each alternative are presented in Column 4. These ranges represent the additional cost-effectiveness values achieved at successively higher alternatives. Column 3 presents the average costs per Mg of VOC removed for each alternative. Thus, for example, Regulatory Alternative III could theoretically control 7 of the 56 process units with an average cost of \$1,700/Mg of VOC controlled (in 1982 dollars).

Column 6 in Table 1 presents an estimate of the VOC emissions reduction over baseline from the 56 units. At baseline 2,400 Mg/yr of VOC would be emitted by the 56 units. Under Alternative II, 4 units would be controlled resulting in a reduction of 300 Mg/yr. However, under Alternative III, a total of 7 units are theoretically controlled resulting in an emission reduction of 2,100 Mg/yr. If all 56 units were controlled at 98 weight-percent (Alternative IX), there would be a reduction of 2,300 Mg/yr of VOC being emitted from the 56 units. This alternative is the most stringent possible. These 2,300 Mg/yr of VOC emissions are the maximum available for control. Column 7 presents the percentage of the "controllable" emissions that each regulatory alternative would control "Controllable" emissions are 98 percent of total emissions from the 56 units (98 percent of 2,400 Mg/yr).

It is evident from Columns 6 and 7 that most of the emissions reduction

occurs as a result of controlling only a small fraction of the 56 process units. For example, Alternative III would control only 7 of the 56 process units. For example, Alternative IX would control only 7 of the 56 process units but would account for about 90 percent of the controllable emissions.

Column 8 presents the national annualized costs requirements for each alternative. These cost impacts range from \$0.15 million (1982 dollars) for Alternative II to \$9.3 million for Alternative IX. Capital costs accumulated over the 5-year period (not shown in the table) range from \$270,000 for Alternative II to \$17.3 million for Alternative IX. These cost and cost-effectiveness data reflect the costs of controlling these units at 98 weight-percent VOC reduction through the use of incinerators and flares. The actual costs and cost effectiveness should be considerably less than those indicated in Table 1 for two reasons. First, plant owners and operators may be able to use boilers, process heaters or catalytic oxidizers rather than the more expensive flares and incinerators to comply with the 98 weight-percent reduction requirement. Secondly, as will be discussed later in this preamble, plant owners and operators may be able to increase the efficiency of product recovery sufficiently to comply with this standard and thereby would not have to apply 98 weight-percent-efficient reduction controls. To the extent that this alternative means of compliance is used; costs as well as emission reduction will be lower than those indicated in Table 1.

Column 9 presents the energy impacts of the various alternatives. Electricity is frequently required to operate the pumps, fans, blowers and instrumentation that may be necessary to control VOC using an incinerator or flare. The amount of supplemental fuel

needed to increase the heating value of vent streams depends on vent stream temperature, net heating value of vent streams depends on vent stream temperature, net heating value, flow rate, combustion temperature, and type of heat recovery used. Due to the use of heat recovery techniques, combustion of some reactor process vent streams would result in a net production of energy even though supplemental fuel would be necessary for flame stability. Total electricity needs are relatively small compared to energy requirements in the form of supplemental fuel for combustion. The fifth year national energy use would range from about 3 terajoules per year (TJ/yr) (453 barrels of oil/yr) for Alternative II to 517 TJ/yr (85,000 barrels of oil/yr) for Alternative IX. As with the cost data, these impacts may be overstated because some facility operators will choose to comply with the standards through the alternative devices and mechanisms previously discussed.

F. Selection of Best Demonstrated Technology

As explained previously, the control of reactor process units would not result in unreasonable nonair environmental impacts or cause any of the chemicals to experience a significant adverse economic impact. Therefore, the Administrator analyzed the cost per megagram of emission reduction and energy impacts before determining which regulatory alternative should be selected. This analysis assures that the cost of units being controlled is reasonable, not only in terms of economic impacts, but also in terms of the emission reductions that would result. In this analysis, the cost data in Table 1 were first considered. The energy impacts shown in Table 1 indicate that there would be no unreasonable adverse energy impacts,

even if all units were controlled by combustion devices.

In selecting cutoffs related to applicability of NSPS, EPA looks at a variety of factors including: (1) The technical feasibility of additional control; (2) the economic feasibility associated with different control alternatives; (3) the magnitude of emission reductions associated with a control alternative (e.g., a slightly higher cutoff could be selected if it led to a substantial increase in the emission reduction achieved by the NSPS); (4) the cost effectiveness (C/E) of the control alternative in terms of annual cost per megagram (\$/Mg) of emissions reduced; (5) the quality of the cost estimates (e.g., worst case versus realistic estimates); (6) potential reductions in other air pollutants not specifically regulated by the NSPS resulting from a control alternative; and (7) the location of the sources (e.g., urban versus rural). Because these factors vary from industry to industry and, in some cases, within the same industry, decisions on the appropriate level of control are made on a category-by-category basis.

After evaluating the above factors, the Administrator concluded that the cost of requiring control of any reactor process unit below the \$2,500/Mg cutoff (1982 dollars) is reasonable and found that the following considerations were key to selecting the cutoff: (1) The cost effectiveness of NSPS for VOC emissions previously promulgated by EPA; (2) the probability that these maximum costs will not actually be incurred by industry; and (3) the presence of potentially toxic compounds in SOCM reactor process vent streams and the fact that many of the facilities are located in urban areas.

In the past, the estimated cost per megagram of VOC removed has sometimes ranged as high as \$2,800/Mg (1982 dollars) for affected facilities covered by other NSPS. (See Docket Item No. II-B-64). The Agency's experience in implementing these standards reveals that NSPS requiring this level of control have proved a useful tool in bringing about the installation of much emissions control technology, significant reductions in emissions, and corresponding improvements in air quality, yet have not imposed costs that appear "grossly disproportionate" to the emission reduction achieved. *Portland II*, 513 F.2d at 508. Such an approach simply makes this NSPS consistent (as to dollars spent per metric ton of VOC removed) with the existing body of NSPS regulations, all of which have either been promulgated without legal challenge or have been judicially

upheld. As indicated in column 2 of table 1, the cost-effectiveness cutoff of \$2,500/Mg used in the standard corresponds to Regulatory Alternative III. This alternative is estimated to result in a national annualized cost of \$3.7 million (1982 dollars) by controlling seven process units with a VOC emissions reduction of 2,100 Mg/yr. The range of cost effectiveness would vary from \$250/Mg to \$2,000/Mg with a \$1,700 average cost per megagram of VOC reduced.

Because of the conservative assumptions used to develop the regulatory analysis and because of the flexibility inherent in the means by which industry can comply with the standards, it is very unlikely that any facility would actually have to incur a cost of \$2,500/Mg (the cost-effectiveness cutoff). Data on current capital costs of thermal incinerators indicate that units are now available at substantially reduced costs compared to those used in developing these proposed standards. Lower capital costs would result in lower annualized costs than previous estimates, though the change in annualized costs will not be as significant as the change in capital costs. This is an important factor to consider in selecting the appropriate regulatory alternative. Another consideration is the fact that natural gas prices used to calculate the cost effectiveness for each stream are overstated by about 40 percent. These conservative assumptions have resulted in higher cost and cost-effectiveness estimates than would actually occur. In addition, as discussed earlier, the regulatory analysis assumes (for costing purposes) that flares and incinerators would be used to comply with the standards. In fact, it may be feasible for these facilities to use boilers or process heaters. If they are able to use these devices, the costs of compliance would be significantly reduced. Costs would also be reduced for reactors that share control systems with other process vents. Finally, the proposed standard would encourage pollution prevention by not requiring 98 weight-percent reduction if a TRE index greater than 1.0 is maintained. As detailed in the section entitled "TRE Index," the costs shown in table 1 do not take into account the ability of facilities to comply with the standards through changes in the equipment or operation of the process facility, in certain cases, thereby avoiding additional control device costs. Available data indicate that reactor process facilities with a TRE index just below the 1.0 cutoff (equivalent to \$2,500/Mg) would probably opt to

comply with the standards by making a process change such as adding recovery equipment to reduce VOC emissions and raise their TRE index above 1.0 rather than by combusting the vent stream. The objective of making a process change is to reduce VOC emissions without disposing of the VOC to the point at which the cost effectiveness associated with combustion is over the cutoff. For example, reactor process facilities with TRE values as low as 30 percent below the cutoff could potentially apply product recovery devices to comply with the standards. Due to this ability, no reactor process facility is likely to incur the maximum cost-effectiveness value of \$2,500/Mg. The highest value that a facility would actually incur by using a combustion device is estimated to be approximately \$1,700/Mg.

A third consideration in the selection of this regulatory alternative is that SOCM reactor process vent streams contain a wide variety of suspected or confirmed toxic compounds (e.g., benzene, acrylonitrile, butadiene, ethylene dichloride, ethylene oxide, carbon tetrachloride, and chloroform). A document listing the known toxic effects for the chemicals covered by this standard has been placed in Docket A-83-29 (Item II-I-168). Data on the emissions sources of more than 80 potentially toxic air pollutants indicate that the SOCM emissions account for a disproportionate share of potentially toxic constituents compared to other VOC sources (see Docket Entry II-A-39). In addition, as stated in the EPA's Air Toxics Strategy published in July 1985, the Agency will consider the likely toxic pollutant control benefits in the course of carrying out its responsibilities under section 111. This strategy reduces emissions of potentially toxic compounds from new sources and from industries as their facilities are reconstructed and modified. This approach is to work in tandem with EPA's efforts to control existing and new sources of specific toxic compounds under section 112 of the CAA. In setting an NSPS under section 111 of the CAA, the Agency evaluates all relevant factors (including costs, control technologies, environmental and energy impacts, and secondary impacts or benefits). Control of potentially toxic compounds by this NSPS is a secondary benefit that was considered by the Administrator in determining the reasonableness of the cost of different regulatory alternatives. Therefore, although EPA has not yet decided whether to list many of these compounds under section 112 of the

CAA, the Agency believes that it may properly consider their potential toxicity along with other relevant factors when choosing the cutoff. Many SOCM facilities are located in urban areas and, as a result, many people will be exposed to any hazardous air pollutants emitted from these facilities.

Consideration of all of the above factors confirmed EPA's belief that a TRE value of 1.0 (i.e., \$2,500/Mg) represents an appropriate cutoff for determining which facilities must reduce VOC emissions by 98 weight-percent or to 20 ppmv. The cutoff is specific to the SOCM reactor processes source category and would not necessarily be appropriate for other source categories; therefore, it should not be viewed as a benchmark for other standards. It is not surprising, however, that the cost-effectiveness cutoff for reactors of \$2,500/Mg (1982 dollars) is equivalent to the \$1,900/Mg (1978 dollars) cutoff for the SOCM air oxidation processes and distillation operations standards considering that the industry, the pollutants emitted, and the emission controls are the same. The only differences among the sources are the processes that are the sources of VOC emissions.

G. Selection of Format for the Standards

Several formats could be used to implement the proposed standards. Section 111 of the Clean Air Act requires that numerical standards of performance be prescribed unless, in the judgment of the Administrator, it is not feasible to prescribe or enforce such standards. In this case, section 111(h) allows the Administrator to prescribe design, equipment, work practice or operational standards, or combinations thereof. Under that Section the term "not feasible" is applicable if the emissions cannot be captured and vented through a vent or stack designed for that purpose, or if the application of a measurement methodology is not practicable because of technological or economic limitations. Because emissions from reactor vents and emissions from incinerators, process heaters, and boilers can be measured, an emission limitation (performance) standard for these combustion devices would generally be appropriate.

Because of the variety in process vent flow rates and VOC contents for many chemical reaction processes and facilities in the reactor source category, mass emission rates from sources using 98 weight-percent efficient control devices would vary considerably. Consequently, a mass emission limit based on an average source would require that more than 98 weight-percent

control be selected as BDT at some facilities and less at others. Therefore, a mass emission standard was considered inappropriate, because it would not require the BDT at each source. Reactor process vent streams have as much variation in volume percent organics concentration as in mass emission rates. Any standards based solely on a concentration limit would also require more than BDT at some facilities and less than BDT at others. Therefore, standards based solely upon concentration were considered inappropriate. However, as discussed below, a concentrations limit might be used in combination with another type of emission limit if the applicability of the concentration limit were restricted to facilities within a limited range of process vent gas VOC content.

A weight-percent reduction standard would be feasible for incinerators, boilers, and process heaters because the control device inlet and outlet emission rates can be measured. A weight-percent reduction standard would result in the application of BDT at all sources. Furthermore, a given set of incinerator, boiler, or process heater operating conditions tends to result in a given weight-percent reduction, rather than in an absolute outlet organics concentration or emission rate. As discussed above in the section entitled *Selection of Best Demonstrated Technology*, all new incinerators can achieve at least a 98 weight-percent reduction in total organics (minus methane and ethane), provided that the total organic (minus methane and ethane) concentration of the process vent stream is greater than approximately 2,000 ppmv (corresponding to 1,000 ppmv VOC in the incinerator inlet stream because air dilution is typically 1:1). Therefore, a weight-percent reduction standard, based on the mass rate of organics exiting the control device versus the mass rate of organics entering the device, would be appropriate for vent streams with total organics (minus methane and ethane) concentrations above approximately 2,000 ppmv. For vent streams with organics concentrations below approximately 2,000 ppmv, it has been determined that an incinerator outlet concentration of 20 ppmv is achievable by all new incinerators. Therefore, EPA concluded that the format of the proposed standards for reactor process vents using an incinerator, boiler, or process heater should include a combination of a weight-percent reduction standard and a volume concentration standard. The proposed emission limits would be a 98 weight-

percent reduction in total organic compounds (minus methane and ethane) or reduction to 20 ppmv total organic compounds (minus methane and ethane), whichever would be less stringent. The concentration limit of 20 ppmv would be based on a 3 percent vent stream oxygen concentration in the outlet stream.

Boilers and process heaters can achieve a 98 weight-percent reduction, provided that the waste stream is introduced into the flame zone where temperatures are highest. Unlike incinerators, in which furnace temperatures are fairly constant, furnace temperatures in heat-generating units are highest. Unlike incinerators, in which furnace temperatures are fairly constant, furnace temperatures in heat-generating units are highest in the flame zone, and a temperature gradient is experienced between the flame zone and the walls. The combustion kinetics are much more rapid in the flame zone, due to the higher temperatures (2,800°F to 3,000°F). This results in very small residence time requirements (much less than furnace residence times) to achieve 98 weight-percent reduction or greater than is required in an incinerator. When burned as a fuel in the flame zone, the organic compounds to be destroyed are exposed to these higher temperatures. As a result of the more rapid combustion kinetics at these temperatures, high destruction efficiencies comparable to those achieved by incinerators are attainable. In tests of the combustion of organic compounds burned as fuels in boilers and process heaters, greater than 98 weight-percent destruction efficiencies were demonstrated. Therefore, a reactor process vent stream, when combusted in a boiler or heater, must be introduced into the flame zone to ensure that it reaches sufficient combustion temperatures for destruction of the VOC. If the waste stream is not introduced into the flame zone, measuring 98 weight-percent efficiency across the control device has no value (i.e., does not assure the stream is being reduced by 98 weight-percent) since reactor process vent streams comprise generally a small portion of the total combustible stream to the heat generating unit. It is infeasible to "measure" whether the waste stream is introduced into the flame zone. Therefore, where a boiler or process heater is used as the control device, it is appropriate under section 111(h) of the CAA to have a combination format of performance standard and operational requirement. The proposed emission limit therefore would require any owner or operator using a boiler or process

heater to introduce the reactor process vent stream into the flame zone of the combustion device.

Unlike boilers, heaters and incinerators in which combustion takes place in an enclosed chamber, flaring is an open combustion process. It is very difficult, therefore, to measure the emissions from a flare to determine its efficiency. It may be technologically possible to measure these emissions, but the costs involved due to the necessity of hooding the flare and other equipment needs would be economically impracticable. The Administrator, therefore, has determined that it is not feasible to measure the emissions from a flare. Consequently, an equipment standard with stated specifications is being proposed as the format for the use of flares.

As described in the BID, test data show that flares meeting certain conditions achieve a 98 weight-percent emission reduction. The proposed standards require the use of a flare that meets the requirements of 40 CFR 60.18 to comply with the standards. This means that only flares that are steam assisted, air assisted, or nonassisted may be used. Furthermore, the net heating value of the flared gas must not be less than 11.2 MJ/scm (300 Btu/scf) for steam-assisted and air-assisted flares or less than 7.45 MJ/scm (200 Btu/scf) for a nonassisted flare. In addition, the exit velocity of the flare gas at the flare tip must not exceed 18.3 m/sec (60 ft/sec) for steam-assisted and nonassisted flares, except for the following conditions. If the net heating value of the gas being combusted is greater than 37.3 MJ/scm (1,000 Btu/scf), the exit velocity of the flare gas at the flare tip must not exceed 122 m/sec (400 ft/sec) for steam-assisted and nonassisted flares. When the net heating value is less than 37.3 MJ/scm but greater than 11.2 MJ/scm, the maximum exit velocity for nonassisted and steam-assisted flares is a function of the heating value. Air-assisted flares must also operate below a maximum exit velocity, which is dependent upon the net heating value of the flared stream. There are the only conditions for which EPA has data supporting the finding that flares achieve 98 weight-percent emission reduction.

Another consideration in developing the equipment standard for streams using flares is the potential for process variations such as flow surges that can cause a flare to smoke for short periods of time until the flare can be adjusted. Five minutes is a reasonable period of time for alleviating the smoking conditions by making the needed

adjustment to the steam or air to the flare. The provisions in 40 CFR 60.18 limit visible emissions to no more than 5 minutes within any 2-hour period.

Some reactors process facilities recycle all vapors to the manufacturing process and, therefore, do not emit VOC. For others, the product recovery devices remove virtually all of the vent stream. Analysis by EPA indicates that, even with large vent stream VOC emission rates and heat contents, no vent stream with flow rate below 0.011 scm/min (0.30 scfm) would be required to implement combustion controls. These facilities would have an unreasonably high control cost per megagram of VOC destroyed (greater than \$2,500/Mg). For this reason, the proposed standards exclude facilities with flow rates less than 0.011 scm/min from the provisions of the standards except for an initial measurement and reporting requirement.

H. TRE Index

After selecting the cost-effectiveness cutoff above which additional control of VOC is not required, it was necessary to develop a method for use in the regulation that would distinguish those reactor process units below the cutoff (which would be required to meet the 98 weight-percent reduction requirements) from those process units for which no additional VOC reduction would be required. The EPA, therefore, has included equations in the regulation to calculate an index to determine whether further control is required. This index is termed TRE. An important feature of this index is that it is independent of cost changes over time so that it is not necessary to periodically revise the calculation to reflect current year dollars. The equations include the parameters used in calculating costs considered in selecting the cutoff. These parameters are the vent stream characteristics of flow rate, net heating value, mass flow of total organic compounds, and corrosion properties (presence of halogenated compounds). These parameters can be measured easily and objectively. The TRE value calculation allows the owner or operator of an affected facility to determine if that facility would be required to reduce VOC emissions by 98 weight-percent or to 20 ppmv. The standardized calculation allows objective enforcement since all TRE values would be calculated based on the same parameters and calculated by the same method.

The TRE index of a process vent stream is calculated according to one or both equations given in § 60.704(e)(7). The TRE index cutoff as calculated by

the equation is 1.0. Affected reactor process facilities with a TRE index of less than or equal to 1.0 would be required to reduce VOC emissions by 98 weight-percent or to 20 ppmv, whichever is less, while affected facilities with a TRE index above 1.0 would not be required to comply with emission reduction requirements. The set of coefficients used in the equations that apply to a process vent stream can be obtained from Tables 1 and 2 of the regulation. These coefficients were derived directly from the cost and emission reduction equations associated with control of VOC emissions from reactor process facilities by flares and incinerators.

The standards require that a plant owner or operator calculate the TRE of the process vent stream based on the specific characteristics of the vent stream. If the vent stream contains halogenated VOC, the equation for determining the TRE value for incineration must be used, along with the appropriate coefficients (in Table 1) based upon vent stream heat content and flow rate. For vent streams containing nonhalogenated VOC, the plant owner or operator must calculate TRE values, using both the incineration equation and the equation for flares (selecting the appropriate set of coefficients in Table 1 or 2 based upon heat content and flow rate). After calculating both the incineration and flaring TRE values, the plant owner or operator must select the lowest TRE value for purposes of determining compliance with the standards. In most instances incinerators are more expensive than flares for controlling nonhalogenated vent streams; but in some instances the reverse is true. For this reason the regulation requires that the least expensive technique be used for TRE index calculation purposes. If this requirement did not exist, it is possible that a plant owner or operator could avoid the emission reduction requirements by not selecting the least costly control device in determining TRE.

The vent stream of an affected facility is considered "halogenated" under the proposed standards if it is determined to contain a concentration of halogenated compounds of 20 ppmv (by compound) or greater. This low 20 ppmv halogenation cutoff was chosen for the analysis to avoid control cost and TRE underestimates. Even small amounts of halogenated compounds may be corrosive and can necessitate incinerator temperatures greater than 870 °C to achieve a 98 weight-percent control. Therefore, it was judged

essential to set a low cutoff, so that the control cost and TRE would not be underestimated for any facility. This does not imply that flares, boilers, and process heaters are prohibited from use on streams containing more than 20 ppmv halogenated compounds.

The BDT selected allows flexibility in implementing the standards. For sources below the TRE index cutoff where the cost of combustion control is considered reasonable, BDT is the use of a control device capable of achieving a reduction of 98 weight-percent, or to 20 ppmv total organics (minus methane and ethane) whichever is less stringent. Control is achievable through the use of combustion devices such as incinerators, boilers, process heaters, and flares. Incinerators may be the only applicable combustion device for use on streams containing halogenated VOC. Above the TRE index cutoff, BDT is no additional control.

The use of a TRE index cutoff will also permit the use of recovery techniques or process modification in an effort to raise the TRE index to a point above the 1.0 cutoff. The parameters used to calculate the TRE index are measured at the outlet of the recovery system. Additional recovery can be used to change the values of the parameters (e.g., decrease the emission rate) and subsequently increase the TRE index value. The total cost to a facility for improved recovery to exceed the TRE cutoff may, in some cases, be much lower than the total cost of a flare, boiler, or incinerator. It may, therefore, be economically advantageous for such a facility to choose to improve its recovery system or make some other change within the process. The decision by the owner of a facility concerning the design and resulting VOC removal efficiency of a change within the process is primarily made prior to the construction, modification, or reconstruction of that facility. As a practical matter, EPA has no ability to assess the extent to which VOC removal efficiency is influenced by economic versus regulatory considerations. As such, the source's motivation for establishing a particular process design is not considered when the TRE index value is measured. Consider an example where the owner or operator of a facility chooses to improve the facility's recovery system. For this type of process change, EPA presumes that the recovery systems are integral to the process and that, therefore, BDT is best determined according to the characteristics of the stream existing the last recovery device.

I. Selection of Actual Standards

In summary, under the proposed standards, sources for which the costs of combustion control are reasonable would be subject to the following requirements: (1) A 98 weight-percent reduction of the total organic compounds (minus methane and ethane) in the reactor vent stream or a reduction to 20 ppmv total organic compound (minus methane and ethane), whichever is less stringent; and if a boiler or process heater is used to comply with the standards, the reactor vent stream must be introduced into the flame zone of the boiler or process heater, or (2) when a flare is used to comply with the standards, a smokeless flare is required and must be operated in accordance with the requirements in 40 CFR 60.18. As previously discussed, facilities with low flow rate (less than or equal to 0.011 scm/min) and facilities with low capacities (less than or equal to one Gg/year) would be exempt from these standards except for certain recordkeeping and reporting requirements.

For sources where the costs of control are not reasonable, the proposed standards would require that the TRE index be maintained at a value of 1.0 or above. This TRE concept is explained in Section H.

J. Compounds Used in Determining Compliance

The proposed standards are intended to reduce emissions of VOC through the application of BDT (considering costs and other impacts); and the emission limits in the standards are designed to reflect the performance of BDT. Where a control device for a reactor process is BDT, that control device (i.e., combustion) does not selectively control VOC (that is, the proportion of the organics that is regarded as photochemically reactive), but rather these technologies control all organic compounds. Moreover, the numerical values of the emission limits (98 weight-percent reduction and 20 ppmv) in the case of reactor processes, were based on total organic compounds data that excluded methane and ethane.

To reflect accurately the performance of these control devices and to make the emission limits consistent with the data and test methods from which the limits were derived, EPA has expressed the standards in terms of organic compounds, minus methane and ethane. For the same reason, the test procedure in the proposed standards prescribes measurement of total organic compounds, excluding methane and ethane. In short, EPA is relying on

control of total organic compounds, minus methane and ethane, as the best surrogate for controlling VOC, which react to form ozone in the atmosphere.

K. Modification/Reconstruction Considerations

The proposed standards would apply to all affected facilities which commenced construction, reconstruction, or modification after the date of proposal of the NSPS. Modification is defined in 40 CFR 60.14 as any physical or operational change to an existing facility which results in an increase in the emission rate to the atmosphere of any air pollutant to which a standard applies. (Section 60.14(e) lists the six exemptions which would not be considered modifications even if emissions increased.) Reconstruction, as defined in 40 CFR 60.15, occurs when components of an existing facility are replaced to such an extent that: (1) The fixed capital cost of the new components exceed 50 percent of the fixed capital cost that would be required to construct a comparable entirely new facility, and (2) it is technologically and economically feasible to meet the applicable standards.

Potential modifications involving SOCM reactor processes include process equipment changes, changes in operating parameters, or both. Two types of process changes that may result in modification are: (1) Feedstock (i.e., basic chemical) or reactant substitution in reactors which were not designed to accommodate the new feedstock or reactant, and (2) process equipment changes.

Many of the chemicals produced in reactors can be manufactured from two or more feedstocks. For example, cyclohexanone can be produced using either phenol (a reactor process reactant) or cyclohexanol (an air oxidation reactant). If a feedstock change were made and if: (1) Emissions increased, and (2) as required under § 60.14(e) the reactor was not designed to accommodate the feedstock change, the feedstock change would result in a modification. In the example cited above, all the reactors could have to be rebuilt, possibly requiring a capital expenditure in excess of 50 percent of the capital cost of the affected facility. In this case, a reconstruction could result, regardless of the emissions.

The second type of process change is a process equipment change. As discussed earlier, this type of change rarely occurs within the industry. Examples include the replacement of a fixed-bed reactor with a fluidized-bed reactor, the expansion in the size of a

reactor, or the replacement of an absorber or substitution of a condenser for an absorber in the gas treatment system. If any of these process equipment changes result in an increase in emissions, a modification could result; if any of the changes requires the expenditures of more than half of the replacement cost of the affected facility, then a reconstruction could occur.

L. Selection of Monitoring Requirements and Test Methods

Following is a discussion of the monitoring requirements and test methods selected for demonstrating compliance with both the emission reduction and the TRE provisions of the proposed standards.

Percent Reduction/Concentration Limit

The combined gas chromatograph/flame ionization detection method (GC/FID) (Reference Method 18) is the best available procedure for determining emissions from reactor process facilities. It has the advantage of being able to measure individual organic compounds. Details concerning the use of this methodology, including sampling, analysis, preparation of standards, calibration procedures, and reporting of results are discussed in Reference Method 18, "Measurement of Gaseous Organic Compound Emissions by Gas Chromatography," which was promulgated with the NSPS for SOCM equipment leaks (48 FR 48328).

The owner or operator of a facility using an incinerator to comply with the proposed 98 weight-percent/20 ppmv emission limit would be required to determine compliance according to Reference Method 18 during any performance test. Reference Method 1 or 1A would be required, as appropriate, to be used for selection of the sampling site. The control device inlet sampling site for determination of reduction efficiency would be required to be prior to the inlet of any control device and after all product recovery devices. Reference Methods 2, 2A, 2C, or 2D would be required, as appropriate, to be used for determination of the volumetric flow rate. Reference Method 3 would be required to be used for an air dilution correction, based on 3 percent oxygen in the emission sample.

If any process vent stream(s) from outside the affected facility were normally routed through the product recovery system or directly to the control device of the affected facility, the proposed standards would permit such a stream to be routed normally during any performance test to determine compliance with the proposed reduction requirement. The Agency

considered requiring such streams to be rerouted or turned off, in order to assure that 98 weight-percent reduction or reduction to 20 ppmv would be achieved for control of the reactor process stream itself. However, the Agency determined that if a performance test conducted on such a facility while routing its vent streams from a nonaffected facility showed compliance with the proposed emission limit, that limit would also be achieved by the combustion device when only the reactor process vent stream is routed through it, provided that the combustion device operating parameters, such as temperature and residence time, remained unchanged. Therefore, the Agency concluded that requiring the nonaffected facility process stream to be rerouted or turned off during a performance test would be unnecessary.

The Agency believes that boilers and process heaters with a design heat input capacity of 44 MW (150 million Btu/hr) or greater would achieve a reduction efficiency of 98 weight-percent or reduction to 20 ppmv, so long as the reactor process stream is introduced into the flame zone. Therefore, the Agency believes that an initial measurement of control efficiency would not be necessary for boilers of this size. As explained in the discussion of combustion kinetics given in the BLD, a firebox temperature of 1,100 °C and 1 second residence time represent the conditions that might, in the worst case, be necessary to achieve 98 weight-percent reduction, even if the organics were halogenated. Boilers (and process heaters) with a design heat input capacity of 44 MW or greater are operated at temperatures and residence times greater than 1,100 °C and 1 second, respectively. In some cases, the residence time is less than 1 second. However, in these cases, the firebox temperature is much greater than 1,100 °C, and 98 weight-percent reduction would still be achieved.) Other than an adequately high temperature and residence time, the two primary conditions necessary for high combustion device control efficiency are stable flow rate and adequate mixing of gases. It is the economic advantage of the owners of facilities using boilers or process heaters to design and operate them with stable flow rates to avoid upsets. For the same reason, such devices would be designed and operated with adequate mixing of gases to maximize the extent of the combustion efficiency, thereby maximizing the steam or heat generation rate.

For these reasons, the Administrator has decided that using a boiler or heater with a design heat input capacity of 44

MW or greater to control VOC emissions from reactor process operations is an acceptable means of demonstrating compliance with the proposed standards if the vent stream is introduced into the flame zone. Therefore, in accordance with § 60.8(b), the Administrator has waived the requirement for a performance test on such devices. An initial report is required within 180 days of start-up, describing the location at which the vent stream is introduced into the boiler or process heater. The reference methods applicable to incinerators described below apply to the smaller (i.e., less than 44 MW) boiler and process heaters.

As explained under *Selection of Format for the Standards*, an operational standard was selected for cases where a flare is used to meet the standards. Therefore, a performance test measuring percent reduction is not required for streams equipped with flares. However, the standard requires that the flare operate in accordance with the requirements in 40 CFR 60.18. Flow rate and heat content of the flared stream are to be determined in accordance with the procedures prescribed in § 60.703.

Incinerators used to comply with the proposed emission limit need to be maintained and operated properly if either a 98 weight-percent reduction or reduction to 20 ppmv is to be achieved on a continuing basis. Monitoring can generally be used to ensure such proper operation and maintenance are occurring. Two methods of monitoring to ensure the proper operation and maintenance of the control equipment used to comply with the proposed emission limit were considered. These methods were continuous emission monitoring and continuous combustion control device parameter measurement. Examples of such parameters are combustion temperature and vent stream flow.

Continuous combustion control device inlet and outlet emission monitoring would be the preferred method of monitoring, because it would provide a continuous, direct measurement of actual emissions. However, no continuous monitor measuring total organics (minus methane and ethane) has been demonstrated for incinerators because each of the many different compounds in reactor process vent streams would have to be identified separately and the concentrations of each determined. Therefore, the Administrator has determined that continuous monitoring of compliance with the proposed standards is not feasible.

Provided that combustion parameters that accurately reflect the level of combustion device efficiency can be identified and monitored continuously, monitoring of such parameters alone would have several advantages, such as low cost and high reliability. However, a disadvantage of combustion parameters monitoring alone is that the correlation of the parameters with the numerical emission limit is not exact. However, exact correlation is not necessary if the parameter monitored would demonstrate proper operation and maintenance of the control device.

The combustion device operating parameters that affect incinerator performance were analyzed. These variables are temperature, mixing, type of compound, residence time, inlet concentration, and flow regime. Of these variables, the inlet concentration was judged to have only a small impact on incinerator performance (provided reactor vent concentrations are at least 2,000 ppmv). Residence time is essentially set after incinerator construction unless the vent stream flow rate is changed. At temperatures above 760 °C, the compound type has little effect on combustion efficiency. Temperature and flow rate were then analyzed in more detail to define their impact on performance and the ability to monitor them.

Temperature was analyzed first. Test results and theoretical calculations show that lower temperature can cause significant decreases in control device efficiency. Test results also indicate that temperature increases can also adversely affect control device efficiency, apparently by decreasing the thoroughness of mixing of process vent gases, burner gases, and combustion air. In terms of cost, temperature monitors are relatively inexpensive, costing less than \$5,000 installed with strip charts, and are easily and cheaply operated. Given the large effect of temperature on efficiency and the low cost of temperature monitors, this variable is clearly an effective parameter to monitor. The proposed standards would, therefore, require the owner or operator of an affected facility using a thermal incinerator to comply with the proposed 98 weight-percent/20 ppmv emission limit to install, calibrate, maintain, and operate according to manufacturer's specifications a temperature measurement device. This device would be required to be equipped with a continuous recorder and have an accuracy of 1 percent of the temperature being measured, expressed in degrees Celsius, or ± 0.5 °C, whichever is greater. The device would be required to

be installed in the firebox. If a catalytic incinerator were used, the temperature measuring device would be required to be installed in the gas stream immediately before and after the catalyst bed.

Flow rate of the reactor process vent stream to the combustion device was the next parameters to be analyzed as a potential monitoring parameter. Where a combustion device is used to incinerate VOC streams alone, total flow rate into the unit can provide useful information regarding destruction efficiency since it relates to residence time in the combustion device. Reactor process vent stream flow rates can be small in comparison to other streams that may also be ducted to the same combustion device. Since total flow rate must be monitored in order to provide reliable information, and reactor vents may be combined with other nonreactor vents, then the monitoring requirements would be applied to vents that were not intended to be covered by the standards. Flow indicators, as opposed to flow rate monitors, are relatively inexpensive and easy to operate. Therefore, because it gives an indication that the organic-laden stream is being routed for destruction and it is monitored inexpensively, indication of flow is also an effective parameter to monitor for combustion devices.

The proposed standards would, therefore, require the operator of an affected facility using an incinerator to comply with the proposed emission limit to install, calibrate, maintain, and operate a flow indicator, according to the manufacturer's specifications. The flow indicator would be required to be installed at the combustion device inlet.

These two combustion parameters (temperature and flow) would be required to be monitored during the original (or most recent) performance test. Temperature would then be monitored to determine if it deviated from the values measured during the performance test. Flow indicators would be required to determine whether the vent stream was being continuously routed for destruction.

If a reactor process vent stream is introduced into the flame zone of a boiler (or process heater) of any size, it is necessary, for the purpose of ensuring proper operation and maintenance, to know that the boiler (or process heater) is operating and to know that the vent stream is being introduced into the boiler (or process heater). The maintenance of records (such as steam production records) would be required that would indicate the periods of operation of the boiler (or process

heater). The Administrator must be notified if the location at which the vent stream is introduced into a boiler or process heater is changed after the initial performance test. The nature of the records to be kept to comply with this requirement are left to the discretion of the owner or operator of the facility, but they must be readily available for inspection. To ensure that the vent stream is being introduced into the boiler (or process heater), the proposed standards require owners or operators to install and operate a flow indicator that provides a record of vent stream flow to the boiler (or process heater).

For heat generating units (boilers and process heaters) of less than 44 MW (150 million Btu/hr) heat input design, performance testing is required to ensure efficient VOC destruction. For these units, just as for incinerators, temperature would be required to be measured during the original (or most recent) performance test and to be monitored to determine if it deviated from the values measured during the performance test. Monitoring of temperature would not be required for heat generating units with a design heat capacity of 44 MW or greater.

A flare will be in compliance with the proposed standards provided it is operating in accordance with 40 CFR 60.18 (i.e., it is operating smokelessly (no more than 5 minutes of visible emissions from any 2-hour period), a flame is present, the minimum heat content requirements for the flared gas are met, and a maximum exit gas velocity is not exceeded). Because flares are not enclosed combustion devices, it is not feasible to measure combustion parameters. Moreover, temperatures and residence times are more variable throughout the combustion zone for flares than for enclosed devices and, therefore, such measurements would not necessarily provide a good indicator of flare performance even if measurable. The typical method of monitoring continuous operation of a flare is visual inspection. However, if a flare is operating smokelessly, it can be difficult to visually determine if a flame is present. The presence of a flame can also be determined through the use of a heat sensing device on a flare's pilot flame, such as a thermocouple or ultraviolet (U-V) beam sensor. If a flame is absent, the temperature probe can be used to alert the plant operator. The cost of available thermocouple sensors ranges from \$800 to \$3,000 per pilot. (The more expensive sensors in this price range have elaborate automatic relight and alarm systems.) The cost of a U-V

sensor is approximately \$2,000. While U-V sensors are designed primarily to monitor flames within enclosed combustion devices, they can be applied to open flames so long as any outside interferences are corrected for. The use of either thermocouples or U-V sensors is suitable for indication of the presence of a flame. The proposed standards would require continuous monitoring to indicate the presence of a flame to ensure proper operation and maintenance of a flare, but the standards do not specify a particular monitoring technique.

Among the criteria governing the use of flares under the proposed standards is maximum exit gas velocity requirement. Compliance with this requirement is determined by performance testing. Methods 2, 2A, 2C, or 2D (see § 60.704) are used in performance tests to determine the actual exit velocity of flares. These tests must be performed under representative flare operating conditions. Exceedances of velocity limitations during periods in which one or more processes (that vent to the flare) start-up, shutdown, and malfunction are not considered a violation (see § 60.8(c)). These tests are used to ensure that the flare is designed to be and is capable of being operated within the velocity limitation during representative process conditions. During nonperformance test periods, operators must maintain and operate flares used to comply with Subpart RRR in a manner consistent with good air pollution control practices for minimizing emissions, even during periods of start-up, shutdown and malfunction (see § 60.11(d)).

The formula specified at § 60.704 requires that Method 2, 2A, 2C, or 2D be used as the test method to determine the volumetric flow rate. This flow rate should be determined in the flare header or headers that feed the flare because the volumetric flow rate determined in these headers reflects the flow rate in the flare. After this flow rate is determined, an operator would use design and engineering principles to determine the unobstructed cross-sectional area of the flare tip. With these two factors, the actual exit velocity is determined.

The TRE Index Cutoff

Calculation of the TRE index value for an affected facility is dependent upon measurement of the process vent gas volumetric flow rate, net heating value, total organic compound emission rate, and corrosion properties (presence or absence of halogenated compounds into the stream, and also prior to the inlet of any combustion device). Subject to the

requirements just mentioned, the sampling site would also be required to be downstream of all product recovery equipment except as discussed in the remainder of this section. In the situation where vent streams from new and existing reactors are ducted to a common product recovery system, a single TRE measurement is required downstream of the common product recovery system for the control of the combined new and existing reactor vent streams.

The final piece of recovery equipment will not always be associated with only the affected facility; it can sometimes include nonreactor process facilities. These are configurations that could influence the location and number of sampling sites required. One possible exception to the previous discussion involves a vent stream from an affected facility that is normally routed through a final recovery system that is shared with a nonreactor process gas stream. The Agency considered whether or not to require in the proposed standards that such nonreactor process streams be bypassed during any test to determine the TRE index. The efficiency of the recovery system including both the reactor and the nonreactor process vent stream would often be different from the efficiency of similar devices designed to handle each vent stream separately. Furthermore, it is reasonable to conclude that, especially for recovery devices, their design would be different for reactor and nonreactor vent streams constituents. Therefore, for purposes of determining compliance with the TRE index cutoff of such cases, the Agency requires that the TRE index be determined based upon the portion of the recovery outlet stream contributed by the reactor process facility alone. Thus, it is necessary to locate sampling sites directly upstream and downstream of the recovery system (to determine that overall control efficiency for the device or devices) and also directly downstream of the reactor process facility. In all cases, compliance with the TRE index cutoff would be determined for the total portion of the vent stream contributed by a reactor facility by determining the effects of the overall efficiency of the device upon the characteristics of the vent stream determined from the upstream sampling site (or sites) and by measuring flow rate and molar composition at a point just downstream of each affected facility (i.e., downstream of the final recovery device).

For any sampling site, the volumetric flow rate would be required to be determined according to Reference

Methods 2, 2A, 2C, or 2D, as appropriate. The molar composition of the offgas stream, including the total molar concentration of halogenated compounds, would be required to be calculated according to the proposed Reference Method 18, Measurement of Gaseous Organic Compound Emission by Gas Chromatography. The water vapor concentration of the vent stream would be required to be calculated according to Reference Method 4.

The net heating value of the process vent stream (25 °C, 760 mm Hg) would be required to be calculated according to an equation specified in the regulation. This equation would make use of the molar composition of the process vent stream, as measured by Reference Methods 4 and 18. The net heat of combustion of each vent stream component would be required to be determined using ASTM D2382-76 if published values are not available or cannot be calculated. This method of determining net heating value was chosen because it would not require a separate test procedure from that required for determination of reduction efficiency and offgas halogenation. Moreover, the Agency believes that the proposed method for determining net heating value would be more accurate than any available direct experimental measure, such as bomb calorimetry.

The total organic mass emission rate of the process vent stream would also be required to be calculated according to an equation specified in the regulation. This equation would make use of the molar composition of the offgas stream, as measured by Reference Method 18, and of the volumetric flow rate, as measured by Reference Method 2.

After an initial performance test to determine compliance with the proposed TRE index cutoff value, variations in process parameters, process modifications or improper operation or maintenance of recovery equipment could lead to higher emissions and a true TRE index below the cutoff. Some method is necessary to determine if the TRE index measured during the initial performance test has changed. Methods considered were continuous monitoring of selected operating parameters of the final piece of product recovery equipment in the affected facility and periodic performance testing of the TRE index of the facility. As explained previously, continuous vent stream molar composition and flow rate monitoring are not feasible. The first method investigated for determining if the initial TRE index had changed, involved the monitoring of product

recovery device parameters. The operating parameters of the three types of product recovery equipment commonly used in reactor processes were analyzed for correlation with product recovery device operation and maintenance, which in turn would give an indication of changes in TRE index. The three types of product recovery equipment are absorbers, condensers, and carbon adsorbers.

For an absorber, two operating parameters were identified as the primary determinants of product recovery device operations: absorbing liquid temperature and specific gravity (or some other parameter used by a facility to measure absorbing liquid saturation). In the absence of the proposed standard, facilities employing an absorber for product recovery would, in general, monitor continuously some parameter related to the degree of saturation of absorbing liquid with recovered material. Specific gravity is one such parameter that is frequently monitored. Absorbing liquid temperature monitors and specific gravity measurement devices are available at a reasonable cost. The estimated one-time combined capital investment for such equipment is \$8,000. These absorption parameters would be required to be measured during each performance test. (If approved by the enforcing Agency, an alternate parameter that would indicate the degree of absorbing liquid saturation could be measured during each performance test.) These absorption parameters would then be monitored to determine if any value had changed since the performance test. This monitoring would indicate whether the absorber was being operated and maintained properly. Therefore, an operator of an affected facility for which an absorber was the final device in the product recovery system would be required to install, calibrate, maintain, and operate according to a manufacturer's specifications an absorbing liquid temperature monitor and specific gravity measurement device (or an alternate device that would measure the degree of absorbing liquid saturation, if approved by the enforcing agency), each recorded continuously.

For a condenser, the exit (product side) temperature of the offgas was identified as the primary determinant of product recovery device operation. Condenser temperature monitors are available at a reasonable cost. The estimated one-time capital investment for such equipment is \$3,000. The condenser exit (product side) temperature would be required to be

measured during each performance test. The temperature would then be monitored to determine if the value had changed since the most recent performance test. This monitoring would indicate whether the condenser was being operated and maintained properly. Therefore, an operator of an affected facility for which a condenser was the final device in the product recovery system would be required to install, calibrate, maintain, and operate according to manufacturer's specifications a condenser temperature monitor equipped with a continuous recorder.

For a carbon absorber, the carbon bed temperature (after regeneration and completion of any cooling cycle), as well as the amount of steam used to regenerate the adsorption bed, were identified as the primary determinants of product recovery device operation. Steam flow meters that indicate the quantity of steam used over a period of time and bed temperature monitors are available at a reasonable cost. The estimated one-time capital investment for such equipment is \$10,000. These adsorption parameters would be required to be measured during each performance test. These adsorption parameters would then be monitored to determine if any value had changed since the most recent performance test. This monitoring would indicate whether the carbon adsorption unit was being operated and maintained properly. Therefore, an operator of an affected facility for which a carbon adsorber is the final unit of the product recovery system would be required to install, calibrate, maintain, and operate according to manufacturer's specifications an integrating steam flow meter and a carbon bed temperature measurement device, each equipped to be recorded continuously.

Some carbon absorbers, adsorbers, and condensers may include vent stream organic concentration monitors to aid operators maximizing the recovery of raw materials or products. Such devices equipped with a continuous recorder may be used as an alternative to monitoring the other operating parameters for absorbers, adsorbers, and condensers specified in the regulation.

The enforcement agency would specify, on a case-by-case basis, appropriate monitoring procedures or requirements where the owner or operator of an affected facility uses emission control or product recovery techniques other than those specified to comply with the proposed standards.

The Agency has determined that an affected facility with a TRE index value greater than 8.0 could not lower its TRE index value below 1 without a process change. Therefore, facilities with TRE index values greater than 8.0 are exempt from the monitoring, recordkeeping and reporting requirements other than the initial performance test requirements unless a process change is made to the facility. If a process change occurs, the TRE index value would have to be recalculated. If the recalculated TRE index value is below or equal to 8.0 and greater than 1.0, the facility would have to comply with the monitoring, recordkeeping, and reporting requirements of the standards.

M. Reporting and Recordkeeping Requirements

The General Provisions for the NSPS regulations (40 CFR part 60, subpart A) require submittal of several one-time notifications for occurrences such as construction, modification, reconstruction, scheduled dates for performance tests, and performance test results. Owners and operators of boilers and process heaters with design heat input capacities of 44 MW (150 million Btu/hr) or greater would not report performance test results, since the proposed standards would waive the requirement of such a test. Instead, operators would be required to file an initial report describing the location at which the reactor vent stream is introduced into the boiler (or process heater) to be used. Owners and operators of flares used to comply with the proposed standards would be required to file an initial report on the results of performance testing to determine compliance with the visible emission requirements and the heat content and maximum exit gas velocity criteria for flares.

The proposed standards exempt reactor process facilities from the quarterly report required by the General Provisions. However, records of start-up, shutdown, and malfunction would still be required. Also, records indicating whether control equipment is being operated and maintained properly would be required. The proposed standards would require owners or operators of those facilities, exempted because their operational flow rate was less than 0.011 scm/min, to send an initial report to the Administrator containing a measurement of the operating flow rate, maintain records of and report semiannually if any changes in equipment process operation occur that would increase their flow rate above 0.011 scm/min. Similarly, owners

or operators of those facilities that would be excluded from control requirements because the process unit in which they are located has a design capacity below 1 Gg/yr, would be required to send an initial report to the Administrator of the design production capacity. They would also be required to record and report changes that increase their process unit capacities above the one Gg/yr cutoff.

Records indicating proper operation and maintenance would be based on the monitoring of control device or recovery device parameters discussed in the previous section. Two types of records would be required. The first would be the monitoring results themselves. This information can be automatically recorded, and therefore, essentially the only labor necessary for keeping these records would consist of filing automatically recorded parameters. The second type of record would be a tabulation of periods when the measurements of these automatically recorded parameters significantly deviated from measurements of the same parameters during the most recent performance test. Although this requires more effort, it is a necessary step for both the owner or operator and enforcement agency to ensure that the control equipment is being operated and maintained properly. This information would be necessary for the owner or operator to know when to make necessary corrections to the control equipment. For this second type of record it would be necessary for the owner or operator to record control device or product recovery equipment operating parameters, as appropriate, during all performance tests and keep these records for purposes of comparison. The owner or operator would not be required to record all deviations from these measurements, but only certain deviations as listed in the proposed regulation. All records would be required to be kept up to date and in readily accessible files for 2 years. The parameter boundaries included in the proposed regulation would allow for normal fluctuations in operation of the equipment monitored. The VOC reduction efficiency of the control device would not be affected by such normal fluctuations.

Where a recovery system is used to comply with the proposed TRE index value, the proposed standards would also require recording of any change in production capacity; feedstock; type of catalyst; or of the replacement, removal, or additional of product recovery equipment. When any such change occurs, the TRE index value would have

to be recalculated to document that the facility continues to have a TRE index value above 1.0. Such recalculation can be based on the best engineering estimates of the effects of the change or on emission test data. A record would be maintained of the recalculated TRE value. If the recalculated TRE index value for the facility is below 1.0, the owner, or operator of the facility would have to demonstrate compliance with the 98 weight-percent reduction or 20 ppmv emission limits. 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.

If the initial TRE index value for a facility were above 8.0 and the recalculated value were below or equal to 8.0 but greater than 1.0, the facility must report the recalculated TRE index value to the Administrator as soon as possible after the change and no later than 180 days after the change. In addition, a performance test must be completed within the same time period to verify the recalculated value and to obtain the initial operating parameters. The performance test is subject to the requirements of § 60.8 of the General Provisions. The facility must begin complying with the monitoring, recordkeeping, and reporting requirements immediately after the performance test.

In addition to the one-time notifications and performance test reports discussed above, semiannual reporting of recorded data would be required for instances where monitored parameters exceed the allowable limitations set forth in the standards. These data include the operating parameters cited above for combustion and other control devices. Other instances that would be reported semiannually are periods of no flow to control devices used for compliance with the standards and periods where there is no flame present for flares used for compliance with the standards. The requirement for semiannual reporting, however, is waived for affected facilities in States where the program has been delegated, if EPA, in the course of delegation, approves reporting requirements or an alternative means of source surveillance adopted by the State. Such affected facilities would be required to comply with the requirements adopted by the State.

During the first 3 years of this regulation, the average annual burden of the reporting and recordkeeping requirements would be 7.9 person-years, based on an average of 27 respondents per year.

V. Administrative Requirements

A. Public Hearing

A public hearing will be held, if requested, to discuss the proposed standards in accordance with section 307(d)(5) of the CAA. Persons wishing to make oral presentations should contact EPA at the address given in the ADDRESSES section of the preamble. Oral presentations will be limited to 15 minutes each. Any member of the public may file a written statement before, during, or within 30 days after the hearing. Written statements should be addressed to the Central Docket Section address given in the ADDRESSES section of the preamble.

A verbatim transcript of the hearing and written statements will be available for public inspection and copying during normal working hours at the EPA's Central Docket Section in Washington, DC (see the ADDRESSES section of this preamble).

B. Docket

The docket is an organized and complete file of all the information submitted to, or otherwise considered in, the development of this proposed rulemaking. The principal purposes of the docket are: (1) To allow interested parties to identify and locate documents so that they can effectively participate in the rulemaking process, and (2) to serve as the record in case of judicial review (except for interagency review materials as noted in Section 307(d)(7)(A)).

C. Clean Air Act Procedural Requirements

Administrator Listing—Section 111. As prescribed by section 111 of the CAA, as amended, establishment of standards of performance for SO₂ reactor process units was preceded by the Administrator's determination (40 CFR 60.16, 44 FR 49222, dated August 21, 1979) that SO₂ contributes significantly to air pollution which may reasonably be anticipated to endanger public health or welfare.

Periodic Review—Section 111. This regulation will be reviewed within 4 years from the date of promulgation as required by the CAA. This review will include an assessment of such factors as the need for integration with other programs, the existence of alternative methods, enforceability, improvements in emission control technology, and reporting requirements.

External Participation—Section 117. In accordance with Section 117 of the Act, publication of this proposal was preceded by consultation with

appropriate advisory committees, independent experts, and Federal departments and agencies. In addition, numerous meetings were held with industry representatives and trade associations during development of the proposed standards. The Administrator will welcome comments on all aspects of the proposed regulation, including economic and technological issues.

Economic Impact Assessment—Section 317. Section 317 of the CAA requires the Administrator to prepare an economic impact assessment for any NSPS promulgated under section 111(b) of the Act. An economic impact assessment was prepared for the proposed regulations and for other regulatory alternatives. All aspects of the assessment were considered in the formulation of the proposed standards to ensure that the proposed standards would represent the best system of emission reduction considering costs. The economic impact assessment is included in the BID.

D. Office of Management and Budget Reviews

1. Paperwork Reduction Act

There are no reporting requirements by other governmental agencies for the information required by these standards which would result in overlapping requirements. In particular, there is no overlap with the reporting requirements of the Superfund program. The Superfund program was established in 1980 by the Comprehensive Environmental Response, Compensation, and Liability Act (CERCLA, Pub. L. 96-510) and authorizes the Federal government to respond directly to releases (or threatened releases) of hazardous substances and pollutants or contaminants to any media that may endanger public health or welfare. Under the notification and liability provisions of section 103 (see 48 FR 23552, May 25, 1983), CERCLA requires that persons in charge of vessels or facilities from which hazardous substances have been released in quantities that are equal to, or greater than, the reportable quantities immediately notify the National Response Center of the release (800-424-8802; in Washington, DC, metropolitan area 202-426-2675). However, air releases which qualify as Federally permitted releases, such as VOC emissions that are regulated under section 111 of the Clean Air Act, are not subject to the notification or liability provisions of CERCLA unless the air releases are in excess of the allowable NSPS emissions by an amount equal to

or greater than the reporting quantity; in this case, persons in charge must report the excess air releases to the National Response Center. (Reporting under CERCLA does not excuse the persons in charge from any responsibility, including reporting, or liability under the NSPS program.)

The information collection requirements in this proposed rule have been submitted for approval to the Office of Management and Budget (OMB) under the Paperwork Reduction Act of 1980, 44 U.S.C. 3501 *et seq* and has been assigned an OMB control number. Comments on these requirements should be submitted for approval to the Office of Information and Regulatory Affairs of OMB; 726 Jackson Place, NW.; Washington, DC 20503 marked "Attention: Desk Officer for EPA." The final rule will respond to any OMB or public comments on the information collection requirements.

Public reporting burden for this collection of information is estimated to be 15,771 hours per year, with an average of 584 hours per response, including time for reviewing instructions, searching existing data sources, gathering and maintaining the data needed, and completing and reviewing the collection of information. Send comments regarding the burden estimate or any other aspect of this collection of information, including suggestions for reducing this burden, to Chief, Information Policy Branch PM-223, U.S. Environmental Protection Agency, 401 M St., SW., Washington, DC 20460; and to the Office of Information and Regulatory Affairs, Office of Management and Budget, Washington, DC 20503.

2. Executive Order 12291 Review

Under Executive Order 12291, EPA must judge whether a regulation is "major" and therefore subject to the requirement of a Regulatory Impact Analysis. This proposed regulation is not major because: (1) The national annualized control costs, including capital charges resulting for the standards total less than \$100 million; (2) the standards do not cause a major increase in prices or production costs for most of the chemicals considered; and (3) given the low levels of investment required and the small price increases estimated for chemicals with low TRE values, the effects of the regulation on domestic competition, employment, investment, productivity, innovation, and competition in foreign markets will be negligible.

This regulation was submitted to OMB for review as required by Executive Order 12291. Any written

comments for OMB and any written responses by EPA will be included in Docket A-83-29. This docket is available for public inspection at EPA's Central Docket Section, which is listed under the ADDRESSES section of this notice.

E. Regulatory Flexibility Act Compliance

The Regulatory Flexibility Act (Pub. L. 96-354, September 19, 1980) requires that special consideration be given to the impacts of all Federal regulations on small businesses, small governments, and small organizations. These standards will have no known effects on small governments and small organizations. Some small businesses may be affected. However, the economic analysis described above indicates that these standards will have no significant, adverse economic impact on firms producing affected chemicals, regardless of firm size. Furthermore, no burden will be placed upon small businesses disproportionate to their potential contribution to VOC emissions.

The price increase screening analysis uses many conservative control cost assumptions and demonstrates that not even small plants should incur control costs in excess of 5 percent of production costs. There should be no capital availability or industrial growth problems associated with these standards. Thus, no significant, adverse economic impacts on small businesses are anticipated.

No burden will be placed on any firm disproportionate to the VOC that it would emit in the absence of these standards. This is ensured by application of the TRE index, which identifies facilities that would emit a substantial amount of reasonably controllable VOC in the absence of these standards.

Pursuant to the provisions of 5 U.S.C. 605(b), I hereby certify that this rule will not have a significant impact on a substantial number of small entities.

List of Subjects in 40 CFR Part 60

Air pollution control, Reporting and recordkeeping requirements. Incorporation by reference, Intergovernmental relations, SOCM.

Dated: June 13, 1990.
William K. Reilly,
Administrator.

PART 60—[AMENDED]

It is proposed that 40 CFR part 6 be amended as follows:

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

Authority: Secs. 101, 111, 114, 116, and 301 of the Clean Air Act (CAA) as amended (42 U.S.C. 7401, 7411, 7416, 7601).

2. By adding a new subpart RRR to read as follows:

Subpart RRR—Standards of Performance for Volatile Organic Compound (VOC) Emissions from Synthetic Organic Chemical Manufacturing Industry (SOCMI) Reactor Processes

Sec.

- 60.700 Applicability and designation of affected facility.
- 60.701 Definitions.
- 60.702 Standards.
- 60.703 Monitoring of emissions and operations.
- 60.704 Test methods and procedures.
- 60.705 Reporting and recordkeeping requirements.
- 60.706 Reconstruction.
- 60.707 Chemicals affected by subpart RRR.
- 60.708 Delegation of authority.

Subpart RRR—Standards of Performance for Volatile Organic Compound (VOC) Emissions from Synthetic Organic Chemical Manufacturing Industry (SOCMI) Reactor Processes

§ 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 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; 60.704(d), (e), and (f); and 60.705 (h) and (i).

(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 is exempt from all provisions of this subpart except for the recordkeeping and reporting requirements in paragraphs (j), (l)(6), and (n) of § 60.705.

(4) Each affected facility operated with a vent stream flow rate less than 0.011 scm/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 paragraphs (i), (l)(5), and (o) of § 60.705.

(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. These emission limits reflect the performance of BDT.)

§ 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 meaning given them.

Batch process means any noncontinuous reactor process which 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.

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.

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 ppmv (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 § 60.707. 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 is used for 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.

Total organic compounds (TOC) means those compounds measured according to the procedures in § 60.704(b)(4). For the purpose of measuring molar composition as required in § 60.704(d)(2)(f); and hourly emissions rate as required in § 60.704(d)(5), and § 60.704(d)(6); and TOC concentration as required in § 60.705(b)(4) and § 60.705(g)(4), those compounds which the Administrator has determined do not contribute appreciably to the formation of ozone are to be excluded.

TRE index value means a measure of the supplemental total resource requirement per unit reduction of TOC associated with an individual vent stream from an affected reactor process facility based on vent stream flow rate, emission rate of TOC, net heating value, and corrosive properties (whether or not the 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 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.

§ 60.702 Standards.

Each owner or operator of any affected facility which is subject to the requirements of this subpart 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 80 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:

(a) Reduce emissions of TOC (less methane and ethane) by 98 weight-percent, or to a TOC (less methane and ethane) concentration of 20 ppmv, 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.

(b) Combust the emissions in a flare. Flares used to comply with this subpart shall comply with the requirements of § 60.18.

(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 ± 1 percent of the temperature being monitored expressed in degrees Celsius or $\pm 0.5^\circ\text{C}$, 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 § 60.702(b) shall install, calibrate, maintain and operate according to manufacturer's specifications the following equipment:

(1) A heat sensing device, such as a ultra-violet beam sensor or thermocouple, at the pilot light to indicate 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 § 60.702(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 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 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 ± 1 percent of the temperature being measured expressed in degrees Celsius or $\pm 0.5^\circ\text{C}$, whichever is greater, for boilers or process heaters of less than 44 MW (150 million Btu/hr) design heat input capacity.

(3) 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.

(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 ± 1 percent of the temperature being monitored expressed in degrees Celsius or $\pm 0.5^\circ\text{C}$, whichever is greater, and a specific gravity monitoring device having an accuracy of ± 0.02 specific gravity unit, 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 ± 1 percent of the temperature being monitored expressed in degrees Celsius or $\pm 0.5^\circ\text{C}$, 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 ± 10 percent, and a carbon bed temperature monitoring device having an accuracy of ± 1 percent of the temperature being monitored expressed in degrees Celsius or $\pm 0.5^\circ\text{C}$, 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 control devices other than incinerator, boiler, process heater, or flare; or recovery devices 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) that 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 3 shall be used to determine the oxygen concentration (%O_{2d}) 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 O₂ (C_c) shall be computed using the following equation:

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

Where:

C_c = Concentration of TOC corrected to 3 percent O₂, dry basis, ppm by volume.
C_{TOC} = Concentration of TOC (minus methane and ethane), dry basis, ppm by volume.
%O_{2d} = Concentration of O₂, 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_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:

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

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

where:

C_{TOC} = 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).

K₂ = 2.494 × 10⁻⁶ (1/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 component "j", dry basis, ppm by volume.

n = Number of components in the sample.

(5) 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 § 60.702(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.

(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 as reference methods 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 § 60.702(c).

(1)(i) Method 1 or 1A, as appropriate, for selection of the sampling site. The sampling site for the vent stream molar composition determination and flow rate 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 post-reactor dilution of the stream with air, and prior to any post-reactor 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 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 all vent streams and at the outlet of the final recovery device.

(C) The 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 to determine the concentration of TOC in the reactor 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 vent stream shall be determined as follows:

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

(ii) ASTM D1946-77 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, 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_v (vent stream flow rate).

$$K_1 = \text{Constant, } 1.740 \times 10^{-7} \left(\frac{1}{\text{ppm}} \right) \left(\frac{\text{g-mole}}{\text{scm}} \right) \left(\frac{\text{MJ}}{\text{kcal}} \right) \text{ where standard temperature for } \left(\frac{\text{g-mole}}{\text{scm}} \right) \text{ is } 20^\circ\text{C}.$$

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 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 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:

$$E_{\text{TOC}} = K_2 \left(\sum_{j=1}^n C_j M_j \right) Q_v$$

where:

E_{TOC} = Emission rate of TOC in the sample, kg/hr

K_2 = Constant, $2.494 \times 10^{-6} (1/\text{ppm})(\text{g-mole}/\text{scm})(\text{kg/g})(\text{min}/\text{hr})$, 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_v = Vent stream flow rate (scm/min) at a standard temperature of 20 °C

(6) The total vent stream concentration (by volume) of compounds containing halogens (ppmv, 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 § 60.702(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 paragraph (e)(1) of this section and the flare equation in paragraph (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:

$$\text{TRE} = \frac{1}{E_{\text{TOC}}} [a + b (Q_v)^{0.88} + c (Q_v) + d (Q_v) (H_T) + e (Q_v)^{0.88} (H_T)^{0.88} + f (Y_v)^{0.5}]$$

(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_v = Vent stream flow rate (scm/min) at a standard temperature of 20 °C.

H_T = 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_v .

$Y_v = Q_v$ for all vent stream categories listed in Table 1 except for Category E vent streams where $Y_v = (Q_v) (H_T) / 3.6$.

E_{TOC} = 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.

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TABLE 1. REACTOR PROCESSES NSPS TRE COEFFICIENTS FOR VENT STREAMS CONTROLLED BY AN INCINERATOR

DESIGN CATEGORY A1. FOR HALOGENATED PROCESS VENT STREAMS, IF $0 \leq \text{NET HEATING VALUE (MJ/scm)} \leq 3.5$:

Q_s = Vent Stream Flow rate (scm/min)	a	b	c	d	e	f
$14.2 < Q_s \leq 18.8$	19.65559	0.27948	0.76683	-0.13173	0	0.01044
$18.8 < Q_s \leq 699$	20.48848	0.27948	0.30929	-0.13173	0	0.01044
$699 < Q_s \leq 1400$	40.83338	0.30372	0.30929	-0.13173	0	0.01477
$1400 < Q_s \leq 2100$	61.17828	0.31887	0.30929	-0.13173	0	0.01809
$2100 < Q_s \leq 2800$	81.52318	0.33007	0.30929	-0.13173	0	0.02088
$2800 < Q_s \leq 3500$	101.86808	0.33902	0.30929	-0.13173	0	0.02335

DESIGN CATEGORY A2. FOR HALOGENATED PROCESS VENT STREAMS, IF NET HEATING VALUE > 3.5 MJ/scm:

Q_s = Vent Stream Flow rate (scm/min)	a	b	c	d	e	f
$14.2 < Q_s \leq 18.8$	19.31203	0.27099	-0.20500	0	0	0.01044
$18.8 < Q_s \leq 699$	20.14491	0.27099	-0.25255	0	0	0.01044
$699 < Q_s \leq 1400$	40.14625	0.29449	-0.25255	0	0	0.01477
$1400 < Q_s \leq 2100$	60.14759	0.30917	-0.25255	0	0	0.01809
$2100 < Q_s \leq 2800$	80.14892	0.32003	-0.25255	0	0	0.02088
$2800 < Q_s \leq 3500$	100.15026	0.32872	-0.25255	0	0	0.02335

DESIGN CATEGORY B. FOR NONHALOGENATED PROCESS VENT STREAMS, IF $0 \leq \text{NET HEATING VALUE (MJ/scm)} \leq 0.48$:

Q_s = Vent Stream Flow rate (scm/min)	a	b	c	d	e	f
$14.2 < Q_s \leq 1340$	8.84812	0.10696	0.09188	-0.17252	0	0.01044
$1340 < Q_s \leq 2690$	17.55267	0.11623	0.09188	-0.17252	0	0.01477
$2690 < Q_s \leq 4040$	26.25721	0.12203	0.09188	-0.17252	0	0.01809

DESIGN CATEGORY C. FOR NONHALOGENATED PROCESS VENT STREAMS, IF $0.48 < \text{NET HEATING VALUE (MJ/scm)} \leq 1.9$:

Q_s = Vent Stream Flow rate (scm/min)	a	b	c	d	e	f
$14.2 < Q_s \leq 1340$	9.56783	0.06187	0.32303	-0.16316	0	0.01044
$1340 < Q_s \leq 2690$	18.99209	0.06723	0.32303	-0.16316	0	0.01477
$2690 < Q_s \leq 4040$	28.41635	0.07058	0.32303	-0.16316	0	0.01809

DESIGN CATEGORY D. FOR NONHALOGENATED PROCESS VENT STREAMS, IF $1.9 < \text{NET HEATING VALUE (MJ/scm)} \leq 3.6$:

Q_s = Vent Stream Flow rate (scm/min)	a	b	c	d	e	f
$14.2 < Q_s \leq 1180$	6.87612	0.07036	0.02669	0	0	0.01044
$1180 < Q_s \leq 2370$	13.60866	0.07646	0.02669	0	0	0.01477
$2370 < Q_s \leq 3550$	20.34120	0.08028	0.02669	0	0	0.01809

DESIGN CATEGORY E. FOR NONHALOGENATED PROCESS VENT STREAMS, IF NET HEATING VALUE > 3.6 MJ/scm:

Y_s = Dilution Flow rate (scm/min) = $(Q_s)(H_T)/3.6$	a	b	c	d	e	f
$14.2 < Y_s \leq 1180$	6.87612	0	0	-0.00730	0.02249	0.01044
$1180 < Y_s \leq 2370$	13.60866	0	0	-0.00730	0.02445	0.01477
$2370 < Y_s \leq 3550$	20.34120	0	0	-0.00730	0.02566	0.01809

(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.

$Q_s = 14.2$ scm/min.

$H_T = (\text{FLOW})(\text{HVAL})/14.2$

where the following inputs are used:

FLOW = Vent steam 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_s .

$Y_s = 14.2$ scm/min for all vent streams except for Category E vent streams, where $Y_s = (14.2)(H_T)/3.6$.

E_{TOC} = 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:

$$\text{TRE} = \frac{1}{E_{\text{TOC}}} [a(Q_s) + b(Q_s)^{0.25} + c(Q_s)(H_T) + d(E_{\text{TOC}}) + e]$$

where:

TRE = TRE index value.

E_{TOC} = Hourly emission rate of TOC reported in kg/hr.

Q_s = Vent stream flow rate (scm/min) at a standard temperature of 20 °C.

H_T = 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 definition of Q_s .

a, b, c, d, e, and f are coefficients.

The set of coefficients that apply to a vent stream can be obtained from Table 2.

TABLE 2.—REACTOR PROCESSES NSPS TRE COEFFICIENTS FOR VENT STREAMS CONTROLLED BY A FLARE

	a	b	c	d	e
$H_T < 11.2 \text{ MJ/scm}$	2.25	0.288	-0.193	-0.0051	2.08
$H_T > 11.2 \text{ MJ/scm}$	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 the 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). 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 § 60.704 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 part 60, as appropriate, for determination of volumetric flow rate.

§ 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 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 § 60.702(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 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 § 60.702(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 non-assisted), 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), (b)(4)(ii) or (b)(4)(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 device 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).

(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 up to date, readily accessible continuous records of the indication of flow specified under § 60.703(a)(2), § 60.703(b)(2) and § 60.703(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 or greater to comply with § 60.702(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 § 60.703(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 § 60.703(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 test 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 absorber, condenser, or carbon adsorber is the final recovery device in the recovery system and where an organic 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 § 60.702(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).

(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 § 60.700(c)(4) shall keep up-to-date, readily accessible records to indicate that the 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.

(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 § 60.700(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.

(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 § 60.700(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) and (g).

(2) All periods recorded under § 60.705(d) when the vent stream is diverted from the control device or has no flow rate.

(3) All periods recorded under § 60.705(e) when the boiler or process heater was not operating.

(4) All periods recorded under § 60.705(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 § 60.700(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. 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_{ROC} . 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 § 60.700(c)(3), the facility must begin compliance with the requirements set forth in § 60.702.

(6) Any change in equipment or process operation, as recorded under § 60.705(j), 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. A performance test must be completed within the same time period to obtain the vent stream flow rate, heating value, and E_{ROC} . The performance test is subject to the requirements of § 60.8 of the General Provisions. Unless the facility qualifies for an exemption under the flow exemption in § 60.700(c)(4), the facility must begin compliance with the requirements set forth in § 60.702.

(7) Any recalculation of the TRE index value, as recorded under § 60.702(h).

(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(i), 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) 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).

§ 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.

§ 60.707 Chemicals affected by subpart RRR.

Chemical name	CAS No. ¹
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.....	513-35-8
Amylenes, mixed.....	
Aniline.....	62-53-3
Benzene.....	71-43-2
Benzenesulfonic acid.....	98-11-3
Benzenesulfonic acid C ₁₀₋₁₈ -alkyl derivatives, sodium salts.....	68081-81-2
Benzyl chloride.....	100-44-7
Bisphenol A.....	80-05-7
Bromotone.....	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.....	75-85-0
Butylbenzyl phthalate.....	85-86-7
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.....	110-82-0
Cyclohexane, oxidized.....	68512-15-2

Chemical name	CAS No. ¹
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
Dichlorodifluoromethane.....	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
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
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 monomethyl 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-antra-cenedione.....	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 alkylbenzene.....	123-01-3
Maleic anhydride.....	108-31-6
Mesityl oxide.....	141-79-7
Methanol.....	67-56-1
Methylamine.....	74-39-5
ar-Methylbenzenediamine.....	25378-45-8
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

Chemical name	CAS No. ¹
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.....	143-08-08
Nonylphenol.....	25154-52-3
Nonylphenol, ethoxylated.....	9018-45-9
Octene.....	25377-83-7
Oil-soluble petroleum sulfonate, calcium salt.....	
Pentaerythritol.....	115-77-5
3-Pentenitrile.....	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
1,1,2,2-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

¹CAS 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.

§ 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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