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§ 96.1 Purpose.

This part establishes general provisions and the applicability, permitting, allowance, excess emissions, monitoring, and opt-in provisions for the NO\textsubscript{X} Budget Trading Program for State implementation plans as a means of mitigating the interstate transport of ozone and nitrogen oxides, an ozone precursor. The owner or operator of a unit, or any other person, shall comply with requirements of this part as a matter of federal law only to the extent a State that has jurisdiction over the unit incorporates by reference provisions of this part, or otherwise adopts such requirements of this part, and requires compliance, the State submits to the Administrator a State implementation plan including such adoption and such compliance requirement, and the Administrator approves the portion of the State implementation plan including such adoption and such compliance requirement. To the extent a State adopts requirements of this part, including at a minimum the requirements of subpart A (except for § 96.4(b)), subparts B through D, subpart F (except for § 96.55(c)), and subparts G and H of this part, the State authorizes the Administrator to assist the State in implementing the NO\textsubscript{X} Budget Trading Program by carrying out the functions set forth for the Administrator in such requirements.

§ 96.2 Definitions.

The terms used in this part shall have the meanings set forth in this section as follows:

Account certificate of representation means the completed and signed submission required by subpart B of this part for certifying the designation of a NO\textsubscript{X} authorized account representative for a NO\textsubscript{X} Budget source or a group of identified NO\textsubscript{X} Budget sources who is authorized to represent the owners and operators of such source or sources and of the NO\textsubscript{X} Budget units at such source or sources with regard to matters under the NO\textsubscript{X} Budget Trading Program.

Account number means the identification number given by the Administrator to each NO\textsubscript{X} Allowance Tracking System account.

Acid Rain emissions limitation means, as defined in § 72.2 of this chapter, a limitation on emissions of sulfur dioxide or nitrogen oxides under the Acid Rain Program under title IV of the CAA.

Administrator means the Administrator of the United States Environmental Protection Agency or the Administrator’s duly authorized representative.

Allocate or allocation means the determination by the permitting authority or the Administrator of the number of NO\textsubscript{X} allowances to be initially credited to a NO\textsubscript{X} Budget unit or an allocation set-aside.

Automated data acquisition and handling system or DAHS means that component of the CEMS, or other emissions monitoring system approved for use under subpart H of this part, designed to interpret and convert individual output signals from pollutant concentration monitors, flow monitors, diluent gas monitors, and other component parts of the monitoring system to produce a continuous record of the
measured parameters in the measurement units required by subpart H of this part.

**Boiler** means an enclosed fossil or other fuel-fired combustion device used to produce heat and to transfer heat to recirculating water, steam, or other medium.


**Combined cycle system** means a system comprised of one or more combustion turbines, heat recovery steam generators, and steam turbines configured to improve overall efficiency of electricity generation or steam production.

**Combustion turbine** means an enclosed fossil or other fuel-fired device that is comprised of a compressor, a combuster, and a turbine, and in which the flue gas resulting from the combustion of fuel in the combuster passes through the turbine, rotating the turbine.

**Commence commercial operation** means, with regard to a unit that serves a generator, to have begun to produce steam, gas, or other heated medium used to generate electricity for sale or use, including test generation. Except as provided in §96.5, for a unit that is a NO\textsubscript{X} Budget unit under §96.4 on the date the unit commences commercial operation, such date shall remain the unit’s date of commencement of commercial operation even if the unit is subsequently modified, reconstructed, or repowered. Except as provided in §96.5 or subpart I of this part, for a unit that is not a NO\textsubscript{X} Budget unit under §96.4 on the date of commencement of operation, the date the unit becomes a NO\textsubscript{X} Budget unit under §96.4 shall be the unit’s date of commencement of operation.

**Common stack** means a single flue through which emissions from two or more units are exhausted.

**Compliance account** means a NO\textsubscript{X} Allowance Tracking System account, established by the Administrator for a NO\textsubscript{X} Budget unit under subpart F of this part, in which the NO\textsubscript{X} allowance allocations for the unit are initially recorded and in which are held NO\textsubscript{X} allowances available for use by the unit for a control period for the purpose of meeting the unit’s NO\textsubscript{X} Budget emissions limitation.

**Compliance certification** means a submission to the permitting authority or the Administrator, as appropriate, that is required under subpart D of this part to report a NO\textsubscript{X} Budget source’s or a NO\textsubscript{X} Budget unit’s compliance or non-compliance with this part and that is signed by the NO\textsubscript{X} authorized account representative in accordance with subpart B of this part.

**Continuous emission monitoring system** or **CEMS** means the equipment required under subpart H of this part to sample, analyze, measure, and provide, by readings taken at least once every 15 minutes of the measured parameters, a permanent record of nitrogen oxides emissions, expressed in tons per hour for nitrogen oxides. The following systems are component parts included, consistent with part 75 of this chapter, in a continuous emission monitoring system:

1. **Flow monitor**;
2. **Nitrogen oxides pollutant concentration monitors**;
3. **Diluent gas monitor (oxygen or carbon dioxide)** when such monitoring is required by subpart H of this part;
4. **An automated data acquisition and handling system**.

**Control period** means the period beginning May 1 of a year and ending on September 30 of the same year, inclusive.

**Emissions** means air pollutants exhausted from a unit or source into the atmosphere or deposited on land or water resources.
atmosphere, as measured, recorded, and reported to the Administrator by the NO\textsubscript{X} authorized account representative and as determined by the Administrator in accordance with subpart H of this part.


Excess emissions means any tonnage of nitrogen oxides emitted by a NO\textsubscript{X} Budget unit during a control period that exceeds the NO\textsubscript{X} Budget emissions limitation for the unit.

Fossil fuel means natural gas, petroleum, coal, or any form of solid, liquid, or gaseous fuel derived from such material.

Fossil fuel-fired means, with regard to a unit:

(1) The combustion of fossil fuel, alone or in combination with any other fuel, where fossil fuel actually combusted comprises more than 50 percent of the annual heat input on a Btu basis during any year starting in 1995 or, if a unit had no heat input starting in 1995, during the last year of operation of the unit prior to 1995; or

(2) The combustion of fossil fuel, alone or in combination with any other fuel, where fossil fuel is projected to comprise more than 50 percent of the annual heat input on a Btu basis during any year; provided that the unit shall be "fossil fuel-fired" as of the date, during such year, on which the unit begins combusting fossil fuel.

General account means a NO\textsubscript{X} Allowance Tracking System account, established under subpart F of this part, that is not a compliance account or an overdraft account.

Generator means a device that produces electricity.

Heat input means the product (in mmBtu/time) of the gross calorific value of the fuel (in Btu/lb) and the fuel feed rate into a combustion device (in mass of fuel/time), as measured, recorded, and reported to the Administrator by the NO\textsubscript{X} authorized account representative and as determined by the Administrator in accordance with subpart H of this part, and does not include the heat derived from preheated combustion air, recirculated flue gases, or exhaust from other sources.
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and either the maximum oxygen concentration (in percent O₂) or the minimum carbon dioxide concentration (in percent CO₂), under all operating conditions of the unit except for unit start up, shutdown, and upsets.

Maximum rated hourly heat input means a unit-specific maximum hourly heat input (mmBtu) which is the higher of the manufacturer’s maximum rated hourly heat input or the highest observed hourly heat input.

Monitoring system means any monitoring system that meets the requirements of subpart H of this part, including a continuous emissions monitoring system, an excepted monitoring system, or an alternative monitoring system.

Most stringent State or Federal NOₓ emissions limitation means, with regard to a NOₓ Budget opt-in source, the lowest NOₓ emissions limitation (in terms of lb/mmBtu) that is applicable to the unit under State or Federal law, regardless of the averaging period to which the emissions limitation applies.

Nameplate capacity means the maximum electrical generating output (in MWe) that a generator can sustain over a specified period of time when not restricted by seasonal or other deratings as measured in accordance with the United States Department of Energy standards.

Non-title V permit means a federally enforceable permit administered by the permitting authority pursuant to the CAA and regulatory authority under the CAA, other than title V of the CAA and part 70 or 71 of this chapter.

NOₓ allowance means an authorization by the permitting authority or the Administrator under the NOₓ Budget Trading Program to emit up to one ton of nitrogen oxides during the control period of the specified year or of any year thereafter.

NOₓ allowance deduction or deduct NOₓ allowances means the permanent withdrawal of NOₓ allowances by the Administrator from a NOₓ Allowance Tracking System compliance account or overdraft account to account for the number of tons of NOₓ emissions from a NOₓ Budget unit for a control period, determined in accordance with subpart H of this part, or for any other allowance surrender obligation under this part.

NOₓ allowances held or hold NOₓ allowances means the NOₓ allowances recorded by the Administrator, or submitted to the Administrator for recordation, in accordance with subparts F and G of this part, in a NOₓ Allowance Tracking System account.

NOₓ Allowance Tracking System means the system by which the Administrator records allocations, deductions, and transfers of NOₓ allowances under the NOₓ Budget Trading Program.

NOₓ Allowance Tracking System account means an account in the NOₓ Allowance Tracking System established by the Administrator for purposes of recording the allocation, holding, transferring, or deducting of NOₓ allowances.

NOₓ allowance transfer deadline means midnight of November 30 or, if November 30 is not a business day, midnight of the first business day thereafter and is the deadline by which NOₓ allowances may be submitted for recordation in a NOₓ Budget unit’s compliance account, or the overdraft account of the source where the unit is located, in order to meet the unit’s NOₓ Budget emissions limitation for the control period immediately preceding such deadline.

NOₓ authorized account representative means, for a NOₓ Budget source or NOₓ Budget unit at the source, the natural person who is authorized by the owners and operators of the source and all NOₓ Budget units at the source, in accordance with subpart B of this part, to represent and legally bind each owner and operator in matters pertaining to the NOₓ Budget Trading Program or, for a general account, the natural person who is authorized, in accordance with subpart F of this part, to transfer or otherwise dispose of NOₓ allowances held in the general account.

NOₓ Budget emissions limitation means, for a NOₓ Budget unit, the tonnage equivalent of the NOₓ allowances available for compliance deduction for the unit and for a control period under §96.54(a) and (b), adjusted by any deductions of such NOₓ allowances to account for actual utilization under §96.42(e) for the control period or to account for excess emissions for a prior
control period under §96.54(d) or to account for withdrawal from the NO\textsubscript{X} Budget Program, or for a change in regulatory status, for a NO\textsubscript{X} Budget opt-in source under §96.86 or §96.87.

**NO\textsubscript{X} Budget opt-in permit** means a NO\textsubscript{X} Budget permit covering a NO\textsubscript{X} Budget opt-in source.

**NO\textsubscript{X} Budget opt-in source** means a unit that has been elected to become a NO\textsubscript{X} Budget unit under the NO\textsubscript{X} Budget Trading Program and whose NO\textsubscript{X} Budget opt-in permit has been issued and is in effect under subpart I of this part.

**NO\textsubscript{X} Budget permit** means the legally binding and federally enforceable written document, or portion of such document, issued by the permitting authority under this part, including any permit revisions, specifying the NO\textsubscript{X} Budget Trading Program requirements applicable to a NO\textsubscript{X} Budget source, to each NO\textsubscript{X} Budget unit at the NO\textsubscript{X} Budget source, and to the owners and operators and the NO\textsubscript{X} authorized account representative of the NO\textsubscript{X} Budget source and each NO\textsubscript{X} Budget unit.

**NO\textsubscript{X} Budget source** means a source that includes one or more NO\textsubscript{X} Budget units.

**NO\textsubscript{X} Budget Trading Program** means a multi-state nitrogen oxides air pollution control and emission reduction program established in accordance with this part and pursuant to §51.121 of this chapter, as a means of mitigating the interstate transport of ozone and nitrogen oxides, an ozone precursor.

**NO\textsubscript{X} Budget unit** means a unit that is subject to the NO\textsubscript{X} Budget Trading Program emissions limitation under §96.4 or §96.80.

**Operating** means, with regard to a unit under §§96.22(d)(2) and 96.80, having documented heat input for more than 876 hours in the 6 months immediately preceding the submission of an application for an initial NO\textsubscript{X} Budget permit under §96.83(a).

**Operator** means any person who operates, controls, or supervises a NO\textsubscript{X} Budget unit, a NO\textsubscript{X} Budget source, or unit for which an application for a NO\textsubscript{X} Budget opt-in permit under §96.83 is submitted and not denied or withdrawn and shall include, but not be limited to, any holding company, utility system, or plant manager of such a unit or source.

**Opt-in** means to be elected to become a NO\textsubscript{X} Budget unit under the NO\textsubscript{X} Budget Trading Program through a final, effective NO\textsubscript{X} Budget opt-in permit under subpart I of this part.

**Overdraft account** means the NO\textsubscript{X} Allowance Tracking System account, established by the Administrator under subpart F of this part, for each NO\textsubscript{X} Budget source where there are two or more NO\textsubscript{X} Budget units.

**Owner** means any of the following persons:

1. Any holder of any portion of the legal or equitable title in a NO\textsubscript{X} Budget unit or in a unit for which an application for a NO\textsubscript{X} Budget opt-in permit under §96.83 is submitted and not denied or withdrawn; or

2. Any holder of a leasehold interest in a NO\textsubscript{X} Budget unit or in a unit for which an application for a NO\textsubscript{X} Budget opt-in permit under §96.83 is submitted and not denied or withdrawn; or

3. Any purchaser of power from a NO\textsubscript{X} Budget unit or from a unit for which an application for a NO\textsubscript{X} Budget opt-in permit under §96.83 is submitted and not denied or withdrawn under a life-of-the-unit, firm power contractual arrangement. However, unless expressly provided for in a leasehold agreement, owner shall not include a passive lessor, or a person who has an equitable interest through such lessor, whose rental payments are not based, either directly or indirectly, upon the revenues or income from the NO\textsubscript{X} Budget unit or the unit for which an application for a NO\textsubscript{X} Budget opt-in permit under §96.83 is submitted and not denied or withdrawn; or

4. With respect to any general account, any person who has an ownership interest with respect to the NO\textsubscript{X} allowances held in the general account and who is subject to the binding agreement for the NO\textsubscript{X} authorized account representative to represent that person’s ownership interest with respect to NO\textsubscript{X} allowances.

**Permitting authority** means the State air pollution control agency, local agency, other State agency, or other agency authorized by the Administrator to issue or revise permits to meet the requirements of the NO\textsubscript{X}.
Budget Trading Program in accordance with subpart C of this part.

Receive or receipt of means, when referring to the permitting authority or the Administrator, to come into possession of a document, information, or correspondence (whether sent in writing or by authorized electronic transmission), as indicated in an official correspondence log, or by a notation made on the document, information, or correspondence, by the permitting authority or the Administrator in the regular course of business.

Recordation, record, or recorded means, with regard to NOX allowances, the movement of NOX allowances by the Administrator from one NOX Allowance Tracking System account to another, for purposes of allocation, transfer, or deduction.

Reference method means any direct test method of sampling and analyzing for an air pollutant as specified in appendix A of part 60 of this chapter.

Serial number means, when referring to NOX allowances, the unique identification number assigned to each NOX allowance by the Administrator, under §96.53(c).

Source means any governmental, institutional, commercial, or industrial structure, installation, plant, building, or facility that emits or has the potential to emit any regulated air pollutant under the CAA. For purposes of section 502(c) of the CAA, a “source,” including a “source” with multiple units, shall be considered a single “facility.”

State means one of the 48 contiguous States and the District of Columbia specified in §51.121 of this chapter, or any non-federal authority in or including such States or the District of Columbia (including local agencies, and Statewide agencies) or any eligible Indian tribe in an area of such State or the District of Columbia, that adopts a NOX Budget Trading Program pursuant to §51.121 of this chapter. To the extent a State incorporates by reference the provisions of this part, the term “State” shall mean the incorporating State. The term “State” shall have its conventional meaning where such meaning is clear from the context.

State trading program budget means the total number of NOX tons apportioned to all NOX Budget units in a given State, in accordance with the NOX Budget Trading Program, for use in a given control period.

Submit or serve means to send or transmit a document, information, or correspondence to the person specified in accordance with the applicable regulation:

1. In person;
2. By United States Postal Service; or
3. By other means of dispatch or transmission and delivery. Compliance with any “submission,” “service,” or “mailing” deadline shall be determined by the date of dispatch, transmission, or mailing and not the date of receipt.

Title V operating permit means a permit issued under title V of the CAA and part 70 or part 71 of this chapter.

Title V operating permit regulations means the regulations that the Administrator has approved or issued as meeting the requirements of title V of the CAA and part 70 or 71 of this chapter.

Ton or tonnage means any “short ton” (i.e., 2,000 pounds). For the purpose of determining compliance with the NOX Budget emissions limitation, total tons for a control period shall be calculated as the sum of all recorded hourly emissions (or the tonnage equivalent of the recorded hourly emissions rates) in accordance with subpart H of this part, with any remaining fraction of a ton equal to or greater than 0.50 ton deemed to equal one ton and any fraction of a ton less than 0.50 ton deemed to equal zero tons.

Unit means a fossil fuel-fired stationary boiler, combustion turbine, or combined cycle system.

Unit load means the total (i.e., gross) output of a unit in any control period (or other specified time period) produced by combusting a given heat input of fuel, expressed in terms of:

1. The total electrical generation (MWe) produced by the unit, including generation for use within the plant; or
2. In the case of a unit that uses heat input for purposes other than electrical generation, the total steam pressure (psia) produced by the unit, including steam for use by the unit.

Unit operating day means a calendar day in which a unit combusts any fuel.
UNIT OPERATING HOUR OR HOUR OF UNIT OPERATION means any hour (or fraction of an hour) during which a unit combusts any fuel.

UTILIZATION means the heat input (expressed in mmBtu/time) for a unit. The unit’s total heat input for the control period in each year will be determined in accordance with part 75 of this chapter if the NOX Budget unit was otherwise subject to the requirements of part 75 of this chapter for the year, or will be based on the best available data reported to the Administrator for the unit if the unit was not otherwise subject to the requirements of part 75 of this chapter for the year.

§ 96.3 Measurements, abbreviations, and acronyms.

Measurements, abbreviations, and acronyms used in this part are defined as follows:

Btu—British thermal unit.
hr—hour.
Kwh—kilowatt hour.
lb—pounds.
mmBtu—million Btu.
MWe—megawatt electrical.
ton—2000 pounds.
CO2—carbon dioxide.
NOX—nitrogen oxides.
O2—oxygen.

§ 96.4 Applicability.

(a) The following units in a State shall be NOX Budget units, and any source that includes one or more such units shall be a NOX Budget source, subject to the requirements of this part:

(1) Any unit that, any time on or after January 1, 1995, serves a generator with a nameplate capacity greater than 25 MWe and sells any amount of electricity; or

(2) Any unit that is not a unit under paragraph (a) of this section and that has a maximum design heat input greater than 250 mmBtu/hr.

(b) Notwithstanding paragraph (a) of this section, a unit under paragraph (a) of this section shall be subject only to the requirements of this paragraph (b) if the unit has a federally enforceable permit that meets the requirements of paragraph (b)(1) of this section and restricts the unit to burning only natural gas or fuel oil during a control period in 2003 or later and each control period thereafter and restricts the unit’s operating hours during each such control period to the number of hours (determined in accordance with paragraph (b)(1)(ii) and (iii) of this section) that limits the unit’s potential NOX mass emissions for the control period to 25 tons or less. Notwithstanding paragraph (a) of this section, starting with the effective date of such federally enforceable permit, the unit shall not be a NOX Budget unit.

(1) For each control period under paragraph (b) of this section, the federally enforceable permit must:

(i) Restrict the unit to burning only natural gas or fuel oil.

(ii) Restrict the unit’s operating hours to the number calculated by dividing 25 tons of potential NOX mass emissions by the unit’s maximum potential hourly NOX mass emissions.

(iii) Require that the unit’s potential NOX mass emissions shall be calculated as follows:

(A) Select the default NOX emission rate in Table 2 of §75.19 of this chapter that would otherwise be applicable assuming that the unit burns only the type of fuel (i.e., only natural gas or only fuel oil) that has the highest default NOX emission factor of any type of fuel that the unit is allowed to burn under the fuel use restriction in paragraph (b)(1)(i) of this section; and

(B) Multiply the default NOX emission rate under paragraph (b)(1)(iii)(A) of this section by the unit’s maximum rated hourly heat input. The owner or operator of the unit may petition the permitting authority to use a lower value for the unit’s maximum rated hourly heat input than the value as defined under §96.2. The permitting authority may approve such lower value if the owner or operator demonstrates that the maximum hourly heat input specified by the manufacturer or the highest observed hourly heat input, or both, are not representative, and that such lower value is representative, of the unit’s current capabilities because modifications have been made to the unit, limiting its capacity permanently.

(iv) Require that the owner or operator of the unit shall retain at the source that includes the unit, for at least 5 years, records demonstrating that the
operating hours restriction, the fuel use restriction, and the other requirements of the permit related to these restrictions were met.

(v) Require that the owner or operator of the unit shall report the unit’s hours of operation (treating any partial hour of operation as a whole hour of operation) during each control period to the permitting authority by November 1 of each year for which the unit is subject to the federally enforceable permit.

(2) The permitting authority that issues the federally enforceable permit with the fuel use restriction under paragraph (b)(1)(i) and the operating hours restriction under paragraphs (b)(1)(ii) and (iii) of this section will notify the Administrator in writing of each unit under paragraph (a) of this section whose federally enforceable permit issued by the permitting authority includes such restrictions. The permitting authority will also notify the Administrator in writing of each unit under paragraph (a) of this section whose federally enforceable permit issued by the permitting authority is revised to remove any such restriction, whose federally enforceable permit issued by the permitting authority includes any such restriction that is no longer applicable, or which does not comply with any such restriction.

(3) If, for any control period under paragraph (b) of this section, the fuel use restriction under paragraph (b)(1)(i) of this section or the operating hours restriction under paragraphs (b)(1)(ii) and (iii) of this section is removed from the unit’s federally enforceable permit or otherwise becomes no longer applicable or if, for any such control period, the unit does not comply with the fuel use restriction under paragraph (b)(1)(i) of this section or the operating hours restriction under paragraphs (b)(1)(ii) and (iii) of this section, the unit shall be a NOX Budget unit, subject to the requirements of this part. Such unit shall be treated as commencing operation and, for a unit under paragraph (a)(1) of this section, commencing commercial operation on September 30 of the control period for which the fuel use restriction or the operating hours restriction is no longer applicable or during which the unit does not comply with the fuel use restriction or the operating hours restriction.

§ 96.5 Retired unit exemption.

(a) This section applies to any NOX Budget unit, other than a NOX Budget opt-in source, that is permanently retired.

(b)(1) Any NOX Budget unit, other than a NOX Budget opt-in source, that is permanently retired shall be exempt from the NOX Budget Trading Program, except for the provisions of this section, §§96.2, 96.3, 96.4, 96.7 and subparts E, F, and G of this part.

(2) The exemption under paragraph (b)(1) of this section shall become effective the day on which the unit is permanently retired. Within 30 days of permanent retirement, the NOX authorized account representative (authorized in accordance with subpart B of this part) shall submit a statement to the permitting authority otherwise responsible for administering any NOX Budget permit for the unit. A copy of the statement shall be submitted to the Administrator. The statement shall state (in a format prescribed by the permitting authority) that the unit is permanently retired and will comply with the requirements of paragraph (c) of this section.

(3) After receipt of the notice under paragraph (b)(2) of this section, the permitting authority will amend any permit covering the source at which the unit is located to add the provisions and requirements of the exemption under paragraphs (b)(1) and (c) of this section.

(c) Special provisions. (1) A unit exempt under this section shall not emit any nitrogen oxides, starting on the date that the exemption takes effect. The owners and operators of the unit will be allocated allowances in accordance with subpart E of this part.

(2)(i) A unit exempt under this section and located at a source that is required, or but for this exemption would be required, to have a title V operating permit shall not resume operation unless the NOX authorized account representative of the source submits a complete NOX Budget permit application under §96.22 for the unit not less than 18 months (or such lesser time provided under the permitting
authority’s title V operating permits regulations for final action on a permit application) prior to the later of May 1, 2003 or the date on which the unit is to first resume operation.

(ii) A unit exempt under this section and located at a source that is required, or but for this exemption would be required, to have a non-title V permit shall not resume operation unless the NOx authorized account representative of the source submits a complete NOx Budget permit application under §96.22 for the unit not less than 18 months (or such lesser time provided under the permitting authority’s non-title V permits regulations for final action on a permit application) prior to the later of May 1, 2003 or the date on which the unit is to first resume operation.

(3) The owners and operators and, to the extent applicable, the NOx authorized account representative of a unit exempt under this section shall comply with the requirements of the NOx Budget Trading Program concerning all periods for which the exemption is not in effect, even if such requirements arise, or must be complied with, after the exemption takes effect.

(4) A unit that is exempt under this section is not eligible to be a NOx Budget opt-in source under subpart I of this part.

(5) For a period of 5 years from the date the records are created, the owners and operators of a unit exempt under this section shall retain at the source that includes the unit, records demonstrating that the unit is permanently retired. The 5-year period for keeping records may be extended for cause, at any time prior to the end of the period, in writing by the permitting authority or the Administrator. The owners and operators bear the burden of proof that the unit is permanently retired.

(b) Loss of exemption. (1) On the earlier of the following dates, a unit exempt under paragraph (b) of this section shall lose its exemption:

(A) The date on which the NOx authorized account representative submits a NOx Budget permit application under paragraph (c)(2) of this section; or

(B) The date on which the NOx authorized account representative is required under paragraph (c)(2) of this section to submit a NOx Budget permit application.

(ii) For the purpose of applying monitoring requirements under subpart H of this part, a unit that loses its exemption under this section shall be treated as a unit that commences operation or commercial operation on the first date on which the unit resumes operation.

§96.6 Standard requirements.

(a) Permit Requirements. (1) The NOx authorized account representative of each NOx Budget source required to have a federally enforceable permit and each NOx Budget unit required to have a federally enforceable permit at the source shall:

(i) Submit to the permitting authority a complete NOx Budget permit application under §96.22 in accordance with the deadlines specified in §96.21(b) and (c);

(ii) Submit in a timely manner any supplemental information that the permitting authority determines is necessary in order to review a NOx Budget permit application and issue or deny a NOx Budget permit.

(2) The owners and operators of each NOx Budget source required to have a federally enforceable permit and each NOx Budget unit required to have a federally enforceable permit at the source shall:

(i) Submit to the permitting authority a complete NOx Budget permit application under §96.22 in accordance with the deadlines specified in §96.21(b) and (c);

(ii) Submit in a timely manner any supplemental information that the permitting authority determines is necessary in order to review a NOx Budget permit application and issue or deny a NOx Budget permit.

(b) Monitoring requirements. (1) The owners and operators and, to the extent applicable, the NOx authorized account representative of each NOx Budget source and each NOx Budget unit at the source shall comply with the monitoring requirements of subpart H of this part.

(2) The emissions measurements recorded and reported in accordance with
subpart H of this part shall be used to determine compliance by the unit with the NO\textsubscript{X} Budget emissions limitation under paragraph (c) of this section.

(c) Nitrogen oxides requirements. (1) The owners and operators of each NO\textsubscript{X} Budget source and each NO\textsubscript{X} Budget unit at the source shall hold NO\textsubscript{X} allowances available for compliance deductions under §96.54, as of the NO\textsubscript{X} allowance transfer deadline, in the unit’s compliance account and the source’s overdraft account in an amount not less than the total NO\textsubscript{X} emissions for the control period from the unit, as determined in accordance with subpart H of this part, plus any amount necessary to account for actual utilization under §96.42(e) for the control period.

(2) Each ton of nitrogen oxides emitted in excess of the NO\textsubscript{X} Budget emissions limitation shall constitute a separate violation of this part, the CAA, and applicable State law.

(3) A NO\textsubscript{X} Budget unit shall be subject to the requirements under paragraph (c)(1) of this section starting on the later of May 1, 2003 or the date on which the unit commences operation.

(4) NO\textsubscript{X} allowances shall be held in, deducted from, or transferred among NO\textsubscript{X} Allowance Tracking System accounts in accordance with subparts E, F, G, and I of this part.

(5) A NO\textsubscript{X} allowance shall not be deducted, in order to comply with the requirements under paragraph (c)(1) of this section, for a control period in a year prior to the year for which the NO\textsubscript{X} allowance was allocated.

(6) A NO\textsubscript{X} allowance allocated by the permitting authority or the Administrator under the NO\textsubscript{X} Budget Trading Program is a limited authorization to emit one ton of nitrogen oxides in accordance with the NO\textsubscript{X} Budget Trading Program. No provision of the NO\textsubscript{X} Budget Trading Program, the NO\textsubscript{X} Budget permit application, the NO\textsubscript{X} Budget permit, or an exemption under §96.5 and no provision of law shall be construed to limit the authority of the United States or the State to terminate or limit such authorization.

(7) A NO\textsubscript{X} allowance allocated by the permitting authority or the Administrator under the NO\textsubscript{X} Budget Trading Program does not constitute a property right.

(8) Upon recordation by the Administrator under subpart F, G, or I of this part, every allocation, transfer, or deduction of a NO\textsubscript{X} allowance to or from a NO\textsubscript{X} Budget unit’s compliance account or the overdraft account of the source where the unit is located is deemed to amend automatically, and become a part of, any NO\textsubscript{X} Budget permit of the NO\textsubscript{X} Budget unit by operation of law without any further review.

(d) Excess emissions requirements. (1) The owners and operators of a NO\textsubscript{X} Budget unit that has excess emissions in any control period shall:

(i) Surrender the NO\textsubscript{X} allowances required for deduction under §96.54(d)(1); and

(ii) Pay any fine, penalty, or assessment or comply with any other remedy imposed under §96.54(d)(3).

(e) Recordkeeping and Reporting requirements. (1) Unless otherwise provided, the owners and operators of the NO\textsubscript{X} Budget source and each NO\textsubscript{X} Budget unit at the source shall keep on site at the source each of the following documents for a period of 5 years from the date the document is created. This period may be extended for cause, at any time prior to the end of 5 years, in writing by the permitting authority or the Administrator.

(i) The account certificate of representation for the NO\textsubscript{X} authorized account representative for the source and each NO\textsubscript{X} Budget unit at the source and all documents that demonstrate the truth of the statements in the account certificate of representation, in accordance with §96.13; provided that the certificate and documents shall be retained on site at the source beyond such 5-year period until such documents are superseded because of the submission of a new account certificate of representation changing the NO\textsubscript{X} authorized account representative.

(ii) All emissions monitoring information, in accordance with subpart H of this part; provided that to the extent that subpart H of this part provides for a 3-year period for recordkeeping, the 3-year period shall apply.

(iii) Copies of all reports, compliance certifications, and other submissions and all records made or required under the NO\textsubscript{X} Budget Trading Program.
§ 96.7 Computation of time.

(a) Unless otherwise stated, any time period scheduled, under the NOx Budget Trading Program, to begin on the occurrence of an act or event shall begin on the day the act or event occurs.

(b) Unless otherwise stated, any time period scheduled, under the NOx Budget Trading Program, to begin before the occurrence of an act or event shall be computed so that the period ends the day before the act or event occurs.

(c) Unless otherwise stated, if the final day of any time period, under the NOx Budget Trading Program, falls on a weekend or a State or Federal holiday, the time period shall be extended to the next business day.

Subpart B—NOx Authorized Account Representative for NOx Budget Sources

§ 96.10 Authorization and responsibilities of the NOx authorized account representative.

(a) Except as provided under §96.11, each NOx Budget source, including all NOx Budget units at the source, shall have one and only one NOx authorized account representative, with regard to all matters under the NOx Budget Trading Program concerning the source or any NOx Budget unit at the source.

(iv) Copies of all documents used to complete a NOx Budget permit application and any other submission under the NOx Budget Trading Program or to demonstrate compliance with the requirements of the NOx Budget Trading Program.

(2) The NOx authorized account representative of a NOx Budget source and each NOx Budget unit at the source shall submit the reports and compliance certifications required under the NOx Budget Trading Program, including those under subparts D, H, or I of this part.

(f) Liability. (1) Any person who knowingly violates any requirement or prohibition of the NOx Budget Trading Program, a NOx Budget permit, or an exemption under §96.5 shall be subject to enforcement pursuant to applicable State or Federal law.

(2) Any person who knowingly makes a false material statement in any record, submission, or report under the NOx Budget Trading Program shall be subject to criminal enforcement pursuant to applicable State or Federal law.

(3) No permit revision shall excuse any violation of the requirements of the NOx Budget Trading Program that occurs prior to the date that the revision takes effect.

(4) Each NOx Budget source and each NOx Budget unit shall meet the requirements of the NOx Budget Trading Program.

(5) Any provision of the NOx Budget Trading Program that applies to a NOx Budget source (including a provision applicable to the NOx authorized account representative of a NOx Budget source) shall also apply to the owners and operators of such source and of the NOx Budget units at the source.

(6) Any provision of the NOx Budget Trading Program that applies to a NOx Budget unit (including a provision applicable to the NOx authorized account representative of a NOx budget unit) shall also apply to the owners and operators of such unit. Except with regard to the requirements applicable to units with a common stack under subpart H of this part, the owners and operators and the NOx authorized account representative of one NOx Budget unit shall not be liable for any violation by any other NOx Budget unit of which they are not owners or operators or the NOx authorized account representative and that is located at a source of which they are not owners or operators or the NOx authorized account representative.

(g) Effect on other authorities. No provision of the NOx Budget Trading Program, a NOx Budget permit application, a NOx Budget permit, or an exemption under §96.5 shall be construed as exempting or excluding the owners and operators and, to the extent applicable, the NOx authorized account representative of a NOx Budget source or NOx Budget unit from compliance with any other provision of the applicable, approved State implementation plan, a federally enforceable permit, or the CAA.
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(b) The NO\textsubscript{X} authorized account representative of the NO\textsubscript{X} Budget source shall be selected by an agreement binding on the owners and operators of the source and all NO\textsubscript{X} Budget units at the source.

(c) Upon receipt by the Administrator of a complete account certificate of representation under §96.13, the NO\textsubscript{X} authorized account representative of the source shall represent and, by his or her representations, actions, inactions, or submissions, legally bind each owner and operator of the NO\textsubscript{X} Budget source represented and each NO\textsubscript{X} Budget unit at the source in all matters pertaining to the NO\textsubscript{X} Budget Trading Program, not withstanding any agreement between the NO\textsubscript{X} authorized account representative and such owners and operators. The owners and operators shall be bound by any decision or order issued to the NO\textsubscript{X} authorized account representative by the permitting authority, the Administrator, or a court regarding the source or unit.

(d) No NO\textsubscript{X} Budget permit shall be issued, and no NO\textsubscript{X} Allowance Tracking System account shall be established for a NO\textsubscript{X} Budget unit at a source, until the Administrator has received a complete account certificate of representation under §96.13 for a NO\textsubscript{X} authorized account representative of the source and the NO\textsubscript{X} Budget units at the source.

(e)(1) Each submission under the NO\textsubscript{X} Budget Trading Program shall be submitted, signed, and certified by the NO\textsubscript{X} authorized account representative for each NO\textsubscript{X} Budget source on behalf of which the submission is made. Each such submission shall include the following certification statement by the NO\textsubscript{X} authorized account representative: "I am authorized to make this submission on behalf of the owners and operators of the NO\textsubscript{X} Budget sources or NO\textsubscript{X} Budget units for which the submission is made. I certify under penalty of law that I have personally examined, and am familiar with, the statements and information submitted in this document and all its attachments. Based on my inquiry of those individuals with primary responsibility for obtaining the information, I certify that the statements and information are to the best of my knowledge and belief true, accurate, and complete. I am aware that there are significant penalties for submitting false statements and information or omitting required statements and information, including the possibility of fine or imprisonment."

(2) The permitting authority and the Administrator will accept or act on a submission made on behalf of owner or operators of a NO\textsubscript{X} Budget source or a NO\textsubscript{X} Budget unit only if the submission has been made, signed, and certified in accordance with paragraph (e)(1) of this section.

§ 96.11 Alternate NO\textsubscript{X} authorized account representative.

(a) An account certificate of representation may designate one and only one alternate NO\textsubscript{X} authorized account representative who may act on behalf of the NO\textsubscript{X} authorized account representative. The agreement by which the alternate NO\textsubscript{X} authorized account representative is selected shall include a procedure for authorizing the alternate NO\textsubscript{X} authorized account representative to act in lieu of the NO\textsubscript{X} authorized account representative.

(b) Upon receipt by the Administrator of a complete account certificate of representation under §96.13, any representation, action, inaction, or submission by the alternate NO\textsubscript{X} authorized account representative shall be deemed to be a representation, action, inaction, or submission by the NO\textsubscript{X} authorized account representative.

(c) Except in this section and §§96.10(a), 96.12, 96.13, and 96.51, whenever the term “NO\textsubscript{X} authorized account representative” is used in this part, the term shall be construed to include the alternate NO\textsubscript{X} authorized account representative.

§ 96.12 Changing the NO\textsubscript{X} authorized account representative and the alternate NO\textsubscript{X} authorized account representative; changes in the owners and operators.

(a) Changing the NO\textsubscript{X} authorized account representative. The NO\textsubscript{X} authorized account representative may be changed at any time upon receipt by the Administrator of a superseding
§ 96.13 Account certificate of representation.

(a) A complete account certificate of representation for a NOX authorized account representative or an alternate NOX authorized account representative shall include the following elements in a format prescribed by the Administrator:

(1) Identification of the NOX Budget source and each NOX Budget unit at the source for which the account certificate of representation is submitted.

(2) The name, address, e-mail address (if any), telephone number, and facsimile transmission number (if any) of the NOX authorized account representative and any alternate NOX authorized account representative.

(3) A list of the owners and operators of the NOX Budget source and of each NOX Budget unit at the source.

(4) The following certification statement by the NOX authorized account representative and any alternate NOX authorized account representative, as applicable, by an agreement binding on the owners and operators of the NOX Budget source and each NOX Budget unit at the source. I certify that I have all the necessary authority to carry out my duties and responsibilities under the NOX Budget Trading Program on behalf of the owners and operators of the NOX Budget source and of each NOX Budget unit at the source.

(b) Unless otherwise required by the permitting authority or the Administrator, documents of agreement referred to in the account certificate of representation shall submit a revision to the account certificate of representation amending the list of owners and operators to include the change.
representation shall not be submitted to the permitting authority or the Administrator. Neither the permitting authority nor the Administrator shall be under any obligation to review or evaluate the sufficiency of such documents, if submitted.

§ 96.14 Objections concerning the NO\textsubscript{X} authorized account representative.

(a) Once a complete account certificate of representation under § 96.13 has been submitted and received, the permitting authority and the Administrator will rely on the account certificate of representation unless and until a superseding complete account certificate of representation under § 96.13 is received by the Administrator.

(b) Except as provided in § 96.12(a) or (b), no objection or other communication submitted to the permitting authority or the Administrator concerning the authorization, or any representation, action, inaction, or submission of the NO\textsubscript{X} authorized account representative shall affect any representation, action, inaction, or submission of the NO\textsubscript{X} authorized account representative or the finality of any decision or order by the permitting authority or the Administrator under the NO\textsubscript{X} Budget Trading Program.

(c) Neither the permitting authority nor the Administrator will adjudicate any private legal dispute concerning the authorization or any representation, action, inaction, or submission of any NO\textsubscript{X} authorized account representative, including private legal disputes concerning the proceeds of NO\textsubscript{X} allowance transfers.

Subpart C—Permits

§ 96.20 General NO\textsubscript{X} Budget trading program permit requirements.

(a) For each NO\textsubscript{X} Budget source required to have a federally enforceable permit, such permit shall include a NO\textsubscript{X} Budget permit administered by the permitting authority.

(1) For NO\textsubscript{X} Budget sources required to have a title V operating permit, the NO\textsubscript{X} Budget portion of the title V permit shall be administered in accordance with the permitting authority’s regulations promulgated to administer non-title V permits, except as provided otherwise by this subpart or subpart I of this part. The applicable provisions of such non-title V permits regulations may include, but are not limited to, provisions addressing permit applications, permit application shield, permit duration, permit shield, permit issuance, permit revision and reopening, public participation, State review, and review by the Administrator.

(b) Each NO\textsubscript{X} Budget permit (including a draft or proposed NO\textsubscript{X} Budget permit, if applicable) shall contain all applicable NO\textsubscript{X} Budget Trading Program requirements and shall be a complete and segregable portion of the permit under paragraph (a) of this section.

§ 96.21 Submission of NO\textsubscript{X} Budget permit applications.

(a) Duty to apply. The NO\textsubscript{X} authorized account representative of any NO\textsubscript{X} Budget source required to have a federally enforceable permit shall submit to the permitting authority a complete NO\textsubscript{X} Budget permit application under § 96.22 by the applicable deadline in paragraph (b) of this section.

(b)(1) For NO\textsubscript{X} Budget sources required to have a title V operating permit:

(i) For any source, with one or more NO\textsubscript{X} Budget units under § 96.4 that commence operation before January 1, 2000, the NO\textsubscript{X} authorized account representative shall submit a complete NO\textsubscript{X} Budget permit application under § 96.22 covering such NO\textsubscript{X} Budget units to the permitting authority at least 18
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Each NOX Budget source required to have a non-title V permit, the NOX authorized account representative shall submit a complete NOX Budget permit application under § 96.22 covering such NOX Budget units to the permitting authority at least 18 months (or such lesser time provided under the permitting authority’s title V operating permits regulations for final action on a permit application) before the later of May 1, 2003 or the date on which the NOX Budget units commence operation.

(2) For NOX Budget sources required to have a non-title V permit:

(i) For any source, with one or more NOX Budget units under § 96.4 that commence operation before January 1, 2000, the NOX authorized account representative shall submit a complete NOX Budget permit application under § 96.22 covering such NOX Budget units to the permitting authority at least 18 months (or such lesser time provided under the permitting authority’s title V operating permits regulations for final action on a permit application) before May 1, 2003.

(ii) For any source, with any NOX Budget unit under § 96.4 that commences operation on or after January 1, 2000, the NOX authorized account representative shall submit a complete NOX Budget permit application under § 96.22 covering such NOX Budget unit to the permitting authority at least 18 months (or such lesser time provided under the permitting authority’s title V permits regulations for final action on a permit application) before the later of May 1, 2003 or the date on which the NOX Budget unit commences operation.

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Each NOX Budget permit (including any draft or proposed NOX Budget permit, if applicable) will contain, in a format prescribed by the permitting authority, all elements required for a
Subpart D—Compliance Certification

§ 96.30 Compliance certification report.

(a) Applicability and deadline. For each control period in which one or more NO\textsubscript{X} Budget units at a source are subject to the NO\textsubscript{X} Budget emissions limitation, the NO\textsubscript{X} authorized account representative of the source shall submit to the permitting authority and the Administrator by November 30 of that year, a compliance certification report for each source covering all such units.

(b) Contents of report. The NO\textsubscript{X} authorized account representative shall include in the compliance certification report under paragraph (a) of this section the following elements, in a format prescribed by the Administrator, concerning each unit at the source and subject to the NO\textsubscript{X} Budget emissions limitation for the control period covered by the report:

1. Identification of each NO\textsubscript{X} Budget unit;
2. At the NO\textsubscript{X} authorized account representative’s option, the serial numbers of the NO\textsubscript{X} allowances that are to be deducted from each unit’s compliance account under §96.54 for the control period;
3. At the NO\textsubscript{X} authorized account representative’s option, for units sharing a common stack and having NO\textsubscript{X} emissions that are not monitored separately or apportioned in accordance with subpart H of this part, the percentage of allowances that is to be deducted from each unit’s compliance account under §96.54(e); and
4. The compliance certification under paragraph (c) of this section.

(c) Compliance certification. In the compliance certification report under paragraph (a) of this section, the NO\textsubscript{X} authorized account representative shall certify, based on reasonable inquiry of those persons with primary responsibility for operating the source and the NO\textsubscript{X} Budget units at the source in compliance with the NO\textsubscript{X} Budget Trading Program, whether each NO\textsubscript{X} Budget unit for which the compliance certification is submitted was operated during the calendar year covered by

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§ 96.30 Compliance certification report.

(a) Applicability and deadline. For each control period in which one or more NO\textsubscript{X} Budget units at a source are subject to the NO\textsubscript{X} Budget emissions limitation, the NO\textsubscript{X} authorized account representative of the source shall submit to the permitting authority and the Administrator by November 30 of that year, a compliance certification report for each source covering all such units.

(b) Contents of report. The NO\textsubscript{X} authorized account representative shall include in the compliance certification report under paragraph (a) of this section the following elements, in a format prescribed by the Administrator, concerning each unit at the source and subject to the NO\textsubscript{X} Budget emissions limitation for the control period covered by the report:

1. Identification of each NO\textsubscript{X} Budget unit;
2. At the NO\textsubscript{X} authorized account representative’s option, the serial numbers of the NO\textsubscript{X} allowances that are to be deducted from each unit’s compliance account under §96.54 for the control period;
3. At the NO\textsubscript{X} authorized account representative’s option, for units sharing a common stack and having NO\textsubscript{X} emissions that are not monitored separately or apportioned in accordance with subpart H of this part, the percentage of allowances that is to be deducted from each unit’s compliance account under §96.54(e); and
4. The compliance certification under paragraph (c) of this section.

(c) Compliance certification. In the compliance certification report under paragraph (a) of this section, the NO\textsubscript{X} authorized account representative shall certify, based on reasonable inquiry of those persons with primary responsibility for operating the source and the NO\textsubscript{X} Budget units at the source in compliance with the NO\textsubscript{X} Budget Trading Program, whether each NO\textsubscript{X} Budget unit for which the compliance certification is submitted was operated during the calendar year covered by

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the report in compliance with the requirements of the NO\textsubscript{X} Budget Trading Program applicable to the unit, including:

(1) Whether the unit was operated in compliance with the NO\textsubscript{X} Budget emissions limitation;

(2) Whether the monitoring plan that governs the unit has been maintained to reflect the actual operation and monitoring of the unit, and contains all information necessary to attribute NO\textsubscript{X} emissions to the unit, in accordance with subpart H of this part;

(3) Whether all the NO\textsubscript{X} emissions from the unit, or a group of units (including the unit) using a common stack, were monitored or accounted for through the missing data procedures and reported in the quarterly monitoring reports, including whether conditional data were reported in the quarterly reports in accordance with subpart H of this part. If conditional data were reported, the owner or operator shall indicate whether the status of all conditional data has been resolved and all necessary quarterly report resubmissions has been made;

(4) Whether the facts that form the basis for certification under subpart H of this part of each monitor at the unit or a group of units (including the unit) using a common stack, or for using an excepted monitoring method or alternative monitoring method approved under subpart H of this part, if any, has changed; and

(5) If a change is required to be reported under paragraph (c)(4) of this section, specify the nature of the change, the reason for the change, when the change occurred, and how the unit’s compliance status was determined subsequent to the change, including what method was used to determine emissions when a change mandated the need for monitor recertification.

§ 96.31 Permitting authority’s and Administrator’s action on compliance certifications.

(a) The permitting authority or the Administrator may review and conduct independent audits concerning any compliance certification or any other submission under the NO\textsubscript{X} Budget Trading Program and make appropriate adjustments of the information in the compliance certifications or other submissions.

(b) The Administrator may deduct NO\textsubscript{X} allowances from or transfer NO\textsubscript{X} allowances to a unit’s compliance account or a source’s overdraft account based on the information in the compliance certifications or other submissions, as adjusted under paragraph (a) of this section.

Subpart E—NO\textsubscript{X} Allowance Allocations

§ 96.40 State trading program budget.

The State trading program budget allocated by the permitting authority under §96.42 for a control period will equal the total number of tons of NO\textsubscript{X} emissions apportioned to the NO\textsubscript{X} Budget units under §96.4 in the State for the control period, as determined by the applicable, approved State implementation plan.

§ 96.41 Timing requirements for NO\textsubscript{X} allowance allocations.

(a) By September 30, 1999, the permitting authority will submit to the Administrator the NO\textsubscript{X} allowance allocations, in accordance with §96.42, for the control periods in 2003, 2004, and 2005.

(b) By April 1, 2003 and April 1 of each year thereafter, the permitting authority will submit to the Administrator the NO\textsubscript{X} allowance allocations, in accordance with §96.42, for the control period in the year that is three years after the year of the applicable deadline for submission under this paragraph (b). If the permitting authority fails to submit to the Administrator the NO\textsubscript{X} allowance allocations in accordance with this paragraph (b), the Administrator will allocate, for the applicable control period, the same number of NO\textsubscript{X} allowances as were allocated for the preceding control period.

(c) By April 1, 2004 and April 1 of each year thereafter, the permitting authority will submit to the Administrator the NO\textsubscript{X} allowance allocations, in accordance with §96.42, for any NO\textsubscript{X} allowances remaining in the allocation set-aside for the prior control period.
§ 96.42 NO\textsubscript{X} allowance allocations.

(a)(1) The heat input (in mmBtu) used for calculating NO\textsubscript{X} allowance allocations for each NO\textsubscript{X} Budget unit under § 96.4 will be:

(i) For a NO\textsubscript{X} allowance allocation under § 96.4(a), the average of the two highest amounts of the unit's heat input for the control periods in 1995, 1996, and 1997 if the unit is under § 96.4(a)(1) or the control period in 1995 if the unit is under § 96.4(a)(2); and

(ii) For a NO\textsubscript{X} allowance allocation under § 96.4(b), the unit's heat input for the control period in the year that is four years before the year for which the NO\textsubscript{X} allocation is being calculated.

(b) For each control period under § 96.41, the permitting authority will allocate to all NO\textsubscript{X} Budget units in the State that commenced operation before May 1 of the period used to calculate heat input under paragraph (a)(1) of this section, a total number of NO\textsubscript{X} allowances equal to 95 percent in 2003, 2004, and 2005, or 98 percent thereafter, of the number of tons of NO\textsubscript{X} emissions in the State trading program budget apportioned to electric generating units, the permitting authority will adjust the total number of NO\textsubscript{X} allowances allocated to all such NO\textsubscript{X} Budget units for the control period under paragraph (b)(1) of this section so that the total number of NO\textsubscript{X} allowances allocated equals 95 percent in 2003, 2004, and 2005, or 98 percent thereafter, of the number of tons of NO\textsubscript{X} emissions in the State trading program budget apportioned to electric generating units. This adjustment will be made by: multiplying each unit's allocation by 95 percent in 2003, 2004, and 2005, or 98 percent thereafter, of the number of tons of NO\textsubscript{X} emissions in the State trading program budget apportioned to electric generating units divided by the total number of NO\textsubscript{X} allocations allocated under paragraph (b)(1) of this section, and rounding to the nearest whole NO\textsubscript{X} allowance as appropriate.

(c) For each control period under § 96.41, the permitting authority will allocate to all NO\textsubscript{X} Budget units under § 96.4(a)(2) in the State that commenced operation before May 1 of the period used to calculate heat input under paragraph (a)(1) of this section, a total number of NO\textsubscript{X} allowances equal to 95 percent in 2003, 2004, and 2005, or 98 percent thereafter, of the tons of NO\textsubscript{X} emissions in the State trading program budget apportioned to non-electric generating units under § 96.40 in accordance with the following procedures:

(1) The permitting authority will allocate NO\textsubscript{X} allowances to each NO\textsubscript{X} Budget unit under § 96.4(a)(1) in an amount equaling 0.15 lb/mmBtu multiplied by the heat input determined under paragraph (a) of this section, rounded to the nearest whole NO\textsubscript{X} allowance as appropriate.

(2) If the initial total number of NO\textsubscript{X} allowances allocated to all NO\textsubscript{X} Budget units under § 96.4(a)(1) in the State for a control period under paragraph (b)(1) of this section does not equal 95 percent in 2003, 2004, and 2005, or 98 percent thereafter, of the number of tons of NO\textsubscript{X} emissions in the State trading program budget apportioned to non-electric generating units, the permitting authority will adjust the total number of NO\textsubscript{X} allowances allocated to
all such NOX Budget units for the control period under paragraph (c)(1) of this section so that the total number of NOX allowances allocated equals 95 percent in 2003, 2004, and 2005, or 98 percent thereafter, of the number of tons of NOX emissions in the State trading program budget apportioned to non-electric generating units. This adjustment will be made by: multiplying each unit’s allocation by 95 percent in 2003, 2004, and 2005, or 98 percent thereafter, of the number of tons of NOX emissions in the State trading program budget apportioned to non-electric generating units divided by the total number of NOX allowances allocated under paragraph (c)(1) of this section, and rounding to the nearest whole NOX allowance as appropriate.

(d) For each control period under §96.41, the permitting authority will allocate NOX allowances to NOX Budget units under §96.4 in the State that commenced operation, or is projected to commence operation, on or after May 1 of the period used to calculate heat input under paragraph (a)(1) of this section, in accordance with the following procedures:

(1) The permitting authority will establish one allocation set-aside for each control period. Each allocation set-aside will be allocated NOX allowances equal to 5 percent in 2003, 2004, and 2005, or 2 percent thereafter, of the tons of NOX emissions in the State trading program budget under §96.40, rounded to the nearest whole NOX allowance as appropriate.

(2) The NOX authorized account representative of a NOX Budget unit under paragraph (d) of this section may submit to the permitting authority a request, in writing or in a format specified by the permitting authority, to be allocated NOX allowances for no more than five consecutive control periods under §96.41, starting with the control period during which the NOX Budget unit commenced, or is projected to commence, operation and ending with the control period preceding the control period for which it will receive an allocation under paragraph (b) or (c) of this section. The NOX allowance allocation request must be submitted prior to May 1 of the first control period for which the NOX allowance allocation is requested and after the date on which the permitting authority issues a permit to construct the NOX Budget unit.

(3) In a NOX allowance allocation request under paragraph (d)(2) of this section, the NOX authorized account representative for units under §96.4(a)(1) may request for a control period NOX allowances in an amount that does not exceed 0.15 lb/mmBtu multiplied by the NOX Budget unit’s maximum design heat input (in mmBtu/hr) multiplied by the number of hours remaining in the control period starting with the first day in the control period on which the unit operated or is projected to operate.

(4) In a NOX allowance allocation request under paragraph (d)(2) of this section, the NOX authorized account representative for units under §96.4(a)(2) may request for a control period NOX allowances in an amount that does not exceed 0.17 lb/mmBtu multiplied by the NOX Budget unit’s maximum design heat input (in mmBtu/hr) multiplied by the number of hours remaining in the control period starting with the first day in the control period on which the unit operated or is projected to operate.

(5) The permitting authority will review, and allocate NOX allowances pursuant to, each NOX allowance allocation request under paragraph (d)(2) of this section in the order that the request is received by the permitting authority.

(i) Upon receipt of the NOX allowance allocation request, the permitting authority will determine whether, and will make any necessary adjustments to the request to ensure that, for units under §96.4(a)(1), the control period and the number of allowances specified are consistent with the requirements of paragraphs (d)(2) and (3) of this section and, for units under §96.4(a)(2), the control period and the number of allowances specified are consistent with the requirements of paragraphs (d)(2) and (4) of this section.

(ii) If the allocation set-aside for the control period for which NOX allowances are requested has an amount of NOX allowances not less than the number requested (as adjusted under paragraph (d)(5)(i) of this section), the permitting authority will allocate the
amount of the NO\textsubscript{X} allowances requested (as adjusted under paragraph (d)(5)(i) of this section) to the NO\textsubscript{X} Budget unit.

(iii) If the allocation set-aside for the control period for which NO\textsubscript{X} allowances are requested has a smaller amount of NO\textsubscript{X} allowances than the number requested (as adjusted under paragraph (d)(5)(i) of this section), the permitting authority will deny in part the request and allocate only the remaining number of NO\textsubscript{X} allowances in the allocation set-aside to the NO\textsubscript{X} Budget unit.

(iv) Once an allocation set-aside for a control period has been depleted of all NO\textsubscript{X} allowances, the permitting authority will deny, and will not allocate any NO\textsubscript{X} allowances pursuant to, any NO\textsubscript{X} allowance allocation request under which NO\textsubscript{X} allowances have not already been allocated for the control period.

(6) Within 60 days of receipt of a NO\textsubscript{X} allowance allocation request, the permitting authority will take appropriate action under paragraph (d)(5) of this section and notify the NO\textsubscript{X} authorized account representative that submitted the request and the Administrator of the number of NO\textsubscript{X} allowances (if any) allocated for the control period to the NO\textsubscript{X} Budget unit.

(e) For a NO\textsubscript{X} Budget unit that is allocated NO\textsubscript{X} allowances under paragraph (d) of this section for a control period, the Administrator will deduct NO\textsubscript{X} allowances under §96.54(b) or (e) to account for the actual utilization of the unit during the control period. The Administrator will calculate the number of NO\textsubscript{X} allowances to be deducted to account for the unit’s actual utilization using the following formulas and rounding to the nearest whole NO\textsubscript{X} allowance as appropriate, provided that the number of NO\textsubscript{X} allowances to be deducted shall be zero if the number calculated is less than zero:

\[
\text{NO}\textsubscript{X} \text{ allowances deducted for actual utilization for units under } \text{§96.4(a)(2)} = (\text{Unit’s NO}\textsubscript{X} \text{ allowances allocated for control period}) - (\text{Unit’s actual control period utilization} \times 0.15 \text{ lb/mmBtu})
\]

Where:

- “Unit’s NO\textsubscript{X} allowances allocated for control period” is the number of NO\textsubscript{X} allowances allocated to the unit for the control period under paragraph (d) of this section; and
- “Unit’s actual control period utilization” is the utilization (in mmBtu), as defined in §96.2, of the unit during the control period.

(f) After making the deductions for compliance under §96.54(b) or (e) for a control period, the Administrator will notify the permitting authority whether any NO\textsubscript{X} allowances remain in the allocation set-aside for the control period. The permitting authority will allocate any such NO\textsubscript{X} allowances to the NO\textsubscript{X} Budget units in the State using the following formula and rounding to the nearest whole NO\textsubscript{X} allowance as appropriate:

\[
\text{Unit’s share of NO}\textsubscript{X} \text{ allowances remaining in allocation set-aside} = \frac{\text{Total NO}\textsubscript{X} \text{ allowances remaining in allocation set-aside}}{\text{State trading program budget excluding allocation set-aside}}
\]

Where:

- “Total NO\textsubscript{X} allowances remaining in allocation set-aside” is the total number of NO\textsubscript{X} allowances remaining in the allocation set-aside for the control period to which the allocation set-aside applies;
- “Unit’s NO\textsubscript{X} allowance allocation” is the number of NO\textsubscript{X} allowances allocated under paragraph (b) or (c) of this section to the unit for the control period to which the allocation set-aside applies; and
- “State trading program budget excluding allocation set-aside” is the State trading program budget under §96.40 for the control period to which the allocation set-aside applies multiplied by 95 percent if the control period is in 2003, 2004, or 2005 or 98 percent if the control period is in any year thereafter, rounded to the nearest whole NO\textsubscript{X} allowance as appropriate.

§ 96.50 NO\textsubscript{X} Allowance Tracking System

(a) Nature and function of compliance accounts and overdraft accounts. Consistent with §96.51(a), the Administrator will establish one compliance account for each NO\textsubscript{X} Budget unit and one overdraft account for each source with one or more NO\textsubscript{X} Budget units. Allocations of NO\textsubscript{X} allowances pursuant to subpart E of this part or §96.88 and deductions or transfers of NO\textsubscript{X} allowances pursuant to §96.31, §96.54, §96.56, subpart G of this part, or subpart I of this part will be recorded in the compliance accounts or overdraft accounts in accordance with this subpart.

(b) Nature and function of general accounts. Consistent with §96.51(b), the Administrator will establish, upon request, a general account for any person. Transfers of allowances pursuant to subpart G of this part will be recorded in the general account in accordance with this subpart.

§ 96.51 Establishment of accounts.

(a) Compliance accounts and overdraft accounts. Upon receipt of a complete account certificate of representation under §96.13, the Administrator will establish:

(1) A compliance account for each NO\textsubscript{X} Budget unit for which the account certificate of representation was submitted; and

(2) An overdraft account for each source for which the account certificate of representation was submitted and that has two or more NO\textsubscript{X} Budget units.

(b) General accounts. (1) Any person may apply to open a general account for the purpose of holding and transferring allowances. A complete application for a general account shall be submitted to the Administrator and shall include the following elements in a format prescribed by the Administrator:

(i) Name, mailing address, e-mail address (if any), telephone number, and facsimile transmission number (if any) of the NO\textsubscript{X} authorized account representative and any alternate NO\textsubscript{X} authorized account representative;

(ii) At the option of the NO\textsubscript{X} authorized account representative, organization name and type of organization;

(iii) A list of all persons subject to a binding agreement for the NO\textsubscript{X} authorized account representative or any alternate NO\textsubscript{X} authorized account representative to represent their ownership interest with respect to the allowances held in the general account;

(iv) The following certification statement by the NO\textsubscript{X} authorized account representative and any alternate NO\textsubscript{X} authorized account representative: ‘‘I certify that I was selected as the NO\textsubscript{X} authorized account representative or the NO\textsubscript{X} alternate authorized account representative, as applicable, by an agreement that is binding on all persons who have an ownership interest with respect to allowances held in the general account. I certify that I have all the necessary authority to carry out my duties and responsibilities under the NO\textsubscript{X} Budget Trading Program on behalf of such persons and that each such person shall be fully bound by my representations, actions, inactions, or submissions and by any order or decision issued to me by the Administrator or a court regarding the general account.’’

(v) The signature of the NO\textsubscript{X} authorized account representative and any alternate NO\textsubscript{X} authorized account representative and the dates signed.

(vi) Unless otherwise required by the permitting authority or the Administrator, documents of agreement referred to in the account certificate of representation shall not be submitted to the permitting authority or the Administrator. Neither the permitting authority nor the Administrator shall be under any obligation to review or evaluate the sufficiency of such documents, if submitted.

(2) Upon receipt by the Administrator of a complete application for a general account under paragraph (b)(1) of this section:

(i) The Administrator will establish a general account for the person or persons for whom the application is submitted.

(ii) The NO\textsubscript{X} authorized account representative and any alternate NO\textsubscript{X} authorized account representative for the general account shall represent and, by
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his or her representations, actions, inactions, or submissions, legally bind each person who has an ownership interest with respect to NOX allowances held in the general account in all matters pertaining to the NOX Budget Trading Program, notwithstanding any agreement between the NOX authorized account representative or any alternate NOX authorized account representative and such person. Any such person shall be bound by any order or decision issued to the NOX authorized account representative or any alternate NOX authorized account representative by the Administrator or a court regarding the general account.

(iii) Each submission concerning the general account shall be submitted, signed, and certified by the NOX authorized account representative or any alternate NOX authorized account representative for the persons having an ownership interest with respect to NOX allowances held in the general account. Each such submission shall include the following certification statement by the NOX authorized account representative or any alternate NOX authorized account representative any: “I am authorized to make this submission on behalf of the persons having an ownership interest with respect to the NOX allowances held in the general account. I certify under penalty of law that I have personally examined, and am familiar with, the statements and information submitted in this document and all its attachments. Based on my inquiry of those individuals with primary responsibility for obtaining the information, I certify that the statements and information are to the best of my knowledge and belief true, accurate, and complete. I am aware that there are significant penalties for submitting false statements and information or omitting required statements and information, including the possibility of fine or imprisonment.”

(iv) The Administrator will accept or act on a submission concerning the general account only if the submission has been made, signed, and certified in accordance with paragraph (b)(2)(iii) of this section.

3(i) An application for a general account may designate one and only one NOX authorized account representative and one and only one alternate NOX authorized account representative who may act on behalf of the NOX authorized account representative. The agreement by which the alternate NOX authorized account representative is selected shall include a procedure for authorizing the alternate NOX authorized account representative to act in lieu of the NOX authorized account representative.

(ii) Upon receipt by the Administrator of a complete application for a general account under paragraph (b)(1) of this section, any representation, action, inaction, or submission by any alternate NOX authorized account representative shall be deemed to be a representation, action, inaction, or submission by the NOX authorized account representative.

4(i) The NOX authorized account representative for a general account may be changed at any time upon receipt by the Administrator of a superseding complete application for a general account under paragraph (b)(1) of this section. Notwithstanding any such change, all representations, actions, inactions, and submissions by the previous NOX authorized account representative prior to the time and date when the Administrator receives the superseding application for a general account shall be binding on the new NOX authorized account representative and the persons with an ownership interest with respect to the allowances in the general account.

(ii) The alternate NOX authorized account representative for a general account may be changed at any time upon receipt by the Administrator of a superseding complete application for a general account under paragraph (b)(1) of this section. Notwithstanding any such change, all representations, actions, inactions, and submissions by the previous alternate NOX authorized account representative prior to the time and date when the Administrator receives the superseding application for a general account shall be binding on the new alternate NOX authorized account representative and the persons with an ownership interest with respect to the allowances in the general account.
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(iii)(A) In the event a new person having an ownership interest with respect to NO\textsubscript{X} allowances in the general account is not included in the list of such persons in the account certificate of representation, such new person shall be deemed to be subject to and bound by the account certificate of representation, the representation, actions, inactions, and submissions of the NO\textsubscript{X} authorized account representative and any alternate NO\textsubscript{X} authorized account representative of the source or unit, and the decisions, orders, actions, and inactions of the Administrator, as if the new person were included in such list.

(B) Within 30 days following any change in the persons having an ownership interest with respect to NO\textsubscript{X} allowances in the general account, including the addition of persons, the NO\textsubscript{X} authorized account representative or any alternate NO\textsubscript{X} authorized account representative shall submit a revision to the application for a general account amending the list of persons having an ownership interest with respect to the NO\textsubscript{X} allowances in the general account to include the change.

(5)(i) Once a complete application for a general account under paragraph (b)(1) of this section has been submitted and received, the Administrator will rely on the application unless and until a superseding complete application for a general account under paragraph (b)(1) of this section is received by the Administrator.

(ii) Except as provided in paragraph (b)(4) of this section, no objection or other communication submitted to the Administrator concerning the authorization, or any representation, action, inaction, or submission of the NO\textsubscript{X} authorized account representative or any alternate NO\textsubscript{X} authorized account representative for a general account shall affect any representation, action, inaction, or submission of the NO\textsubscript{X} authorized account representative or any alternate NO\textsubscript{X} authorized account representative or the finality of any decision or order by the Administrator under the NO\textsubscript{X} Budget Trading Program.

(iii) The Administrator will not adjudicate any private legal dispute concerning the authorization or any representation, action, inaction, or submission of the NO\textsubscript{X} authorized account representative or any alternate NO\textsubscript{X} authorized account representative for a general account, including private legal disputes concerning the proceeds of NO\textsubscript{X} allowance transfers.

(c) Account identification. The Administrator will assign a unique identifying number to each account established under paragraph (a) or (b) of this section.

§ 96.52 NO\textsubscript{X} Allowance Tracking System responsibilities of NO\textsubscript{X} authorized account representative.

(a) Following the establishment of a NO\textsubscript{X} Allowance Tracking System account, all submissions to the Administrator pertaining to the account, including, but not limited to, submissions concerning the deduction or transfer of NO\textsubscript{X} allowances in the account, shall be made only by the NO\textsubscript{X} authorized account representative for the account.

(b) Authorized account representative identification. The Administrator will assign a unique identifying number to each NO\textsubscript{X} authorized account representative.

§ 96.53 Recordation of NO\textsubscript{X} allowance allocations.

(a) The Administrator will record the NO\textsubscript{X} allowances for 2003 in the NO\textsubscript{X} Budget units' compliance accounts and the allocation set-asides, as allocated under subpart E of this part. The Administrator will also record the NO\textsubscript{X} allowances allocated under §96.88(a)(1) for each NO\textsubscript{X} Budget opt-in source in its compliance account.

(b) Each year, after the Administrator has made all deductions from a NO\textsubscript{X} Budget unit's compliance account and the overdraft account for the year after the last year for which allowances were previously allocated to the compliance account. Each year, the Administrator will also record NO\textsubscript{X} allowances, as allocated under subpart E of this part, in the allocation set-aside for the year after the last year for which allowances were
previously allocated to an allocation set-aside.

(c) Serial numbers for allocated NO\textsubscript{X} allowances. When allocating NO\textsubscript{X} allowances to and recording them in an account, the Administrator will assign each NO\textsubscript{X} allowance a unique identification number that will include digits identifying the year for which the NO\textsubscript{X} allowance is allocated.

§ 96.54 Compliance.

(a) NO\textsubscript{X} allowance transfer deadline. The NO\textsubscript{X} allowances are available to be deducted for compliance with a unit’s NO\textsubscript{X} Budget emissions limitation for a control period in a given year only if the NO\textsubscript{X} allowances:

(1) Were allocated for a control period in a prior year or the same year; and

(2) Are held in the unit’s compliance account, or the overdraft account of the source where the unit is located, as of the NO\textsubscript{X} allowance transfer deadline for that control period or are transferred into the compliance account or overdraft account by a NO\textsubscript{X} allowance transfer correctly submitted for recordation under §96.60 by the NO\textsubscript{X} allowance transfer deadline for that control period.

(b) Deductions for compliance. (1) Following the recordation, in accordance with §96.61, of NO\textsubscript{X} allowance transfers submitted for recordation in the unit’s compliance account or the overdraft account of the source where the unit is located by the NO\textsubscript{X} allowance transfer deadline for a control period, the Administrator will deduct NO\textsubscript{X} allowances available under paragraph (a) of this section to cover the unit’s NO\textsubscript{X} emissions (as determined in accordance with subpart H of this part), or to account for actual utilization under §96.42(e), for the control period:

(i) From the compliance account; and

(ii) Only if no more NO\textsubscript{X} allowances available under paragraph (a) of this section remain in the compliance account, from the overdraft account. In deducting allowances for units at the source from the overdraft account, the Administrator will begin with the unit having the compliance account with the lowest NO\textsubscript{X} Allowance Tracking System account number and end with the unit having the compliance account with the highest NO\textsubscript{X} Allowance Tracking System account number (with account numbers sorted beginning with the left-most character and ending with the right-most character and the letter characters assigned values in alphabetical order and less than all numeric characters).

(2) The Administrator will deduct NO\textsubscript{X} allowances first under paragraph (b)(1)(i) of this section and then under paragraph (b)(1)(ii) of this section:

(i) Until the number of NO\textsubscript{X} allowances deducted for the control period equals the number of tons of NO\textsubscript{X} emissions, determined in accordance with subpart H of this part, from the unit for the control period for which compliance is being determined, plus the number of NO\textsubscript{X} allowances required for deduction to account for actual utilization under §96.42(e) for the control period; or

(ii) Until no more NO\textsubscript{X} allowances available under paragraph (a) of this section remain in the respective account.

(c)(1) Identification of NO\textsubscript{X} allowances by serial number. The NO\textsubscript{X} authorized account representative for each compliance account may identify by serial number the NO\textsubscript{X} allowances to be deducted from the unit’s compliance account under paragraph (b), (d), or (e) of this section. Such identification shall be made in the compliance certification report submitted in accordance with §96.30.

(2) First-in, first-out. The Administrator will deduct NO\textsubscript{X} allowances for a control period from the compliance account, in the absence of an identification or in the case of a partial identification of NO\textsubscript{X} allowances by serial number under paragraph (c)(1) of this section, or the overdraft account on a first-in, first-out (FIFO) accounting basis in the following order:

(i) Those NO\textsubscript{X} allowances that were allocated for the control period to the unit under subpart E or I of this part;

(ii) Those NO\textsubscript{X} allowances that were allocated for the control period to any unit and transferred and recorded in the account pursuant to subpart G of this part, in order of their date of recordation;

(iii) Those NO\textsubscript{X} allowances that were allocated for a prior control period to
§ 96.55 Banking.

(a) NOX allowances may be banked for future use or transfer in a compliance account, an overdraft account, or a general account, as follows:

1. Any NOX allowance that is held in a compliance account, an overdraft account, or a general account will remain in such account unless and until the NOX allowance is deducted or transferred under §96.31, §96.54, §96.56, subpart G of this part, or subpart I of this part.

2. The Administrator will designate, as a “banked” NOX allowance, any NOX allowance that remains in a compliance account, an overdraft account, or a general account after the Administrator has made all deductions for a given control period from the compliance account or overdraft account pursuant to §96.54.

(b) Each year starting in 2004, after the Administrator has completed the designation of banked NOX allowances under paragraph (a)(2) of this section and before May 1 of the year, the Administrator will determine the extent to which banked NOX allowances may be deducted from each such unit’s compliance account to cover the unit’s share of NOX emissions from the common stack for a control period. Such identification shall be made in the compliance certification report submitted in accordance with §96.30.

3. Notwithstanding paragraph (b)(2)(i) of this section, the Administrator will deduct NOX allowances for each such unit until the number of NOX allowances deducted equals the unit’s identified percentage (under paragraph (e)(1) of this section) of the number of tons of NOX emissions, as determined in accordance with subpart H of this part, from the common stack for the control period for which compliance is being determined or, if no percentage is identified, an equal percentage for each such unit, plus the number of allowances required for deduction to account for actual utilization under §96.42(e) for the control period.

(f) The Administrator will record in the appropriate compliance account or overdraft account all deductions from such an account pursuant to paragraphs (b), (d), or (e) of this section.

§ 96.55 Banking.

(a) NOX allowances may be banked for future use or transfer in a compliance account, an overdraft account, or a general account, as follows:

1. Any NOX allowance that is held in a compliance account, an overdraft account, or a general account will remain in such account unless and until the NOX allowance is deducted or transferred under §96.31, §96.54, §96.56, subpart G of this part, or subpart I of this part.

2. The Administrator will designate, as a “banked” NOX allowance, any NOX allowance that remains in a compliance account, an overdraft account, or a general account after the Administrator has made all deductions for a given control period from the compliance account or overdraft account pursuant to §96.54.

(b) Each year starting in 2004, after the Administrator has completed the designation of banked NOX allowances under paragraph (a)(2) of this section and before May 1 of the year, the Administrator will determine the extent to which banked NOX allowances may be
be used for compliance in the control period for the current year, as follows:

(1) The Administrator will determine the total number of banked NOx allowances held in compliance accounts, overdraft accounts, or general accounts.

(2) If the total number of banked NOx allowances determined, under paragraph (b)(1) of this section, to be held in compliance accounts, overdraft accounts, or general accounts is less than or equal to 10% of the sum of the State trading program budgets for the control period for the States in which NOx Budget units are located, any banked NOx allowance may be deducted for compliance in accordance with § 96.54.

(3) If the total number of banked NOx allowances determined, under paragraph (b)(1) of this section, to be held in compliance accounts, overdraft accounts, or general accounts exceeds 10% of the sum of the State trading program budgets for the control period for the States in which NOx Budget units are located, any banked allowance may be deducted for compliance in accordance with § 96.54, except as follows:

(i) The Administrator will determine the following ratio: 0.10 multiplied by the sum of the State trading program budgets for the control period for the States in which NOx Budget units are located and divided by the total number of banked NOx allowances determined, under paragraph (b)(1) of this section, to be held in compliance accounts, overdraft accounts, or general accounts.

(ii) The Administrator will multiply the number of banked NOx allowances in each compliance account or overdraft account. The resulting product is the number of banked NOx allowances in the account that may be deducted for compliance in accordance with § 96.54. Any banked NOx allowances in excess of the resulting product may be deducted for compliance in accordance with § 96.54, except that, if such NOx allowances are used to make a deduction, two such NOx allowances must be deducted for each deduction of one NOx allowance required under § 96.54.

(c) Any NOx Budget unit may reduce its NOx emission rate in the 2001 or 2002 control period, the owner or operator of the unit may request early reduction credits, and the permitting authority may allocate NOx allowances in 2003 to the unit in accordance with the following requirements.

(1) Each NOx Budget unit for which the owner or operator requests any early reduction credits under paragraph (c)(4) of this section shall monitor NOx emissions in accordance with subpart H of this part starting in the 2000 control period and for each control period for which such early reduction credits are requested. The unit’s monitoring system availability shall be not less than 90 percent during the 2000 control period, and the unit must be in compliance with any applicable State or Federal emissions or emissions-related requirements.

(2) NOx emission rate and heat input under paragraphs (c)(3) through (5) of this section shall be determined in accordance with subpart H of this part.

(3) Each NOx Budget unit for which the owner or operator requests any early reduction credits under paragraph (c)(4) of this section shall reduce its NOx emission rate, for each control period for which early reduction credits are requested, to less than both 0.25 lb/mmBtu and 80 percent of the unit’s NOx emission rate in the 2000 control period.

(4) The NOx authorized account representative of a NOx Budget unit that meets the requirements of paragraphs (c)(1) and (3) of this section may submit to the permitting authority a request for early reduction credits for the unit based on NOx emission rate reductions made by the unit in the control period for 2001 or 2002 in accordance with paragraph (c)(3) of this section.

(i) In the early reduction credit request, the NOx authorized account may request early reduction credits for such control period in an amount equal to the unit’s heat input for such control period multiplied by the difference between 0.25 lb/mmBtu and the unit’s NOx emission rate for such control period, divided by 2000 lb/ton, and rounded to the nearest ton.

(ii) The early reduction credit request must be submitted, in a format specified by the permitting authority, by October 31 of the year in which the NOx emission rate reductions on which
the request is based are made or such later date approved by the permitting authority.

(5) The permitting authority will allocate NOX allowances, to NOX Budget units meeting the requirements of paragraphs (c)(1) and (3) of this section and covered by early reduction requests meeting the requirements of paragraph (c)(4)(ii) of this section, in accordance with the following procedures:

(i) Upon receipt of each early reduction credit request, the permitting authority will accept the request only if the requirements of paragraphs (c)(1), (c)(3), and (c)(4)(ii) of this section are met and, if the request is accepted, will make any necessary adjustments to the request to ensure that the amount of the early reduction credits requested meets the requirement of paragraphs (c)(2) and (4) of this section.

(ii) If the State’s compliance supplement pool has an amount of NOX allowances not less than the number of early reduction credit requests for 2001 and 2002 (as adjusted under paragraph (c)(5)(i) of this section), the permitting authority will allocate to each NOX Budget unit covered by such accepted requests one allowance for each early reduction credit requested (as adjusted under paragraph (c)(5)(i) of this section).

(iii) If the State’s compliance supplement pool has a smaller amount of NOX allowances than the number of early reduction credit requests for 2001 and 2002 (as adjusted under paragraph (c)(5)(i) of this section), the permitting authority will allocate NOX allowances to each NOX Budget unit covered by such accepted requests according to the following formula:

\[
\text{Unit's allocated early reduction credits} = \left( \frac{\text{Unit's adjusted early reduction credits}}{\text{Total adjusted early reduction credits requested by all units}} \right) \times \text{(Available NOX allowances from the State's compliance supplement pool)}
\]

where:

"Unit's adjusted early reduction credits" is the number of early reduction credits for the unit for 2001 and 2002 in accepted early reduction credit requests, as adjusted under paragraph (c)(5)(i) of this section.

"Total adjusted early reduction credits requested by all units" is the number of early reduction credits for all units for 2001 and 2002 in accepted early reduction credit requests, as adjusted under paragraph (c)(5)(i) of this section.

"Available NOX allowances from the State’s compliance supplement pool" is the number of NOX allowances in the State’s compliance supplement pool and available for early reduction credits for 2001 and 2002.

(6) By May 1, 2003, the permitting authority will submit to the Administrator the allocations of NOX allowances determined under paragraph (c)(5) of this section. The Administrator will record such allocations to the extent that they are consistent with the requirements of paragraphs (c)(1) through (5) of this section.

(7) NOX allowances recorded under paragraph (c)(6) of this section may be deducted for compliance under §96.54 for the control periods in 2003 or 2004. Notwithstanding paragraph (a) of this section, the Administrator will deduct as retired any NOX allowance that is recorded under paragraph (c)(6) of this section and is not deducted for compliance in accordance with §96.54 for the control period in 2003 or 2004.

(8) NOX allowances recorded under paragraph (c)(6) of this section are treated as banked allowances in 2004 for the purposes of paragraphs (a) and (b) of this section.

§ 96.56 Account error.

The Administrator may, at his or her sole discretion and on his or her own motion, correct any error in any NOX Allowance Tracking System account. Within 10 business days of making such correction, the Administrator will notify the NOX authorized account representative for the account.

§ 96.57 Closing of general accounts.

(a) The NOX authorized account representative of a general account may instruct the Administrator to close the account by submitting a statement requesting deletion of the account from the NOX Allowance Tracking System account and by correctly submitting for recordation under §96.60 an allowance transfer of all NOX allowances in the
account to one or more other NO\textsubscript{X} Allowance Tracking System accounts.

(b) If a general account shows no activity for a period of a year or more and does not contain any NO\textsubscript{X} allowances, the Administrator may notify the NO\textsubscript{X} authorized account representative for the account that the account will be closed and deleted from the NO\textsubscript{X} Allowance Tracking System following 20 business days after the notice is sent. The account will be closed after the 20-day period unless before the end of the 20-day period the Administrator receives a correctly submitted transfer of NO\textsubscript{X} allowances into the account under §96.60 or a statement submitted by the NO\textsubscript{X} authorized account representative demonstrating to the satisfaction of the Administrator good cause as to why the account should not be closed.

Subpart G—NO\textsubscript{X} Allowance Transfers

§96.60 Submission of NO\textsubscript{X} allowance transfers.

The NO\textsubscript{X} authorized account representatives seeking recordation of a NO\textsubscript{X} allowance transfer shall submit the transfer to the Administrator. To be considered correctly submitted, the NO\textsubscript{X} allowance transfer shall include the following elements in a format specified by the Administrator:

(a) The numbers identifying both the transferor and transferee accounts;

(b) A specification by serial number of each NO\textsubscript{X} allowance to be transferred; and

(c) The printed name and signature of the NO\textsubscript{X} authorized account representative of the transferor account and the date signed.

§96.61 EPA recordation.

(a) Within 5 business days of receiving a NO\textsubscript{X} allowance transfer, except as provided in paragraph (b) of this section, the Administrator will record a NO\textsubscript{X} allowance transfer by moving each NO\textsubscript{X} allowance from the transferor account to the transferee account as specified by the request, provided that:

(1) The transfer is correctly submitted under §96.60;

(2) The transferor account includes each NO\textsubscript{X} allowance identified by serial number in the transfer; and

(3) The transfer meets all other requirements of this part.

(b) A NO\textsubscript{X} allowance transfer that is submitted for recordation following the NO\textsubscript{X} allowance transfer deadline that includes any NO\textsubscript{X} allowances allocated for a control period prior to or the same as the control period to which the NO\textsubscript{X} allowance transfer deadline applies will not be recorded until after completion of the process of recordation of NO\textsubscript{X} allowance allocations in §96.53(b).

(c) Where a NO\textsubscript{X} allowance transfer submitted for recordation fails to meet the requirements of paragraph (a) of this section, the Administrator will not record such transfer.

§96.62 Notification.

(a) Notification of recordation. Within 5 business days of recordation of a NO\textsubscript{X} allowance transfer under §96.61, the Administrator will notify each party to the transfer. Notice will be given to the NO\textsubscript{X} authorized account representatives of both the transferor and transferee accounts.

(b) Notification of non-recordation. Within 10 business days of receipt of a NO\textsubscript{X} allowance transfer that fails to meet the requirements of §96.61(a), the Administrator will notify the NO\textsubscript{X} authorized account representatives of both accounts subject to the transfer of:

(1) A decision not to record the transfer, and (2) The reasons for such non-recordation.

(c) Nothing in this section shall preclude the submission of a NO\textsubscript{X} allowance transfer for recordation following notification of non-recordation.

Subpart H—Monitoring and Reporting

§96.70 General requirements.

The owners and operators, and to the extent applicable, the NO\textsubscript{X} authorized account representative of a NO\textsubscript{X} Budget unit, shall comply with the monitoring and reporting requirements as provided in this subpart and in subpart...
H of part 75 of this chapter. For purposes of complying with such requirements, the definitions in §96.2 and in §72.2 of this chapter shall apply, and the terms “affected unit,” “designated representative,” and “continuous emission monitoring system” (or “CEMS”) in part 75 of this chapter shall be replaced by the terms “NOX Budget unit,” “NOx authorized account representative,” and “continuous emission monitoring system” (or “CEMS”), respectively, as defined in §96.2.

(a) Requirements for installation, certification, and data accounting. The owner or operator of each NOX Budget unit must meet the following requirements. These provisions also apply to a unit for which an application for a NOx Budget opt-in permit is submitted and not denied or withdrawn, as provided in subpart I of this part:

(1) Install all monitoring systems required under this subpart for monitoring NOX mass. This includes all systems required to monitor NOx emission rate, NOX concentration, heat input, and flow, in accordance with §§75.72 and 75.76.

(2) Install all monitoring systems for monitoring heat input, if required under §96.76 for developing NOX allowance allocations.

(3) Successfully complete all certification tests required under §96.71 and meet all other provisions of this subpart and part 75 of this chapter applicable to the monitoring systems under paragraphs (a)(1) and (2) of this section.

(4) Record and report data from the monitoring systems under paragraphs (a)(1) and (2) of this section.

(b) Compliance dates. The owner or operator must meet the requirements of paragraphs (a)(1) through (a)(3) of this section on or before the following dates and must record and report data on and after the following dates:

(1) NOx Budget units for which the owner or operator intends to apply for early reduction credits under §96.55(d) must comply with the requirements of this subpart by May 1, 2000.

(2) Except for NOx Budget units under paragraph (b)(1) of this section, NOx Budget units under §96.4 that commence operation before January 1, 2002, must comply with the requirements of this subpart by May 1, 2002.

(3) NOx Budget units under §96.4 that commence operation on or after January 1, 2002 and that report on an annual basis under §96.74(d) must comply with the requirements of this subpart by the later of the following dates:

   (i) May 1, 2002; or
   (ii) The earlier of:

      (A) 180 days after the date on which the unit commences operation or, (B) For units under §96.4(a)(1), 90 days after the date on which the unit commences commercial operation.

(4) NOx Budget units under §96.4 that commence operation on or after January 1, 2002 and that report on a control season basis under §96.74(d) must comply with the requirements of this subpart by the later of the following dates:

   (i) The earlier of:

      (A) 180 days after the date on which the unit commences operation or, (B) For units under §96.4(a)(1), 90 days after the date on which the unit commences commercial operation.

   (ii) However, if the applicable deadline under paragraph (b)(4)(i) section does not occur during a control period, May 1; immediately following the date determined in accordance with paragraph (b)(4)(i) of this section.

(5) For a NOx Budget unit with a new stack or flue for which construction is completed after the applicable deadline under paragraph (b)(1), (b)(2) or (b)(3) of this section or subpart I of this part:

   (i) 90 days after the date on which emissions first exit to the atmosphere through the new stack or flue;

   (ii) However, if the unit reports on a control season basis under §96.74(d) and the applicable deadline under paragraph (b)(5)(i) of this section does not occur during the control period, May 1 immediately following the applicable deadline in paragraph (b)(5)(i) of this section.

(6) For a unit for which an application for a NOx Budget opt in permit is submitted and not denied or withdrawn, the compliance dates specified under subpart I of this part.

(c) Reporting data prior to initial certification. (1) The owner or operator of a NOx Budget unit that misses the certification deadline under paragraph (b)(5)(i) of this section is not eligible to apply for early reduction credits. The owner or operator of the unit becomes
subject to the certification deadline under paragraph (b)(2) of this section.

(2) The owner or operator of a NO\textsubscript{X} Budget under paragraphs (b)(3) or (b)(4) of this section must determine, record and report NO\textsubscript{X} mass, heat input (if required for purposes of allocations) and any other values required to determine NO\textsubscript{X} Mass (e.g. NO\textsubscript{X} emission rate and heat input or NO\textsubscript{X} concentration and stack flow) using the provisions of §75.70(g) of this chapter, from the date and hour that the unit starts operating until all required certification tests are successfully completed.

(d) Prohibitions. (1) No owner or operator of a NO\textsubscript{X} Budget unit or a non-NO\textsubscript{X} Budget unit monitored under §75.72(b)(2)(ii) shall use any alternative monitoring system, alternative reference method, or any other alternative for the required continuous emission monitoring system without having obtained prior written approval in accordance with §96.75.

(2) No owner or operator of a NO\textsubscript{X} Budget unit or a non-NO\textsubscript{X} Budget unit monitored under §75.72(b)(2)(ii) shall operate the unit so as to discharge, or allow to be discharged, NO\textsubscript{X} emissions to the atmosphere without accounting for all such emissions in accordance with the applicable provisions of this subpart and part 75 of this chapter except as provided for in §75.74 of this chapter.

(3) No owner or operator of a NO\textsubscript{X} Budget unit or a non-NO\textsubscript{X} Budget unit monitored under §75.72(b)(2)(ii) shall disrupt the continuous emission monitoring system, any portion thereof, or any other approved emission monitoring method, and thereby avoid monitoring and recording NO\textsubscript{X} mass emissions discharged into the atmosphere, except for periods of recertification or periods when calibration, quality assurance testing, or maintenance is performed in accordance with the applicable provisions of this subpart and part 75 of this chapter except as provided for in §75.74 of this chapter.

(4) No owner or operator of a NO\textsubscript{X} Budget unit or a non-NO\textsubscript{X} Budget unit monitored under §75.72(b)(2)(ii) shall retire or permanently discontinue use of the continuous emission monitoring system, any component thereof, or any other approved emission monitoring system under this subpart, except under any one of the following circumstances:

(i) During the period that the unit is covered by a retired unit exemption under §96.5 that is in effect;

(ii) The owner or operator is monitoring emissions from the unit with another certified monitoring system approved, in accordance with the applicable provisions of this subpart and part 75 of this chapter, by the permitting authority for use at that unit that provides emission data for the same pollutant or parameter as the retired or discontinued monitoring system; or

(iii) The NO\textsubscript{X} authorized account representative submits notification of the date of certification testing of a replacement monitoring system in accordance with §96.71(b)(2).

§ 96.71 Initial certification and recertification procedures

(a) The owner or operator of a NO\textsubscript{X} Budget unit that is subject to an Acid Rain emissions limitation shall comply with the initial certification and recertification procedures of part 75 of this chapter, except that:

(1) If, prior to January 1, 1998, the Administrator approved a petition under §75.17(a) or (b) of this chapter for apportioning the NO\textsubscript{X} emission rate measured in a common stack or a petition under §75.66 of this chapter for an alternative to a requirement in §75.17 of this chapter, the NO\textsubscript{X} authorized account representative shall resubmit the petition to the Administrator under §96.75(a) to determine if the approval applies under the NO\textsubscript{X} Budget Trading Program.

(2) For any additional CEMS required under the common stack provisions in §75.72 of this chapter, or for any NO\textsubscript{X} concentration CEMS used under the provisions of §75.71(a)(2) of this chapter, the owner or operator shall meet the requirements of paragraph (b) of this section.

(b) The owner or operator of a NO\textsubscript{X} Budget unit that is not subject to an Acid Rain emissions limitation shall comply with the following initial certification and recertification procedures, except that the owner or operator of a unit that qualifies to use the
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low mass emissions excepted monitoring methodology under §75.19 shall also meet the requirements of paragraph (c) of this section and the owner or operator of a unit that qualifies to use an alternative monitoring system under subpart E of part 75 of this chapter shall also meet the requirements of paragraph (d) of this section. The owner or operator of a NO\textsubscript{X} Budget unit that is subject to an Acid Rain emissions limitation, but requires additional CEMS under the common stack provisions in §75.72 of this chapter, or that uses a NO\textsubscript{X} concentration CEMS under §75.71(a)(2) of this chapter also shall comply with the following initial certification and recertification procedures.

(1) Requirements for initial certification. The owner or operator shall ensure that each monitoring system required by subpart H of part 75 of this chapter (which includes the automated data acquisition and handling system) successfully completes all of the initial certification testing required under §75.20 of this chapter. The owner or operator shall ensure that all applicable certification tests are successfully completed by the deadlines specified in §96.70(b).

In addition, whenever the owner or operator installs a monitoring system in order to meet the requirements of this part in a location where no such monitoring system was previously installed, initial certification according to §75.20 is required.

(2) Requirements for recertification. Whenever the owner or operator makes a replacement, modification, or change in a certified monitoring system that the Administrator or the permitting authority determines significantly affects the ability of the system to accurately measure or record NO\textsubscript{X} mass emissions or heat input or to meet the requirements of §75.21 of this chapter or appendix B to part 75 of this chapter, the owner or operator shall recertify the monitoring system according to §75.20(b) of this chapter. Examples of changes which require recertification include: replacement of the analyzer, change in location or orientation of the sampling probe or site, or changing of flow rate monitor polynomial coefficients.

(3) Certification approval process for initial certifications and recertification.

(i) Notification of certification. The NO\textsubscript{X} authorized account representative shall submit to the permitting authority, the appropriate EPA Regional Office and the permitting authority a written notice of the dates of certification in accordance with §96.73.

(ii) Certification application. The NO\textsubscript{X} authorized account representative shall submit to the permitting authority a certification application for each monitoring system required under subpart H of part 75 of this chapter. A complete certification application shall include the information specified in subpart H of part 75 of this chapter.

(iii) Except for units using the low mass emission excepted methodology under §75.19 of this chapter, the provisional certification date for a monitor shall be determined using the procedures set forth in §75.20(a)(3) of this chapter. A provisionally certified monitoring system may be used under the NO\textsubscript{X} Budget Trading Program for a period not to exceed 120 days after receipt by the permitting authority of the complete certification application for the monitoring system or component thereof under paragraph (b)(3)(ii) of this section. Data measured and recorded by the provisionally certified monitoring system or component thereof, in accordance with the requirements of part 75 of this chapter, will be considered valid quality-assured data (retroactive to the date and time of provisional certification), provided that the permitting authority does not invalidate the provisional certification by issuing a notice of disapproval within 120 days of receipt of the complete certification application by the permitting authority.
(iv) Certification application formal approval process. The permitting authority will issue a written notice of approval or disapproval of the certification application to the owner or operator within 120 days of receipt of the complete certification application under paragraph (b)(3)(ii) of this section. In the event the permitting authority does not issue such a notice within such 120-day period, each monitoring system which meets the applicable performance requirements of part 75 of this chapter and is included in the certification application will be deemed certified for use under the NOx Budget Trading Program.

(A) Approval notice. If the certification application is complete and shows that each monitoring system meets the applicable performance requirements of part 75 of this chapter, then the permitting authority will issue a written notice of approval of the certification application within 120 days of receipt.

(B) Incomplete application notice. A certification application will be considered complete when all of the applicable information required to be submitted under paragraph (b)(3)(ii) of this section has been received by the permitting authority. If the certification application is not complete, then the permitting authority will issue a written notice of incompleteness that sets a reasonable date by which the NOx authorized account representative must submit the additional information required to complete the certification application. If the NOx authorized account representative does not comply with the notice of incompleteness by the specified date, then the permitting authority may issue a notice of disapproval under paragraph (b)(3)(iv)(C) of this section.

(C) Disapproval notice. If the certification application shows that any monitoring system or component thereof does not meet the performance requirements of this part, or if the certification application is incomplete and the requirement for disapproval under paragraph (b)(3)(iv)(B) of this section has been met, the permitting authority will issue a written notice of disapproval of the certification application. Upon issuance of such notice of disapproval, the provisional certification is invalidated by the permitting authority and the data measured and recorded by each uncertified monitoring system or component thereof shall not be considered valid quality-assured data beginning with the date and hour of provisional certification. The owner or operator shall follow the procedures for loss of certification in paragraph (b)(3)(v) of this section for each monitoring system or component thereof which is disapproved for initial certification.

(D) Audit decertification. The permitting authority may issue a notice of disapproval of the certification status of a monitor in accordance with §96.72(b).

(v) Procedures for loss of certification. If the permitting authority issues a notice of disapproval of a certification application under paragraph (b)(3)(iv)(C) of this section or a notice of disapproval of certification status under paragraph (b)(3)(iv)(D) of this section, then:

(A) The owner or operator shall substitute the following values, for each hour of unit operation during the period of invalid data beginning with the date and hour of provisional certification and continuing until the time, date, and hour specified under §75.20(a)(5)(i) of this chapter:

1. For units using or intending to monitor for NOx emission rate and heat input or for units using the low mass emission excepted methodology under §75.19 of this chapter, the maximum potential NOx emission rate and the maximum potential hourly heat input of the unit.

2. For units intending to monitor for NOx mass emissions using a NOx pollutant concentration monitor and a flow monitor, the maximum potential concentration of NOx and the maximum potential flow rate of the unit under section 2.1 of appendix A of part 75 of this chapter.

(B) The NOx authorized account representative shall submit a notification of certification retest dates and a new certification application in accordance with paragraphs (b)(3)(i) and (ii) of this section; and
§ 96.72 Out of control periods.

(a) Whenever any monitoring system fails to meet the quality assurance requirements of appendix B of part 75 of this chapter, the owner or operator shall repeat all certification tests or other requirements that were failed by the monitoring system, as indicated in the notice of disapproval, no later than 30 unit operating days after the date of issuance of the notice of disapproval.

(c) Initial certification and recertification procedures for low mass emission units using the excepted methodologies under §75.19 of this chapter. The owner or operator of a gas-fired or oil-fired unit using the low mass emissions excepted methodology under §75.19 of this chapter shall meet the applicable general operating requirements of §75.10 of this chapter, the applicable requirements of §75.19 of this chapter, and the applicable certification requirements of §96.71 of this chapter, except that the excepted methodology shall be deemed provisionally certified for use under the NOX Budget Trading Program, as of the following dates:

(i) For a unit that has commenced operation before its compliance deadline under §96.71(b), from January 1 of the year following submission of the certification application for approval to use the low mass emissions excepted methodology under §75.19 of this chapter until the completion of the period for the permitting authority review; or

(ii) For a unit that commenced operation after its compliance deadline under §96.71(b), from May 1 of the year following submission of the certification application for approval to use the low mass emissions excepted methodology under §75.19 of this chapter until the completion of the period for the permitting authority review.

(d) Certification/recertification procedures for alternative monitoring systems. The NOX authorized account representative representing the owner or operator of each unit applying to monitor using an alternative monitoring system approved by the Administrator and, if applicable, the permitting authority under subpart E of part 75 of this chapter shall apply for certification to the permitting authority prior to use of the system under the NOX Trading Program. The NOX authorized account representative shall apply for recertification following a replacement, modification or change according to the procedures in paragraph (b) of this section. The owner or operator of an alternative monitoring system shall comply with the notification and application requirements for certification according to the procedures specified in paragraph (b)(3) of this section and §75.20(f) of this chapter.

§ 96.72 Out of control periods.

(a) Whenever any monitoring system fails to meet the quality assurance requirements of appendix B of part 75 of this chapter, the owner or operator shall repeat all certification tests or other requirements that were failed by the monitoring system, as indicated in the notice of disapproval, no later than 30 unit operating days after the date of issuance of the notice of disapproval.

(c) Initial certification and recertification procedures for low mass emission units using the excepted methodologies under §75.19 of this chapter. The owner or operator of a gas-fired or oil-fired unit using the low mass emissions excepted methodology under §75.19 of this chapter shall meet the applicable general operating requirements of §75.10 of this chapter, the applicable requirements of §75.19 of this chapter, and the applicable certification requirements of §96.71 of this chapter, except that the excepted methodology shall be deemed provisionally certified for use under the NOX Budget Trading Program, as of the following dates:

(i) For a unit that has commenced operation before its compliance deadline under §96.71(b), from January 1 of the year following submission of the certification application for approval to use the low mass emissions excepted methodology under §75.19 of this chapter until the completion of the period for the permitting authority review; or

(ii) For a unit that commenced operation after its compliance deadline under §96.71(b), from May 1 of the year following submission of the certification application for approval to use the low mass emissions excepted methodology under §75.19 of this chapter until the completion of the period for the permitting authority review.

(d) Certification/recertification procedures for alternative monitoring systems. The NOX authorized account representative representing the owner or operator of each unit applying to monitor using an alternative monitoring system approved by the Administrator and, if applicable, the permitting authority under subpart E of part 75 of this chapter shall apply for certification to the permitting authority prior to use of the system under the NOX Trading Program. The NOX authorized account representative shall apply for recertification following a replacement, modification or change according to the procedures in paragraph (b) of this section. The owner or operator of an alternative monitoring system shall comply with the notification and application requirements for certification according to the procedures specified in paragraph (b)(3) of this section and §75.20(f) of this chapter.
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§ 96.74 Recordkeeping and reporting.

(a) General provisions. (1) The NOX authorized account representative shall comply with all recordkeeping and reporting requirements in this section and with the requirements of §96.10(e).

(2) If the NOX authorized account representative for a NOX Budget unit subject to an Acid Rain Emission limitation who signed and certified any submission that is made under subpart F or G of part 75 of this chapter and which includes data and information required under this subpart or subpart H of part 75 of this chapter is not the same person as the designated representative or the alternative designated representative for the unit under part 72 of this chapter, the submission must also be signed by the designated representative or the alternative designated representative.

(b) Monitoring plans. (1) The owner or operator of a unit subject to an Acid Rain emissions limitation shall comply with requirements of §75.62 of this chapter, except that the monitoring plan shall also include all of the information required by subpart H of part 75 of this chapter.

(2) The owner or operator of a unit that is not subject to an Acid Rain emissions limitation shall comply with requirements of §75.62 of this chapter, except that the monitoring plan is only required to include the information required by subpart H of part 75 of this chapter.

(c) Certification applications. The NOX authorized account representative shall submit an application to the permitting authority within 45 days after completing all initial certification or recertification tests required under §96.71 including the information required under subpart H of part 75 of this chapter.

(d) Quarterly reports. The NOX authorized account representative shall submit quarterly reports, as follows:

(1) If a unit is subject to an Acid Rain emission limitation or if the owner or operator of the NOX budget unit chooses to meet the annual reporting requirements of this subpart H, the NOX authorized account representative shall submit a quarterly report for each calendar quarter beginning with:

(i) For units that elect to comply with the early reduction credit provisions under §96.55 of this part, the CALENDAR quarter that includes the date of initial provisional certification...
under §96.71(b)(3)(ii). Data shall be re-
ported from the date and hour cor-
responding to the date and hour of pro-
visional certification; or

(ii) For units commencing operation prior to May 1, 2002 that are not re-
quired to certify monitors by May 1, 2002 under §96.70(b)(1), the earlier of the
CALENDER quarter that includes the
date of initial provisional certification
under §96.71(b)(3)(iii) or, if the certifi-
cation tests are not completed by May
1, 2002, the partial CALENDER quarter
from May 1, 2002 through June 30, 2002.
Data shall be recorded and reported
from the earlier of the date and hour cor-
responding to the date and hour of pro-
visional certification or the first
hour on May 1, 2002; or

(iii) If a NOX budget unit is not subject
to an Acid Rain emission limitation,
then the NOX authorized account rep-
resentative shall either:
(i) Meet all of the requirements of
part 75 related to monitoring and re-
porting NOX mass emissions during the
entire year and meet the reporting
deadlines specified in paragraph (d)(1)
of this section; or

(ii) Submit quarterly reports only for
the periods from the earlier of May 1 or
the date and hour that the owner or op-
erator successfully completes all of the
recertification tests required under
§75.74(d)(3) through September 30 of
each year in accordance with the provi-
sions of §75.74(b) of this chapter. The
NOX authorized account representative
shall submit quarterly reports for
each calendar quarter, beginning with:
(A) For units that elect to comply
with the early reduction credit provi-
sions under §96.55, the CALENDER
quarter that includes the date of initial
provisional certification under §96.71(b)(3)(iii). Data shall be reported
from the date and hour corresponding
to the date and hour of provisional cer-
tification; or

(B) For units commencing operation
prior to May 1, 2002 that are not re-
quired to certify monitors by May 1, 2000 under §96.70(b)(1), the earlier of the
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§ 96.76 Additional requirements to provide heat input data for allocations purposes.

(a) The NOx authorized account representative of a NOx Budget unit that is subject to an Acid Rain emissions limitation may submit a petition under §75.66 of this chapter to the permitting authority and the Administrator requesting approval to apply an alternative to any requirement of this subpart.

(1) Application of an alternative to any requirement of this subpart is in accordance with this subpart only to the extent the petition is approved by the Administrator, in consultation with the permitting authority.

(2) Notwithstanding paragraph (a)(1) of this section, if the petition requests approval to apply an alternative to a requirement concerning any additional CEMS required under the common stack provisions of §75.72 of this chapter, the petition is governed by paragraph (b) of this section.

(b) The NOx authorized account representative of a NOx Budget unit that is not subject to an Acid Rain emissions limitation may submit a petition under §75.66 of this chapter to the permitting authority and the Administrator requesting approval to apply an alternative to any requirement of this subpart.

(1) The NOx authorized account representative of a NOx Budget unit that is subject to an Acid Rain emissions limitation may submit a petition under §75.66 of this chapter to the permitting authority and the Administrator requesting approval to apply an alternative to a requirement concerning any additional CEMS required under the common stack provisions of §75.72 of this chapter or a NOx concentration CEMS used under 75.71(a)(2) of this chapter.

(2) Application of an alternative to any requirement of this subpart is in accordance with this subpart only to the extent the petition under paragraph (b) of this section is approved by both the permitting authority and the Administrator.
source allocations based upon heat input.

(b) The owner or operator of a unit that monitor and report NOx Mass emissions using a NOx concentration system and a flow system shall also monitor and report heat input at the unit level using the procedures set forth in part 75 of this chapter for any source that is applying for early reduction credits under §96.55.

Subpart I—Individual Unit Opt-ins

§ 96.80 Applicability.

A unit that is in the State, is not a NOx Budget unit under §96.4, vents all of its emissions to a stack, and is operating, may qualify, under this subpart, to become a NOx Budget opt-in source. A unit that is a NOx Budget unit, is covered by a retired unit exemption under §96.5 that is in effect, or is not operating is not eligible to become a NOx Budget opt-in source.

§ 96.81 General.

Except otherwise as provided in this part, a NOx Budget opt-in source shall be treated as a NOx Budget unit for purposes of applying subparts A through H of this part.

§ 96.82 NOx authorized account representative.

A unit for which an application for a NOx Budget opt-in permit is submitted and not denied or withdrawn, or a NOx Budget opt-in source, located at the same source as one or more NOx Budget units, shall have the same NOx authorized account representative as such NOx Budget units.

§ 96.83 Applying for NOx Budget opt-in permit.

(a) Applying for initial NOx Budget opt-in permit. In order to apply for an initial NOx Budget opt-in permit, the NOx authorized account representative of a unit qualified under §96.80 may submit to the permitting authority at any time, except as provided under §96.86(g):

(1) A complete NOx Budget permit application under §96.22;

(2) A monitoring plan submitted in accordance with subpart H of this part; and

(3) A complete account certificate of representation under §96.13. If no NOx authorized account representative has been previously designated for the unit.

(b) Duty to reapply. The NOx authorized account representative of a NOx Budget opt-in source shall submit a complete NOx Budget permit application under §96.22 to renew the NOx Budget opt-in permit in accordance with §96.21(c) and, if applicable, an updated monitoring plan in accordance with subpart H of this part.

§ 96.84 Opt-in process.

The permitting authority will issue or deny a NOx Budget opt-in permit for a unit for which an initial application for a NOx Budget opt-in permit under §96.83 is submitted, in accordance with §96.20 and the following:

(a) Interim review of monitoring plan. The permitting authority will determine, on an interim basis, the sufficiency of the monitoring plan accompanying the initial application for a NOx Budget opt-in permit under §96.83. A monitoring plan is sufficient, for purposes of interim review, if the plan appears to contain information demonstrating that the NOx emissions rate and heat input of the unit are monitored and reported in accordance with subpart H of this part. A determination of sufficiency shall not be construed as acceptance or approval of the unit’s monitoring plan.

(b) If the permitting authority determines that the unit’s monitoring plan is sufficient under paragraph (a) of this section and after completion of monitoring system certification under subpart H of this part, the NOx emissions rate and the heat input of the unit shall be monitored and reported in accordance with subpart H of this part for one full control period during which monitoring system availability is not less than 90 percent and during which the unit is in full compliance with any applicable State or Federal emissions or emissions-related requirements. Solely for purposes of applying the requirements in the prior sentence, the unit shall be treated as a “NOx Budget unit” prior to issuance of a NOx Budget opt-in permit covering the unit.
§ 96.86 Withdrawal from NOx Budget Trading Program.

(a) Requesting withdrawal. To withdraw from the NOx Budget Trading Program, the NOx authorized account representative of a NOx Budget opt-in source shall submit to the permitting authority a request to withdraw effective as of a specified date prior to May 1 or after September 30. The submission shall be made no later than 90 days prior to the requested effective date of withdrawal.

(b) Conditions for withdrawal. Before a NOx Budget opt-in source covered by a request under paragraph (a) of this section may withdraw from the NOx Budget Trading Program and the NOx Budget opt-in permit may be terminated under paragraph (e) of this section, the following conditions must be met:

(1) For the control period immediately before the withdrawal is to be effective, the NOx authorized account representative must submit or must

(c) Based on the information monitored and reported under paragraph (b) of this section, the unit’s baseline heat rate shall be calculated as the unit’s total heat input (in mmBtu) for the control period and the unit’s baseline NOx emissions rate shall be calculated as the unit’s total NOx emissions (in lb) for the control period divided by the unit’s baseline heat rate.

(d) After calculating the baseline heat input and the baseline NOx emissions rate for the unit under paragraph (c) of this section, the permitting authority will serve a draft NOx Budget opt-in permit on the NOx authorized account representative of the unit.

(e) Confirmation of intention to opt-in. Within 20 days after the issuance of the draft NOx Budget opt-in permit, the NOx authorized account representative of the unit must submit to the permitting authority a confirmation of the intention to opt in the unit or a withdrawal of the application for a NOx Budget opt-in permit under §96.83. The permitting authority will treat the failure to make a timely submission as a withdrawal of the NOx Budget opt-in permit application.

(f) Issuance of draft NOx Budget opt-in permit. If the NOx authorized account representative confirms the intention to opt-in the unit under paragraph (e) of this section, the permitting authority will issue the draft NOx Budget opt-in permit in accordance with §96.20.

(g) Notwithstanding paragraphs (a) through (f) of this section, if at any time before issuance of a draft NOx Budget opt-in permit for the unit, the permitting authority determines that the unit does not qualify as a NOx Budget opt-in source under §96.80, the permitting authority will issue a draft denial of a NOx Budget opt-in permit for the unit in accordance with §96.20.

(h) Withdrawal of application for NOx Budget opt-in permit. A NOx authorized account representative of a unit may withdraw its application for a NOx Budget opt-in permit under §96.83 at any time prior to the issuance of the final NOx Budget opt-in permit. Once the application for a NOx Budget opt-in permit is withdrawn, a NOx authorized account representative wanting to reapply must submit a new application for a NOx Budget permit under §96.83.

(i) Effective date. The effective date of the initial NOx Budget opt-in permit shall be May 1 of the first control period starting after the issuance of the initial NOx Budget opt-in permit by the permitting authority. The unit shall be a NOx Budget opt-in source and a NOx Budget unit as of the effective date of the initial NOx Budget opt-in permit.

§ 96.85 NOx Budget opt-in permit contents.

(a) Each NOx Budget opt-in permit (including any draft or proposed NOx Budget opt-in permit, if applicable) will contain all elements required for a complete NOx Budget opt-in permit application under §96.22 as approved or adjusted by the permitting authority.

(b) Each NOx Budget opt-in permit is deemed to incorporate automatically the definitions of terms under §96.2 and, upon recordation by the Administrator under subpart F, G, or I of this part, every allocation, transfer, or deduction of NOx allowances to or from the compliance accounts of each NOx Budget opt-in source covered by the NOx Budget opt-in permit or the over-draft account of the NOx Budget source where the NOx Budget opt-in source is located.

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have submitted to the permitting authority an annual compliance certification report in accordance with §96.30.

(2) If the NOx Budget opt-in source has excess emissions for the control period immediately before the withdrawal is to be effective, the Administrator will deduct or has deducted from the NOx Budget opt-in source’s compliance account, or the overdraft account of the NOx Budget source where the NOx Budget opt-in source is located, the full amount required under §96.54(d) for the control period.

(3) After the requirements for withdrawal under paragraphs (b)(1) and (2) of this section are met, the Administrator will deduct from the NOx Budget opt-in source’s compliance account, or the overdraft account of the NOx Budget source where the NOx Budget opt-in source is located, NOx allowances equal in number to and allocated for the same or a prior control period as any NOx allowances allocated to that source under §96.88 for any control period for which the withdrawal is to be effective. The Administrator will close the NOx Budget opt-in source’s compliance account and will establish, and transfer any remaining allowances to, a new general account for the owners and operators of the NOx Budget opt-in source. The NOx authorized account representative for the NOx Budget opt-in source shall become the NOx authorized account representative for the general account.

(c) A NOx Budget opt-in source that withdraws from the NOx Budget Trading Program shall comply with all requirements under the NOx Budget Trading Program concerning all years for which such NOx Budget opt-in source was a NOx Budget opt-in source, even if such requirements arise or must be complied with after the withdrawal takes effect.

(d) Notification. (1) After the requirements for withdrawal under paragraphs (a) and (b) of this section are met (including deduction of the full amount of NOx allowances required), the permitting authority will issue a notification to the NOx authorized account representative of the NOx Budget opt-in source of the acceptance of the withdrawal of the NOx Budget opt-in source as of a specified effective date that is after such requirements have been met and that is prior to May 1 or after September 30.

(2) If the requirements for withdrawal under paragraphs (a) and (b) of this section are not met, the permitting authority will issue a notification to the NOx authorized account representative of the NOx Budget opt-in source that the NOx Budget opt-in source’s request to withdraw is denied. If the NOx Budget opt-in source’s request to withdraw is denied, the NOx Budget opt-in source shall remain subject to the requirements for a NOx Budget opt-in source.

(e) Permit amendment. After the permitting authority issues a notification under paragraph (d)(1) of this section that the requirements for withdrawal have been met, the permitting authority will revise the NOx Budget permit covering the NOx Budget opt-in source to terminate the NOx Budget opt-in permit as of the effective date specified under paragraph (d)(1) of this section. A NOx Budget opt-in source shall continue to be a NOx Budget opt-in source until the effective date of the termination.

(f) Reapplication upon failure to meet conditions of withdrawal. If the permitting authority denies the NOx Budget opt-in source’s request to withdraw, the NOx authorized account representative may submit another request to withdraw in accordance with paragraphs (a) and (b) of this section.

(g) Ability to return to the NOx Budget Trading Program. Once a NOx Budget opt-in source withdraws from the NOx Budget Trading Program and its NOx Budget opt-in permit is terminated under this section, the NOx authority account representative may not submit another application for a NOx Budget opt-in permit under §96.83 for the unit prior to the date that is 4 years after the date on which the terminated NOx Budget opt-in permit became effective.

§ 96.87 Change in regulatory status.

(a) Notification. When a NOx Budget opt-in source becomes a NOx Budget unit under §96.4, the NOx authorized account representative shall notify in writing the permitting authority and the Administrator of such change in
the NO\textsubscript{X} Budget opt-in source’s regulatory status, within 30 days of such change.

(b) Permitting authority’s and Administrator’s action. (1)(i) When the NO\textsubscript{X} Budget opt-in source becomes a NO\textsubscript{X} Budget unit under §96.4, the permitting authority will revise the NO\textsubscript{X} Budget opt-in source’s NO\textsubscript{X} Budget opt-in permit to meet the requirements of a NO\textsubscript{X} Budget permit under §96.23 as of an effective date that is the date on which such NO\textsubscript{X} Budget opt-in source becomes a NO\textsubscript{X} Budget unit under §96.4.

(ii)(A) The Administrator will deduct from the compliance account for the NO\textsubscript{X} Budget unit under paragraph (b)(1)(i) of this section, or the overdraft account of the NO\textsubscript{X} Budget source where the unit is located, NO\textsubscript{X} allowances equal in number to and allocated for the same or a prior control period:

(i) Any NO\textsubscript{X} allowances allocated to the NO\textsubscript{X} Budget unit (as a NO\textsubscript{X} Budget opt-in source) under §96.88 for any control period after the last control period during which the unit’s NO\textsubscript{X} Budget opt-in permit was effective; and

(ii) If the effective date of the NO\textsubscript{X} Budget permit revision under paragraph (b)(1)(i) of this section is during a control period, the NO\textsubscript{X} allowances allocated to the NO\textsubscript{X} Budget unit (as a NO\textsubscript{X} Budget opt-in source) under §96.88 for the control period multiplied by the ratio of the number of days, in the control period, starting with the effective date of the permit revision under paragraph (b)(1)(i) of this section, divided by the total number of days in the control period.

(B) The NO\textsubscript{X} authorized account representative shall ensure that the compliance account of the NO\textsubscript{X} Budget unit under paragraph (b)(1)(i) of this section, or the overdraft account of the NO\textsubscript{X} Budget source where the unit is located, includes the NO\textsubscript{X} allowances necessary for completion of the deduction under paragraph (b)(1)(ii)(A) of this section. If the compliance account or overdraft account does not contain sufficient NO\textsubscript{X} allowances, the Administrator will deduct the required number of NO\textsubscript{X} allowances, regardless of the control period for which they were allocated, whenever NO\textsubscript{X} allowances are recorded in either account.

(ii)(A) For every control period during which the NO\textsubscript{X} Budget permit revised under paragraph (b)(1)(i) of this section is effective, the NO\textsubscript{X} Budget unit under paragraph (b)(1)(i) of this section will be treated, solely for purposes of NO\textsubscript{X} allowance allocations under §96.42, as a unit that commenced operation on the effective date of the NO\textsubscript{X} Budget permit revision under paragraph (b)(1)(i) of this section and will be allocated NO\textsubscript{X} allowances under §96.42.

(B) Notwithstanding paragraph (b)(1)(iii)(A) of this section, if the effective date of the NO\textsubscript{X} Budget permit revision under paragraph (b)(1)(i) of this section is during a control period, the following number of NO\textsubscript{X} allowances will be allocated to the NO\textsubscript{X} Budget unit under paragraph (b)(1)(i) of this section under §96.42 for the control period: the number of NO\textsubscript{X} allowances otherwise allocated to the NO\textsubscript{X} Budget unit under §96.42 for the control period multiplied by the ratio of the number of days, in the control period, starting with the effective date of the permit revision under paragraph (b)(1)(i) of this section, divided by the total number of days in the control period.

(2)(i) When the NO\textsubscript{X} authorized account representative of a NO\textsubscript{X} Budget opt-in source does not renew its NO\textsubscript{X} Budget opt-in permit under §96.83(b), the Administrator will deduct from the NO\textsubscript{X} Budget opt-in unit’s compliance account, or the overdraft account of the NO\textsubscript{X} Budget source where the NO\textsubscript{X} Budget opt-in source is located, NO\textsubscript{X} allowances equal in number to and allocated for the same or a prior control period as any NO\textsubscript{X} allowances allocated to the NO\textsubscript{X} Budget opt-in source under §96.88 for any control period after the last control period for which the NO\textsubscript{X} Budget opt-in permit is effective. The NO\textsubscript{X} authorized account representative shall ensure that the NO\textsubscript{X} Budget opt-in source’s compliance account or the overdraft account of the NO\textsubscript{X} Budget source where the NO\textsubscript{X} Budget opt-in source is located includes the NO\textsubscript{X} allowances necessary for completion of such deduction. If the compliance account or overdraft account does not contain sufficient NO\textsubscript{X} allowances, the Administrator will deduct the required number of NO\textsubscript{X} allowances, regardless
§ 96.88 of the control period for which they were allocated, whenever NO\textsubscript{X} allowances are recorded in either account.

(ii) After the deduction under paragraph (b)(2)(i) of this section is completed, the Administrator will close the NO\textsubscript{X} Budget opt-in source’s compliance account. If any NO\textsubscript{X} allowances remain in the compliance account after completion of such deduction and any deduction under §96.54, the Administrator will close the NO\textsubscript{X} Budget opt-in source’s compliance account and will establish, and transfer any remaining allowances to, a new general account for the owners and operators of the NO\textsubscript{X} Budget opt-in source. The NO\textsubscript{X} authorized account representative for the NO\textsubscript{X} Budget opt-in source shall become the NO\textsubscript{X} authorized account representative for the general account.

§ 96.88 NO\textsubscript{X} allowance allocations to opt-in units.

(a) NO\textsubscript{X} allowance allocation. (1) By December 31 immediately before the first control period for which the NO\textsubscript{X} Budget opt-in permit is effective, the permitting authority will allocate NO\textsubscript{X} allowances to the NO\textsubscript{X} Budget opt-in source and submit to the Administrator the allocation for the control period in accordance with paragraph (b) of this section.

(2) By no later than December 31, after the first control period for which the NO\textsubscript{X} Budget opt-in permit is in effect, and December 31 of each year thereafter, the permitting authority will allocate NO\textsubscript{X} allowances to the NO\textsubscript{X} Budget opt-in source and submit to the Administrator the allocation for the control period in accordance with paragraph (b) of this section.

(b) For each control period for which the NO\textsubscript{X} Budget opt-in source has an approved NO\textsubscript{X} Budget opt-in permit, the NO\textsubscript{X} Budget opt-in source shall be allocated NO\textsubscript{X} allowances in accordance with the following procedures:

(1) The heat input (in mmBtu) used for calculating NO\textsubscript{X} allowance allocations will be the lesser of:

(i) The NO\textsubscript{X} Budget opt-in source’s baseline heat input determined pursuant to §96.84(c); or

(ii) The NO\textsubscript{X} Budget opt-in source’s heat input, as determined in accordance with subpart H of this part, for the control period in the year prior to the year of the control period for which the NO\textsubscript{X} allocations are being calculated.

(2) The permitting authority will allocate NO\textsubscript{X} allowances to the NO\textsubscript{X} Budget opt-in source in an amount equaling the heat input (in mmBtu) determined under paragraph (b)(1) of this section multiplied by the lesser of:

(i) The NO\textsubscript{X} Budget opt-in source’s baseline NO\textsubscript{X} emissions rate (in lb/mmBtu) determined pursuant to §96.84(c); or

(ii) The most stringent State or Federal NO\textsubscript{X} emissions limitation applicable to the NO\textsubscript{X} Budget opt-in source during the control period.

Subpart J—Mobile and Area Sources [Reserved]

Subparts K—Z [Reserved]

Subpart AA—CAIR NO\textsubscript{X} Annual Trading Program General Provisions

SOURCE: 70 FR 25339, May 12, 2005, unless otherwise noted.

§ 96.101 Purpose.

This subpart and subparts BB through II establish the model rule comprising general provisions and the designated representative, permitting, allowance, monitoring, and opt-in provisions for the State Clean Air Interstate Rule (CAIR) NO\textsubscript{X} Annual Trading Program, under section 110 of the Clean Air Act and §51.123 of this chapter, as a means of mitigating interstate transport of fine particulates and nitrogen oxides. The owner or operator of a unit or a source shall comply with the requirements of this subpart and subparts BB through II as a matter of federal law only if the State with jurisdiction over the unit and the source incorporates by reference such subparts or otherwise adopts the requirements of such subparts in accordance with §51.123(o)(1) or (2) of this chapter, the State submits to the Administrator one or more revisions of the State implementation plan that include such adoption, and the Administrator approves such revisions. If the State
adopts the requirements of such subparts in accordance with §51.123(o)(1) or (2) of this chapter, then the State authorizes the Administrator to assist the State in implementing the CAIR NO\textsubscript{X} Annual Trading Program by carrying out the functions set forth for the Administrator in such subparts.

\section*{\textsection 96.102 \ Definitions.}

The terms used in this subpart and subparts BB through II shall have the meanings set forth in this section as follows:

\begin{itemize}
  \item \textit{Account number} means the identification number given by the Administrator to each CAIR NO\textsubscript{X} Allowance Tracking System account.
  \item \textit{Acid Rain emissions limitation} means a limitation on emissions of sulfur dioxide or nitrogen oxides under the Acid Rain Program.
  \item \textit{Acid Rain Program} means a multi-state sulfur dioxide and nitrogen oxides air pollution control and emission reduction program established by the Administrator under title IV of the CAA and parts 72 through 78 of this chapter.
  \item \textit{Administrator} means the Administrator of the United States Environmental Protection Agency or the Administrator’s duly authorized representative.
  \item \textit{Allocate} or \textit{allocation} means, with regard to CAIR NO\textsubscript{X} allowances, the determination by a permitting authority or the Administrator of the amount of such CAIR NO\textsubscript{X} allowances to be initially credited to a CAIR NO\textsubscript{X} unit, a new unit set-aside, or other entity.
  \item \textit{Allowance transfer deadline} means, for a control period, midnight of March 1 (if it is a business day), or midnight of the first business day thereafter (if March 1 is not a business day), immediately following the control period and is the deadline by which a CAIR NO\textsubscript{X} allowance transfer must be submitted for recordation in a CAIR NO\textsubscript{X} source’s compliance account in order to be used to meet the source’s CAIR NO\textsubscript{X} emissions limitation for such control period in accordance with §96.154.
  \item \textit{Alternate CAIR designated representative} means, for a CAIR NO\textsubscript{X} source and each CAIR NO\textsubscript{X} unit at the source, the natural person who is authorized by the owners and operators of the source and all such units at the source, in accordance with subparts BB and II of this part, to act on behalf of the CAIR designated representative in matters pertaining to the CAIR NO\textsubscript{X} Annual Trading Program. If the CAIR NO\textsubscript{X} source is also a CAIR SO\textsubscript{2} source, then this natural person shall be the same person as the alternate CAIR designated representative under the CAIR SO\textsubscript{2} Trading Program. If the CAIR NO\textsubscript{X} source is also a CAIR NO\textsubscript{X} Ozone Season source, then this natural person shall be the same person as the alternate designated representative under the CAIR NO\textsubscript{X} Ozone Season Trading Program. If the CAIR NO\textsubscript{X} source is also subject to the Acid Rain Program, then this natural person shall be the same person as the alternate designated representative under the Acid Rain Program. If the CAIR NO\textsubscript{X} source is also subject to the Hg Budget Trading Program, then this natural person shall be the same person as the alternate Hg designated representative under the Hg Budget Trading Program.
  \item \textit{Automated data acquisition and handling system} or \textit{DAHS} means that component of the continuous emission monitoring system, or other emissions monitoring system approved for use under subpart HH of this part, designed to interpret and convert individual output signals from pollutant concentration monitors, flow monitors, diluent gas monitors, and other component parts of the monitoring system to produce a continuous record of the measured parameters in the measurement units required by subpart HH of this part.
  \item \textit{Biomass} means—
    \begin{enumerate}
      \item Any organic material grown for the purpose of being converted to energy;
      \item Any organic byproduct of agriculture that can be converted into energy; or
      \item Any material that can be converted into energy and is nonmerchantable for other purposes, that is segregated from other nonmerchantable material, and that is:
        \begin{enumerate}
          \item A forest-related organic resource, including mill residues, precommercial thinnings, slash, brush, or byproduct from conversion of trees to merchantable material; or
        \end{enumerate}
    \end{enumerate}
(i) A wood material, including pallets, crates, dunnage, manufacturing and construction materials (other than pressure-treated, chemically-treated, or painted wood products), and landscape or right-of-way tree trimmings.

Boiler means an enclosed fossil- or other-fuel-fired combustion device used to produce heat and to transfer heat to recirculating water, steam, or other medium.

Bottoming-cycle cogeneration unit means a cogeneration unit in which the energy input to the unit is first used to produce useful thermal energy and at least some of the reject heat from the useful thermal energy application or process is then used for electricity production.

CAIR authorized account representative means, with regard to a general account, a responsible natural person who is authorized, in accordance with subparts BB, FF, and II of this part, to transfer and otherwise dispose of CAIR NO\textsubscript{X} allowances held in the general account and, with regard to a compliance account, the CAIR designated representative of the source.

CAIR designated representative means, for a CAIR NO\textsubscript{X} source and each CAIR NO\textsubscript{X} unit at the source, the natural person who is authorized by the owners and operators of the source and all such units at the source, in accordance with subparts BB and II of this part, to represent and legally bind each owner and operator in matters pertaining to the CAIR NO\textsubscript{X} Annual Trading Program. If the CAIR NO\textsubscript{X} source is also a CAIR SO\textsubscript{2} source, then this natural person shall be the same person as the CAIR designated representative under the CAIR SO\textsubscript{2} Trading Program. If the CAIR NO\textsubscript{X} source is also a CAIR NO\textsubscript{X} Ozone Season source, then this natural person shall be the same person as the CAIR designated representative under the CAIR NO\textsubscript{X} Ozone Season Trading Program. If the CAIR NO\textsubscript{X} source is also subject to the Acid Rain Program, then this natural person shall be the same person as the Acid Rain Program representative under the Acid Rain Program.

CAIR NO\textsubscript{X} allowance means a limited authorization issued by a permitting authority or the Administrator under provisions of a State implementation plan that are approved under §51.123(o)(1) or (2) or (p) of this chapter, or under subpart EE of part 97 or §97.188 of this chapter, to emit one ton of nitrogen oxides during a control period of the specified calendar year for which the authorization is allocated or of any calendar year thereafter under the CAIR NO\textsubscript{X} Program. An authorization to emit nitrogen oxides that is not issued under provisions of a State implementation plan that are approved under §51.123(o)(1) or (2) or (p) of this chapter or subpart EE of part 97 or §97.188 of this chapter shall not be a CAIR NO\textsubscript{X} allowance.

CAIR NO\textsubscript{X} allowance deduction or deduct CAIR NO\textsubscript{X} allowances means the permanent withdrawal of CAIR NO\textsubscript{X} allowances by the Administrator from a compliance account, e.g., in order to account for a specified number of tons of total nitrogen oxides emissions from all CAIR NO\textsubscript{X} units at a CAIR NO\textsubscript{X} source for a control period, determined in accordance with subpart EE of this part, or to account for excess emissions.

CAIR NO\textsubscript{X} Allowance Tracking System means the system by which the Administrator records allocations, deductions, and transfers of CAIR NO\textsubscript{X} allowances under the CAIR NO\textsubscript{X} Annual Trading Program. Such allowances will be allocated, held, deducted, or transferred only as whole allowances.

CAIR NO\textsubscript{X} Allowance Tracking System account means an account in the CAIR NO\textsubscript{X} Allowance Tracking System established by the Administrator for purposes of recording the allocation, holding, transferring, or deducting of CAIR NO\textsubscript{X} allowances.

CAIR NO\textsubscript{X} allowances held or hold CAIR NO\textsubscript{X} allowances means the CAIR NO\textsubscript{X} allowances recorded by the Administrator, or submitted to the Administrator for recordation, in accordance with subparts FF, GG, and II of this part, in a CAIR NO\textsubscript{X} Allowance Tracking System account.

CAIR NO\textsubscript{X} Annual Trading Program means a multi-state nitrogen oxides trading program.
pollution control and emission reduction program approved and administered by the Administrator in accordance with subparts AA through II of this part and §51.123(o)(1) or (2) of this chapter or established by the Administrator in accordance with subparts AA through III of this part and §§51.123(p) and 52.35 of this chapter, as a means of mitigating interstate transport of fine particulates and nitrogen oxides.

CAIR NO\textsubscript{X} emissions limitation means, for a CAIR NO\textsubscript{X} source, the tonnage equivalent of NO\textsubscript{X} emissions in a control period, of the CAIR NO\textsubscript{X} allowances available for deduction for the source under §96.154(a) and (b) for the control period.

CAIR NO\textsubscript{X} Ozone Season source means a source that is subject to the CAIR NO\textsubscript{X} Ozone Season Trading Program.

CAIR NO\textsubscript{X} Ozone Season Trading Program means a multi-state nitrogen oxides air pollution control and emission reduction program approved and administered by the Administrator in accordance with subparts AAA through IIII of this part and §§51.123(aa)(1) or (2) and (bb)(1), (bb)(2), or (dd) of this chapter, as a means of mitigating interstate transport of ozone and nitrogen oxides.

CAIR NO\textsubscript{X} source means a source that includes one or more CAIR NO\textsubscript{X} units.

CAIR NO\textsubscript{X} unit means a unit that is subject to the CAIR NO\textsubscript{X} Annual Trading Program under §96.104 and, except for purposes of §96.105 and subpart EE of this part, a CAIR NO\textsubscript{X} opt-in unit under subpart II of this part.

CAIR permit means the legally binding and federal enforceable written document, or portion of such document, issued by the permitting authority under subpart CC of this part, including any permit revisions, specifying the CAIR NO\textsubscript{X} Annual Trading Program requirements applicable to a CAIR NO\textsubscript{X} source, to each CAIR NO\textsubscript{X} unit at the source, and to the owners and operators and the CAIR designated representative of the source and each such unit.

CAIR SO\textsubscript{2} source means a source that is subject to the CAIR SO\textsubscript{2} Trading Program.

CAIR SO\textsubscript{2} Trading Program means a multi-state sulfur dioxide air pollution control and emission reduction program approved and administered by the Administrator in accordance with subparts AAA through III of this part and §51.124(o)(1) or (2) of this chapter or established by the Administrator in accordance with subparts AAA through III of part 97 of this chapter and §§51.124(r) and 52.36 of this chapter, as a means of mitigating interstate transport of fine particulates and sulfur dioxide.

Clean Air Act or CAA means the Clean Air Act, 42 U.S.C. 7401, et seq.

Coal means any solid fuel classified as anthracite, bituminous, subbituminous, or lignite.

Coal-derived fuel means any fuel (whether in a solid, liquid, or gaseous state) produced by the mechanical, thermal, or chemical processing of coal.

Coal-fired means:

(1) Except for purposes of subpart EE of this part, combusting any amount of coal or coal-derived fuel, alone or in combination with any amount of any other fuel, during any year; or

(2) For purposes of subpart EE of this part, combusting any amount of coal or coal-derived fuel, alone or in combination with any amount of any other fuel, during a specified year.

Cogeneration unit means a stationary, fossil-fuel-fired boiler or stationary, fossil-fuel-fired combustion turbine:

(1) Having equipment used to produce electricity and useful thermal energy for industrial, commercial, heating, or cooling purposes through the sequential use of energy; and

(2) Producing during the 12-month period starting on the date the unit first produces electricity and during any calendar year after the calendar year in which the unit first produces electricity—

(i) For a topping-cycle cogeneration unit,

(A) Useful thermal energy not less than 5 percent of total energy output;
(B) Useful power that, when added to one-half of useful thermal energy produced, is not less than 42.5 percent of total energy input, if useful thermal energy produced is 15 percent or more of total energy output, or not less than 45 percent of total energy input, if useful thermal energy produced is less than 15 percent of total energy output.

(ii) For a bottoming-cycle cogeneration unit, useful power not less than 45 percent of total energy input;

(3) Provided that the total energy input under paragraphs (2)(i)(B) and (2)(ii) of this definition shall equal the unit’s total energy input from all fuel except biomass if the unit is a boiler.

Combustion turbine means:

(1) An enclosed device comprising a compressor, a combustor, and a turbine and in which the flue gas resulting from the combustion of fuel in the combustor passes through the turbine, rotating the turbine; and

(2) If the enclosed device under paragraph (1) of this definition is combined cycle, any associated duct burner, heat recovery steam generator, and steam turbine.

Commence commercial operation means, with regard to a unit:

(1) To have begun to produce steam, gas, or other heated medium used to generate electricity for sale or use, including test generation, except as provided in §96.105 and §96.184(h).

(i) For a unit that is a CAIR NOₓ unit under §96.104 on the later of November 15, 1990 or the date the unit commences commercial operation as defined in paragraph (1) of this definition and that subsequently undergoes a physical change (other than replacement of the unit by a unit at the same source), such date shall remain the date of commencement of commercial operation of the unit, which shall continue to be treated as the same unit.

(ii) For a unit that undergoes a physical change (other than replacement of the unit by a unit at the same source) after the date the unit commences operation as defined in paragraph (1) of this definition, such date shall remain the date of commencement of commercial operation of the unit, which shall continue to be treated as the same unit.

(iii) For a unit that is replaced by a unit at the same source (e.g., repowered) after the date the unit commences operation as defined in paragraph (1) of this definition, such date shall remain the replaced unit’s date of commencement of commercial operation as defined in paragraph (1) of this definition and that is subsequently replaced by a unit at the same source (e.g., repowered), such date shall remain the replaced unit’s date of commencement of commercial operation of the unit, which shall continue to be treated as the same unit.

Commence operation means:

(1) To have begun any mechanical, chemical, or electronic process, including test generation, except as provided in §96.105 and §96.184(h).

(2) For a unit that undergoes a physical change (other than replacement of the unit by a unit at the same source) after the date the unit commences operation as defined in paragraph (1) of this definition, such date shall remain the date of commencement of commercial operation of the unit, which shall continue to be treated as the same unit.

(3) For a unit that is replaced by a unit at the same source (e.g., repowered) after the date the unit commences operation as defined in paragraph (1) of this definition, such date shall remain the replaced unit’s date of commencement of commercial operation as defined in paragraph (1) of this definition.
commencement of operation, and the replacement unit shall be treated as a separate unit with a separate date for commencement of operation as defined in paragraph (1), (2), or (3) of this definition as appropriate, except as provided in §96.184(h).

Compliance account means a CAIR NO\textsubscript{X} Allowance Tracking System account, established by the Administrator for a CAIR NO\textsubscript{X} source under subpart FF or II of this part, in which any CAIR NO\textsubscript{X} allowance allocations for the CAIR NO\textsubscript{X} units at the source are initially recorded and in which are held any CAIR NO\textsubscript{X} allowances available for use for a control period in order to meet the source’s CAIR NO\textsubscript{X} emissions limitation in accordance with §96.154.

Continuous emission monitoring system or CEMS means the equipment required under subpart HH of this part to sample, analyze, measure, and provide, by means of readings recorded at least once every 15 minutes (using an automated data acquisition and handling system (DAHS)), a permanent record of nitrogen oxides emissions, stack gas volumetric flow rate, stack gas moisture content, and oxygen or carbon dioxide concentration (as applicable), in a manner consistent with part 75 of this chapter. The following systems are the principal types of continuous emission monitoring systems required under subpart HH of this part:

1. A flow monitoring system, consisting of a stack flow rate monitor and an automated data acquisition and handling system and providing a permanent, continuous record of stack gas volumetric flow rate, in standard cubic feet per hour (scfh);
2. A nitrogen oxides concentration monitoring system, consisting of a NO\textsubscript{X} pollutant concentration monitor and an automated data acquisition and handling system and providing a permanent, continuous record of NO\textsubscript{X} emissions, in parts per million (ppm);
3. A nitrogen oxides emission rate (or NO\textsubscript{X}-diluent) monitoring system, consisting of a NO\textsubscript{X} pollutant concentration monitor, a diluent gas (CO\textsubscript{2} or O\textsubscript{2}) monitor, and an automated data acquisition and handling system and providing a permanent, continuous record of NO\textsubscript{X} concentration, in parts per million (ppm), diluent gas concentration, in percent CO\textsubscript{2} or O\textsubscript{2}; and NO\textsubscript{X} emission rate, in pounds per million British thermal units (lb/mmBtu);
4. A moisture monitoring system, as defined in §75.11(b)(2) of this chapter and providing a permanent, continuous record of the stack gas moisture content, in percent \textsubscript{H2}O;
5. A carbon dioxide monitoring system, consisting of a CO\textsubscript{2} pollutant concentration monitor (or an oxygen monitor plus suitable mathematical equations from which the CO\textsubscript{2} concentration is derived) and an automated data acquisition and handling system and providing a permanent, continuous record of CO\textsubscript{2} emissions, in percent CO\textsubscript{2}; and
6. An oxygen monitoring system, consisting of an O\textsubscript{2} concentration monitor and an automated data acquisition and handling system and providing a permanent, continuous record of O\textsubscript{2}, in percent O\textsubscript{2}.

Control period means the period beginning January 1 of a calendar year, except as provided in §96.106(c)(2), and ending on December 31 of the same year, inclusive.

Excess emissions means any ton of nitrogen oxides emitted by the CAIR NO\textsubscript{X} units at a CAIR NO\textsubscript{X} source during a control period that exceeds the CAIR NO\textsubscript{X} emissions limitation for the source.

Fossil fuel means natural gas, petroleum, coal, or any form of solid, liquid, or gaseous fuel derived from such material.

Fossil-fuel-fired means, with regard to a unit, combusting any amount of fossil fuel in any calendar year.

Fuel oil means any petroleum-based fuel (including diesel fuel or petroleum derivatives such as oil tar) and any recycled or blended petroleum products or petroleum by-products used as a fuel whether in a liquid, solid, or gaseous state.
General account means a CAIR NO\textsubscript{X} Allowance Tracking System account, established under subpart FF of this part, that is not a compliance account.

Generator means a device that produces electricity.

Gross electrical output means, with regard to a cogeneration unit, electricity made available for use, including any such electricity used in the power production process (which process includes, but is not limited to, any on-site processing or treatment of fuel combusted at the unit and any on-site emission controls).

Heat input means, with regard to a specified period of time, the product (in mmBtu/time) of the gross calorific value of the fuel (in Btu/lb) divided by 1,000,000 Btu/mmBtu and multiplied by the fuel feed rate into a combustion device (in lb of fuel/time), as measured, recorded, and reported to the Administrator by the CAIR designated representative and determined by the Administrator in accordance with subpart HH of this part and excluding the heat derived from preheated combustion air, recirculated flue gases, or exhaust from other sources.

Heat input rate means the amount of heat input (in mmBtu) divided by unit operating time (in hr) or, with regard to a specific fuel, the amount of heat input attributed to the fuel (in mmBtu) divided by the unit operating time (in hr) during which the unit combusted the fuel.

Hg Budget Trading Program means a multi-state Hg air pollution control and emission reduction program approved and administered by the Administrator in accordance with subpart HHHH of part 60 of this chapter and §60.24(h)(6), or established by the Administrator under section 111 of the Clean Air Act, as a means of reducing national Hg emissions.

Life-of-the-unit, firm power contractual arrangement means a unit participation power sales agreement under which a utility or industrial customer reserves, or is entitled to receive, a specified amount or percentage of nameplate capacity and associated energy generated by any specified unit and pays its proportional amount of such unit’s total costs, pursuant to a contract:

(1) For the life of the unit;

(2) For a cumulative term of no less than 30 years, including contracts that permit an election for early termination; or

(3) For a period no less than 25 years or 70 percent of the economic useful life of the unit determined as of the time the unit is built, with option rights to purchase or release some portion of the nameplate capacity and associated energy generated by the unit at the end of the period.

Maximum design heat input means the maximum amount of fuel per hour (in Btu/hr) that a unit is capable of combusting on a steady state basis as of the initial installation of the unit as specified by the manufacturer of the unit.

Monitoring system means any monitoring system that meets the requirements of subpart HH of this part, including a continuous emissions monitoring system, an alternative monitoring system, or an excepted monitoring system under part 75 of this chapter.

Most stringent State or Federal NO\textsubscript{X} emissions limitation means, with regard to a unit, the lowest NO\textsubscript{X} emissions limitation (in terms of lb/mmBtu) that is applicable to the unit under State or Federal law, regardless of the averaging period to which the emissions limitation applies.

Nameplate capacity means, starting from the initial installation of a generator, the maximum electrical generating output (in MWe) that the generator is capable of producing on a steady state basis and during continuous operation (when not restricted by seasonal or other deratings) as of such installation as specified by the manufacturer of the generator or, starting from the completion of any subsequent physical change in the generator resulting in an increase in the maximum electrical generating output (in MWe) that the generator is capable of producing on a steady state basis and during continuous operation (when not restricted by seasonal or other deratings), such increased maximum amount as of such completion as specified by the person conducting the physical change.

Oil-fired means, for purposes of subpart EE of this part, combusting fuel
oil for more than 15.0 percent of the annual heat input in a specified year and not qualifying as coal-fired.

Operator means any person who operates, controls, or supervises a CAIR NO\textsubscript{X} unit or a CAIR NO\textsubscript{X} source and shall include, but not be limited to, any holding company, utility system, or plant manager of such a unit or source.

Owner means any of the following persons:

(1) With regard to a CAIR NO\textsubscript{X} source or a CAIR NO\textsubscript{X} unit at a source, respectively:
   (i) Any holder of any portion of the legal or equitable title in a CAIR NO\textsubscript{X} unit at the source or the CAIR NO\textsubscript{X} unit;
   (ii) Any holder of a leasehold interest in a CAIR NO\textsubscript{X} unit at the source or the CAIR NO\textsubscript{X} unit; or
   (iii) Any purchaser of power from a CAIR NO\textsubscript{X} unit at the source or the CAIR NO\textsubscript{X} unit under a life-of-the-unit, firm power contractual arrangement; provided that, unless expressly provided for in a leasehold agreement, owner shall not include a passive lessor, or a person who has an equitable interest through such lessor, whose rental payments are not based (either directly or indirectly) on the revenues or income from such CAIR NO\textsubscript{X} unit; or

(2) With regard to any general account, any person who has an ownership interest with respect to the CAIR NO\textsubscript{X} allowances held in the general account and who is subject to the binding agreement for the CAIR authorized account representative to represent the person’s ownership interest with respect to CAIR NO\textsubscript{X} allowances.

Permitting authority means the State air pollution control agency, local agency, other State agency, or other agency authorized by the Administrator to issue or revise permits to meet the requirements of the CAIR NO\textsubscript{X} Annual Trading Program or, if no such agency has been so authorized, the Administrator.

Potential electrical output capacity means 33 percent of a unit’s maximum design heat input, divided by 3,413 Btu/kWh, divided by 1,000 kWh/MWh, and multiplied by 8,760 hr/yr.

Receive or receipt of means, when referring to the permitting authority or the Administrator, to come into possession of a document, information, or correspondence (whether sent in hard copy or by authorized electronic transmission), as indicated in an official log, or by a notation made on the document, information, or correspondence, by the permitting authority or the Administrator in the regular course of business.

Recordation, record, or recorded means, with regard to CAIR NO\textsubscript{X} allowances, the movement of CAIR NO\textsubscript{X} allowances by the Administrator into or between CAIR NO\textsubscript{X} Allowance Tracking System accounts, for purposes of allocation, transfer, or deduction.

Reference method means any direct test method of sampling and analyzing for an air pollutant as specified in §75.22 of this chapter.

Replacement, replace, or replaced means, with regard to a unit, the demolishing of a unit, or the permanent shutdown and permanent disabling of a unit, and the construction of another unit (the replacement unit) to be used instead of the demolished or shutdown unit (the replaced unit).

Repowered means, with regard to a unit, replacement of a coal-fired boiler with one of the following coal-fired technologies at the same source as the coal-fired boiler:

(1) Atmospheric or pressurized fluidized bed combustion;
(2) Integrated gasification combined cycle;
(3) Magnetohydrodynamics;
(4) Direct and indirect coal-fired turbines;
(5) Integrated gasification fuel cells;

or

(6) As determined by the Administrator in consultation with the Secretary of Energy, a derivative of one or more of the technologies under paragraphs (1) through (5) of this definition and any other coal-fired technology capable of controlling multiple combustion emissions simultaneously with improved boiler or generation efficiency and with significantly greater waste reduction relative to the performance of technology in widespread commercial use as of January 1, 2005.

Script number means, for a CAIR NO\textsubscript{X} allowance, the unique identification
number assigned to each CAIR NO\textsubscript{X} allowance by the Administrator.

*Sequential use of energy* means:
(1) For a topping-cycle cogeneration unit, the use of reject heat from electricity production in a useful thermal energy application or process; or
(2) For a bottoming-cycle cogeneration unit, the use of reject heat from useful thermal energy application or process in electricity production.

*Solid waste incineration unit* means a stationary, fossil-fuel-fired boiler or stationary, fossil-fuel-fired combustion turbine that is a “solid waste incineration unit” as defined in section 129(g)(1) of the Clean Air Act.

*Source* means all buildings, structures, or installations located in one or more contiguous or adjacent properties under common control of the same person or persons. For purposes of section 502(c) of the Clean Air Act, a “source,” including a “source” with multiple units, shall be considered a single “facility.”

*State* means one of the States or the District of Columbia that adopts the CAIR NO\textsubscript{X} Annual Trading Program pursuant to §51.123(o)(1) or (2) of this chapter.

*Submit or serve* means to send or transmit a document, information, or correspondence to the person specified in accordance with the applicable regulation:
(1) In person;
(2) By United States Postal Service; or
(3) By other means of dispatch or transmission and delivery. Compliance with any “submission” or “service” deadline shall be determined by the date of dispatch, transmission, or mailing and not the date of receipt.

*Title V operating permit* means a permit issued under title V of the Clean Air Act and part 70 or part 71 of this chapter.

*Title V operating permit regulations* means the regulations that the Administrator has approved or issued as meeting the requirements of title V of the Clean Air Act and part 70 or 71 of this chapter.

*Ton* means 2,000 pounds. For the purpose of determining compliance with the CAIR NO\textsubscript{X} emissions limitation, total tons of nitrogen oxides emissions for a control period shall be calculated as the sum of all recorded hourly emissions (or the mass equivalent of the recorded hourly emission rates) in accordance with subpart HH of this part, but with any remaining fraction of a ton equal to or greater than 0.50 tons deemed to equal one ton and any remaining fraction of a ton less than 0.50 tons deemed to equal zero tons.

*Topping-cycle cogeneration unit* means a cogeneration unit in which the energy input to the unit is first used to produce useful power including electricity, and at least some of the reject heat from the electricity production is then used to provide useful thermal energy.

*Total energy input* means, with regard to a cogeneration unit, total energy of all forms supplied to the cogeneration unit, excluding energy produced by the cogeneration unit itself. Each form of energy supplied shall be measured by the lower heating value of that form of energy calculated as follows:

\[
\text{LHV} = \text{HHV} - 10.55(W + 9H)
\]

Where:

LHV = lower heating value of fuel in Btu/\text{lb},
HHV = higher heating value of fuel in Btu/\text{lb},
W = Weight \% of moisture in fuel, and
H = Weight \% of hydrogen in fuel.

*Total energy output* means, with regard to a cogeneration unit, the sum of useful power and useful thermal energy produced by the cogeneration unit.

*Unit* means a stationary, fossil-fuel-fired boiler or combustion turbine or other stationary, fossil-fuel-fired combustion device.

*Unit operating day* means a calendar day in which a unit combusts any fuel.

*Unit operating hour or hour of unit operation* means an hour in which a unit combusts any fuel.

*Useful power* means, with regard to a cogeneration unit, electricity or mechanical energy made available for use, excluding any such energy used in the power production process (which process includes, but is not limited to, any on-site processing or treatment of fuel combusted at the unit and any on-site emission controls).

*Useful thermal energy* means, with regard to a cogeneration unit, thermal energy that is:
(1) Made available to an industrial or commercial process (not a power production process), excluding any heat contained in condensate return or makeup water;

(2) Used in a heating application (e.g., space heating or domestic hot water heating); or

(3) Used in a space cooling application (i.e., thermal energy used by an absorption chiller).

Utility power distribution system means the portion of an electricity grid owned or operated by a utility and dedicated to delivering electricity to customers.

§ 96.103 Measurements, abbreviations, and acronyms.

Measurements, abbreviations, and acronyms used in this subpart and subparts BB through II are defined as follows:

Btu—British thermal unit.

CO₂—carbon dioxide

H₂O—water

Hg—mercury

hr—hour

kW—kilowatt electrical

kWh—kilowatt hour

lb—pound

mmBtu—million Btu

MWe—megawatt electrical

MWh—megawatt hour

NOₓ—nitrogen oxides

O₂—oxygen

ppm—parts per million

scfh—standard cubic feet per hour

SO₂—sulfur dioxide

yr—year

§ 96.104 Applicability.

(a) Except as provided in paragraph (b) of this section:

(1) The following units in a State shall be CAIR NOₓ units, and any source that includes one or more such units shall be a CAIR NOₓ source, subject to the requirements of this subpart and subparts BB through HH of this part: any stationary, fossil-fuel-fired boiler or stationary, fossil-fuel-fired combustion turbine serving at any time, since the later of November 15, 1990 or the start-up of the unit’s combustion chamber, a generator with nameplate capacity of more than 25 MWe producing electricity for sale.

(2) If a stationary boiler or stationary combustion turbine that, under paragraph (a)(1) of this section, is not a CAIR NOₓ unit begins to combust fossil fuel or to serve a generator with nameplate capacity of more than 25 MWe producing electricity for sale, the unit shall become a CAIR NOₓ unit as provided in paragraph (a)(1) of this section on the first date on which it both combusts fossil fuel and serves such generator.

(b) The units in a State that meet the requirements set forth in paragraph (b)(1)(i), (b)(2)(i), or (b)(2)(ii) of this section shall not be CAIR NOₓ units:

(1)(i) Any unit that is a CAIR NOₓ unit under paragraph (a)(1) or (2) of this section:

(A) Qualifying as a cogeneration unit during the 12-month period starting on the date the unit first produces electricity and continuing to qualify as a cogeneration unit; and

(B) Not serving at any time, since the later of November 15, 1990 or the start-up of the unit’s combustion chamber, a generator with nameplate capacity of more than 25 MWe supplying in any calendar year more than one-third of the unit’s potential electric output capacity or 219,000 MWh, whichever is greater, to any utility power distribution system for sale.

(ii) If a unit qualifies as a cogeneration unit during the 12-month period starting on the date the unit first produces electricity and meets the requirements of paragraphs (b)(1)(i) of this section for at least one calendar year, but subsequently no longer meets all such requirements, the unit shall become a CAIR NOₓ unit starting on the earlier of January 1 after the first calendar year during which the unit first produces electricity and meets the requirements of paragraphs (b)(1)(i)(B) of this section.

(2)(i) Any unit that is a CAIR NOₓ unit under paragraph (a)(1) or (2) of this section commencing operation before January 1, 1985:

(A) Qualifying as a cogeneration unit during the 12-month period starting on the later of November 15, 1990 or the start-up of the unit’s combustion chamber, a generator with nameplate capacity of more than 25 MWe producing electricity for sale.
(B) With an average annual fuel consumption of non-fossil fuel for 1985–1987 exceeding 80 percent (on a Btu basis) and an average annual fuel consumption of non-fossil fuel for any 3 consecutive calendar years after 1990 exceeding 80 percent (on a Btu basis).

(ii) Any unit that is a CAIR NO\textsubscript{X} unit under paragraph (a)(1) or (2) of this section commencing operation on or after January 1, 1985:
   (A) Qualifying as a solid waste incineration unit; and
   (B) With an average annual fuel consumption of non-fossil fuel for the first 3 calendar years of operation exceeding 80 percent (on a Btu basis) and an average annual fuel consumption of non-fossil fuel for any 3 consecutive calendar years after 1990 exceeding 80 percent (on a Btu basis).

(iii) If a unit qualifies as a solid waste incineration unit and meets the requirements of paragraph (b)(2)(i) or (ii) of this section for at least 3 consecutive calendar years after 1990 for which the unit has an average annual fuel consumption of fossil fuel of 20 percent or more.

§ 96.105 Retired unit exemption.

(a)(1) Any CAIR NO\textsubscript{X} unit that is permanently retired and is not a CAIR NO\textsubscript{X} opt-in unit under subpart II of this part shall be exempt from the CAIR NO\textsubscript{X} Annual Trading Program, except for the provisions of this section, §96.102, §96.103, §96.104, §96.106(c)(4) through (7), §96.107, §96.108, and subparts BB and EE through GG.

(2) The exemption under paragraph (a)(1) of this section shall become effective the day on which the CAIR NO\textsubscript{X} unit is permanently retired. Within 30 days of the unit’s permanent retirement, the CAIR designated representative shall submit a statement to the permitting authority otherwise responsible for administering any CAIR permit for the unit and shall submit a copy of the statement to the Administrator. The statement shall state, in a format prescribed by the permitting authority, that the unit was permanently retired on a specific date and will comply with the requirements of paragraph (b) of this section.

(3) After receipt of the statement under paragraph (a)(2) of this section, the permitting authority will amend any permit under subpart CC of this part covering the source at which the unit is located to add the provisions and requirements of the exemption under paragraphs (a)(1) and (b) of this section.

(b) Special provisions. (1) A unit exempt under paragraph (a) of this section shall not emit any nitrogen oxides, starting on the date that the exemption takes effect.

(2) The permitting authority will allocate CAIR NO\textsubscript{X} allowances under subpart EE of this part to a unit exempt under paragraph (a) of this section.

(3) For a period of 5 years from the date the records are created, the owners and operators of a unit exempt under paragraph (a) of this section shall retain, at the source that includes the unit, records demonstrating that the unit is permanently retired. The 5-year period for keeping records may be extended for cause, at any time before the end of the period, in writing by the permitting authority or the Administrator. The owners and operators bear the burden of proof that the unit is permanently retired.

(4) The owners and operators and, to the extent applicable, the CAIR designated representative of a unit exempt under paragraph (a) of this section shall comply with the requirements of the CAIR NO\textsubscript{X} Annual Trading Program concerning all periods for which the exemption is not in effect, even if such requirements arise, or must be complied with, after the exemption takes effect.

(5) A unit exempt under paragraph (a) of this section and located at a source that is required, or but for this exemption would be required, to have a title V operating permit shall not resume operation unless the CAIR designated representative of the source submits a complete CAIR permit application under §96.122 for the unit not less than
§ 96.106 Standard requirements.

(a) Permit requirements. (1) The CAIR designated representative of each CAIR NO\textsubscript{X} source required to have a title V operating permit and each CAIR NO\textsubscript{X} unit required to have a title V operating permit at the source shall:

(i) Submit to the permitting authority a complete CAIR permit application under §96.122 in accordance with the deadlines specified in §96.121; and

(ii) Submit in a timely manner any supplemental information that the permitting authority determines is necessary in order to review a CAIR permit application and issue or deny a CAIR permit.

(2) The owners and operators of each CAIR NO\textsubscript{X} source required to have a title V operating permit and each CAIR NO\textsubscript{X} unit required to have a title V operating permit at the source shall have a CAIR permit issued by the permitting authority under subpart CC of this part for the source and operate the source and the unit in compliance with such CAIR permit.

(3) Except as provided in subpart II of this part, the owners and operators of a CAIR NO\textsubscript{X} source that is not otherwise required to have a title V operating permit and each CAIR NO\textsubscript{X} unit that is not otherwise required to have a title V operating permit are not required to submit a CAIR permit application, and to have a CAIR permit, under subpart CC of this part for such CAIR NO\textsubscript{X} source and such CAIR NO\textsubscript{X} unit.

(b) Monitoring, reporting, and recordkeeping requirements. (1) The owners and operators, and the CAIR designated representative, of each CAIR NO\textsubscript{X} source and each CAIR NO\textsubscript{X} unit at the source shall comply with the monitoring, reporting, and recordkeeping requirements of subpart HH of this part.

(2) The emissions measurements recorded and reported in accordance with subpart HH of this part shall be used to determine compliance by each CAIR NO\textsubscript{X} source with the CAIR NO\textsubscript{X} emissions limitation under paragraph (c) of this section.

(c) Nitrogen oxides emission requirements. (1) As of the allowance transfer deadline for a control period, the owners and operators of each CAIR NO\textsubscript{X} source and each CAIR NO\textsubscript{X} unit at the source shall hold, in the source’s compliance account, CAIR NO\textsubscript{X} allowances available for compliance deductions for the control period under §96.154(a) in an amount not less than the tons of total nitrogen oxides emissions for the control period from all CAIR NO\textsubscript{X} units at the source, as determined in accordance with subpart HH of this part.

(2) A CAIR NO\textsubscript{X} unit shall be subject to the requirements under paragraph (c)(1) of this section for the control period starting on the later of January 1, 2009 or the deadline for meeting the unit’s monitor certification requirements under §96.170(b)(1), (2), or (5) and for each control period thereafter.

(3) A CAIR NO\textsubscript{X} allowance shall not be deducted, for compliance with the requirements under paragraph (c)(1) of this section, for a control period in a calendar year before the year for which the CAIR NO\textsubscript{X} allowance was allocated.
§ 96.106

(4) CAIR NO\textsubscript{X} allowances shall be held in, deducted from, or transferred into or among CAIR NO\textsubscript{X} Allowance Tracking System accounts in accordance with subparts FF, GG, and II of this part.

(5) A CAIR NO\textsubscript{X} allowance is a limited authorization to emit one ton of nitrogen oxides in accordance with the CAIR NO\textsubscript{X} Annual Trading Program. No provision of the CAIR NO\textsubscript{X} Annual Trading Program, the CAIR permit application, the CAIR permit, or an exemption under §96.105 and no provision of law shall be construed to limit the authority of the State or the United States to terminate or limit such authorization.

(6) A CAIR NO\textsubscript{X} allowance does not constitute a property right.

(7) Upon recordation by the Administrator under subpart EE, FF, GG, or II of this part, every allocation, transfer, or deduction of a CAIR NO\textsubscript{X} allowance to or from a CAIR NO\textsubscript{X} source’s compliance account is incorporated automatically in any CAIR permit of the source.

(d) Excess emissions requirements. If a CAIR NO\textsubscript{X} source emits nitrogen oxides during any control period in excess of the CAIR NO\textsubscript{X} emissions limitation, then:

(1) The owners and operators of the source and each CAIR NO\textsubscript{X} unit at the source shall surrender the CAIR NO\textsubscript{X} allowances required for deduction under §96.154(d)(1) and pay any fine, penalty, or assessment or comply with any other remedy imposed, for the same violations, under the Clean Air Act or applicable State law; and

(2) Each CAIR NO\textsubscript{X} unit at the source shall keep on site at the source or the CAIR designated representative of a CAIR NO\textsubscript{X} source and each CAIR NO\textsubscript{X} unit shall also apply to the owners and operators of such source and of the CAIR NO\textsubscript{X} units at the source.

(e) Recordkeeping and reporting requirements. (1) Unless otherwise provided, the owners and operators of the CAIR NO\textsubscript{X} source and each CAIR NO\textsubscript{X} unit at the source each of the following documents for a period of 5 years from the date the document is created. This period may be extended for cause, at any time before the end of 5 years, in writing by the permitting authority or the Administrator.

(i) The certificate of representation under §96.113 for the CAIR designated representative for the source and each CAIR NO\textsubscript{X} unit at the source and all documents that demonstrate the truth of the statements in the certificate of representation; provided that the certificate and documents shall be retained on site at the source beyond such 5-year period until such documents are superseded because of the submission of a new certificate of representation under §96.113 changing the CAIR designated representative.

(ii) All emissions monitoring information, in accordance with subpart HH of this part, provided that to the extent that subpart HH of this part provides for a 3-year period for recordkeeping, the 3-year period shall apply.

(iii) Copies of all reports, compliance certifications, and other submissions and all records made or required under the CAIR NO\textsubscript{X} Annual Trading Program.

(iv) Copies of all documents used to complete a CAIR permit application and any other submission under the CAIR NO\textsubscript{X} Annual Trading Program or to demonstrate compliance with the requirements of the CAIR NO\textsubscript{X} Annual Trading Program.

(2) The CAIR designated representative of a CAIR NO\textsubscript{X} source and each CAIR NO\textsubscript{X} unit at the source shall submit the reports required under the CAIR NO\textsubscript{X} Annual Trading Program, including those under subpart HH of this part.

(f) Liability. (1) Each CAIR NO\textsubscript{X} source and each CAIR NO\textsubscript{X} unit shall meet the requirements of the CAIR NO\textsubscript{X} Annual Trading Program.

(2) Any provision of the CAIR NO\textsubscript{X} Annual Trading Program that applies to a CAIR NO\textsubscript{X} source or the CAIR designated representative of a CAIR NO\textsubcript{X} source shall also apply to the owners and operators of such source and of the CAIR NO\textsubscript{X} units at the source.

(3) Any provision of the CAIR NO\textsubscript{X} Annual Trading Program that applies to a CAIR NO\textsubscript{X} unit or the CAIR designated representative of a CAIR NO\textsubscript{X} unit shall also apply to the owners and operators of such unit.

(g) Effect on other authorities. No provision of the CAIR NO\textsubscript{X} Annual Trading Program, a CAIR permit application, a
CAIR permit, or an exemption under §96.105 shall be construed as exempting or excluding the owners and operators, and the CAIR designated representative, of a CAIR NO\textsubscript{x} source or CAIR NO\textsubscript{x} unit from compliance with any other provision of the applicable, approved State implementation plan, a federally enforceable permit, or the Clean Air Act.

[70 FR 25339, May 12, 2005, as amended at 71 FR 25382, Apr. 28, 2006]

§ 96.107 Computation of time.

(a) Unless otherwise stated, any time period scheduled, under the CAIR NO\textsubscript{x} Annual Trading Program, to begin on the occurrence of an act or event shall begin on the day the act or event occurs.

(b) Unless otherwise stated, any time period scheduled, under the CAIR NO\textsubscript{x} Annual Trading Program, to begin before the occurrence of an act or event shall be computed so that the period ends the day before the act or event occurs.

(c) Unless otherwise stated, if the final day of any time period, under the CAIR NO\textsubscript{x} Annual Trading Program, falls on a weekend or a State or Federal holiday, the time period shall be extended to the next business day.

§ 96.108 Appeal procedures.

The appeal procedures for decisions of the Administrator under the CAIR NO\textsubscript{x} Annual Trading Program are set forth in part 78 of this chapter.

Subpart BB—CAIR Designated Representative for CAIR NO\textsubscript{x} Sources

Source: 70 FR 25339, May 12, 2005, unless otherwise noted.

§ 96.110 Authorization and responsibilities of CAIR designated representative.

(a) Except as provided under §96.111, each CAIR NO\textsubscript{x} source, including all CAIR NO\textsubscript{x} units at the source, shall have one and only one CAIR designated representative, with regard to all matters under the CAIR NO\textsubscript{x} Annual Trading Program concerning the source or any CAIR NO\textsubscript{x} unit at the source.

(b) The CAIR designated representative of the CAIR NO\textsubscript{x} source shall be selected by an agreement binding on the owners and operators of the source and all CAIR NO\textsubscript{x} units at the source and shall act in accordance with the certification statement in §96.113(a)(4)(iv).

(c) Upon receipt by the Administrator of a complete certificate of representation under §96.113, the CAIR designated representative of the source shall represent and, by his or her representations, actions, inactions, or submissions, legally bind each owner and operator of the CAIR NO\textsubscript{x} source represented and each CAIR NO\textsubscript{x} unit at the source in all matters pertaining to the CAIR NO\textsubscript{x} Annual Trading Program, notwithstanding any agreement between the CAIR designated representative and such owners and operators. The owners and operators shall be bound by any decision or order issued to the CAIR designated representative by the permitting authority, the Administrator, or a court regarding the source or unit.

(d) No CAIR permit will be issued, no emissions data reports will be accepted, and no CAIR NO\textsubscript{x} Allowance Tracking System account will be established for a CAIR NO\textsubscript{x} unit at a source, until the Administrator has received a complete certificate of representation under §96.113 for a CAIR designated representative of the source and the CAIR NO\textsubscript{x} units at the source.

(e)(1) Each submission under the CAIR NO\textsubscript{x} Annual Trading Program shall be submitted, signed, and certified by the CAIR designated representative for each CAIR NO\textsubscript{x} source on behalf of which the submission is made. Each such submission shall include the following certification statement by the CAIR designated representative: “I am authorized to make this submission on behalf of the owners and operators of the source or units for which the submission is made. I certify under penalty of law that I have personally examined, and am familiar with, the statements and information submitted in this document and all its attachments. Based on my inquiry of those individuals with primary responsibility for obtaining the information, I...
§ 96.111 Alternate CAIR designated representative.

(a) A certificate of representation under §96.113 may designate one and only one alternate CAIR designated representative, who may act on behalf of the CAIR designated representative. The agreement by which the alternate CAIR designated representative is selected shall include a procedure for authorizing the alternate CAIR designated representative to act in lieu of the CAIR designated representative.

(b) Upon receipt by the Administrator of a complete certificate of representation under §96.113, any representation, action, inaction, or submission by the alternate CAIR designated representative shall be deemed to be a representation, action, inaction, or submission by the CAIR designated representative.

(c) Except in this section and §§96.102, 96.110(a) and (d), 96.112, 96.113, 96.115, 96.151, and 96.182, whenever the term “CAIR designated representative” is used in subparts AA through II of this part, the term shall be construed to include the CAIR designated representative or any alternate CAIR designated representative.

[70 FR 25339, May 12, 2005, as amended at 71 FR 25382, Apr. 28, 2006]

§ 96.112 Changing CAIR designated representative and alternate CAIR designated representative; changes in owners and operators.

(a) Changing CAIR designated representative. The CAIR designated representative may be changed at any time upon receipt by the Administrator of a superseding complete certificate of representation under §96.113. Notwithstanding any such change, all representations, actions, inactions, and submissions by the previous CAIR designated representative before the time and date when the Administrator receives the superseding certificate of representation shall be binding on the new CAIR designated representative and the owners and operators of the CAIR NOX source and the CAIR NOX units at the source.

(b) Changing alternate CAIR designated representative. The alternate CAIR designated representative may be changed at any time upon receipt by the Administrator of a superseding complete certificate of representation under §96.113. Notwithstanding any such change, all representations, actions, inactions, and submissions by the previous alternate CAIR designated representative before the time and date when the Administrator receives the superseding certificate of representation shall be binding on the new alternate CAIR designated representative and the owners and operators of the CAIR NOX source and the CAIR NOX units at the source.

(c) Changes in owners and operators.

(1) In the event an owner or operator of a CAIR NOX source or a CAIR NOX unit is not included in the list of owners and operators in the certificate of representation under §96.113, such owner or operator shall be deemed to be subject to and bound by the certificate of representation, the representations, actions, inactions, and submissions of the CAIR designated representative and any alternate CAIR designated representative of the source or unit, and the decisions and orders of the permitting authority, the Administrator, or a court, as if the owner or operator were included in such list.

(2) Within 30 days following any change in the owners and operators of a CAIR NOX source or a CAIR NOX unit, including the addition of a new owner or operator, the CAIR designated representative or any alternate CAIR designated representative shall submit a revision to the certificate of representation under §96.113 amending the list...
§ 96.113 Certificate of representation.

(a) A complete certificate of representation for a CAIR designated representative or an alternate CAIR designated representative shall include the following elements in a format prescribed by the Administrator:

(1) Identification of the CAIR NO\textsubscript{X} source, and each CAIR NO\textsubscript{X} unit at the source, for which the certificate of representation is submitted, including identification and nameplate capacity of each generator served by each such unit.

(2) The name, address, e-mail address (if any), telephone number, and facsimile transmission number (if any) of the CAIR designated representative and any alternate CAIR designated representative.

(3) A list of the owners and operators of the CAIR NO\textsubscript{X} source and of each CAIR NO\textsubscript{X} unit at the source.

(4) The following certification statements by the CAIR designated representative and any alternate CAIR designated representative:

(i) “I certify that I was selected as the CAIR designated representative or alternate CAIR designated representative, as applicable, by an agreement binding on the owners and operators of the source and each CAIR NO\textsubscript{X} unit at the source.”

(ii) “I certify that I have all the necessary authority to carry out my duties and responsibilities under the CAIR NO\textsubscript{X} Annual Trading Program on behalf of the owners and operators of the source and each CAIR NO\textsubscript{X} unit at the source and that each such owner and operator shall be fully bound by my representations, actions, inactions, or submissions.”

(iii) “I certify that the owners and operators of the source and each CAIR NO\textsubscript{X} unit at the source shall be bound by any order issued to me by the Administrator, the permitting authority, or a court regarding the source or unit.”

(iv) “Where there are multiple holders of a legal or equitable title to, or a leasehold interest in, a CAIR NO\textsubscript{X} unit, or where a utility or industrial customer purchases power from a CAIR NO\textsubscript{X} unit under a life-of-the-unit, firm power contractual arrangement, I certify that: I have given a written notice of my selection as the ‘CAIR designated representative’ or ‘alternate CAIR designated representative’, as applicable, and of the agreement by which I was selected to each owner and operator of the source and of each CAIR NO\textsubscript{X} unit at the source; and CAIR NO\textsubscript{X} allowances and proceeds of transactions involving CAIR NO\textsubscript{X} allowances will be deemed to be held or distributed in proportion to each holder’s legal, equitable, leasehold, or contractual reservation or entitlement, except that, if such multiple holders have expressly provided for a different distribution of CAIR NO\textsubscript{X} allowances by contract, CAIR NO\textsubscript{X} allowances and proceeds of transactions involving CAIR NO\textsubscript{X} allowances will be deemed to be held or distributed in accordance with the contract.”

(5) The signature of the CAIR designated representative and any alternate CAIR designated representative and the dates signed.

(b) Unless otherwise required by the permitting authority or the Administrator, documents of agreement referred to in the certificate of representation shall not be submitted to the permitting authority or the Administrator. Neither the permitting authority nor the Administrator shall be under any obligation to review or evaluate the sufficiency of such documents, if submitted.

§ 96.114 Objections concerning CAIR designated representative.

(a) Once a complete certificate of representation under §96.113 has been submitted and received, the permitting authority and the Administrator will rely on the certificate of representation unless and until a superseding complete certificate of representation under §96.113 is received by the Administrator.
(b) Except as provided in §96.112(a) or (b), no objection or other communication submitted to the permitting authority or the Administrator concerning the authorization, or any representation, action, inaction, or submission, of the CAIR designated representative shall affect any representation, action, inaction, or submission of the CAIR designated representative or the finality of any decision or order by the permitting authority or the Administrator under the CAIR NOx Annual Trading Program.

(c) Neither the permitting authority nor the Administrator will adjudicate any private legal dispute concerning the authorization or any representation, action, inaction, or submission of any CAIR designated representative, including private legal disputes concerning the proceeds of CAIR NOx allowance transfers.

§96.115 Delegation by CAIR designated representative and alternate CAIR designated representative.

(a) A CAIR designated representative may delegate, to one or more natural persons, his or her authority to make an electronic submission to the Administrator provided for or required under this part.

(b) An alternate CAIR designated representative may delegate, to one or more natural persons, his or her authority to make an electronic submission to the Administrator provided for or required under this part.

(c) In order to delegate authority to make an electronic submission to the Administrator in accordance with paragraph (a) or (b) of this section, the CAIR designated representative or alternate CAIR designated representative, as appropriate, must submit to the Administrator a notice of delegation, in a format prescribed by the Administrator, that includes the following elements:

(1) The name, address, e-mail address, telephone number, and facsimile transmission number (if any) of such CAIR designated representative or alternate CAIR designated representative;

(2) The name, address, e-mail address, telephone number, and facsimile transmission number (if any) of each such natural person (referred to as an “agent”):

(3) For each such natural person, a list of the type or types of electronic submissions under paragraph (a) or (b) of this section for which authority is delegated to him or her; and

(4) The following certification statements by such CAIR designated representative or alternate CAIR designated representative:

(i) “I agree that any electronic submission to the Administrator that is by an agent identified in this notice of delegation and of a type listed for such agent in this notice of delegation and that is made when I am a CAIR designated representative or alternate CAIR designated representative, as appropriate, and before this notice of delegation is superseded by another notice of delegation under 40 CFR 96.115(d) shall be deemed to be an electronic submission by me.”

(ii) “Until this notice of delegation is superseded by another notice of delegation under 40 CFR 96.115(d), I agree to maintain an e-mail account and to notify the Administrator immediately of any change in my e-mail address unless all delegation of authority by me under 40 CFR 96.115 is terminated.”

(d) A notice of delegation submitted under paragraph (c) of this section shall be effective, with regard to the CAIR designated representative or alternate CAIR designated representative identified in such notice, upon receipt of such notice by the Administrator and until receipt by the Administrator of a superseding notice of delegation submitted by such CAIR designated representative or alternate CAIR designated representative, as appropriate. The superseding notice of delegation may replace any previously identified agent, add a new agent, or eliminate entirely any delegation of authority.

(e) Any electronic submission covered by the certification in paragraph (c)(4)(i) of this section and made in accordance with a notice of delegation effective under paragraph (d) of this section shall be deemed to be an electronic submission by the CAIR designated representative or alternate
CAIR designated representative submitting such notice of delegation.


Subpart CC—Permits

SOURCE: 70 FR 25339, May 12, 2005, unless otherwise noted.

§96.120 General CAIR NO\textsubscript{X} Annual Trading Program permit requirements.

(a) For each CAIR NO\textsubscript{X} source required to have a title V operating permit or required, under subpart II of this part, to have a title V operating permit or other federally enforceable permit, such permit shall include a CAIR permit administered by the permitting authority for the title V operating permit or the federally enforceable permit as applicable. The CAIR portion of the title V permit or other federally enforceable permit as applicable shall be administered in accordance with the permitting authority’s title V operating permits regulations promulgated under part 70 or 71 of this chapter or the permitting authority’s regulations for other federally enforceable permits as applicable, except as provided otherwise by §96.105, this subpart, and subpart II of this part.

(b) Each CAIR permit shall contain, with regard to the CAIR NO\textsubscript{X} source and the CAIR NO\textsubscript{X} units at the source covered by the CAIR permit, all applicable CAIR NO\textsubscript{X} Annual Trading Program, CAIR NO\textsubscript{X} Ozone Season Trading Program, and CAIR SO\textsubscript{2} Trading Program requirements and shall be a complete and separable portion of the title V operating permit or other federally enforceable permit under paragraph (a) of this section.

[70 FR 25339, May 12, 2005, as amended at 71 FR 25383, Apr. 28, 2006]

§96.121 Submission of CAIR permit applications.

(a) Duty to apply. The CAIR designated representative of any CAIR NO\textsubscript{X} source required to have a title V operating permit shall submit to the permitting authority a complete CAIR permit application under §96.122 for the source covering each CAIR NO\textsubscript{X} unit at the source at least 18 months (or such lesser time provided by the permitting authority) before the later of January 1, 2009 or the date on which the CAIR NO\textsubscript{X} unit commences commercial operation, except as provided in §96.183(a).

(b) Duty to Reapply. For a CAIR NO\textsubscript{X} source required to have a title V operating permit, the CAIR designated representative shall submit a complete CAIR permit application under §96.122 for the source covering each CAIR NO\textsubscript{X} unit at the source to renew the CAIR permit in accordance with the permitting authority’s title V operating permits regulations addressing permit renewal, except as provided in §96.183(b).

[70 FR 25339, May 12, 2005, as amended at 71 FR 25383, Apr. 28, 2006]

§96.122 Information requirements for CAIR permit applications.

A complete CAIR permit application shall include the following elements concerning the CAIR NO\textsubscript{X} source for which the application is submitted, in a format prescribed by the permitting authority:

(a) Identification of the CAIR NO\textsubscript{X} source;

(b) Identification of each CAIR NO\textsubscript{X} unit at the CAIR NO\textsubscript{X} source; and

(c) The standard requirements under §96.106.

§96.123 CAIR permit contents and term.

(a) Each CAIR permit will contain, in a format prescribed by the permitting authority, all elements required for a complete CAIR permit application under §96.122.

(b) Each CAIR permit is deemed to incorporate automatically the definitions of terms under §96.102 and, upon recordation by the Administrator under subpart EE, FF, GG, or II of this part, every allocation, transfer, or deduction of a CAIR NO\textsubscript{X} allowance to or from the compliance account of the CAIR NO\textsubscript{X} source covered by the permit.

(c) The term of the CAIR permit will be set by the permitting authority, as necessary to facilitate coordination of the renewal of the CAIR permit with issuance, revision, or renewal of the CAIR NO\textsubscript{X} source’s title V operating permit.
§ 96.124 Permit or other federally enforceable permit as applicable.

[70 FR 25339, May 12, 2005, as amended at 71 FR 25383, Apr. 28, 2006]

§ 96.124 CAIR permit revisions.

Except as provided in §96.123(b), the permitting authority will revise the CAIR permit, as necessary, in accordance with the permitting authority’s title V operating permits regulations or the permitting authority’s regulations for other federally enforceable permits as applicable addressing permit revisions.

Subpart DD [Reserved]

Subpart EE—CAIR NOx Allowance Allocations

SOURCE: 70 FR 25339, May 12, 2005, unless otherwise noted.

§ 96.140 State trading budgets.

The State trading budgets for annual allocations of CAIR NOx allowances for the control periods in 2009 through 2014 and in 2015 and thereafter are respectively as follows:

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<th>State trading budget for 2015 and thereafter (tons)</th>
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[70 FR 25339, May 12, 2005, as amended at 71 FR 25302, Apr. 28, 2006]

§ 96.141 Timing requirements for CAIR NOx allowance allocations.

(a) By October 31, 2006, the permitting authority will submit to the Administrator the CAIR NOx allowance allocations, in a format prescribed by the Administrator and in accordance with §96.122(a) and (b), for the control periods in 2009, 2010, 2011, 2012, 2013, and 2014.

(b) By October 31, 2009 and October 31 of each year thereafter, the permitting authority will submit to the Administrator the CAIR NOx allowance allocations, in a format prescribed by the Administrator and in accordance with §96.142(a) and (b), for the control period in the sixth year after the year of the applicable deadline for submission under this paragraph.

(c) By October 31, 2009 and October 31 of each year thereafter, the permitting authority will submit to the Administrator the CAIR NOx allowance allocations, in a format prescribed by the Administrator and in accordance with §96.122(a), (c), and (d), for the control period in the year of the applicable deadline for submission under this paragraph.

[70 FR 25339, May 12, 2005, as amended at 71 FR 25383, Apr. 28, 2006]

§ 96.142 CAIR NOx allowance allocations.

(1) The baseline heat input (in mmBtu) used with respect to CAIR NOx allowance allocations under paragraph (b) of this section for each CAIR NOx unit will be:

(i) For units commencing operation before January 1, 2001 the average of the 3 highest amounts of the unit’s adjusted control period heat input for 2000 through 2004, with the adjusted control period heat input for each year calculated as follows:

(A) If the unit is coal-fired during the year, the unit’s control period heat input for such year is multiplied by 100 percent;

(B) If the unit is oil-fired during the year, the unit’s control period heat input for such year is multiplied by 60 percent; and

(C) If the unit is not subject to paragraph (a)(1)(i)(A) or (B) of this section, the unit’s control period heat input for such year is multiplied by 40 percent.
(i) For units commencing operation on or after January 1, 2001 and operating each calendar year during a period of 5 or more consecutive calendar years, the average of the 3 highest amounts of the unit’s total converted control period heat input over the first such 5 years.

(2)(i) A unit’s control period heat input, and a unit’s status as coal-fired or oil-fired, for a calendar year under paragraph (a)(1)(i) of this section, and a unit’s total tons of NO\textsubscript{X} emissions during a calendar year under paragraph (c)(3) of this section, will be determined in accordance with part 75 of this chapter, to the extent the unit was otherwise subject to the requirements of part 75 of this chapter for the year, or will be based on the best available data reported to the permitting authority for the unit, to the extent the unit was not otherwise subject to the requirements of part 75 of this chapter for the year.

(ii) A unit’s converted control period heat input for a calendar year specified under paragraph (a)(1)(ii) of this section equals:

(A) Except as provided in paragraph (a)(2)(ii)(B) or (C) of this section, the control period gross electrical output of the generator or generators served by the unit multiplied by 7,900 Btu/kWh, if the unit is coal-fired for the year, or 6,675 Btu/kWh, if the unit is not coal-fired for the year, and divided by 1,000,000 Btu/mmBtu, provided that if a generator is served by 2 or more units, then the gross electrical output of the generator will be attributed to each unit in proportion to the unit’s share of the total control period heat input of such units for the year;

(B) For a unit that is a boiler and has equipment used to produce electricity and useful thermal energy for industrial, commercial, heating, or cooling purposes through the sequential use of energy, the total heat energy (in Btu) of the steam produced by any associated heat recovery steam generator during the control period divided by 0.8, and with the sum divided by 1,000,000 Btu/mmBtu.

(b)(1) For each control period in 2009 and thereafter, the permitting authority will allocate to all CAIR NO\textsubscript{X} units in the State that have a baseline heat input (as determined under paragraph (a) of this section) a total amount of CAIR NO\textsubscript{X} allowances equal to 95 percent for a control period during 2009 through 2014, and 97 percent for a control period during 2015 and thereafter, of the tons of NO\textsubscript{X} emissions in the State trading budget under §96.140 (except as provided in paragraph (d) of this section).

(2) The permitting authority will allocate CAIR NO\textsubscript{X} allowances to each CAIR NO\textsubscript{X} unit under paragraph (b)(1) of this section in an amount determined by multiplying the total amount of CAIR NO\textsubscript{X} allowances allocated under paragraph (b)(1) of this section by the ratio of the baseline heat input of such CAIR NO\textsubscript{X} unit to the total amount of baseline heat input of all such CAIR NO\textsubscript{X} units in the State and rounding to the nearest whole allowance as appropriate.

(c) For each control period in 2009 and thereafter, the permitting authority will allocate CAIR NO\textsubscript{X} allowances to CAIR NO\textsubscript{X} units in a State that are not allocated CAIR NO\textsubscript{X} allowances under paragraph (b) of this section because the units do not yet have a baseline heat input under paragraph (a) of this section or because the units have a baseline heat input but all CAIR NO\textsubscript{X} allowances available under paragraph (b) of this section for the control period are already allocated, in accordance with the following procedures:

(1) The permitting authority will establish a separate new unit set-aside for each control period. Each new unit set-aside will be allocated CAIR NO\textsubscript{X} allowances equal to 5 percent for a control period in 2009 through 2014, and 3 percent for a control period in 2015 and thereafter, of the amount of tons of
NO\textsubscript{X} emissions in the State trading budget under §96.140.

(2) The CAIR designated representative of such a CAIR NO\textsubscript{X} unit may submit to the permitting authority a request, in a format specified by the permitting authority, to be allocated CAIR NO\textsubscript{X} allowances, starting with the later of the control period in 2009 or the first control period after the control period in which the CAIR NO\textsubscript{X} unit commences commercial operation and until the first control period for which the unit is allocated CAIR NO\textsubscript{X} allowances under paragraph (b) of this section. A separate CAIR NO\textsubscript{X} allowance allocation request for each control period for which CAIR NO\textsubscript{X} allowances are sought must be submitted on or before May 1 of such control period and after the date on which the CAIR NO\textsubscript{X} unit commences commercial operation.

(3) In a CAIR NO\textsubscript{X} allowance allocation request under paragraph (c)(2) of this section, the CAIR designated representative may request for a control period CAIR NO\textsubscript{X} allowances in an amount not exceeding the CAIR NO\textsubscript{X} unit’s total tons of NO\textsubscript{X} emissions during the calendar year immediately before such control period.

(4) The permitting authority will review each CAIR NO\textsubscript{X} allowance allocation request under paragraph (c)(2) of this section and will allocate CAIR NO\textsubscript{X} allowances for each control period pursuant to such request as follows:

(i) The permitting authority will accept an allowance allocation request only if the request meets, or is adjusted by the permitting authority as necessary to meet, the requirements of paragraphs (c)(2) and (3) of this section.

(ii) On or after May 1 of the control period, the permitting authority will determine the sum of the CAIR NO\textsubscript{X} allowances requested (as adjusted under paragraph (c)(4)(i) of this section) in all allowance allocation requests accepted under paragraph (c)(4)(i) of this section for the control period.

(iii) If the amount of CAIR NO\textsubscript{X} allowances in the new unit set-aside for the control period is greater than or equal to the sum under paragraph (c)(4)(ii) of this section, then the permitting authority will allocate the amount of CAIR NO\textsubscript{X} allowances requested (as adjusted under paragraph (c)(4)(i) of this section) to each CAIR NO\textsubscript{X} unit covered by an allowance allocation request accepted under paragraph (c)(4)(i) of this section.

(iv) If the amount of CAIR NO\textsubscript{X} allowances in the new unit set-aside for the control period is less than the sum under paragraph (c)(4)(ii) of this section, then the permitting authority will allocate to each CAIR NO\textsubscript{X} unit covered by an allowance allocation request accepted under paragraph (c)(4)(i) of this section the amount of the CAIR NO\textsubscript{X} allowances requested (as adjusted under paragraph (c)(4)(i) of this section), multiplied by the amount of CAIR NO\textsubscript{X} allowances in the new unit set-aside for the control period, divided by the sum determined under paragraph (c)(4)(ii) of this section, and rounded to the nearest whole allowance as appropriate.

(v) The permitting authority will notify each CAIR designated representative that submitted an allowance allocation request of the amount of CAIR NO\textsubscript{X} allowances (if any) allocated for the control period to the CAIR NO\textsubscript{X} unit covered by the request.

(d) If, after completion of the procedures under paragraph (c)(4) of this section for a control period, any unallocated CAIR NO\textsubscript{X} allowances remain in the new unit set-aside for the control period, the permitting authority will allocate to each CAIR NO\textsubscript{X} unit that was allocated CAIR NO\textsubscript{X} allowances under paragraph (b) of this section an amount of CAIR NO\textsubscript{X} allowances equal to the total amount of such remaining unallocated CAIR NO\textsubscript{X} allowances, multiplied by the unit’s allocation under paragraph (b) of this section, divided by 95 percent for a control period during 2009 through 2014, and 97 percent for a control period during 2015 and thereafter, of the amount of tons of NO\textsubscript{X} emissions in the State trading budget under §96.140, and rounded to the nearest whole allowance as appropriate.

[70 FR 25339, May 12, 2005, as amended at 71 FR 25383, Apr. 28, 2006]
the control period in 2009 up to the following amount of CAIR NO\textsubscript{X} allowances to CAIR NO\textsubscript{X} units in the respective State:

<table>
<thead>
<tr>
<th>State</th>
<th>Compliance supplement pool</th>
</tr>
</thead>
<tbody>
<tr>
<td>Alabama</td>
<td>10,166</td>
</tr>
<tr>
<td>Delaware</td>
<td>843</td>
</tr>
<tr>
<td>District Of Columbia</td>
<td>0</td>
</tr>
<tr>
<td>Florida</td>
<td>8,335</td>
</tr>
<tr>
<td>Georgia</td>
<td>12,397</td>
</tr>
<tr>
<td>Illinois</td>
<td>11,239</td>
</tr>
<tr>
<td>Indiana</td>
<td>20,155</td>
</tr>
<tr>
<td>Iowa</td>
<td>6,978</td>
</tr>
<tr>
<td>Kentucky</td>
<td>14,935</td>
</tr>
<tr>
<td>Louisiana</td>
<td>2,251</td>
</tr>
<tr>
<td>Maryland</td>
<td>4,670</td>
</tr>
<tr>
<td>Michigan</td>
<td>8,347</td>
</tr>
<tr>
<td>Minnesota</td>
<td>6,528</td>
</tr>
<tr>
<td>Mississippi</td>
<td>3,066</td>
</tr>
<tr>
<td>Missouri</td>
<td>9,044</td>
</tr>
<tr>
<td>New Jersey</td>
<td>660</td>
</tr>
<tr>
<td>New York</td>
<td>0</td>
</tr>
<tr>
<td>North Carolina</td>
<td>0</td>
</tr>
<tr>
<td>Ohio</td>
<td>25,037</td>
</tr>
<tr>
<td>Pennsylvania</td>
<td>18,009</td>
</tr>
<tr>
<td>South Carolina</td>
<td>2,600</td>
</tr>
<tr>
<td>Tennessee</td>
<td>8,944</td>
</tr>
<tr>
<td>Texas</td>
<td>772</td>
</tr>
<tr>
<td>Virginia</td>
<td>5,144</td>
</tr>
<tr>
<td>West Virginia</td>
<td>16,929</td>
</tr>
<tr>
<td>Wisconsin</td>
<td>4,898</td>
</tr>
</tbody>
</table>

(b) For any CAIR NO\textsubscript{X} unit in the State that achieves NO\textsubscript{X} emission reductions in 2007 and 2008 that are not necessary to comply with any State or federal emissions limitation applicable during such years, the CAIR designated representative of such CAIR NO\textsubscript{X} unit shall demonstrate that, in the absence of allocation to the unit of any State or federal emissions limitation for the control period in 2009, it would create an undue risk to the reliability of electricity supply during such control period.

(c) For any CAIR NO\textsubscript{X} unit in the State whose compliance with the CAIR NO\textsubscript{X} emissions limitation for the control period in 2009 would create an undue risk to the reliability of electricity supply during such control period, the CAIR designated representative of the unit may request the allocation of CAIR NO\textsubscript{X} allowances from the compliance supplement pool under paragraph (a) of this section, in accordance with the following:

(1) The CAIR designated representative of such CAIR NO\textsubscript{X} unit shall submit to the permitting authority by May 1, 2009 a request, in a format specified by the permitting authority, for allocation of an amount of CAIR NO\textsubscript{X} allowances from the compliance supplement pool not exceeding the minimum amount of CAIR NO\textsubscript{X} allowances necessary to remove such undue risk to the reliability of electricity supply.

(2) In the request under paragraph (c)(1) of this section, the CAIR designated representative of such CAIR NO\textsubscript{X} unit shall demonstrate that, in the absence of allocation to the unit of the amount of CAIR NO\textsubscript{X} allowances requested, the unit’s compliance with the CAIR NO\textsubscript{X} emissions limitation for the control period in 2009 would create an undue risk to the reliability of electricity supply during such control period. This demonstration must include a showing that it would not be feasible for the owners and operators of the unit to:

(i) Obtain a sufficient amount of electricity from other electricity generation facilities, during the installation of control technology at the unit for compliance with the CAIR NO\textsubscript{X} emissions limitation, to prevent such undue risk; or

(ii) Obtain under paragraphs (b) and (d) of this section, or otherwise obtain, a sufficient amount of CAIR NO\textsubscript{X} allowances to prevent such undue risk.

(d) The permitting authority will review each request under paragraph (b) or (c) of this section submitted by May 1, 2009 and will allocate CAIR NO\textsubscript{X} allowances for the control period in 2009.
to CAIR NO\(_x\) units in the State and covered by such request as follows:

(1) Upon receipt of each such request, the permitting authority will make any necessary adjustments to the request to ensure that the amount of the CAIR NO\(_x\) allowances requested meets the requirements of paragraph (b) or (c) of this section.

(2) If the State’s compliance supplement pool under paragraph (a) of this section has an amount of CAIR NO\(_x\) allowances not less than the total amount of CAIR NO\(_x\) allowances in all such requests (as adjusted under paragraph (d)(1) of this section), the permitting authority will allocate to each CAIR NO\(_x\) unit covered by such requests the amount of CAIR NO\(_x\) allowances requested (as adjusted under paragraph (d)(1) of this section).

(3) If the State’s compliance supplement pool under paragraph (a) of this section has a smaller amount of CAIR NO\(_x\) allowances than the total amount of CAIR NO\(_x\) allowances in all such requests (as adjusted under paragraph (d)(1) of this section), the permitting authority will allocate CAIR NO\(_x\) allowances to each CAIR NO\(_x\) unit covered by such requests according to the following formula and rounding to the nearest whole allowance as appropriate:

\[
\text{Unit’s allocation} = \text{Unit’s adjusted allocation} \times \frac{\text{State’s compliance supplement pool}}{\text{Total adjusted allocations for all units}}
\]

Where:
- ‘Unit’s allocation’ is the amount of CAIR NO\(_x\) allowances allocated to the unit from the State’s compliance supplement pool.
- ‘Unit’s adjusted allocation’ is the amount of CAIR NO\(_x\) allowances requested for the unit under paragraph (b) or (c) of this section, as adjusted under paragraph (d)(1) of this section.
- “State’s compliance supplement pool” is the amount of CAIR NO\(_x\) allowances in the State’s compliance supplement pool.
- “Total adjusted allocations for all units” is the sum of the amounts of allocations requested for all units under paragraph (b) or (c) of this section, as adjusted under paragraph (d)(1) of this section.

(4) By November 30, 2009, the permitting authority will determine, and submit to the Administrator, the allocations under paragraph (d)(2) or (3) of this section.

(5) By January 1, 2010, the Administrator will record the allocations under paragraph (d)(4) of this section.


Subpart FF—CAIR NO\(_x\) Allowance Tracking System

SOURCE: 70 FR 25339, May 12, 2005, unless otherwise noted.

§ 96.150 [Reserved]

§ 96.151 Establishment of accounts.

(a) Compliance accounts. Except as provided in §96.184(e), upon receipt of a complete certificate of representation under §96.113, the Administrator will establish a compliance account for the CAIR NO\(_x\) source for which the certificate of representation was submitted unless the source already has a compliance account.

(b) General accounts—(1) Application for general account. (i) Any person may apply to open a general account for the purpose of holding and transferring CAIR NO\(_x\) allowances. An application for a general account may designate one and only one CAIR authorized account representative and one and only one alternate CAIR authorized account representative who may act on behalf of the CAIR authorized account representative. The agreement by which the alternate CAIR authorized account representative is selected shall include a procedure for authorizing the alternate CAIR authorized account representative to act in lieu of the CAIR authorized account representative.

(ii) A complete application for a general account shall be submitted to the Administrator and shall include the following elements in a format prescribed by the Administrator:

(A) Name, mailing address, e-mail address (if any), telephone number, and facsimile transmission number (if any) of the CAIR authorized account representative and any alternate CAIR authorized account representative;

(B) Organization name and type of organization, if applicable;

(C) A list of all persons subject to a binding agreement for the CAIR authorized account representative and
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any alternate CAIR authorized account representative to represent their ownership interest with respect to the CAIR NO\textsubscript{X} allowances held in the general account:

(D) The following certification statement by the CAIR authorized account representative and any alternate CAIR authorized account representative: "I certify that I was selected as the CAIR authorized account representative or the alternate CAIR authorized account representative, as applicable, by an agreement that is binding on all persons who have an ownership interest with respect to CAIR NO\textsubscript{X} allowances held in the general account. I certify that I have all the necessary authority to carry out my duties and responsibilities under the CAIR NO\textsubscript{X} Annual Trading Program on behalf of such persons and that each such person shall be fully bound by my representations, actions, inactions, or submissions and by any order or decision issued to me by the Administrator or a court regarding the general account."

(E) The signature of the CAIR authorized account representative and any alternate CAIR authorized account representative and the dates signed.

(iii) Unless otherwise required by the permitting authority or the Administrator, documents of agreement referred to in the application for a general account shall not be submitted to the permitting authority or the Administrator. Neither the permitting authority nor the Administrator shall be under any obligation to review or evaluate the sufficiency of such documents, if submitted.

(2) Authorization of CAIR authorized account representative and alternate CAIR authorized account representative.

(i) Upon receipt by the Administrator of a complete application for a general account under paragraph (b)(1) of this section:

(A) The Administrator will establish a general account for the person or persons for whom the application is submitted.

(B) The CAIR authorized account representative and any alternate CAIR authorized account representative for the general account shall represent and, by his or her representations, actions, inactions, or submissions, legally bind each person who has an ownership interest with respect to CAIR NO\textsubscript{X} allowances held in the general account in all matters pertaining to the CAIR NO\textsubscript{X} Annual Trading Program, notwithstanding any agreement between the CAIR authorized account representative or any alternate CAIR authorized account representative and such person. Any such person shall be bound by any order or decision issued to the CAIR authorized account representative or any alternate CAIR authorized account representative by the Administrator or a court regarding the general account.

(C) Any representation, action, inaction, or submission by any alternate CAIR authorized account representative shall be deemed to be a representation, action, inaction, or submission by the CAIR authorized account representative.

(ii) Each submission concerning the general account shall be submitted, signed, and certified by the CAIR authorized account representative or any alternate CAIR authorized account representative for the persons having an ownership interest with respect to CAIR NO\textsubscript{X} allowances held in the general account. Each such submission shall include the following certification statement by the CAIR authorized account representative or any alternate CAIR authorized account representative: "I am authorized to make this submission on behalf of the persons having an ownership interest with respect to the CAIR NO\textsubscript{X} allowances held in the general account. I certify under penalty of law that I have personally examined and am familiar with, the statements and information submitted in this document and all its attachments. Based on my inquiry of those individuals with primary responsibility for obtaining the information, I certify that the statements and information are to the best of my knowledge and belief true, accurate, and complete. I am aware that there are significant penalties for submitting false statements and information or omitting required statements and information, including the possibility of fine or imprisonment."

(iii) The Administrator will accept or act on a submission concerning the
general account only if the submission has been made, signed, and certified in accordance with paragraph (b)(2)(ii) of this section.

(3) Changing CAIR authorized account representative and alternate CAIR authorized account representative; changes in persons with ownership interest. (i) The CAIR authorized account representative for a general account may be changed at any time upon receipt by the Administrator of a superseding complete application for a general account under paragraph (b)(1) of this section. Notwithstanding any such change, all representations, actions, inactions, and submissions by the previous CAIR authorized account representative before the time and date when the Administrator receives the superseding application for a general account shall be binding on the new CAIR authorized account representative and the persons with an ownership interest with respect to the CAIR NO\textsubscript{X} allowances in the general account.

(ii) The alternate CAIR authorized account representative for a general account may be changed at any time upon receipt by the Administrator of a superseding complete application for a general account under paragraph (b)(1) of this section. Notwithstanding any such change, all representations, actions, inactions, and submissions by the previous alternate CAIR authorized account representative before the time and date when the Administrator receives the superseding application for a general account shall be binding on the new alternate CAIR authorized account representative and the persons with an ownership interest with respect to the CAIR NO\textsubscript{X} allowances in the general account.

(iii)(A) In the event a person having an ownership interest with respect to CAIR NO\textsubscript{X} allowances in the general account is not included in the list of such persons in the application for a general account, such person shall be deemed to be subject to and bound by the application for a general account, the representation, actions, inactions, and submissions of the CAIR authorized account representative and any alternate CAIR authorized account representative for the account, and the decisions and orders of the Administrator or a court, as if the person were included in such list.

(B) Within 30 days following any change in the persons having an ownership interest with respect to CAIR NO\textsubscript{X} allowances in the general account, including the addition of a new person, the CAIR authorized account representative or any alternate CAIR authorized account representative shall submit a revision to the application for a general account amending the list of persons having an ownership interest with respect to the CAIR NO\textsubscript{X} allowances in the general account to include the change.

(4) Objections concerning CAIR authorized account representative and alternate CAIR authorized account representative. (i) Once a complete application for a general account under paragraph (b)(1) of this section has been submitted and received, the Administrator will rely on the application unless and until a superseding complete application for a general account under paragraph (b)(1) of this section is received by the Administrator.

(ii) Except as provided in paragraph (b)(3)(i) or (ii) of this section, no objection or other communication submitted to the Administrator concerning the authorization, or any representation, action, inaction, or submission of the CAIR authorized account representative or any alternate CAIR authorized account representative for a general account shall affect any representation, action, inaction, or submission of the CAIR authorized account representative or any alternate CAIR authorized account representative or the finality of any decision or order by the Administrator under the CAIR NO\textsubscript{X} Annual Trading Program.

(iii) The Administrator will not adjudicate any private legal dispute concerning the authorization or any representation, action, inaction, or submission of the CAIR authorized account representative or any alternate CAIR authorized account representative for a general account, including private legal disputes concerning the proceeds of CAIR NO\textsubscript{X} allowance transfers.
§ 96.152 Responsibilities of CAIR authorized account representative.

Following the establishment of a CAIR NO\textsubscript{X} Allowance Tracking System account, all submissions to the Administrator pertaining to the account, including, but not limited to, submissions concerning the deduction or transfer of CAIR NO\textsubscript{X} allowances in the...
§ 96.153 Recordation of CAIR NO\textsubscript{X} allowance allocations.

(a) By September 30, 2007, the Administrator will record in the CAIR NO\textsubscript{X} source’s compliance account the CAIR NO\textsubscript{X} allowances allocated for the CAIR NO\textsubscript{X} units at the source, as submitted by the permitting authority in accordance with §96.141(a), for the control periods in 2009, 2010, 2011, 2012, 2013, and 2014.

(b) By December 1, 2009, the Administrator will record in the CAIR NO\textsubscript{X} source’s compliance account the CAIR NO\textsubscript{X} allowances allocated for the CAIR NO\textsubscript{X} units at the source, as submitted by the permitting authority in accordance with §96.141(b), for the control period in 2015.

(c) By December 1, 2009 and December 1 of each year thereafter, the Administrator will record in the CAIR NO\textsubscript{X} source’s compliance account the CAIR NO\textsubscript{X} allowances allocated for the CAIR NO\textsubscript{X} units at the source, as submitted by the permitting authority in accordance with §96.141(b), for the control period in the sixth year after the year of the applicable deadline for recordation under this paragraph.

(d) By December 1, 2009 and December 1 of each year thereafter, the Administrator will record in the CAIR NO\textsubscript{X} source’s compliance account the CAIR NO\textsubscript{X} allowances allocated for the CAIR NO\textsubscript{X} units at the source, as submitted by the permitting authority or determined by the Administrator in accordance with §96.141(c), for the control period in the year of the applicable deadline for recordation under this paragraph.

(e) Serial numbers for allocated CAIR NO\textsubscript{X} allowances. When recording the allocation of CAIR NO\textsubscript{X} allowances for a CAIR NO\textsubscript{X} unit in a compliance account, the Administrator will assign each CAIR NO\textsubscript{X} allowance a unique identification number that will include digits identifying the year of the control period for which the CAIR NO\textsubscript{X} allowance is allocated.

[70 FR 25339, May 12, 2005, as amended at 71 FR 25384, Apr. 28, 2006]
Environmental Protection Agency

§ 96.157

this section. Such request shall be submitted to the Administrator by the allowance transfer deadline for the control period and include, in a format prescribed by the Administrator, the identification of the CAIR NOX source and the appropriate serial numbers.

(2) First-in, first-out. The Administrator will deduct CAIR NOX allowances under paragraph (b) or (d) of this section from the source’s compliance account, in the absence of an identification or in the case of a partial identification of CAIR NOX allowances by serial number under paragraph (c)(1) of this section, on a first-in, first-out (FIFO) accounting basis in the following order:

(i) Any CAIR NOX allowances that were allocated to the units at the source, in the order of recordation; and then

(ii) Any CAIR NOX allowances that were allocated to any entity and transferred and recorded in the compliance account pursuant to subpart GG of this part, in the order of recordation.

(d) Deductions for excess emissions. (1) After making the deductions for compliance under paragraph (b) of this section for a control period in a calendar year in which the CAIR NOX source has excess emissions, the Administrator will deduct from the source’s compliance account an amount of CAIR NOX allowances, allocated for the control period in the immediately following calendar year, equal to 3 times the number of tons of the source’s excess emissions.

(2) Any allowance deduction required under paragraph (d)(1) of this section shall not affect the liability of the owners and operators of the CAIR NOX source or the CAIR NOX units at the source for any fine, penalty, or assessment, or their obligation to comply with any other remedy, for the same violations, as ordered under the Clean Air Act or applicable State law.

§ 96.156 Account error.

The Administrator may, at his or her sole discretion and on his or her own motion, correct any error in any CAIR NOX Allowance Tracking System account. Within 10 business days of making such correction, the Administrator will notify the CAIR authorized account representative for the account.

§ 96.157 Closing of general accounts.

(a) The CAIR authorized account representative of a general account may submit to the Administrator a request to close the account, which shall include a correctly submitted allowance transfer under §§96.160 and 96.161 for any CAIR NOX allowances in the account to one or more other CAIR NOX Allowance Tracking System accounts.

(b) If a general account has no allowance transfers in or out of the account for a 12-month period or longer and does not contain any CAIR NOX allowances, the Administrator may notify

[70 FR 25339, May 12, 2005, as amended at 71 FR 25384, Apr. 28, 2006]

§ 96.155 Banking.

(a) CAIR NOX allowances may be banked for future use or transfer in a compliance account or a general account in accordance with paragraph (b) of this section.

(b) Any CAIR NOX allowance that is held in a compliance account or a general account will remain in such account unless and until the CAIR NOX allowance is deducted or transferred under §96.154, §96.156, or subpart GG or II of this part.

[70 FR 25339, May 12, 2005, as amended at 71 FR 25384, Apr. 28, 2006]
§ 96.160 Submission of CAIR NO\textsubscript{X} allowance transfers.

A CAIR authorized account representative seeking recordation of a CAIR NO\textsubscript{X} allowance transfer shall submit the transfer to the Administrator. To be considered correctly submitted, the CAIR NO\textsubscript{X} allowance transfer shall include the following elements, in a format specified by the Administrator:

(a) The account numbers for both the transferor and transferee accounts;

(b) The serial number of each CAIR NO\textsubscript{X} allowance that is in the transferor account and is to be transferred; and

(c) The name and signature of the CAIR authorized account representative of the transferor account and the date signed.

§ 96.161 EPA recordation.

(a) Within 5 business days (except as provided in paragraph (b) of this section) of receiving a CAIR NO\textsubscript{X} allowance transfer, the Administrator will record a CAIR NO\textsubscript{X} allowance transfer by moving each CAIR NO\textsubscript{X} allowance from the transferor account to the transferee account as specified by the request, provided that:

1. The transfer is correctly submitted under §96.160; and

2. The transferor account includes each CAIR NO\textsubscript{X} allowance identified by serial number in the transfer.

(b) A CAIR NO\textsubscript{X} allowance transfer that is submitted for recordation after the allowance transfer deadline for a control period and that includes any CAIR NO\textsubscript{X} allowances allocated for any control period before such allowance transfer deadline will not be recorded until after the Administrator completes the deductions under §96.154 for the control period immediately before such allowance transfer deadline.

(c) Where a CAIR NO\textsubscript{X} allowance transfer submitted for recordation fails to meet the requirements of paragraph (a) of this section, the Administrator will not record such transfer.

§ 96.162 Notification.

(a) Notification of recordation. Within 5 business days of recordation of a CAIR NO\textsubscript{X} allowance transfer under §96.161, the Administrator will notify the CAIR authorized account representatives of both the transferor and transferee accounts.

(b) Notification of non-recordation. Within 10 business days of receipt of a CAIR NO\textsubscript{X} allowance transfer that fails to meet the requirements of §96.161(a), the Administrator will notify the CAIR authorized account representatives of both accounts subject to the transfer of:

1. A decision not to record the transfer, and

2. The reasons for such non-recordation.

(c) Nothing in this section shall preclude the submission of a CAIR NO\textsubscript{X} allowance transfer for recordation following notification of non-recordation.

Subpart HH—Monitoring and Reporting

§ 96.170 General requirements.

The owners and operators, and to the extent applicable, the CAIR designated representative, of a CAIR NO\textsubscript{X} unit, shall comply with the monitoring, recordkeeping, and reporting requirements as provided in this subpart and in subpart H of part 75 of this chapter.
For purposes of complying with such requirements, the definitions in §96.102 and in §72.2 of this chapter shall apply, and the terms “affected unit,” “designated representative,” and “continuous emission monitoring system” (or “CEMS”) in part 75 of this chapter shall be deemed to refer to the terms “CAIR NO\textsubscript{X} unit,” “CAIR designated representative,” and “continuous emission monitoring system” (or “CEMS”) respectively, as defined in §96.102. The owner or operator of a unit that is not a CAIR NO\textsubscript{X} unit but that is monitored under §75.72(b)(2)(ii) of this chapter shall comply with the same monitoring, recordkeeping, and reporting requirements as a CAIR NO\textsubscript{X} unit.

(a) Requirements for installation, certification, and data accounting. The owner or operator of each CAIR NO\textsubscript{X} unit shall:

(1) Install all monitoring systems required under this subpart for monitoring NO\textsubscript{X} mass emissions and individual unit heat input (including all systems required to monitor NO\textsubscript{X} emission rate, NO\textsubscript{X} concentration, stack gas moisture content, stack gas flow rate, CO\textsubscript{2} or O\textsubscript{2} concentration, and fuel flow rate, as applicable, in accordance with §§75.71 and 75.72 of this chapter);

(2) Successfully complete all certification tests required under §96.171 and meet all other requirements of this subpart and part 75 of this chapter applicable to the monitoring systems under paragraph (a)(1) of this section; and

(3) Record, report, and quality-assure the data from the monitoring systems under paragraph (a)(1) of this section.

(b) Compliance deadlines. Except as provided in paragraph (a) of this section, the owner or operator shall meet the monitoring system certification and other requirements of paragraphs (a)(1) and (2) of this section on or before the following dates. The owner or operator shall record, report, and quality-assure the data from the monitoring systems under paragraph (a)(1) of this section on and after the following dates.

(1) For the owner or operator of a CAIR NO\textsubscript{X} unit that commences commercial operation before July 1, 2007, by January 1, 2008.

(2) For the owner or operator of a CAIR NO\textsubscript{X} unit that commences commercial operation on or after July 1, 2007, by the later of the following dates:

(i) January 1, 2008; or

(ii) 90 unit operating days or 180 calendar days, whichever occurs first, after the date on which the unit commences commercial operation.

(3) For the owner or operator of a CAIR NO\textsubscript{X} unit for which construction of a new stack or flue or installation of add-on NO\textsubscript{X} emission controls is completed after the applicable deadline under paragraph (b)(1), (2), (4), or (5) of this section, by 90 unit operating days or 180 calendar days, whichever occurs first, after the date on which emissions first exit to the atmosphere through the new stack or flue or add-on NO\textsubscript{X} emissions controls.

(4) Notwithstanding the dates in paragraphs (b)(1) and (2) of this section, for the owner or operator of a unit for which a CAIR opt-in permit application is submitted and not withdrawn and a CAIR opt-in permit is not yet issued or denied under subpart II of this part, by the date specified in §96.184(b).

(5) Notwithstanding the dates in paragraphs (b)(1) and (2) of this section, for the owner or operator of a CAIR NO\textsubscript{X} opt-in unit under subpart II of this part, by the date on which the CAIR NO\textsubscript{X} opt-in unit enters the CAIR NO\textsubscript{X} Annual Trading Program as provided in §96.184(g).

(c) Reporting data. The owner or operator of a CAIR NO\textsubscript{X} unit that does not meet the applicable compliance date set forth in paragraph (b) of this section for any monitoring system under paragraph (a)(1) of this section shall, for each such monitoring system, determine, record, and report maximum potential (or, as appropriate, minimum potential) values for NO\textsubscript{X} concentration, NO\textsubscript{X} emission rate, stack gas flow rate, stack gas moisture content, fuel flow rate, and any other parameters required to determine NO\textsubscript{X} mass emissions and heat input in accordance with §75.31(b)(2) or (c)(3) of this chapter, section 2.4 of appendix D to part 75 of this chapter, or section 2.5 of appendix E to part 75 of this chapter, as applicable.
§ 96.171 Prohibitions.

(1) No owner or operator of a CAIR NO\(_X\) unit shall use any alternative monitoring system, alternative reference method, or any other alternative to any requirement of this subpart without having obtained prior written approval in accordance with §96.175.

(2) No owner or operator of a CAIR NO\(_X\) unit shall operate the unit so as to discharge, or allow to be discharged, NO\(_X\) emissions to the atmosphere without accounting for all such emissions in accordance with the applicable provisions of this subpart and part 75 of this chapter.

(3) No owner or operator of a CAIR NO\(_X\) unit shall disrupt the continuous emission monitoring system, any portion thereof, or any other approved emission monitoring method, and thereby avoid monitoring and recording NO\(_X\) mass emissions discharged into the atmosphere or heat input, except for periods of recertification or periods when calibration, quality assurance testing, or maintenance is performed in accordance with the applicable provisions of this subpart and part 75 of this chapter.

(4) No owner or operator of a CAIR NO\(_X\) unit shall retire or permanently discontinue use of the continuous emission monitoring system, any component thereof, or any other approved monitoring system under this subpart, except under any one of the following circumstances:

(i) During the period that the unit is covered by an exemption under §96.105 that is in effect;

(ii) The owner or operator is monitoring emissions from the unit with another certified monitoring system approved, in accordance with the applicable provisions of this subpart and part 75 of this chapter, by the permitting authority for use at that unit that provides emission data for the same pollutant or parameter as the retired or discontinued monitoring system; or

(iii) The CAIR designated representative submits notification of the date of certification testing of a replacement monitoring system for the retired or discontinued monitoring system in accordance with §96.171(d)(3)(i).

(e) Long-term cold storage. The owner or operator of a CAIR NO\(_X\) unit is subject to the applicable provisions of part 75 of this chapter concerning units in long-term cold storage.

[70 FR 25339, May 12, 2005, as amended at 71 FR 25384, Apr. 28, 2006]

§ 96.171 Initial certification and recertification procedures.

(a) The owner or operator of a CAIR NO\(_X\) unit shall be exempt from the initial certification requirements of this section for a monitoring system under §96.170(a)(1) if the following conditions are met:

(1) The monitoring system has been previously certified in accordance with part 75 of this chapter; and

(2) The applicable quality-assurance and quality-control requirements of §75.21 of this chapter and appendix B, appendix D, and appendix E to part 75 of this chapter are fully met for the certified monitoring system described in paragraph (a)(1) of this section.

(b) The recertification provisions of this section shall apply to a monitoring system under §96.170(a)(1) exempt from initial certification requirements under paragraph (a) of this section.

(c) If the Administrator has previously approved a petition under §75.17(a) or (b) of this chapter for apportioning the NO\(_X\) emission rate measured in a common stack or a petition under §75.66 of this chapter for an alternative to a requirement in §75.12 or §75.17 of this chapter, the CAIR designated representative shall resubmit the petition to the Administrator under §96.175(a) to determine whether the approval applies under the CAIR NO\(_X\) Annual Trading Program.

(d) Except as provided in paragraph (a) of this section, the owner or operator of a CAIR NO\(_X\) unit shall comply with the following initial certification and recertification procedures for a continuous monitoring system (i.e., a continuous emission monitoring system and an excepted monitoring system under appendices D and E to part 75 of this chapter) under §96.170(a)(1).

The owner or operator of a unit that qualifies to use the low mass emissions excepted monitoring methodology under §75.19 of this chapter or that qualifies to use an alternative monitoring system under subpart E of part
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75 of this chapter shall comply with the procedures in paragraph (e) or (f) of this section respectively.

(1) Requirements for initial certification. The owner or operator shall ensure that each continuous monitoring system under §96.170(a)(1) (including the automated data acquisition and handling system) successfully completes all of the initial certification testing required under §75.20 of this chapter by the applicable deadline in §96.170(b). In addition, whenever the owner or operator installs a monitoring system to meet the requirements of this subpart in a location where no such monitoring system was previously installed, initial certification in accordance with §75.20 of this chapter is required.

(2) Requirements for recertification. Whenever the owner or operator makes a replacement, modification, or change in any certified continuous emission monitoring system under §96.170(a)(1) that may significantly affect the ability of the system to accurately measure or record NO\textsubscript{X} mass emissions or heat input rate or to meet the quality-assurance and quality-control requirements of §75.21 of this chapter, the owner or operator shall recertify the monitoring system in accordance with §75.20 of this chapter. Furthermore, whenever the owner or operator makes a replacement, modification, or change to the flue gas handling system or the unit’s operation that may significantly change the stack flow or concentration profile, the owner or operator shall recertify each continuous emission monitoring system whose accuracy is potentially affected by the change, in accordance with §75.20(b) of this chapter. Examples of changes to a continuous emission monitoring system that require recertification include replacement of the analyzer, complete replacement of an existing continuous emission monitoring system, or change in location or orientation of the sampling probe or site. Any fuel flowmeter system, and any excepted NO\textsubscript{X} monitoring system under appendix E to part 75 of this chapter, under §96.170(a)(1) are subject to the recertification requirements in §75.20(g)(6) of this chapter.

(3) Approval process for initial certification and recertification. Paragraphs (d)(3)(i) through (iv) of this section apply to both initial certification and recertification of a continuous monitoring system under §96.170(a)(1). For recertifications, replace the words “certification” and “initial certification” with the word “recertification”, replace the word “certified” with the word “recertified,” and follow the procedures in §§75.20(b)(5) and (g)(7) of this chapter in lieu of the procedures in paragraph (d)(3)(v) of this section.

(i) Notification of certification. The CAIR designated representative shall submit to the permitting authority, the appropriate EPA Regional Office, and the Administrator written notice of the dates of certification testing, in accordance with §96.173.

(ii) Certification application. The CAIR designated representative shall submit to the permitting authority a certification application for each monitoring system. A complete certification application shall include the information specified in §75.63 of this chapter.

(iii) Provisional certification date. The provisional certification date for a monitoring system shall be determined in accordance with §75.20(a)(3) of this chapter. A provisionally certified monitoring system may be used under the CAIR NO\textsubscript{X} Annual Trading Program for a period not to exceed 120 days after receipt by the permitting authority of the complete certification application for the monitoring system under paragraph (d)(3)(i) of this section. Data measured and recorded by the provisionally certified monitoring system, in accordance with the requirements of part 75 of this chapter, will be considered valid quality-assured data (retroactive to the date and time of provisional certification), provided that the permitting authority does not invalidate the provisional certification by issuing a notice of disapproval within 120 days of the date of receipt of the complete certification application by the permitting authority.

(iv) Certification application approval process. The permitting authority will issue a written notice of approval or disapproval of the certification application to the owner or operator within
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120 days of receipt of the complete certification application under paragraph (d)(3)(ii) of this section. In the event the permitting authority does not issue such a notice within such 120-day period, each monitoring system that meets the applicable performance requirements of part 75 of this chapter and is included in the certification application will be deemed certified for use under the CAIR NO_X Annual Trading Program.

(A) Approval notice. If the certification application is complete and shows that each monitoring system meets the applicable performance requirements of part 75 of this chapter, then the permitting authority will issue a written notice of approval of the certification application within 120 days of receipt.

(B) Incomplete application notice. If the certification application is not complete, then the permitting authority will issue a written notice of incompleteness that sets a reasonable date by which the CAIR designated representative must submit the additional information required to complete the certification application. If the CAIR designated representative does not comply with the notice of incompleteness by the specified date, then the permitting authority may issue a notice of disapproval under paragraph (d)(3)(iv)(C) of this section. The 120-day review period shall not begin before receipt of a complete certification application.

(C) Disapproval notice. If the certification application shows that any monitoring system does not meet the performance requirements of this chapter or if the certification application is incomplete and the requirement for disapproval under paragraph (d)(3)(iv)(B) of this section is met, then the permitting authority will issue a written notice of disapproval of the certification application. Upon issuance of such notice of disapproval, the provisional certification is invalidated by the permitting authority and the data measured and recorded by each uncertified monitoring system shall not be considered valid quality-assured data beginning with the date and hour of provisional certification (as defined under §75.20(a)(3) of this chapter). The owner or operator shall follow the procedures for loss of certification in paragraph (d)(3)(v) of this section for each monitoring system that is disapproved for initial certification.

(D) Audit decertification. The permitting authority or, for a CAIR NO_X opt-in unit or a unit for which a CAIR opt-in permit application is submitted and not withdrawn and a CAIR opt-in permit is not yet issued or denied under subpart II of this part, the Administrator issues a notice of disapproval of the certification status of a monitor in accordance with §96.172(b).

(v) Procedures for loss of certification. If the permitting authority or the Administrator issues a notice of disapproval of a certification application under paragraph (d)(3)(iv)(C) of this section or a notice of disapproval of certification status under paragraph (d)(3)(iv)(D) of this section, then:

(A) The owner or operator shall submit the following values, for each disapproved monitoring system, for each hour of unit operation during the period of invalid data specified under §75.20(a)(4)(iii), §75.20(g)(7), or §75.21(e) of this chapter and continuing until the applicable date and hour specified under §75.20(a)(5)(i) or (g)(7) of this chapter:

(1) For a disapproved NO_X emission rate (i.e., NO_X-diluent) system, the maximum potential NO_X emission rate, as defined in §72.2 of this chapter.

(2) For a disapproved NO_X pollutant concentration monitor and disapproved flow monitor, respectively, the maximum potential concentration of NO_X and the maximum potential flow rate, as defined in sections 2.1.2.1 and 2.1.4.1 of appendix A to part 75 of this chapter.

(3) For a disapproved moisture monitoring system and disapproved diluent gas monitoring system, respectively, the minimum potential moisture percentage and either the maximum potential CO_2 concentration or the minimum potential O_2 concentration (as applicable), as defined in sections 2.1.5, 2.1.3.1, and 2.1.3.2 of appendix A to part 75 of this chapter.

(4) For a disapproved fuel flowmeter system, the maximum potential fuel flow rate, as defined in section 2.4.2.1 of appendix D to part 75 of this chapter.
(5) For a disapproved excepted NO\textsubscript{X} monitoring system under appendix E to part 75 of this chapter, the fuel-specific maximum potential NO\textsubscript{X} emission rate, as defined in §72.2 of this chapter.

(B) The CAIR designated representative shall submit a notification of certification retest dates and a new certification application in accordance with paragraphs (d)(3)(i) and (ii) of this section.

(C) The owner or operator shall repeat all certification tests or other requirements that were failed by the monitoring system, as indicated in the permitting authority’s or the Administrator’s notice of disapproval, no later than 30 unit operating days after the date of issuance of the notice of disapproval.

(e) Initial certification and recertification procedures for units using the low mass emission excepted methodology under §75.19 of this chapter. The owner or operator of a unit qualified to use the low mass emissions (LME) excepted methodology under §75.19 of this chapter shall meet the applicable certification and recertification requirements in §§75.19(a)(2) and 75.20(h) of this chapter. If the owner or operator of such a unit elects to certify a fuel flowmeter system for heat input determination, the owner or operator shall also meet the certification and recertification requirements in §75.20(g) of this chapter.

(f) Certification/recertification procedures for alternative monitoring systems. The CAIR designated representative of each unit for which the owner or operator intends to use an alternative monitoring system approved by the Administrator and, if applicable, the permitting authority under subpart E of part 75 of this chapter shall comply with the applicable notification and application procedures of §75.20(f) of this chapter.

§ 96.173 Notifications.

The CAIR designated representative for a CAIR NO\textsubscript{X} unit shall submit written notice to the permitting authority and the Administrator in accordance with §75.61 of this chapter.

§ 96.172 Out of control periods.

(a) Whenever any monitoring system fails to meet the quality-assurance and quality-control requirements or data validation requirements of part 75 of this chapter, data shall be substituted using the applicable missing data procedures in subpart D or subpart H of, or appendix D or appendix E to, part 75 of this chapter.

(b) Audit decertification. Whenever both an audit of a monitoring system and a review of the initial certification or recertification application reveal that any monitoring system should not have been certified or recertified because it did not meet a particular performance specification or other requirement under §96.171 or the applicable provisions of part 75 of this chapter, both at the time of the initial certification or recertification application submission and at the time of the audit, the permitting authority or, for a CAIR NO\textsubscript{X} opt-in unit or a unit for which a CAIR opt-in permit application is submitted and not withdrawn and a CAIR opt-in permit is not yet issued or denied under subpart II of this part, the Administrator will issue a notice of disapproval of the certification status of such monitoring system. For the purposes of this paragraph, an audit shall be either a field audit or an audit of any information submitted to the permitting authority or the Administrator. By issuing the notice of disapproval, the permitting authority or the Administrator revokes prospectively the certification status of the monitoring system. The data measured and recorded by the monitoring system shall not be considered valid quality-assured data from the date of issuance of the notification of the revoked certification status until the date and time that the owner or operator completes subsequently approved initial certification or recertification tests for the monitoring system. The owner or operator shall follow the applicable initial certification or recertification procedures in §96.171 for each disapproved monitoring system.

§ 96.174 Recordkeeping and reporting.

(a) General provisions. The CAIR designated representative shall comply
with all recordkeeping and reporting requirements in this section, the applicable recordkeeping and reporting requirements under §75.73 of this chapter, and the requirements of §96.110(e)(1).

(b) Monitoring Plans. The owner or operator of a CAIR NO\_X unit shall comply with requirements of §75.73(c) and (e) of this chapter and, for a unit for which a CAIR opt-in permit application is submitted and not withdrawn and a CAIR opt-in permit is not yet issued or denied under subpart II of this part, §§96.183 and 96.184(a).

(c) Certification Applications. The CAIR designated representative shall submit an application to the permitting authority within 45 days after completing all initial certification or recertification tests required under §96.171, including the information required under §75.63 of this chapter.

(d) Quarterly reports. The CAIR designated representative shall submit quarterly reports, as follows:

(1) The CAIR designated representative shall report the NO\_X mass emissions data and heat input data for the CAIR NO\_X unit, in an electronic quarterly report in a format prescribed by the Administrator, for each calendar quarter beginning with:

   (i) For a unit that commences commercial operation before July 1, 2007, the calendar quarter covering January 1, 2008 through March 31, 2008;

   (ii) For a unit that commences commercial operation on or after July 1, 2007, the calendar quarter corresponding to the earlier of the date of provisional certification or the applicable deadline for initial certification under §96.170(b), unless that quarter is the third or fourth quarter of 2007, in which case reporting shall commence in the quarter covering January 1, 2008 through March 31, 2008;

   (iii) Notwithstanding paragraphs (d)(1)(i) and (ii) of this section, for a unit for which a CAIR opt-in permit application is submitted and not withdrawn and a CAIR opt-in permit is not yet issued or denied under subpart II of this part, the calendar quarter corresponding to the date specified in §96.184(b); and

   (iv) Notwithstanding paragraphs (d)(1)(i) and (ii) of this section, for a CAIR NO\_X opt-in unit under subpart II of this part, the calendar quarter corresponding to the date on which the CAIR NO\_X opt-in unit enters the CAIR NO\_X Annual Trading Program as provided in §96.184(g).

(2) The CAIR designated representative shall submit each quarterly report to the Administrator within 30 days following the end of the calendar quarter covered by the report. Quarterly reports shall be submitted in the manner specified in §75.73(f) of this chapter.

(3) For CAIR NO\_X units that are also subject to an Acid Rain emissions limitation or the CAIR NO\_X Ozone Season Trading Program, CAIR SO\_2 Trading Program, or Hg Budget Trading Program, quarterly reports shall include the applicable data and information required by subparts F through I of part 75 of this chapter as applicable, in addition to the NO\_X mass emission data, heat input data, and other information required by this subpart.

(e) Compliance certification. The CAIR designated representative shall submit to the Administrator a compliance certification (in a format prescribed by the Administrator) in support of each quarterly report based on reasonable inquiry of those persons with primary responsibility for ensuring that all of the unit’s emissions are correctly and fully monitored. The certification shall state that:

   (1) The monitoring data submitted were recorded in accordance with the applicable requirements of this subpart and part 75 of this chapter, including the quality assurance procedures and specifications; and

   (2) For a unit with add-on NO\_X emission controls and for all hours where NO\_X data are substituted in accordance with §75.34(a)(1) of this chapter, the add-on emission controls were operating within the range of parameters listed in the quality assurance/quality control program under appendix B to part 75 of this chapter and the substitute data values do not systematically underestimate NO\_X emissions.

[70 FR 25339, May 12, 2005, as amended at 71 FR 25385, Apr. 28, 2006]
§ 96.175 Petitions.
(a) Except as provided in paragraph (b)(2) of this section, the CAIR designated representative of a CAIR NO\textsubscript{X} unit that is subject to an Acid Rain emissions limitation may submit a petition under §75.66 of this chapter to the Administrator requesting approval to apply an alternative to any requirement of this subpart. Application of an alternative to any requirement of this subpart is in accordance with this subpart only to the extent that the petition is approved in writing by the Administrator, in consultation with the permitting authority.

(b)(1) The CAIR designated representative of a CAIR NO\textsubscript{X} unit that is not subject to an Acid Rain emissions limitation may submit a petition under §75.66 of this chapter to the permitting authority and the Administrator requesting approval to apply an alternative to any requirement of this subpart. Application of an alternative to any requirement of this subpart is in accordance with this subpart only to the extent that the petition is approved in writing by both the permitting authority and the Administrator.

(2) The CAIR designated representative of a CAIR NO\textsubscript{X} unit that is subject to an Acid Rain emissions limitation may submit a petition under §75.66 of this chapter to the permitting authority and the Administrator requesting approval to apply an alternative to any requirement concerning any additional continuous emission monitoring system required under §75.72 of this chapter. Application of an alternative to any such requirement is in accordance with this subpart only to the extent that the petition is approved in writing by both the permitting authority and the Administrator.

§ 96.180 Applicability.
A CAIR NO\textsubscript{X} opt-in unit must be a unit that:
(a) Is located in the State;
(b) Is not a CAIR NO\textsubscript{X} unit under §96.104 and is not covered by a retired unit exemption under §96.105 that is in effect;
(c) Is not covered by a retired unit exemption under §72.8 of this chapter that is in effect;
(d) Has or is required or qualified to have a title V operating permit or other federally enforceable permit; and
(e) Vents all of its emissions to a stack and can meet the monitoring, recordkeeping, and reporting requirements of subpart HH of this part.

§ 96.181 General.
(a) Except as otherwise provided in §§96.101 through 96.104, §§96.106 through 96.108, and subparts BB and CC and subparts FF through HH of this part, a CAIR NO\textsubscript{X} opt-in unit shall be treated as a CAIR NO\textsubscript{X} unit for purposes of applying such sections and subparts of this part.

(b) Solely for purposes of applying, as provided in this subpart, the requirements of subpart HH of this part to a unit for which a CAIR opt-in permit application is submitted and not withdrawn and a CAIR opt-in permit is not yet issued or denied under this subpart, such unit shall be treated as a CAIR NO\textsubscript{X} unit before issuance of a CAIR opt-in permit for such unit.

§ 96.182 CAIR designated representative.
Any CAIR NO\textsubscript{X} opt-in unit, and any unit for which a CAIR opt-in permit application is submitted and not withdrawn and a CAIR opt-in permit is not yet issued or denied under this subpart, located at the same source as one or more CAIR NO\textsubscript{X} units shall have the same CAIR designated representative and alternate CAIR designated representative as such CAIR NO\textsubscript{X} units.

§ 96.183 Applying for CAIR opt-in permit.
(a) Applying for initial CAIR opt-in permit. The CAIR designated representative of a unit meeting the requirements for a CAIR NO\textsubscript{X} opt-in unit in §96.180 may apply for an initial CAIR opt-in permit at any time, except as provided under §96.186(f) and (g), and, in order to apply, must submit the following:
(1) A complete CAIR permit application under §96.122;
(2) A certification, in a format specified by the permitting authority, that the unit:
   (i) Is not a CAIR NO\textsubscript{X} unit under §96.104 and is not covered by a retired unit exemption under §96.105 that is in effect;
   (ii) Is not covered by a retired unit exemption under §72.8 of this chapter that is in effect;
   (iii) Vents all of its emissions to a stack, and
   (iv) Has documented heat input for more than 876 hours during the 6 months immediately preceding submission of the CAIR permit application under §96.122;
(3) A monitoring plan in accordance with subpart HH of this part;
(4) A complete certificate of representation under §96.113 consistent with §96.182, if no CAIR designated representative has been previously designated for the source that includes the unit; and
(5) A statement, in a format specified by the permitting authority, whether the CAIR designated representative requests that the unit be allocated CAIR NO\textsubscript{X} allowances under §96.188(b) or §96.188(c) (subject to the conditions in §§96.194(h) and 96.186(g)). If allocation under §96.188(c) is requested, this statement shall include a statement that the owners and operators of the unit intend to repower the unit before January 1, 2015 and that they will provide, upon request, documentation demonstrating such intent.

(b) Duty to reapply.
(1) The CAIR designated representative of a CAIR NO\textsubscript{X} opt-in unit shall submit a complete CAIR permit application under §96.122 to renew the CAIR opt-in unit permit in accordance with the permitting authority’s regulations for title V operating permits, or the permitting authority’s regulations for other federally enforceable permits if applicable, addressing permit renewal.
(2) Unless the permitting authority issues a notification of acceptance of withdrawal of the CAIR NO\textsubscript{X} opt-in unit from the CAIR NO\textsubscript{X} Annual Trading Program in accordance with §96.186 or the unit becomes a CAIR NO\textsubscript{X} unit under §96.104, the CAIR NO\textsubscript{X} opt-in unit shall remain subject to the requirements for a CAIR NO\textsubscript{X} opt-in unit, even if the CAIR designated representative for the CAIR NO\textsubscript{X} opt-in unit fails to submit a CAIR permit application that is required for renewal of the CAIR opt-in permit under paragraph (b)(1) of this section.

§96.184 Opt-in process.
The permitting authority will issue or deny a CAIR opt-in permit for a unit for which an initial application for a CAIR opt-in permit under §96.183 is submitted in accordance with the following:

(a) Interim review of monitoring plan.
The permitting authority and the Administrator will determine, on an interim basis, the sufficiency of the monitoring plan accompanying the initial application for a CAIR opt-in permit under §96.183. A monitoring plan is sufficient, for purposes of interim review, if the plan appears to contain information demonstrating that the NO\textsubscript{X} emissions rate and heat input of the unit and all other applicable parameters are monitored and reported in accordance with subpart HH of this part. A determination of sufficiency shall not be construed as acceptance or approval of the monitoring plan.

(b) Monitoring and reporting.
(1)(i) If the permitting authority and the Administrator determine that the monitoring plan is sufficient under paragraph (a) of this section, the owner or operator shall monitor and report the NO\textsubscript{X} emissions rate and the heat input of the unit and all other applicable parameters, in accordance with subpart HH of this part, starting on the date of certification of the appropriate monitoring systems under subpart HH of this part and continuing until a CAIR opt-in permit is denied under §96.184(f) or, if a CAIR opt-in permit is issued, the date and time when the unit is withdrawn from the CAIR NO\textsubscript{X} Annual Trading Program in accordance with §96.186.
(2) If the permitting authority issues a notification of acceptance of withdrawal of the CAIR NO\textsubscript{X} opt-in unit from the CAIR NO\textsubscript{X} Annual Trading Program in accordance with §96.186 or the unit becomes a CAIR NO\textsubscript{X} unit under §96.104, the CAIR NO\textsubscript{X} opt-in unit shall remain subject to the requirements for a CAIR NO\textsubscript{X} opt-in unit, even if the CAIR designated representative for the CAIR NO\textsubscript{X} opt-in unit fails to submit a CAIR permit application that is required for renewal of the CAIR opt-in permit under paragraph (b)(1) of this section.

[70 FR 25339, May 12, 2005, as amended at 71 FR 25385, Apr. 28, 2006]
availability must not be less than 90 percent under subpart HH of this part and the unit must be in full compliance with any applicable State or Federal emissions or emissions-related requirements.

(2) To the extent the NOx emissions rate and the heat input of the unit are monitored and reported in accordance with subpart HH of this part for one or more control periods, in addition to the control period under paragraph (b)(1)(ii) of this section, during which control periods monitoring system availability is not less than 90 percent under subpart HH of this part and the unit is in full compliance with any applicable State or Federal emissions or emissions-related requirements and which control periods begin not more than 3 years before the unit enters the CAIR NOx Annual Trading Program under §96.184(g), such information shall be used as provided in paragraphs (c) and (d) of this section.

(c) Baseline heat input. The unit’s baseline heat input shall equal:

(1) If the unit’s NOx emissions rate and heat input are monitored and reported for only one control period, in accordance with paragraph (b)(1) of this section, the unit’s total heat input (in mmBtu) for the control period; or

(2) If the unit’s NOx emissions rate and heat input are monitored and reported for more than one control period, in accordance with paragraphs (b)(1) and (2) of this section, the average of the amounts of the unit’s total heat input (in mmBtu) for the control period; or

(3) If the unit’s NOx emissions rate and heat input are monitored and reported for more than one control period, in accordance with paragraphs (b)(1) and (2) of this section, and the unit has add-on NOx emission controls during any such control periods, the average of the amounts of the unit’s NOx emissions rate (in lb/mmBtu) for the control periods under paragraphs (b)(1)(ii) and (2) of this section; or

(e) Issuance of CAIR opt-in permit. After calculating the baseline heat input and the baseline NOx emissions rate for the unit under paragraphs (c) and (d) of this section and if the permitting authority determines that the CAIR designated representative shows that the unit meets the requirements for a CAIR NOx opt-in unit in §96.180 and meets the elements certified in §96.183(a)(2), the permitting authority will issue a CAIR opt-in permit. The permitting authority will provide a copy of the CAIR opt-in permit to the Administrator, who will then establish a compliance account for the source that includes the CAIR NOx opt-in unit unless the source already has a compliance account.

(f) Issuance of denial of CAIR opt-in permit. Notwithstanding paragraphs (a) through (e) of this section, if at any time before issuance of a CAIR opt-in permit for the unit, the permitting authority determines that the CAIR designated representative fails to show that the unit meets the requirements for a CAIR NOx opt-in unit in §96.180 or meets the elements certified in §96.183(a)(2), the permitting authority will issue a denial of a CAIR opt-in permit for the unit.

(g) Date of entry into CAIR NOx Annual Trading Program. A unit for which an initial CAIR opt-in permit is issued by the permitting authority shall become a CAIR NOx opt-in unit, and a CAIR NOx unit, as of the later of January 1, 2009 or January 1 of the first control period during which such CAIR opt-in permit is issued.

(h) Repowered CAIR NOx opt-in unit. (1) If CAIR designated representative
requests, and the permitting authority issues a CAIR opt-in permit providing for allocation to a CAIR NO\textsubscript{X} opt-in unit of CAIR NO\textsubscript{X} allowances under §96.188(c) and such unit is repowered after its date of entry into the CAIR NO\textsubscript{X} Annual Trading Program under paragraph (g) of this section, the repowered unit shall be treated as a CAIR NO\textsubscript{X} opt-in unit replacing the original CAIR NO\textsubscript{X} opt-in unit, as of the date of start-up of the repowered unit’s combustion chamber.

(2) Notwithstanding paragraphs (c) and (d) of this section, as of the date of start-up under paragraph (h)(1) of this section, the repowered unit shall be deemed to have the same date of commencement of operation, date of commencement of commercial operation, baseline heat input, and baseline NO\textsubscript{X} emission rate as the original CAIR NO\textsubscript{X} opt-in unit, and the original CAIR NO\textsubscript{X} opt-in unit shall no longer be treated as a CAIR NO\textsubscript{X} opt-in unit or a CAIR NO\textsubscript{X} unit.

§ 96.186 Withdrawal from CAIR NO\textsubscript{X} Annual Trading Program.

Except as provided under paragraph (g) of this section, a CAIR NO\textsubscript{X} opt-in unit may withdraw from the CAIR NO\textsubscript{X} Annual Trading Program, but only if the permitting authority issues a notification to the CAIR designated representative of the CAIR NO\textsubscript{X} opt-in unit of the acceptance of the withdrawal of the CAIR NO\textsubscript{X} opt-in unit in accordance with paragraph (d) of this section.

(a) Requesting withdrawal. In order to withdraw a CAIR CAIR NO\textsubscript{X} opt-in unit from the CAIR NO\textsubscript{X} Annual Trading Program, the CAIR designated representative of the CAIR NO\textsubscript{X} opt-in unit shall submit to the permitting authority a request to withdraw effective as of midnight of December 31 of a specified calendar year, which date must be at least 4 years after December 31 of the year of entry into the CAIR NO\textsubscript{X} Annual Trading Program under §96.184(g). The request must be submitted no later than 90 days before the requested effective date of withdrawal.

(b) Conditions for withdrawal. Before a CAIR NO\textsubscript{X} opt-in unit covered by a request under paragraph (a) of this section may withdraw from the CAIR NO\textsubscript{X} Annual Trading Program and the CAIR opt-in permit may be terminated under paragraph (e) of this section, the following conditions must be met:

(1) For the control period ending on the date on which the withdrawal is to be effective, the source that includes the CAIR NO\textsubscript{X} opt-in unit must meet the requirement to hold CAIR NO\textsubscript{X} allowances under §96.106(c) and cannot have any excess emissions.

§ 96.185 CAIR opt-in permit contents.

(a) Each CAIR opt-in permit will contain:

(1) All elements required for a complete CAIR permit application under §96.122;

(2) The certification in §96.183(a)(2);

(3) The unit’s baseline heat input under §96.184(c);

(4) The unit’s baseline NO\textsubscript{X} emission rate under §96.184(d);

(5) A statement whether the unit is to be allocated CAIR NO\textsubscript{X} allowances §96.188(b) or §96.188(c) (subject to the conditions in §§96.184(h) and 96.186(g));

(6) A statement that the unit may withdraw from the CAIR NO\textsubscript{X} Annual Trading Program only in accordance with §96.186; and

(7) A statement that the unit is subject to, and the owners and operators of the unit must comply with, the requirements of §96.187.

(b) Each CAIR opt-in permit is deemed to incorporate automatically the definitions of terms under §96.102 and, upon recordation by the Administrator under subpart FF or GG of this part or this subpart, every allocation, transfer, or deduction of CAIR NO\textsubscript{X} allowances to or from the compliance account of the source that includes a CAIR NO\textsubscript{X} opt-in unit covered by the CAIR opt-in permit.
(2) After the requirement for withdrawal under paragraph (b)(1) of this section is met, the Administrator will deduct from the compliance account of the source that includes the CAIR NOₓ opt-in unit CAIR NOₓ allowances equal in amount to and allocated for the same or a prior control period as any CAIR NOₓ allowances allocated to the CAIR NOₓ opt-in unit under §96.188 for any control period for which the withdrawal is to be effective. If there are no remaining CAIR NOₓ units at the source, the Administrator will close the compliance account, and the owners and operators of the CAIR NOₓ opt-in unit may submit a CAIR NOₓ allowance transfer for any remaining CAIR NOₓ allowances to another CAIR NOₓ Allowance Tracking System in accordance with subpart GG of this part.

(c) Notification. (1) After the requirements for withdrawal under paragraphs (a) and (b) of this section are met (including deduction of the full amount of CAIR NOₓ allowances required), the permitting authority will issue a notification to the CAIR designated representative of the CAIR NOₓ opt-in unit of the acceptance of the withdrawal of the CAIR NOₓ opt-in unit as of midnight on December 31 of the calendar year for which the withdrawal was requested.

(2) If the requirements for withdrawal under paragraphs (a) and (b) of this section are not met, the permitting authority will issue a notification to the CAIR designated representative of the CAIR NOₓ opt-in unit that the CAIR NOₓ opt-in unit’s request to withdraw is denied. Such CAIR NOₓ opt-in unit shall continue to be a CAIR NOₓ opt-in unit.

(d) Permit amendment. After the permitting authority issues a notification under paragraph (c)(1) of this section that the requirements for withdrawal have been met, the permitting authority will revise the CAIR permit covering the CAIR NOₓ opt-in unit to terminate the CAIR opt-in permit for such unit as of the effective date specified under paragraph (c)(1) of this section. The unit shall continue to be a CAIR NOₓ opt-in unit until the effective date of the termination and shall comply with all requirements under the CAIR NOₓ Annual Trading Program concerning any control periods for which the unit is a CAIR NOₓ opt-in unit, even if such requirements arise or must be complied with after the withdrawal takes effect.

(e) Reapplication upon failure to meet conditions of withdrawal. If the permitting authority denies the CAIR NOₓ opt-in unit’s request to withdraw, the CAIR designated representative may submit another request to withdraw in accordance with paragraphs (a) and (b) of this section.

(f) Ability to reapply to the CAIR NOₓ Annual Trading Program. Once a CAIR NOₓ opt-in unit withdraws from the CAIR NOₓ Annual Trading Program and its CAIR opt-in permit is terminated under this section, the CAIR designated representative may not submit another application for a CAIR opt-in permit under §96.183 for such CAIR NOₓ opt-in unit before the date that is 4 years after the date on which the withdrawal became effective. Such new application for a CAIR opt-in permit will be treated as an initial application for a CAIR opt-in permit under §96.184.

(g) Inability to withdraw. Notwithstanding paragraphs (a) through (f) of this section, a CAIR NOₓ opt-in unit shall not be eligible to withdraw from the CAIR NOₓ Annual Trading Program if the CAIR designated representative of the CAIR NOₓ opt-in unit requests, and the permitting authority issues a CAIR NOₓ opt-in permit providing for, allocation to the CAIR NOₓ opt-in unit of CAIR NOₓ allowances under §96.188(c).

[70 FR 25385, May 12, 2005, as amended at 71 FR 25385, Apr. 28, 2006]

§96.187 Change in regulatory status.

(a) Notification. If a CAIR NOₓ opt-in unit becomes a CAIR NOₓ unit under §96.104, then the CAIR designated representative shall notify in writing the permitting authority and the Administrator of such change in the CAIR NOₓ opt-in unit’s regulatory status, within 30 days of such change.

(b) Permitting authority’s and Administrator’s actions. (1) If a CAIR NOₓ opt-in unit becomes a CAIR NOₓ unit under §96.104, the permitting authority will revise the CAIR NOₓ opt-in unit’s CAIR opt-in permit to meet the requirements...
§ 96.188 CAIR NOₓ allowance allocations to CAIR NOₓ opt-in units.

(a) Timing requirements. (1) When the CAIR opt-in permit is issued under § 96.184(e), the permitting authority will allocate CAIR NOₓ allowances to the CAIR NOₓ opt-in unit, and submit to the Administrator the allocation for the control period in which a CAIR NOₓ opt-in unit enters the CAIR NOₓ Annual Trading Program under § 96.184(g), in accordance with paragraph (b) or (c) of this section.

(2) By no later than October 31 of the control period after the control period in which a CAIR NOₓ opt-in unit enters the CAIR NOₓ Annual Trading Program under § 96.184(c); or

(b) Calculation of allocation. For each control period for which a CAIR NOₓ opt-in unit is to be allocated CAIR NOₓ allowances, the permitting authority will allocate in accordance with the following procedures:

(1) The heat input (in mmBtu) used for calculating the CAIR NOₓ allowance allocation will be the lesser of:

(i) The CAIR NOₓ opt-in unit’s baseline heat input determined under § 96.184(c); or

(ii) The CAIR NOₓ opt-in unit’s heat input, as determined in accordance with subpart HH of this part, for the

of a CAIR permit under § 96.123, and remove the CAIR opt-in permit provisions, as of the date on which the CAIR NOₓ opt-in unit becomes a CAIR NOₓ unit under § 96.104.

(2)(i) The Administrator will deduct from the compliance account of the source that includes the CAIR NOₓ opt-in unit that becomes a CAIR NOₓ unit under § 96.104, CAIR NOₓ allowances equal in amount to and allocated for the same or a prior control period as:

(A) Any CAIR NOₓ allowances allocated to the CAIR NOₓ opt-in unit under § 96.188 for any control period after the date on which the CAIR NOₓ opt-in unit becomes a CAIR NOₓ unit under § 96.104; and

(B) If the date on which the CAIR NOₓ opt-in unit becomes a CAIR NOₓ unit under § 96.104 is not December 31, the CAIR NOₓ allowances allocated to the CAIR NOₓ opt-in unit under § 96.188 for the control period that includes the date on which the CAIR NOₓ opt-in unit becomes a CAIR NOₓ unit under § 96.104, multiplied by the ratio of the number of days, in the control period, starting with the date on which the CAIR NOₓ opt-in unit becomes a CAIR NOₓ unit under § 96.104 divided by the total number of days in the control period and rounded to the nearest whole allowance as appropriate.

(ii) The CAIR designated representative shall ensure that the compliance account of the source that includes the CAIR NOₓ opt-in unit that becomes a CAIR NOₓ unit under § 96.104 contains the CAIR NOₓ allowances necessary for completion of the deduction under paragraph (b)(2)(i) of this section.

(3)(i) For every control period after the date on which the CAIR NOₓ opt-in unit becomes a CAIR NOₓ unit under § 96.104, the CAIR NOₓ opt-in unit will be allocated CAIR NOₓ allowances under § 96.142.

(ii) If the date on which the CAIR NOₓ opt-in unit becomes a CAIR NOₓ unit under § 96.104 is not December 31, the following amount of CAIR NOₓ allowances will be allocated to the CAIR NOₓ opt-in unit (as a CAIR NOₓ unit) under § 96.142 for the control period that includes the date on which the CAIR NOₓ opt-in unit becomes a CAIR NOₓ unit under § 96.104:

(A) The amount of CAIR NOₓ allowances otherwise allocated to the CAIR NOₓ opt-in unit (as a CAIR NOₓ unit) under § 96.142 for the control period multiplied by:

(B) The ratio of the number of days, in the control period, starting with the date on which the CAIR NOₓ opt-in unit becomes a CAIR NOₓ unit under § 96.104, divided by the total number of days in the control period; and

(C) Rounded to the nearest whole allowance as appropriate.
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immediately prior control period, except when the allocation is being calculated for the control period in which the CAIR NO\textsubscript{X} opt-in unit enters the CAIR NO\textsubscript{X} Annual Trading Program under §96.184(g).

(2) The NO\textsubscript{X} emission rate (in lb/mmBtu) used for calculating CAIR NO\textsubscript{X} allowance allocations will be the lesser of:

(i) The CAIR NO\textsubscript{X} opt-in unit’s baseline NO\textsubscript{X} emissions rate (in lb/mmBtu) determined under §96.184(d) and multiplied by 70 percent; or

(ii) The most stringent State or Federal NO\textsubscript{X} emissions limitation applicable to the CAIR NO\textsubscript{X} opt-in unit at any time during the control period for which CAIR NO\textsubscript{X} allowances are to be allocated.

(3) The permitting authority will allocate CAIR NO\textsubscript{X} allowances to the CAIR NO\textsubscript{X} opt-in unit in an amount equaling the heat input under paragraph (b)(1) of this section, multiplied by the NO\textsubscript{X} emission rate under paragraph (b)(2) of this section, divided by 2,000 lb/ton, and rounded to the nearest whole allowance as appropriate.

(c) Notwithstanding paragraph (b) of this section and if the CAIR designated representative requests, and the permitting authority issues a CAIR opt-in permit (based on a demonstration of the intent to repower stated under §96.183(a)(5)) providing for allocation to a CAIR NO\textsubscript{X} opt-in unit of CAIR NO\textsubscript{X} allowances under this paragraph (subject to the conditions in §§96.184(h) and 96.186(g)), the permitting authority will allocate to the CAIR NO\textsubscript{X} opt-in unit as follows:

(1) For each control period in 2009 through 2014 for which the CAIR NO\textsubscript{X} opt-in unit is to be allocated CAIR NO\textsubscript{X} allowances,

(i) The heat input (in mmBtu) used for calculating CAIR NO\textsubscript{X} allowance allocations will be determined as described in paragraph (b)(1) of this section.

(ii) The NO\textsubscript{X} emission rate (in lb/mmBtu) used for calculating CAIR NO\textsubscript{X} allowance allocations will be the lesser of:

(A) The CAIR NO\textsubscript{X} opt-in unit’s baseline NO\textsubscript{X} emissions rate (in lb/mmBtu) determined under §96.184(d); or

(B) The most stringent State or Federal NO\textsubscript{X} emissions limitation applicable to the CAIR NO\textsubscript{X} opt-in unit at any time during the control period in which the CAIR NO\textsubscript{X} opt-in unit enters the CAIR NO\textsubscript{X} Annual Trading Program under §96.184(g).

(iii) The permitting authority will allocate CAIR NO\textsubscript{X} allowances to the CAIR NO\textsubscript{X} opt-in unit in an amount equaling the heat input under paragraph (c)(1)(i) of this section, multiplied by the NO\textsubscript{X} emission rate under paragraph (c)(1)(ii) of this section, divided by 2,000 lb/ton, and rounded to the nearest whole allowance as appropriate.

(2) For each control period in 2015 and thereafter for which the CAIR NO\textsubscript{X} opt-in unit is to be allocated CAIR NO\textsubscript{X} allowances, the NO\textsubscript{X} emission rate (in lb/mmBtu) used for calculating the CAIR NO\textsubscript{X} allowance allocation will be the lesser of:

(A) 0.15 lb/mmBtu;

(B) The CAIR NO\textsubscript{X} opt-in unit’s baseline NO\textsubscript{X} emissions rate (in lb/mmBtu) determined under §96.184(d); or

(C) The most stringent State or Federal NO\textsubscript{X} emissions limitation applicable to the CAIR NO\textsubscript{X} opt-in unit at any time during the control period for which CAIR NO\textsubscript{X} allowances are to be allocated.

(iii) The permitting authority will allocate CAIR NO\textsubscript{X} allowances to the CAIR NO\textsubscript{X} opt-in unit in an amount equaling the heat input under paragraph (c)(2)(i) of this section, multiplied by the NO\textsubscript{X} emission rate under paragraph (c)(2)(ii) of this section, divided by 2,000 lb/ton, and rounded to the nearest whole allowance as appropriate.

(d) Recordation. (1) The Administrator will record, in the compliance account of the source that includes the CAIR NO\textsubscript{X} opt-in unit, the CAIR NO\textsubscript{X} allowances allocated by the permitting authority to the CAIR NO\textsubscript{X} opt-in unit under paragraph (a)(1) of this section.

(2) By December 1 of the control period in which a CAIR NO\textsubscript{X} opt-in unit...
§ 96.201 Purpose.

This subpart and subparts BBB through III establish the model rule comprising general provisions and the designated representative, permitting, allowance, monitoring, and opt-in provisions for the State Clean Air Interstate Rule (CAIR) SO₂ Trading Program, under section 110 of the Clean Air Act and §51.124 of this chapter, as a means of mitigating interstate transport of fine particulates and sulfur dioxide. The owner or operator of a unit or a source shall comply with the requirements of this subpart and subparts BBB through III as a matter of federal law only if the State with jurisdiction over the unit and the source incorporates by reference such subparts or otherwise adopts the requirements of such subparts in accordance with §51.124(o)(1) or (2) of this chapter, the State submits to the Administrator one or more revisions of the State implementation plan that include such adoption, and the Administrator approves such revisions. If the State adopts the requirements of such subparts in accordance with §51.124(o)(1) or (2) of this chapter, then the State authorizes the Administrator to assist the State in implementing the CAIR SO₂ Trading Program by carrying out the functions set forth for the Administrator in such subparts.

§ 96.202 Definitions.

The terms used in this subpart and subparts BBB through III shall have the meanings set forth in this section as follows:

Account number means the identification number given by the Administrator to each CAIR SO₂ Allowance Tracking System account.

Acid Rain emissions limitation means a limitation on emissions of sulfur dioxide or nitrogen oxides under the Acid Rain Program.

Acid Rain Program means a multi-state sulfur dioxide and nitrogen oxides air pollution control and emission reduction program established by the Administrator under title IV of the CAA and parts 72 through 78 of this chapter.

Administrator means the Administrator of the United States Environmental Protection Agency or the Administrator’s duly authorized representative.

Allocate or allocation means, with regard to CAIR SO₂ allowances issued under the Acid Rain Program, the determination by the Administrator of the amount of such CAIR SO₂ allowances to be initially credited to a CAIR SO₂ unit or other entity and, with regard to CAIR SO₂ allowances issued under provisions of a State implementation plan that are approved under §51.124(o)(1) or (2) or (r) of this chapter or §97.288 of this chapter, the determination by a permitting authority of the amount of such CAIR SO₂ allowances to be initially credited to a CAIR SO₂ unit or other entity.

Allowance transfer deadline means, for a control period, midnight of March 1 (if it is a business day), or midnight of the first business day thereafter (if March 1 is not a business day), immediately following the control period and is the deadline by which a CAIR SO₂ allowance transfer must be submitted for recordation in a CAIR SO₂ source’s compliance account in order to be used to meet the source’s CAIR SO₂ emissions limitation for such control period in accordance with §96.254.

Alternate CAIR designated representative means, for a CAIR SO₂ source and each CAIR SO₂ unit at the source, the natural person who is authorized by the owners and operators of the source...
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and all such units at the source, in accordance with subparts BBB and III of this part, to act on behalf of the CAIR designated representative in matters pertaining to the CAIR SO\(_2\) Trading Program. If the CAIR SO\(_2\) source is also a CAIR NO\(_x\) source, then this natural person shall be the same person as the alternate CAIR designated representative under the CAIR NO\(_x\) Annual Trading Program. If the CAIR SO\(_2\) source is also subject to the Acid Rain Program, then this natural person shall be the same person as the alternate designated representative under the Acid Rain Program. If the CAIR SO\(_2\) source is also subject to the Hg Budget Trading Program, then this natural person shall be the same person as the designated representative under the Hg Budget Trading Program.

**Automated data acquisition and handling system or DAHS** means that component of the continuous emission monitoring system, or other emissions monitoring system approved for use under subpart HHH of this part, designed to interpret and convert individual output signals from pollutant concentration monitors, flow monitors, diluent gas monitors, and other component parts of the monitoring system to produce a continuous record of the measured parameters in the measurement units required by subpart HHH of this part.

**Biomass** means—

1. Any organic material grown for the purpose of being converted to energy;
2. Any organic byproduct of agriculture that can be converted into energy; or
3. Any material that can be converted into energy and is nonmerchantable for other purposes, that is segregated from other nonmerchantable material, and that is;
   1. A forest-related organic resource, including mill residues, precommercial thinnings, slash, brush, or byproduct from conversion of trees to merchantable material; or
   2. A wood material, including pallets, crates, dunnage, manufacturing and construction materials (other than pressure-treated, chemically-treated, or painted wood products), and landscape or right-of-way tree trimmings.

**Boiler** means an enclosed fossil- or other-fuel-fired combustion device used to produce heat and to transfer heat to recirculating water, steam, or other medium.

**Bottoming-cycle cogeneration unit** means a cogeneration unit in which the energy input to the unit is first used to produce useful thermal energy and at least some of the reject heat from the useful thermal energy application or process is then used for electricity production.

**CAIR authorized account representative** means, with regard to a general account, a responsible natural person who is authorized, in accordance with subparts BBB, FFF, and III of this part, to transfer and otherwise dispose of CAIR SO\(_2\) allowances held in the general account and, with regard to a compliance account, the CAIR designated representative of the source.

**CAIR designated representative** means, for a CAIR SO\(_2\) source and each CAIR SO\(_2\) unit at the source, the natural person who is authorized by the owners and operators of the source and all such units at the source, in accordance with subparts BBB and III of this part, to represent and legally bind each owner and operator in matters pertaining to the CAIR SO\(_2\) Trading Program. If the CAIR SO\(_2\) source is also a CAIR NO\(_x\) source, then this natural person shall be the same person as the CAIR designated representative under the CAIR NO\(_x\) Annual Trading Program. If the CAIR SO\(_2\) source is also subject to the Acid Rain Program, then this natural person shall be the same person as the designated representative under the Acid Rain Program. If the CAIR SO\(_2\) source is also subject to the Hg Budget Trading Program, then this natural person shall be the same person as the designated representative under the Hg Budget Trading Program.
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shall be the same person as the Hg designated representative under the Hg Budget Trading Program.

CAIR NOx Annual Trading Program means a multi-state nitrogen oxides air pollution control and emission reduction program approved and administered by the Administrator in accordance with subparts AA through II of this part and §51.123(o)(1) or (2) of this chapter or established by the Administrator in accordance with subparts AA through II of part 97 of this chapter and §§51.123(t) and 52.35 of this chapter, as a means of mitigating interstate transport of fine particulates and nitrogen oxides.

CAIR NOx Ozone Season source means a source that includes one or more CAIR NOx Ozone Season units.

CAIR NOx Ozone Season Trading Program means a multi-state nitrogen oxides air pollution control and emission reduction program approved and administered by the Administrator in accordance with subparts AAAA through IIII of this part and §51.123(aa)(1) or (2) (and (bb)(1)), (bb)(2), or (dd) of this chapter or established by the Administrator in accordance with subparts AA through II of part 97 of this chapter and §§51.123(p) and 52.35 of this chapter, as a means of mitigating interstate transport of ozone and nitrogen oxides.

CAIR NOx source means a source that is subject to the CAIR NOx Ozone Season Trading Program.

CAIR permit means the legally binding and federally enforceable written document, or portion of such document, issued by the permitting authority under subpart CCC of this part, including any permit revisions, specifying the CAIR SO2 Trading Program requirements applicable to a CAIR SO2 source, to each CAIR SO2 unit at the source, and to the owners and operators and the CAIR designated representative of the source and each such unit.

CAIR SO2 allowance means a limited authorization issued by the Administrator under the Acid Rain Program, or by a permitting authority under provisions of a State implementation plan that are approved under §51.124(o)(1) or (2) or (r) of this chapter or §97.288 of this chapter, by designating the last sentence of the definition as paragraph (4), and by revising in paragraph (4) the words “(Program or under the provisions of a State implementation plan that is approved under §51.124(o)(1) or (2) of this chapter” to read “(Program, provisions of a State implementation plan that are approved under §51.124(o)(1) or (2) or (r) of this chapter, or §97.288 of this chapter, to emit sulfur dioxide during the control period of the specified calendar year for which the authorization is allocated or of any calendar year thereafter under the CAIR SO2 Trading Program as follows:

(1) For one CAIR SO2 allowance allocated for a control period in a year before 2010, one ton of sulfur dioxide, except as provided in §96.254(b);

(2) For one CAIR SO2 allowance allocated for a control period in 2010 through 2014, 0.50 ton of sulfur dioxide, except as provided in §96.254(b); and

(3) For one CAIR SO2 allowance allocated for a control period in 2015 or later, 0.35 ton of sulfur dioxide, except as provided in §96.254(b).

An authorization to emit sulfur dioxide that is not issued under the Acid Rain Program or under the provisions of a State implementation plan that is approved under §51.124(o)(1) or (2) of this chapter shall not be a CAIR SO2 allowance.

CAIR SO2 allowance deduction or deduct CAIR SO2 allowances means the permanent withdrawal of CAIR SO2 allowances by the Administrator from a compliance account, e.g., in order to account for a specified number of tons of total sulfur dioxide emissions from all CAIR SO2 units at a CAIR SO2 source for a control period, determined in accordance with subpart HHH of this part, or to account for excess emissions.

CAIR SO2 Allowance Tracking System means the system by which the Administrator records allocations, deductions, and transfers of CAIR SO2 allowances under the CAIR SO2 Trading Program. This is the same system as the Allowance Tracking System under §72.2 of this chapter by which the Administrator records allocations, deductions, and transfers of Acid Rain SO2 allowances under the Acid Rain Program.

CAIR SO2 Allowance Tracking System account means an account in the CAIR
SO₂ Allowance Tracking System established by the Administrator for purposes of recording the allocation, holding, transferring, or deducting of CAIR SO₂ allowances. Such allowances will be allocated, held, deducted, or transferred only as whole allowances.

CAIR SO₂ allowances held or hold CAIR SO₂ allowances means the CAIR SO₂ allowances recorded by the Administrator, or submitted to the Administrator for recordation, in accordance with subparts FFF, GGG, and III of this part or part 73 of this chapter, in a CAIR SO₂ Allowance Tracking System account.

CAIR SO₂ emissions limitation means, for a CAIR SO₂ source, the tonnage equivalent, in SO₂ emissions in a control period, of the CAIR SO₂ allowances available for deduction for the source under §96.254(a) and (b) for the control period.

CAIR SO₂ source means a source that includes one or more CAIR SO₂ units.

CAIR SO₂ Trading Program means a multi-state sulfur dioxide air pollution control and emission reduction program approved and administered by the Administrator in accordance with subparts AAA through III of this part and §51.124(o)(1) or (2) of this chapter or established by the Administrator in accordance with subparts AAA through III of part 97 of this chapter and §§51.124(r) and 52.36 of this chapter, as a means of mitigating interstate transport of fine particulates and sulfur dioxide.

CAIR SO₂ unit means a unit that is subject to the CAIR SO₂ Trading Program under §96.204 and, except for purposes of §96.205, a CAIR SO₂ opt-in unit under subpart III of this part.

Clean Air Act or CAA means the Clean Air Act, 42 U.S.C. 7401, et seq.

Coal means any solid fuel classified as anthracite, bituminous, subbituminous, or lignite.

Coal-derived fuel means any fuel (whether in a solid, liquid, or gaseous state) produced by the mechanical, thermal, or chemical processing of coal.

Coal-fired means combusting any amount of coal or coal-derived fuel, alone, or in combination with any amount of any other fuel.

Cogeneration unit means a stationary, fossil-fuel-fired boiler or stationary, fossil-fuel-fired combustion turbine:

1. Having equipment used to produce electricity and useful thermal energy for industrial, commercial, heating, or cooling purposes through the sequential use of energy; and

2. Producing during the 12-month period starting on the date the unit first produces electricity and during any calendar year after the calendar year in which the unit first produces electricity—

   (1) For a topping-cycle cogeneration unit,

      A. Useful thermal energy not less than 5 percent of total energy output; and

      B. Useful power that, when added to one-half of useful thermal energy produced, is not less than 42.5 percent of total energy input, if useful thermal energy produced is 15 percent or more of total energy output, or not less than 45 percent of total energy input, if useful thermal energy produced is less than 15 percent of total energy output.

   (ii) For a bottoming-cycle cogeneration unit, useful power not less than 45 percent of total energy input;

3. Provided that the total energy input under paragraphs (2)(i)(B) and (2)(ii) of this definition shall equal the unit’s total energy input from all fuel except biomass if the unit is a boiler.

Combustion turbine means:

1. An enclosed device comprising a compressor, a combustor, and a turbine and in which the flue gas resulting from the combustion of fuel in the combustor passes through the turbine, rotating the turbine; and

2. If the enclosed device under paragraph (1) of this definition is combined cycle, any associated duct burner, heat recovery steam generator, and steam turbine.

Commence commercial operation means, with regard to a unit:

1. To have begun to produce steam, gas, or other heated medium used to generate electricity for sale or use, including test generation, except as provided in §96.205 and §96.284(h).

   (1) For a unit that is a CAIR SO₂ unit under §96.204 on the later of November 15, 1990 or the date the unit commences commercial operation as defined in
paragraph (1) of this definition and that subsequently undergoes a physical change (other than replacement of the unit by a unit at the same source), such date shall remain the date of commencement of commercial operation of the unit, which shall continue to be treated as the same unit.

(ii) For a unit that is a CAIR SO₂ unit under §96.204 on the later of November 15, 1990 or the date the unit commences commercial operation as defined in paragraph (1) of this definition and that is subsequently replaced by a unit at the same source (e.g., repowered), such date shall remain the replaced unit’s date of commencement of commercial operation, and the replacement unit shall be treated as a separate unit with a separate date for commencement of commercial operation as defined in paragraph (1) or (2) of this definition as appropriate.

(2) Notwithstanding paragraph (1) of this definition and except as provided in §96.205, for a unit that is not a CAIR SO₂ unit under §96.204 on the later of November 15, 1990 or the date the unit commences commercial operation as defined in paragraph (1) of this definition, the unit’s date for commencement of commercial operation shall be the date on which the unit becomes a CAIR SO₂ unit under §96.204.

(i) For a unit with a date for commencement of commercial operation as defined in paragraph (2) of this definition and that subsequently undergoes a physical change (other than replacement of the unit by a unit at the same source), such date shall remain the date of commencement of commercial operation of the unit, which shall continue to be treated as the same unit.

(ii) For a unit with a date for commencement of commercial operation as defined in paragraph (2) of this definition and that is subsequently replaced by a unit at the same source (e.g., repowered), such date shall remain the replaced unit’s date of commencement of commercial operation, and the replacement unit shall be treated as a separate unit with a separate date for commencement of commercial operation as defined in paragraph (1) or (2) of this definition as appropriate.

Commence operation means:

(1) To have begun any mechanical, chemical, or electronic process, including, with regard to a unit, start-up of a unit’s combustion chamber, except as provided in §96.284(h).

(2) For a unit that undergoes a physical change (other than replacement of the unit by a unit at the same source) after the date the unit commences operation as defined in paragraph (1) of this definition, such date shall remain the date of commencement of operation of the unit, which shall continue to be treated as the same unit.

(3) For a unit that is replaced by a unit at the same source (e.g., repowered) after the date the unit commences operation as defined in paragraph (1) of this definition, such date shall remain the replaced unit’s date of commencement of operation, and the replacement unit shall be treated as a separate unit with a separate date for commencement of operation as defined in paragraph (1), (2), or (3) of this definition as appropriate, except as provided in §96.284(h).

Compliance account means a CAIR SO₂ Allowance Tracking System account, established by the Administrator for a CAIR SO₂ source subject to an Acid Rain emissions limitation under §73.31(a) or (b) of this chapter or for any other CAIR SO₂ source under subpart FFF or III of this part, in which any CAIR SO₂ allowances for the CAIR SO₂ units at the source are initially recorded and in which are held any CAIR SO₂ allowances available for use for a control period in order to meet the source’s CAIR SO₂ emissions limitation in accordance with §96.254.

Continuous emission monitoring system or CEMS means the equipment required under subpart HHH of this part to sample, analyze, measure, and provide, by means of readings recorded at least once every 15 minutes (using an automated data acquisition and handling system (DAHS)), a permanent record of sulfur dioxide emissions, stack gas volumetric flow rate, stack gas moisture content, and oxygen or carbon dioxide concentration (as applicable), in a manner consistent with part 75 of this chapter. The following systems are the principal types of continuous emission monitoring systems required under subpart HHH of this part:
(1) A flow monitoring system, consisting of a stack flow rate monitor and an automated data acquisition and handling system and providing a permanent, continuous record of stack gas volumetric flow rate, in standard cubic feet per hour (scfh);

(2) A sulfur dioxide monitoring system, consisting of a SO\textsubscript{2} pollutant concentration monitor and an automated data acquisition handling system and providing a permanent, continuous record of SO\textsubscript{2} emissions, in parts per million (ppm);

(3) A moisture monitoring system, as defined in §75.11(b)(2) of this chapter and providing a permanent, continuous record of the stack gas moisture content, in percent H\textsubscript{2}O;

(4) A carbon dioxide monitoring system, consisting of a CO\textsubscript{2} pollutant concentration monitor (or an oxygen monitor plus suitable mathematical equations from which the CO\textsubscript{2} concentration is derived) and an automated data acquisition and handling system and providing a permanent, continuous record of CO\textsubscript{2} emissions, in percent CO\textsubscript{2}; and

(5) An oxygen monitoring system, consisting of an O\textsubscript{2} concentration monitor and an automated data acquisition and handling system and providing a permanent, continuous record of O\textsubscript{2} in percent O\textsubscript{2}.

Control period means the period beginning January 1 of a calendar year, except as provided in §96.206(c)(2), and ending on December 31 of the same year, inclusive.

Emissions means air pollutants exhausted from a unit or source into the atmosphere, as measured, recorded, and reported to the Administrator by the CAIR designated representative and as determined by the Administrator in accordance with subpart HHH of this part.

Excess emissions means any ton, or portion of a ton, of sulfur dioxide emitted by the CAIR SO\textsubscript{2} units at a CAIR SO\textsubscript{2} source during a control period that exceeds the CAIR SO\textsubscript{2} emissions limitation for the source, provided that any portion of a ton of excess emissions shall be treated as one ton of excess emissions.

Fossil fuel means natural gas, petroleum, coal, or any form of solid, liquid, or gaseous fuel derived from such material.

Fossil-fuel-fired means, with regard to a unit, combusting any amount of fossil fuel in any calendar year.

General account means a CAIR SO\textsubscript{2} Allowance Tracking System account, established under subpart FFF of this part, that is not a compliance account.

Generator means a device that produces electricity.

Heat input means, with regard to a specified period of time, the product (in mmBtu/time) of the gross calorific value of the fuel (in Btu/lb) divided by 1,000,000 Btu/mmBtu and multiplied by the fuel feed rate into a combustion device (in lb of fuel/time), as measured, recorded, and reported to the Administrator by the CAIR designated representative and determined by the Administrator in accordance with subpart HHH of this part and excluding the heat derived from preheated combustion air, recirculated flue gases, or exhaust from other sources.

Heat input rate means the amount of heat input (in mmBtu) divided by unit operating time (in hr) or, with regard to a specific fuel, the amount of heat input attributed to the fuel (in mmBtu) divided by the unit operating time (in hr) during which the unit combusted the fuel.

Hg Budget Trading Program means a multi-state Hg air pollution control and emission reduction program approved and administered by the Administrator in accordance with subpart HHHH of part 60 of this chapter and §60.24(h)(6), or established by the Administrator under section 111 of the Clean Air Act, as a means of reducing national Hg emissions.

Life-of-the-unit, firm power contractual arrangement means a unit participation power sales agreement under which a utility or industrial customer reserves, or is entitled to receive, a specified amount or percentage of nameplate capacity and associated energy generated by any specified unit and pays its proportional amount of such unit’s total costs, pursuant to a contract:

(1) For the life of the unit;

(2) For a cumulative term of no less than 30 years, including contracts that permit an election for early termination; or
(3) For a period no less than 25 years or 70 percent of the economic useful life of the unit determined as of the time the unit is built, with option rights to purchase or release some portion of the nameplate capacity and associated energy generated by the unit at the end of the period.

Maximum design heat input means the maximum amount of fuel per hour (in Btu/hr) that a unit is capable of combusting on a steady state basis as of the initial installation of the unit as specified by the manufacturer of the unit.

Monitoring system means any monitoring system that meets the requirements of subpart HHH of this part, including a continuous emissions monitoring system, an alternative monitoring system, or an excepted monitoring system under part 75 of this chapter.

Most stringent State or Federal SO\textsubscript{2} emissions limitation means, with regard to a unit, the lowest SO\textsubscript{2} emissions limitation (in terms of lb/mmBtu) that is applicable to the unit under State or Federal law, regardless of the averaging period to which the emissions limitation applies.

Nameplate capacity means, starting from the initial installation of a generator, the maximum electrical generating output (in MWe) that the generator is capable of producing on a steady state basis and during continuous operation (when not restricted by seasonal or other deratings) as of such installation as specified by the manufacturer of the generator or, starting from the completion of any subsequent physical change in the generator resulting in an increase in the maximum electrical generating output (in MWe) that the generator is capable of producing on a steady state basis and during continuous operation (when not restricted by seasonal or other deratings), such increased maximum amount as of such completion as specified by the person conducting the physical change.

Operator means any person who operates, controls, or supervises a CAIR SO\textsubscript{2} unit or a CAIR SO\textsubscript{2} source and shall include, but not be limited to, any holding company, utility system, or plant manager of such a unit or source.

Owner means any of the following persons:

(1) With regard to a CAIR SO\textsubscript{2} source or a CAIR SO\textsubscript{2} unit at a source, respectively:

(i) Any holder of any portion of the legal or equitable title in a CAIR SO\textsubscript{2} unit at the source or the CAIR SO\textsubscript{2} unit;

(ii) Any holder of a leasehold interest in a CAIR SO\textsubscript{2} unit at the source or the CAIR SO\textsubscript{2} unit; or

(iii) Any purchaser of power from a CAIR SO\textsubscript{2} unit at the source or the CAIR SO\textsubscript{2} unit under a life-of-the-unit, firm power contractual arrangement; provided that, unless expressly provided for in a leasehold agreement, owner shall not include a passive lessor, or a person who has an equitable interest through such lessor, whose rental payments are not based (either directly or indirectly) on the revenues or income from such CAIR SO\textsubscript{2} unit; or

(2) With regard to any general account, any person who has an ownership interest with respect to the CAIR SO\textsubscript{2} allowances held in the general account and who is subject to the binding agreement for the CAIR authorized account representative to represent the person’s ownership interest with respect to CAIR SO\textsubscript{2} allowances.

Permitting authority means the State air pollution control agency, local agency, other State agency, or other agency authorized by the Administrator to issue or revise permits to meet the requirements of the CAIR SO\textsubscript{2} Trading Program or, if no such agency has been so authorized, the Administrator.

Potential electrical output capacity means 33 percent of a unit’s maximum design heat input, divided by 3,413 Btu/kWh, divided by 1,000 kWh/MWh, and multiplied by 8,760 hr/yr.

Receive or receipt of means, when referring to the permitting authority or the Administrator, to come into possession of a document, information, or correspondence (whether sent in hard copy or by authorized electronic transmission), as indicated in an official log, or by a notation made on the document, information, or correspondence,
Environmental Protection Agency § 96.202

by the permitting authority or the Administrator in the regular course of business.

Recordation, record, or recorded means, with regard to CAIR SO\textsubscript{2} allowances, the movement of CAIR SO\textsubscript{2} allowances by the Administrator into or between CAIR SO\textsubscript{2} Allowance Tracking System accounts, for purposes of allocation, transfer, or deduction.

Reference method means any direct test method of sampling and analyzing for an air pollutant as specified in §75.22 of this chapter.

Replacement, replace, or replaced means, with regard to a unit, the demolishing of a unit, or the permanent shutdown and permanent disabling of a unit, and the construction of another unit (the replacement unit) to be used instead of the demolished or shutdown unit (the replaced unit).

Repowered means, with regard to a unit, replacement of a coal-fired boiler with one of the following coal-fired technologies at the same source as the coal-fired boiler:

(1) Atmospheric or pressurized fluidized bed combustion;
(2) Integrated gasification combined cycle;
(3) Magnetohydrodynamics;
(4) Direct and indirect coal-fired turbines;
(5) Integrated gasification fuel cells; or
(6) As determined by the Administrator in consultation with the Secretary of Energy, a derivative of one or more of the technologies under paragraphs (1) through (5) of this definition and any other coal-fired technology capable of controlling multiple combustion emissions simultaneously with improved boiler or generation efficiency and with significantly greater waste reduction relative to the performance of technology in widespread commercial use as of January 1, 2005.

Serial number means, for a CAIR SO\textsubscript{2} allowance, the unique identification number assigned to each CAIR SO\textsubscript{2} allowance by the Administrator.

Sequential use of energy means:

(1) For a topping-cycle cogeneration unit, the use of reject heat from useful thermal energy application or process in electricity production.
(2) For a bottoming-cycle cogeneration unit, the use of reject heat from useful thermal energy application or process in electricity production.

Solid waste incineration unit means a stationary, fossil-fuel-fired boiler or stationary, fossil-fuel-fired combustion turbine that is a “solid waste incineration unit” as defined in section 129(g)(1) of the Clean Air Act.

Source means all buildings, structures, or installations located in one or more contiguous or adjacent properties under common control of the same person or persons. For purposes of section 502(c) of the Clean Air Act, a “source,” including a “source” with multiple units, shall be considered a single “facility.”

State means one of the States or the District of Columbia that adopts the CAIR SO\textsubscript{2} Trading Program pursuant to §51.124 (o)(1) or (2) of this chapter.

Submit or serve means to send or transmit a document, information, or correspondence to the person specified in accordance with the applicable regulation:

(1) In person;
(2) By United States Postal Service; or
(3) By other means of dispatch or transmission and delivery. Compliance with any “submission” or “service” deadline shall be determined by the date of dispatch, transmission, or mailing and not the date of receipt.

Title V operating permit means a permit issued under title V of the Clean Air Act and part 70 or part 71 of this chapter.

Title V operating permit regulations means the regulations that the Administrator has approved or issued as meeting the requirements of title V of the Clean Air Act and part 70 or 71 of this chapter.

Ton means 2,000 pounds. For the purpose of determining compliance with the CAIR SO\textsubscript{2} emissions limitation, total tons of sulfur dioxide emissions for a control period shall be calculated as the sum of all recorded hourly emissions (or the mass equivalent of the recorded hourly emission rates) in accordance with subpart HHH of this part, but with any remaining fraction of a ton equal to or greater than 0.50 tons deemed to equal one ton and any
remaining fraction of a ton less than 0.50 tons deemed to equal zero tons.

*Topping-cycle cogeneration unit* means a cogeneration unit in which the energy input to the unit is first used to produce useful power, including electricity, and at least some of the reject heat from the electricity production is then used to provide useful thermal energy.

*Total energy input* means, with regard to a cogeneration unit, total energy of all forms supplied to the cogeneration unit, excluding energy produced by the cogeneration unit itself. Each form of energy supplied shall be measured by the lower heating value of that form of energy calculated as follows:

\[ \text{LHV} = \text{HHV} - 10.55(W + 9H) \]

Where:

- \( \text{LHV} \) = lower heating value of fuel in Btu/lb
- \( \text{HHV} \) = higher heating value of fuel in Btu/lb
- \( W \) = Weight % of moisture in fuel, and
- \( H \) = Weight % of hydrogen in fuel.

*Total energy output* means, with regard to a cogeneration unit, the sum of useful power and useful thermal energy produced by the cogeneration unit.

*Unit* means a stationary, fossil-fuel-fired boiler or combustion turbine or other stationary, fossil-fuel-fired combustion device.

*Unit operating day* means a calendar day in which a unit combusts any fuel.

*Unit operating hour or hour of unit operation* means an hour in which a unit combusts any fuel.

*Useful power* means, with regard to a cogeneration unit, electricity or mechanical energy made available for use, excluding any such energy used in the power production process (which process includes, but is not limited to, any on-site processing or treatment of fuel combusted at the unit and any on-site emission controls).

*Useful thermal energy* means, with regard to a cogeneration unit, thermal energy that is:

1. Used in a space cooling application (i.e., thermal energy used by an absorption chiller).
2. \( \text{CO}_2 \)—carbon dioxide
3. \( \text{H}_2\text{O} \)—water
4. \( \text{Hg} \)—mercury
5. \( \text{hr} \)—hour
6. \( \text{kWh} \)—kilowatt hour
7. \( \text{lb} \)—pound
8. \( \text{mmBtu} \)—million Btu
9. \( \text{MWe} \)—megawatt electrical
10. \( \text{MWh} \)—megawatt hour
11. \( \text{NO}_x \)—nitrogen oxides
12. \( \text{O}_2 \)—oxygen
13. \( \text{ppm} \)—parts per million
14. \( \text{scfh} \)—standard cubic feet per hour
15. \( \text{SO}_2 \)—sulfur dioxide
16. \( \text{yr} \)—year

*Utility power distribution system* means the portion of an electricity grid owned or operated by a utility and dedicated to delivering electricity to customers.

§ 96.203 Measurements, abbreviations, and acronyms.

Measurements, abbreviations, and acronyms used in this subpart and subparts BBB through III are defined as follows:

- Btu—British thermal unit
- CO\(_2\)—carbon dioxide
- H\(_2\)O—water
- Hg—mercury
- hr—hour
- kW—kilowatt electrical
- kWh—kilowatt hour
- lb—pound
- mmBtu—million Btu
- MWe—megawatt electrical
- MWh—megawatt hour
- NO\(_x\)—nitrogen oxides
- O\(_2\)—oxygen
- ppm—parts per million
- scfh—standard cubic feet per hour
- SO\(_2\)—sulfur dioxide
- yr—year

§ 96.204 Applicability.

(a) Except as provided in paragraph (b) of this section:

1. The following units in a State shall be CAIR \( \text{SO}_2 \) units, and any source that includes one or more such units shall be a CAIR \( \text{SO}_2 \) source, subject to the requirements of this subpart
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§ 96.205 Retired unit exemption.

(a)(1) Any CAIR SO₂ unit that is permanently retired and is not a CAIR SO₂ opt-in unit under subpart III of this part shall be exempt from the CAIR SO₂ Trading Program, except for the provisions of this section, § 96.202, § 96.203, § 96.204, § 96.206(c)(4) through (7), § 96.207, § 96.208, and subparts BBB, PFF, and GGG of this part.

and subparts BBB through HHH of this part: any stationary, fossil-fuel-fired boiler or stationary, fossil-fuel-fired combustion turbine serving at any time, since the later of November 15, 1990 or the start-up of the unit’s combustion chamber, a generator with nameplate capacity of more than 25 MWe producing electricity for sale.

(2) If a stationary boiler or stationary combustion turbine that, under paragraph (a)(1) of this section, is not a CAIR SO₂ unit begins to combust fossil fuel or to serve a generator with nameplate capacity of more than 25 MWe producing electricity for sale, the unit shall become a CAIR SO₂ unit as provided in paragraph (a)(1) of this section on the first date on which it both combusts fossil fuel and serves such generator;

(b) The units in a State that meet the requirements set forth in paragraph (b)(1)(i), (b)(2)(i), or (b)(2)(ii) of this section shall not be CAIR SO₂ units:

(1)(i) Any unit that is a CAIR SO₂ unit under paragraph (a)(1) or (2) of this section:

(A) Qualifying as a cogeneration unit; and

(B) Not serving at any time, since the later of November 15, 1990 or the start-up of the unit’s combustion chamber, a generator with nameplate capacity of more than 25 MWe supplying in any calendar year more than one-third of the unit’s potential electric output capacity or 219,000 MWh, whichever is greater, to any utility power distribution system for sale.

(ii) If a unit qualifies as a cogeneration unit during the 12-month period starting on the date the unit first produces electricity and continues to qualify as a cogeneration unit; and

(B) Not serving at any time, since the later of November 15, 1990 or the start-up of the unit’s combustion chamber, a generator with nameplate capacity of more than 25 MWe supplying in any calendar year more than one-third of the unit’s potential electric output capacity or 219,000 MWh, whichever is greater, to any utility power distribution system for sale.

(ii) If a unit qualifies as a cogeneration unit during the 12-month period starting on the date the unit first produces electricity and meets the requirements of paragraphs (b)(1)(i); (b)(2)(i); or (b)(2)(ii) of this section for at least 3 consecutive calendar years, but subsequently no longer meets all such requirements, the unit shall become a CAIR SO₂ unit starting on the earlier of January 1 after the first calendar year during which the unit first no longer qualifies as a solid waste incineration unit or January 1 after the first 3 consecutive calendar years after 1990 for which the unit has an average annual fuel consumption of fossil fuel of 20 percent or more.

[71 FR 25387, Apr. 28, 2006]
§ 96.206 Standard requirements.

(a) Permit requirements. (1) The CAIR designated representative of each CAIR SO₂ source required to have a title V operating permit and each CAIR SO₂ unit required to have a title V operating permit at the source shall:

(i) Submit to the permitting authority a complete CAIR permit application under §96.222 in accordance with the deadlines specified in §96.221; and

(ii) Submit in a timely manner any supplemental information that the permitting authority determines is necessary in order to review a CAIR permit application and issue or deny a CAIR permit.

(2) The owners and operators of each CAIR SO₂ source required to have a
title V operating permit and each CAIR SO₂ unit required to have a title V operating permit at the source shall have a CAIR permit issued by the permitting authority under subpart CCC of this part for the source and operate the source and the unit in compliance with such CAIR permit.

(3) Except as provided in subpart III of this part, the owners and operators of a CAIR SO₂ source that is not otherwise required to have a title V operating permit and each CAIR SO₂ unit that is not otherwise required to have a title V operating permit are not required to submit a CAIR permit application, and to have a CAIR permit, under subpart CCC of this part for such CAIR SO₂ source and such CAIR SO₂ unit.

(b) Monitoring, reporting, and recordkeeping requirements. (1) The owners and operators, and the CAIR designated representative, of each CAIR SO₂ source and each CAIR SO₂ unit at the source shall comply with the monitoring, reporting, and recordkeeping requirements of subpart HHH of this part.

(2) The emissions measurements recorded and reported in accordance with subpart HHH of this part shall be used to determine compliance by each CAIR SO₂ source with the CAIR SO₂ emissions limitation under paragraph (c) of this section.

(c) Sulfur dioxide emission requirements. (1) As of the allowance transfer deadline for a control period, the owners and operators of each CAIR SO₂ source and each CAIR SO₂ unit at the source shall hold, in the source’s compliance account, a tonnage equivalent in CAIR SO₂ allowances available for compliance deductions for the control period, as determined in accordance with §96.254(a) and (b), not less than the tons of total sulfur dioxide emissions for the control period from all CAIR SO₂ units at the source, as determined in accordance with subpart HHH of this part.

(2) A CAIR SO₂ unit shall be subject to the requirements under paragraph (c)(1) of this section for the control period starting on the later of January 1, 2010 or the deadline for meeting the unit’s monitor certification requirements under §96.276(b)(1), (2), or (5) and for each control period thereafter.

(3) A CAIR SO₂ allowance shall not be deducted, for compliance with the requirements under paragraph (c)(1) of this section, for a control period in a calendar year before the year for which the CAIR SO₂ allowance was allocated.

(4) CAIR SO₂ allowances shall be held in, deducted from, or transferred into or among CAIR SO₂ Allowance Tracking System accounts in accordance with subparts FFF, GGG, and III of this part.

(d) Excess emissions requirements—If a CAIR SO₂ source emits sulfur dioxide in excess of the CAIR SO₂ emissions limitation, then:

(1) The owners and operators of the source and each CAIR SO₂ unit at the source shall surrender the CAIR SO₂ allowances required for deduction under §96.254(d)(1) and pay any fine, penalty, or assessment or comply with any other remedy imposed, for the same violations, under the Clean Air Act or applicable State law; and

(2) Each ton of such excess emissions and each day of such control period shall constitute a separate violation of this subpart, the Clean Air Act, and applicable State law.

(e) Recordkeeping and reporting requirements. (1) Unless otherwise provided, the owners and operators of the CAIR SO₂ source and each CAIR SO₂ unit at the source shall keep on site at
§ 96.207 Computation of time.

(a) Unless otherwise stated, any time period scheduled, under the CAIR SO\textsubscript{2} Trading Program, to begin on the occurrence of an act or event shall begin on the day the act or event occurs.

(b) Unless otherwise stated, any time period scheduled, under the CAIR SO\textsubscript{2} Trading Program, to begin before the occurrence of an act or event shall be computed so that the period ends the day before the act or event occurs.

(c) Unless otherwise stated, if the final day of any time period, under the CAIR SO\textsubscript{2} Trading Program, falls on a weekend or a State or Federal holiday, the time period shall be extended to the next business day.

§ 96.208 Appeal procedures.

The appeal procedures for decisions of the Administrator under the CAIR SO\textsubscript{2} Trading Program are set forth in part 78 of this chapter.

Subpart BBB—CAIR Designated Representative for CAIR SO\textsubscript{2} Sources

SOURCE: 70 FR 25362, May 12, 2005, unless otherwise noted.

§ 96.210 Authorization and responsibilities of CAIR designated representative.

(a) Except as provided under § 96.211, each CAIR SO\textsubscript{2} source, including all CAIR SO\textsubscript{2} units at the source, shall have one and only one CAIR designated representative of a CAIR SO\textsubscript{2} source shall also apply to the owners and operators of such unit.
§ 96.211 Alternate CAIR designated representative.

(a) A certificate of representation under § 96.213 may designate one and only one alternate CAIR designated representative, who may act on behalf of the CAIR designated representative. The agreement by which the alternate CAIR designated representative is selected shall include a procedure for authorizing the alternate CAIR designated representative to act in lieu of the CAIR designated representative.

(b) Upon receipt by the Administrator of a complete certificate of representation under § 96.213, any representation, action, inaction, or submission by the alternate CAIR designated representative shall be deemed to be a representation, action, inaction, or submission by the CAIR designated representative.

(c) Except in this section and §§ 96.202, 96.210(a) and (d), 96.212, 96.213, 96.215, 96.251, and 96.282, whenever the term "CAIR designated representative" is used in subparts AAA through III of this part, the term shall be construed to include the CAIR designated representative or any alternate CAIR designated representative.

[70 FR 25362, May 12, 2005, as amended at 71 FR 25388, Apr. 28, 2006]
§ 96.212 Changing CAIR designated representative and alternate CAIR designated representative; changes in owners and operators.

(a) Changing CAIR designated representative. The CAIR designated representative may be changed at any time upon receipt by the Administrator of a superseding complete certificate of representation under §96.213. Notwithstanding any such change, all representations, actions, inactions, and submissions by the previous CAIR designated representative before the time and date when the Administrator receives the superseding certificate of representation shall be binding on the new CAIR designated representative and the owners and operators of the CAIR SO₂ source and the CAIR SO₂ units at the source.

(b) Changing alternate CAIR designated representative. The alternate CAIR designated representative may be changed at any time upon receipt by the Administrator of a superseding complete certificate of representation under §96.213. Notwithstanding any such change, all representations, actions, inactions, and submissions by the previous alternate CAIR designated representative before the time and date when the Administrator receives the superseding certificate of representation shall be binding on the new alternate CAIR designated representative and the owners and operators of the CAIR SO₂ source and the CAIR SO₂ units at the source.

(c) Changes in owners and operators.

(1) In the event an owner or operator of a CAIR SO₂ source or a CAIR SO₂ unit is not included in the list of owners and operators in the certificate of representation under §96.213, such owner or operator shall be deemed to be subject to and bound by the certificate of representation, the representations, actions, inactions, and submissions of the CAIR designated representative and any alternate CAIR designated representative of the source or unit, and the decisions and orders of the permitting authority, the Administrator, or a court, as if the owner or operator were included in such list.

(2) Within 30 days following any change in the owners and operators of a CAIR SO₂ source or a CAIR SO₂ unit, including the addition of a new owner or operator, the CAIR designated representative or any alternate CAIR designated representative shall submit a revision to the certificate of representation under §96.213 amending the list of owners and operators to include the change.

[70 FR 25362, May 12, 2005, as amended at 71 FR 25388, Apr. 28, 2006]

§ 96.213 Certificate of representation.

(a) A complete certificate of representation for a CAIR designated representative or an alternate CAIR designated representative shall include the following elements in a format prescribed by the Administrator:

(1) Identification of the CAIR SO₂ source, and each CAIR SO₂ unit at the source, for which the certificate of representation is submitted, including identification and nameplate capacity of each generator served by each such unit.

(2) The name, address, e-mail address (if any), telephone number, and facsimile transmission number (if any) of the CAIR designated representative and any alternate CAIR designated representative.

(3) A list of the owners and operators of the CAIR SO₂ source and of each CAIR SO₂ unit at the source.

(4) The following certification statements by the CAIR designated representative and any alternate CAIR designated representative—

(i) “I certify that I was selected as the CAIR designated representative or alternate CAIR designated representative, as applicable, by an agreement binding on the owners and operators of the source and each CAIR SO₂ unit at the source.”

(ii) “I certify that I have all the necessary authority to carry out my duties and responsibilities under the CAIR SO₂ Trading Program on behalf of the owners and operators of the source and each CAIR SO₂ unit at the source.”

(iii) “I certify that the owners and operators of the source and each CAIR SO₂ unit at the source shall be fully bound by my representations, actions, inactions, or submissions.”

(iv) “I certify that the owners and operators of the source and each CAIR SO₂ unit at the source shall be fully bound by the decisions and orders of the permitting authority, the Administrator, or a court, as if the owner or operator were included in such list.”
Administrator, the permitting authority, or a court regarding the source or unit.’’

(iv) ‘‘Where there are multiple holders of a legal or equitable title to, or a leasehold interest in, a CAIR SO₂ unit, or where a utility or industrial customer purchases power from a CAIR SO₂ unit under a life-of-the-unit, firm power contractual arrangement, I certify that: I have given a written notice of my selection as the ‘CAIR designated representative’ or ‘alternate CAIR designated representative’, as applicable, and of the agreement by which I was selected to each owner and operator of the source and of each CAIR SO₂ unit at the source; and CAIR SO₂ allowances and proceeds of transactions involving CAIR SO₂ allowances will be deemed to be held or distributed in proportion to each holder’s legal, equitable, leasehold, or contractual reservation or entitlement, except that, if such multiple holders have expressly provided for a different distribution of CAIR SO₂ allowances by contract, CAIR SO₂ allowances and proceeds of transactions involving CAIR SO₂ allowances will be deemed to be held or distributed in accordance with the contract.’’

(5) The signature of the CAIR designated representative and any alternate CAIR designated representative and the dates signed.

(b) Unless otherwise required by the permitting authority or the Administrator, documents of agreement referred to in the certificate of representation shall not be submitted to the permitting authority or the Administrator. Neither the permitting authority nor the Administrator shall be under any obligation to review or evaluate the sufficiency of such documents, if submitted.

[70 FR 25362, May 12, 2005, as amended at 71 FR 25388, Apr. 28, 2006]

§ 96.214 Objections concerning CAIR designated representative.

(a) Once a complete certificate of representation under §96.213 has been submitted and received, the permitting authority and the Administrator will rely on the certificate of representation unless and until a superseding complete certificate of representation under §96.213 is received by the Administrator.

(b) Except as provided in §96.212(a) or (b), no objection or other communication submitted to the permitting authority or the Administrator concerning the authorization, or any representation, action, inaction, or submission, of the CAIR designated representative shall affect any representation, action, inaction, or submission of the CAIR designated representative or the finality of any decision or order by the permitting authority or the Administrator under the CAIR SO₂ Trading Program.

(c) Neither the permitting authority nor the Administrator will adjudicate any private legal dispute concerning the authorization or any representation, action, inaction, or submission of any CAIR designated representative, including private legal disputes concerning the proceeds of CAIR SO₂ allowance transfers.

§ 96.215 Delegation by CAIR designated representative and alternate CAIR designated representative.

(a) A CAIR designated representative may delegate, to one or more natural persons, his or her authority to make an electronic submission to the Administrator provided for or required under this part.

(b) An alternate CAIR designated representative may delegate, to one or more natural persons, his or her authority to make an electronic submission to the Administrator provided for or required under this part.

(c) In order to delegate authority to make an electronic submission to the Administrator in accordance with paragraph (a) or (b) of this section, the CAIR designated representative or alternate CAIR designated representative, as appropriate, must submit to the Administrator a notice of delegation, in a format prescribed by the Administrator, that includes the following elements:

(1) The name, address, e-mail address, telephone number, and facsimile transmission number (if any) of such CAIR designated representative or alternate CAIR designated representative;
(2) The name, address, e-mail address, telephone number, and facsimile transmission number (if any) of each such natural person “referred to as an “agent’’;

(3) For each such natural person, a list of the type or types of electronic submissions under paragraph (a) or (b) of this section for which authority is delegated to him or her; and

(4) The following certification statements by such CAIR designated representative or alternate CAIR designated representative:

(i) “I agree that any electronic submission to the Administrator that is by an agent identified in this notice of delegation and of a type listed for such agent in this notice of delegation and that is made when I am a CAIR designated representative or alternate CAIR designated representative, as appropriate, and before this notice of delegation is superseded by another notice of delegation under 40 CFR 96.215(d) shall be deemed to be an electronic submission by me.”

(ii) “Until this notice of delegation is superseded by another notice of delegation under 40 CFR 96.215(d), I agree to maintain an e-mail account and to notify the Administrator immediately of any change in my e-mail address unless all delegation of authority by me under 40 CFR 96.215 is terminated.”

(d) A notice of delegation submitted under paragraph (c) of this section shall be effective, with regard to the CAIR designated representative or alternate CAIR designated representative identified in such notice, upon receipt of such notice by the Administrator and until receipt by the Administrator of a superseding notice of delegation submitted by such CAIR designated representative or alternate CAIR designated representative, as appropriate. The superseding notice of delegation may replace any previously identified agent, add a new agent, or eliminate entirely any delegation of authority.

(e) Any electronic submission covered by the certification in paragraph (c)(4)(i) of this section and made in accordance with a notice of delegation effective under paragraph (d) of this section shall be deemed to be an electronic submission by the CAIR designated representative or alternate CAIR designated representative submitting such notice of delegation.


Subpart CCC—Permits

SOURCE: 70 FR 25362, May 12, 2005, unless otherwise noted.

§ 96.220 General CAIR SO₂ Trading Program permit requirements.

(a) For each CAIR SO₂ source required to have a title V operating permit or required, under subpart III of this part, to have a title V operating permit or other federally enforceable permit, such permit shall include a CAIR permit administered by the permitting authority for the title V operating permit or the federally enforceable permit as applicable. The CAIR portion of the title V permit or other federally enforceable permit as applicable shall be administered in accordance with the permitting authority’s title V operating permits regulations promulgated under part 70 or 71 of this chapter or the permitting authority’s regulations for other federally enforceable permits as applicable, except as provided otherwise by §96.205, this subpart, and subpart III of this part.

(b) Each CAIR permit shall contain, with regard to the CAIR SO₂ source and the CAIR SO₂ units at the source covered by the CAIR permit, all applicable CAIR SO₂ Trading Program, CAIR NOₓ Annual Trading Program, and CAIR NOₓ Ozone Season Trading Program requirements and shall be a complete and separable portion of the title V operating permit or other federally enforceable permit under paragraph (a) of this section.

[70 FR 25362, May 12, 2005, as amended at 71 FR 25388, Apr. 28, 2006]

§ 96.221 Submission of CAIR permit applications.

(a) Duty to apply. The CAIR designated representative of any CAIR SO₂ source required to have a title V operating permit shall submit to the permitting authority a complete CAIR permit application under §96.222 for the source covering each CAIR SO₂ unit at
the source at least 18 months (or such lesser time provided by the permitting authority) before the later of January 1, 2010 or the date on which the CAIR SO₂ unit commences commercial operation, except as provided in §96.283(a).

(b) Duty to Reapply. For a CAIR SO₂ source required to have a title V operating permit, the CAIR designated representative shall submit a complete CAIR permit application under §96.222 for the source covering each CAIR SO₂ unit at the source to renew the CAIR permit in accordance with the permitting authority’s regulations addressing permit renewal, except as provided in §96.283(b).

[70 FR 25362, May 12, 2005, as amended at 71 FR 25388, Apr. 28, 2006]

§ 96.222 Information requirements for CAIR permit applications.

A complete CAIR permit application shall include the following elements concerning the CAIR SO₂ source for which the application is submitted, in a format prescribed by the permitting authority:

(a) Identification of the CAIR SO₂ source;
(b) Identification of each CAIR SO₂ unit at the CAIR SO₂ source; and
(c) The standard requirements under §96.206.

§ 96.223 CAIR permit contents and term.

(a) Each CAIR permit will contain, in a format prescribed by the permitting authority, all elements required for a complete CAIR permit application under §96.222.

(b) Each CAIR permit is deemed to incorporate automatically the definitions of terms under §96.202 and, upon recordation by the Administrator under subpart FFF, GGG, or III of this part, every allocation, transfer, or deduction of a CAIR SO₂ allowance to or from the compliance account of the CAIR SO₂ source covered by the permit.

(c) The term of the CAIR permit will be set by the permitting authority, as necessary to facilitate coordination of the renewal of the CAIR permit with issuance, revision, or renewal of the CAIR SO₂ source’s title V operating permit or other federally enforceable permit as applicable.

§ 96.224 CAIR permit revisions.

Except as provided in §96.223(b), the permitting authority will revise the CAIR permit, as necessary, in accordance with the permitting authority’s title V operating permits regulations or the permitting authority’s regulations for other federally enforceable permits as applicable addressing permit revisions.

Subparts DDD—EEE [Reserved]

Subpart FFF—CAIR SO₂ Allowance Tracking System

SOURCE: 70 FR 25362, May 12, 2005, unless otherwise noted.

§ 96.250 [Reserved]

§ 96.251 Establishment of accounts.

(a) Compliance accounts. Except as provided in §96.284(e), upon receipt of a complete certificate of representation under §96.213, the Administrator will establish a compliance account for the CAIR SO₂ source for which the certificate of representation was submitted, unless the source already has a compliance account.

(b) General accounts—(1) Application for general account. (i) Any person may apply to open a general account for the purpose of holding and transferring CAIR SO₂ allowances. An application for a general account may designate one and only one CAIR authorized account representative and one and only one alternate CAIR authorized account representative who may act on behalf of the CAIR authorized account representative. The agreement by which the alternate CAIR authorized account representative is selected shall include a procedure for authorizing the alternate CAIR authorized account representative to act in lieu of the CAIR authorized account representative.

(ii) A complete application for a general account shall be submitted to the Administrator and shall include the following elements in a format prescribed by the Administrator:
(A) Name, mailing address, e-mail address (if any), telephone number, and
facsimile transmission number (if any) of the CAIR authorized account representative and any alternate CAIR authorized account representative;

(B) Organization name and type of organization, if applicable;

(C) A list of all persons subject to a binding agreement for the CAIR authorized account representative and any alternate CAIR authorized account representative to represent their ownership interest with respect to the CAIR SO2 allowances held in the general account;

(D) The following certification statement by the CAIR authorized account representative and any alternate CAIR authorized account representative: “I certify that I was selected as the CAIR authorized account representative or the alternate CAIR authorized account representative, as applicable, by an agreement that is binding on all persons who have an ownership interest with respect to CAIR SO2 allowances held in the general account. I certify that I have all the necessary authority to carry out my duties and responsibilities under the CAIR SO2 Trading Program, notwithstanding any agreement between the CAIR authorized account representative or any alternate CAIR authorized account representative and such person. Any such person shall be bound by any order or decision issued to the CAIR authorized account representative or any alternate CAIR authorized account representative by the Administrator or a court regarding the general account.”

(E) The signature of the CAIR authorized account representative and any alternate CAIR authorized account representative and the dates signed.

(iii) Unless otherwise required by the permitting authority or the Administrator, documents of agreement referred to in the application for a general account shall not be submitted to the permitting authority or the Administrator. Neither the permitting authority nor the Administrator shall be under any obligation to review or evaluate the sufficiency of such documents, if submitted.

(2) Authorization of CAIR authorized account representative and alternate CAIR authorized account representative.

(i) Upon receipt by the Administrator of a complete application for a general account under paragraph (b)(1) of this section:

(A) The Administrator will establish a general account for the person or persons for whom the application is submitted.

(B) The CAIR authorized account representative and any alternate CAIR authorized account representative for the general account shall represent and, by his or her representations, actions, inactions, or submissions, legally bind each person who has an ownership interest with respect to CAIR SO2 allowances held in the general account in all matters pertaining to the CAIR SO2 Trading Program, notwithstanding any agreement between the CAIR authorized account representative or any alternate CAIR authorized account representative and such person. Any such person shall be bound by any order or decision issued to the CAIR authorized account representative or any alternate CAIR authorized account representative by the Administrator or a court regarding the general account.

(C) Any representation, action, inaction, or submission by any alternate CAIR authorized account representative shall be deemed to be a representation, action, inaction, or submission by the CAIR authorized account representative.

(ii) Each submission concerning the general account shall be submitted, signed, and certified by the CAIR authorized account representative or any alternate CAIR authorized account representative for the persons having an ownership interest with respect to CAIR SO2 allowances held in the general account. Each such submission shall include the following certification statement by the CAIR authorized account representative or any alternate CAIR authorized account representative: “I am authorized to make this submission on behalf of the persons having an ownership interest with respect to the CAIR SO2 allowances held in the general account. I certify under penalty of law that I have personally examined, and am familiar with, the statements and information submitted in this document and all its attachments. Based on my inquiry of those individuals with primary responsibility for obtaining the information, I
certify that the statements and information are to the best of my knowledge and belief true, accurate, and complete. I am aware that there are significant penalties for submitting false statements and information or omitting required statements and information, including the possibility of fine or imprisonment."

(iii) The Administrator will accept or act on a submission concerning the general account only if the submission has been made, signed, and certified in accordance with paragraph (b)(2)(ii) of this section.

(3) Changing CAIR authorized account representative and alternate CAIR authorized account representative; changes in persons with ownership interest. (i) The CAIR authorized account representative for a general account may be changed at any time upon receipt by the Administrator of a superseding complete application for a general account under paragraph (b)(1) of this section. Notwithstanding any such change, all representations, actions, inactions, and submissions by the previous CAIR authorized account representative before the time and date when the Administrator receives the superseding application for a general account shall be binding on the new CAIR authorized account representative and the persons with an ownership interest with respect to the CAIR SO2 allowances in the general account.

(ii) The alternate CAIR authorized account representative for a general account may be changed at any time upon receipt by the Administrator of a superseding complete application for a general account under paragraph (b)(1) of this section. Notwithstanding any such change, all representations, actions, inactions, and submissions by the previous alternate CAIR authorized account representative before the time and date when the Administrator receives the superseding application for a general account shall be binding on the new alternate CAIR authorized account representative and the persons with an ownership interest with respect to the CAIR SO2 allowances in the general account.

(iii)(A) In the event a person having an ownership interest with respect to CAIR SO2 allowances in the general account is not included in the list of such persons in the application for a general account, such person shall be deemed to be subject to and bound by the application for a general account, the representation, actions, inactions, and submissions of the CAIR authorized account representative and any alternate CAIR authorized account representative of the account, and the decisions and orders of the Administrator or a court, as if the person were included in such list.

(B) Within 30 days following any change in the persons having an ownership interest with respect to CAIR SO2 allowances in the general account, including the addition of a new person, the CAIR authorized account representative or any alternate CAIR authorized account representative shall submit a revision to the application for a general account amending the list of persons having an ownership interest with respect to the CAIR SO2 allowances in the general account to include the change.

(4) Objections concerning CAIR authorized account representative and alternate CAIR authorized account representative. (i) Once a complete application for a general account under paragraph (b)(1) of this section has been submitted and received, the Administrator will rely on the application unless and until a superseding complete application for a general account under paragraph (b)(1) of this section is received by the Administrator.

(ii) Except as provided in paragraph (b)(3)(i) or (ii) of this section, no objection or other communication submitted to the Administrator concerning the authorization, any representation, action, inaction, or submission of the CAIR authorized account representative or any alternate CAIR authorized account representative for a general account shall affect any representation, action, inaction, or submission of the CAIR authorized account representative or any alternate CAIR authorized account representative or the finality of any decision or order by the Administrator under the CAIR SO2 Trading Program.
(iii) The Administrator will not adjudicate any private legal dispute concerning the authorization or any representation, action, inaction, or submission of the CAIR authorized account representative or any alternate CAIR authorized account representative for a general account, including private legal disputes concerning the proceeds of CAIR SO2 allowance transfers.

(5) Delegation by CAIR authorized account representative and alternate CAIR authorized account representative. (i) A CAIR authorized account representative may delegate, to one or more natural persons, his or her authority to make an electronic submission to the Administrator provided for or required under subparts FFP and GGG of this part.

(ii) An alternate CAIR authorized account representative may delegate, to one or more natural persons, his or her authority to make an electronic submission to the Administrator provided for or required under subparts FFP and GGG of this part.

(iii) In order to delegate authority to make an electronic submission to the Administrator in accordance with paragraph (b)(5)(i) or (ii) of this section, the CAIR authorized account representative or alternate CAIR authorized account representative, as appropriate, must submit to the Administrator a notice of delegation, in a format prescribed by the Administrator, that includes the following elements:

(A) The name, address, e-mail address, telephone number, and facsimile transmission number (if any) of such CAIR authorized account representative or alternate CAIR authorized account representative;

(B) The name, address, e-mail address, telephone number, and, facsimile transmission number (if any) of each such natural person (referred to as an "agent");

(C) For each such natural person, a list of the type or types of electronic submissions under paragraph (b)(5)(i) or (ii) of this section for which authority is delegated to him or her;

(D) The following certification statement by such CAIR authorized account representative or alternate CAIR authorized account representative: "I agree that any electronic submission to the Administrator that is by an agent identified in this notice of delegation and of a type listed for such agent in this notice of delegation and that is made when I am a CAIR authorized account representative or alternate CAIR authorized representative, as appropriate, and before this notice of delegation is superseded by another notice of delegation under 40 CFR 96.251(b)(5)(iv) shall be deemed to be an electronic submission by me."; and

(E) The following certification statement by such CAIR authorized account representative or alternate CAIR authorized account representative: "Until this notice of delegation is superseded by another notice of delegation under 40 CFR 96.251(b)(5)(iv), I agree to maintain an e-mail account and to notify the Administrator immediately of any change in my e-mail address unless all delegation of authority by me under 40 CFR 96.251(b)(5) is terminated."

(iv) A notice of delegation submitted under paragraph (b)(5)(iii) of this section shall be effective, with regard to the CAIR authorized account representative or alternate CAIR authorized account representative identified in such notice, upon receipt of such notice by the Administrator and until receipt by the Administrator of a superseding notice of delegation submitted by such CAIR authorized account representative or alternate CAIR authorized account representative, as appropriate. The superseding notice of delegation may replace any previously identified agent, add a new agent, or eliminate entirely any delegation of authority.

(v) Any electronic submission covered by the certification in paragraph (b)(5)(iii)(D) of this section and made in accordance with a notice of delegation effective under paragraph (b)(5)(iv) of this section shall be deemed to be an electronic submission by the CAIR designated representative or alternate CAIR designated representative submitting such notice of delegation.
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(c) Account identification. The Administrator will assign a unique identifying number to each account established under paragraph (a) or (b) of this section.


§ 96.252 Responsibilities of CAIR authorized account representative.

Following the establishment of a CAIR SO2 Allowance Tracking System account, all submissions to the Administrator pertaining to the account, including, but not limited to, submissions concerning the deduction or transfer of CAIR SO2 allowances in the account, shall be made only by the CAIR authorized account representative for the account.

§ 96.253 Recordation of CAIR SO2 allowances.

(a)(1) After a compliance account is established under §96.251(a) or §73.31(a) or (b) of this chapter, the Administrator will record in the compliance account any CAIR SO2 allowance allocated to any CAIR SO2 unit at the source for each of the 30 years starting the later of 2010 or the year in which the compliance account is established and transferred to the source in accordance with subpart GGG of this part or subpart D of part 73 of this chapter.

(2) In 2011 and each year thereafter, after Administrator has completed all deductions under §96.254(b), the Administrator will record in the general account any CAIR SO2 allowance allocated for the new 30th year (i.e., the year that is 30 years after the calendar year for which such deductions are or could be made) and transferred to the source in accordance with subpart GGG of this part or subpart D of part 73 of this chapter.

(c) Serial numbers for allocated CAIR SO2 allowances. When recording the allocation of CAIR SO2 allowances issued by a permitting authority under §96.288, the Administrator will assign each such CAIR SO2 allowance a unique identification number that will include digits identifying the year of the control period for which the CAIR SO2 allowance is allocated.

§ 96.254 Compliance with CAIR SO2 emissions limitation.

(a) Allowance transfer deadline. The CAIR SO2 allowances are available to be deducted for compliance with a source’s CAIR SO2 emissions limitation for a control period in a given calendar year only if the CAIR SO2 allowances:

(1) Were allocated for the control period in the year or a prior year; and

(2) Are held in the compliance account as of the allowance transfer deadline for the control period or are transferred into the compliance account by a CAIR SO2 allowance transfer correctly submitted for recordation under §§96.260 and 96.261 by the allowance transfer deadline for the control period.

(b) Deductions for compliance. Following the recordation, in accordance with §96.261, of CAIR SO2 allowance transfers submitted for recordation in a source’s compliance account by the allowance transfer deadline for a control period, the Administrator will deduct from the compliance account CAIR SO2 allowances available under paragraph (a) of this section in order to determine whether the source meets
§ 96.254 the CAIR SO₂ emissions limitation for the control period as follows:
(1) For a CAIR SO₂ source subject to an Acid Rain emissions limitation, the Administrator will, in the following order:
(i) Deduct the amount of CAIR SO₂ allowances, available under paragraph (a) of this section and not issued by a permitting authority under § 96.288, that is required under §§ 73.35(b) and (c) of this part. If there are sufficient CAIR SO₂ allowances to complete this deduction, the deduction will be treated as satisfying the requirements of §§ 73.35(b) and (c) of this chapter.
(ii) Deduct the amount of CAIR SO₂ allowances, not issued by a permitting authority under § 96.288, that is required under §§ 73.35(d) and 77.5 of this part. If there are sufficient CAIR SO₂ allowances to complete this deduction, the deduction will be treated as satisfying the requirements of §§ 73.35(d) and 77.5 of this chapter.
(iii) Treating the CAIR SO₂ allowances deducted under paragraph (b)(1)(i) of this section as also being deducted under this paragraph (b)(1)(iii), deduct CAIR SO₂ allowances available under paragraph (a) of this section (including any issued by a permitting authority under § 96.288) in order to determine whether the source meets the CAIR SO₂ emissions limitation for the control period, as follows:
(A) Until the tonnage equivalent of the CAIR SO₂ allowances deducted equals, or exceeds in accordance with paragraphs (c)(1) and (2) of this section, the number of tons of total sulfur dioxide emissions, determined in accordance with subpart HHH of this part, from all CAIR SO₂ units at the source for the control period; or
(B) If there are insufficient CAIR SO₂ allowances to complete the deductions in paragraph (b)(1)(iii)(A) of this section, until no more CAIR SO₂ allowances available under paragraph (a) of this section (including any issued by a permitting authority under § 96.288) remain in the compliance account.
(ii) Identification of CAIR SO₂ allowances by serial number. The CAIR authorized account representative for a source’s compliance account may request that specific CAIR SO₂ allowances, identified by serial number, in the compliance account be deducted for emissions or excess emissions for a control period in accordance with paragraph (b) or (d) of this section. Such request shall be submitted to the Administrator by the allowance transfer deadline for the control period and include, in a format prescribed by the Administrator, the identification of the CAIR SO₂ source and the appropriate serial numbers.
(2) First-in, first-out. The Administrator will deduct CAIR SO₂ allowances under paragraph (b) or (d) of this section from the source’s compliance account, in the absence of an identification or in the case of a partial identification of CAIR SO₂ allowances by serial number under paragraph (c)(1) of this section, on a first-in, first-out (FIFO) accounting basis in the following order:
(i) Any CAIR SO₂ allowances that were allocated to the units at the source for a control period before 2010, in the order of recordation;
(ii) Any CAIR SO₂ allowances that were allocated to any entity for a control period before 2010 and transferred and recorded in the compliance account pursuant to subpart GGG of this
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part or subpart D of part 73 of this chapter, in the order of recordation:

(iii) Any CAIR SO₂ allowances that were allocated to the units at the source for a control period during 2010 through 2014, in the order of recordation;

(iv) Any CAIR SO₂ allowances that were allocated to any entity for a control period during 2010 through 2014 and transferred and recorded in the compliance account pursuant to subpart GGG of this part or subpart D of part 73 of this chapter, in the order of recordation;

(v) Any CAIR SO₂ allowances that were allocated to the units at the source for a control period in 2015 or later, in the order of recordation; and

(vi) Any CAIR SO₂ allowances that were allocated to any entity for a control period in 2015 or later and transferred and recorded in the compliance account pursuant to subpart GGG of this part or subpart D of part 73 of this chapter, in the order of recordation.

(d) Deductions for excess emissions. (1) After making the deductions for compliance under paragraph (b) of this section for a control period in a calendar year in which the CAIR SO₂ source has excess emissions, the Administrator will deduct from the source’s compliance account the tonnage equivalent in CAIR SO₂ allowances, allocated for the control period in the immediately following calendar year (including any issued by a permitting authority under §96.288), equal to, or exceeding in accordance with paragraphs (c)(1) and (2) of this section, 3 times the following amount: the number of tons of the source’s excess emissions minus, if the source is subject to an Acid Rain emissions limitation, the amount of the CAIR SO₂ allowances required to be deducted under paragraph (b)(1)(ii) of this section.

(2) Any allowance deduction required under paragraph (d)(1) of this section shall not affect the liability of the owners and operators of the CAIR SO₂ source or the CAIR SO₂ units at the source for any fine, penalty, or assessment, or their obligation to comply with any other remedy, for the same violations, as ordered under the Clean Air Act or applicable State law.

(e) Recordation of deductions. The Administrator will record in the appropriate compliance account all deductions from such an account under paragraphs (b) and (d) of this section and subpart III.

(f) Administrator’s action on submissions. (1) The Administrator may review and conduct independent audits concerning any submission under the CAIR SO₂ Trading Program and make appropriate adjustments of the information in the submissions.

(2) The Administrator may deduct CAIR SO₂ allowances from or transfer CAIR SO₂ allowances to a source’s compliance account based on the information in the submissions, as adjusted under paragraph (f)(1) of this section, and record such deductions and transfers.

§ 96.255 Banking.

(a) CAIR SO₂ allowances may be banked for future use or transfer in a compliance account or a general account in accordance with paragraph (b) of this section.

(b) Any CAIR SO₂ allowance that is held in a compliance account or a general account will remain in such account unless and until the CAIR SO₂ allowance is deducted or transferred under §96.254, §96.256, or subpart GGG or III of this part.

§ 96.256 Account error.

The Administrator may, at his or her sole discretion and on his or her own motion, correct any error in any CAIR SO₂ Allowance Tracking System account. Within 10 business days of making such correction, the Administrator will notify the CAIR authorized account representative for the account.

§ 96.257 Closing of general accounts.

(a) The CAIR authorized account representative of a general account may submit to the Administrator a request to close the account, which shall include a correctly submitted allowance transfer under §§96.260 and 96.261 for
any CAIR SO\textsubscript{2} allowances in the account to one or more other CAIR SO\textsubscript{2} Allowance Tracking System accounts.

(b) If a general account has no allowance transfers in or out of the account for a 12-month period or longer and does not contain any CAIR SO\textsubscript{2} allowances, the Administrator may notify the CAIR authorized account representative for the account that the account will be closed following 20 business days after the notice is sent. The account will be closed after the 20-day period unless, before the end of the 20-day period, the Administrator receives a correctly submitted transfer of CAIR SO\textsubscript{2} allowances into the account under §§96.260 and 96.261 or a statement submitted by the CAIR authorized account representative demonstrating to the satisfaction of the Administrator good cause as to why the account should not be closed.

[70 FR 25362, May 12, 2005, as amended at 71 FR 25389, Apr. 28, 2006]

Subpart GGG—CAIR SO\textsubscript{2} Allowance Transfers

Source: 70 FR 25362, May 12, 2005, unless otherwise noted.

§ 96.260 Submission of CAIR SO\textsubscript{2} allowance transfers.

(a) A CAIR authorized account representative seeking recordation of a CAIR SO\textsubscript{2} allowance transfer shall submit the transfer to the Administrator. To be considered correctly submitted, the CAIR SO\textsubscript{2} allowance transfer shall include the following elements, in a format specified by the Administrator:

(1) The account numbers of both the transferor and transferee accounts;

(2) The serial number of each CAIR SO\textsubscript{2} allowance that is in the transferor account and is to be transferred; and

(3) The name and signature of the CAIR authorized account representatives of the transferor and transferee accounts and the dates signed.

(b)(1) The CAIR authorized account representative for the transferee account can meet the requirements in paragraph (a)(3) of this section by submitting, in a format prescribed by the Administrator, a statement signed by the CAIR authorized account representative and identifying each account into which any transfer of allowances, submitted on or after the date on which the Administrator receives such statement, is authorized. Such authorization shall be binding on any CAIR authorized account representative for such account and shall apply to all transfers into the account that are submitted on or after such date of receipt, unless and until the Administrator receives a statement signed by the CAIR authorized account representative retracting the authorization for the account.

(2) The statement under paragraph (b)(1) of this section shall include the following: "By this signature I authorize any transfer of allowances into each account listed herein, except that I do not waive any remedies under State or Federal law to obtain correction of any erroneous transfers into such accounts. This authorization shall be binding on any CAIR authorized account representative for such account unless and until a statement signed by the CAIR authorized account representative retracting this authorization for the account is received by the Administrator."

§ 96.261 EPA recordation.

(a) Within 5 business days (except as necessary to perform a transfer in perpetuity of CAIR SO\textsubscript{2} allowances allocated to a CAIR SO\textsubscript{2} unit or as provided in paragraph (b) of this section) of receiving a CAIR SO\textsubscript{2} allowance transfer, the Administrator will record a CAIR SO\textsubscript{2} allowance transfer by moving each CAIR SO\textsubscript{2} allowance from the transferor account to the transferee account as specified by the request, provided that:

(1) The transfer is correctly submitted under §96.260;

(2) The transferor account includes each CAIR SO\textsubscript{2} allowance identified by serial number in the transfer; and

(3) The transfer is in accordance with the limitation on transfer under §74.42 of this chapter and §74.47(c) of this chapter, as applicable.

(b) A CAIR SO\textsubscript{2} allowance transfer that is submitted for recordation after the allowance transfer deadline for a control period and that includes any CAIR SO\textsubscript{2} allowances allocated for any
control period before such allowance transfer deadline will not be recorded until after the Administrator completes the deductions under §96.254 for the control period immediately before such allowance transfer deadline.

(c) Where a CAIR SO₂ allowance transfer submitted for recordation fails to meet the requirements of paragraph (a) of this section, the Administrator will not record such transfer.

[70 FR 25362, May 12, 2005, as amended at 71 FR 25389, Apr. 28, 2006]

§ 96.262 Notification.

(a) Notification of recordation. Within 5 business days of recordation of a CAIR SO₂ allowance transfer under §96.261, the Administrator will notify the CAIR authorized account representatives of both the transferor and transferee accounts.

(b) Notification of non-recordation. Within 10 business days of receipt of a CAIR SO₂ allowance transfer that fails to meet the requirements of §96.261(a), the Administrator will notify the CAIR authorized account representatives of both accounts subject to the transfer of:

(1) A decision not to record the transfer, and

(2) The reasons for such non-recordation.

(c) Nothing in this section shall preclude the submission of a CAIR SO₂ allowance transfer for recordation following notification of non-recordation.

Subpart HHH—Monitoring and Reporting

SOURCE: 70 FR 25362, May 12, 2005, unless otherwise noted.

§ 96.270 General requirements.

The owners and operators, and to the extent applicable, the CAIR designated representative, of a CAIR SO₂ unit, shall comply with the monitoring, recordkeeping, and reporting requirements as provided in this subpart and in subparts F and G of part 75 of this chapter. For purposes of complying with such requirements, the definitions in §96.202 and in §72.2 of this chapter shall apply, and the terms “affected unit,” “designated representative,” and “continuous emission monitoring system” (or “CEMS”) in part 75 of this chapter shall be deemed to refer to the terms “CAIR SO₂ unit,” “CAIR designated representative,” and “continuous emission monitoring system” (or “CEMS”) respectively, as defined in §96.202. The owner or operator of a unit that is not a CAIR SO₂ unit but that is monitored under §75.16(b)(2) of this chapter shall comply with the same monitoring, recordkeeping, and reporting requirements as a CAIR SO₂ unit.

(a) Requirements for installation, certification, and data accounting. The owner or operator of each CAIR SO₂ unit shall:

(1) Install all monitoring systems required under this subpart for monitoring SO₂ mass emissions and individual unit heat input (including all systems required to monitor SO₂ concentration, stack gas moisture content, stack gas flow rate, CO₂ or O₂ concentration, and fuel flow rate, as applicable, in accordance with §§75.11 and 75.16 of this chapter);

(2) Successfully complete all certification tests required under §96.271 and meet all other requirements of this subpart and part 75 of this chapter applicable to the monitoring systems under paragraph (a)(1) of this section; and

(3) Record, report, and quality-assure the data from the monitoring systems under paragraph (a)(1) of this section.

(b) Compliance deadlines. Except as provided in paragraph (e) of this section, the owner or operator shall meet the monitoring system certification and other requirements of paragraphs (a)(1) and (2) of this section on or before the following dates. The owner or operator shall record, report, and quality-assure the data from the monitoring systems under paragraph (a)(1) of this section on and after the following dates:

(1) For the owner or operator of a CAIR SO₂ unit that commences commercial operation before July 1, 2008, by January 1, 2009.

(2) For the owner or operator of a CAIR SO₂ unit that commences commercial operation on or after July 1, 2008, by the later of the following dates:

(i) January 1, 2009; or
(ii) 90 unit operating days or 180 calendar days, whichever occurs first, after the date on which the unit commences commercial operation.

(3) For the owner or operator of a CAIR SO₂ unit for which construction of a new stack or flue or installation of add-on SO₂ emission controls is completed after the applicable deadline under paragraph (b)(1), (2), (4), or (5) of this section, by 90 unit operating days or 180 calendar days, whichever occurs first, after the date on which emissions first exit to the atmosphere through the new stack or flue or add-on SO₂ emissions controls.

(4) Notwithstanding the dates in paragraphs (b)(1) and (2) of this section, for the owner or operator of a unit for which a CAIR opt-in permit application is submitted and not withdrawn and a CAIR opt-in permit is not yet issued or denied under subpart III of this part, by the date specified in §96.284(b).

(5) Notwithstanding the dates in paragraphs (b)(1) and (2) of this section, for the owner or operator of a CAIR SO₂ opt-in unit under subpart III of this part, by the date on which the CAIR SO₂ opt-in unit enters the CAIR SO₂ Trading Program as provided in §96.284(g).

(c) Reporting data. The owner or operator of a CAIR SO₂ unit that does not meet the applicable compliance date set forth in paragraph (b) of this section for any monitoring system under paragraph (a)(1) of this section shall, for each such monitoring system, determine, record, and report maximum potential (or, as appropriate, minimum potential) values for SO₂ concentration, stack gas flow rate, stack gas moisture content, fuel flow rate, and any other parameters required to determine SO₂ mass emissions and heat input in accordance with §75.31(b)(2) or (c)(3) of this chapter or section 2.4 of appendix D to part 75 of this chapter, as applicable.

(d) Prohibitions. (1) No owner or operator of a CAIR SO₂ unit shall use any alternative monitoring system, alternative reference method, or any other alternative to any requirement of this subpart without having obtained prior written approval in accordance with §96.275.

(2) No owner or operator of a CAIR SO₂ unit shall operate the unit so as to discharge, or allow to be discharged, SO₂ emissions to the atmosphere without accounting for all such emissions in accordance with the applicable provisions of this subpart and part 75 of this chapter.

(iii) No owner or operator of a CAIR SO₂ unit shall disrupt the continuous emission monitoring system, any portion thereof, or any other approved emission monitoring method, and thereby avoid monitoring and recording SO₂ mass emissions discharged into the atmosphere or heat input, except for periods of recertification or periods when calibration, quality assurance testing, or maintenance is performed in accordance with the applicable provisions of this subpart and part 75 of this chapter.

(4) No owner or operator of a CAIR SO₂ unit shall retire or permanently discontinue use of the continuous emission monitoring system, any component thereof, or any other approved monitoring system under this subpart, except under any one of the following circumstances:

(i) During the period that the unit is covered by an exemption under §96.205 that is in effect;

(ii) The owner or operator is monitoring emissions from the unit with another certified monitoring system approved, in accordance with the applicable provisions of this subpart and part 75 of this chapter, by the permitting authority for use at that unit that provides emission data for the same pollutant or parameter as the retired or discontinued monitoring system; or

(iii) The CAIR designated representative submits notification of the date of certification testing of a replacement monitoring system for the retired or discontinued monitoring system in accordance with §96.271(d)(3)(i).

(e) Long-term cold storage. The owner or operator of a CAIR SO₂ unit is subject to the applicable provisions of part 75 of this chapter concerning units in long-term cold storage.

[70 FR 25362, May 12, 2005, as amended at 71 FR 25389, Apr. 28, 2006]
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§ 96.271 Initial certification and recertification procedures.

(a) The owner or operator of a CAIR SO₂ unit shall be exempt from the initial certification requirements of this section for a monitoring system under §96.270(a)(1) if the following conditions are met:

(1) The monitoring system has been previously certified in accordance with part 75 of this chapter; and

(2) The applicable quality-assurance and quality-control requirements of §75.21 of this chapter and appendix B and appendix D to part 75 of this chapter are fully met for the certified monitoring system described in paragraph (a)(1) of this section.

(b) The recertification provisions of this section shall apply to a monitoring system under §96.270(a)(1) exempt from initial certification requirements under paragraph (a) of this section.

(c) [Reserved]

(d) Except as provided in paragraph (a) of this section, the owner or operator of a CAIR SO₂ unit shall comply with the following initial certification and recertification procedures, for a continuous monitoring system (i.e., a continuous emission monitoring system and an excepted monitoring system under appendix D to part 75 of this chapter) under §96.270(a)(1). The owner or operator of a unit that qualifies to use the low mass emissions excepted monitoring methodology under §75.19 of this chapter or that qualifies to use an alternative monitoring system under subpart E of part 75 of this chapter shall comply with the procedures in paragraph (e) or (f) of this section respectively.

(1) Requirements for initial certification.

The owner or operator shall ensure that each continuous monitoring system under §96.270(a)(1) (including the automated data acquisition and handling system) successfully completes all of the initial certification testing required under §75.20 of this chapter by the applicable deadline in §96.270(b). In addition, whenever the owner or operator installs a monitoring system to meet the requirements of this subpart in a location where no such monitoring system was previously installed, initial certification in accordance with §75.20 of this chapter is required.

(2) Requirements for recertification.

Whenever the owner or operator makes a replacement, modification, or change in any certified continuous emission monitoring system under §96.270(a)(1) that may significantly affect the ability of the system to accurately measure or record SO₂ mass emissions or heat input rate or to meet the quality-assurance and quality-control requirements of §75.21 of this chapter or appendix B to part 75 of this chapter, the owner or operator shall recertify the monitoring system in accordance with §75.20(b) of this chapter. Furthermore, whenever the owner or operator makes a replacement, modification, or change to the flue gas handling system or the unit’s operation that may significantly change the stack flow or concentration profile, the owner or operator shall recertify each continuous emission monitoring system whose accuracy is potentially affected by the change, in accordance with §75.20(b) of this chapter. Examples of changes to a continuous emission monitoring system that require recertification include: replacement of the analyzer, complete replacement of an existing continuous emission monitoring system, or change in location or orientation of the sampling probe or site. Any fuel flowmeter system under §96.270(a)(1) is subject to the recertification requirements in §75.20(g)(6) of this chapter.

(3) Approval process for initial certification and recertification.

Paragraphs (d)(3)(i) through (iv) of this section apply to both initial certification and recertification of a continuous monitoring system under §96.270(a)(1). For recertifications, replace the words “certification” and “initial certification” with the word “recertification”, replace the word “certified” with the word “recertified,” and follow the procedures in §§75.20(b)(5) and (g)(7) of this chapter in lieu of the procedures in paragraph (d)(3)(v) of this section.

(i) Notification of certification. The CAIR designated representative shall submit to the permitting authority, the appropriate EPA Regional Office, and the Administrator written notice of the dates of certification testing, in accordance with §96.273.
(i) Certification application. The CAIR designated representative shall submit to the permitting authority a certification application for each monitoring system. A complete certification application shall include the information specified in §75.63 of this chapter.

(ii) Provisional certification date. The provisional certification date for a monitoring system shall be determined in accordance with §75.20(a)(3) of this chapter. A provisionally certified monitoring system may be used under the CAIR SO_2_ Trading Program for a period not to exceed 120 days after receipt by the permitting authority of the complete certification application for the monitoring system under paragraph (d)(3)(ii) of this section. Data measured and recorded by the provisionally certified monitoring system, in accordance with the requirements of part 75 of this chapter, will be considered valid quality-assured data (retroactive to the date and time of provisional certification), provided that the permitting authority does not invalidate the provisional certification by issuing a notice of disapproval within 120 days of receipt of the complete certification application.

(iv) Certification application approval process. The permitting authority will issue a written notice of approval or disapproval of the certification application to the owner or operator within 120 days of receipt of the complete certification application under paragraph (d)(3)(ii) of this section. In the event the permitting authority does not issue such a notice within such 120-day period, each monitoring system that meets the applicable performance requirements of part 75 of this chapter and is included in the certification application will be deemed certified for use under the CAIR SO_2_ Trading Program.

(A) Approval notice. If the certification application is complete and shows that each monitoring system meets the applicable performance requirements of part 75 of this chapter, then the permitting authority will issue a written notice of approval of the certification application within 120 days of receipt.

(B) Incomplete application notice. If the certification application is not complete, then the permitting authority will issue a written notice of incompleteness that sets a reasonable date by which the CAIR designated representative must submit the additional information required to complete the certification application. If the CAIR designated representative does not comply with the notice of incompleteness by the specified date, then the permitting authority may issue a notice of disapproval under paragraph (d)(3)(iv)(C) of this section. The 120-day review period shall not begin before receipt of a complete certification application.

(C) Disapproval notice. If the certification application shows that any monitoring system does not meet the performance requirements of part 75 of this chapter or if the certification application is incomplete and the requirement for disapproval under paragraph (d)(3)(iv)(B) of this section is met, then the permitting authority will issue a written notice of disapproval of the certification application. Upon issuance of such notice of disapproval, the provisional certification is invalidated by the permitting authority and the data measured and recorded by each uncertified monitoring system shall not be considered valid quality-assured data beginning with the date and hour of provisional certification (as defined under §75.20(a)(3) of this chapter). The owner or operator shall follow the procedures for loss of certification in paragraph (d)(3)(v) of this section for each monitoring system that is disapproved for initial certification.

(D) Audit decertification. The permitting authority or, for a CAIR SO_2_ opt-in unit or a unit for which a CAIR opt-in permit application is submitted and not withdrawn and a CAIR opt-in permit is not yet issued or denied under subpart III of this part, the Administrator may issue a notice of disapproval of the certification status of a monitor in accordance with §96.272(b).

(v) Procedures for loss of certification. If the permitting authority or the Administrator issues a notice of disapproval of a certification application under paragraph (d)(3)(iv)(C) of this...
section or a notice of disapproval of certification status under paragraph (d)(3)(iv)(D) of this section, then:

(A) The owner or operator shall substitute the following values, for each disapproved monitoring system, for each hour of unit operation during the period of invalid data specified under §75.20(a)(4)(iii), §75.20(g)(7), or §75.21(e) of this chapter and continuing until the applicable date and hour specified under §75.20(a)(5)(i) or (g)(7) of this chapter:

(1) For a disapproved SO\(_2\) pollutant concentration monitor and disapproved flow monitor, respectively, the maximum potential concentration of SO\(_2\) and the maximum potential flow rate, as defined in sections 2.1.1.1 and 2.1.4.1 of appendix A to part 75 of this chapter.

(2) For a disapproved moisture monitoring system and disapproved diluent gas monitoring system, respectively, the minimum potential moisture percentage and either the maximum potential CO\(_2\) concentration or the minimum potential O\(_2\) concentration (as applicable), as defined in sections 2.1.5, 2.1.3.1, and 2.1.3.2 of appendix A to part 75 of this chapter.

(3) For a disapproved fuel flowmeter system, the maximum potential fuel flow rate, as defined in section 2.4.2.1 of appendix D to part 75 of this chapter.

(B) The CAIR designated representative shall submit a notification of certification retest dates and a new certification application in accordance with paragraphs (d)(3)(i) and (ii) of this section.

(C) The owner or operator shall repeat all certification tests or other requirements that were failed by the monitoring system, as indicated in the permitting authority’s or the Administrator’s notice of disapproval, no later than 30 unit operating days after the date of issuance of the notice of disapproval.

(e) Initial certification and recertification procedures for units using the low mass emission excepted methodology under §75.19 of this chapter. The owner or operator of a unit qualified to use the low mass emissions (LME) excepted methodology under §75.19 of this chapter shall meet the applicable certification and recertification requirements in §§75.19(a)(2) and 75.20(h) of this chapter. If the owner or operator of such a unit elects to certify a fuel flowmeter system for heat input determination, the owner or operator shall also meet the certification and recertification requirements in §75.20(g) of this chapter.

(f) Certification/recertification procedures for alternative monitoring systems. The CAIR designated representative of each unit for which the owner or operator intends to use an alternative monitoring system approved by the Administrator and, if applicable, the permitting authority under subpart E of part 75 of this chapter shall comply with the applicable notification and application procedures of §75.20(f) of this chapter.

§96.272 Out of control periods.

(a) Whenever any monitoring system fails to meet the quality-assurance and quality-control requirements or data validation requirements of part 75 of this chapter, data shall be substituted using the applicable missing data procedures in subpart D of or appendix D to part 75 of this chapter.

(b) Audit decertification. Whenever both an audit of a monitoring system and a review of the initial certification or recertification application reveal that any monitoring system should not have been certified or recertified because it did not meet a particular performance specification or other requirement under §96.271 or the applicable provisions of part 75 of this chapter, both at the time of the initial certification or recertification application submission and at the time of the audit, the permitting authority or, for a CAIR SO\(_2\) opt-in unit or a unit for which a CAIR opt-in permit application is submitted and not withdrawn and a CAIR opt-in permit is not yet issued or denied under subpart III of this part, the Administrator will issue a notice of disapproval of the certification status of such monitoring system. For the purposes of this paragraph, an audit shall be either a field audit or an audit of any information submitted to the permitting authority or the Administrator. By issuing the notice of disapproval, the permitting authority or
§ 96.273 Notifications.

The CAIR designated representative for a CAIR SO\textsubscript{2} unit shall submit written notice to the permitting authority and the Administrator in accordance with §75.61 of this chapter.

[70 FR 25362, May 12, 2005, as amended at 71 FR 25390, Apr. 28, 2006]

§ 96.274 Recordkeeping and reporting.

(a) General provisions. The CAIR designated representative shall comply with all recordkeeping and reporting requirements in this section, the applicable recordkeeping and reporting requirements in subparts F and G of part 75 of this chapter, and the requirements of §96.210(e)(1).

(b) Monitoring plans. The owner or operator of a CAIR SO\textsubscript{2} unit shall comply with requirements of §75.62 of this chapter and, for a unit for which a CAIR opt-in permit application is submitted and not withdrawn and a CAIR opt-in permit is not yet issued or denied under subpart III of this part, the calendar quarter corresponding to the date on which the CAIR SO\textsubscript{2} opt-in unit enters the CAIR SO\textsubscript{2} Trading Program as provided in §96.284(g).

(2) The CAIR designated representative shall submit each quarterly report to the Administrator within 30 days following the end of the calendar quarter covered by the report. Quarterly reports shall be submitted in the manner specified in §75.64 of this chapter.

(3) For CAIR SO\textsubscript{2} units that are also subject to an Acid Rain emissions limitation or the CAIR NO\textsubscript{X} Annual Trading Program CAIR NO\textsubscript{X} Ozone Season Trading Program, or Hg Budget Trading Program, quarterly reports shall include the applicable data and information required by subparts F through I of part 75 of this chapter as applicable, in addition to the SO\textsubscript{2} mass emission data, heat input data, and other information required by this subpart.

(e) Compliance certification. The CAIR designated representative shall submit to the Administrator a certification of compliance (in a format prescribed by the Administrator) in support of each quarterly report in a format prescribed by the Administrator, for each calendar quarter beginning with:

(i) For a unit that commences commercial operation before July 1, 2008, the calendar quarter covering January 1, 2009 through March 31, 2009;

(ii) For a unit that commences commercial operation on or after July 1, 2008, the calendar quarter corresponding to the earlier of the date of provisional certification or the applicable deadline for initial certification under §96.270(b), unless that quarter is the third or fourth quarter of 2008, in which case reporting shall commence in the quarter covering January 1, 2009 through March 31, 2009;

(iii) Notwithstanding paragraphs (d)(1)(i) and (ii) of this section, for a unit for which a CAIR opt-in permit application is submitted and not withdrawn and a CAIR opt-in permit is not yet issued or denied under subpart III of this part, the calendar quarter corresponding to the date specified in §96.284(b); and

(iv) Notwithstanding paragraphs (d)(1)(i) and (ii) of this section, for a CAIR SO\textsubscript{2} opt-in unit under subpart III of this part, the calendar quarter corresponding to the date on which the CAIR SO\textsubscript{2} opt-in unit enters the CAIR SO\textsubscript{2} Trading Program as provided in §96.284(g).
quarterly report based on reasonable inquiry of those persons with primary responsibility for ensuring that all of the unit's emissions are correctly and fully monitored. The certification shall state that:

(1) The monitoring data submitted were recorded in accordance with the applicable requirements of this subpart and part 75 of this chapter, including the quality assurance procedures and specifications; and

(2) For a unit with add-on SO$_2$ emission controls and for all hours where SO$_2$ data are substituted in accordance with §75.34(a)(1) of this chapter, the add-on emission controls were operating within the range of parameters listed in the quality assurance/quality control program under appendix B to part 75 of this chapter and the substitute data values do not systematically underestimate SO$_2$ emissions.

[70 FR 25362, May 12, 2005, as amended at 71 FR 25390, Apr. 28, 2006]

§ 96.275 Petitions.

(a) The CAIR designated representative of a CAIR SO$_2$ unit that is subject to an Acid Rain emissions limitation may submit a petition under §75.66 of this chapter to the Administrator requesting approval to apply an alternative to any requirement of this subpart. Application of an alternative to any requirement of this subpart is in accordance with this subpart only to the extent that the petition is approved in writing by the Administrator, in consultation with the permitting authority.

(b) The CAIR designated representative of a CAIR SO$_2$ unit that is not subject to an Acid Rain emissions limitation may submit a petition under §75.66 of this chapter to the permitting authority and the Administrator requesting approval to apply an alternative to any requirement of this subpart. Application of an alternative to any requirement of this subpart is in accordance with this subpart only to the extent that the petition is approved in writing by both the permitting authority and the Administrator.

§ 96.277 Subpart III—CAIR SO$_2$ Opt-in Units

SOURCE: 70 FR 25362, May 12, 2005, unless otherwise noted.

§ 96.280 Applicability.

A CAIR SO$_2$ opt-in unit must be a unit that:

(a) Is located in the State;
(b) Is not a CAIR SO$_2$ unit under §96.204 and is not covered by a retired unit exemption under §96.205 that is in effect;
(c) Is not covered by a retired unit exemption under §72.8 of this chapter that is in effect and is not an opt-in source under part 74 of this chapter;
(d) Has or is required or qualified to have a title V operating permit or other federally enforceable permit; and
(e) Vents all of its emissions to a stack and can meet the monitoring, recordkeeping, and reporting requirements of subpart HHH of this part.

§ 96.281 General.

(a) Except as otherwise provided in §§96.201 through 96.204, §§96.206 through 96.208, and subparts BBB and CCC and subparts FFF through HHH of this part, a CAIR SO$_2$ opt-in unit shall be treated as a CAIR SO$_2$ unit for purposes of applying such sections and subparts of this part.
(b) Solely for purposes of applying, as provided in this subpart, the requirements of subpart HHH of this part to a unit for which a CAIR opt-in permit application is submitted and not withdrawn and a CAIR opt-in permit is not yet issued or denied under this subpart, such unit shall be treated as a CAIR SO$_2$ unit before issuance of a CAIR opt-in permit for such unit.

§ 96.282 CAIR designated representative.

Any CAIR SO$_2$ opt-in unit, and any unit for which a CAIR opt-in permit application is submitted and not withdrawn and a CAIR opt-in permit is not yet issued or denied under this subpart, located at the same source as one or more CAIR SO$_2$ units shall have the same CAIR designated representative and alternate CAIR designated representative as such CAIR SO$_2$ units.
§ 96.283 Applying for CAIR opt-in permit.

(a) Applying for initial CAIR opt-in permit. The CAIR designated representative of a unit meeting the requirements for a CAIR SO₂ opt-in unit in §96.280 may apply for an initial CAIR opt-in permit at any time, except as provided under §96.286(f) and (g), and, in order to apply, must submit the following:

1. A complete CAIR permit application under §96.222;
2. A certification, in a format specified by the permitting authority, that the unit:
   i. Is not a CAIR SO₂ unit under §96.204 and is not covered by a retired unit exemption under §96.205 that is in effect;
   ii. Is not covered by a retired unit exemption under §72.8 of this chapter that is in effect;
   iii. Is not and, so long as the unit is a CAIR SO₂ opt-in unit, will not become, an opt-in source under part 74 of this chapter;
   iv. Vents all of its emissions to a stack; and
   v. Has documented heat input for more than 876 hours during the 6 months immediately preceding submission of the CAIR permit application under §96.222;
3. A monitoring plan in accordance with subpart HHH of this part;
4. A complete certificate of representation under §96.213 consistent with §96.282, if no CAIR designated representative has been previously designated for the source that includes the unit; and
5. A statement, in a format specified by the permitting authority, whether the CAIR designated representative requests that the unit be allocated CAIR SO₂ allowances under §96.288(b) or §96.288(c) (subject to the conditions in §§96.284(h) and 96.286(g)). If allocation under §96.288(c) is requested, this statement shall include a statement that the owners and operators of the unit intend to repower the unit before January 1, 2015 and that they will provide, upon request, documentation demonstrating such intent.

(b) Duty to reapply. (1) The CAIR designated representative of a CAIR SO₂ opt-in unit shall submit a complete CAIR permit application under §96.222 to renew the CAIR opt-in unit permit in accordance with the permitting authority’s regulations for title V operating permits, or the permitting authority’s regulations for other federally enforceable permits if applicable, addressing permit renewal.
   (2) Unless the permitting authority issues a notification of acceptance of withdrawal of the CAIR SO₂ opt-in unit from the CAIR SO₂ Trading Program in accordance with §96.286 or the unit becomes a CAIR SO₂ unit under §96.204, the CAIR SO₂ opt-in unit shall remain subject to the requirements for a CAIR SO₂ opt-in unit, even if the CAIR designated representative for the CAIR SO₂ opt-in unit fails to submit a CAIR permit application that is required for renewal of the CAIR opt-in permit under paragraph (b)(1) of this section.

[70 FR 25362, May 12, 2005, as amended at 71 FR 25390, Apr. 28, 2006]

§ 96.284 Opt-in process.

The permitting authority will issue or deny a CAIR opt-in permit for a unit for which an initial application for a CAIR opt-in permit under §96.283 is submitted in accordance with the following:

(a) Interim review of monitoring plan. The permitting authority and the Administrator will determine, on an interim basis, the sufficiency of the monitoring plan accompanying the initial application for a CAIR opt-in permit under §96.283. A monitoring plan is sufficient, for purposes of interim review, if the plan appears to contain information demonstrating that the SO₂ emissions rate and heat input of the unit and all other applicable parameters are monitored and reported in accordance with subpart HHH of this part. A determination of sufficiency shall not be construed as acceptance or approval of the monitoring plan.

(b) Monitoring and reporting. (1) If the permitting authority and the Administrator determine that the monitoring plan is sufficient under paragraph (a) of this section, the owner or operator shall monitor and report the SO₂ emissions rate and the heat input of the unit and all other applicable parameters, in accordance with subpart HHH of this part, starting on the date...
of certification of the appropriate monitoring systems under subpart HHH of this part and continuing until a CAIR opt-in permit is denied under § 96.284(f) or, if a CAIR opt-in permit is issued, the date and time when the unit is withdrawn from the CAIR SO\textsubscript{2} Trading Program in accordance with § 96.286.

(ii) The monitoring and reporting under paragraph (b)(1)(i) of this section shall include the entire control period immediately before the date on which the unit enters the CAIR SO\textsubscript{2} Trading Program under § 96.284(g), during which period monitoring system availability must not be less than 90 percent under subpart HHH of this part and the unit must be in full compliance with any applicable State or Federal emissions or emissions-related requirements.

(2) To the extent the SO\textsubscript{2} emissions rate and the heat input of the unit are monitored and reported in accordance with subpart HHH of this part for one or more control periods, in addition to the control period under paragraph (b)(1)(ii) of this section, during which control periods monitoring system availability is not less than 90 percent under subpart HHH of this part and the unit is in full compliance with any applicable State or Federal emissions or emissions-related requirements and which control periods begin not more than 3 years before the unit enters the CAIR SO\textsubscript{2} Trading Program under § 96.284(g), such information shall be used as provided in paragraphs (c) and (d) of this section.

(c) Baseline heat input. The unit’s baseline heat input shall equal:

(1) If the unit’s SO\textsubscript{2} emissions rate and heat input are monitored and reported for only one control period, in accordance with paragraph (b)(1) of this section, the unit’s total heat input (in mmBtu) for the control period; or

(2) If the unit’s SO\textsubscript{2} emissions rate and heat input are monitored and reported for more than one control period, in accordance with paragraphs (b)(1) and (2) of this section, the average of the amounts of the unit’s total heat input (in mmBtu) for the control periods under paragraphs (b)(1)(ii) and (2) of this section.

(d) Baseline SO\textsubscript{2} emission rate. The unit’s baseline SO\textsubscript{2} emission rate shall equal:

(1) If the unit’s SO\textsubscript{2} emissions rate and heat input are monitored and reported for only one control period, in accordance with paragraph (b)(1)(i) of this section, the unit’s SO\textsubscript{2} emissions rate (in lb/mmBtu) for the control period;

(2) If the unit’s SO\textsubscript{2} emissions rate and heat input are monitored and reported for more than one control period, in accordance with paragraphs (b)(1) and (2) of this section, and the unit does not have add-on SO\textsubscript{2} emission controls during any such control periods, the average of the amounts of the unit’s SO\textsubscript{2} emissions rate (in lb/mmBtu) for the control periods under paragraphs (b)(1)(ii) and (2) of this section; or

(3) If the unit’s SO\textsubscript{2} emissions rate and heat input are monitored and reported for more than one control period, in accordance with paragraphs (b)(1) and (2) of this section, and the unit has add-on SO\textsubscript{2} emission controls during any such control periods, the average of the amounts of the unit’s SO\textsubscript{2} emissions rate (in lb/mmBtu) for such control periods during which the unit has add-on SO\textsubscript{2} emission controls.

(e) Issuance of CAIR opt-in permit. After calculating the baseline heat input and the baseline SO\textsubscript{2} emissions rate for the unit under paragraphs (c) and (d) of this section and if the permitting authority determines that the CAIR designated representative shows that the unit meets the requirements for a CAIR SO\textsubscript{2} opt-in unit in § 96.280 and meets the elements certified in § 96.283(a)(2), the permitting authority will issue a CAIR opt-in permit. The permitting authority will provide a copy of the CAIR opt-in permit to the Administrator, who will then establish a compliance account for the source that includes the CAIR SO\textsubscript{2} opt-in unit unless the source already has a compliance account.

(f) Issuance of denial of CAIR opt-in permit. Notwithstanding paragraphs (a) through (e) of this section, if at any time before issuance of a CAIR opt-in permit for the unit, the permitting authority determines that the CAIR designated representative fails to show
that the unit meets the requirements for a CAIR SO\(_2\) opt-in unit in §96.280 or meets the elements certified in §96.283(a)(2), the permitting authority will issue a denial of a CAIR opt-in permit for the unit.

(g) Date of entry into CAIR SO\(_2\) Trading Program. A unit for which an initial CAIR opt-in permit is issued by the permitting authority shall become a CAIR SO\(_2\) opt-in unit, and a CAIR SO\(_2\) unit, as of the later of January 1, 2010 or January 1 of the first control period during which such CAIR opt-in permit is issued.

(h) Repowered CAIR SO\(_2\) opt-in unit.

(1) If CAIR designated representative requests, and the permitting authority issues a CAIR opt-in permit providing for, allocation to a CAIR SO\(_2\) opt-in unit of CAIR SO\(_2\) allowances under §96.288(c) and such unit is repowered after its date of entry into the CAIR SO\(_2\) Trading Program under paragraph (g) of this section, the repowered unit shall be treated as a CAIR SO\(_2\) opt-in unit replacing the original CAIR SO\(_2\) opt-in unit, as of the date of start-up of the repowered unit’s combustion chamber.

(2) Notwithstanding paragraphs (c) and (d) of this section, as of the date of start-up under paragraph (h)(1) of this section, the repowered unit shall be deemed to have the same date of commencement of operation, date of commencement of commercial operation, baseline heat input, and baseline SO\(_2\) emission rate as the original CAIR SO\(_2\) opt-in unit.

§96.285 CAIR opt-in permit contents.

(a) Each CAIR opt-in permit will contain:

(1) All elements required for a complete CAIR permit application under §96.222;

(2) The certification in §96.283(a)(2);

(3) The unit’s baseline heat input under §96.284(c);

(4) The unit’s baseline SO\(_2\) emission rate under §96.284(d);

(5) A statement whether the unit is to be allocated CAIR SO\(_2\) allowances §96.288(b) or §96.288(c) (subject to the conditions in §§96.284(h) and 96.286(g));

(6) A statement that the unit may withdraw from the CAIR SO\(_2\) Trading Program only in accordance with §96.286; and

(7) A statement that the unit is subject to, and the owners and operators of the unit must comply with, the requirements of §96.287.

(b) Each CAIR opt-in permit is deemed to incorporate automatically the definitions of terms under §96.202 and, upon recordation by the Administrator under subpart FFF or GGG of this part or this subpart, every allocation, transfer, or deduction of CAIR SO\(_2\) allowances to or from the compliance account of the source that includes a CAIR SO\(_2\) opt-in unit covered by the CAIR opt-in permit.

(c) The CAIR opt-in permit shall be included, in a format specified by the permitting authority, in the CAIR permit for the source where the CAIR SO\(_2\) opt-in unit is located and in a title V operating permit or other federally enforceable permit for the source.

§96.286 Withdrawal from CAIR SO\(_2\) Trading Program.

Except as provided under paragraph (g) of this section, a CAIR SO\(_2\) opt-in unit may withdraw from the CAIR SO\(_2\) Trading Program, but only if the permitting authority issues a notification to the CAIR designated representative of the CAIR SO\(_2\) opt-in unit of the acceptance of the withdrawal of the CAIR SO\(_2\) opt-in unit in accordance with paragraph (d) of this section.

(a) Requesting withdrawal. In order to withdraw a CAIR SO\(_2\) opt-in unit from the CAIR SO\(_2\) Trading Program, the CAIR designated representative of the CAIR SO\(_2\) opt-in unit shall submit to the permitting authority a request to withdraw effective as of midnight of December 31 of a specified calendar year, which date must be at least 4 years after December 31 of the year of entry into the CAIR SO\(_2\) Trading Program under §96.284(g). The request must be submitted no later than 90
days before the requested effective date of withdrawal.

(b) Conditions for withdrawal. Before a CAIR SO\textsubscript{2} opt-in unit covered by a request under paragraph (a) of this section may withdraw from the CAIR SO\textsubscript{2} Trading Program and the CAIR opt-in permit may be terminated under paragraph (e) of this section, the following conditions must be met:

(1) For the control period ending on the date on which the withdrawal is to be effective, the source that includes the CAIR SO\textsubscript{2} opt-in unit must meet the requirement to hold CAIR SO\textsubscript{2} allowances under §96.206(c) and cannot have any excess emissions.

(2) After the requirement for withdrawal under paragraph (b)(1) of this section is met, the Administrator will deduct from the compliance account of the source that includes the CAIR SO\textsubscript{2} opt-in unit CAIR SO\textsubscript{2} allowances equal in amount to and allocated for the same or a prior control period as any CAIR SO\textsubscript{2} allowances allocated to the CAIR SO\textsubscript{2} opt-in unit under §96.288 for any control period for which the withdrawal is to be effective. If there are no remaining CAIR SO\textsubscript{2} units at the source, the Administrator will close the compliance account, and the owners and operators of the CAIR SO\textsubscript{2} opt-in unit may submit a CAIR SO\textsubscript{2} allowance transfer for any remaining CAIR SO\textsubscript{2} allowances to another CAIR SO\textsubscript{2} Allowance Tracking System in accordance with subpart GGG of this part.

(c) Notification. (1) After the requirements for withdrawal under paragraphs (a) and (b) of this section are met (including deduction of the full amount of CAIR SO\textsubscript{2} allowances required), the permitting authority will issue a notification to the CAIR designated representative of the CAIR SO\textsubscript{2} opt-in unit of the acceptance of the withdrawal of the CAIR SO\textsubscript{2} opt-in unit as of midnight on December 31 of the calendar year for which the withdrawal was requested.

(2) If the requirements for withdrawal under paragraphs (a) and (b) of this section are not met, the permitting authority will issue a notification to the CAIR designated representative of the CAIR SO\textsubscript{2} opt-in unit that the CAIR SO\textsubscript{2} opt-in unit's request to withdraw is denied. Such CAIR SO\textsubscript{2} opt-in unit shall continue to be a CAIR SO\textsubscript{2} opt-in unit.

(d) Permit amendment. After the permitting authority issues a notification under paragraph (c)(1) of this section that the requirements for withdrawal have been met, the permitting authority will revise the CAIR permit covering the CAIR SO\textsubscript{2} opt-in unit to terminate the CAIR opt-in permit for such unit as of the effective date specified under paragraph (c)(1) of this section. The unit shall continue to be a CAIR SO\textsubscript{2} opt-in unit until the effective date of the termination and shall comply with all requirements under the CAIR SO\textsubscript{2} Trading Program concerning any control periods for which the unit is a CAIR SO\textsubscript{2} opt-in unit, even if such requirements arise or must be complied with after the withdrawal takes effect.

(e) Reapplication upon failure to meet conditions of withdrawal. If the permitting authority denies the CAIR SO\textsubscript{2} opt-in unit's request to withdraw, the CAIR designated representative may submit another request to withdraw in accordance with paragraphs (a) and (b) of this section.

(f) Ability to reapply to the CAIR SO\textsubscript{2} Trading Program. Once a CAIR SO\textsubscript{2} opt-in unit withdraws from the CAIR SO\textsubscript{2} Trading Program and its CAIR opt-in permit is terminated under this section, the CAIR designated representative may not submit another application for a CAIR opt-in permit under §96.283 for such CAIR SO\textsubscript{2} opt-in unit before the date that is 4 years after the date on which the withdrawal became effective. Such new application for a CAIR opt-in permit will be treated as an initial application for a CAIR opt-in permit under §96.284.

(g) Inability to withdraw. Notwithstanding paragraphs (a) through (f) of this section, a CAIR SO\textsubscript{2} opt-in unit shall not be eligible to withdraw from the CAIR SO\textsubscript{2} Trading Program if the CAIR designated representative of the CAIR SO\textsubscript{2} opt-in unit requests, and the permitting authority issues a CAIR opt-in permit providing for, allocation to the CAIR SO\textsubscript{2} opt-in unit of CAIR SO\textsubscript{2} allowances under §96.288(c).
§ 96.287 Change in regulatory status.

(a) Notification. If a CAIR SO₂ opt-in unit becomes a CAIR SO₂ unit under §96.204, then the CAIR designated representative shall notify in writing the permitting authority and the Administrator of such change in the CAIR SO₂ opt-in unit’s regulatory status, within 30 days of such change.

(b) Permitting authority’s and Administrator’s actions.

(1) If a CAIR SO₂ opt-in unit becomes a CAIR SO₂ unit under §96.204, the permitting authority will revise the CAIR SO₂ opt-in unit’s CAIR opt-in permit to meet the requirements of a CAIR permit under §96.223, and remove the CAIR opt-in permit provisions, as of the date on which the CAIR SO₂ opt-in unit becomes a CAIR SO₂ unit under §96.204.

(2)(i) The Administrator will deduct from the compliance account of the source that includes a CAIR SO₂ opt-in unit that becomes a CAIR SO₂ unit under §96.204, CAIR SO₂ allowances equal in amount to and allocated for the same or a prior control period as:

(A) Any CAIR SO₂ allowances allocated to the CAIR SO₂ opt-in unit under §96.288 for any control period after the date on which the CAIR SO₂ opt-in unit becomes a CAIR SO₂ unit under §96.204; and

(B) If the date on which the CAIR SO₂ opt-in unit becomes a CAIR SO₂ unit under §96.204 is not December 31, the CAIR SO₂ allowances allocated to the CAIR SO₂ opt-in unit under §96.288 for the control period that includes the date on which the CAIR SO₂ opt-in unit becomes a CAIR SO₂ unit under §96.204, multiplied by the ratio of the number of days, in the control period, starting with the date on which the CAIR SO₂ opt-in unit becomes a CAIR SO₂ unit under §96.204 divided by the total number of days in the control period and rounded to the nearest whole allowance as appropriate.

(ii) The CAIR designated representative shall ensure that the compliance account of the source that includes the CAIR SO₂ opt-in unit that becomes a CAIR SO₂ unit under §96.204 contains the CAIR SO₂ allowances necessary for completion of the deduction under paragraph (b)(2)(i) of this section.


§ 96.288 CAIR SO₂ allowance allocations to CAIR SO₂ opt-in units.

(a) Timing requirements.

(1) When the CAIR opt-in permit is issued under §96.204(e), the permitting authority will allocate CAIR SO₂ allowances to the CAIR SO₂ opt-in unit, and submit to the Administrator the allocation for the control period in which a CAIR SO₂ opt-in unit enters the CAIR SO₂ Trading Program under §96.284(g). In accordance with paragraph (b) or (c) of this section.

(2) By no later than October 31 of the control period after the control period in which a CAIR SO₂ opt-in unit enters the CAIR SO₂ Trading Program under §96.284(g) and October 31 of each year thereafter, the permitting authority will allocate CAIR SO₂ allowances to the CAIR SO₂ opt-in unit, and submit to the Administrator the allocation for the control period that includes such submission deadline and in which the unit is a CAIR SO₂ opt-in unit, in accordance with paragraph (b) or (c) of this section.

(b) Calculation of allocation.

For each control period for which a CAIR SO₂ opt-in unit is to be allocated CAIR SO₂ allowances, the permitting authority will allocate in accordance with the following procedures:

(1) The heat input (in mmBtu) used for calculating the CAIR SO₂ allowance allocation will be the lesser of:

(i) The CAIR SO₂ opt-in unit’s baseline heat input determined under §96.284(c); or

(ii) The CAIR SO₂ opt-in unit’s heat input, as determined in accordance with subpart HHH of this part, for the immediately prior control period, except when the allocation is being calculated for the control period in which the CAIR SO₂ opt-in unit enters the CAIR SO₂ Trading Program under §96.284(g).

(2) The SO₂ emission rate (in lb/mmBtu) used for calculating CAIR SO₂ allowance allocations will be the lesser of:
(i) The CAIR SO₂ opt-in unit’s baseline SO₂ emissions rate (in lb/mmBtu) determined under §96.284(d) and multiplied by 70 percent; or

(ii) The most stringent State or Federal SO₂ emissions limitation applicable to the CAIR SO₂ opt-in unit at any time during the control period for which CAIR SO₂ allowances are to be allocated.

(3) The permitting authority will allocate CAIR SO₂ allowances to the CAIR SO₂ opt-in unit with a tonnage equivalent equal to, or less than by the smallest possible amount, the heat input under paragraph (b)(1) of this section, multiplied by the SO₂ emission rate under paragraph (b)(2) of this section, and divided by 2,000 lb/ton.

(c) Notwithstanding paragraph (b) of this section and if the CAIR designated representative requests, and the permitting authority issues a CAIR opt-in permit (based on a demonstration of the intent to repower stated under §96.283(a)(5)) providing for, allocation to a CAIR SO₂ opt-in unit of CAIR SO₂ allowances under this paragraph (subject to the conditions in §§96.284(h) and 96.286(g)), the permitting authority will allocate to the CAIR SO₂ opt-in unit as follows:

(1) For each control period in 2010 through 2014 for which the CAIR SO₂ opt-in unit is to be allocated CAIR SO₂ allowances,

(i) The heat input (in mmBtu) used for calculating CAIR SO₂ allowances allocated by the permitting authority to the CAIR SO₂ opt-in unit at any time during the control period for which CAIR SO₂ allowances are to be allocated,

(ii) The SO₂ emission rate (in lb/mmBtu) used for calculating the CAIR SO₂ allowance will be the lesser of:

(A) The CAIR SO₂ opt-in unit’s baseline SO₂ emissions rate (in lb/mmBtu) determined under §96.284(d); or

(B) The most stringent State or Federal SO₂ emissions limitation applicable to the CAIR SO₂ opt-in unit at any time during the control period in which the CAIR SO₂ opt-in unit enters the CAIR SO₂ Trading Program under §96.284(g).

(iii) The permitting authority will allocate CAIR SO₂ allowances to the CAIR SO₂ opt-in unit with a tonnage equivalent equal to, or less than by the smallest possible amount, the heat input under paragraph (c)(1)(i) of this section, multiplied by the SO₂ emission rate under paragraph (c)(1)(ii) of this section, and divided by 2,000 lb/ton.

(2) For each control period in 2015 and thereafter for which the CAIR SO₂ opt-in unit is to be allocated CAIR SO₂ allowances,

(i) The heat input (in mmBtu) used for calculating the CAIR SO₂ allowance will be the lesser of:

(A) The CAIR SO₂ opt-in unit’s baseline SO₂ emissions rate (in lb/mmBtu) determined under §96.284(d) multiplied by 10 percent; or

(B) The most stringent State or Federal SO₂ emissions limitation applicable to the CAIR SO₂ opt-in unit at any time during the control period for which CAIR SO₂ allowances are to be allocated.

(ii) The SO₂ emission rate (in lb/mmBtu) used for calculating the CAIR SO₂ allowance will be the lesser of:

(A) The CAIR SO₂ opt-in unit’s baseline SO₂ emissions rate (in lb/mmBtu) determined under §96.284(d) and divided by 2,000 lb/ton.

(d) Recordation. (1) The Administrator will record, in the compliance account of the source that includes the CAIR SO₂ opt-in unit, the CAIR SO₂ allowances allocated by the permitting authority to the CAIR SO₂ opt-in unit under paragraph (a)(1) of this section.

(2) By December 1 of the control period in which a CAIR SO₂ opt-in unit enters the CAIR SO₂ Trading Program under §96.284(g), and December 1 of each year thereafter, the Administrator will record, in the compliance account of the source that includes the CAIR SO₂ opt-in unit, the CAIR SO₂ allowances allocated by the permitting authority to the CAIR SO₂ opt-in unit under paragraph (a)(2) of this section.

[70 FR 25362, May 12, 2005, as amended at 71 FR 25390, Apr. 20, 2006]
Subpart AAAA—CAIR NO<br/>X Ozone Season Trading Program General Provisions

SOURCE: 70 FR 25382, May 12, 2005, unless otherwise noted.

§ 96.301 Purpose.

This subpart and subparts BBBB through IIII establish the model rule comprising general provisions and the designated representative, permitting, allowance, monitoring, and opt-in provisions for the State Clean Air Interstate Rule (CAIR) NO<br/>X Ozone Season Trading Program, under section 110 of the Clean Air Act and § 51.123 of this chapter, as a means of mitigating interstate transport of ozone and nitrogen oxides. The owner or operator of a unit or a source shall comply with the requirements of this subpart and subparts BBBB through IIII as a matter of federal law only if the State with jurisdiction over the unit and the source incorporates by reference such subparts or otherwise adopts the requirements of such subparts in accordance with § 51.123(aa)(1) or (2), of this chapter, the State submits to the Administrator one or more revisions of the State implementation plan that include such adoption, and the Administrator approves such revisions. If the State adopts the requirements of such subparts in accordance with § 51.123(aa)(1) or (2), (bb), or (dd) of this chapter, then the State authorizes the Administrator to assist the State in implementing the CAIR NO<br/>X Ozone Season Trading Program by carrying out the functions set forth for the Administrator in such subparts.

§ 96.302 Definitions.

The terms used in this subpart and subparts BBBB through IIII shall have the meanings set forth in this section as follows:

Account number means the identification number given by the Administrator to each CAIR NO<br/>X Ozone Season Allowance Tracking System account.

Acid Rain emissions limitation means a limitation on emissions of sulfur dioxide or nitrogen oxides under the Acid Rain Program.

Acid Rain Program means a multi-state sulfur dioxide and nitrogen oxides air pollution control and emission reduction program established by the Administrator under title IV of the CAA and parts 72 through 78 of this chapter.

Administrator means the Administrator of the United States Environmental Protection Agency or the Administrator’s duly authorized representative.

Allocate or allocation means, with regard to CAIR NO<br/>X Ozone Season allowances, the determination by a permitting authority or the Administrator of the amount of such CAIR NO<br/>X Ozone Season allowances to be initially credited to a CAIR NO<br/>X Ozone Season unit, a new unit set-aside, or other entity.

Allowance transfer deadline means, for a control period, midnight of November 30 (if it is a business day), or midnight of the first business day thereafter (if November 30 is not a business day), immediately following the control period and is the deadline by which a CAIR NO<br/>X Ozone Season allowance transfer must be submitted for recordation in a CAIR NO<br/>X Ozone Season source’s compliance account in order to be used to meet the source’s CAIR NO<br/>X Ozone Season emissions limitation for such control period in accordance with § 96.354.

Alternate CAIR designated representative means, for a CAIR NO<br/>X Ozone Season source and each CAIR NO<br/>X Ozone Season unit at the source, the natural person who is authorized by the owners and operators of the source and all such units at the source, in accordance with subparts BBBB and IIII of this part, to act on behalf of the CAIR designated representative in matters pertaining to the CAIR NO<br/>X Ozone Season Trading Program. If the CAIR NO<br/>X Ozone Season source is also a CAIR NO<br/>X source, then this natural person shall be the same person as the alternate CAIR designated representative under the CAIR NO<br/>X Annual Trading Program. If the CAIR NO<br/>X Ozone Season source is also a CAIR SO<br/>2 source, then this natural person shall be the same person as the alternate CAIR designated representative under the CAIR SO<br/>2 Trading Program. If the CAIR NO<br/>X Ozone Season source is also subject to
the Acid Rain Program, then this natural person shall be the same person as the alternate designated representative under the Acid Rain Program. If the CAIR NOx Ozone Season source is also subject to the Hg Budget Trading Program, then this natural person shall be the same person as the designated representative under the Hg Budget Trading Program.

Automated data acquisition and handling system or DAHS means that component of the continuous emission monitoring system, or other emissions monitoring system approved for use under subpart HHHH of this part, designed to interpret and convert individual output signals from pollutant concentration monitors, flow monitors, diluent gas monitors, and other component parts of the monitoring system to produce a continuous record of the measured parameters in the measurement units required by subpart HHHH of this part.

Biomass means—

(1) Any organic material grown for the purpose of being converted to energy;

(2) Any organic byproduct of agriculture that can be converted into energy; or

(3) Any material that can be converted into energy and is nonmerchantable for other purposes, that is segregated from other nonmerchantable material, and that is;

(i) A forest-related organic resource, including mill residues, precommercial thinnings, slash, brush, or byproduct from conversion of trees to merchantable material; or

(ii) A wood material, including pallets, crates, dunnage, manufacturing and construction materials (other than pressure-treated, chemically-treated, or painted wood products), and landscape or right-of-way tree trimmings.

Boiler means an enclosed fossil- or other-fuel-fired combustion device used to produce heat and to transfer heat to recirculating water, steam, or other medium.

Bottoming-cycle cogeneration unit means a cogeneration unit in which the energy input to the unit is first used to produce useful thermal energy and at least some of the reject heat from the useful thermal energy application or process is then used for electricity production.

CAIR authorized account representative means, with regard to a general account, a responsible natural person who is authorized, in accordance with subparts BBBB, FFFF, and IIII of this part, to transfer and otherwise dispose of CAIR NOx Ozone Season allowances held in the general account and, with regard to a compliance account, the CAIR designated representative of the source.

CAIR designated representative means, for a CAIR NOx Ozone Season source and each CAIR NOx Ozone Season unit at the source, the natural person who is authorized by the owners and operators of the source and all such units at the source, in accordance with subparts BBBB and IIII of this part, to represent and legally bind each owner and operator in matters pertaining to the CAIR NOx Ozone Season Trading Program. If the CAIR NOx Ozone Season source is also a CAIR NOx source, then this natural person shall be the same person as the CAIR designated representative under the CAIR NOx Annual Trading Program. If the CAIR NOx Ozone Season source is also subject to the Acid Rain Program, then this natural person shall be the same person as the designated representative under the Acid Rain Program. If the CAIR NOx Ozone Season source is also subject to the Hg Budget Trading Program, then this natural person shall be the same person as the Hg designated representative under the Hg Budget Trading Program.

CAIR NOx Annual Trading Program means a multi-state nitrogen oxides air pollution control and emission reduction program approved and administered by the Administrator in accordance with subparts AA through II of this part and §51.123(o)(1) or (2) of this chapter or established by the Administrator in accordance with subparts AA through II of part 97 of this chapter and §§51.123(p) and 52.35 of this chapter, as
a means of mitigating interstate transport of fine particulates and nitrogen oxides.

CAIR NOX Ozone Season allowance means a limited authorization issued by a permitting authority or the Administrator under provisions of a State implementation plan that are approved under §51.123(aa)(1) or (2) (and (bb)(1)), (bb)(2), (dd), or (ee) of this chapter, or under subpart EEEE of part 97 or §97.388 of this chapter, to emit one ton of nitrogen oxides during a control period of the specified calendar year for which the authorization is allocated or of any calendar year thereafter under the CAIR NOX Ozone Season Trading Program or a limited authorization issued by a permitting authority for a control period during 2003 through 2008 under the NOX Budget Trading Program in accordance with §51.121(p) of this chapter to emit one ton of nitrogen oxides during a control period, provided that the provision in §51.121(b)(2)(ii)(E) of this chapter shall not be applied in applying this definition and the limited authorization shall not have been used to meet the allowance-holding requirement under the NOX Budget Trading Program. An authorization to emit nitrogen oxides that is not issued under provisions of a State implementation plan approved under §51.123(aa)(1) or (2) (and (bb)(1)), (bb)(2), (dd), or (ee) of this chapter or subpart EEEE of part 97 or §97.388 of this chapter or under the NOX Budget Trading Program as described in the prior sentence shall not be a CAIR NOX Ozone Season allowance.

CAIR NOX Ozone Season allowance deduction or deduct CAIR NOX Ozone Season allowances means the permanent withdrawal of CAIR NOX Ozone Season allowances by the Administrator from a compliance account, e.g., in order to account for a specified number of tons of total nitrogen oxides emissions from all CAIR NOX Ozone Season units at a CAIR NOX Ozone Season source for a control period, determined in accordance with subpart HHHH of this part, or to account for excess emissions.

CAIR NOX Ozone Season Allowance Tracking System means the system by which the Administrator records allocations, deductions, and transfers of CAIR NOX Ozone Season allowances under the CAIR NOX Ozone Season Trading Program. Such allowances will be allocated, held, deducted, or transferred only as whole allowances.

CAIR NOX Ozone Season Allowance Tracking System account means an account in the CAIR NOX Ozone Season Allowance Tracking System established by the Administrator for purposes of recording the allocation, holding, transferring, or deducting of CAIR NOX Ozone Season allowances.

CAIR NOX Ozone Season allowances held or hold CAIR NOX Ozone Season allowances means the CAIR NOX Ozone Season allowances recorded by the Administrator, or submitted to the Administrator for recordation, in accordance with subparts FFFF, GGGG, and IIII of this part, in a CAIR NOX Ozone Season Allowance Tracking System account.

CAIR NOX Ozone Season emissions limitation means, for a CAIR NOX Ozone Season source, the tonnage equivalent, in NOX emissions in a control period, of the CAIR NOX Ozone Season allowances available for deduction for the source under §96.354(a) and (b) for the control period.

CAIR NOX Ozone Season Trading Program means a multi-state nitrogen oxides air pollution control and emission reduction program approved and administered by the Administrator in accordance with subparts AAAA through IIII of this part and §§51.123(aa)(1) or (2) (and (bb)(1)), (bb)(2), or (dd) of this chapter or established by the Administrator in accordance with subparts AAAA through IIII of part 97 of this chapter and §§51.123(ee) and 52.35 of this chapter, as a means of mitigating interstate transport of ozone and nitrogen oxides.

CAIR NOX Ozone Season source means a source that includes one or more CAIR NOX Ozone Season units.

CAIR NOX Ozone Season unit means a unit that is subject to the CAIR NOX Ozone Season Trading Program under §96.304 and, except for purposes of §96.305 and subpart EEEE of this part, a CAIR NOX Ozone Season opt-in unit under subpart IIII of this part.

CAIR NOX source means a source that is subject to the CAIR NOX Annual Trading Program.
CAIR permit means the legally binding and federally enforceable written document, or portion of such document, issued by the permitting authority under subpart CCCC of this part, including any permit revisions, specifying the CAIR NOx Ozone Season Trading Program requirements applicable to a CAIR NOx Ozone Season source, to each CAIR NOx Ozone Season unit at the source, and to the owners and operators and the CAIR designated representative of the source and each such unit.

CAIR SO2 source means a source that is subject to the CAIR SO2 Trading Program.

CAIR SO2 Trading Program means a multi-state sulfur dioxide air pollution control and emission reduction program approved and administered by the Administrator in accordance with subparts AAA through III of this part and §51.124(o)(1) or (2) of this chapter or established by the Administrator in accordance with subparts AAA through III of part 97 of this chapter and §§51.124(r) and 52.36 of this chapter, as a means of mitigating interstate transport of fine particulates and sulfur dioxide.

Clean Air Act or CAA means the Clean Air Act, 42 U.S.C. 7401, et seq.

Coal means any solid fuel classified as anthracite, bituminous, subbituminous, or lignite.

Coal-derived fuel means any fuel (whether in a solid, liquid, or gaseous state) produced by the mechanical, thermal, or chemical processing of coal.

Coal-fired means:
(1) Except for purposes of subpart EEEE of this part, combusting any amount of coal or coal-derived fuel, alone or in combination with any amount of any other fuel, during any year; or
(2) For purposes of subpart EEEE of this part, combusting any amount of coal or coal-derived fuel, alone or in combination with any amount of any other fuel, during a specified year.

Cogeneration unit means a stationary, fossil-fuel-fired boiler or stationary, fossil-fuel-fired combustion turbine:
(1) Having equipment used to produce electricity and useful thermal energy for industrial, commercial, heating, or cooling purposes through the sequential use of energy; and
(2) Producing during the 12-month period starting on the date the unit first produces electricity and during any calendar year after the calendar year in which the unit first produces electricity—
   (i) For a topping-cycle cogeneration unit,
      (A) Useful thermal energy not less than 5 percent of total energy output; and
      (B) Useful power that, when added to one-half of useful thermal energy produced, is not less than 42.5 percent of total energy input, if useful thermal energy produced is 15 percent or more of total energy output, or not less than 45 percent of total energy input, if useful thermal energy produced is less than 15 percent of total energy output.
   (ii) For a bottoming-cycle cogeneration unit, useful power not less than 45 percent of total energy input;
(3) Provided that the total energy input under paragraphs (2)(i)(B) and (2)(ii) of this definition shall equal the unit’s total energy input from all fuel except biomass if the unit is a boiler.

Combustion turbine means:
(1) An enclosed device comprising a compressor, a combustor, and a turbine and in which the flue gas resulting from the combustion of fuel in the combustor passes through the turbine, rotating the turbine; and
(2) If the enclosed device under paragraph (1) of this definition is combined cycle, any associated duct burner, heat recovery steam generator, and steam turbine.

Commence commercial operation means, with regard to a unit:
(1) To have begun to produce steam, gas, or other heated medium used to generate electricity for sale or use, including test generation, except as provided in §96.305 and §96.384(h).
(1) For a unit that is a CAIR NOx Ozone Season unit under §96.304 on the later of November 15, 1990 or the date the unit commences commercial operation as defined in paragraph (1) of this definition and that subsequently undergoes a physical change (other than replacement of the unit by a unit at the same source), such date shall remain the date of commencement of
commercial operation of the unit, which shall continue to be treated as the same unit.

(ii) For a unit that is a CAIR NOx Ozone Season unit under §96.304 on the later of November 15, 1990 or the date the unit commences commercial operation as defined in paragraph (1) of this definition and that is subsequently replaced by a unit at the same source (e.g., repowered), such date shall remain the replaced unit’s date of commencement of commercial operation, and the replacement unit shall be treated as a separate unit with a separate date for commencement of commercial operation as defined in paragraph (1) or (2) of this definition as appropriate.

(2) Notwithstanding paragraph (1) of this definition and except as provided in §96.305, for a unit that is not a CAIR NOx Ozone Season unit under §96.304 on the later of November 15, 1990 or the date the unit commences commercial operation as defined in paragraph (1) of this definition, the unit’s date for commencement of commercial operation shall be the date on which the unit becomes a CAIR NOx Ozone Season unit under §96.304.

(i) For a unit with a date for commencement of commercial operation as defined in paragraph (2) of this definition and that subsequently undergoes a physical change (other than replacement of the unit by a unit at the same source), such date shall remain the date of commencement of commercial operation of the unit, which shall continue to be treated as the same unit.

(ii) For a unit with a date for commencement of commercial operation as defined in paragraph (2) of this definition and that is subsequently replaced by a unit at the same source (e.g., repowered), such date shall remain the replaced unit’s date of commencement of commercial operation, and the replacement unit shall be treated as a separate unit with a separate date for commencement of commercial operation as defined in paragraph (1) or (2) of this definition as appropriate.

Commence operation means:

(1) To have begun any mechanical, chemical, or electronic process, including, with regard to a unit, start-up of a unit’s combustion chamber, except as provided in §96.384(h).

(2) For a unit that undergoes a physical change (other than replacement of the unit by a unit at the same source) after the date the unit commences operation as defined in paragraph (1) of this definition, such date shall remain the date of commencement of operation of the unit, which shall continue to be treated as the same unit.

(3) For a unit that is replaced by a unit at the same source (e.g., repowered) after the date the unit commences operation as defined in paragraph (1) of this definition, such date shall remain the replaced unit’s date of commencement of operation, and the replacement unit shall be treated as a separate unit with a separate date for commencement of operation as defined in paragraph (1), (2), or (3) of this definition as appropriate, except as provided in §96.384(h).

Common stack means a single flue through which emissions from 2 or more units are exhausted.

Compliance account means a CAIR NOx Ozone Season Allowance Tracking System account, established by the Administrator for a CAIR NOx Ozone Season source under subpart FFFF or IIII of this part, in which any CAIR NOx Ozone Season allowance allocations for the CAIR NOx Ozone Season units at the source are initially recorded and in which are held any CAIR NOx Ozone Season allowances available for use for a control period in order to meet the source’s CAIR NOx Ozone Season emissions limitation in accordance with §96.354.

Continuous emission monitoring system or CEMS means the equipment required under subpart HHHH of this part to sample, analyze, measure, and provide, by means of readings recorded at least once every 15 minutes (using an automated data acquisition and handling system (DAHS)), a permanent record of nitrogen oxides emissions, stack gas volumetric flow rate, stack gas moisture content, and oxygen or carbon dioxide concentration (as applicable), in a manner consistent with part 75 of this chapter. The following systems are the principal types of continuous emission monitoring systems required under subpart HHHH of this part:
(1) A flow monitoring system, consisting of a stack flow rate monitor and an automated data acquisition and handling system and providing a permanent, continuous record of stack gas volumetric flow rate, in standard cubic feet per hour (scfh);

(2) A nitrogen oxides concentration monitoring system, consisting of a NO\textsubscript{X} pollutant concentration monitor and an automated data acquisition and handling system and providing a permanent, continuous record of NO\textsubscript{X} emissions, in parts per million (ppm);

(3) A nitrogen oxides emission rate (or NO\textsubscript{X}-diluent) monitoring system, consisting of a NO\textsubscript{X} pollutant concentration monitor, a diluent gas (CO\textsubscript{2} or O\textsubscript{2}) monitor, and an automated data acquisition and handling system and providing a permanent, continuous record of NO\textsubscript{X} concentration, in parts per million (ppm), diluent gas concentration, in percent CO\textsubscript{2} or O\textsubscript{2}, and NO\textsubscript{X} emission rate, in pounds per million British thermal units (lb/mmBtu);

(4) A moisture monitoring system, as defined in §75.11(b)(2) of this chapter and providing a permanent, continuous record of the stack gas moisture content, in percent H\textsubscript{2}O;

(5) A carbon dioxide monitoring system, consisting of a CO\textsubscript{2} pollutant concentration monitor (or an oxygen monitor plus suitable mathematical equations from which the CO\textsubscript{2} concentration is derived) and an automated data acquisition and handling system and providing a permanent, continuous record of CO\textsubscript{2} emissions, in percent CO\textsubscript{2}; and

(6) An oxygen monitoring system, consisting of an O\textsubscript{2} concentration monitor and an automated data acquisition and handling system and providing a permanent, continuous record of O\textsubscript{2} in percent O\textsubscript{2}.

Control period or ozone season means the period beginning May 1 of a calendar year, except as provided in §96.306(c)(2), and ending on September 30 of the same year, inclusive.

Emissions means air pollutants exhausted from a unit or source into the atmosphere, as measured, recorded, and reported to the Administrator by the CAIR designated representative and as determined by the Administrator in accordance with subpart HHHH of this part.

Excess emissions means any ton of nitrogen oxides emitted by the CAIR NO\textsubscript{X} Ozone Season units at a CAIR NO\textsubscript{X} Ozone Season source during a control period that exceeds the CAIR NO\textsubscript{X} Ozone Season emissions limitation for the source.

Fossil fuel means natural gas, petroleum, coal, or any form of solid, liquid, or gaseous fuel derived from such material.

Fossil-fuel-fired means, with regard to a unit, combusting any amount of fossil fuel in any calendar year.

Fuel oil means any petroleum-based fuel (including diesel fuel or petroleum derivatives such as oil tar) and any recycled or blended petroleum products or petroleum by-products used as a fuel whether in a liquid, solid, or gaseous state.

General account means a CAIR NO\textsubscript{X} Ozone Season Allowance Tracking System account, established under subpart FFFF of this part, that is not a compliance account.

Generator means a device that produces electricity.

Gross electrical output means, with regard to a cogeneration unit, electricity made available for use, including any such electricity used in the power production process (which process includes, but is not limited to, any on-site processing or treatment of fuel combusted at the unit and any on-site emission controls).

Heat input means, with regard to a specified period of time, the product (in mmBtu/time) of the gross calorific value of the fuel (in Btu/lb) divided by 1,000,000 Btu/mmBtu and multiplied by the fuel feed rate into a combustion device (in lb of fuel/time), as measured, recorded, and reported to the Administrator by the CAIR designated representative and determined by the Administrator in accordance with subpart HHHH of this part and excluding the heat derived from preheated combustion air, recirculated flue gases, or exhaust from other sources.

Heat input rate means the amount of heat input (in mmBtu) divided by unit operating time (in hr) or, with regard to a specific fuel, the amount of heat input attributed to the fuel (in mmBtu).
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divided by the unit operating time (in hr) during which the unit combusts the fuel.

Life-of-the-unit, firm power contractual arrangement means a unit participation power sales agreement under which a utility or industrial customer reserves, or is entitled to receive, a specified amount or percentage of nameplate capacity and associated energy generated by any specified unit and pays its proportional amount of such unit’s total costs, pursuant to a contract:

(1) For the life of the unit;

(2) For a cumulative term of no less than 30 years, including contracts that permit an election for early termination; or

(3) For a period no less than 25 years or 70 percent of the economic useful life of the unit determined as of the time the unit is built, with option rights to purchase or release some portion of the nameplate capacity and associated energy generated by the unit at the end of the period.

Maximum design heat input means the maximum amount of fuel per hour (in Btu/hr) that a unit is capable of combusting on a steady state basis as of the initial installation of the unit as specified by the manufacturer of the unit.

Monitoring system means any monitoring system that meets the requirements of subpart HHHH of this part, including a continuous emissions monitoring system, an alternative monitoring system, or an excepted monitoring system under part 75 of this chapter.

Most stringent State or Federal NO\textsubscript{X} emissions limitation means, with regard to a unit, the lowest NO\textsubscript{X} emissions limitation (in terms of lb/mmBtu) that is applicable to the unit under State or Federal law, regardless of the averaging period to which the emissions limitation applies.

Nameplate capacity means, starting from the initial installation of a generator, the maximum electrical generating output (in MWe) that the generator is capable of producing on a steady state basis and during continuous operation (when not restricted by seasonal or other deratings) as of such installation as specified by the manufacturer of the generator or, starting from the completion of any subsequent physical change in the generator resulting in an increase in the maximum electrical generating output (in MWe) that the generator is capable of producing on a steady state basis and during continuous operation (when not restricted by seasonal or other deratings), such increased maximum amount as of such completion as specified by the person conducting the physical change.

Oil-fired means, for purposes of subpart EEEE of this part, combusting fuel oil for more than 15.0 percent of the annual heat input in a specified year and not qualifying as coal-fired.

Operator means any person who operates, controls, or supervises a CAIR NO\textsubscript{X} Ozone Season unit or a CAIR NO\textsubscript{X} Ozone Season source and shall include, but not be limited to, any holding company, utility system, or plant manager of such a unit or source.

Owner means any of the following persons:

(1) With regard to a CAIR NO\textsubscript{X} Ozone Season source or a CAIR NO\textsubscript{X} Ozone Season unit at a source, respectively:

(i) Any holder of any portion of the legal or equitable title in a CAIR NO\textsubscript{X} Ozone Season unit at the source or the CAIR NO\textsubscript{X} Ozone Season unit;

(ii) Any holder of a leasehold interest in a CAIR NO\textsubscript{X} Ozone Season unit at the source or the CAIR NO\textsubscript{X} Ozone Season unit; or

(iii) Any purchaser of power from a CAIR NO\textsubscript{X} Ozone Season unit at the source or the CAIR NO\textsubscript{X} Ozone Season unit under a life-of-the-unit, firm power contractual arrangement; provided that, unless expressly provided for in a leasehold agreement, owner shall not include a passive lessor, or a person who has an equitable interest through such lessor, whose rental payments are not based (either directly or indirectly) on the revenues or income from such CAIR NO\textsubscript{X} Ozone Season unit.

(2) With regard to any general account, any person who has an ownership interest with respect to the CAIR NO\textsubscript{X} Ozone Season allowances held in the general account and who is subject to the binding agreement for the CAIR authorized account representative to
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represent the person’s ownership interest with respect to CAIR NO\textsubscript{X} Ozone Season allowances.

Permitting authority means the State air pollution control agency, local agency, other State agency, or other agency authorized by the Administrator to issue or revise permits to meet the requirements of the CAIR NO\textsubscript{X} Ozone Season Trading Program or, if no such agency has been so authorized, the Administrator.

Potential electrical output capacity means 33 percent of a unit’s maximum design heat input, divided by 3,413 Btu/kWh, divided by 1,000 kWh/MWh, and multiplied by 8,760 hr/yr.

Receive or receipt of means, when referring to the permitting authority or the Administrator, to come into possession of a document, information, or correspondence (whether sent in hard copy or by authorized electronic transmission), as indicated in an official log, or by a notation made on the document, information, or correspondence, by the permitting authority or the Administrator in the regular course of business.

Recordation, record, or recorded means, with regard to CAIR NO\textsubscript{X} Ozone Season allowances, the movement of CAIR NO\textsubscript{X} Ozone Season allowances by the Administrator into or between CAIR NO\textsubscript{X} Ozone Season Allowance Tracking System accounts, for purposes of allocation, transfer, or deduction.

Reference method means any direct test method of sampling and analyzing for an air pollutant as specified in §75.22 of this chapter.

Replacement, replace, or replaced means, with regard to a unit, the demolishing of a unit, or the permanent shutdown and permanent disabling of a unit, and the construction of another unit (the replacement unit) to be used instead of the demolished or shutdown unit (the replaced unit).

Repowered means, with regard to a unit, replacement of a coal-fired boiler with one of the following coal-fired technologies at the same source as the coal-fired boiler:

(1) Atmospheric or pressurized fluidized bed combustion;

(2) Integrated gasification combined cycle;

(3) Magnetohydrodynamics;

(4) Direct and indirect coal-fired turbines;

(5) Integrated gasification fuel cells; or

(6) As determined by the Administrator in consultation with the Secretary of Energy, a derivative of one or more of the technologies under paragraphs (1) through (5) of this definition and any other coal-fired technology capable of controlling multiple combustion emissions simultaneously with improved boiler or generation efficiency and with significantly greater waste reduction relative to the performance of technology in widespread commercial use as of January 1, 2005.

Serial number means, for a CAIR NO\textsubscript{X} Ozone Season allowance, the unique identification number assigned to each CAIR NO\textsubscript{X} Ozone Season allowance by the Administrator.

Sequential use of energy means:

(1) For a topping-cycle cogeneration unit, the use of reject heat from electricity production in a useful thermal energy application or process; or

(2) For a bottoming-cycle cogeneration unit, the use of reject heat from useful thermal energy application or process in electricity production.

Solid waste incineration unit means a stationary, fossil-fuel-fired boiler or stationary, fossil-fuel-fired combustion turbine that is a “solid waste incineration unit” as defined in section 129(g)(1) of the Clean Air Act.

Source means all buildings, structures, or installations located in one or more contiguous or adjacent properties under common control of the same person or persons. For purposes of section 502(c) of the Clean Air Act, a “source,” including a “source” with multiple units, shall be considered a single “facility.”

State means one of the States or the District of Columbia that adopts the CAIR NO\textsubscript{X} Ozone Season Trading Program pursuant to §51.123(aa)(1) or (2), (bb), or (dd) of this chapter.

Submit or serve means to send or transmit a document, information, or correspondence to the person specified in accordance with the applicable regulation:

(1) In person;
(2) By United States Postal Service; or
(3) By other means of dispatch or transmission and delivery. Compliance with any “submission” or “service” deadline shall be determined by the date of dispatch, transmission, or mailing and not the date of receipt.

**Title V operating permit** means a permit issued under title V of the Clean Air Act and part 70 or part 71 of this chapter.

**Title V operating permit regulations** means the regulations that the Administrator has approved or issued as meeting the requirements of title V of the Clean Air Act and part 70 or 71 of this chapter.

**Ton** means 2,000 pounds. For the purpose of determining compliance with the CAIR NO\textsubscript{X} Ozone Season emissions limitation, total tons of nitrogen oxides emissions for a control period shall be calculated as the sum of all recorded hourly emissions (or the mass equivalent of the recorded hourly emission rates) in accordance with subpart HHHH of this part, but with any remaining fraction of a ton equal to or greater than 0.50 tons deemed to equal one ton and any remaining fraction of a ton less than 0.50 tons deemed to equal zero tons.

**Topping-cycle cogeneration unit** means a cogeneration unit in which the energy input to the unit is first used to produce useful power, including electricity, and at least some of the reject heat from the electricity production is then used to provide useful thermal energy.

**Total energy input** means, with regard to a cogeneration unit, total energy of all forms supplied to the cogeneration unit, excluding energy produced by the cogeneration unit itself. Each form of energy supplied shall be measured by the lower heating value of that form of energy calculated as follows:

\[
\text{LHV} = \text{HHV} - 10.55(W + 9H)
\]

Where:

- LHV = lower heating value of fuel in Btu/lb,
- HHV = higher heating value of fuel in Btu/lb,
- W = Weight % of moisture in fuel, and
- H = Weight % of hydrogen in fuel.

**Total energy output** means, with regard to a cogeneration unit, the sum of useful power and useful thermal energy produced by the cogeneration unit.

**Unit** means a stationary, fossil-fuel-fired boiler or combustion turbine or other stationary, fossil-fuel-fired combustion device.

**Unit operating day** means a calendar day in which a unit combusts any fuel.

**Unit operating hour or hour of unit operation** means an hour in which a unit combusts any fuel.

**Useful power** means, with regard to a cogeneration unit, electricity or mechanical energy made available for use, excluding any such energy used in the power production process (which process includes, but is not limited to, any on-site processing or treatment of fuel combusted at the unit and any on-site emission controls).

**Useful thermal energy** means, with regard to a cogeneration unit, thermal energy that is:

1. Made available to an industrial or commercial process (not a power production process), excluding any heat contained in condensate return or makeup water;
2. Used in a heating application (e.g., space heating or domestic hot water heating); or
3. Used in a space cooling application (i.e., thermal energy used by an absorption chiller).

**Utility power distribution system** means the portion of an electricity grid owned or operated by a utility and dedicated to delivering electricity to customers.


## § 96.303 Measurements, abbreviations, and acronyms.

Measurements, abbreviations, and acronyms used in this subpart and subparts BBBBB through IIII are defined as follows:

- Btu—British thermal unit
- CO\textsubscript{2}—carbon dioxide
- H\textsubscript{2}O—water
- Hg—mercury
- hr—hour
- kW—kilowatt electrical
- kWh—kilowatt hour
- lb—pound
- mmBtu—million Btu
- MWe—megawatt electrical
- MWh—megawatt hour
§ 96.304 Applicability.

(a) Except as provided in paragraph (b) of this section:

(1) The following units in a State shall be CAIR NO\textsubscript{X} Ozone Season units, and any source that includes one or more such units shall be a CAIR NO\textsubscript{X} Ozone Season source, subject to the requirements of this subpart and subparts BBBBB through HHHH of this part: any stationary, fossil-fuel-fired boiler or stationary, fossil-fuel-fired combustion turbine serving at any time, since the later of November 15, 1990 or the start-up of the unit’s combustion chamber, a generator with nameplate capacity of more than 25 MWe producing electricity for sale.

(2) If a stationary boiler or stationary combustion turbine that, under paragraph (a)(1) of this section, is not a CAIR NO\textsubscript{X} Ozone Season unit begins to combust fossil fuel or to serve a generator with nameplate capacity of more than 25 MWe producing electricity for sale, the unit shall become a CAIR NO\textsubscript{X} Ozone Season unit as provided in paragraph (a)(1) of this section on the first date on which it both combusts fossil fuel and serves such generator.

(b) The units in a State that meet the requirements set forth in paragraph (b)(1)(i), (b)(2)(i), or (b)(2)(ii) of this section shall not be CAIR NO\textsubscript{X} Ozone Season units:

(i) Any unit that is a CAIR NO\textsubscript{X} Ozone Season unit commencing operation before January 1, 1985:

(A) Qualifying as a solid waste incineration unit; and

(B) With an average annual fuel consumption of non-fossil fuel for 1985–1987 exceeding 80 percent (on a Btu basis) and an average annual fuel consumption of non-fossil fuel for any 3 consecutive calendar years after 1990 exceeding 80 percent (on a Btu basis).

(ii) Any unit that is a CAIR NO\textsubscript{X} Ozone Season unit commencing operation on or after January 1, 1985:

(A) Qualifying as a solid waste incineration unit; and

(B) With an average annual fuel consumption of non-fossil fuel for the first 3 calendar years of operation exceeding 80 percent (on a Btu basis) and an average annual fuel consumption of non-fossil fuel for any 3 consecutive calendar years after 1990 exceeding 80 percent (on a Btu basis).

(iii) If a unit qualifies as a solid waste incineration unit and meets the requirements of paragraph (b)(2)(i) or (ii) of this section for at least 3 consecutive calendar years, but subsequently no longer meets all such requirements, the unit shall become a CAIR NO\textsubscript{X} Ozone Season unit starting on the earlier of January 1 after the first calendar year during which the unit first no longer qualifies as a cogeneration unit or January 1 after the first calendar year during which the unit no longer meets the requirements of paragraph (b)(1)(i)(B) of this section.

(ii) Any unit that is a CAIR NO\textsubscript{X} Ozone Season unit starting on the earlier of January 1 after the first calendar year during which the unit first no longer qualifies as a cogeneration unit or January 1 after the first calendar year during which the unit no longer meets the requirements of paragraph (b)(1)(i)(B) of this section.

(iv) If a unit qualifies as a cogeneration unit during the 12-month period starting on the date the unit first produces electricity and meets the requirements of paragraphs (b)(1)(i) of this section for at least one calendar year, but subsequently no longer meets all such requirements, the unit shall become a CAIR NO\textsubscript{X} Ozone Season unit starting on the earlier of January 1 after the first calendar year during which the unit first no longer qualifies as a cogeneration unit or January 1 after the first calendar year during which the unit no longer meets the requirements of paragraph (b)(1)(i)(B) of this section.

(v) Any unit that is a CAIR NO\textsubscript{X} Ozone Season unit commencing operation before January 1, 1985:

(A) Qualifying as a solid waste incineration unit; and

(B) With an average annual fuel consumption of non-fossil fuel for 1985–1987 exceeding 80 percent (on a Btu basis) and an average annual fuel consumption of non-fossil fuel for any 3 consecutive calendar years after 1990 exceeding 80 percent (on a Btu basis).

(ii) Any unit that is a CAIR NO\textsubscript{X} Ozone Season unit commencing operation on or after January 1, 1985:

(A) Qualifying as a solid waste incineration unit; and

(B) With an average annual fuel consumption of non-fossil fuel for the first 3 calendar years of operation exceeding 80 percent (on a Btu basis) and an average annual fuel consumption of non-fossil fuel for any 3 consecutive calendar years after 1990 exceeding 80 percent (on a Btu basis).

(iii) If a unit qualifies as a solid waste incineration unit and meets the requirements of paragraph (b)(2)(i) or (ii) of this section for at least 3 consecutive calendar years, but subsequently no longer meets all such requirements, the unit shall become a CAIR NO\textsubscript{X} Ozone Season unit starting on the earlier of January 1 after the first calendar year during which the unit first no longer qualifies as a solid waste incineration unit or January 1 after the first 3 consecutive calendar...
§ 96.305 Retired unit exemption.

(a)(1) Any CAIR NO<sub>X</sub> Ozone Season unit that is permanently retired and is not a CAIR NO<sub>X</sub> Ozone Season opt-in unit under subpart IIII of this part shall be exempt from the CAIR NO<sub>X</sub> Ozone Season Trading Program, except for the provisions of this section, §96.302, §96.303, §96.304, §96.306(c)(4) through (7), §96.307, §96.308, and subparts BBBB and EEEE through GGGG of this part.

(2) The exemption under paragraph (a)(1) of this section shall become effective the day on which the CAIR NO<sub>X</sub> Ozone Season unit is permanently retired. Within 30 days of the unit’s permanent retirement, the CAIR designated representative shall submit a statement to the permitting authority otherwise responsible for administering any CAIR permit for the unit and shall submit a copy of the statement to the Administrator. The statement shall state, in a format prescribed by the permitting authority, that the unit was permanently retired on a specific date and will comply with the requirements of paragraph (b) of this section.

(3) After receipt of the statement under paragraph (a)(2) of this section, the permitting authority will amend any permit under subpart CCCC of this part covering the source at which the unit is located to add the provisions and requirements of the exemption under paragraphs (a)(1) and (b) of this section.

(b) Special provisions.

(1) A unit exempt under paragraph (a) of this section shall not emit any nitrogen oxides, starting on the date that the exemption takes effect.

(2) The permitting authority will allocate CAIR NO<sub>X</sub> Ozone Season allowances under subpart EEEE of this part to a unit exempt under paragraph (a) of this section.

(3) For a period of 5 years from the date the records are created, the owners and operators of a unit exempt under paragraph (a) of this section shall retain, at the source that includes the unit, records demonstrating that the unit is permanently retired. The 5-year period for keeping records may be extended for cause, at any time before the end of the period, by writing to the permitting authority or the Administrator. The owners and operators bear the burden of proof that the unit is permanently retired.

(4) The owners and operators and, to the extent applicable, the CAIR designated representative of a unit exempt under paragraph (a) of this section shall comply with the requirements of the CAIR NO<sub>X</sub> Ozone Season Trading Program concerning all periods for which the exemption is not in effect, even if such requirements arise, or must be complied with, after the exemption takes effect.

(5) A unit exempt under paragraph (a) of this section and located at a source that is required, or but for this exemption would be required, to have a Title V operating permit shall not resume operation unless the CAIR designated representative of the source submits a complete CAIR permit application under §96.322 for the unit not less than 18 months (or such lesser time provided by the permitting authority) before the later of January 1, 2009 or the date on which the unit resumes operation.

(6) On the earlier of the following dates, a unit exempt under paragraph (a) of this section shall lose its exemption:

(i) The date on which the CAIR designated representative submits a CAIR permit application for the unit under paragraph (b)(5) of this section;

(ii) The date on which the CAIR designated representative is required under paragraph (b)(5) of this section to submit a CAIR permit application for the unit; or

(iii) The date on which the unit resumes operation, if the CAIR designated representative is not required to submit a CAIR permit application for the unit.

(7) For the purpose of applying monitoring, reporting, and recordkeeping requirements under subpart HHHH of this part, a unit that loses its exemption under paragraph (a) of this section shall be treated as a unit that commences commercial operation on the
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§ 96.306 Standard requirements.

(a) Permit requirements. (1) The CAIR designated representative of each CAIR NOx Ozone Season source required to have a title V operating permit and each CAIR NOx Ozone Season unit required to have a title V operating permit at the source shall:

(i) Submit to the permitting authority a complete CAIR permit application under §96.322 in accordance with the deadlines specified in §96.321; and

(ii) Submit in a timely manner any supplemental information that the permitting authority determines is necessary in order to review a CAIR permit application and issue or deny a CAIR permit.

(2) The owners and operators of each CAIR NOx Ozone Season source required to have a title V operating permit and each CAIR NOx Ozone Season unit required to have a title V operating permit at the source shall:

(i) Submit to the permitting authority a complete CAIR permit application under §96.322 in accordance with the deadlines specified in §96.321; and

(ii) Submit in a timely manner any supplemental information that the permitting authority determines is necessary in order to review a CAIR permit application and issue or deny a CAIR permit.

(3) Except as provided in subpart IIII of this part, the owners and operators of a CAIR NOx Ozone Season source that is not otherwise required to have a title V operating permit and each CAIR NOx Ozone Season unit that is not otherwise required to have a title V operating permit are not required to submit a CAIR permit application, and to have a CAIR permit, under subpart CCCC of this part.

(b) Monitoring, reporting, and recordkeeping requirements. (1) The owners and operators, and the CAIR designated representative, of each CAIR NOx Ozone Season source and each CAIR NOx Ozone Season unit at the source shall comply with the monitoring, reporting, and recordkeeping requirements of subpart HHHH of this part.

(2) The emissions measurements recorded and reported in accordance with subpart HHHH of this part shall be used to determine compliance by each CAIR NOx Ozone Season source with the CAIR NOx Ozone Season emissions limitation under paragraph (c) of this section.

(c) Nitrogen oxides ozone season emission requirements. (1) As of the allowance transfer deadline for a control period, the owners and operators of each CAIR NOx Ozone Season source and each CAIR NOx Ozone Season unit at the source shall hold, in the source’s compliance account, CAIR NOx Ozone Season allowances available for compliance deductions for the control period under §96.334(a) in an amount not less than the tons of total nitrogen oxides emissions for the control period from all CAIR NOx Ozone Season units at the source, as determined in accordance with subpart HHHH of this part.

(2) A CAIR NOx Ozone Season source shall be subject to the requirements under paragraph (c)(1) of this section for the control period starting on the later of May 1, 2009 or the deadline for meeting the unit’s monitor certification requirements under §96.370(b)(1), (2), (3), or (7) and for each control period thereafter.

(3) A CAIR NOx Ozone Season allowance shall not be deducted, for compliance with the requirements under paragraph (c)(1) of this section, for a control period in a calendar year before the year for which the CAIR NOx Ozone Season allowance was allocated.

(4) CAIR NOx Ozone Season allowances shall be held in, deducted from, or transferred into or among CAIR NOx Ozone Season Allowance Tracking System accounts in accordance with subparts FFFF, GGGG, and IIII of this part.

(5) A CAIR NOx Ozone Season allowance is a limited authorization to emit one ton of nitrogen oxides in accordance with the CAIR NOx Ozone Season Trading Program. No provision of the CAIR NOx Ozone Season Trading Program, the CAIR permit application, the CAIR permit, or an exemption under §96.305 and no provision of law shall be construed to limit the authority of the State or the United States to terminate or limit such authorization.

(6) A CAIR NOx Ozone Season allowance does not constitute a property right.
(7) Upon recordation by the Administrator under subpart FFFF, GGGG, or IIII of this part, every allocation, transfer, or deduction of a CAIR NO\textsubscript{X} Ozone Season allowance to or from a CAIR NO\textsubscript{X} Ozone Season source’s compliance account is incorporated automatically in any CAIR permit of the source.

(d) Excess emissions requirements. If a CAIR NO\textsubscript{X} Ozone Season source emits nitrogen oxides during any control period in excess of the CAIR NO\textsubscript{X} Ozone Season emissions limitation, then:

(1) The owners and operators of the source and each CAIR NO\textsubscript{X} Ozone Season unit at the source shall surrender the CAIR NO\textsubscript{X} Ozone Season allowances required for deduction under §96.354(d)(1) and pay any fine, penalty, or assessment or comply with any other remedy imposed, for the same violations, under the Clean Air Act or applicable State law; and

(2) Each ton of such excess emissions and each day of such control period shall constitute a separate violation of this subpart, the Clean Air Act, and applicable State law.

(e) Recordkeeping and reporting requirements. (1) Unless otherwise provided, the owners and operators of the CAIR NO\textsubscript{X} Ozone Season source and each CAIR NO\textsubscript{X} Ozone Season unit at the source shall keep on site at the source each of the following documents for a period of 5 years from the date the document is created. This period may be extended for cause, at any time before the end of 5 years, in writing by the permitting authority or the Administrator.

(i) The certificate of representation under §96.313 for the CAIR designated representative for the source and each CAIR NO\textsubscript{X} Ozone Season unit at the source and all documents that demonstrate the truth of the statements in the certificate of representation; provided that the certificate and documents shall be retained on site at the source beyond such 5-year period until such documents are superseded because of the submission of a new certificate of representation under §96.313 changing the CAIR designated representative.

(ii) All emissions monitoring information, in accordance with subpart HHHH of this part, provided that to the extent that subpart HHHH of this part provides for a 3-year period for record-keeping, the 3-year period shall apply.

(iii) Copies of all reports, compliance certifications, and other submissions and all records made or required under the CAIR NO\textsubscript{X} Ozone Season Trading Program.

(iv) Copies of all documents used to complete a CAIR permit application and any other submission under the CAIR NO\textsubscript{X} Ozone Season Trading Program or to demonstrate compliance with the requirements of the CAIR NO\textsubscript{X} Ozone Season Trading Program.

(2) The CAIR designated representative of a CAIR NO\textsubscript{X} Ozone Season source and each CAIR NO\textsubscript{X} Ozone Season unit at the source shall submit the reports required under the CAIR NO\textsubscript{X} Ozone Season Trading Program, including those under subpart HHHH of this part.

(f) Liability. (1) Each CAIR NO\textsubscript{X} Ozone Season source and each CAIR NO\textsubscript{X} Ozone Season unit shall meet the requirements of the CAIR NO\textsubscript{X} Ozone Season Trading Program.

(2) Any provision of the CAIR NO\textsubscript{X} Ozone Season Trading Program that applies to a CAIR NO\textsubscript{X} Ozone Season source or the CAIR designated representative of a CAIR NO\textsubscript{X} Ozone Season source shall also apply to the owners and operators of such source and of the CAIR NO\textsubscript{X} Ozone Season units at the source.

(3) Any provision of the CAIR NO\textsubscript{X} Ozone Season Trading Program that applies to a CAIR NO\textsubscript{X} Ozone Season unit or the CAIR designated representative of a CAIR NO\textsubscript{X} Ozone Season unit shall also apply to the owners and operators of such unit.

(g) Effect on other authorities. No provision of the CAIR NO\textsubscript{X} Ozone Season Trading Program, a CAIR permit application, a CAIR permit, or an exemption under §96.305 shall be construed as exempting or excluding the owners and operators, and the CAIR designated representative, of a CAIR NO\textsubscript{X} Ozone Season source or CAIR NO\textsubscript{X} Ozone Season unit from compliance with any other provision of the applicable, approved State implementation plan, a
§ 96.307 Computation of time.

(a) Unless otherwise stated, any time period scheduled, under the CAIR NO\textsubscript{X} Ozone Season Trading Program, to begin on the occurrence of an act or event shall begin on the day the act or event occurs.

(b) Unless otherwise stated, any time period scheduled, under the CAIR NO\textsubscript{X} Ozone Season Trading Program, to begin before the occurrence of an act or event shall be computed so that the period ends the day before the act or event occurs.

(c) Unless otherwise stated, if the final day of any time period, under the CAIR NO\textsubscript{X} Ozone Season Trading Program, falls on a weekend or a State or Federal holiday, the time period shall be extended to the next business day.

§ 96.308 Appeal procedures.

The appeal procedures for decisions of the Administrator under the CAIR NO\textsubscript{X} Ozone Season Trading Program are set forth in part 78 of this chapter.

Subpart BBBB—CAIR Designated Representative for CAIR NO\textsubscript{X} Ozone Season Sources

SOURCE: 70 FR 25382, May 12, 2005, unless otherwise noted.

§ 96.310 Authorization and responsibilities of CAIR designated representative.

(a) Except as provided under §96.311, each CAIR NO\textsubscript{X} Ozone Season source, including all CAIR NO\textsubscript{X} Ozone Season units at the source, shall have one and only one CAIR designated representative, with regard to all matters under the CAIR NO\textsubscript{X} Ozone Season Trading Program concerning the source or any CAIR NO\textsubscript{X} Ozone Season unit at the source.

(b) The CAIR designated representative of the CAIR NO\textsubscript{X} Ozone Season source shall be selected by an agreement binding on the owners and operators of the source and all CAIR NO\textsubscript{X} Ozone Season units at the source and shall act in accordance with the certification statement in §96.313(a)(4)(iv).

(c) Upon receipt by the Administrator of a complete certificate of representation under §96.313, the CAIR designated representative of the source shall represent and, by his or her representations, actions, inactions, or submissions, legally bind each owner and operator of the CAIR NO\textsubscript{X} Ozone Season source represented and each CAIR NO\textsubscript{X} Ozone Season unit at the source in all matters pertaining to the CAIR NO\textsubscript{X} Ozone Season Trading Program, notwithstanding any agreement between the CAIR designated representative and such owners and operators. The owners and operators shall be bound by any decision or order issued to the CAIR designated representative by the permitting authority, the Administrator, or a court regarding the source or unit.

(d) No CAIR permit will be issued, no emissions data reports will be accepted, and no CAIR NO\textsubscript{X} Ozone Season Allowance Tracking System account will be established for a CAIR NO\textsubscript{X} Ozone Season unit at a source, until the Administrator has received a complete certificate of representation under §96.313 for a CAIR designated representative of the source and the CAIR NO\textsubscript{X} Ozone Season units at the source.

(e)(1) Each submission under the CAIR NO\textsubscript{X} Ozone Season Trading Program shall be submitted, signed, and certified by the CAIR designated representative for each CAIR NO\textsubscript{X} Ozone Season source on behalf of which the submission is made. Each such submission shall include the following certification statement by the CAIR designated representative: “I am authorized to make this submission on behalf of the owners and operators of the source or units for which the submission is made. I certify under penalty of law that I have personally examined, and am familiar with, the statements and information submitted in this document and all its attachments. Based on my inquiry of those individuals with primary responsibility for obtaining the information, I certify that the statements and information are to the best of my knowledge and belief true, accurate, and complete. I am aware that there are significant penalties for
§ 96.311 Alternate CAIR designated representative.

(a) A certificate of representation under §96.313 may designate one and only one alternate CAIR designated representative, who may act on behalf of the CAIR designated representative. The agreement by which the alternate CAIR designated representative is selected shall include a procedure for authorizing the alternate CAIR designated representative to act in lieu of the CAIR designated representative.

(b) Upon receipt by the Administrator of a complete certificate of representation under §96.313, any representation, action, inaction, or submission by the alternate CAIR designated representative shall be deemed to be a representation, action, inaction, or submission by the CAIR designated representative.

(c) Except in this section and §§96.302, 96.310(a) and (d), 96.312, 96.313, 96.315, and 96.392 whenever the term “CAIR designated representative” is used in subparts AAAA through IIII of this part, the term shall be construed to include the CAIR designated representative or any alternate CAIR designated representative.

§ 96.312 Changing CAIR designated representative and alternate CAIR designated representative; changes in owners and operators.

(a) Changing CAIR designated representative. The CAIR designated representative may be changed at any time upon receipt by the Administrator of a superseding complete certificate of representation under §96.313. Notwithstanding any such change, all representations, actions, inactions, and submissions by the previous CAIR designated representative before the time and date when the Administrator receives the superseding certificate of representation shall be binding on the new CAIR designated representative and the owners and operators of the CAIR NOx Ozone Season source and the CAIR NOx Ozone Season units at the source.

(b) Changing alternate CAIR designated representative. The alternate CAIR designated representative may be changed at any time upon receipt by the Administrator of a superseding complete certificate of representation under §96.313. Notwithstanding any such change, all representations, actions, inactions, and submissions by the previous alternate CAIR designated representative before the time and date when the Administrator receives the superseding certificate of representation shall be binding on the new alternate CAIR designated representative and the owners and operators of the CAIR NOx Ozone Season source and the CAIR NOx Ozone Season units at the source.

(c) Changes in owners and operators.

(1) In the event an owner or operator of a CAIR NOx Ozone Season source or a CAIR NOx Ozone Season unit is not included in the list of owners and operators in the certificate of representation under §96.313, such owner or operator shall be deemed to be subject to and bound by the certificate of representation, the representations, actions, inactions, and submissions of the CAIR designated representative and any alternate CAIR designated representative.

(2) Within 30 days following any change in the owners and operators of a CAIR NOx Ozone Season source or a CAIR NOx Ozone Season unit, including the addition of a new owner or operator, the CAIR designated representative or any alternate CAIR designated representative shall submit a revision to the certificate of representation.
under §96.313 amending the list of owners and operators to include the change.

§ 96.313 Certificate of representation.

(a) A complete certificate of representation for a CAIR designated representative or an alternate CAIR designated representative shall include the following elements in a format prescribed by the Administrator:

(1) Identification of the CAIR NOx Ozone Season source, and each CAIR NOx Ozone Season unit at the source, for which the certificate of representation is submitted, including identification and nameplate capacity of each generator served by each such unit.

(2) The name, address, e-mail address (if any), telephone number, and facsimile transmission number (if any) of the CAIR designated representative and any alternate CAIR designated representative.

(3) A list of the owners and operators of the CAIR NOx Ozone Season source and of each CAIR NOx Ozone Season unit at the source.

(4) The following certification statements by the CAIR designated representative and any alternate CAIR designated representative:

(i) “I certify that I was selected as the CAIR designated representative or alternate CAIR designated representative, as applicable, by an agreement binding on the owners and operators of the source and each CAIR NOx Ozone Season unit at the source.”

(ii) “I certify that I have all the necessary authority to carry out my duties and responsibilities under the CAIR NOx Ozone Season Trading Program on behalf of the owners and operators of the source and each CAIR NOx Ozone Season unit at the source and that each such owner and operator shall be fully bound by my representations, actions, inactions, or submissions.”

(iii) “I certify that the owners and operators of the source and of each CAIR NOx Ozone Season unit at the source shall be bound by any order issued to me by the Administrator, the permitting authority, or a court regarding the source or unit.”

(iv) “Where there are multiple holders of a legal or equitable title to, or a leasehold interest in, a CAIR NOx Ozone Season unit, or where a utility or industrial customer purchases power from a CAIR NOx Ozone Season unit under a life-of-the-unit, firm power contractual arrangement, I certify that: I have given a written notice of my selection as the ‘CAIR designated representative’ or ‘alternate CAIR designated representative’, as applicable, and of the agreement by which I was selected to each owner and operator of the source and of each CAIR NOx Ozone Season unit at the source; and CAIR NOx Ozone Season allowances and proceeds of transactions involving CAIR NOx Ozone Season allowances will be deemed to be held or distributed in proportion to each holder’s legal, equitable, leasehold, or contractual reservation or entitlement, except that, if such multiple holders have expressly provided for a different distribution of CAIR NOx Ozone Season allowances by contract, CAIR NOx Ozone Season allowances and proceeds of transactions involving CAIR NOx Ozone Season allowances will be deemed to be held or distributed in accordance with the contract.”

(5) The signature of the CAIR designated representative and any alternate CAIR designated representative and the dates signed.

(b) Unless otherwise required by the permitting authority or the Administrator, documents of agreement referred to in the certificate of representation shall not be submitted to the permitting authority or the Administrator. Neither the permitting authority nor the Administrator shall be under any obligation to review or evaluate the sufficiency of such documents, if submitted.

§ 96.314 Objections concerning CAIR designated representative.

(a) Once a complete certificate of representation under §96.313 has been submitted and received, the permitting authority and the Administrator will rely on the certificate of representation unless and until a superseding complete certificate of representation
under §96.313 is received by the Administrator.

(b) Except as provided in §96.312(a) or (b), no objection or other communication submitted to the permitting authority or the Administrator concerning the authorization, or any representation, action, inaction, or submission, of the CAIR designated representative shall affect any representation, action, inaction, or submission of the CAIR designated representative or the finality of any decision or order by the permitting authority or the Administrator under the CAIR NOx Ozone Season Trading Program.

(c) Neither the permitting authority nor the Administrator will adjudicate any private legal dispute concerning the authorization or any representation, action, inaction, or submission of any CAIR designated representative, including private legal disputes concerning the proceeds of CAIR NOx Ozone Season allowance transfers.

§ 96.315 Delegation by CAIR designated representative and alternate CAIR designated representative.

(a) A CAIR designated representative may delegate, to one or more natural persons, his or her authority to make an electronic submission to the Administrator provided for or required under this part.

(b) An alternate CAIR designated representative may delegate, to one or more natural persons, his or her authority to make an electronic submission to the Administrator provided for or required under this part.

(c) In order to delegate authority to make an electronic submission to the Administrator in accordance with paragraph (a) or (b) of this section, the CAIR designated representative or alternate CAIR designated representative, as appropriate, must submit to the Administrator a notice of delegation, in a format prescribed by the Administrator, that includes the following elements:

(1) The name, address, e-mail address, telephone number, and facsimile transmission number (if any) of each such natural person (referred to as an “agent”);

(2) The name, address, e-mail address, telephone number, and facsimile transmission number (if any) of each such natural person (referred to as an “agent”);

(3) For each such natural person, a list of the type or types of electronic submissions under paragraph (a) or (b) of this section for which authority is delegated to him or her; and

(4) The following certification statements by such CAIR designated representative or alternate CAIR designated representative:

(i) “I agree that any electronic submission to the Administrator that is by an agent identified in this notice of delegation and of a type listed for such agent in this notice of delegation and that is made when I am a CAIR designated representative or alternate CAIR designated representative, as appropriate, and before this notice of delegation is superseded by another notice of delegation under 40 CFR 96.315(d) shall be deemed to be an electronic submission by me.”

(ii) “Until this notice of delegation is superseded by another notice of delegation under 40 CFR 96.315(d), I agree to maintain an e-mail account and to notify the Administrator immediately of any change in my e-mail address unless all delegation of authority by me under 40 CFR 96.315 is terminated.”

(d) A notice of delegation submitted under paragraph (c) of this section shall be effective, with regard to the CAIR designated representative or alternate CAIR designated representative identified in such notice, upon receipt of such notice by the Administrator and until receipt by the Administrator of a superseding notice of delegation submitted by such CAIR designated representative or alternate CAIR designated representative, as appropriate. The superseding notice of delegation may replace any previously identified agent, add a new agent, or eliminate entirely any delegation of authority.

(e) Any electronic submission covered by the certification in paragraph
Subpart CCCC—Permits

SOURCE: 70 FR 25382, May 12, 2005, unless otherwise noted.

§ 96.320 General CAIR NOx Ozone Season Trading Program permit requirements.

(a) For each CAIR NOx Ozone Season source required to have a title V operating permit or required, under subpart III of this part, to have a title V operating permit or other federally enforceable permit, such permit shall include a CAIR permit administered by the permitting authority for the title V operating permit or the federally enforceable permit as applicable. The CAIR portion of the title V permit or other federally enforceable permit as applicable shall be administered in accordance with the permitting authority’s title V operating permits regulations promulgated under part 70 or 71 of this chapter or the permitting authority’s regulations for other federally enforceable permits as applicable, except as provided otherwise by §96.305, this subpart and subpart III of this part.

(b) Each CAIR permit shall contain, with regard to the CAIR NOx Ozone Season source and the CAIR NOx Ozone Season units at the source covered by the CAIR permit, all applicable CAIR NOx Ozone Season Trading Program, CAIR NOx Annual Trading Program, and CAIR SO2 Trading Program requirements and shall be a complete and separable portion of the title V operating permit or other federally enforceable permit under paragraph (a) of this section.

[70 FR 25382, May 12, 2005, as amended at 71 FR 25394, Apr. 28, 2006]

§ 96.321 Submission of CAIR permit applications.

(a) Duty to apply. The CAIR designated representative of any CAIR NOx Ozone Season source required to have a title V operating permit shall submit to the permitting authority a complete CAIR permit application under §96.322 for the source covering each CAIR NOx Ozone Season unit at the source at least 18 months (or such lesser time provided by the permitting authority) before the later of January 1, 2009 or the date on which the CAIR NOx Ozone Season unit commences commercial operation, except as provided in §96.383(a).

(b) Duty to Reapply. For a CAIR NOx Ozone Season source required to have a title V operating permit, the CAIR designated representative shall submit a complete CAIR permit application under §96.322 for the source covering each CAIR NOx Ozone Season unit at the source to renew the CAIR permit in accordance with the permitting authority’s title V operating permits regulations addressing permit renewal, except as provided in §96.383(b).

[70 FR 25382, May 12, 2005, as amended at 71 FR 25394, Apr. 28, 2006]

§ 96.322 Information requirements for CAIR permit applications.

A complete CAIR permit application shall include the following elements concerning the CAIR NOx Ozone Season source for which the application is submitted, in a format prescribed by the permitting authority:

(a) Identification of the CAIR NOx Ozone Season source;

(b) Identification of each CAIR NOx Ozone Season unit at the CAIR NOx Ozone Season source; and

(c) The standard requirements under §96.306.

§ 96.323 CAIR permit contents and term.

(a) Each CAIR permit will contain, in a format prescribed by the permitting authority, all elements required for a complete CAIR permit application under §96.322.

(b) Each CAIR permit is deemed to incorporate automatically the definitions of terms under §96.302 and, upon recordation by the Administrator.
under subpart FFFF, GGGG, or IIII of this part, every allocation, transfer, or deduction of a CAIR NO\textsubscript{X} Ozone Season allowance to or from the compliance account of the CAIR NO\textsubscript{X} Ozone Season source covered by the permit.

(c) The term of the CAIR permit will be set by the permitting authority, as necessary to facilitate coordination of the renewal of the CAIR permit with issuance, revision, or renewal of the CAIR NO\textsubscript{X} Ozone Season source’s title V operating permit or other federally enforceable permit as applicable.

§ 96.324 CAIR permit revisions.

Except as provided in §96.323(b), the permitting authority will revise the CAIR permit, as necessary, in accordance with the permitting authority’s title V operating permits regulations or the permitting authority’s regulations for other federally enforceable permits as applicable addressing permit revisions.

Subpart DDDD [Reserved]

Subpart EEEE—CAIR NO\textsubscript{X} Ozone Season Allowance Allocations

SOURCE: 70 FR 25382, May 12, 2005, unless otherwise noted.

§ 96.340 State trading budgets.

(a) Except as provided in paragraph (b) of this section, the State trading budgets for annual allocations of CAIR NO\textsubscript{X} Ozone Season allowances for the control periods in 2009 through 2014 and in 2015 and thereafter are respectively as follows:

<table>
<thead>
<tr>
<th>State</th>
<th>State trading budget for 2009–2014 (tons)</th>
<th>State trading budget for 2015 and thereafter (tons)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Alabama</td>
<td>32,182</td>
<td>26,181</td>
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<tr>
<td>Arkansas</td>
<td>11,515</td>
<td>9,596</td>
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<tr>
<td>Connecticut</td>
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<td>Delaware</td>
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<td>Missouri</td>
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<td>22,231</td>
</tr>
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</table>

(b) If a permitting authority issues additional CAIR NO\textsubscript{X} Ozone Season allowance allocations under §51.123(aa)(2)(iii)(A) of this chapter, the amount in the State trading budget for a control period in a calendar year will be the sum of the amount set forth for the State and for the year in paragraph (a) of this section and the amount of additional CAIR NO\textsubscript{X} Ozone Season allowance allocations issued under §51.123(aa)(2)(iii)(A) of this chapter for the year.

§ 96.341 Timing requirements for CAIR NO\textsubscript{X} Ozone Season allowance allocations.

(a) By October 31, 2006, the permitting authority will submit to the Administrator the CAIR NO\textsubscript{X} Ozone Season allowance allocations, in a format prescribed by the Administrator and in accordance with §96.342(a) and (b), for the control periods in 2009, 2010, 2011, 2012, 2013, and 2014.

(b) By October 31, 2009 and October 31 of each year thereafter, the permitting authority will submit to the Administrator the CAIR NO\textsubscript{X} Ozone Season allowance allocations, in a format prescribed by the Administrator and in accordance with §96.342(a) and (b), for the control period in the sixth year after the year of the applicable deadline for submission under this paragraph.

(c) By July 31, 2009 and July 31 of each year thereafter, the permitting authority will submit to the Administrator the CAIR NO\textsubscript{X} Ozone Season allowance allocations, in a format prescribed by the Administrator and in accordance with §96.342(c), (a), and (d), for the control period in the year of the applicable deadline for submission under this paragraph.

[70 FR 25382, May 12, 2005, as amended at 71 FR 25394, Apr. 28, 2006]
§ 96.342 CAIR NO\textsubscript{X} Ozone Season allowance allocations.

(a)(1) The baseline heat input (in mmBtu) used with respect to CAIR NO\textsubscript{X} Ozone Season allowance allocations under paragraph (b) of this section for each CAIR NO\textsubscript{X} Ozone Season unit will be:

(i) For units commencing operation before January 1, 2001, the average of the 3 highest amounts of the unit’s adjusted control period heat input for 2000 through 2004, with the adjusted control period heat input for each year calculated as follows:

(A) If the unit is coal-fired during the year, the unit’s control period heat input for such year is multiplied by 100 percent;

(B) If the unit is oil-fired during the year, the unit’s control period heat input for such year is multiplied by 60 percent; and

(C) If the unit is not subject to paragraph (a)(1)(i)(A) or (B) of this section, the unit’s control period heat input for such year is multiplied by 40 percent.

(ii) For units commencing operation on or after January 1, 2001 and operating each calendar year during a period of 5 or more consecutive calendar years, the average of the 3 highest amounts of the unit’s total converted control period heat input over the first such 5 years.

(b)(1) For each control period in 2009 and thereafter, the permitting authority will allocate to all CAIR NO\textsubscript{X} Ozone Season units in the State that have a baseline heat input (as determined under paragraph (a) of this section) a total amount of CAIR NO\textsubscript{X} Ozone Season allowances equal to 95 percent for a control period during 2009 through 2014, and 97 percent for a control period during 2015 and thereafter, of the tons of NO\textsubscript{X} emissions in the State trading budget under §96.340 (except as provided in paragraph (d) of this section).

(b)(2) The permitting authority will allocate CAIR NO\textsubscript{X} Ozone Season allowances to each CAIR NO\textsubscript{X} Ozone Season unit under paragraph (b)(1) of this section in an amount determined by multiplying the total amount of CAIR NO\textsubscript{X} Ozone Season allowances allocated under paragraph (b)(1) of this section by the ratio of the baseline heat input of the generator or generators served by the unit multiplied by 7,900 Btu/kWh, if the unit is coal-fired for the year, or 6,675 Btu/kWh, if the unit is not coal-fired for the year, and divided by 1,000,000 Btu/mmBtu, provided that if a generator is served by 2 or more units, then the gross electrical output of the generator will be attributed to each unit in proportion to the unit’s share of the total control period heat input of such units for the year;

(B) For a unit that is a boiler and has equipment used to produce electricity and useful thermal energy for industrial, commercial, heating, or cooling purposes through the sequential use of energy, the total heat energy (in Btu) of the steam produced by the boiler during the control period, divided by 0.8 and by 1,000,000 Btu/mmBtu; or

(C) For a unit that is a combustion turbine and has equipment used to produce electricity and useful thermal energy for industrial, commercial, heating, or cooling purposes through the sequential use of energy, the control period gross electrical output of the enclosed device comprising the compressor, combustor, and turbine multiplied by 3,413 Btu/kWh, plus the total heat energy (in Btu) of the steam produced by any associated heat recovery steam generator during the control period divided by 0.8, and with the sum divided by 1,000,000 Btu/mmBtu.

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of such CAIR NOₓ Ozone Season unit to the total amount of baseline heat input of all such CAIR NOₓ Ozone Season units in the State and rounding to the nearest whole allowance as appropriate.

(c) For each control period in 2009 and thereafter, the permitting authority will allocate CAIR NOₓ Ozone Season allowances to CAIR NOₓ Ozone Season units in a State that are not allocated CAIR NOₓ Ozone Season allowances under paragraph (b) of this section because the units do not yet have a baseline heat input under paragraph (a) of this section or because the units have a baseline heat input but all CAIR NOₓ Ozone Season allowances available under paragraph (b) of this section for the control period are already allocated, in accordance with the following procedures:

(1) The permitting authority will establish a separate new unit set-aside for each control period. Each new unit set-aside will be allocated CAIR NOₓ Ozone Season allowances equal to 5 percent for a control period in 2009 through 2014, and 3 percent for a control period in 2015 and thereafter, of the amount of tons of NOₓ emissions in the State trading budget under §96.340.

(2) The CAIR designated representative of such a CAIR NOₓ Ozone Season unit may submit to the permitting authority a request, in a format specified by the permitting authority, to be allocated CAIR NOₓ Ozone Season allowances, starting with the later of the control period in 2009 or the first control period after the control period in which the CAIR NOₓ Ozone Season unit commences commercial operation and until the first control period for which the unit is allocated CAIR NOₓ Ozone Season allowances under paragraph (b) of this section. A separate CAIR NOₓ Ozone Season allowance allocation request for each control period for which CAIR NOₓ Ozone Season allowances are sought must be submitted on or before February 1 before such control period and after the date on which the CAIR NOₓ Ozone Season unit commences commercial operation.

(3) In a CAIR NOₓ Ozone Season allowance allocation request under paragraph (c)(2) of this section, the CAIR designated representative may request for a control period CAIR NOₓ Ozone Season allowances in an amount not exceeding the CAIR NOₓ Ozone Season unit's total tons of NOₓ emissions during the control period immediately before such control period.

(4) The permitting authority will review each CAIR NOₓ Ozone Season allowance allocation request under paragraph (c)(2) of this section and will allocate CAIR NOₓ Ozone Season allowances for each control period pursuant to such request as follows:

(i) The permitting authority will accept an allowance allocation request only if the request meets, or is adjusted by the permitting authority as necessary to meet, the requirements of paragraphs (c)(2) and (3) of this section.

(ii) On or after February 1 before the control period, the permitting authority will determine the sum of the CAIR NOₓ Ozone Season allowances requested (as adjusted under paragraph (c)(4)(i) of this section) in all allowance allocation requests accepted under paragraph (c)(4)(i) of this section for the control period.

(iii) If the amount of CAIR NOₓ Ozone Season allowances in the new unit set-aside for the control period is greater than or equal to the sum under paragraph (c)(4)(i) of this section, then the permitting authority will allocate the amount of CAIR NOₓ Ozone Season allowances requested (as adjusted under paragraph (c)(4)(i) of this section) to each CAIR NOₓ Ozone Season unit covered by an allowance allocation request accepted under paragraph (c)(4)(i) of this section.

(iv) If the amount of CAIR NOₓ Ozone Season allowances in the new unit set-aside for the control period is less than the sum under paragraph (c)(4)(i) of this section, then the permitting authority will allocate to each CAIR NOₓ Ozone Season unit covered by an allowance allocation request accepted under paragraph (c)(4)(i) of this section the amount of the CAIR NOₓ Ozone Season allowances requested (as adjusted under paragraph (c)(4)(i) of this section), multiplied by the amount of CAIR NOₓ Ozone Season allowances in the new unit set-aside for the control period, divided by the sum determined.
Environmental Protection Agency

§ 96.351 Establishment of accounts.

(a) Compliance accounts. Except as provided in §96.384(e), upon receipt of a complete certificate of representation under §96.313, the Administrator will establish a compliance account for the CAIR NOx Ozone Season source for which the certificate of representation was submitted, unless the source already has a compliance account.

(b) General accounts—(1) Application for general account. (i) Any person may apply to open a general account for the purpose of holding and transferring CAIR NOx Ozone Season allowances. An application for a general account may designate one and only one CAIR authorized account representative and one and only one alternate CAIR authorized account representative who may act on behalf of the CAIR authorized account representative. The agreement by which the alternate CAIR authorized account representative is selected shall include a procedure for authorizing the alternate CAIR authorized account representative to act in lieu of the CAIR authorized account representative.

(ii) A complete application for a general account shall be submitted to the Administrator and shall include the following elements in a format prescribed by the Administrator:

(A) Name, mailing address, e-mail address (if any), telephone number, and facsimile transmission number (if any) of the CAIR authorized account representative and any alternate CAIR authorized account representative;

(B) Organization name and type of organization, if applicable;

(C) A list of all persons subject to a binding agreement for the CAIR authorized account representative and any alternate CAIR authorized account representative to represent their ownership interest with respect to the CAIR NOx Ozone Season allowances held in the general account;

(D) The following certification statement by the CAIR authorized account representative and any alternate CAIR authorized account representative: "I certify that I was selected as the CAIR authorized account representative or the alternate CAIR authorized account representative, as applicable, by an agreement that is binding on all persons who have an ownership interest with respect to the CAIR NOx Ozone Season allowances held in the general account;"

(E) A list of all persons subject to a binding agreement for the CAIR authorized account representative and any alternate CAIR authorized account representative to represent their ownership interest with respect to the CAIR NOx Ozone Season allowances held in the general account.


Subpart FFFF—CAIR NOx Ozone Season Allowance Tracking System

SOURCE: 70 FR 25382, May 12, 2005, unless otherwise noted.

§ 96.350 [Reserved]

§ 96.351 Establishment of accounts.
(E) The signature of the CAIR authorized account representative and any alternate CAIR authorized account representative and the dates signed.

(iii) Unless otherwise required by the permitting authority or the Administrator, documents of agreement referred to in the application for a general account shall not be submitted to the permitting authority or the Administrator. Neither the permitting authority nor the Administrator shall be under any obligation to review or evaluate the sufficiency of such documents, if submitted.

(2) Authorization of CAIR authorized account representative and alternate CAIR authorized account representative.

(i) Upon receipt by the Administrator of a complete application for a general account under paragraph (b)(1) of this section:

(A) The Administrator will establish a general account for the person or persons for whom the application is submitted.

(B) The CAIR authorized account representative and any alternate CAIR authorized account representative for the general account shall represent and, by his or her representations, actions, inactions, or submissions, legally bind each person who has an ownership interest with respect to CAIR NO\textsubscript{X} Ozone Season allowances held in the general account in all matters pertaining to the CAIR NO\textsubscript{X} Ozone Season Trading Program, notwithstanding any agreement between the CAIR authorized account representative or any alternate CAIR authorized account representative and such person. Any such person shall be bound by any order or decision issued to the CAIR authorized account representative or any alternate CAIR authorized account representative by the Administrator or a court regarding the general account.

(C) Any representation, action, inaction, or submission by any alternate CAIR authorized account representative shall be deemed to be a representation, action, inaction, or submission by the CAIR authorized account representative.

(ii) Each submission concerning the general account shall be submitted, signed, and certified by the CAIR authorized account representative or any alternate CAIR authorized account representative for the persons having an ownership interest with respect to CAIR NO\textsubscript{X} Ozone Season allowances held in the general account. Each such submission shall include the following certification statement by the CAIR authorized account representative or any alternate CAIR authorized account representative: “I am authorized to make this submission on behalf of the persons having an ownership interest with respect to the CAIR NO\textsubscript{X} Ozone Season allowances held in the general account. I certify under penalty of law that I have personally examined, and am familiar with, the statements and information submitted in this document and all its attachments. Based on my inquiry of those individuals with primary responsibility for obtaining the information, I certify that the statements and information are to the best of my knowledge and belief true, accurate, and complete. I am aware that there are significant penalties for submitting false statements and information or omitting required statements and information, including the possibility of fine or imprisonment.”

(iii) The Administrator will accept or act on a submission concerning the general account only if the submission has been made, signed, and certified in accordance with paragraph (b)(2)(ii) of this section.

(3) Changing CAIR authorized account representative and alternate CAIR authorized account representative; changes in persons with ownership interest.

(i) The CAIR authorized account representative for a general account may be changed at any time upon receipt by the Administrator of a superseding complete application for a general account under paragraph (b)(1) of this section. Notwithstanding any such change, all representations, actions, inactions, and submissions by the previous CAIR authorized account representative before the time and date when the Administrator receives the superseding application for a general account shall be binding on the new
CAIR authorized account representative and the persons with an ownership interest with respect to the CAIR NOₓ Ozone Season allowances in the general account.

(ii) The alternate CAIR authorized account representative for a general account may be changed at any time upon receipt by the Administrator of a superseding complete application for a general account under paragraph (b)(1) of this section. Notwithstanding any such change, all representations, actions, inactions, and submissions by the previous alternate CAIR authorized account representative before the time and date when the Administrator receives the superseding application for a general account shall be binding on the new alternate CAIR authorized account representative and the persons with an ownership interest with respect to the CAIR NOₓ Ozone Season allowances in the general account.

(iii)(A) In the event a person having an ownership interest with respect to CAIR NOₓ Ozone Season allowances in the general account is not included in the list of such persons in the application for a general account, such person shall be deemed to be subject to and bound by the application for a general account, the representation, actions, inactions, and submissions of the CAIR authorized account representative and any alternate CAIR authorized account representative of the account, and the decisions and orders of the Administrator or a court, as if the person were included in such list.

(B) Within 30 days following any change in the persons having an ownership interest with respect to CAIR NOₓ Ozone Season allowances in the general account, including the addition of a new person, the CAIR authorized account representative or any alternate CAIR authorized account representative shall submit a revision to the application for a general account amending the list of persons having an ownership interest with respect to the CAIR NOₓ Ozone Season allowances in the general account to include the change.

(4) Objections concerning CAIR authorized account representative and alternate CAIR authorized account representative. (i) Once a complete application for a general account under paragraph (b)(1) of this section has been submitted and received, the Administrator will rely on the application unless and until a superseding complete application for a general account under paragraph (b)(1) of this section is received by the Administrator.

(ii) Except as provided in paragraph (b)(3)(i) or (ii) of this section, no objection or other communication submitted to the Administrator concerning the authorization, or any representation, action, inaction, or submission of the CAIR authorized account representative or any alternate CAIR authorized account representative for a general account shall affect any representation, action, inaction, or submission of the CAIR authorized account representative or any alternative CAIR authorized account representative or the finality of any decision or order by the Administrator under the CAIR NOₓ Ozone Season Trading Program.

(iii) The Administrator will not adjudicate any private legal dispute concerning the authorization or any representation, action, inaction, or submission of the CAIR authorized account representative or any alternate CAIR authorized account representative for a general account, including private legal disputes concerning the proceeds of CAIR NOₓ Ozone Season allowance transfers.

(c) Account identification. The Administrator will assign a unique identifying number to each account established under paragraph (a) or (b) of this section.

(5) Delegation by CAIR authorized account representative and alternate CAIR authorized account representative. (i) A CAIR authorized account representative may delegate, to one or more natural persons, his or her authority to make an electronic submission to the Administrator provided for or required under subparts PFFF and GGGG of this part.

(ii) An alternate CAIR authorized account representative may delegate, to one or more natural persons, his or her authority to make an electronic submission to the Administrator provided for or required under subparts PFFF and GGGG of this part.
§ 96.352 Responsibilities of CAIR authorized account representative.

Following the establishment of a CAIR NO_x Ozone Season Allowance Tracking System account, all submissions to the Administrator pertaining to the account, including, but not limited to, submissions concerning the deduction or transfer of CAIR NO_x Ozone Season allowances in the account, shall be made only by the CAIR designated representative or alternate CAIR designated representative submitting such notice of delegation.

§ 96.353 Recordation of CAIR NO_x Ozone Season allowance allocations.

(a) By September 30, 2007, the Administrator will record in the CAIR NO_x Ozone Season source's compliance account the CAIR NO_x Ozone Season allowances allocated for the CAIR NO_x Ozone Season units at the source, as submitted by the permitting authority in accordance with § 96.341(a), for the control periods in 2009, 2010, 2011, 2012, 2013, and 2014.

(b) By December 1, 2009, the Administrator will record in the CAIR NO_x
Ozone Season source’s compliance account, the CAIR NO\textsubscript{X} Ozone Season allowances allocated for the CAIR NO\textsubscript{X} Ozone Season units at the source, as submitted by the permitting authority in accordance with §96.341(b), for the control period in 2015.

(c) By December 1, 2010 and December 1 of each year thereafter, the Administrator will record in the CAIR NO\textsubscript{X} Ozone Season source’s compliance account the CAIR NO\textsubscript{X} Ozone Season allowances allocated for the CAIR NO\textsubscript{X} Ozone Season units at the source, as submitted by the permitting authority in accordance with §96.341(b), for the control period in the sixth year after the year of the applicable deadline for recordation under this paragraph.

(d) By September 1, 2009 and September 1 of each year thereafter, the Administrator will record in the CAIR NO\textsubscript{X} Ozone Season source’s compliance account the CAIR NO\textsubscript{X} Ozone Season allowances allocated for the CAIR NO\textsubscript{X} Ozone Season units at the source, as submitted by the permitting authority or determined by the Administrator in accordance with §96.341(c), for the control period in the year of the applicable deadline for recordation under this paragraph.

(e) Serial numbers for allocated CAIR NO\textsubscript{X} Ozone Season allowances. When recording the allocation of CAIR NO\textsubscript{X} Ozone Season allowances for a CAIR NO\textsubscript{X} Ozone Season unit in a compliance account, the Administrator will assign each CAIR NO\textsubscript{X} Ozone Season allowance a unique identification number that will include digits identifying the year of the control period for which the CAIR NO\textsubscript{X} Ozone Season allowance is allocated.

[70 FR 25382, May 12, 2005, as amended at 71 FR 25395, Apr. 28, 2006]

EDITORIAL NOTE: At 71 FR 25395, Apr. 28, 2006, §96.354(d) was amended; however, the amendment could not be incorporated due to inaccurate amendatory instruction.

§96.354 Compliance with CAIR NO\textsubscript{X} emissions limitation.

(a) Allowance transfer deadline. The CAIR NO\textsubscript{X} Ozone Season allowances are available to be deducted for compliance with a source’s CAIR NO\textsubscript{X} Ozone Season emissions limitation for a control period in a given calendar year only if the CAIR NO\textsubscript{X} Ozone Season allowances:

(1) Were allocated for the control period in the year or a prior year; and

(2) Are held in the compliance account as of the allowance transfer deadline for the control period or are transferred into the compliance account by a CAIR NO\textsubscript{X} Ozone Season allowance transfer correctly submitted for recordation under §§96.360 and 96.361 by the allowance transfer deadline for the control period.

(c)(1) Identification of CAIR NO\textsubscript{X} Ozone Season allowances by serial number. The CAIR authorized account representative for a source’s compliance account may request that specific CAIR NO\textsubscript{X} Ozone Season allowances, identified by serial number, in the compliance account be deducted for emissions or excess emissions for a control period in accordance with paragraph (b) or (d) of this section. Such request shall be submitted to the Administrator by the allowance transfer deadline for the control period and include, in a format prescribed by the Administrator, the identification of the CAIR NO\textsubscript{X} Ozone Season source and the appropriate serial numbers.

(2) First-in, first-out. The Administrator will deduct CAIR NO\textsubscript{X} Ozone Season allowances under paragraph (b) or (d) of this section from the source’s compliance account, in the absence of an identification or in the case of a partial identification of CAIR NO\textsubscript{X} Ozone Season allowances by serial number under paragraph (c)(1) of this section, on a first-in, first-out (FIFO) accounting basis in the following order:

(i) Any CAIR NO\textsubscript{X} Ozone Season allowances that were allocated to the units at the source, in the order of recordation; and then

(ii) Any CAIR NO\textsubscript{X} Ozone Season allowances that were allocated to any entity and transferred and recorded in the compliance account pursuant to subpart GGGG of this part, in the order of recordation.

(d) Deductions for excess emissions. (1) After making the deductions for compliance under paragraph (b) of this section for a control period in a calendar year in which the CAIR NO\textsubscript{X} Ozone Season source has excess emissions, the Administrator will deduct from the
source's compliance account an amount of CAIR NO\textsubscript{X} Ozone Season allowances, allocated for the control period in the immediately following calendar year, equal to 3 times the number of tons of the source's excess emissions.

(2) Any allowance deduction required under paragraph (d)(1) of this section shall not affect the liability of the owners and operators of the CAIR NO\textsubscript{X} Ozone Season source or the CAIR NO\textsubscript{X} Ozone Season units at the source for any fine, penalty, or assessment, or their obligation to comply with any other remedy, for the same violations, as ordered under the Clean Air Act or applicable State law.

(e) Recordation of deductions. The Administrator will record in the appropriate compliance account all deductions from such an account under paragraphs (b) and (d) of this section and subpart III.

(f) Administrator's action on submissions. (1) The Administrator may review and conduct independent audits concerning any submission under the CAIR NO\textsubscript{X} Ozone Season Trading Program and make appropriate adjustments of the information in the submissions.

(2) The Administrator may deduct CAIR NO\textsubscript{X} Ozone Season allowances from or transfer CAIR NO\textsubscript{X} Ozone Season allowances to a source's compliance account based on the information in the submissions, as adjusted under paragraph (f)(1) of this section, and record such deductions and transfers.

§ 96.356 Account error.

The Administrator may, at his or her sole discretion and on his or her own motion, correct any error in any CAIR NO\textsubscript{X} Ozone Season Allowance Tracking System account. Within 10 business days of making such correction, the Administrator will notify the CAIR authorized account representative for the account.

§ 96.357 Closing of general accounts.

(a) The CAIR authorized account representative of a general account may submit to the Administrator a request to close the account, which shall include a correctly submitted allowance transfer under §§ 96.360 and 96.361 for any CAIR NO\textsubscript{X} Ozone Season allowances in the account to one or more other CAIR NO\textsubscript{X} Ozone Season Allowance Tracking System accounts.

(b) If a general account has no allowance transfers in or out of the account for a 12-month period or longer and does not contain any CAIR NO\textsubscript{X} Ozone Season allowances, the Administrator may notify the CAIR authorized account representative for the account that the account will be closed following 20 business days after the notice is sent. The account will be closed after the 20-day period unless, before the end of the 20-day period, the Administrator receives a correctly submitted transfer of CAIR NO\textsubscript{X} Ozone Season allowances into the account under §§ 96.360 and 96.361 or a statement submitted by the CAIR authorized account representative demonstrating to the satisfaction of the Administrator good cause as to why the account should not be closed.
Environmental Protection Agency

Subpart GGGG—CAIR NOx Ozone Season Allowance Transfers

Source: 70 FR 25382, May 12, 2005, unless otherwise noted.

§ 96.360 Submission of CAIR NOx Ozone Season allowance transfers.

A CAIR authorized account representative seeking recordation of a CAIR NOx Ozone Season allowance transfer shall submit the transfer to the Administrator. To be considered correctly submitted, the CAIR NOx Ozone Season allowance transfer shall include the following elements, in a format specified by the Administrator:

(a) The account numbers for both the transferor and transferee accounts;

(b) The serial number of each CAIR NOx Ozone Season allowance that is in the transferor account and is to be transferred; and

(c) The name and signature of the CAIR authorized account representative of the transferor account and the date signed.

§ 96.361 EPA recordation.

(a) Within 5 business days (except as provided in paragraph (b) of this section) of receiving a CAIR NOx Ozone Season allowance transfer, the Administrator will record a CAIR NOx Ozone Season allowance transfer by moving each CAIR NOx Ozone Season allowance from the transferor account to the transferee account as specified by the request, provided that:

(1) The transfer is correctly submitted under § 96.360; and

(2) The transferor account includes each CAIR NOx Ozone Season allowance identified by serial number in the transfer.

(b) A CAIR NOx Ozone Season allowance transfer that is submitted for recordation after the allowance transfer deadline for a control period and that includes any CAIR NOx Ozone Season allowances allocated for any control period before such allowance transfer deadline will not be recorded until after the Administrator completes the deductions under § 96.354 for the control period immediately before such allowance transfer deadline.

(c) Where a CAIR NOx Ozone Season allowance transfer submitted for recordation fails to meet the requirements of paragraph (a) of this section, the Administrator will not record such transfer.

§ 96.362 Notification.

(a) Notification of recordation. Within 5 business days of recordation of a CAIR NOx Ozone Season allowance transfer under § 96.361, the Administrator will notify the CAIR authorized account representatives of both the transferor and transferee accounts.

(b) Notification of non-recordation. Within 10 business days of receipt of a CAIR NOx Ozone Season allowance transfer that fails to meet the requirements of § 96.361(a), the Administrator will notify the CAIR authorized account representatives of both accounts subject to the transfer of:

(1) A decision not to record the transfer, and

(2) The reasons for such non-recordation.

(c) Nothing in this section shall preclude the submission of a CAIR NOx Ozone Season allowance transfer for recordation following notification of non-recordation.

Subpart HHHH—Monitoring and Reporting

Source: 70 FR 25382, May 12, 2005, unless otherwise noted.

§ 96.370 General requirements.

The owners and operators, and to the extent applicable, the CAIR designated representative, of a CAIR NOx Ozone Season unit, shall comply with the monitoring, recordkeeping, and reporting requirements as provided in this subpart and in subpart H of part 75 of this chapter. For purposes of complying with such requirements, the definitions in § 96.302 and in § 72.2 of this chapter shall apply, and the terms “affected unit,” “designated representative,” and “continuous emission monitoring system” (or “CEMS”) in part 75 of this chapter shall be deemed to refer to the terms “CAIR NOx Ozone Season unit,” “CAIR designated representative,” and “continuous emission monitoring system” (or “CEMS”) respectively, as defined in § 96.302. The owner or operator of a unit that is not a CAIR...
NO\textsubscript{X} Ozone Season unit but that is monitored under §75.72(b)(2)(ii) of this chapter shall comply with the same monitoring, recordkeeping, and reporting requirements as a CAIR NO\textsubscript{X} Ozone Season unit.

(a) Requirements for installation, certification, and data accounting. The owner or operator of each CAIR NO\textsubscript{X} Ozone Season unit shall:

(1) Install all monitoring systems required under this subpart for monitoring NO\textsubscript{X} mass emissions and individual unit heat input (including all systems required to monitor NO\textsubscript{X} emission rate, NO\textsubscript{X} concentration, stack gas moisture content, stack gas flow rate, CO\textsubscript{2} or O\textsubscript{2} concentration, and fuel flow rate, as applicable, in accordance with §§75.71 and 75.72 of this chapter);

(2) Successfully complete all certification tests required under §96.371 and meet all other requirements of this subpart and part 75 of this chapter applicable to the monitoring systems under paragraph (a)(1) of this section; and

(3) Record, report, and quality-assure the data from the monitoring systems under paragraph (a)(1) of this section.

(b) Compliance deadlines. Except as provided in paragraph (e) of this section, the owner or operator shall:

(1) For the owner or operator of a CAIR NO\textsubscript{X} Ozone Season unit that commences commercial operation before July 1, 2007, by May 1, 2008.

(2) For the owner or operator of a CAIR NO\textsubscript{X} Ozone Season unit that commences commercial operation on or after July 1, 2007 and that reports on a control period basis under §96.374(d)(2)(ii), by the later of the following dates:

(i) 90 unit operating days or 180 calendar days, whichever occurs first, after the date on which the unit commences commercial operation; or

(ii) If the compliance date under paragraph (b)(3)(i) of this section is not during a control period, May 1 immediately following the compliance date under paragraph (b)(3)(i) of this section.

(4) For the owner or operator of a CAIR NO\textsubscript{X} Ozone Season unit for which construction of a new stack or flue or installation of add-on NO\textsubscript{X} emission controls is completed after the applicable deadline under paragraph (b)(1), (2), (6), or (7) of this section and that reports on an annual basis under §96.374(d), by 90 unit operating days or 180 calendar days, whichever occurs first, after the date on which emissions first exit to the atmosphere through the new stack or flue or add-on NO\textsubscript{X} emissions controls.

(5) For the owner or operator of a CAIR NO\textsubscript{X} Ozone Season unit for which construction of a new stack or flue or installation of add-on NO\textsubscript{X} emission controls is completed after the applicable deadline under paragraph (b)(1), (3), (6), or (7) of this section and that reports on a control period basis under §96.374(d)(2)(ii), by the later of the following dates:

(i) 90 unit operating days or 180 calendar days, whichever occurs first, after the date on which emissions first exit to the atmosphere through the new stack or flue or add-on NO\textsubscript{X} emissions controls; or

(ii) If the compliance date under paragraph (b)(5)(i) of this section is not during a control period, May 1 immediately following the compliance date under paragraph (b)(5)(i) of this section.

(6) Notwithstanding the dates in paragraphs (b)(1), (2), and (3) of this section, for the owner or operator of a unit for which a CAIR NO\textsubscript{X} Ozone Season opt-in permit application is submitted and not withdrawn and a CAIR...
opt-in permit is not yet issued or denied under subpart III of this part, by the date specified in §96.384(b).

(7) Notwithstanding the dates in paragraphs (b)(1), (2), and (3) of this section, for the owner or operator of a CAIR NOx Ozone Season opt-in unit, by the date on which the CAIR NOx Ozone Season opt-in unit under subpart III of this part enters the CAIR NOx Ozone Season Trading Program as provided in §96.384(g).

(c) Reporting data. The owner or operator of a CAIR NOx Ozone Season unit that does not meet the applicable compliance date set forth in paragraph (b) of this section for any monitoring system under paragraph (a)(1) of this section shall, for each such monitoring system, determine, record, and report maximum potential (or, as appropriate, minimum potential) values for NOx concentration, NOx emission rate, stack gas flow rate, stack gas moisture content, fuel flow rate, and any other parameters required to determine NOx mass emissions and heat input in accordance with §75.31(b)(2) or (c)(3) of this chapter, section 2.4 of appendix D to part 75 of this chapter, or section 2.5 of appendix E to part 75 of this chapter, as applicable.

(d) Prohibitions. (1) No owner or operator of a CAIR NOx Ozone Season unit shall use any alternative monitoring system, alternative reference method, or any other alternative to any requirement of this subpart without having obtained prior written approval in accordance with §96.375.

(2) No owner or operator of a CAIR NOx Ozone Season unit shall operate the unit so as to discharge, or allow to be discharged, NOx emissions to the atmosphere without accounting for all such emissions in accordance with the applicable provisions of this subpart and part 75 of this chapter.

(3) No owner or operator of a CAIR NOx Ozone Season unit shall disrupt the continuous emission monitoring system, any portion thereof, or any other approved emission monitoring method, and thereby avoid monitoring and recording NOx mass emissions discharged into the atmosphere or heat input, except for periods of recertification or periods when calibration, quality assurance testing, or maintenance is performed in accordance with the applicable provisions of this subpart and part 75 of this chapter.

(4) No owner or operator of a CAIR NOx Ozone Season unit shall retire or permanently discontinue use of the continuous emission monitoring system, any component thereof, or any other approved monitoring system under this subpart, except under any one of the following circumstances:

(i) During the period that the unit is covered by an exemption under §96.305 that is in effect;

(ii) The owner or operator is monitoring emissions from the unit with another certified monitoring system approved, in accordance with the applicable provisions of this subpart and part 75 of this chapter, by the permitting authority for use at that unit that provides emission data for the same pollutant or parameter as the retired or discontinued monitoring system; or

(iii) The CAIR designated representative submits notification of the date of certification testing of a replacement monitoring system for the retired or discontinued monitoring system in accordance with §96.371(d)(3)(i).

(e) Long-term cold storage. The owner or operator of a CAIR NOx Ozone Season unit is subject to the applicable provisions of part 75 of this chapter concerning units in long-term cold storage.

§96.371 Initial certification and recertification procedures.

(a) The owner or operator of a CAIR NOx Ozone Season unit shall be exempt from the initial certification requirements of this section for a monitoring system under §96.370(a)(1) if the following conditions are met:

(1) The monitoring system has been previously certified in accordance with part 75 of this chapter; and

(2) The applicable quality-assurance and quality-control requirements of §75.21 of this chapter and appendix B, appendix D, and appendix E to part 75 of this chapter are fully met for the certified monitoring system described in paragraph (a)(1) of this section.
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(b) The recertification provisions of this section shall apply to a monitoring system under §96.370(a)(1) exempt from initial certification requirements under paragraph (a) of this section.

(c) If the Administrator has previously approved a petition under §75.17(a) or (b) of this chapter for apportioning the NOX emission rate measured in a common stack or a petition under §75.66 of this chapter, the CAIR designated representative shall reinspect the petition to the Administrator under §96.375(a) to determine whether the approval applies under the CAIR NOX Ozone Season Trading Program.

(d) Except as provided in paragraph (a) of this section, the owner or operator of a CAIR NOX Ozone Season unit shall comply with the following initial certification and recertification procedures for a continuous monitoring system (i.e., a continuous emission monitoring system and an excepted monitoring system under appendices D and E to part 75 of this chapter) under §96.370(a)(1). The owner or operator of a unit that qualifies to use the low mass emissions excepted monitoring methodology under §75.19 of this chapter or that qualifies to use an alternative monitoring system under appendices D and E to part 75 of this chapter shall comply with the procedures in paragraph (e) or (f) of this section respectively.

(1) Requirements for initial certification. The owner or operator shall ensure that each continuous monitoring system under §96.370(a)(1) including the automated data acquisition and handling system) successfully completes all of the initial certification testing required under §75.20 of this chapter by the applicable deadline in §96.370(b). In addition, whenever the owner or operator installs a monitoring system to meet the requirements of this subpart in a location where no such monitoring system was previously installed, initial certification in accordance with §75.20 of this chapter is required.

(2) Requirements for recertification. Whenever the owner or operator makes a replacement, modification, or change in any certified continuous emission monitoring system under §96.370(a)(1) that may significantly affect the ability of the system to accurately measure or record NOX mass emissions or heat input rate or to meet the quality-assurance and quality-control requirements of §75.21 of this chapter or appendix B to part 75 of this chapter, the owner or operator shall recertify the monitoring system in accordance with §75.20(b) of this chapter. Furthermore, whenever the owner or operator makes a replacement, modification, or change to the flue gas handling system or the unit’s operation that may significantly change the stack flow or concentration profile, the owner or operator shall recertify each continuous emission monitoring system whose accuracy is potentially affected by the change, in accordance with §75.20(b) of this chapter. Examples of changes to a continuous emission monitoring system that require recertification include: replacement of the analyzer, complete replacement of an existing continuous emission monitoring system, or change in location or orientation of the sampling probe or site. Any fuel flowmeter systems, and any excepted NOX monitoring system under appendix E to part 75 of this chapter, under §96.370(a)(1) are subject to the recertification requirements in §75.20(g)(6) of this chapter.

(3) Approval process for initial certification and recertification. Paragraphs (d)(3)(i) through (iv) of this section apply to both initial certification and recertification of a continuous monitoring system under §96.370(a)(1). For recertifications, replace the words “certification” and “initial certification” with the word “recertification”, replace the word “certified” with the word “recertified,” and follow the procedures in §§75.20(b)(5) and (g)(7) of this chapter in lieu of the procedures in paragraph (d)(3)(v) of this section.

(i) Notification of certification. The CAIR designated representative shall submit to the permitting authority, the appropriate EPA Regional Office, and the Administrator written notice of the dates of certification testing, in accordance with §96.373.

(ii) Certification application. The CAIR designated representative shall submit to the permitting authority a certification application for each monitoring
system. A complete certification application shall include the information specified in §75.63 of this chapter.

(iii) Provisional certification date. The provisional certification date for a monitoring system shall be determined in accordance with §75.20(a)(3) of this chapter. A provisionally certified monitoring system may be used under the CAIR NOX Ozone Season Trading Program for a period not to exceed 120 days after receipt by the permitting authority of the complete certification application for the monitoring system under paragraph (d)(3)(ii) of this section. Data measured and recorded by the provisionally certified monitoring system, in accordance with the requirements of part 75 of this chapter, will be considered valid quality-assured data (retroactive to the date and time of provisional certification), provided that the permitting authority does not invalidate the provisional certification by issuing a notice of disapproval within 120 days of the date of receipt of the complete certification application by the permitting authority.

(iv) Certification application approval process. The permitting authority will issue a written notice of approval or disapproval of the certification application to the owner or operator within 120 days of receipt of the complete certification application under paragraph (d)(3)(ii) of this section. In the event the permitting authority does not issue such a notice within such 120-day period, each monitoring system that meets the applicable performance requirements of part 75 of this chapter and is included in the certification application will be deemed certified for use under the CAIR NOX Ozone Season Trading Program.

(A) Approval notice. If the certification application is complete and shows that each monitoring system meets the applicable performance requirements of part 75 of this chapter, then the permitting authority will issue a written notice of approval of the certification application within 120 days of receipt.

(B) Incomplete application notice. If the certification application is not complete, then the permitting authority will issue a written notice of incompleteness that sets a reasonable date by which the CAIR designated representative must submit the additional information required to complete the certification application. If the CAIR designated representative does not comply with the notice of incompleteness by the specified date, then the permitting authority may issue a notice of disapproval under paragraph (d)(3)(iv)(C) of this section. The 120-day review period shall not begin before receipt of a complete certification application.

(C) Disapproval notice. If the certification application shows that any monitoring system does not meet the performance requirements of part 75 of this chapter or if the certification application is incomplete and the requirement for disapproval under paragraph (d)(3)(iv)(B) of this section is met, then the permitting authority will issue a written notice of disapproval of the certification application. Upon issuance of such notice of disapproval, the provisional certification is invalidated by the permitting authority and the data measured and recorded by each uncertified monitoring system shall not be considered valid quality-assured data beginning with the date and hour of provisional certification (as defined under §75.20(a)(3) of this chapter). The owner or operator shall follow the procedures for loss of certification in paragraph (d)(3)(v) of this section for each monitoring system that is disapproved for initial certification.

(D) Audit decertification. The permitting authority or, for a CAIR NOX Ozone Season opt-in unit or a unit for which a CAIR opt-in permit application is submitted and not withdrawn and a CAIR opt-in permit is not yet issued or denied under subpart III of this part, the Administrator may issue a notice of disapproval of the certification status of a monitor in accordance with §96.372(b).

(v) Procedures for loss of certification. If the permitting authority or the Administrator issues a notice of disapproval of a certification application under paragraph (d)(3)(iv)(C) of this section or a notice of disapproval of certification status under paragraph (d)(3)(iv)(D) of this section, then:
§ 96.372 Out of control periods.

(a) Whenever any monitoring system fails to meet the quality-assurance and quality-control requirements or data validation requirements of part 75 of this chapter, data shall be substituted using the applicable missing data procedures in subpart D or subpart H of, or appendix D or appendix E to, part 75 of this chapter.

(b) Audit decertification. Whenever both an audit of a monitoring system and a review of the initial certification or recertification application reveal that any monitoring system should not have been certified or recertified because it did not meet a particular performance specification or other requirement under §96.371 or the applicable provisions of part 75 of this chapter, both at the time of the initial certification or recertification application submission and at the time of the audit, the permitting authority or, for a CAIR NOX Ozone Season opt-in unit or a unit for which a CAIR opt-in permit application is submitted and not yet issued or denied under subpart III of this part, the Administrator will
issue a notice of disapproval of the certification status of such monitoring system. For the purposes of this paragraph, an audit shall be either a field audit or an audit of any information submitted to the permitting authority or the Administrator. By issuing the notice of disapproval, the permitting authority or the Administrator revokes prospectively the certification status of the monitoring system. The data measured and recorded by the monitoring system shall not be considered valid quality-assured data from the date of issuance of the notification of the revoked certification status until the date and time that the owner or operator completes subsequently approved initial certification or recertification tests for the monitoring system. The owner or operator shall follow the applicable initial certification or recertification procedures in §96.371 for each disapproved monitoring system.

§96.373 Notifications.

The CAIR designated representative for a CAIR NOX Ozone Season unit shall submit written notice to the permitting authority and the Administrator in accordance with §75.61 of this chapter.

§96.374 Recordkeeping and reporting.

(a) General provisions. The CAIR designated representative shall comply with all recordkeeping and reporting requirements in this section, the applicable recordkeeping and reporting requirements under §75.73 of this chapter, and the requirements of §96.310(e)(1).

(b) Monitoring plans. The owner or operator of a CAIR NOx Ozone Season unit shall comply with requirements of §75.73(c) and (e) of this chapter and, for a unit for which a CAIR opt-in permit application is submitted and not withdrawn and a CAIR opt-in permit is not yet issued or denied under subpart III of this part, §§96.383 and 96.384(a).

(c) Certification applications. The CAIR designated representative shall submit an application to the permitting authority within 45 days after completing all initial certification or recertification tests required under §96.371, including the information required under §75.63 of this chapter.

(d) Quarterly reports. The CAIR designated representative shall submit quarterly reports, as follows:

1. If the CAIR NOx Ozone Season unit is subject to an Acid Rain emissions limitation or a CAIR NOx emissions limitation or if the owner or operator of such unit chooses to report on an annual basis under this subpart, the CAIR designated representative shall meet the requirements of subpart H of part 75 of this chapter (concerning monitoring of NOx mass emissions) for such unit for the entire year and shall report the NOx mass emissions data and heat input data for such unit, in an electronic quarterly report in a format prescribed by the Administrator, for each calendar quarter beginning with:

(i) For a unit that commences commercial operation before July 1, 2007, the calendar quarter covering May 1, 2008 through June 30, 2008;

(ii) For a unit that commences commercial operation on or after July 1, 2007, the calendar quarter corresponding to the earlier of the date of provisional certification or the applicable deadline for initial certification under §96.370(b), unless that quarter is the third or fourth quarter of 2007 or the first quarter of 2008, in which case reporting shall commence in the quarter covering May 1, 2008 through June 30, 2008;

(iii) Notwithstanding paragraphs (d)(1)(i) and (ii) of this section, for a unit for which a CAIR opt-in permit application is submitted and not withdrawn and a CAIR opt-in permit is not yet issued or denied under subpart III of this part, the calendar quarter corresponding to the date specified in §96.384(b); and

(iv) Notwithstanding paragraphs (d)(1)(i) and (ii) of this section, for a CAIR NOx Ozone Season opt-in unit under subpart III of this part, the calendar quarter corresponding to the date on which the CAIR NOx Ozone Season opt-in unit enters the CAIR NOx Ozone Season Trading Program as provided in §96.384(g).

2. If the CAIR NOx Ozone Season unit is not subject to an Acid Rain emissions limitation or a CAIR NOx...
emissions limitation, then the CAIR designated representative shall either:

(i) Meet the requirements of subpart H of part 75 (concerning monitoring of NOX mass emissions) for such unit for the entire year and report the NOX mass emissions data and heat input data for such unit in accordance with paragraph (d)(1) of this section; or

(ii) Meet the requirements of subpart H of part 75 for the control period (including the requirements in §75.74(c) of this chapter) and report NOX mass emissions data and heat input data (including the data described in §75.74(c)(6) of this chapter) for such unit only for the control period of each year and report, in an electronic quarterly report in a format prescribed by the Administrator, for each calendar quarter beginning with:

(A) For a unit that commences commercial operation before July 1, 2007, the calendar quarter covering May 1, 2008 through June 30, 2008;

(B) For a unit that commences commercial operation on or after July 1, 2007, the calendar quarter corresponding to the earlier of the date of provisional certification or the applicable deadline for initial certification under §96.370(b), unless that date is not during a control period, in which case reporting shall commence in the quarter that includes May 1 through June 30 of the first control period after such date;

(C) Notwithstanding paragraphs (d)(2)(ii)(A) and (2)(ii)(B) of this section, for a unit for which a CAIR opt-in permit application is submitted and not withdrawn and a CAIR opt-in permit is not yet issued or denied under subpart III of this part, the calendar quarter corresponding to the date specified in §96.384(b); and

(D) Notwithstanding paragraphs (d)(2)(ii)(A) and (2)(ii)(B) of this section, for a CAIR NOX Ozone Season opt-in unit under subpart III of this part, the calendar quarter corresponding to the date on which the CAIR NOX Ozone Season opt-in unit enters the CAIR NOX Ozone Season Trading Program as provided in §96.384(g).

(2) The CAIR designated representative shall submit each quarterly report to the Administrator within 30 days following the end of the calendar quarter covered by the report. Quarterly reports shall be submitted in the manner specified in §75.73(f) of this chapter.

(3) For CAIR NOX Ozone Season units that are also subject to an Acid Rain emissions limitation or the CAIR NOX Annual Trading Program or CAIR SO2 Trading Program, quarterly reports shall include the applicable data and information required by subparts F through H of part 75 of this chapter as applicable, in addition to the NOX mass emission data, heat input data, and other information required by this subpart.

(e) Compliance certification. The CAIR designated representative shall submit to the Administrator a compliance certification (in a format prescribed by the Administrator) in support of each quarterly report based on reasonable inquiry of those persons with primary responsibility for ensuring that all of the unit’s emissions are correctly and fully monitored. The certification shall state that:

(1) The monitoring data submitted were recorded in accordance with the applicable requirements of this subpart and part 75 of this chapter, including the quality assurance procedures and specifications;

(2) For a unit with add-on NOX emission controls and for all hours where NOX data are substituted in accordance with §75.34(a)(1) of this chapter, the add-on emission controls were operating within the range of parameters listed in the quality assurance/quality control program under appendix B to part 75 of this chapter and the substitute data values do not systematically underestimate NOX emissions; and

(3) For a unit that is reporting on a control period basis under paragraph (d)(2)(ii) of this section, the NOX emission rate and NOX concentration values substituted for missing data under subpart D of part 75 of this chapter are calculated using only values from a control period and do not systematically underestimate NOX emissions.

[70 FR 25382, May 12, 2005, as amended at 71 FR 25395, Apr. 28, 2006]
Environmental Protection Agency

§ 96.375 Petitions.

(a) Except as provided in paragraph (b)(2) of this section, the CAIR designated representative of a CAIR NO$_X$ Ozone Season unit that is subject to an Acid Rain emissions limitation may submit a petition under §75.66 of this chapter to the Administrator requesting approval to apply an alternative to any requirement of this subpart. Application of an alternative to any requirement of this subpart is in accordance with this subpart only to the extent that the petition is approved in writing by the Administrator, in consultation with the permitting authority.

(b)(1) The CAIR designated representative of a CAIR NO$_X$ Ozone Season unit that is not subject to an Acid Rain emissions limitation may submit a petition under §75.66 of this chapter to the permitting authority and the Administrator requesting approval to apply an alternative to any requirement of this subpart. Application of an alternative to any requirement of this subpart is in accordance with this subpart only to the extent that the petition is approved in writing by both the permitting authority and the Administrator.

(2) The CAIR designated representative of a CAIR NO$_X$ Ozone Season unit that is subject to an Acid Rain emissions limitation may submit a petition under §75.66 of this chapter to the permitting authority and the Administrator requesting approval to apply an alternative to any requirement concerning any additional continuous emission monitoring system required under §75.72 of this chapter. Application of an alternative to any such requirement is in accordance with this subpart only to the extent that the petition is approved in writing by both the permitting authority and the Administrator.

Subpart III—CAIR NO$_X$ Ozone Season Opt-in Units

Source: 70 FR 25382, May 12, 2005, unless otherwise noted.

§ 96.380 Applicability.

A CAIR NO$_X$ Ozone Season opt-in unit must be a unit that:

(a) Is located in the State;
(b) Is not a CAIR NO$_X$ Ozone Season unit under §96.304 and is not covered by a retired unit exemption under §96.305 that is in effect;
(c) Is not covered by a retired unit exemption under §72.8 of this chapter that is in effect;
(d) Has or is required or qualified to have a title V operating permit or other federally enforceable permit; and
(e) Vents all of its emissions to a stack and can meet the monitoring, recordkeeping, and reporting requirements of subpart HHHH of this part.

§ 96.381 General.

(a) Except as otherwise provided in §§96.301 through 96.304, §§96.306 through 96.308, and subparts BBBB and CCCC and subparts FFFF through HHHH of this part, a CAIR NO$_X$ Ozone Season unit shall be treated as a CAIR NO$_X$ Ozone Season unit for purposes of applying such sections and subparts of this part.

(b) Solely for purposes of applying, as provided in this subpart, the requirements of subpart HHHH of this part to a unit for which a CAIR opt-in permit application is submitted and not withdrawn and a CAIR opt-in permit is not yet issued or denied under this subpart, such unit shall be treated as a CAIR NO$_X$ Ozone Season unit before issuance of a CAIR opt-in permit for such unit.

§ 96.382 CAIR designated representative.

Any CAIR NO$_X$ Ozone Season opt-in unit, and any unit for which a CAIR opt-in permit application is submitted and not withdrawn and a CAIR opt-in permit is not yet issued or denied under this subpart, located at the same source as one or more CAIR NO$_X$ Ozone Season opt-in units shall have the same CAIR designated representative and alternate CAIR designated representative as such CAIR NO$_X$ Ozone Season units.

§ 96.383 Applying for CAIR opt-in permit.

(a) Applying for initial CAIR opt-in permit. The CAIR designated representative of a unit meeting the requirements for a CAIR NO$_X$ Ozone Season opt-in unit in §96.380 may apply for an initial CAIR opt-in permit at any time, except...
as provided under §96.386 (f) and (g), and, in order to apply, must submit the following:

1. A complete CAIR permit application under §96.322;
2. A certification, in a format specified by the permitting authority, that the unit:
   (i) Is not a CAIR NO\textsubscript{X} Ozone Season unit under §96.304 and is not covered by a retired unit exemption under §96.305 that is in effect;
   (ii) Is not covered by a retired unit exemption under §72.8 of this chapter that is in effect;
   (iii) Vents all of its emissions to a stack; and
   (iv) Has documented heat input for more than 876 hours during the 6 months immediately preceding submission of the CAIR permit application under §96.322;
3. A monitoring plan in accordance with subpart HHHH of this part;
4. A complete certificate of representation under §96.313 consistent with §96.382, if no CAIR designated representative has been previously designated for the source that includes the unit; and
5. A statement, in a format specified by the permitting authority, whether the CAIR designated representative requests that the unit be allocated CAIR NO\textsubscript{X} Ozone Season allowances under §96.388(b) or §96.388(c) (subject to the conditions in §§96.384(h) and 96.386(g)).

§96.384 Opt-in process.

The permitting authority will issue or deny a CAIR opt-in permit for a unit for which an initial application for a CAIR opt-in permit under §96.383 is submitted in accordance with the following:

(a) Interim review of monitoring plan. The permitting authority and the Administrator will determine, on an interim basis, the sufficiency of the monitoring plan accompanying the initial application for a CAIR opt-in permit under §96.383. A monitoring plan is sufficient, for purposes of interim review, if the plan appears to contain information demonstrating that the NO\textsubscript{X} emissions rate and heat input of the unit and all other applicable parameters are monitored and reported in accordance with subpart HHHH of this part. A determination of sufficiency shall not be construed as acceptance or approval of the monitoring plan.

(b) Duty to repower. 1. The CAIR designated representative of a CAIR NO\textsubscript{X} Ozone Season opt-in unit shall submit a complete CAIR permit application under §96.322 to renew the CAIR opt-in unit permit in accordance with the permitting authority’s regulations for Title V operating permits, or the permitting authority’s regulations for other federally enforceable permits if applicable, addressing permit renewal.
2. Unless the permitting authority issues a notification of acceptance of withdrawal of the CAIR NO\textsubscript{X} Ozone Season opt-in unit from the CAIR NO\textsubscript{X} Ozone Season Trading Program in accordance with §96.186 or the unit becomes a CAIR NO\textsubscript{X} Ozone Season unit under §96.304, the CAIR NO\textsubscript{X} opt-in unit shall remain subject to the requirements for a CAIR NO\textsubscript{X} Ozone Season opt-in unit, even if the CAIR designated representative for the CAIR NO\textsubscript{X} Ozone Season opt-in unit fails to submit a CAIR permit application that is required for renewal of the CAIR opt-in permit under paragraph (b)(1) of this section.
(i) The monitoring and reporting under paragraph (b)(1)(i) of this section shall include the entire control period immediately before the date on which the unit enters the CAIR NO\textsubscript{X} Ozone Season Trading Program under §96.384(g), during which period monitoring system availability must not be less than 90 percent under subpart HHHH of this part and the unit must be in full compliance with any applicable State or Federal emissions or emissions-related requirements.

(2) To the extent the NO\textsubscript{X} emissions rate and the heat input of the unit are monitored and reported in accordance with subpart HHHH of this part for one or more control periods, in addition to the control period under paragraph (b)(1)(ii) of this section, during which control periods monitoring system availability is not less than 90 percent under subpart HHHH of this part and the unit is in full compliance with any applicable State or Federal emissions or emissions-related requirements and which control periods begin not more than 3 years before the unit enters the CAIR NO\textsubscript{X} Ozone Season Trading Program under §96.384(g), such information shall be used as provided in paragraphs (c) and (d) of this section.

(c) Baseline heat input. The unit’s baseline heat input shall equal:

(1) If the unit’s NO\textsubscript{X} emissions rate and heat input are monitored and reported for only one control period, in accordance with paragraph (b)(1) of this section, the unit’s total heat input (in mmBtu) for the control period; or

(2) If the unit’s NO\textsubscript{X} emissions rate and heat input are monitored and reported for more than one control period, in accordance with paragraphs (b)(1) and (2) of this section, and the unit does not have add-on NO\textsubscript{X} emission controls during any such control periods, the average of the amounts of the unit’s NO\textsubscript{X} emissions rate (in lb/mmBtu) for the control periods under paragraphs (b)(1)(ii) and (2) of this section; or

(3) If the unit’s NO\textsubscript{X} emissions rate and heat input are monitored and reported for more than one control period, in accordance with paragraphs (b)(1) and (2) of this section, and the unit has add-on NO\textsubscript{X} emission controls during any such control periods, the average of the amounts of the unit’s NO\textsubscript{X} emissions rate (in lb/mmBtu) for such control periods during which the unit has add-on NO\textsubscript{X} emission controls.

(e) Issuance of CAIR opt-in permit. After calculating the baseline heat input and the baseline NO\textsubscript{X} emissions rate for the unit under paragraphs (c) and (d) of this section and if the permitting authority determines that the CAIR designated representative shows that the unit meets the requirements for a CAIR NO\textsubscript{X} Ozone Season opt-in unit in §96.380 and meets the elements certified in §96.383(a)(2), the permitting authority will issue a CAIR opt-in permit. The permitting authority will provide a copy of the CAIR opt-in permit to the Administrator, who will then establish a compliance account for the source that includes the CAIR NO\textsubscript{X} Ozone Season opt-in unit unless the source already has a compliance account.

(f) Issuance of denial of CAIR opt-in permit. Notwithstanding paragraphs (a) through (e) of this section, if at any time before issuance of a CAIR opt-in permit for the unit, the permitting authority determines that the CAIR designated representative fails to show that the unit meets the requirements for a CAIR NO\textsubscript{X} Ozone Season opt-in unit in §96.380 or meets the elements certified in §96.383(a)(2), the permitting authority will issue a denial of a CAIR opt-in permit for the unit.

(g) Date of entry into CAIR NO\textsubscript{X} Ozone Season Trading Program. A unit for which an initial CAIR opt-in permit is
(b) Repowered CAIR NO\textsubscript{X} Ozone Season opt-in unit. (1) If CAIR designated representative requests, and the permitting authority issues a CAIR opt-in permit providing for, allocation to a CAIR NO\textsubscript{X} Ozone Season opt-in unit of CAIR NO\textsubscript{X} Ozone Season allowances under §96.388(c) and such unit is repowered after its date of entry into the CAIR NO\textsubscript{X} Ozone Season Trading Program under paragraph (g) of this section, the repowered unit shall be treated as a CAIR NO\textsubscript{X} Ozone Season opt-in unit replacing the original CAIR NO\textsubscript{X} Ozone Season opt-in unit, as of the date of start-up of the repowered unit's combustion chamber.

(2) Notwithstanding paragraphs (c) and (d) of this section, as of the date of start-up under paragraph (h)(1) of this section, the repowered unit shall be deemed to have the same date of commencement of operation, date of commencement of commercial operation, baseline heat input, and baseline NO\textsubscript{X} emission rate as the original CAIR NO\textsubscript{X} Ozone Season opt-in unit, and the original CAIR NO\textsubscript{X} Ozone Season opt-in unit shall no longer be treated as a CAIR NO\textsubscript{X} Ozone Season opt-in unit or a CAIR NO\textsubscript{X} Ozone Season unit.

(70 FR 25382, May 12, 2005, as amended at 71 FR 25396, Apr. 28, 2006)

§96.386 Withdrawal from CAIR NO\textsubscript{X} Ozone Season Trading Program.

Except as provided under paragraph (g) of this section, a CAIR NO\textsubscript{X} Ozone Season opt-in unit may withdraw from the CAIR NO\textsubscript{X} Ozone Season Trading Program, but only if the permitting authority issues a notification to the CAIR designated representative of the CAIR NO\textsubscript{X} Ozone Season opt-in unit of the acceptance of the withdrawal of the CAIR NO\textsubscript{X} Ozone Season opt-in unit in accordance with paragraph (d) of this section.

(a) Requesting withdrawal. In order to withdraw a CAIR NO\textsubscript{X} Ozone Season opt-in unit from the CAIR NO\textsubscript{X} Ozone Season Trading Program, the CAIR designated representative of the CAIR NO\textsubscript{X} Ozone Season opt-in unit shall submit to the permitting authority a request to withdraw effective as of midnight of September 30 of a specified calendar year, which date must be at least 4 years after September 30 of the year of entry into the CAIR NO\textsubscript{X} Ozone Season Trading Program.
§ 96.384(g). The request must be submitted no later than 90 days before the requested effective date of withdrawal.

(b) Conditions for withdrawal. Before a CAIR NO\textsubscript{X} Ozone Season opt-in unit covered by a request under paragraph (a) of this section may withdraw from the CAIR NO\textsubscript{X} Ozone Season Trading Program and the CAIR opt-in permit may be terminated under paragraph (e) of this section, the following conditions must be met:

1. For the control period ending on the date on which the withdrawal is to be effective, the source that includes the CAIR NO\textsubscript{X} Ozone Season opt-in unit must meet the requirement to hold CAIR NO\textsubscript{X} Ozone Season allowances under §96.308(c) and cannot have any excess emissions.

2. After the requirement for withdrawal under paragraph (b)(1) of this section is met, the Administrator will deduct from the compliance account of the source that includes the CAIR NO\textsubscript{X} Ozone Season allowances equal in amount to and allocated for the same or a prior control period as any CAIR NO\textsubscript{X} Ozone Season allowances allocated to the CAIR NO\textsubscript{X} Ozone Season opt-in unit under §96.388 for any control period for which the withdrawal is to be effective. If there are no remaining CAIR NO\textsubscript{X} Ozone Season units at the source, the Administrator will close the compliance account, and the owners and operators of the CAIR NO\textsubscript{X} Ozone Season opt-in unit may submit a CAIR NO\textsubscript{X} Ozone Season allowance transfer for any remaining CAIR NO\textsubscript{X} Ozone Season allowances to another CAIR NO\textsubscript{X} Ozone Season Allowance Tracking System in accordance with subpart GGGG of this part.

(c) Notification. (1) After the requirements for withdrawal under paragraphs (a) and (b) of this section are met (including deduction of the full amount of CAIR NO\textsubscript{X} Ozone Season allowances required), the permitting authority will issue a notification to the CAIR designated representative of the CAIR NO\textsubscript{X} Ozone Season opt-in unit of the acceptance of the withdrawal of the CAIR NO\textsubscript{X} Ozone Season opt-in unit as of midnight on September 30 of the calendar year for which the withdrawal was requested.

(2) If the requirements for withdrawal under paragraphs (a) and (b) of this section are not met, the permitting authority will issue a notification to the CAIR designated representative of the CAIR NO\textsubscript{X} Ozone Season opt-in unit that the CAIR NO\textsubscript{X} Ozone Season opt-in unit’s request to withdraw is denied. Such CAIR NO\textsubscript{X} Ozone Season opt-in unit shall continue to be a CAIR NO\textsubscript{X} Ozone Season opt-in unit.

(d) Permit amendment. After the permitting authority issues a notification under paragraph (c)(1) of this section that the requirements for withdrawal have been met, the permitting authority will revise the CAIR permit covering the CAIR NO\textsubscript{X} Ozone Season opt-in unit to terminate the CAIR opt-in permit for such unit as of the effective date specified under paragraph (c)(1) of this section. The unit shall continue to be a CAIR NO\textsubscript{X} Ozone Season opt-in unit until the effective date of the termination and shall comply with all requirements under the CAIR NO\textsubscript{X} Ozone Season Trading Program concerning any control periods for which the unit is a CAIR NO\textsubscript{X} Ozone Season opt-in unit, even if such requirements arise or must be complied with after the withdrawal takes effect.

(e) Reapplication upon failure to meet conditions of withdrawal. If the permitting authority denies the CAIR NO\textsubscript{X} Ozone Season opt-in unit’s request to withdraw, the CAIR designated representative may submit another request to withdraw in accordance with paragraphs (a) and (b) of this section.

(f) Ability to reapply to the CAIR NO\textsubscript{X} Ozone Season Trading Program. Once a CAIR NO\textsubscript{X} Ozone Season opt-in unit withdraws from the CAIR NO\textsubscript{X} Ozone Season Trading Program and its CAIR opt-in permit is terminated under this section, the CAIR designated representative may not submit another application for a CAIR opt-in permit under §96.383 for such CAIR NO\textsubscript{X} Ozone Season opt-in unit before the date that is 4 years after the date on which the withdrawal became effective. Such new application for a CAIR opt-in permit will be treated as an initial application for a CAIR opt-in permit under §96.384.

(g) Inability to withdraw. Notwithstanding paragraphs (a) through (f) of this section, a CAIR NO\textsubscript{X} Ozone Season
§ 96.387 Change in regulatory status.

(a) Notification. If a CAIR NO\textsubscript{X} Ozone Season opt-in unit becomes a CAIR NO\textsubscript{X} Ozone Season unit under §96.304, then the CAIR designated representative shall notify in writing the permitting authority and the Administrator of such change in the CAIR NO\textsubscript{X} Ozone Season opt-in unit’s regulatory status, within 30 days of such change.

(b) Permitting authority’s and Administrator’s actions. (1) If a CAIR NO\textsubscript{X} Ozone Season opt-in unit becomes a CAIR NO\textsubscript{X} Ozone Season unit under §96.304, the permitting authority will revise the CAIR NO\textsubscript{X} Ozone Season opt-in unit’s CAIR opt-in permit to meet the requirements of a CAIR permit under §96.323, and remove the CAIR opt-in permit provisions, as of the date on which the CAIR NO\textsubscript{X} Ozone Season opt-in unit becomes a CAIR NO\textsubscript{X} Ozone Season unit under §96.304.

(2)(i) The Administrator will deduct from the compliance account of the source that includes the CAIR NO\textsubscript{X} Ozone Season opt-in unit that becomes a CAIR NO\textsubscript{X} Ozone Season unit under §96.304, CAIR NO\textsubscript{X} Ozone Season allowances equal in amount to and allocated for the same or a prior control period as:

(A) Any CAIR NO\textsubscript{X} Ozone Season allowances allocated to the CAIR NO\textsubscript{X} Ozone Season opt-in unit under §96.388 for any control period after the date on which the CAIR NO\textsubscript{X} Ozone Season opt-in unit becomes a CAIR NO\textsubscript{X} Ozone Season unit under §96.304; and

(B) If the date on which the CAIR NO\textsubscript{X} Ozone Season opt-in unit becomes a CAIR NO\textsubscript{X} Ozone Season unit under §96.304 is not September 30, the CAIR NO\textsubscript{X} Ozone Season allowances allocated to the CAIR NO\textsubscript{X} Ozone Season opt-in unit under §96.388 for the control period that includes the date on which the CAIR NO\textsubscript{X} Ozone Season opt-in unit becomes a CAIR NO\textsubscript{X} Ozone Season unit under §96.304, multiplied by the ratio of the number of days in the control period, starting with the date on which the CAIR NO\textsubscript{X} Ozone Season opt-in unit becomes a CAIR NO\textsubscript{X} Ozone Season unit under §96.304 divided by the total number of days in the control period and rounded to the nearest whole allowance as appropriate.

(ii) The CAIR designated representative shall ensure that the compliance account of the source that includes the CAIR NO\textsubscript{X} Ozone Season opt-in unit that becomes a CAIR NO\textsubscript{X} Ozone Season unit under §96.304 contains the CAIR NO\textsubscript{X} Ozone Season allowances necessary for completion of the deduction under paragraph (b)(2)(i) of this section.

(3)(i) For every control period after the date on which the CAIR NO\textsubscript{X} Ozone Season opt-in unit becomes a CAIR NO\textsubscript{X} Ozone Season unit under §96.304 is not September 30, the following amount of CAIR NO\textsubscript{X} Ozone Season allowances will be allocated to the CAIR NO\textsubscript{X} Ozone Season opt-in unit (as a CAIR NO\textsubscript{X} Ozone Season unit) under §96.342 for the control period that includes the date on which the CAIR NO\textsubscript{X} Ozone Season opt-in unit becomes a CAIR NO\textsubscript{X} Ozone Season unit under §96.304:

(A) The amount of CAIR NO\textsubscript{X} Ozone Season allowances otherwise allocated to the CAIR NO\textsubscript{X} Ozone Season opt-in unit (as a CAIR NO\textsubscript{X} Ozone Season unit) under §96.342 for the control period multiplied by:

(B) The ratio of the number of days, in the control period, starting with the date on which the CAIR NO\textsubscript{X} Ozone Season opt-in unit becomes a CAIR NO\textsubscript{X} Ozone Season unit under §96.304, divided by the total number of days in the control period; and
§ 96.388 CAIR NO\textsubscript{X} Ozone Season allowance allocations to CAIR NO\textsubscript{X} Ozone Season opt-in units.

(a) Timing requirements. (1) When the CAIR opt-in permit is issued under §96.384(e), the permitting authority will allocate CAIR NO\textsubscript{X} Ozone Season allowances to the CAIR NO\textsubscript{X} Ozone Season opt-in unit, and submit to the Administrator the allocation for the control period in which a CAIR NO\textsubscript{X} Ozone Season opt-in unit enters the CAIR NO\textsubscript{X} Ozone Season Trading Program under §96.384(g), in accordance with paragraph (b) or (c) of this section.

(2) By no later than July 31 of the control period after the control period in which a CAIR NO\textsubscript{X} Ozone Season opt-in unit enters the CAIR NO\textsubscript{X} Ozone Season Trading Program under §96.384(g) and July 31 of each year thereafter, the permitting authority will allocate CAIR NO\textsubscript{X} Ozone Season allowances to the CAIR NO\textsubscript{X} Ozone Season opt-in unit, and submit to the Administrator the allocation for the control period that includes such submission deadline and in which the unit is a CAIR NO\textsubscript{X} Ozone Season opt-in unit, in accordance with paragraph (b) or (c) of this section.

(b) Calculation of allocation. For each control period for which a CAIR NO\textsubscript{X} Ozone Season opt-in unit is to be allocated CAIR NO\textsubscript{X} Ozone Season allowances, the permitting authority will allocate in accordance with the following procedures:

(1) The heat input (in mmBtu) used for calculating the CAIR NO\textsubscript{X} Ozone Season allowance allocation will be the lesser of:

(i) The CAIR NO\textsubscript{X} Ozone Season opt-in unit’s baseline heat input determined under §96.384(c); or

(ii) The CAIR NO\textsubscript{X} Ozone Season opt-in unit’s heat input, as determined in accordance with subpart HHHH of this part, for the immediately prior control period, except when the allocation is being calculated for the control period in which the CAIR NO\textsubscript{X} Ozone Season opt-in unit enters the CAIR NO\textsubscript{X} Ozone Season Trading Program under §96.384(g).

(2) The NO\textsubscript{X} emission rate (in lb/mmBtu) used for calculating CAIR NO\textsubscript{X} Ozone Season allowance allocations will be the lesser of:

(i) The CAIR NO\textsubscript{X} Ozone Season opt-in unit’s baseline NO\textsubscript{X} emissions rate (in lb/mmBtu) determined under §96.384(d) and multiplied by 70 percent; or

(ii) The most stringent State or Federal NO\textsubscript{X} emissions limitation applicable to the CAIR NO\textsubscript{X} Ozone Season opt-in unit at any time during the control period for which CAIR NO\textsubscript{X} Ozone Season allowances are to be allocated.

(3) The permitting authority will allocate CAIR NO\textsubscript{X} Ozone Season allowances to the CAIR NO\textsubscript{X} Ozone Season opt-in unit in an amount equaling the heat input under paragraph (b)(1) of this section, multiplied by the NO\textsubscript{X} emission rate under paragraph (b)(2) of this section, divided by 2,000 lb/ton, and rounded to the nearest whole allowance as appropriate.

(c) Notwithstanding paragraph (b) of this section and if the CAIR designated representative requests, and the permitting authority issues a CAIR opt-in permit” (based on a demonstration of the intent to repower stated under §96.383(a)(5)) providing for, allocation to a CAIR NO\textsubscript{X} Ozone Season opt-in unit of CAIR NO\textsubscript{X} Ozone Season allowances under this paragraph (subject to the conditions in §§96.384(h) and 96.386(g)), the permitting authority will allocate to the CAIR NO\textsubscript{X} Ozone Season opt-in unit as follows:

(1) For each control period in 2009 through 2014 for which the CAIR NO\textsubscript{X} Ozone Season opt-in unit is to be allocated CAIR NO\textsubscript{X} Ozone Season allowances, the permitting authority will allocate in accordance with the following procedures:

(i) The heat input (in mmBtu) used for calculating the CAIR NO\textsubscript{X} Ozone Season allowance allocation will be determined as described in paragraph (b)(1) of this section.

(ii) The NO\textsubscript{X} emission rate (in lb/mmBtu) used for calculating CAIR NO\textsubscript{X} Ozone Season allowance allocations will be the lesser of:

(A) The CAIR NO\textsubscript{X} Ozone Season opt-in unit’s baseline NO\textsubscript{X} emissions rate...
(in lb/mmBtu) determined under §96.384(d); or

(B) The most stringent State or Federal NOX emissions limitation applicable to the CAIR NOX Ozone Season opt-in unit at any time during the control period in which the CAIR NOX Ozone Season opt-in unit enters the CAIR NOX Ozone Season Trading Program under §96.384(g).

(iii) The permitting authority will allocate CAIR NOX Ozone Season allowances to the CAIR NOX Ozone Season opt-in unit in an amount equaling the heat input under paragraph (c)(1)(i) of this section, multiplied by the NOX emission rate under paragraph (c)(1)(ii) of this section, divided by 2,000 lb/ton, and rounded to the nearest whole allowance as appropriate.

(2) For each control period in 2015 and thereafter for which the CAIR NOX Ozone Season opt-in unit is to be allocated CAIR NOX Ozone Season allowances,

(i) The heat input (in mmBtu) used for calculating the CAIR NOX Ozone Season allowance allocations will be determined as described in paragraph (b)(1) of this section.

(ii) The NOX emission rate (in lb/mmBtu) used for calculating the CAIR NOX Ozone Season opt-in unit’s baseline NOX emissions rate (in lb/mmBtu) determined under §96.384(d); or

(C) The most stringent State or Federal NOX emissions limitation applicable to the CAIR NOX Ozone Season opt-in unit at any time during the control period for which CAIR NOX Ozone Season allowances are to be allocated.

(iii) The permitting authority will allocate CAIR NOX Ozone Season allowances to the CAIR NOX Ozone Season opt-in unit in an amount equaling the heat input under paragraph (c)(2)(i) of this section, multiplied by the NOX emission rate under paragraph (c)(2)(ii) of this section, divided by 2,000 lb/ton, and rounded to the nearest whole allowance as appropriate.

(d) Recordation. (1) The Administrator will record, in the compliance account of the source that includes the CAIR NOX Ozone Season opt-in unit, the CAIR NOX Ozone Season allowances allocated by the permitting authority to the CAIR NOX Ozone Season opt-in unit under paragraph (a)(1) of this section.

(2) By September 1, of the control period in which a CAIR NOX Ozone Season opt-in unit enters the CAIR NOX Ozone Season Trading Program under §96.384(g), and September 1 of each year thereafter, the Administrator will record, in the compliance account of the source that includes the CAIR NOX Ozone Season opt-in unit, the CAIR NOX Ozone Season allowances allocated by the permitting authority to the CAIR NOX Ozone Season opt-in unit under paragraph (a)(2) of this section.

[70 FR 25382, May 12, 2005, as amended at 71 FR 25396, Apr. 28, 2006]
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APPENDIX A TO PART 97—FINAL SECTION 126 RULE: EGU ALLOCATIONS, 2003–2007
APPENDIX B TO PART 97—FINAL SECTION 126 RULE: NON-EGU ALLOCATIONS, 2003–2007
APPENDIX C TO PART 97—FINAL SECTION 126 RULE: TRADING BUDGET, 2003–2007
APPENDIX D TO PART 97—FINAL SECTION 126 RULE: STATE COMPLIANCE SUPPLEMENT POOLS FOR THE SECTION 126 FINAL RULE (TONS)

AUTHORITY: 42 U.S.C. 7401, 7403, 7410, 7426, 7601, and 7651, et seq.
§ 97.1 Purpose.

This part establishes general provisions and the applicability, permitting, allowance, excess emissions, monitoring, and opt-in provisions for the federal NO\textsubscript{X} Budget Trading Program, under section 126 of the CAA and § 52.34 of this chapter, as a means of mitigating the interstate transport of ozone and nitrogen oxides, an ozone precursor.

§ 97.2 Definitions.

The terms used in this part shall have the meanings set forth in this section as follows:

Account number means the identification number given by the Administrator to each NO\textsubscript{X} Allowance Tracking System account.

Acid Rain emissions limitation means, as defined in §72.2 of this chapter, a limitation on emissions of sulfur dioxide or nitrogen oxides under the Acid Rain Program under title IV of the Clean Air Act.

Administrator means the Administrator of the United States Environmental Protection Agency or the Administrator’s duly authorized representative.

Allocate or allocation means, with regard to NO\textsubscript{X} allowances, the determination by the Administrator of the number of NO\textsubscript{X} allowances to be initially credited to a NO\textsubscript{X} Budget unit or an allocation set-aside.

Automated data acquisition and handling system or DAHS means that component of the CEMS, or other emissions monitoring system approved for use under subpart H of this part, designed to interpret and convert individual output signals from pollutant concentration monitors, flow monitors, diluent gas monitors, and other component parts of the monitoring system to produce a continuous record of the measured parameters in the measurement units required by subpart H of this part.

Boiler means an enclosed fossil or other fuel-fired combustion device used to produce heat and to transfer heat to recirculating water, steam, or other medium.

Clean Air Act means the Clean Air Act, 42 U.S.C. 7401 et seq.

Combined cycle system means a system comprised of one or more combustion turbines, heat recovery steam generators, and steam turbines configured to improve overall efficiency of electricity generation or steam production.

Combustion turbine means an enclosed fossil or other fuel-fired device that is comprised of a compressor, a combustor, and a turbine, and in which the flue gas resulting from the combustion of fuel in the combustor passes through the turbine, rotating the turbine.

Commence commercial operation means, with regard to a unit that serves a generator, to have begun to produce steam, gas, or other heated medium used to generate electricity for sale or use, including test generation. Except as provided in §97.4(b), §97.5, or subpart I of this part, for a unit that is a NO\textsubscript{X} Budget unit under §97.4(a) on the date the unit commences commercial operation, such date shall remain the unit’s date of commencement of commercial operation even if the unit is subsequently modified, reconstructed, or repowered. Except as provided in §97.4(b), §97.5, or subpart I of this part, for a unit that is not a NO\textsubscript{X} Budget unit under §97.4(a) on the date the unit commences commercial operation, the date the unit becomes a NO\textsubscript{X} Budget unit under §97.4(a) shall be the unit’s date of commencement of commercial operation.

Commence operation means to have begun any mechanical, chemical, or electronic process, including, with regard to a unit, start-up of a unit’s combustion chamber. Except as provided in §97.4(b), §97.5, or subpart I of this part for a unit that is a NO\textsubscript{X} Budget unit under §97.4(a) on the date of commencement of operation, such date shall remain the unit’s date of commencement of operation even if the unit is subsequently modified, reconstructed, or repowered. Except as provided in §97.4(b), §97.5, or subpart I of this part, for a unit that is not a NO\textsubscript{X} Budget unit under §97.4(a) on the date
of commencement of operation, the date the unit becomes a NO\textsubscript{X} Budget unit under §97.4(a) shall be the unit’s date of commencement of operation.

*Common stack* means a single flue through which emissions from two or more units are exhausted.

*Compliance account* means a NO\textsubscript{X} Allowance Tracking System account, established by the Administrator for a NO\textsubscript{X} Budget unit under subpart F of this part, in which the NO\textsubscript{X} allowances available for use by the unit for a control period for the purpose of meeting the unit’s NO\textsubscript{X} Budget emissions limitation.

*Continuous emission monitoring system* or *CEMS* means the equipment required under subpart H of this part to sample, analyze, measure, and provide, by means of readings taken at least once every 15 minutes (using an automated data acquisition and handling system (DAHS)), a permanent record of nitrogen oxides (NO\textsubscript{X}) emissions, stack gas volumetric flow rate or stack gas moisture content (as applicable), in a manner consistent with part 75 of this chapter. The following are the principal types of continuous emission monitoring systems required under subpart H of this part:

1. A flow monitoring system, consisting of a stack flow rate monitor and an automated DAHS. A flow monitoring system provides a permanent, continuous record of stack gas volumetric flow rate, in units of standard cubic feet per hour (scfh);

2. A nitrogen oxides concentration monitoring system, consisting of a NO\textsubscript{X} pollutant concentration monitor and an automated DAHS. A NO\textsubscript{X} concentration monitoring system provides a permanent, continuous record of NO\textsubscript{X} emissions in units of parts per million (ppm);

3. A nitrogen oxides emission rate (or NO\textsubscript{X}-diluent) monitoring system, consisting of a NO\textsubscript{X} pollutant concentration monitor, a diluent gas (CO\textsubscript{2} or \text{O}_2) monitor, and an automated DAHS. A NO\textsubscript{X} concentration monitoring system provides a permanent, continuous record of NO\textsubscript{X} concentration in units of parts per million (ppm), diluent gas concentration in units of percent O\textsubscript{2} or CO\textsubscript{2} (percent O\textsubscript{2} or CO\textsubscript{2}), and NO\textsubscript{X} emission rate in units of pounds per million British thermal units (lb/mmBtu); and

4. A moisture monitoring system, as defined in §75.11(b)(2) of this chapter. A moisture monitoring system provides a permanent, continuous record of the stack gas moisture content, in units of percent H\textsubscript{2}O (percent H\textsubscript{2}O).

*Control period* means the period beginning May 1 of a year and ending on September 30 of the same year, inclusive.

*Electricity for sale under firm contract to the grid* means electricity for sale where the capacity involved is intended to be available at all times during the period covered by a guaranteed commitment to deliver, even under adverse conditions.

*Emissions* means air pollutants exhausted from a unit or source into the atmosphere, as measured, recorded, and reported to the Administrator by the NO\textsubscript{X} authorized account representative and as determined by the Administrator in accordance with subpart H of this part.


*Excess emissions* means any tonnage of nitrogen oxides emitted by a NO\textsubscript{X} Budget unit during a control period that exceeds the NO\textsubscript{X} Budget emissions limitation for the unit.

*Fossil fuel* means natural gas, petroleum, coal, or any form of solid, liquid, or gaseous fuel derived from such material.

*Fossil fuel fired* means, with regard to a unit:

1. For units that commenced operation before January 1, 1996, the combustion of fossil fuel, alone or in combination with any other fuel, where fossil fuel actually combusted comprises more than 50 percent of the annual heat input on a Btu basis during 1995, or, if a unit had no heat input in 1995, during the last year of operation of the unit prior to 1995;

2. For units that commenced operation on or after January 1, 1996 and before January 1, 1997, the combustion of fossil fuel, alone or in combination with any other fuel, where fossil fuel
actually combusted comprises more than 50 percent of the annual heat input on a Btu basis during 1996; or

(3) For units that commence operation on or after January 1, 1997:
   (i) The combination of fossil fuel, alone or in combustion with any other fuel, where fossil fuel actually combusted comprises more than 50 percent of the annual heat input on a Btu basis during any year; or
   (ii) The combination of fossil fuel, alone or in combination with any other fuel, where fossil fuel is projected to comprise more than 50 percent of the annual heat input on a Btu basis during any year, provided that the unit shall be “fossil fuel-fired” as of the date, during such year, on which the unit begins combusting fossil fuel.

General account means a NO\textsubscript{X} Allowance Tracking System account, established under subpart F of this part, that is not a compliance account or an overdraft account.

Generator means a device that produces electricity.

Heat input means, with regard to a specified period to time, the product (in mmBtu/time) of the gross calorific value of the fuel (in Btu/lb) divided by 1,000,000 Btu/mmBtu and multiplied by the fuel feed rate into a combustion device (in lb of fuel/time), as measured, recorded, and reported to the Administrator by the NO\textsubscript{X} authorized account representative and as determined by the Administrator in accordance with subpart H of this part. Heat input does not include the heat derived from preheated combustion air, recirculated flue gases, or exhaust from other sources.

Heat input rate means the amount of heat input (in mmBtu) divided by unit operating time (in hr) or, with regard to a specific fuel, the amount of heat input attributed to the fuel (in mmBtu) divided by the unit operating time (in hr) during which the unit combats the fuel.

Life-of-the-unit, firm power contractual arrangement means a unit participation power sales agreement under which a utility or industrial customer reserves, or is entitled to receive, a specified amount or percentage of nameplate capacity and associated energy from any specified unit and pays its proportional amount of such unit’s total costs, pursuant to a contract:
   (1) For the life of the unit;
   (2) For a cumulative term of no less than 30 years, including contracts that permit an election for early termination; or
   (3) For a period equal to or greater than 25 years or 70 percent of the economic useful life of the unit determined as of the time the unit is built, with option rights to purchase or release some portion of the nameplate capacity and associated energy generated by the unit at the end of the period.

Maximum design heat input means the ability of a unit to combust a stated maximum amount of fuel per hour (in mmBtu/hr) on a steady state basis, as determined by the physical design and physical characteristics of the unit.

Maximum potential hourly heat input means an hourly heat input (in mmBtu/hr) used for reporting purposes when a unit lacks certified monitors to report heat input. If the unit intends to use appendix D of part 75 of this chapter to report heat input, this value should be calculated, in accordance with part 75 of this chapter, using the maximum fuel flow rate and the maximum gross calorific value. If the unit intends to use a flow monitor and a diluent gas monitor, this value should be reported, in accordance with part 75 of this chapter, using the maximum potential flowrate and either the maximum carbon dioxide concentration (in percent CO\textsubscript{2}) or the minimum oxygen concentration (in percent O\textsubscript{2}).

Maximum potential NO\textsubscript{X} emission rate means the emission rate of nitrogen oxides (in lb/mmBtu) calculated in accordance with section 3 of appendix F of part 75 of this chapter, using the maximum potential concentration of NO\textsubscript{X} under section 2 of appendix A of part 75 of this chapter, and either the maximum oxygen concentration (in percent O\textsubscript{2}) or the minimum carbon dioxide concentration (in percent CO\textsubscript{2}), under all operating conditions of the unit except for unit start up, shutdown, and upsets.

Maximum rated hourly heat input means a unit specific maximum hourly heat input (in mmBtu/hr) which is the higher of the manufacturer’s maximum
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rated hourly heat input or the highest observed hourly heat input.

Monitoring system means any monitoring system that meets the requirements of subpart H of this part, including a continuous emissions monitoring system, an excepted monitoring system, or an alternative monitoring system.

Most stringent State or Federal NO\textsubscript{X} emissions limitation means the lowest NO\textsubscript{X} emissions limitation (in lb/tn/MMBtu) that is applicable to the unit under State or Federal law, regardless of the averaging period to which the emissions limitation applies.

Nameplate capacity means the maximum electrical generating output (in MWe) that a generator can sustain over a specified period of time when not restricted by seasonal or other deratings as measured in accordance with the United States Department of Energy standards.

Non-title V permit means a federally enforceable permit administered by the permitting authority pursuant to the Clean Air Act and regulatory authority under the Clean Air Act, other than title V of the Clean Air Act and part 70 or 71 of this chapter.

NO\textsubscript{X} allowance means a limited authorization by the Administrator under the NO\textsubscript{X} Budget Trading Program to emit up to one ton of nitrogen oxides during the control period of the specified year or of any year thereafter, except as provided under §97.54(f). No provision of the NO\textsubscript{X} Budget Trading Program, the NO\textsubscript{X} Budget permit application, the NO\textsubscript{X} Budget permit, or an exemption under §97.4(b) or §97.5 and no provision of law shall be construed to limit the authority of the United States to terminate or limit such authorization, which does not constitute a property right. For purposes of all sections of this part except §97.40, §97.41, §97.42, §97.43, or §97.88, “NO\textsubscript{X} allowance” also includes an authorization to emit up to one ton of nitrogen oxides during the control period of the specified year or of any year thereafter by the permitting authority or the Administrator in accordance with a State NO\textsubscript{X} Budget Trading Program established, and approved and administered by the Administrator, pursuant to §51.121 of this chapter.

NO\textsubscript{X} allowance deduction or deduct NO\textsubscript{X} allowances means the permanent withdrawal of NO\textsubscript{X} allowances by the Administrator from a NO\textsubscript{X} Allowance Tracking System compliance account or overdraft account to account for the number of tons of NO\textsubscript{X} emissions from a NO\textsubscript{X} Budget unit for a control period, determined in accordance with subparts H and F of this part, or for any other NO\textsubscript{X} allowance withdrawal requirement under this part.

NO\textsubscript{X} Allowance Tracking System means the system by which the Administrator records allocations, deductions, and transfers of NO\textsubscript{X} allowances under the NO\textsubscript{X} Budget Trading Program.

NO\textsubscript{X} Allowance Tracking System account means an account in the NO\textsubscript{X} Allowance Tracking System established by the Administrator for purposes of recording the allocation, holding, transferring, or deducting of NO\textsubscript{X} allowances.

NO\textsubscript{X} allowance transfer deadline means midnight of November 30 or, if November 30 is not a business day, midnight of the first business day thereafter and is the deadline by which NO\textsubscript{X} allowances must be submitted for recordation in a NO\textsubscript{X} Budget unit’s compliance account, or the overdraft account of the source where the unit is located, in order to meet the unit’s NO\textsubscript{X} Budget emissions limitation for the control period immediately preceding such deadline.

NO\textsubscript{X} allowances held or hold NO\textsubscript{X} allowances means the NO\textsubscript{X} allowances recorded by the Administrator, or submitted to the Administrator for recordation, in accordance with subparts F and G of this part, in a NO\textsubscript{X} Allowance Tracking System account.

NO\textsubscript{X} authorized account representative means, for a NO\textsubscript{X} Budget source or NO\textsubscript{X} Budget unit at the source, the natural person who is authorized by the owners and operators of the source and all NO\textsubscript{X} Budget units at the source, in accordance with subpart B of this part, to represent and legally bind each owner and operator in matters pertaining to the NO\textsubscript{X} Budget Trading Program or, for a general account, the natural person who is authorized, in accordance with subpart F of this part, to transfer or otherwise dispose of NO\textsubscript{X} allowances held in the general account.
§ 97.2 NOx Budget emissions limitation

for a NOx Budget unit, the tonnage equivalent of the NOx allowances available for compliance deduction for the unit under §97.54(a), (b), (e), and (f) in a control period adjusted by deductions of such NOx allowances to account for actual heat input under §97.42(e) for the control period or to account for excess emissions for a prior control period under §97.54(d) or to account for withdrawal from the NOx Budget Trading Program, or for a change in regulatory status, of a NOx Budget opt-in unit under §97.86 or §97.87.

NOx Budget opt-in permit means a NOx Budget permit covering a NOx Budget opt-in unit.

NOx Budget opt-in unit means a unit that has been elected to become a NOx Budget unit under the NOx Budget Trading Program and whose NOx Budget opt-in permit has been issued and is in effect under subpart I of this part.

NOx Budget permit means the legally binding and federally enforceable written document, or portion of such document, issued by the permitting authority under this part, including any permit revisions, specifying the NOx Budget Trading Program requirements applicable to a NOx Budget source, to each NOx Budget unit at the NOx Budget source, and to the owners and operators and the NOx authorized account representative of the NOx Budget source and each NOx Budget unit.

NOx Budget source means a source that includes one or more NOx Budget units.

NOx Budget Trading Program means a multistate nitrogen oxides air pollution control and emission reduction program established by the Administrator in accordance with this part and pursuant to §52.34 of this chapter, as a means of mitigating the interstate transport of ozone and nitrogen oxides, an ozone precursor.

NOx Budget unit means a unit that is subject to the NOx Budget emissions limitation under §97.4(a) or §97.80.

Operating means, with regard to a unit under §§97.22(d)(2) and 97.80, having documented heat input for more than 876 hours in the 6 months immediately preceding the submission of an application for an initial NOx Budget permit under §97.83(a). The unit’s documented heat input will be determined in accordance with part 75 of this chapter if the unit was otherwise subject to the requirements of part 75 of this chapter during that 6-month period or will be based on the best available data reported to the Administrator for the unit if the unit was not otherwise subject to the requirements of part 75 of this chapter during that 6-month period.

Operator means any person who operates, controls, or supervises a NOx Budget unit, a NOx Budget source, or a unit for which an application for a NOx Budget opt-in permit under §97.83 is submitted and not denied or withdrawn and shall include, but not be limited to, any holding company, utility system, or plant manager of such a unit or source.

Opt-in means to be elected to become a NOx Budget unit under the NOx Budget Trading Program through a final, effective NOx Budget opt-in permit under subpart I of this part.

Overdraft account means the NOx Allowance Tracking System account, established by the Administrator under subpart F of this part, for each NOx Budget source where there are two or more NOx Budget units.

Owner means any of the following persons:

(1) Any holder of any portion of the legal or equitable title in a NOx Budget unit or in a unit for which an application for a NOx Budget opt-in permit under §97.83 is submitted and not denied or withdrawn; or

(2) Any holder of a leasehold interest in a NOx Budget unit or in a unit for which an application for a NOx Budget opt-in permit under §97.83 is submitted and not denied or withdrawn; or

(3) Any purchaser of power from a NOx Budget unit or from a unit for which an application for a NOx Budget opt-in permit under §97.83 is submitted and not denied or withdrawn under a life-of-the-unit, firm power contractual arrangement. However, unless expressly provided for in a leasehold agreement, owner shall not include a passive lessor, or a person who has an equitable interest through such lessor, whose rental payments are not based, either directly or indirectly, upon the revenues or income from the NOx Unit.
Budget unit or the unit for which an application for a NO\textsubscript{X} Budget opt-in permit under §97.83 is submitted and not denied or withdrawn; or

(4) With respect to any general account, any person who has an ownership interest with respect to the NO\textsubscript{X} allowances held in the general account and who is subject to the binding agreement for the NO\textsubscript{X} authorized account representative to represent that person’s ownership interest with respect to the NO\textsubscript{X} allowances.

Percent monitor data availability means, for purposes of §97.43 (a)(1) and §97.84(b), total unit operating hours for which quality-assured data were recorded under subpart H of this part in a control period, divided by the total number of unit operating hours in the control period, and multiplied by 100 percent.

Permitting authority means the State air pollution control agency, local agency, other State agency, or other agency authorized by the Administrator to issue or revise permits to meet the requirements of the NO\textsubscript{X} Budget Trading Program in accordance with subpart C of this part.

Potential electrical output capacity means 33 percent of a unit’s maximum design heat input.

Receive or receipt of means, when referring to the permitting authority or the Administrator, to come into possession of a document, information, or correspondence (whether sent in writing or by authorized electronic transmission), as indicated in an official correspondence log, or by a notation made on the document, information, or correspondence, by the permitting authority or the Administrator in the regular course of business.

Recordation, record, or recorded means, with regard to NO\textsubscript{X} allowances, the movement of NO\textsubscript{X} allowances by the Administrator from one NO\textsubscript{X} Allowance Tracking System account to another, for purposes of allocation, transfer, or deduction.

Reference method means any direct test method of sampling and analyzing for an air pollutant as specified in appendix A of part 60 of this chapter.

Serial number means, when referring to NO\textsubscript{X} allowances, the unique identification number assigned to each NO\textsubscript{X} allowance by the Administrator, under §97.53(c).

Source means any governmental, institutional, commercial, or industrial structure, installation, plant, building, or facility that emits or has the potential to emit any regulated air pollutant under the Clean Air Act. For purposes of section 502(c) of the Clean Air Act, a “source,” including a “source” with multiple units, shall be considered a single “facility.”

State means one of the 48 contiguous States or a portion thereof or the District of Columbia that is specified in §52.34 of this chapter and in which are located units for which the Administrator makes an effective finding under §52.34 of this chapter.

Submit or serve means to send or transmit a document, information, or correspondence to the person specified in accordance with the applicable regulation:

(1) In person;

(2) By United States Postal Service; or

(3) By other means of dispatch or transmission and delivery. Compliance with any “submission,” “service,” or “mailing” deadline shall be determined by the date of dispatch, transmission, or mailing and not the date of receipt.

Title V operating permit means a permit issued under title V of the Clean Air Act and part 70 or part 71 of this chapter.

Title V operating permit regulations means the regulations that the Administrator has approved or issued as meeting the requirements of title V of the Clean Air Act and part 70 or 71 of this chapter.

Ton or tonnage means any “short ton” (i.e., 2,000 pounds). For the purpose of determining compliance with the NO\textsubscript{X} Budget emissions limitation, total tons for a control period shall be calculated as the sum of all recorded hourly emissions (or the tonnage equivalent of the recorded hourly emissions rates) in accordance with subpart H of this part, with any remaining fraction of a ton equal to or greater than 0.50 ton deemed to equal one ton and any fraction of a ton less than 0.50 ton deemed to equal zero tons.
§ 97.3 Measurements, abbreviations, and acronyms.

Measurements, abbreviations, and acronyms used in this part are defined as follows:

Btu—British thermal unit.
CO₂—carbon dioxide.
hr—hour.
KWh—kilowatt hour.
lb—pounds.
mmBtu—million Btu.
MWe—megawatt electrical.
NOₓ—nitrogen oxides.
O₂—oxygen.
ton—2000 pounds.

§ 97.4 Applicability.

(a) The following units in a State shall be a NOₓ Budget unit, and any source that includes one or more such units shall be a NOₓ Budget source, subject to the requirements of this part:

(1)(i) For units other than cogeneration units—

(A) For units commencing operation before January 1, 1997, a unit serving during 1995 or 1996 a generator—

(1) With a nameplate capacity greater than 25 MWe and
(2) Producing electricity for sale under a firm contract to the electric grid.

(B) For units commencing operation in 1997 or 1998, a unit serving during 1997 or 1998 a generator with a nameplate capacity greater than 25 MWe and failing to qualify as an unaffected unit under §72.6(b)(4) of this chapter for 1997 or 1998 under the Acid Rain Program.

(C) For units commencing operation on or after January 1, 1999, a unit serving at any time a generator with a nameplate capacity greater than 25 MWe and failing to qualify as an unaffected unit under §72.6(b)(4) of this chapter under the Acid Rain Program for any year.

(2)(i) For units other than cogeneration units—

(A) For units commencing operation before January 1, 1997, a unit—

(1) With a maximum design heat input greater than 250 mmBtu/hr and
(2) Not serving during 1995 or 1996 a generator producing electricity for sale under a firm contract to the electric grid.

(B) For units commencing operation in 1997 or 1998, a unit—

(1) With a maximum design heat input greater than 250 mmBtu/hr and
(2) Not serving during 1997 or 1998 a generator producing electricity for sale under a firm contract to the electric grid.

(C) For units commencing on or after January 1, 1999, a unit with a maximum design heat input greater than 250 mmBtu/hr:

(1) At no time serving a generator producing electricity for sale; or
(2) At any time serving a generator with a nameplate capacity of 25 MWe or less producing electricity for sale and with the potential to use no more than 50 percent of the potential electrical output capacity of the unit.

(ii) For cogeneration units—

(A) For units commencing operation before January 1, 1997, a unit with a maximum design heat input greater than 250 mmBtu/hr and qualifying as
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an unaffected unit under §72.6(b)(4) of this chapter under the Acid Rain Program for 1995 and 1996.

(B) For units commencing operation in 1997 or 1998, a unit with a maximum design heat input greater than 250 mmBtu/hr and qualifying as an unaffected unit under §72.6(b)(4) under the Acid Rain Program for 1997 and 1998.

(C) For units commencing on or after January 1, 1999, a unit with a maximum design heat input greater than 250 mmBtu/hr and qualifying as an unaffected unit under §72.6(b)(4) of this chapter under the Acid Rain Program for each year.

(b)(1) Notwithstanding paragraph (a) of this section, a unit under paragraph (a)(1) or (a)(2) of this section that has a federally enforceable permit that restricts the unit to combusting only natural gas or fuel oil (as defined in §75.2 of this chapter) during a control period includes a NO\textsubscript{X} emission limitation restricting NO\textsubscript{X} emissions during a control period to 25 tons or less, and includes the special provisions in paragraph (b)(4) of this section shall be exempt from the requirements of the NO\textsubscript{X} Budget Trading Program, except for the provisions of this paragraph (b), §97.2, §97.3, §97.4(a), §97.7, and subparts E, F, and G of this part. The NO\textsubscript{X} emission limitation under this paragraph (b)(1) shall restrict NO\textsubscript{X} emissions during the control period by limiting unit operating hours. The restriction on unit operating hours shall be calculated by dividing 25 tons by the unit’s maximum potential hourly NO\textsubscript{X} mass emissions, which shall equal the unit’s maximum rated hourly heat input multiplied by the highest default NO\textsubscript{X} emission rate otherwise applicable to the unit under §75.19 of this chapter.

(2) The exemption under paragraph (b)(1) of this section shall become effective as follows:

(i) The exemption shall become effective on the date on which the NO\textsubscript{X} emission limitation and the special provisions in the permit under paragraph (b)(1) of this section become final; or

(ii) If the NO\textsubscript{X} emission limitation and the special provisions in the permit under paragraph (b)(1) of this section become final during a control period and after the first date on which the unit operates during such control period, then the exemption shall become effective on May 1 of such control period, provided that such NO\textsubscript{X} emission limitation and the special provisions apply to the unit as of such first date of operation. If such NO\textsubscript{X} emission limitation and special provisions do not apply to the unit as of such first date of operation, then the exemption under paragraph (b)(1) of this section shall become effective on October 1 of the year during which such NO\textsubscript{X} emission limitation and the special provisions become final.

(3) The permitting authority that issues a federally enforceable permit under paragraph (b)(1) of this section for a unit under paragraph (a)(1) or (a)(2) of this section will provide the Administrator written notice of the issuance of such permit and, upon request, a copy of the permit.

(4) Special provisions. (i) A unit exempt under paragraph (b)(1) of this section shall comply with the restriction on fuel use and unit operating hours described in paragraph (b)(1) of this section during the control period in each year.

(ii) The Administrator will allocate NO\textsubscript{X} allowances to the unit under §§97.41(a) through (c) and 97.42(a) through (c). For each control period for which the unit is allocated NO\textsubscript{X} allowances under §§97.41(a) through (c) and 97.42(a) through (c):

(A) The owners and operators of the unit must specify a general account, in which the Administrator will record the NO\textsubscript{X} allowances; and

(B) After the Administrator records a NO\textsubscript{X} allowance allocations under §§97.41(a) through (c) and 97.42(a) through (c), the Administrator will deduct, from the general account under paragraph (b)(4)(ii)(A) of this section, NO\textsubscript{X} allowances that are allocated for the same or a prior control period as the NO\textsubscript{X} allowances allocated to the unit under §§97.41(a) through (c) and 97.42(a) through (c) and that equal the NO\textsubscript{X} emission limitation (in tons of NO\textsubscript{X}) on which the unit’s exemption under paragraph (b)(1) of this section is...
§ 97.5 Retired unit exemption.
(a) This section applies to any NOX Budget unit, other than a NOX Budget opt-in unit, that is permanently retired.
(b)(1) Any NOX Budget unit, other than a NOX Budget opt-in unit, that is permanently retired shall be exempt from the NOX Budget Trading Program, except for the provisions of this section, §97.2, §97.3, §97.4, §97.7, and subparts E, F, and G of this part.
(2) The exemption under paragraph (b)(1) of this section shall become effective the day on which the unit is permanently retired. Within 30 days of permanent retirement, the NOX authorized account representative (authorized in accordance with subpart B of this part) shall submit a statement to the permitting authority otherwise responsible for administering any NOX Budget permit for the unit. The NOX authorized account representative shall submit a copy of the statement to the Administrator. The statement shall state, in a format prescribed by the permitting authority, that the unit is permanently retired and will comply with the requirements of paragraph (c) of this section.
(3) After receipt of the notice under paragraph (b)(2) of this section, the permitting authority will amend any permit covering the source at which
the unit is located to add the provisions and requirements of the exemption under paragraphs (b)(1) and (c) of this section.

(c) Special provisions. (1) A unit exempt under this section shall not emit any nitrogen oxides, starting on the date that the exemption takes effect.

(2) The Administrator will allocate NOX allowances under subpart E of this part to a unit exempt under this section. For each control period for which the unit is allocated one or more NOX allowances, the owners and operators of the unit shall specify a general account, in which the Administrator will record such NOX allowances.

(3) For a period of 5 years from the date the records are created, the owners and operators of a unit exempt under this section shall retain at the source that includes the unit, records demonstrating that the unit is permanently retired. The 5-year period for keeping records may be extended for cause, at any time prior to the end of the period, in writing by the permitting authority or the Administrator. The owners and operators bear the burden of proof that the unit is permanently retired.

(4) The owners and operators and, to the extent applicable, the NOX authorized account representative of a unit exempt under this section shall comply with the requirements of the NOX Budget Trading Program concerning all periods for which the exemption is not in effect, even if such requirements arise, or must be complied with, after the exemption takes effect.

(5)(i) A unit exempt under this section and located at a source that is required, or but for this exemption would be required, to have a title V operating permit shall not resume operation unless the NOX authorized account representative of the source submits a complete NOX Budget permit application under §97.22 for the unit not less than 18 months (or such lesser time provided by the permitting authority) before the later of May 31, 2004 or the date on which the unit is to first resume operation.

(ii) The date on which the NOX authorized account representative submits a NOX Budget permit application under paragraph (c)(5) of this section;

(iii) The date on which the unit resumes operation, if the unit is not required to submit a NOX permit application.

(6) On the earlier of the following dates, a unit exempt under paragraph (b) of this section shall lose its exemption:

(i) The date on which the NOX authorized account representative submits a NOX Budget permit application under paragraph (c)(5) of this section;

(ii) The date on which the NOX authorized account representative is required under paragraph (c)(5) of this section to submit a NOX Budget permit application; or

(iii) The date on which the unit resumes operation, if the unit is not required to submit a NOX permit application.

(7) For the purpose of applying monitoring requirements under subpart H of this part, a unit that loses its exemption under this section shall be treated as a unit that commences operation or commercial operation on the first date on which the unit resumes operation.

(8) A unit that is exempt under this section is not eligible to be a NOX Budget opt-in unit under subpart I of this part.

[65 FR 2727, Jan. 18, 2000, as amended at 67 FR 21529, Apr. 30, 2002; 69 FR 21646, Apr. 21, 2004]

§97.6 Standard requirements.

(a) Permit requirements. (1) The NOX authorized account representative of each NOX Budget source required to have a federally enforceable permit and each NOX Budget unit required to have a federally enforceable permit at the source shall:

(i) Submit to the permitting authority a complete NOX Budget permit application under §97.22 for the unit not less than 18 months (or such lesser time provided by the permitting authority) before the later of May 31, 2004 or the date on which the unit resumes operation.

(ii) Submit in a timely manner any supplemental information that the permitting authority determines is necessary in order to review a NOX Budget permit.
(2) The owners and operators of each NO\textsubscript{X} Budget source required to have a federally enforceable permit and each NO\textsubscript{X} Budget unit required to have a federally enforceable permit at the source shall have a NO\textsubscript{X} Budget permit issued by the permitting authority and operate the unit in compliance with such NO\textsubscript{X} Budget permit.

(3) The owners and operators of a NO\textsubscript{X} Budget source that is not otherwise required to have a federally enforceable permit are not required to submit a NO\textsubscript{X} Budget permit application, and to have a NO\textsubscript{X} Budget permit, under subpart C of this part for such NO\textsubscript{X} Budget source.

(b) Monitoring requirements. (1) The owners and operators and, to the extent applicable, the NO\textsubscript{X} authorized account representative of each NO\textsubscript{X} Budget source and each NO\textsubscript{X} Budget unit at the source shall comply with the monitoring requirements of subpart H of this part.

(2) The emissions measurements recorded and reported in accordance with subpart H of this part shall be used to determine compliance by the unit with the NO\textsubscript{X} Budget emissions limitation under paragraph (c) of this section.

(c) Nitrogen oxides requirements. (1) The owners and operators of each NO\textsubscript{X} Budget source and each NO\textsubscript{X} Budget unit at the source shall hold NO\textsubscript{X} allowances available for compliance deductions under §97.54(a), (b), (e), or (f) as of the NO\textsubscript{X} allowance transfer deadline, in the unit’s compliance account and the source’s overdraft account in an amount not less than the total NO\textsubscript{X} emissions for the control period from the unit, as determined in accordance with subpart H of this part, plus any amount necessary to account for actual heat input under §97.42(e) for the control period or to account for excess emissions for a prior control period under §97.54(d) or to account for withdrawal from the NO\textsubscript{X} Budget Trading Program, or a change in regulatory status, of a NO\textsubscript{X} Budget opt-in unit under §97.86 or §97.87.

(2) Each ton of nitrogen oxides emitted in excess of the NO\textsubscript{X} Budget emissions limitation shall constitute a separate violation of this part, the Clean Air Act, and applicable State law.

(3) A NO\textsubscript{X} Budget unit shall be subject to the requirements under paragraph (c)(1) of this section starting on the later of May 31, 2004 or the date on which the unit commences operation.

(4) NO\textsubscript{X} allowances shall be held in, deducted from, or transferred among NO\textsubscript{X} Allowance Tracking System accounts in accordance with subparts E, F, G, and I of this part.

(5) A NO\textsubscript{X} allowance shall not be deducted, in order to comply with the requirements under paragraph (c)(1) of this section, for a control period in a year prior to the year for which the NO\textsubscript{X} allowance was allocated.

(6) A NO\textsubscript{X} allowance allocated by the Administrator under the NO\textsubscript{X} Budget Trading Program is a limited authorization to emit one ton of nitrogen oxides in accordance with the NO\textsubscript{X} Budget Trading Program. No provision of the NO\textsubscript{X} Budget Trading Program, the NO\textsubscript{X} Budget permit application, the NO\textsubscript{X} Budget permit, or an exemption under §97.4(b) or §97.5 and no provision of law shall be construed to limit the authority of the United States to terminate or limit such authorization.

(7) A NO\textsubscript{X} allowance allocated by the Administrator under the NO\textsubscript{X} Budget Trading Program does not constitute a property right.

(8) Upon recordation by the Administrator under subpart F or G of this part, every allocation, transfer, or deduction of a NO\textsubscript{X} allowance to or from a NO\textsubscript{X} Budget unit’s compliance account or the overdraft account of the source where the unit is located is incorporated automatically in any NO\textsubscript{X} Budget permit of the NO\textsubscript{X} Budget unit.

(d) Excess emissions requirements. (1) The owners and operators of a NO\textsubscript{X} Budget unit that has excess emissions in any control period shall:

(i) Surrender the NO\textsubscript{X} allowances required for deduction under §97.54(d)(1); and

(ii) Pay any fine, penalty, or assessment or comply with any other remedy imposed under §97.54(d)(3).

(e) Recordkeeping and reporting requirements. (1) Unless otherwise provided, the owners and operators of the NO\textsubscript{X} Budget source and each NO\textsubscript{X} Budget unit at the source shall keep on site
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at the source each of the following documents for a period of 5 years from the date the document is created. This period may be extended for cause, at any time prior to the end of 5 years, in writing by the permitting authority or the Administrator.

(i) The account certificate of representation under §97.13 for the NOX authorized account representative for the source and each NOX Budget unit at the source and all documents that demonstrate the truth of the statements in the account certificate of representation; provided that the certificate and documents shall be retained on site at the source beyond such 5-year period until such documents are superseded because of the submission of a new account certificate of representation under §97.13 changing the NOX authorized account representative.

(ii) All emissions monitoring information, in accordance with subpart H of this part; provided that to the extent that subpart H of this part provides for a 3-year period for record-keeping, the 3-year period shall apply.

(iii) Copies of all reports, compliance certifications, and other submissions and all records made or required under the NOX Budget Trading Program.

(iv) Copies of all documents used to complete a NOX Budget permit application and any other submission under the NOX Budget Trading Program or to demonstrate compliance with the requirements of the NOX Budget Trading Program.

(2) The NOX authorized account representative of a NOX Budget source and each NOX Budget unit at the source shall submit the reports and compliance certifications required under the NOX Budget Trading Program, including those under subpart D, H, or I of this part.

(f) Liability. (1) Any person who knowingly violates any requirement or prohibition of the NOX Budget Trading Program, a NOX Budget permit, or an exemption under §97.4(b) or §97.5 shall be subject to enforcement pursuant to applicable State or Federal law.

(3) No permit revision shall excuse any violation of the requirements of the NOX Budget Trading Program that occurs prior to the date that the revision takes effect.

(4) Each NOX Budget source and each NOX Budget unit shall meet the requirements of the NOX Budget Trading Program.

(5) Any provision of the NOX Budget Trading Program that applies to a NOX Budget source or the NOX authorized account representative of a NOX Budget source shall also apply to the owners and operators of such source and of the NOX Budget units at the source.

(6) Any provision of the NOX Budget Trading Program that applies to a NOX Budget unit or the NOX authorized account representative of a NOX budget unit shall also apply to the owners and operators of such unit. Except with regard to the requirements applicable to units with a common stack under subpart H of this part, the owners and operators and the NOX authorized account representative of one NOX Budget unit shall not be liable for any violation by any other NOX Budget unit of which they are not owners or operators or the NOX authorized account representative and that is located at a source of which they are not owners or operators or the NOX authorized account representative.

(g) Effect on other authorities. No provision of the NOX Budget Trading Program, a NOX Budget permit application, a NOX Budget permit, or an exemption under §97.4(b) or §97.5 shall be construed as exempting or excluding the owners and operators and, to the extent applicable, the NOX authorized account representative of a NOX Budget source or NOX Budget unit from compliance with any other provision of the applicable, approved State implementation plan, a federally enforceable permit, or the Clean Air Act.

[65 FR 2727, Jan. 18, 2000, as amended at 67 FR 21559, Apr. 30, 2002]

§ 97.7 Computation of time.

(a) Unless otherwise stated, any time period scheduled, under the NOX Budget Trading Program, to begin on the occurrence of an act or event shall

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§ 97.10 Authorization and responsibilities of NOx authorized account representative.

(a) Except as provided under §97.11, each NOx Budget source, including all NOx Budget units at the source, shall have one and only one NOx authorized account representative, with regard to all matters under the NOx Budget Trading Program concerning the source or any NOx Budget unit at the source.

(b) The NOx authorized account representative of the NOx Budget source shall be selected by an agreement binding on the owners and operators of the source and all NOx Budget units at the source.

(c) Upon receipt by the Administrator of a complete account certificate of representation under §97.13, the NOx authorized account representative of the source shall represent and, by his or her representations, actions, inactions, or submissions, legally bind each owner and operator of the NOx Budget source represented and each NOx Budget unit at the source in all matters pertaining to the NOx Budget Trading Program, not withstanding any agreement between the NOx authorized account representative and such owners and operators. The owners and operators shall be bound by any decision or order issued to the NOx authorized account representative by the permitting authority, the Administrator, or a court regarding the source or unit.

(d) No NOx Budget permit shall be issued, and no NOx Allowance Tracking System account shall be established for a NOx Budget unit at a source, until the Administrator has received a complete account certificate of representation under §97.13 for a NOx authorized account representative of the source and the NOx Budget units at the source.

(e) (1) Each submission under the NOx Budget Trading Program shall be submitted, signed, and certified by the NOx authorized account representative for each NOx Budget source on behalf of which the submission is made. Each such submission shall include the following certification statement by the NOx authorized account representative: ‘‘I am authorized to make this submission on behalf of the owners and operators of the NOx Budget sources or NOx Budget units for which the submission is made. I certify under penalty of law that I have personally examined, and am familiar with, the statements and information submitted in this document and all its attachments. Based on my inquiry of those individuals with primary responsibility for obtaining the information, I certify that the statements and information are to the best of my knowledge and belief true, accurate, and complete. I am aware that there are significant penalties for submitting false statements and information or omitting required statements and information, including the possibility of fine or imprisonment.’’

(2) The permitting authority and the Administrator will accept or act on a submission made on behalf of owner or operators of a NOx Budget source or a NOx Budget unit only if the submission has been made, signed, and certified in accordance with paragraph (e)(1) of this section.

§ 97.11 Alternate NOx authorized account representative.

(a) An account certificate of representation may designate one and only one alternate NOx authorized account representative who may act on behalf of the NOx authorized account representative. The agreement by which the alternate NOx authorized account representative is selected shall include a procedure for authorizing the
§ 97.12 Changing NOₓ authorized account representative and alternate NOₓ authorized account representative; changes in owners and operators.

(a) Changing NOₓ authorized account representative. The NOₓ authorized account representative may be changed at any time upon receipt by the Administrator of a superseding complete account certificate of representation under §97.13. Notwithstanding any such change, all representations, actions, inactions, and submissions by the previous NOₓ authorized account representative prior to the time and date when the Administrator receives the superseding account certificate of representation shall be binding on the new NOₓ authorized account representative and the owners and operators of the NOₓ Budget unit at the source.

(b) Changing alternate NOₓ authorized account representative. The alternate NOₓ authorized account representative may be changed at any time upon receipt by the Administrator of a superseding complete account certificate of representation under §97.13. Notwithstanding any such change, all representations, actions, inactions, and submissions by the previous alternate NOₓ authorized account representative prior to the time and date when the Administrator receives the superseding account certificate of representation shall be binding on the new alternate NOₓ authorized account representative and the owners and operators of the NOₓ Budget unit at the source.

§ 97.13 Account certificate of representation.

(a) A complete account certificate of representation for a NOₓ authorized account representative or an alternate NOₓ authorized account representative shall include the following elements in a format prescribed by the Administrator:

(1) Identification of the NOₓ Budget source and each NOₓ Budget unit at the source for which the account certificate of representation is submitted.

(2) The name, address, e-mail address (if any), telephone number, and facsimile transmission number (if any) of the NOₓ authorized account representative and any alternate NOₓ authorized account representative.

(3) A list of the owners and operators of the NOₓ Budget source and each NOₓ Budget unit at the source.

(4) The following certification statement by the NOₓ authorized account representative and any alternate NOₓ authorized account representative: "I
certify that I was selected as the NO\textsubscript{X} authorized account representative or alternate NO\textsubscript{X} authorized account representative, as applicable, by an agreement binding on the owners and operators of the NO\textsubscript{X} Budget source and each NO\textsubscript{X} Budget unit at the source. I certify that I have all the necessary authority to carry out my duties and responsibilities under the NO\textsubscript{X} Budget Trading Program on behalf of the owners and operators of the NO\textsubscript{X} Budget source and of each NO\textsubscript{X} Budget unit at the source and that each such owner and operator shall be fully bound by my representations, actions, inactions, or submissions and by any decision or order issued to me by the permitting authority, the Administrator, or a court regarding the source or unit.”

(5) The signature of the NO\textsubscript{X} authorized account representative and any alternate NO\textsubscript{X} authorized account representative and the dates signed.

(b) Unless otherwise required by the permitting authority or the Administrator, documents of agreement referred to in the account certificate of representation shall not be submitted to the permitting authority or the Administrator. Neither the permitting authority nor the Administrator shall be under any obligation to review or evaluate the sufficiency of such documents, if submitted.

§97.14 Objections concerning NO\textsubscript{X} authorized account representative.

(a) Once a complete account certificate of representation under §97.13 has been submitted and received, the permitting authority and the Administrator will rely on the account certificate of representation unless and until a superseding complete account certificate of representation under §97.13 is received by the Administrator.

(b) Except as provided in §97.12 (a) or (b), no objection or other communication submitted to the permitting authority or the Administrator concerning the authorization, or any representation, action, inaction, or submission of the NO\textsubscript{X} authorized account representative shall affect any representation, action, inaction, or submission of the NO\textsubscript{X} authorized account representative or the finality of any decision or order by the permitting authority or the Administrator under the NO\textsubscript{X} Budget Trading Program.

(c) Neither the permitting authority nor the Administrator will adjudicate any private legal dispute concerning the authorization or any representation, action, inaction, or submission of any NO\textsubscript{X} authorized account representative, including private legal disputes concerning the proceeds of NO\textsubscript{X} allowance transfers.

Subpart C—Permits

§97.20 General NO\textsubscript{X} Budget Trading Program permit requirements.

(a) For each NO\textsubscript{X} Budget source required to have a federally enforceable permit, such permit shall include a NO\textsubscript{X} Budget permit administered by the permitting authority for the federally enforceable permit.

(1) For NO\textsubscript{X} Budget sources required to have a title V operating permit, the NO\textsubscript{X} Budget portion of the title V permit shall be administered in accordance with the permitting authority’s title V operating permits regulations promulgated under part 70 or 71 of this chapter, except as provided otherwise by this subpart or subpart I of this part.

(2) For NO\textsubscript{X} Budget sources required to have a non-title V permit, the NO\textsubscript{X} Budget portion of the non-title V permit shall be administered in accordance with the permitting authority’s regulations promulgated to administer non-title V permits, except as provided otherwise by this subpart or subpart I of this part.

(b) Each NO\textsubscript{X} Budget permit shall contain all applicable NO\textsubscript{X} Budget Trading Program requirements and shall be a complete and segregable portion of the permit under paragraph (a) of this section.

§97.21 Submission of NO\textsubscript{X} Budget permit applications.

(a) Duty to apply. The NO\textsubscript{X} authorized account representative of any NO\textsubscript{X} Budget source required to have a federally enforceable permit shall submit to the permitting authority a complete NO\textsubscript{X} Budget permit application under §97.22 by the applicable deadline in paragraph (b) of this section.
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(b)(1) For NO\textsubscript{X} Budget sources required to have a title V operating permit:

(i) For any source, with one or more NO\textsubscript{X} Budget units under §97.4(a) that commence operation on or after January 1, 2001, the NO\textsubscript{X} authorized account representative shall submit a complete NO\textsubscript{X} Budget permit application under §97.22 covering such NO\textsubscript{X} Budget units to the permitting authority at least 18 months (or such lesser time provided by the permitting authority) before May 31, 2004.

(ii) For any source, with any NO\textsubscript{X} Budget unit under §97.4(a) that commences operation on or after January 1, 2001, the NO\textsubscript{X} authorized account representative shall submit a complete NO\textsubscript{X} Budget permit application under §97.22 covering such NO\textsubscript{X} Budget unit to the permitting authority at least 18 months (or such lesser time provided by the permitting authority) before May 31, 2004.

(2) For NO\textsubscript{X} Budget sources required to have a non-title V permit, the NO\textsubscript{X} Budget source covering the NO\textsubscript{X} Budget units at the source in accordance with the permitting authority's title V operating permits regulations addressing operating permit renewal.

(ii) For any source, with any NO\textsubscript{X} Budget unit under §97.4(a) that commences operation on or after January 1, 2001, the NO\textsubscript{X} authorized account representative shall submit a complete NO\textsubscript{X} Budget permit application under §97.22 covering such NO\textsubscript{X} Budget units to the permitting authority at least 18 months (or such lesser time provided by the permitting authority) before the later of May 31, 2004 or the date on which the NO\textsubscript{X} Budget unit commences operation.

(ii) For any source, with any NO\textsubscript{X} Budget unit under §97.4(a) that commences operation on or after January 1, 2001, the NO\textsubscript{X} authorized account representative shall submit a complete NO\textsubscript{X} Budget permit application under §97.22 covering such NO\textsubscript{X} Budget units to the permitting authority at least 18 months (or such lesser time provided by the permitting authority) before May 31, 2004.

(ii) For any source, with any NO\textsubscript{X} Budget unit under §97.4(a) that commences operation on or after January 1, 2001, the NO\textsubscript{X} authorized account representative shall submit a complete NO\textsubscript{X} Budget permit application under §97.22 covering such NO\textsubscript{X} Budget unit to the permitting authority at least 18 months (or such lesser time provided by the permitting authority) before the later of May 31, 2004 or the date on which the NO\textsubscript{X} Budget unit commences operation.

(c) Duty to reapply. (1) For a NO\textsubscript{X} Budget source required to have a title V operating permit, the NO\textsubscript{X} authorized account representative shall submit a complete NO\textsubscript{X} Budget permit application under §97.22 for the NO\textsubscript{X} Budget source covering the NO\textsubscript{X} Budget units at the source in accordance with the permitting authority's title V operating permits regulations addressing operating permit renewal.

(2) For a NO\textsubscript{X} Budget permit application under §97.22 for the NO\textsubscript{X} Budget source covering the NO\textsubscript{X} Budget units at the source in accordance with the permitting authority's non-title V permits regulations addressing permit renewal.

[65 FR 2727, Jan. 18, 2000, as amended at 67 FR 21529, Apr. 30, 2002]

§ 97.22 Information requirements for NO\textsubscript{X} Budget permit applications.

A complete NO\textsubscript{X} Budget permit application shall include the following elements concerning the NO\textsubscript{X} Budget source for which the application is submitted, in a format prescribed by the permitting authority:

(a) Identification of the NO\textsubscript{X} Budget source, including plant name and the ORIS (Office of Regulatory Information Systems) or facility code assigned to the source by the Energy Information Administration, if applicable;

(b) Identification of each NO\textsubscript{X} Budget unit at the NO\textsubscript{X} Budget source and whether it is a NO\textsubscript{X} Budget unit under 40 CFR 97.4(a) or under subpart I of this part;

(c) The standard requirements under §97.6; and

(d) For each NO\textsubscript{X} Budget opt-in unit at the NO\textsubscript{X} Budget source, the following certification statements by the NO\textsubscript{X} authorized account representative:

(1) “I certify that each unit for which this permit application is submitted under subpart I of this part is not a NO\textsubscript{X} Budget unit under 40 CFR 97.4(a) and is not covered by an exemption under 40 CFR 97.4(b) or 97.5 that is in effect.”

(2) If the application is for an initial NO\textsubscript{X} Budget opt-in permit, “I certify that each unit for which this permit application is submitted under subpart I of 40 CFR part 97 is operating, as that term is defined under 40 CFR 97.2.”
§ 97.23 NOx Budget permit contents.

(a) Each NOx Budget permit will contain, in a format prescribed by the permitting authority, all elements required for a complete NOx Budget permit application under §97.22.

(b) Each NOx Budget permit is deemed to incorporate automatically the definitions of terms under §97.2 and, upon recordation by the Administrator under subpart F or G of this part, every allocation, transfer, or deduction of a NOx allowance to or from the compliance accounts of the NOx Budget units covered by the permit or the overdraft account of the NOx Budget source covered by the permit.

§ 97.24 NOx Budget permit revisions.

(a) For a NOx Budget source with a title V operating permit, except as provided in §97.23(b), the permitting authority will revise the NOx Budget permit, as necessary, in accordance with the permitting authority's title V operating permits regulations addressing permit revisions.

(b) For a NOx Budget source with a non-title V permit, except as provided in §97.23(b), the permitting authority will revise the NOx Budget permit, as necessary, in accordance with the permitting authority's non-title V permits regulations addressing permit revisions.

Subpart D—Compliance Certification

§ 97.30 Compliance certification report.

(a) Applicability and deadline. For each control period in which one or more NOx Budget units at a source are subject to the NOx Budget emissions limitation, the NOx authorized account representative of the source shall submit to the permitting authority and the Administrator by November 30 of that year, a compliance certification report for each source covering all such units.

(b) Contents of report. The NOx authorized account representative shall include in the compliance certification report under paragraph (a) of this section the following elements, in a format prescribed by the Administrator, concerning each unit at the source and subject to the NOx Budget emissions limitation for the control period covered by the report:

1. Identification of each NOx Budget unit;
2. At the NOx authorized account representative's option, the serial numbers of the NOx allowances that are to be deducted from each unit's compliance account under §97.54 for the control period;
3. At the NOx authorized account representative's option, for units sharing a common stack and having NOx emissions that are not monitored separately or apportioned in accordance with subpart H of this part, the percentage of allowances that is to be deducted from each unit's compliance account under §97.54(e); and
4. The compliance certification under paragraph (c) of this section.

(c) Compliance certification. In the compliance certification report under paragraph (a) of this section, the NOx authorized account representative shall certify, based on reasonable inquiry of those persons with primary responsibility for operating the source and the NOx Budget units at the source in compliance with the NOx Budget Trading Program, whether each NOx Budget unit for which the compliance certification is submitted was operated during the calendar year covered by the report in compliance with the requirements of the NOx Budget Trading Program applicable to the unit, including:

1. Whether the unit was operated in compliance with the NOx Budget emissions limitation;
2. Whether the monitoring plan that governs the unit has been maintained to reflect the actual operation and monitoring of the unit and contains all information necessary to attribute NOx emissions to the unit, in accordance with subpart H of this part;
3. Whether all the NOx emissions from the unit, or a group of units (including the unit) using a common stack, were monitored or accounted for through the missing data procedures and reported in the quarterly monitoring reports, including whether conditional data were reported in the quarterly reports in accordance with...
subpart H of this part. If conditional data were reported, the owner or operator shall indicate whether the status of all conditional data has been resolved and all necessary quarterly report resubmissions have been made;

(4) Whether the facts that form the basis for certification under subpart H of this part of each monitor at the unit or a group of units (including the unit) using a common stack, or for using an excepted monitoring method or alternative monitoring method approved under subpart H of this part, if any, have changed; and

(5) If a change is required to be reported under paragraph (c)(4) of this section, specify the nature of the change, the reason for the change, when the change occurred, and how the unit’s compliance status was determined subsequent to the change, including what method was used to determine emissions when a change mandated the need for monitor recertification.

§ 97.41 Timing requirements for NOX allowance allocations.

(a) The NOX allowance allocations, determined in accordance with §§97.42(a) through (c), for the control periods in 2004 through 2007 are set forth in appendices A and B of this part.

(b) By April 1, 2005, the Administrator will determine by order the NOX allowance allocations, in accordance with §§97.42 (a) through (c), for the control periods in 2008 through 2012.

(c) By April 1, 2010, by April 1 of 2015, and thereafter by April 1 of the year that is 5 years after the last year for which NOX allowances allocations are determined, the Administrator will determine by order the NOX allowance allocations, in accordance with §§97.42(a) through (c), for the control periods in the years that are 3, 4, 5, 6, and 7 years after the applicable deadline under this paragraph (c).

(d) By April 1, 2004 and April 1 of each year thereafter, the Administrator will determine by order the NOX allowance allocations, in accordance with §97.42(d), for the control period in the year of the applicable deadline under this paragraph (d).

(e) The Administrator will make available to the public each determination of NOX allowance allocations under paragraph (b), (c), or (d) of this section and will provide an opportunity for submission of objections to the determination. Objections shall be limited to addressing whether the determination is in accordance with §97.42. Based on any such objections, the Administrator will adjust each determination to the extent necessary to ensure that it is in accordance with §97.42.

[65 FR 2727, Jan. 18, 2000, as amended at 69 FR 21646, Apr. 21, 2004]

§ 97.40 Trading program budget.

In accordance with §§97.31 and 97.42, the Administrator will allocate to the NOX Budget units under §97.4(a) in a State, for each control period specified in §97.41, a total number of NOX allowances equal to the trading budget for the State, as set forth in appendix C of this part, less the sum of the NOX emission limitations (in tons) for each unit exempt under §97.4(b) that is not allocated any NOX allowances under §97.42 (b) or (c) for the control period and whose NOX emission limitation (in tons of NOX) is not included in the amount calculated under §97.42(d)(5)(ii)(B) for the control period.

[65 FR 2727, Jan. 18, 2000, as amended at 67 FR 21529, Apr. 30, 2002]
§ 97.42 NO\textsubscript{X} allowance allocations.

(a)(1) The heat input (in mmBtu) used for calculating NO\textsubscript{X} allowance allocations for each NO\textsubscript{X} Budget unit under §97.4(a) will be:

(i) For a NO\textsubscript{X} allowance allocation under §97.41(a):

(A) For a unit under §97.4(a)(1), the average of the two highest amounts of the unit's heat input for the control periods in 1995 through 1998; or

(B) For a unit under §97.4(a)(2), the control period in 1995 or, if the Administrator determines that reasonably reliable data are available for control periods in 1996 through 1998, the average of the two highest amounts of the unit's heat input for the control periods in 1995 through 1998.

(ii) For a NO\textsubscript{X} allowance allocation under §97.41(b), the unit's average heat input for the control periods in 2002 through 2004.

(iii) For a NO\textsubscript{X} allowance allocation under §97.41(c), the unit's average heat input for the control period in the years that are 4, 5, 6, 7, and 8 years before the first year for which the allocation is being calculated.

(2) The unit's heat input for the control period in each year specified under paragraph (a)(1) of this section will be determined in accordance with part 75 of this chapter. Notwithstanding the first sentence of this paragraph (a)(2):

(i) For a NO\textsubscript{X} allowance allocation under §97.41(a), such heat input will be determined using the best available data reported to the Administrator for the unit if the unit was not otherwise subject to the requirements of part 75 of this chapter for the control period.

(ii) For a NO\textsubscript{X} allowance allocation under §97.41(b) or (c) for a unit exempt under §97.4(b), such heat input shall be treated as zero if the unit is exempt under §97.4(b) during the control period.

(b) For each group of control periods specified in §97.41(a) through (c), the Administrator will allocate to all NO\textsubscript{X} Budget units in a given State under §97.4(a)(1) that commenced operation before May 1, 1997 for allocations under §97.41(a), May 1, 2003 for allocations under §97.41(b), and May 1 of the year 5 years before the first year for which the allocation under §97.41(c) is being calculated, a total number of NO\textsubscript{X} allowances equal to 95 percent of the portion of the State's trading program budget under §97.40 covering such units. The Administrator will allocate in accordance with the following procedures:

(1) The Administrator will allocate NO\textsubscript{X} allowances to each NO\textsubscript{X} Budget unit under §97.4(a)(1) for each control period in an amount equaling 0.15 lb/mmBtu multiplied by the heat input determined under paragraph (a) of this section, divided by 2,000 lb/ton, and rounded to the nearest whole number of NO\textsubscript{X} allowances as appropriate.

(2) If the initial total number of NO\textsubscript{X} allowances allocated to all NO\textsubscript{X} Budget units under §97.4(a)(1) in the State for a control period under paragraph (b)(1) of this section does not equal 95 percent of the portion of the State's trading program budget under §97.40 covering such units, the Administrator will adjust the total number of NO\textsubscript{X} allowances allocated to all such NO\textsubscript{X} Budget units for the control period under paragraph (b)(1) of this section so that the total number of NO\textsubscript{X} allowances allocated equals 95 percent of such portion of the State's trading program budget. This adjustment will be made by: multiplying each unit's allocation by 95 percent of such portion of the State's trading program budget; dividing by the total number of NO\textsubscript{X} allowances allocated under paragraph (b)(1) of this section for the control period; and rounding to the nearest whole number of NO\textsubscript{X} allowances as appropriate.

(c) For each group of control periods specified in §97.41(a) through (c), the Administrator will allocate to all NO\textsubscript{X} Budget units in a given State under §97.4(a)(2) that commenced operation before May 1, 1997 for allocations under §97.41(a), May 1, 2003 for allocations under §97.41(b), and May 1 of the year 5 years before the first year for which the allocation under §97.41(c) is being calculated, a total number of NO\textsubscript{X} allowances equal to 95 percent of the portion of the State's trading program budget under §97.40 covering such units. The Administrator will allocate in accordance with the following procedures:

(1) The Administrator will allocate NO\textsubscript{X} allowances to each NO\textsubscript{X} Budget...
unit under §97.4(a)(2) for each control period in an amount equaling 0.17 lb/mmBtu multiplied by the heat input determined under paragraph (a) of this section, divided by 2,000 lb/ton, and rounded to the nearest whole number of NOx allowances as appropriate.

(2) If the initial total number of NOx allowances allocated to all NOx Budget units under §97.4(a)(2) in the State for a control period under paragraph (c)(1) of this section does not equal 95 percent of the portion of the State’s trading program budget under §97.40 covering such units, the Administrator will adjust the total number of NOx allowances allocated to all such NOx Budget units for the control period under paragraph (a)(1) of this section so that the total number of NOx allowances allocated equals 95 percent of the portion of the State’s trading program budget under §97.40 covering such units. This adjustment will be made by: multiplying each unit’s allocation by 95 percent of the portion of the State’s trading program budget under §97.40 covering such units; dividing by the total number of NOx allowances allocated under paragraph (c)(1) of this section for the control period; and rounding to the nearest whole number of NOx allowances as appropriate.

(4) In a NOx allowance allocation request under paragraph (d)(2) of this section, the NOx authorized account representative for a NOx Budget unit under §97.4(a)(1) may request for the control period NOx allowances in an amount that does not exceed the lesser of:

(i) 0.15 lb/mmBtu multiplied by the unit’s maximum design heat input, multiplied by the lesser of 3,672 hours or the number of hours remaining in the control period starting with the day in the control period on which the unit commences operation or is projected to commence operation, divided by 2,000 lb/ton, and rounded to the nearest whole number of NOx allowances as appropriate; or

(ii) The unit’s most stringent State or Federal NOx emission limitation multiplied by the unit’s maximum design heat input, multiplied by the lesser of 3,672 hours or the number of hours remaining in the control period starting with the day in the control period on which the unit commences operation or is projected to commence operation, divided by 2,000 lb/ton, and rounded to the nearest whole number of NOx allowances as appropriate; or

(2) The NOx authorized account representative of a NOx Budget unit specified in this paragraph (d) may submit to the Administrator a request, in a format specified by the Administrator, to be allocated NOx allowances for the control period. The NOx allowance allocation request must be received by the Administrator on or after the date on which the State permitting authority issues a permit to construct the unit and by January 1 before the control period for which NOx allowances are requested.

(3) In a NOx allowance allocation request under paragraph (d)(2) of this section, the NOx authorized account representative for a NOx Budget unit under §97.4(a)(1) may request for the control period NOx allowances in an amount that does not exceed the lesser of:

(i) 0.15 lb/mmBtu multiplied by the unit’s maximum design heat input, multiplied by the lesser of 3,672 hours or the number of hours remaining in the control period starting with the day in the control period on which the unit commences operation or is projected to commence operation, divided by 2,000 lb/ton, and rounded to the nearest whole number of NOx allowances as appropriate; or

(ii) The unit’s most stringent State or Federal NOx emission limitation multiplied by the unit’s maximum design heat input, multiplied by the lesser of 3,672 hours or the number of hours remaining in the control period starting with the day in the control period on which the unit commences operation or is projected to commence operation, divided by 2,000 lb/ton, and rounded to the nearest whole number of NOx allowances as appropriate; or
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unit commences operation or is projected to commence operation, divided by 2,000 lb/ton, and rounded to the nearest whole number of NOX allowances as appropriate; or

(ii) The unit’s most stringent State or Federal NOX emission limitation multiplied by the unit’s maximum design heat input, multiplied by the lesser of 3,672 hours or the number of hours remaining in the control period starting with the day in the control period on which the unit commences operation or is projected to commence operation, divided by 2,000 lb/ton, and rounded to the nearest whole number of NOX allowances as appropriate.

(5) The Administrator will review each NOX allowance allocation request submitted in accordance with paragraph (d)(2) of this section and will allocate NOX allowances pursuant to such request as follows:

(i) Upon receipt of the NOX allowance allocation request, the Administrator will make any necessary adjustments to the request to ensure that the requirements of paragraphs (d) introductory text, (d)(2), (d)(3), and (d)(4) are met.

(ii) The Administrator will determine the following amounts:

(A) The sum of the NOX allowances requested (as adjusted under paragraph (d)(5)(i) of this section) in all NOX allowance allocation requests under paragraph (d)(2) of this section for the control period; and

(B) For units exempt under §97.4(b) in the State that commenced operation, or are projected to commence operation, on or after May 1, 1997 (for control periods under §97.41(a)); May 1, 2003, (for control periods under §97.41(b)); and May 1 of the year 5 years before beginning of the group of 5 years that includes the control period (for control periods under §97.41(c)), the sum of the NOX emission limitations (in tons of NOX) on which each unit’s exemption under §97.4(b) is based.

(iii) If the number of NOX allowances in the allocation set-aside for the control period less the amount under paragraph (d)(5)(i)(B) of this section is not less than the amount determined under paragraph (d)(5)(i)(A) of this section, the Administrator will allocate the amount of the NOX allowances requested (as adjusted under paragraph (d)(5)(i) of this section) to the NOX Budget unit for which the allocation request was submitted.

(iv) If the number of NOX allowances in the allocation set-aside for the control period less the amount under paragraph (d)(5)(i)(B) of this section is less than the amount determined under paragraph (d)(5)(i)(A) of this section, the Administrator will allocate, to the NOX Budget unit for which the allocation request was submitted, the amount of NOX allowances requested (as adjusted under paragraph (d)(5)(i) of this section) multiplied by the number of NOX allowances in the allocation set-aside for the control period less the amount determined under paragraph (d)(5)(i)(A) of this section, and rounded to the nearest whole number of NOX allowances as appropriate.

(e)(1) For a NOX Budget unit that is allocated NOX allowances under paragraph (d) of this section for a control period, the Administrator will deduct NOX allowances under §97.54(b), (e), or (f) to account for the actual heat input of the unit during the control period. The Administrator will calculate the number of NOX allowances to be deducted to account for the unit’s actual heat input using the following formulas and rounding to the nearest whole number of NOX allowance as appropriate, provided that the number of NOX allowances to be deducted shall be zero if the number calculated is less than zero:

NOX allowances deducted for actual heat input for a unit under §97.4(a)(1) = Unit’s NOX allowances allocated for control period - (Unit’s actual control period heat input × the lesser of 0.15 lb/mmBtu the unit’s most stringent State or Federal emission limitation × 2,000 lb/ton); and NOX allowances deducted for actual heat input for a unit under §97.4(a)(2) = Unit’s NOX allowances allocated for control period - (Unit’s actual control period heat input × the lesser of 0.17 lb/mmBtu the unit’s most stringent State or Federal emission limitation × 2,000 lb/ton)

Where:

\[ \text{Unit’s NOX allowances allocated for control period} \]
§ 97.43 Compliance Supplement Pool.

(a) For any NOx Budget unit that reduces its NOx emission rate in the 2001 through 2003 control period, the owners and operators may request early reduction credits in accordance with the following requirements:

(1) Each NOx Budget unit for which the owners and operators intend to request, or request, any early reduction credits in accordance with paragraph

(b) The Administrator will transfer any NOx allowances deducted under paragraph (e)(1) of this section to the allocation set-aside for the control period which they were allocated.

(2) The Administrator will transfer any NOx allowances deducted under paragraph (e), (e), or (f) for a control period, the Administrator will determine whether any NOx allowances remain in the allocation set-aside for the control period. The Administrator will allocate any such NOx allowances to the NOx Budget units in the State using the following formula and rounding to the nearest whole number of NOx allowances as appropriate:

Unit’s share of NOx allowances remaining in allocation set-aside = Total NOx allowances remaining in allocation set-aside ÷ (Unit’s NOx allowance allocation + State’s trading program budget excluding allocation set-aside)

Where:

“Total NOx allowances remaining in allocation set-aside” is the total number of NOx allowances remaining in the allocation set-aside for the control period;

“Unit’s NOx allowance allocation” is the number of NOx allowances allocated under paragraph (b) or (c) of this section to the unit for the control period to which the allocation set-aside applies; and

“State’s trading program budget excluding allocation set-aside” is the State’s trading program budget under §97.40 for the control period to which the allocation set-aside applies multiplied by 95 percent, rounded to the nearest whole number of NOx allowances as appropriate.

(g) If the Administrator determines that NOx allowances were allocated under paragraph (b), (c), or (d) of this section for a control period and the recipient of the allocation is not actually a NOx Budget unit under §97.4(a), the Administrator will notify the NOx authorized account representative and then will act in accordance with the following procedures:

(1)(i) The Administrator will not record such NOx allowances for the control period in an account under §97.53;

(ii) If the Administrator already recorded such NOx allowances for the control period in an account under §97.53 and if the Administrator makes such determination before making all deductions pursuant to §97.54 (except deductions pursuant to §97.54(d)(2)) for the control period, then the Administrator will deduct from the account NOx allowances equal in number to and allocated for the same or a prior control period as the NOx allowances allocated to such recipient for the control period. The NOx authorized account representative shall ensure that the account contains the NOx allowances necessary for completion of such deduction. If account does not contain the necessary NOx allowances, the Administrator will deduct the required number of NOx allowances, regardless of the control period for which they were allocated, whenever NOx allowances are recorded in the account; or

(iii) If the Administrator already recorded such NOx allowances for the control period in an account under §97.53 and if the Administrator makes such determination after making all deductions pursuant to §97.54 (except deductions pursuant to §97.54(d)(2)) for the control period, then the Administrator will apply paragraph (g)(1)(ii) of this section to any subsequent control period for which NOx allowances were allocated to such recipient.

(2) The Administrator will transfer the NOx allowances that are not recorded, or that are deducted, pursuant to paragraph (g)(1) of this section to an allocation set-aside for the State in which such source is located.

[65 FR 2727, Jan. 18, 2000, as amended at 67 FR 21529, Apr. 30, 2002; 69 FR 21646, Apr. 21, 2004]

Environmental Protection Agency

“Unit’s NOx allowances allocated for control period” is the number of NOx allowances allocated to the unit for the control period under paragraph (d) of this section; and

“Unit’s actual control period heat input” is the heat input (in mmBtu) of the unit during the control period.
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(a)(4) of this section shall monitor and report NO\textsubscript{X} emissions in accordance with subpart H of this part starting in the 2000 control period and for each control period for which such early reduction credits are requested. The unit’s percent monitor data availability shall not be less than 90 percent during the 2000 control period, and the unit must be in full compliance with any applicable State or Federal NO\textsubscript{X} emission control requirements during 2000 through 2002.

(2) NO\textsubscript{X} emission rate and heat input under paragraphs (a)(3) and (4) of this section shall be determined in accordance with subpart H of this part.

(3) Each NO\textsubscript{X} Budget unit for which the owners and operators intend to request, or request, any early reduction credits under paragraph (a)(4) of this section shall reduce its NO\textsubscript{X} emission rate, for each control period for which early reduction credits are requested, to less than both 0.25 lb/mm\textsubscript{Btu} and 80 percent of the unit’s NO\textsubscript{X} emission rate in the 2000 control period.

(4) The NO\textsubscript{X} authorized account representative of a NO\textsubscript{X} Budget unit that meets the requirements of paragraphs (a)(1) and (3) of this section may submit to the Administrator a request for early reduction credits in an amount equal to the amount of banked allowances under the Ozone Transport Commission NO\textsubscript{X} Budget Program that were allocated for the control period in 2001 through 2003 and are held by the unit, in accordance with the Ozone Transport Commission NO\textsubscript{X} Budget Program, as of the date of submission of the request. During the entire control period in 2001 through 2003 for which the allowances were allocated, the unit must have monitored and reported NO\textsubscript{X} emissions in accordance with part 75 (except for subpart H) of this chapter and the Guidance for Implementation of Emission Monitoring Requirements for the NO\textsubscript{X} Budget Program (January 28, 1997).

(2) The early reduction credit request under paragraph (b)(1) must be submitted, in a format specified by the Administrator, by February 1, 2004.

(3) The NO\textsubscript{X} authorized account representative of the unit shall not submit a request for early reduction credits under paragraph (b)(1) of this section for banked allowances under the Ozone Transport Commission NO\textsubscript{X} Budget Program that were allocated for any control period during which the unit made NO\textsubscript{X} emission reductions for which he or she submits a request for early reduction credits under paragraph (a) of this section for the unit.

(c) The Administrator will review each early reduction credit request submitted in accordance with paragraphs (a) or (b) of this section and will allocate NO\textsubscript{X} allowances to NO\textsubscript{X} Budget units in a given State and covered by such request as follows:

(1) Upon receipt of each early reduction credit request, the Administrator will make available to the public a statement of the total number of early reduction credits requested meets the requirements of paragraph (a) or (b) of this section.

(2) After February 1, 2004, the Administrator will make any necessary adjustments to the request to ensure that the amount of the early reduction credits requested meets the requirements of paragraph (a) or (b) of this section.

(3) If the State’s compliance supplement pool set forth in appendix D of this part has a number of NO\textsubscript{X} allowances not less than the amount of early...
reduction credits in all early reduction credit requests under paragraph (a) or (b) of this section for 2001 through 2003 (as adjusted under paragraph (c)(1) of this section) submitted by February 1, 2004, the Administrator will allocate to each NOX Budget unit covered by such requests one allowance for each early reduction credit requested (as adjusted under paragraph (c)(1) of this section).

(4) If the State’s compliance supplement pool set forth in appendix D of this part has a smaller number of NOX allowances than the amount of early reduction credits in all early reduction credit requests under paragraph (a) or (b) of this section for 2001 through 2003 (as adjusted under paragraph (c)(1) of this section) submitted by February 1, 2004, the Administrator will allocate NOX allowances to each NOX Budget unit covered by such requests according to the following formula and rounding to the nearest whole number of NOX allowances as appropriate:

\[
\text{Unit's allocation for early reduction credits} = \frac{\text{Unit's adjusted early reduction credits} \times (\text{State's compliance supplement pool})}{\text{Total adjusted early reduction credits for all units}}
\]

Where:

- "Unit's allocation for early reduction credits" is the number of NOX allowances allocated to the unit for early reduction credits.
- "Unit's adjusted early reduction credits" is the amount of early reduction credits requested for the unit for 2001 and 2002 in early reduction credit requests under paragraph (a) or (b) of this section, as adjusted under paragraph (c)(1) of this section.
- "State's compliance supplement pool" is the number of NOX allowances in the State's compliance supplement pool set forth in appendix D of this part.
- "Total adjusted early reduction credits for all units" is the amount of early reduction credits requested for all units for 2001 and 2002 in early reduction credit requests under paragraph (a) or (b) of this section, as adjusted under paragraph (c)(1) of this section.

(5) By April 1, 2004, the Administrator will determine by order the allocations under paragraph (c)(3) or (4) of this section. The Administrator will make available to the public each determination of NOX allowance allocations and will provide an opportunity for submission of objections to the determination. Objections shall be limited to addressing whether the determination is in accordance with paragraph (c)(1), (3), or (4) of this section. Based on any such objections, the Administrator will adjust each determination to the extent necessary to ensure that it is in accordance with paragraph (c)(1), (3), or (4) of this section.

(6) By May 1, 2004, the Administrator will record the allocations under paragraph (c)(3) or (4) of this section.

(7) NOX allowances recorded under paragraph (c)(6) of this section may be deducted for compliance under §97.54 for the control period in 2004 or 2005. Notwithstanding §97.55(a), the Administrator will deduct as retired any NOX allowance that is recorded under paragraph (c)(6) of this section and that is not deducted for compliance under §97.54 for the control period in 2003 or 2004.

[65 FR 2727, Jan. 18, 2000, as amended at 67 FR 21529, Apr. 30, 2002; 69 FR 21646, Apr. 21, 2004]

Subpart F—NOX Allowance Tracking System

§97.50 NOX Allowance Tracking System accounts.

(a) Nature and function of compliance accounts and overdraft accounts. Consistent with §97.51(a), the Administrator will establish one compliance account for each NOX Budget unit and one overdraft account for each source with two or more NOX Budget units. Allocations of NOX allowances pursuant to subpart E of this part or §97.88, and deductions or transfers of NOX allowances pursuant to §97.31, §96.54, §96.56, subpart G of this part, or subpart I of this part will be recorded in compliance accounts or overdraft accounts in accordance with this subpart.

(b) Nature and function of general accounts. Consistent with §97.51(b), the Administrator will establish, upon request, a general account for any person. Allocations of NOX allowances pursuant to §97.4(b)(4)(ii) or §97.5(c)(2) and transfers of allowances pursuant to subpart G of this part will be recorded in general accounts in accordance with this subpart.
§ 97.51 Establishment of accounts.

(a) Compliance accounts and overdraft accounts. Upon receipt of a complete account certificate of representation under §97.13, the Administrator will establish:

(1) A compliance account for each NOX Budget unit for which the account certificate of representation was submitted; and

(2) An overdraft account for each source for which the account certificate of representation was submitted and that has two or more NOX Budget units.

(b) General accounts—(1) Application for general account. (i) Any person may apply to open a general account for the purpose of holding and transferring allowances. An application for a general account may designate one and only one NOX authorized account representative and one and only one alternate NOX authorized account representative who may act on behalf of the NOX authorized account representative. The agreement by which the alternate NOX authorized account representative is selected shall include a procedure for authorizing the alternate NOX authorized account representative to act in lieu of the NOX authorized account representative. The application for a general account shall be submitted to the Administrator and shall include the following elements in a format prescribed by the Administrator:

(A) Name, mailing address, e-mail address (if any), telephone number, and facsimile transmission number (if any) of the NOX authorized account representative and any alternate NOX authorized account representative;

(B) At the option of the NOX authorized account representative, organization name and type of organization;

(C) A list of all persons subject to a binding agreement for the NOX authorized account representative and any alternate NOX authorized account representative to represent their ownership interest with respect to the allowances held in the general account;

(D) The following certification statement by the NOX authorized account representative and any alternate NOX authorized account representative: ‘‘I certify that I was selected as the NOX authorized account representative or the NOX alternate authorized account representative, as applicable, by an agreement that is binding on all persons who have an ownership interest with respect to NOX allowances held in the general account. I certify that I have all the necessary authority to carry out my duties and responsibilities under the NOX Budget Trading Program on behalf of such persons and that each such person shall be fully bound by my representations, actions, inactions, or submissions and by any order or decision issued to me by the Administrator or a court regarding the general account.”

(E) The signature of the NOX authorized account representative and any alternate NOX authorized account representative and the dates signed.

(ii) Unless otherwise required by the permitting authority or the Administrator, documents of agreement referred to in the application for a general account shall not be submitted to the permitting authority or the Administrator. Neither the permitting authority nor the Administrator shall be under any obligation to review or evaluate the sufficiency of such documents, if submitted.

(2) Authorization of NOX authorized account representative. Upon receipt by the Administrator of a complete application for a general account under paragraph (b)(1) of this section:

(i) The Administrator will establish a general account for the person or persons for whom the application is submitted.

(ii) The NOX authorized account representative and any alternate NOX authorized account representative for the general account shall represent and, by his or her representations, actions, inactions, or submissions, legally bind each person who has an ownership interest with respect to NOX allowances held in the general account and that each such person shall be fully bound by any order or decision issued to the NOX authorized account representative and any alternate NOX authorized account representative and such person. Any such person shall be bound by any order or decision issued to the NOX authorized account representative and any alternate NOX authorized account representative and such person.
account representative or any alternate NO\textsubscript{X} authorized account representative by the Administrator or a court regarding the general account.

(iii) Any representation, action, inaction, or submission by any alternate NO\textsubscript{X} authorized account representative shall be deemed to be a representation, action, inaction, or submission by the NO\textsubscript{X} authorized account representative.

(iv) Each submission concerning the general account shall be submitted, signed, and certified by the NO\textsubscript{X} authorized account representative or any alternate NO\textsubscript{X} authorized account representative for the persons having an ownership interest with respect to NO\textsubscript{X} allowances held in the general account. Each such submission shall include the following certification statement by the NO\textsubscript{X} authorized account representative or any alternate NO\textsubscript{X} authorizing account representative: “I am authorized to make this submission on behalf of the persons having an ownership interest with respect to NO\textsubscript{X} allowances held in the general account. I certify under penalty of law that I have personally examined, and am familiar with, the statements and information submitted in this document and all its attachments. Based on my inquiry of those individuals with primary responsibility for obtaining the information, I certify that the statements and information are to the best of my knowledge and belief true, accurate, and complete. I am aware that there are significant penalties for submitting false statements and information or omitting required statements and information, including the possibility of fine or imprisonment.”

(v) The Administrator will accept or act on a submission concerning the general account only if the submission has been made, signed, and certified in accordance with paragraph (b)(2)(iv) of this section.

(3) Changing NO\textsubscript{X} authorized account representative and alternate NO\textsubscript{X} authorized account representative; changes in persons with ownership interest. (i) The NO\textsubscript{X} authorized account representative for a general account may be changed at any time upon receipt by the Administrator of a superseding complete application for a general account under paragraph (b)(1) of this section. Notwithstanding any such change, all representations, actions, inactions, and submissions by the previous NO\textsubscript{X} authorized account representative prior to the time and date when the Administrator receives the superseding application for a general account shall be binding on the new NO\textsubscript{X} authorized account representative and the persons with an ownership interest with respect to the NO\textsubscript{X} allowances in the general account.

(ii) The alternate NO\textsubscript{X} authorized account representative for a general account may be changed at any time upon receipt by the Administrator of a superseding complete application for a general account under paragraph (b)(1) of this section. Notwithstanding any such change, all representations, actions, inactions, and submissions by the previous alternate NO\textsubscript{X} authorized account representative prior to the time and date when the Administrator receives the superseding application for a general account shall be binding on the new alternate NO\textsubscript{X} authorized account representative and the persons with an ownership interest with respect to the NO\textsubscript{X} allowances in the general account.

(iii)(A) In the event a new person having an ownership interest with respect to NO\textsubscript{X} allowances in the general account is not included in the list of such persons in the account certificate of representation, such new person shall be deemed to be subject to and bound by the account certificate of representation, the representation, actions, inactions, and submissions of the NO\textsubscript{X} authorized account representative and any alternate NO\textsubscript{X} authorized account representative of the source or unit, and the decisions, orders, actions, and inactions of the Administrator, as if the new person were included in such list.

(B) Within 30 days following any change in the persons having an ownership interest with respect to NO\textsubscript{X} allowances in the general account, including the addition of persons, the NO\textsubscript{X} authorized account representative or any alternate NO\textsubscript{X} authorized account representative shall submit a revision to the application for a general account amending the list of persons...
§97.52 NO\textsubscript{X} Allowance Tracking System responsibilities of NO\textsubscript{X} authorized account representative.

(a) Following the establishment of a NO\textsubscript{X} Allowance Tracking System account, all submissions to the Administrator pertaining to the account, including, but not limited to, submissions concerning the deduction or transfer of NO\textsubscript{X} allowances in the account, shall be made only by the NO\textsubscript{X} authorized account representative for the account.

(b) Authorized account representative identification. The Administrator will assign a unique identifying number to each NO\textsubscript{X} authorized account representative.

§97.53 Recordation of NO\textsubscript{X} allowance allocations.

(a) The Administrator will record the NO\textsubscript{X} allowances for 2004 for a NO\textsubscript{X} Budget unit allocated under subpart E of this part in the unit’s compliance account, except for NO\textsubscript{X} allowances under §97.4(b)(4)(ii) or §97.5(c)(2), which will be recorded in the general account specified by the owners and operators of the unit. The Administrator will record NO\textsubscript{X} allowances for 2004 for a NO\textsubscript{X} Budget opt-in unit in the unit’s compliance account as allocated under §97.88(a).

(b) By May 1, 2003, the Administrator will record the NO\textsubscript{X} allowances for 2005 for a NO\textsubscript{X} Budget unit allocated under subpart E of this part in the unit’s compliance account, except for NO\textsubscript{X} allowances under §97.4(b)(4)(ii) or §97.5(c)(2), which will be recorded in the general account specified by the owners and operators of the unit. The Administrator will record NO\textsubscript{X} allowances for 2005 for a NO\textsubscript{X} Budget opt-in unit in the unit’s compliance account as allocated under §97.88(a).

(c) By May 1, 2003, the Administrator will record the NO\textsubscript{X} allowances for 2006 for a NO\textsubscript{X} Budget unit allocated under subpart E of this part in the unit’s compliance account, except for NO\textsubscript{X} allowances under §97.4(b)(4)(ii) or §97.5(c)(2), which will be recorded in the general account specified by the owners and operators of the unit. The Administrator will record NO\textsubscript{X} allowances for 2006 for a NO\textsubscript{X} Budget opt-in unit in the unit’s compliance account as allocated under §97.88(a).

(d) By May 1, 2004, the Administrator will record the NO\textsubscript{X} allowances for 2007 for a NO\textsubscript{X} Budget unit allocated under subpart E of this part in the unit’s compliance account, except for NO\textsubscript{X} allowances under §97.4(b)(4)(ii) or §97.5(c)(2), which will be recorded in the general account specified by the owners and operators of the unit. The
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§ 97.54 Compliance.

(a) NOx allowances transfer deadline. The NOx allowances available to be deducted for compliance with a unit’s NOx Budget emissions limitation for a control period in a given year only if the NOx allowances:

(1) Were allocated for a control period in a prior year or the same year; and

(2) Are held in the unit’s compliance account, or the overdraft account of the source where the unit is located, as of the NOx allowance transfer deadline for that control period or are transferred into the compliance account or overdraft account by a NOx allowance transfer correctly submitted for recordation under §97.60 by the NOx allowance transfer deadline for that control period.

(b) Deductions for compliance. (1) Following the recordation, in accordance with §97.61, of NOx allowance transfers submitted for recordation in the unit’s compliance account or the overdraft account of the source where the unit is located by the NOx allowance transfer deadline for a control period, the Administrator will deduct NOx allowances available under paragraph (a) of this section to cover the unit’s NOx emissions (as determined in accordance with subpart H of this part), or to account for actual heat input under §97.42(e), for the control period:

(i) From the compliance account; and

(ii) Only if no more NOx allowances available under paragraph (a) of this section remain in the compliance account, from the overdraft account. In deducting allowances for units at the source from the overdraft account, the Administrator will begin with the unit having the compliance account with the lowest account number and end with the unit having the compliance account with the highest account number (with account numbers sorted beginning with the left-most character and ending with the right-most character and the letter characters assigned values in alphabetical order and less than all numeric characters).

(2) The Administrator will deduct NOx allowances first under paragraph (b)(1)(i) of this section and then under paragraph (b)(1)(ii) of this section:

(i) Until the number of NOx allowances deducted for the control period equals the number of tons of NOx emissions, determined in accordance with subpart H of this part, from the unit for the control period for which compliance is being determined, plus the number of NOx allowances required for deduction to account for actual heat input under §97.42(e) for the control period; or

(ii) Until no more NOx allowances available under paragraph (a) of this section remain in the respective account.

(c)(1) Identification of NOx allowances by serial number. The NOx authorized account representative for each compliance account may identify by serial number the NOx allowances to be deducted from the unit’s compliance account under paragraph (b), (d), (e), or
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(2) First-in, first-out. The Administrator will deduct NO\textsubscript{X} allowances for a control period from the compliance account, in the absence of an identification or in the case of a partial identification of NO\textsubscript{X} allowances by serial number under paragraph (c)(1) of this section, or the overdraft account on a first-in, first-out (FIFO) accounting basis in the following order:

(i) Those NO\textsubscript{X} allowances that were allocated for the control period to the unit under subpart E or I of this part;

(ii) Those NO\textsubscript{X} allowances that were allocated for the control period to any unit and transferred and recorded in the account pursuant to subpart G of this part, in order of their date of recordation;

(iii) Those NO\textsubscript{X} allowances that were allocated for a prior control period to the unit under subpart E or I of this part; and

(iv) Those NO\textsubscript{X} allowances that were allocated for a prior control period to any unit and transferred and recorded in the account pursuant to subpart G of this part, in order of their date of recordation.

(d) Deductions for excess emissions. (1) After making the deductions for compliance under paragraph (b) of this section, the Administrator will deduct from the unit's compliance account or the overdraft account of the source where the unit is located a number of NO\textsubscript{X} allowances, allocated for a control period after the control period in which the unit has excess emissions, equal to three times the number of the unit's excess emissions.

(2) If the compliance account or overdraft account does not contain sufficient NO\textsubscript{X} allowances, the Administrator will deduct the required number of NO\textsubscript{X} allowances, regardless of the control period for which they were allocated, whenever NO\textsubscript{X} allowances are recorded in either account.

(3) Any allowance deduction required under paragraph (d) of this section shall not affect the liability of the owners and operators of the NO\textsubscript{X} Budget unit for any fine, penalty, or assessment, or their obligation to comply with any other remedy, for the same violation, as ordered under the Clean Air Act or applicable State law. The following guidelines will be followed in assessing fines, penalties or other obligations:

(i) For purposes of determining the number of days the violation, if a NO\textsubscript{X} Budget unit has excess emissions for a control period, each day in the control period (153 days) constitutes a day in violation unless the owners and operators of the unit demonstrate that a lesser number of days should be considered.

(ii) Each ton of excess emissions is a separate violation.

(e) Deductions for units sharing a common stack. In the case of units sharing a common stack and having emissions that are not separately monitored or apportioned in accordance with subpart H of this part:

(1) The NO\textsubscript{X} authorized account representative of the units may identify the percentage of NO\textsubscript{X} allowances to be deducted from each such unit's compliance account to cover the unit's share of NO\textsubscript{X} emissions from the common stack for a control period. Such identification shall be made in the compliance certification report submitted in accordance with §97.30.

(2) Notwithstanding paragraph (b)(2)(i) of this section, the Administrator will deduct NO\textsubscript{X} allowances for each such unit until the number of NO\textsubscript{X} allowances deducted equals the unit's identified percentage under paragraph (e)(1) of this section or, if no percentage is identified, an equal percentage for each unit multiplied by the number of tons of NO\textsubscript{X} emissions, as determined in accordance with subpart H of this part, from the common stack for the control period for which compliance is being determined. In addition to the deductions under the first sentence of this paragraph (e)(1), the Administrator will deduct NO\textsubscript{X} allowances for each such unit until the number of NO\textsubscript{X} allowances deducted equals the number of NO\textsubscript{X} allowances required to account for actual heat input under §97.42(e) for the unit for the control period.

(f) Deduction of banked allowances. Each year starting in 2006, after the
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§ 97.55 Banking.

NOX allowances may be banked for future use or transfer in a compliance account, an overdraft account, or a general account, as follows:

(a) Any NOX allowance that is held in a compliance account, an overdraft account, or a general account will remain in such account unless and until the Administrator has completed the designation of banked NOX allowances under §97.55(b) and before May 1 of the year, the Administrator will determine the extent to which banked NOX allowances otherwise available under paragraph (a) of this section are available for compliance in the control period for the current year, as follows. For each State NOX Budget Trading Program that is established, and approved and administered by the Administrator pursuant to §51.121 of this chapter, the terms “compliance account” or “compliance accounts”, “overdraft account” or “overdraft accounts”, “general account” or “general accounts”, “States”, and “trading program budgets under §97.40” in paragraphs (f)(1) through (f)(3) of this section shall be read to include respectively: A compliance account or compliance accounts established under such State NOX Budget Trading Program; an overdraft account or overdraft accounts established under such State NOX Budget Trading Program; a general account or general accounts established under such State NOX Budget Trading Program; the State or portion of a State covered by such State NOX Budget Trading Program; and the trading program budget of the State or portion of a State covered by such State NOX Budget Trading Program.

(1) The Administrator will determine the total number of banked NOX allowances held in compliance accounts, overdraft accounts, or general accounts.

(2) If the total number of banked NOX allowances determined under paragraph (f)(1) of this section, to be held in compliance accounts, overdraft accounts, or general accounts is less than or equal to 10 percent of the sum of the trading program budgets under §97.40 for all States for the control period, any banked allowance may be deducted for compliance in accordance with paragraphs (a) through (e) of this section, except as follows:

(i) The Administrator will determine the following ratio: 0.10 multiplied by the sum of the trading program budgets under §97.40 for all States for the control period and divided by the total number of banked NOX allowances determined, under paragraph (f)(1) of this section, to be held in compliance accounts, overdraft accounts, or general accounts.

(ii) The Administrator will multiply the number of banked NOX allowances in each compliance account or overdraft account by the ratio determined under paragraph (f)(3)(i) of this section. The resulting product is the number of banked NOX allowances in excess of the resulting product may be deducted for compliance in accordance with paragraphs (a) through (e) of this section. Any banked NOX allowances in excess of the resulting product may be deducted for compliance in accordance with paragraphs (a) through (e) of this section, except that, if such NOX allowances are used to make a deduction under paragraph (b) or (e) of this section, two (rather than one) such NOX allowances shall authorize up to one ton of NOX emissions during the control period and must be deducted for each deduction of one NOX allowance required under paragraph (b) or (e) of this section.

(g) Recordation of deductions. The Administrator will record in the appropriate compliance account or overdraft account all deductions from such an account pursuant to paragraph (b), (d), (e), or (f) of this section.

[65 FR 2727, Jan. 18, 2000, as amended at 67 FR 21530, Apr. 30, 2002; 69 FR 21646, Apr. 21, 2004]
NO\textsubscript{X} allowance is deducted or transferred under §97.31, §97.54, §97.56, or subpart G or I of this part.

(b) The Administrator will designate, as a "banked" NO\textsubscript{X} allowance, any NO\textsubscript{X} allowance that remains in a compliance account, an overdraft account, or a general account after the Administrator has made all deductions for a given control period from the compliance account or overdraft account pursuant to §97.54 (except deductions pursuant to §97.54(d)(2)) and that was allocated for that control period or a control period in a prior year.

§ 97.56 Account error.

The Administrator may, at his or her sole discretion and on his or her own motion, correct any error in any NO\textsubscript{X} Allowance Tracking System account. Within 10 business days of making such correction, the Administrator will notify the NO\textsubscript{X} authorized account representative for the account.

§ 97.57 Closing of general accounts.

(a) The NO\textsubscript{X} authorized account representative of a general account may instruct the Administrator to close the account by submitting a statement requesting deletion of the account from the NO\textsubscript{X} Allowance Tracking System account and by correctly submitting for recordation under §97.60 an allowance transfer of all NO\textsubscript{X} allowances in the account to one or more other NO\textsubscript{X} Allowance Tracking System accounts.

(b) If a general account shows no activity for a period of a year or more and does not contain any NO\textsubscript{X} allowances, the Administrator may notify the NO\textsubscript{X} authorized account representative for the account that the account will be closed and deleted from the NO\textsubscript{X} Allowance Tracking System following 20 business days after the notice is sent. The account will be closed after the 20-day period unless before the end of the 20-day period the Administrator receives a correctly submitted transfer of NO\textsubscript{X} allowances into the account under §97.60 or a statement submitted by the NO\textsubscript{X} authorized account representative demonstrating to the satisfaction of the Administrator good cause as to why the account should not be closed.

§ 97.60 Submission of NO\textsubscript{X} allowance transfers.

The NO\textsubscript{X} authorized account representatives seeking recordation of a NO\textsubscript{X} allowance transfer shall submit the transfer to the Administrator. To be considered correctly submitted, the NO\textsubscript{X} allowance transfer shall include the following elements in a format specified by the Administrator:

(a) The numbers identifying both the transferor and transferee accounts; and

(b) A specification by serial number of each NO\textsubscript{X} allowance to be transferred; and

(c) The printed name and signature of the NO\textsubscript{X} authorized account representative of the transferee account and the date signed.

§ 97.61 EPA recordation.

(a) Within 5 business days of receiving a NO\textsubscript{X} allowance transfer, except as provided in paragraph (b) of this section, the Administrator will record a NO\textsubscript{X} allowance transfer by moving each NO\textsubscript{X} allowance from the transferor account to the transferee account as specified by the request, provided that:

(1) The transfer is correctly submitted under §97.60; and

(2) The transferor account includes each NO\textsubscript{X} allowance identified by serial number in the transfer.

(b) A NO\textsubscript{X} allowance transfer that is submitted for recordation following the NO\textsubscript{X} allowance transfer deadline and that includes any NO\textsubscript{X} allowances allocated for a control period prior to or the same as the control period to which the NO\textsubscript{X} allowance transfer deadline applies will not be recorded until after the Administrator completes the recordation of NO\textsubscript{X} allowance allocations under §97.53 for the control period in the fourth year after the control period to which the NO\textsubscript{X} allowance transfer deadline applies.

(c) Where a NO\textsubscript{X} allowance transfer submitted for recordation fails to meet the requirements of paragraph (a) of this section, the Administrator will not record such transfer.

[65 FR 2727, Jan. 18, 2000, as amended at 69 FR 21647, Apr. 21, 2004]
§ 97.62 Notification.

(a) Notification of recordation. Within 5 business days of recordation of a NOx allowance transfer under §97.61, the Administrator will notify the NOx authorized account representatives of both the transferor and transferee accounts.

(b) Notification of non-recordation. Within 10 business days of receipt of a NOx allowance transfer that fails to meet the requirements of §97.61(a), the Administrator will notify the NOx authorized account representatives of both accounts subject to the transfer of:

1. A decision not to record the transfer; and
2. The reasons for such non-recordation.

(c) Nothing in this section shall preclude the submission of a NOx allowance transfer for recordation following notification of non-recordation.

Subpart H—Monitoring and Reporting

§ 97.70 General requirements.

The owners and operators, and to the extent applicable, the NOx authorized account representative of a NOx Budget unit, shall comply with the monitoring, recordkeeping, and reporting requirements as provided in this subpart and in subpart H of part 75 of this chapter. For purposes of complying with such requirements, the definitions in §97.2 and in §72.2 of this chapter shall apply, and the terms “affected unit,” “designated representative,” and “continuous emission monitoring system” (or “CEMS”) in part 75 of this chapter shall be deemed to refer to the terms “NOx Budget unit,” “NOx authorized account representative,” and “continuous emission monitoring system” (or “CEMS”) respectively, as defined in §97.2. The owner or operator of a unit that is not a NOx Budget unit but that is monitored under §75.72(b)(2)(ii) of this chapter shall comply with the monitoring, recordkeeping, and reporting requirements for a NOx Budget unit under this part.

(a) Requirements for installation, certification, and data accounting. The owner or operator of each NOx Budget unit shall meet the following requirements. These provisions shall also apply to a unit for which an application for a NOx Budget opt-in permit is submitted and not denied or withdrawn, as provided in subpart I of this part:

1. Install all monitoring systems required under this subpart for monitoring NOx mass emissions. This includes all systems required to monitor NOx emission rate, NOx concentration, heat input rate, and stack flow rate, in accordance with §§75.71 and 75.72 of this chapter.

2. Install all monitoring systems for monitoring heat input rate.

3. Successfully complete all certification tests required under §97.71 and meet all other requirements of this subpart and part 75 of this chapter applicable to the monitoring systems under paragraphs (a)(1) and (2) of this section.

4. Record, report, and quality-assure the data from the monitoring systems under paragraphs (a)(1) and (2) of this section.

(b) Compliance deadlines. The owner or operator shall meet the certification and other requirements of paragraphs (a)(1) through (a)(3) of this section on or before the following dates. The owner or operator shall record, report and quality-assure the data from the monitoring systems under paragraphs (a)(1) and (a)(2) of this section on and after the following dates.

1. For the owner or operator of a NOx Budget unit for which the owner or operator intends to apply for early reduction credits under §97.43, by May 1, 2001. If the owner or operator of a NOx Budget unit fails to meet this deadline, he or she is not eligible to apply for early reduction credits and is subject to the deadline under paragraph (b)(2) of this section.

2. For the owner or operator of a NOx Budget unit under §97.4(a) that commences operation before January 1, 2003 and that is not subject to or does not meet the deadline under paragraph (b)(1) of this section, by May 1, 2003.

3. For the owner or operator of a NOx Budget unit under §97.4(a) that...
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commences operation on or after January 1, 2003 and that reports on an annual basis under §97.74(d) by the following dates:

(i) The earlier of 90 unit operating days after the date on which the unit commences commercial operation or 180 calendar days after the date on which the unit commences commercial operation; or

(ii) May 1, 2003, if the compliance date under paragraph (b)(3)(i) of this section is before May 1, 2003.

(4) For the owner or operator of a NO\(\text{X}\) Budget unit under §97.4(a) that commences operation on or after January 1, 2003 and that reports on a control period basis under §97.74(d)(2)(ii), by the following dates:

(i) The earlier of 90 unit operating days or 180 calendar days after the date on which the unit commences commercial operation, if this compliance date is during a control period; or

(ii) May 1 immediately following the compliance date under paragraph (b)(4)(i) of this section, if such compliance date is not during a control period.

(5) For the owner or operator of a NO\(\text{X}\) Budget unit that has a new stack or flue or add-on NO\(\text{X}\) emission controls for which construction is completed after the applicable deadline under paragraph (b)(1), (b)(2), (b)(3), or (b)(4) of this section and that reports on an annual basis under §97.74(d), by the earlier of 90 unit operating days or 180 calendar days after the date on which emissions first exit to the atmosphere through the new stack or flue or add-on NO\(\text{X}\) emission controls.

(6) For the owner or operator of a NO\(\text{X}\) Budget unit that has a new stack or flue or add-on NO\(\text{X}\) emission controls for which construction is completed after the applicable deadline under paragraph (b)(1), (b)(2), (b)(3), or (b)(4) of this section or under subpart I of this part and that reports on an annual basis under §97.74(d), by the earlier of 90 unit operating days or 180 calendar days after the date on which emissions first exit to the atmosphere through the new stack or flue or add-on NO\(\text{X}\) emission controls, if this compliance date is during a control period; or

(ii) May 1 immediately following the compliance date under paragraph (b)(6)(i) of this section, if such compliance date is not during a control period.

(7) For the owner or operator of a unit for which an application for a NO\(\text{X}\) Budget opt-in permit is submitted and not denied or withdrawn, by the date specified under subpart I of this part.

(c) Commencement of data reporting.

(1) The owner or operator of NO\(\text{X}\) Budget units under paragraph (b)(1) or (b)(2) of this section shall determine, record and report NO\(\text{X}\) mass emissions, heat input rate, and any other values required to determine NO\(\text{X}\) mass emissions (e.g., NO\(\text{X}\) emission rate and heat input rate, or NO\(\text{X}\) concentration and stack flow rate) in accordance with §75.70(g) of this chapter, beginning on the first hour of the applicable compliance deadline in paragraph (b)(1) or (b)(2) of this section.

(2) The owner or operator of a NO\(\text{X}\) Budget unit under paragraph (b)(3) or (b)(4) of this section shall determine, record and report NO\(\text{X}\) mass emissions, heat input rate, and any other values required to determine NO\(\text{X}\) mass emissions (e.g., NO\(\text{X}\) emission rate and heat input rate, or NO\(\text{X}\) concentration and stack flow rate) and electric and thermal output in accordance with §75.70(g) of this chapter, beginning on:

(i) The date and hour on which the unit commences operation, if the date and hour on which the unit commences operation is during a control period; or

(ii) The first hour on May 1 of the first control period after the date and hour on which the unit commences operation, if the date and hour on which the unit commences operation is not during a control period.

(3) Notwithstanding paragraphs (c)(2)(i) and (c)(2)(ii) of this section, the owner or operator may begin reporting NO\(\text{X}\) mass emission data and heat input data before the date and hour under paragraph (c)(2)(i) or (c)(2)(ii) of this section if the unit reports on an annual basis and if the required monitoring systems are certified before the applicable date and hour under paragraph (c)(1) or (c)(2) of this section.
§ 97.71 Initial certification and recertification procedures.

(a) The owner or operator of a NOX Budget unit that is subject to an Acid Rain emissions limitation shall comply with the initial certification and recertification procedures of part 75 of this chapter for NOX-diluent CEMS, flow monitors, NOX concentration CEMS, or excepted monitoring systems under appendix E of part 75 of this chapter for NOX, under appendix D for heat input, or under §75.19 for NOX and heat input, except that:

(1) If, prior to January 1, 1998, the Administrator approved a petition under §75.17(a) or (b) of this chapter for apportioning the NOX emission rate measured in a common stack or a petition under §75.66 of this chapter for an alternative to a requirement in §75.17 of this chapter, the NOX authorized account representative shall resubmit the petition to the Administrator under §97.75(a) to determine if the approval applies under the NOX Budget Trading Program.

(2) For any additional CEMS required under the common stack provisions in §75.72 of this chapter or for any NOX concentration CEMS used under the provisions of §75.71(a)(2) of this chapter, the owner or operator shall meet the requirements of paragraph (b) of this section.

(b) The owner or operator of a NOX Budget unit that is not subject to an Acid Rain emissions limitation shall comply with the following initial certification and recertification procedures. The owner or operator of such a unit that qualifies to use the low mass emissions excepted monitoring methodology under §75.19 of this chapter or that qualifies to use an alternative monitoring system under subpart E of part 75 of this chapter shall comply with the following procedures, as modified by paragraph (c) or (d) of this section. The owner or operator of a NOX Budget unit that is subject to an Acid Rain emissions limitation shall comply with the following initial certification and recertification procedures.
Rain emissions limitation and that requires additional CEMS under the common stack provisions in §75.72 of this chapter or uses a NO\textsubscript{X} concentration CEMS under §75.71(a)(2) of this chapter shall comply with the following procedures.

1. **Requirements for initial certification.** The owner or operator shall ensure that each emission monitoring system required by subpart H of part 75 of this chapter (which includes the automated data acquisition and handling system) successfully completes all of the initial certification testing required under §75.20 of this chapter by the applicable deadline in §97.70(b). In addition, whenever the owner or operator installs an emission monitoring system in order to meet the requirements of this part in a location where no such emission monitoring system was previously installed, initial certification in accordance with §75.20 of this chapter is required.

2. **Requirements for recertification.** Whenever the owner or operator makes a replacement, modification, or change in a certified emission monitoring system that may significantly affect the ability of the system to accurately measure or record NO\textsubscript{X} mass emissions or heat input rate or to meet the requirements of §75.21 of this chapter or appendix B to part 75 of this chapter, the owner or operator shall recertify the emission monitoring system in accordance with §75.20(b) of this chapter. Furthermore, whenever the owner or operator makes a replacement, modification, or change to the flue gas handling system or the unit’s operation that may significantly change the stack flow or concentration profile, the owner or operator shall recertify the continuous emissions monitoring system in accordance with §75.20(b) of this chapter. Examples of changes that require recertification include: replacement of the analyzer, complete replacement of an existing continuous emission monitoring system, or change in location or orientation of the sampling probe or site.

3. **Certification approval process for initial certification and recertification—(i) Notification of certification.** The NO\textsubscript{X} authorized account representative shall submit to the Administrator, the appropriate EPA Regional Office and the permitting authority a certification application for each emission monitoring system required under subpart H of part 75 of this chapter. A complete certification application shall include the information specified in subpart H of part 75 of this chapter. (ii) Certification application. The NO\textsubscript{X} authorized account representative shall submit to the Administrator, the appropriate EPA Regional Office and the permitting authority a certification application for each emission monitoring system required under subpart H of part 75 of this chapter. A complete certification application shall include the information specified in subpart H of part 75 of this chapter. (iii) Except for units using the low mass emission excepted methodology under §75.19 of this chapter, the provisional certification date for a monitor shall be determined in accordance with §75.20(a)(3) of this chapter. A provisionally certified monitor may be used under the NO\textsubscript{X} Budget Trading Program for a period not to exceed 120 days after receipt by the Administrator of the complete certification application for the monitoring system under paragraph (b)(3)(ii) of this section. Data measured and recorded by the provisionally certified monitoring system, in accordance with the requirements of part 75 of this chapter, will be considered valid quality-assured data (retroactive to the date and time of provisional certification), provided that the Administrator does not invalidate the provisional certification by issuing a notice of disapproval within 120 days of receipt of the complete certification application by the Administrator. (iv) Certification application formal approval process. The Administrator will issue a written notice of approval or disapproval of the certification application to the owner or operator within 120 days of receipt of the complete certification application under paragraph (b)(3)(ii) of this section. In the event the Administrator does not issue such a notice within such 120-day period, each monitoring system that meets the applicable performance requirements of part 75 of this chapter and is included in the certification application will be deemed certified for use under the NO\textsubscript{X} Budget Trading Program.

(A) Approval notice. If the certification application is complete and shows that each monitoring system
meets the applicable performance requirements of part 75 of this chapter, then the Administrator will issue a written notice of approval of the certification application within 120 days of receipt.

(B) Incomplete application notice. A certification application will be considered complete when all of the applicable information required to be submitted under paragraph (b)(3)(ii) of this section has been received by the Administrator. If the certification application is not complete, then the Administrator will issue a written notice of incompleteness that sets a reasonable date by which the NOX authorized account representative must submit the additional information required to complete the certification application. If the NOX authorized account representative does not comply with the notice of incompleteness by the specified date, then the Administrator may issue a notice of disapproval under paragraph (b)(3)(iv)(C) of this section. The 120-day review period shall not begin prior to receipt of a complete certification application.

(C) Disapproval notice. If the certification application shows that any monitoring system or component thereof does not meet the performance requirements of this part, or if the certification application is incomplete and the requirement for disapproval under paragraph (b)(3)(iv)(B) of this section has been met, then the Administrator will issue a written notice of disapproval of the certification application. Upon issuance of such notice of disapproval, the provisional certification is invalidated by the Administrator and the data measured and recorded by each uncertified monitoring system shall not be considered valid quality-assured data beginning with the date and hour of provisional certification (as defined under §75.20(a)(3) of this chapter). The owner or operator shall repeat all certification tests or other requirements that were failed by the monitoring system, as indicated in the Administrator’s notice of disapproval, no later than 30 unit operating days after the date of issuance of the notice of disapproval.

(D) Audit decertification. The Administrator may issue a notice of disapproval of the certification status of a monitor in accordance with §97.72(b).

(v) Procedures for loss of certification. If the Administrator issues a notice of disapproval of a certification application under paragraph (b)(3)(iv)(C) of this section or a notice of disapproval of certification status under paragraph (b)(3)(iv)(D) of this section, then:

(A) The owner or operator shall substitute the following values, for each hour of unit operation during the period of invalid data specified under §75.20(a)(4)(iii), §75.20(b)(5), §75.20(h)(4), or §75.21(e) and continuing until the date and hour specified under §75.20(a)(5)(i) of this chapter:

(1) For units that the owner or operator intends to monitor or monitors for NOX emission rate and heat input rate or intends to determine or determines NOX mass emissions using the low mass emission excepted methodology under §75.19 of this chapter, the maximum potential NOX emission rate and the maximum potential hourly heat input of the unit; and

(2) For units that the owner or operator intends to monitor or monitors for NOX mass emissions using a NOX pollutant concentration monitor and a flow monitor, the maximum potential concentration of NOX and the maximum potential flow rate of the unit under section 2 of appendix A of part 75 of this chapter.

(B) The NOX authorized account representative shall submit a notification of certification retest dates and a new certification application in accordance with paragraphs (b)(3)(i) and (ii) of this section.

(C) The owner or operator shall repeat all certification tests or other requirements that were failed by the monitoring system, as indicated in the Administrator’s notice of disapproval, no later than 30 unit operating days after the date of issuance of the notice of disapproval.

(c) Initial certification and recertification procedures for low mass emission units using the excepted methodologies under §75.19 of this chapter. The owner or operator of a gas-fired or oil-fired unit using the low mass emissions excepted methodology under §75.19 of this chapter and not subject to an Acid Rain emissions limitation shall meet the applicable general operating requirements of §75.10 of this chapter and
§ 97.72 Out of control periods.
(a) Whenever any emission monitoring system fails to meet the quality assurance or data validation requirements of part 75 of this chapter, data shall be substituted using the applicable procedures in subpart D, subpart H, appendix D, or appendix E of part 75 of this chapter.

(b) Audit decertification. Whenever both an audit of an emission monitoring system and a review of the initial certification or recertification application reveal that any system should not have been certified or recertified because it did not meet a particular performance specification or other requirement under §97.71 or the applicable provisions of part 75 of this chapter, both at the time of the initial certification or recertification application submission and at the time of the audit, the Administrator will issue a notice of disapproval of the certification status of such system. For the purposes of this paragraph, an audit shall be either a field audit or an audit of any information submitted to the permitting authority or the Administrator. By issuing the notice of disapproval, the Administrator revokes prospectively the certification status of the system. The data measured and recorded by the system shall not be considered valid quality-assured data from the date of issuance of the notification of the revoked certification status until the date and time that the owner or operator completes subsequently approved initial certification or recertification tests for the system. The owner or operator shall follow the initial certification or recertification procedures in §97.71 for each disapproved system.

§ 97.73 Notifications.
(a) The NOX authorized account representative for a NOX Budget unit shall submit written notice to the Administrator, the appropriate EPA Regional Office, and the permitting authority in accordance with §75.61 of this chapter.

(b) For any unit that does not have an Acid Rain emissions limitation, the permitting authority in accordance with §75.61 of this chapter.

§ 97.74 Recordkeeping and reporting.
(a) General provisions. (1) The NOX authorized account representative shall comply with all recordkeeping and reporting requirements in this section, with the recordkeeping and reporting requirements under §75.73 of this chapter, and with the requirements of §97.10(e)(1).
(2) If the NO\textsubscript{X} authorized account representative for a NO\textsubscript{X} Budget unit subject to an Acid Rain emission limitation who signed and certified any submission that is made under subpart F or G of part 75 of this chapter and that includes data and information required under this subpart or subpart H of part 75 of this chapter is not the same person as the designated representative or the alternative designated representative for the unit under part 72 of this chapter, then the submission must also be signed by the designated representative or the alternative designated representative.

(b) Monitoring plans. (1) The owner or operator of a unit subject to an Acid Rain emissions limitation shall comply with requirements of §75.62 of this chapter, except that the monitoring plan shall also include all of the information required by subpart H of part 75 of this chapter.

(2) The owner or operator of a unit that is not subject to an Acid Rain emissions limitation shall comply with requirements of §75.62 of this chapter, except that the monitoring plan is only required to include the information required by subpart H of part 75 of this chapter.

(c) Certification applications. The NO\textsubscript{X} authorized account representative shall submit an application to the Administrator, the appropriate EPA Regional Office, and the permitting authority within 45 days after completing all initial certification or recertification tests required under §97.71 including the information required under subpart H of part 75 of this chapter.

(d) Quarterly reports. The NO\textsubscript{X} authorized account representative shall submit quarterly reports, as follows:

(1) If a unit is subject to an Acid Rain emission limitation or if the owner or operator of the NO\textsubscript{X} budget unit chooses to meet the annual reporting requirements of this subpart H, the NO\textsubscript{X} authorized account representative shall submit a quarterly report for each calendar quarter beginning with:

(i) For a unit for which the owner or operator intends to apply or applies for the early reduction credits under §97.43, the calendar quarter that covers May 1, 2000 through June 30, 2000. The NO\textsubscript{X} mass emission data shall be recorded and reported from the first hour on May 1, 2000; or

(ii) For a unit that commences operation before January 1, 2003 and that is not subject to paragraph (d)(1)(i) of this section, the calendar quarter covering May 1, 2003 through June 30, 2003. The NO\textsubscript{X} mass emission data shall be recorded and reported from the first hour on May 1, 2003; or

(iii) For a unit that commences operation on or after January 1, 2003:

(A) The calendar quarter in which the unit commences operation, if unit operation commences during a control period. The NO\textsubscript{X} mass emission data shall be recorded and reported from the date and hour when the unit commences operation; or

(B) The calendar quarter which includes May 1 through June 30 of the first control period following the date on which the unit commences operation, if the unit does not commence operation during a control period. The NO\textsubscript{X} mass emission data shall be recorded and reported from the first hour on May 1 of that control period; or

(iv) A calendar quarter before the quarter specified in paragraph (d)(1)(i), (d)(1)(ii), or (d)(1)(iii)(B) of this section, if the owner or operator elects to begin reporting early under §97.70(c)(3).

(2) If a NO\textsubscript{X} budget unit is not subject to an Acid Rain emission limitation, then the NO\textsubscript{X} authorized account representative shall either:

(i) Meet all of the requirements of part 75 related to monitoring and reporting NO\textsubscript{X} mass emissions during the entire year and meet the deadlines specified in paragraph (d)(1) of this section; or

(ii) Submit quarterly reports, documenting NO\textsubscript{X} mass emissions from the unit, only for the period from May 1 through September 30 of each year and including the data described in §75.74(c)(6) of this chapter. The NO\textsubscript{X} authorized account representative shall submit such quarterly reports, beginning with:

(A) For a unit for which the owner or operator intends to apply or applies for the early reduction credits under §97.43, the calendar quarter that covers May 1, 2000 through June 30, 2000. The
NO\textsubscript{X} mass emission data shall be recorded and reported from the first hour on May 1, 2000; or

(B) For a unit that commences operation before January 1, 2003 and that is not subject to paragraph (d)(2)(ii)(A) of this section, the calendar quarter covering May 1, 2003 through June 30, 2003.

(C) For a unit that commences operation on or after January 1, 2003 and during a control period, the calendar quarter in which the unit commences operation. The NO\textsubscript{X} mass emission data shall be recorded and reported from the date and hour when the unit commences operation; or

(D) For a unit that commences operation on or after January 1, 2003 and not during a control period, the calendar quarter which includes May 1 through June 30 of the first control period following the date on which the unit commences operation. The NO\textsubscript{X} mass emission data shall be recorded and reported from the first hour on May 1 of that control period.

(3) The NO\textsubscript{X} authorized account representative shall submit each quarterly report to the Administrator within 30 days following the end of the calendar quarter covered by the report. Quarterly reports shall be submitted in the manner specified in subpart H of part 75 of this chapter.

(4) Compliance certification. The NO\textsubscript{X} authorized account representative shall submit to the Administrator a compliance certification in support of each quarterly report based on reasonable inquiry of those persons with primary responsibility for ensuring that all of the unit’s emissions are correctly and fully monitored. The certification shall state:

(i) The monitoring data submitted were recorded in accordance with the applicable requirements of this subpart and part 75 of this chapter, including the quality assurance procedures and specifications;

(ii) For a unit with add-on NO\textsubscript{X} emission controls and for all hours where data are substituted in accordance with §75.34(a)(1) of this chapter, the add-on emission controls were operating within the range of parameters listed in the quality assurance/quality control program under appendix B of part 75 of this chapter and the substitute values do not systematically underestimate NO\textsubscript{X} emissions; and

(iii) For a unit that is reporting on a control period basis under paragraph (d)(2)(ii) of this section, the NO\textsubscript{X} emission rate and NO\textsubscript{X} concentration values substituted for missing data under subpart D of part 75 of this chapter are calculated using only values from a control period and do not systematically underestimate NO\textsubscript{X} emissions.

[65 FR 2727, Jan. 18, 2000, as amended at 67 FR 21530, Apr. 30, 2002; 69 FR 21648, Apr. 21, 2004]

§97.76 Additional requirements to provide heat input data.

The owner or operator of a NO\textsubscript{X} Budget unit that monitors and reports NO\textsubscript{X} mass emissions using a NO\textsubscript{X} concentration system and a flow system shall also monitor and report heat input rate at the unit level using the procedures set forth in part 75 of this chapter.

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Subpart I—Individual Unit Opt-ins

§ 97.80 Applicability.

A unit that is in a State (as defined in §97.2), is not a NOX Budget unit under §97.4(a), is not a unit exempt under §97.4(b), vents all of its emissions to a stack, and is operating, may qualify to be a NOX Budget opt-in unit under this subpart. A unit that is a NOX Budget unit under §97.4(a), is covered by an exemption under §97.4(b) or §97.5 that is in effect, or is not operating is not eligible to be a NOX Budget opt-in unit.

§ 97.81 General.

Except otherwise as provided in this part, a NOX Budget opt-in unit shall be treated as a NOX Budget unit for purposes of applying subparts A through H of this part.

§ 97.82 NOX authorized account representative.

A unit for which an application for a NOX Budget opt-in permit is submitted, or a NOX Budget opt-in unit, located at the same source as one or more NOX Budget units, shall have the same NOX authorized account representative as such NOX Budget units.

§ 97.83 Applying for NOX Budget opt-in permit.

(a) Applying for initial NOX Budget opt-in permit. In order to apply for an initial NOX Budget opt-in permit, the NOX authorized account representative of a unit qualified under §97.80 may submit to the Administrator and the permitting authority at any time, except as provided under §97.86(g):

(1) A complete NOX Budget permit application under §97.22;

(2) A monitoring plan submitted in accordance with subpart H of this part; and

(3) A complete account certificate of representation under §97.13, if no NOX authorized account representative has been previously designated for the unit.

(b) Duty to reapply. Unless the NOX Budget opt-in permit is terminated or revised under §97.86(e) or §97.87(b)(1)(1), the NOX authorized account representative of a NOX Budget opt-in unit shall submit to the Administrator and permitting authority a complete NOX Budget permit application under §97.22 to renew the NOX Budget opt-in permit in accordance with §97.21(c) and, if applicable, an updated monitoring plan in accordance with subpart H of this part.

§ 97.84 Opt-in process.

The permitting authority will issue or deny an initial NOX Budget opt-in permit for a unit for which an application for a NOX Budget opt-in permit under §97.83 is submitted, in accordance with §97.20 and the following:

(a) Interim review of monitoring plan. The Administrator will determine, on an interim basis, the sufficiency of the monitoring plan accompanying the initial application for a NOX Budget opt-in permit under §97.83. A monitoring plan is sufficient, for purposes of interim review, if the plan appears to contain information demonstrating that the NOX emissions rate and heat input rate of the unit are monitored and reported in accordance with subpart H of this part. A determination of sufficiency shall not be construed as acceptance or approval of the unit’s monitoring plan.

(b) If the Administrator determines that the unit’s monitoring plan is sufficient under paragraph (a) of this section and after completion of monitoring system certification under subpart H of this part, the NOX emissions rate and the heat input of the unit shall be monitored and reported in accordance with subpart H of this part for one full control period during which percent monitor data availability is not less than 90 percent and during which the unit is in full compliance with any applicable State or Federal emissions or emissions-related requirements. Solely for purposes of applying the requirements in the prior sentence, the unit shall be treated as a “NOX Budget unit” prior to issuance of a NOX Budget opt-in permit covering the unit.

(c) Based on the information monitored and reported under paragraph (b) of this section, the Administrator will calculate the unit’s baseline heat input, which will equal the unit’s total heat input (in mmBtu) for the control period, and the unit’s baseline NOX emissions rate, which will equal the unit’s total NOX mass emissions (in lb)
§ 97.85  NOX Budget opt-in permit contents.

(a) Each NOX Budget opt-in permit will contain all elements required for a complete NOX Budget opt-in permit application under §97.22.

(b) Each NOX Budget opt-in permit is deemed to incorporate automatically the definitions of terms under §97.2 and, upon recordation by the Administrator under subpart F or G of this part, every allocation, transfer, or deduction of NOX allowances to or from the compliance accounts of each NOX Budget opt-in unit covered by the NOX Budget opt-in permit or the overdraft account of the NOX Budget source where the NOX Budget opt-in unit is located.

§ 97.86  NOX Budget opt-in permit for public comment.

(d) Issuance of draft NOX Budget opt-in permit for public comment. The permitting authority will issue a draft NOX Budget opt-in permit for public comment in accordance with §97.20.

(e) Notwithstanding paragraphs (a) through (d) of this section, if at any time before issuance of a draft NOX Budget opt-in permit for public comment for the unit, the Administrator or the permitting authority determines that the unit does not qualify as a NOX Budget opt-in unit under §97.80, the permitting authority will issue a draft denial of a NOX Budget opt-in permit for public comment for the unit in accordance with §97.20.

(f) Withdrawal of application for NOX Budget opt-in permit. A NOX authorized account representative of a unit may withdraw its application for an initial NOX Budget opt-in permit under §97.83 at any time prior to the issuance of the initial NOX Budget opt-in permit. Once the application for a NOX Budget opt-in permit is withdrawn, a NOX authorized account representative wanting to reapply must submit a new application for an initial NOX Budget permit under §97.83.

(g) The unit shall be a NOX Budget opt-in unit and a NOX Budget unit starting May 1 of the first control period starting after the issuance of the initial NOX Budget opt-in permit by the permitting authority.

§ 97.85  NOX Budget opt-in permit contents.

(a) Each NOX Budget opt-in permit will contain all elements required for a complete NOX Budget opt-in permit application under §97.22.

(b) Each NOX Budget opt-in permit is deemed to incorporate automatically the definitions of terms under §97.2 and, upon recordation by the Administrator under subpart F or G of this part, every allocation, transfer, or deduction of NOX allowances to or from the compliance accounts of each NOX Budget opt-in unit covered by the NOX Budget opt-in permit or the overdraft account of the NOX Budget source where the NOX Budget opt-in unit is located.

§ 97.86  Withdrawal from NOX Budget Trading Program.

(a) Requesting withdrawal. To withdraw from the NOX Budget Trading Program, the NOX authorized account representative of a NOX Budget opt-in unit shall submit to the Administrator and the permitting authority a request to withdraw effective as of a specified date prior to May 1 or after September 30. The submission shall be made no later than 90 days prior to the requested effective date of withdrawal.

(b) Conditions for withdrawal. Before a NOX Budget opt-in unit covered by a request under paragraph (a) of this section may withdraw from the NOX Budget Trading Program and the NOX Budget opt-in permit may be terminated under paragraph (e) of this section, the following conditions must be met:

(1) For the control period immediately before the withdrawal is to be effective, the NOX authorized account representative must submit or must have submitted to the Administrator and the permitting authority an annual compliance certification report in accordance with §97.30.

(2) If the NOX Budget opt-in unit has excess emissions for the control period immediately before the withdrawal is to be effective, the Administrator will deduct or has deducted from the NOX Budget opt-in unit’s compliance account, or the overdraft account of the NOX Budget source where the NOX Budget opt-in unit is located, the full amount required under §97.54(d) for the control period.

(3) After the requirements for withdrawal under paragraphs (b)(1) and (2) of this section are met, the Administrator will deduct from the NOX Budget opt-in unit’s compliance account, or the overdraft account of the NOX Budget source where the NOX Budget opt-in unit is located, NOX allowances equal in number to and allocated for the same or a prior control period as any NOX allowances allocated to that source under §97.86 for any control period for which the withdrawal is to be effective. The Administrator will close the NOX Budget opt-in unit’s compliance account and transfer any remaining allowances to a general account specified by the owners and operators of the NOX Budget opt-in unit.
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(c) A NOx Budget opt-in unit that withdraws from the NOx Budget Trading Program shall comply with all requirements under the NOx Budget Trading Program concerning all years for which such NOx Budget opt-in unit was a NOx Budget opt-in unit, even if such requirements arise or must be complied with after the withdrawal takes effect.

(d) Notification. (1) After the requirements for withdrawal under paragraphs (a) and (b) of this section are met (including deduction of the full amount of NOx allowances required), the Administrator will issue a notification to the permitting authority and the NOx authorized account representative of the NOx Budget opt-in unit of the acceptance of the withdrawal of the NOx Budget opt-in unit as of a specified effective date that is after such requirements have been met and that is prior to May 1 or after September 30.

(2) If the requirements for withdrawal under paragraphs (a) and (b) of this section are not met, the Administrator will issue a notification to the permitting authority and the NOx authorized account representative of the NOx Budget opt-in unit that the request to withdraw is denied. If the NOx Budget opt-in unit’s request to withdraw is denied, the NOx Budget opt-in unit shall remain subject to the requirements for a NOx Budget opt-in unit.

(e) Permit revision. After the Administrator issues a notification under paragraph (d)(1) of this section that the requirements for withdrawal have been met, the permitting authority will revise the NOx Budget permit covering the NOx Budget opt-in unit to terminate the NOx Budget opt-in permit as of the effective date specified under paragraph (d)(1) of this section. A NOx Budget opt-in unit shall continue to be a NOx Budget opt-in unit until the effective date of the termination.

(f) Reapplication upon failure to meet conditions of withdrawal. If the Administrator denies the request to withdraw the NOx Budget opt-in unit, the NOx authorized account representative may submit another request to withdraw in accordance with paragraphs (a) and (b) of this section.

(g) Ability to return to the NOx Budget Trading Program. Once a NOx Budget opt-in unit withdraws from the NOx Budget Trading Program and its NOx Budget opt-in permit is terminated under paragraph (e) of this section, the NOx authorized account representative may not submit another application for a NOx Budget opt-in permit under §97.83 for the unit prior to the date that is 4 years after the date on which the terminated NOx Budget opt-in permit became effective.

§ 97.87 Change in regulatory status.

(a) Notification. When a NOx Budget opt-in unit becomes a NOx Budget unit under §97.4(a), the NOx authorized account representative shall notify in writing the permitting authority and the Administrator of such change in the NOx Budget opt-in unit’s regulatory status, within 30 days of such change.

(b) Permitting authority’s and Administrator’s action. (1)(i) When the NOx Budget opt-in unit becomes a NOx Budget unit under §97.4(a), the permitting authority will revise the NOx Budget opt-in unit’s NOx Budget opt-in permit to meet the requirements of a NOx Budget permit under §97.23 as of an effective date that is the date on which such NOx Budget opt-in unit becomes a NOx Budget unit under §97.4(a).

(ii)(A) The Administrator will deduct from the compliance account for the NOx Budget unit under paragraph (b)(1)(i) of this section, or the overdraft account of the NOx Budget source where the unit is located, NOx allowances equal in number to and allocated for the same or a prior control period as:

(1) Any NOx allowances allocated to the NOx Budget unit (as a NOx Budget opt-in unit) under §97.88 for any control period after the last control period during which the unit’s NOx Budget opt-in permit was effective; and

(2) If the effective date of the NOx Budget permit revision under paragraph (b)(1)(i) of this section is during a control period, the NOx allowances allocated to the NOx Budget unit (as a NOx Budget opt-in unit) under §97.88 for the control period multiplied by the number of days in the control period...
starting with the effective date of the permit revision under paragraph (b)(1)(i) of this section, divided by the total number of days in the control period, and rounded to the nearest whole number of NO\textsubscript{X} allowances as appropriate.

(B) The NO\textsubscript{X} authorized account representative shall ensure that the compliance account of the NO\textsubscript{X} Budget unit under paragraph (b)(1)(i) of this section, or the overdraft account of the NO\textsubscript{X} Budget source where the unit is located, contains the NO\textsubscript{X} allowances necessary for completion of the deduction under paragraph (b)(1)(i)(A) of this section. If the compliance account or overdraft account does not contain the necessary NO\textsubscript{X} allowances, the Administrator will deduct the required number of NO\textsubscript{X} allowances, regardless of the control period for which they were allocated, whenever NO\textsubscript{X} allowances are recorded in either account.

(iii)(A) For every control period during which the NO\textsubscript{X} Budget permit revision under paragraph (b)(1)(i) of this section is in effect, the NO\textsubscript{X} Budget unit under paragraph (b)(1)(i) of this section will be treated, solely for purposes of NO\textsubscript{X} allowance allocations under §97.42, as a unit that commenced operation on the effective date of the NO\textsubscript{X} Budget permit revision under paragraph (b)(1)(i) of this section and will be allocated NO\textsubscript{X} allowances under §97.42. The unit’s deadline under §97.84(b) for meeting monitoring requirements in accordance with subpart H of this part shall not be changed by the change in the unit’s regulatory status or by the revision of the NO\textsubscript{X} Budget permit under paragraph (b)(1)(i) of this section.

(B) Notwithstanding paragraph (b)(1)(iii)(A) of this section, if the effective date of the NO\textsubscript{X} Budget permit revision under paragraph (b)(1)(i) of this section is during a control period, the following number of NO\textsubscript{X} allowances will be allocated to the NO\textsubscript{X} Budget unit under paragraph (b)(1)(i) of this section under §97.42 for the control period: the number of NO\textsubscript{X} allowances otherwise allocated to the NO\textsubscript{X} Budget unit under §97.42 for the control period multiplied by the number of days in the control period starting with the effective date of the permit revision under paragraph (b)(1)(i) of this section, divided by the total number of days in the control period, and rounded to the nearest whole number of NO\textsubscript{X} allowances as appropriate.

(ii) When the NO\textsubscript{X} authorized account representative of a NO\textsubscript{X} Budget opt-in unit does not renew its NO\textsubscript{X} Budget opt-in permit under §97.83(b), the Administrator will deduct from the NO\textsubscript{X} Budget opt-in unit’s compliance account, or the overdraft account of the NO\textsubscript{X} Budget source where the NO\textsubscript{X} Budget opt-in unit is located, NO\textsubscript{X} allowances equal in number to and allocated for the same or a prior control period as any NO\textsubscript{X} allowances allocated to the NO\textsubscript{X} Budget opt-in unit under §97.88 for any control period after the last control period for which the NO\textsubscript{X} Budget opt-in permit is effective. The NO\textsubscript{X} authorized account representative shall ensure that the NO\textsubscript{X} Budget opt-in unit’s compliance account or the overdraft account of the NO\textsubscript{X} Budget source where the NO\textsubscript{X} Budget opt-in unit is located contains the NO\textsubscript{X} allowances necessary for completion of such deduction. If the compliance account or overdraft account does not contain the necessary NO\textsubscript{X} allowances, the Administrator will deduct the required number of NO\textsubscript{X} allowances, regardless of the control period for which they were allocated, whenever NO\textsubscript{X} allowances are recorded in either account.

(iii) If the compliance account or overdraft account does not contain the necessary NO\textsubscript{X} allowances, the Administrator will deduct any remaining allowances to a general account representative of the NO\textsubscript{X} Budget opt-in unit. The NO\textsubscript{X} authorized account representative shall ensure that the NO\textsubscript{X} Budget opt-in unit’s compliance account and transfer any remaining allowances to a general account specified by the owners and operators of the NO\textsubscript{X} Budget opt-in unit.

§97.88 NO\textsubscript{X} allowance allocations to opt-in units.

(a) NO\textsubscript{X} allotment allocation. (1) By April 1 immediately before the first control period for which the NO\textsubscript{X} Budget opt-in permit is effective, the Administrator will determine by order
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the NOₓ allowance allocations for the NOₓ Budget opt-in unit for the control period in accordance with paragraph (b) of this section.

(2) By no later than April 1, after the first control period for which the NOₓ Budget opt-in permit is in effect, and April 1 of each year thereafter, the Administrator will determine by order the NOₓ allowance allocations for the NOₓ Budget opt-in unit for the next control period, in accordance with paragraph (b) of this section.

(3) The Administrator will make available to the public each determination of NOₓ allowance allocations under paragraph (a)(1) or (2) of this section and will provide an opportunity for submission of objections to the determination. Objections shall be limited to addressing whether the determination is in accordance with paragraph (b) of this section. Based on any such objections, the Administrator will adjust each determination to the extent necessary to ensure that it is in accordance with paragraph (b) of this section.

(b) For each control period for which the NOₓ Budget opt-in unit has an approved NOₓ Budget opt-in permit, the NOₓ Budget opt-in unit will be allocated NOₓ allowances in accordance with the following procedures:

(1) The heat input (in mmBtu) used for calculating NOₓ allowance allocations will be the lesser of:

(i) The unit’s baseline heat input determined pursuant to §97.84(c); or

(ii) The unit’s heat input, as determined in accordance with subpart H of this part, for the control period in the year prior to the year of the control period for which the NOₓ allocations are being calculated.

(2) The Administrator will allocate NOₓ allowances to the unit in an amount equaling the heat input determined under paragraph (b)(1) of this section multiplied by the lesser of the unit’s baseline NOₓ emissions rate determined under §97.84(c) or the most stringent State or federal NOₓ emissions limitation applicable to the unit during the control period, divided by 2,000 lb/ton, and rounded to the nearest whole number of NOₓ allowances as appropriate.

Subpart J—Appeal Procedures

§ 97.90 Appeal procedures.

The appeal procedures for the NOₓ Budget Trading Program are set forth in part 78 of this chapter.

[69 FR 21648, Apr. 21, 2004]

Subpart AA—CAIR NOₓ Annual Trading Program General Provisions

§ 97.101 Purpose.

This subpart and subparts BB through II set forth the general provisions and the designated representative, permitting, allowance, monitoring, and opt-in provisions for the Federal Clean Air Interstate Rule (CAIR) NOₓ Annual Trading Program, under section 110 of the Clean Air Act and §52.35 of this chapter, as a means of mitigating interstate transport of fine particulates and nitrogen oxides.

§ 97.102 Definitions.

The terms used in this subpart and subparts BB through II shall have the meanings set forth in this section as follows:

Account number means the identification number given by the Administrator to each CAIR NOₓ Allowance Tracking System account.

Acid Rain emissions limitation means a limitation on emissions of sulfur dioxide or nitrogen oxides under the Acid Rain Program.

Acid Rain Program means a multi-state sulfur dioxide and nitrogen oxides air pollution control and emission reduction program established by the Administrator under title IV of the CAA and parts 72 through 78 of this chapter.

Actual weighted average NOₓ emission rate means, for a NOₓ averaging plan under §76.11 of this chapter and for a year:

(1) The sum of the products of the actual annual average NOₓ emission rate and actual annual heat input (as determined in accordance with part 75 of this chapter) for all units in the NOₓ averaging plan for the year; divided by

(2) The sum of the actual annual heat input (as determined in accordance with part 75 of this chapter) for all
units in the NO\textsubscript{X} averaging plan for the year.

Administrator means the Administrator of the United States Environmental Protection Agency or the Administrator’s duly authorized representative.

Allocate or allocation means, with regard to CAIR NO\textsubscript{X} allowances, the determination by a permitting authority or the Administrator of the amount of such CAIR NO\textsubscript{X} allowances to be initially credited to a CAIR NO\textsubscript{X} unit, a new unit set-aside, or other entity.

Allowance transfer deadline means, for a control period, midnight of March 1 (if it is a business day), or midnight of the first business day thereafter (if March 1 is not a business day), immediately following the control period and is the deadline by which a CAIR NO\textsubscript{X} allowance transfer must be submitted for recordation in a CAIR NO\textsubscript{X} source’s compliance account in order to be used to meet the source’s CAIR NO\textsubscript{X} emissions limitation for such control period in accordance with §97.154.

Alternate CAIR designated representative means, for a CAIR NO\textsubscript{X} source and each CAIR NO\textsubscript{X} unit at the source, the natural person who is authorized by the owners and operators of the source and all such units at the source, in accordance with subparts BB and II of this part, to act on behalf of the CAIR designated representative in matters pertaining to the CAIR NO\textsubscript{X} Annual Trading Program. If the CAIR NO\textsubscript{X} source is also a CAIR NO\textsubscript{X} Ozone Season source, then this natural person shall be the same person as the alternate designated representative under the CAIR NO\textsubscript{X} Ozone Season Trading Program. If the CAIR NO\textsubscript{X} source is also subject to the Acid Rain Program, then this natural person shall be the same person as the alternate designated representative under the Acid Rain Program. If the CAIR NO\textsubscript{X} source is also subject to the Acid Rain Program, then this natural person shall be the same person as the alternate designated representative under the Acid Rain Program.

Automated data acquisition and handling system or DAHS means that component of the continuous emission monitoring system, or other emissions monitoring system approved for use under subpart HH of this part, designed to interpret and convert individual output signals from pollutant concentration monitors, flow monitors, diluent gas monitors, and other component parts of the monitoring system to produce a continuous record of the measured parameters in the measurement units required by subpart HH of this part.

Biomass means—

(1) Any organic material grown for the purpose of being converted to energy;

(2) Any organic byproduct of agriculture that can be converted into energy; or

(3) Any material that can be converted into energy and is nonmerchantable for other purposes, that is segregated from other nonmerchantable material, and that is:

(i) A forest-related organic resource, including mill residues, precommercial thinnings, slash, brush, or byproduct from conversion of trees to merchantable material; or

(ii) A wood material, including pallets, crates, dunnage, manufacturing and construction materials (other than pressure-treated, chemically-treated, or painted wood products), and landscape or right-of-way tree trimmings.

Boiler means an enclosed fossil- or other-fuel-fired combustion device used to produce heat and to transfer heat to recirculating water, steam, or other medium.

Bottoming-cycle cogeneration unit means a cogeneration unit in which the energy input to the unit is first used to produce useful thermal energy and at least some of the reject heat from the useful thermal energy application or process is then used for electricity production.

CAIR authorized account representative means, with regard to a general account, a responsible natural person who is authorized, in accordance with subparts BB, FF, and II of this part, to transfer and otherwise dispose of CAIR
NO\textsubscript{X} allowances held in the general account and, with regard to a compliance account, the CAIR designated representative of the source.  

\textit{CAIR designated representative} means, for a CAIR NO\textsubscript{X} source and each CAIR NO\textsubscript{X} unit at the source, the natural person who is authorized by the owners and operators of the source and all such units at the source, in accordance with subparts BB and II of this part, to represent and legally bind each owner and operator in matters pertaining to the CAIR NO\textsubscript{X} Annual Trading Program. If the CAIR NO\textsubscript{X} source is also a CAIR SO\textsubscript{2} source, then this natural person shall be the same person as the CAIR designated representative under the CAIR SO\textsubscript{2} Trading Program. If the CAIR NO\textsubscript{X} source is also a CAIR NO\textsubscript{X} Ozone Season source, then this natural person shall be the same person as the CAIR designated representative under the CAIR NO\textsubscript{X} Ozone Season Trading Program. If the CAIR NO\textsubscript{X} source is also subject to the Acid Rain Program, then this natural person shall be the same person as the CAIR designated representative under the Acid Rain Program. If the CAIR NO\textsubscript{X} source is also subject to the Hg Budget Trading Program, then this natural person shall be the same person as the Hg designated representative under the Hg Budget Trading Program.

\textit{CAIR NO\textsubscript{X} allowance} means a limited authorization issued by a permitting authority or the Administrator under subpart EE of this part or §97.188, or under provisions of a State implementation plan that are approved under §51.123(o)(1) or (2) or (p) of this chapter, to emit one ton of nitrogen oxides during a control period of the specified calendar year for which the authorization is allocated or of any calendar year thereafter under the CAIR NO\textsubscript{X} Program. An authorization to emit nitrogen oxides that is not issued under subpart EE of this part, §97.188, or provisions of a State implementation plan that are approved under §51.123(o)(1) or (2) or (p) of this chapter shall not be a CAIR NO\textsubscript{X} allowance.

\textit{CAIR NO\textsubscript{X} allowance deduction or deduct CAIR NO\textsubscript{X} allowances} means the permanent withdrawal of CAIR NO\textsubscript{X} allowances by the Administrator from a compliance account, \textit{e.g.}, in order to account for a specified number of tons of total nitrogen oxides emissions from all CAIR NO\textsubscript{X} units at a CAIR NO\textsubscript{X} source for a control period, determined in accordance with subpart HH of this part, or to account for excess emissions.

\textit{CAIR NO\textsubscript{X} Allowance Tracking System} means the system by which the Administrator records allocations, deductions, and transfers of CAIR NO\textsubscript{X} allowances under the CAIR NO\textsubscript{X} Annual Trading Program. Such allowances will be allocated, held, deducted, or transferred only as whole allowances.

\textit{CAIR NO\textsubscript{X} Allowance Tracking System account} means an account in the CAIR NO\textsubscript{X} Allowance Tracking System established by the Administrator for purposes of recording the allocation, holding, transferring, or deducting of CAIR NO\textsubscript{X} allowances.

\textit{CAIR NO\textsubscript{X} allowances held or hold CAIR NO\textsubscript{X} allowances} means the CAIR NO\textsubscript{X} allowances recorded by the Administrator, or submitted to the Administrator for recordation, in accordance with subparts FF, GG, and II of this part, in a CAIR NO\textsubscript{X} Allowance Tracking System account.

\textit{CAIR NO\textsubscript{X} Annual Trading Program} means a multi-state nitrogen oxides air pollution control and emission reduction program established by the Administrator in accordance with subparts AA through II of this part and §§51.123(p) and 52.35 of this chapter or approved and administered by the Administrator in accordance with subparts AA through II of part 96 of this chapter and §§51.123(o)(1) or (2) of this chapter, as a means of mitigating interstate transport of fine particulates and nitrogen oxides.

\textit{CAIR NO\textsubscript{X} emissions limitation} means, for a CAIR NO\textsubscript{X} source, the tonnage equivalent, in NO\textsubscript{X} emissions in a control period, of the CAIR NO\textsubscript{X} allowances available for deduction for the source under §97.154 (a) and (b) for the control period.

\textit{CAIR NO\textsubscript{X} Ozone Season source} means a source that is subject to the CAIR NO\textsubscript{X} Ozone Season Trading Program.

\textit{CAIR NO\textsubscript{X} Ozone Season Trading Program} means a multi-state nitrogen oxides air pollution control and emission reduction program established by the
Administrator in accordance with subparts AAAA through IIII of this part and §§51.123(ee) and 52.35 of this chapter or approved and administered by the Administrator in accordance with subparts AAAA through IIII of part 96 and §§51.125(aa)(1) or (2) (and (bb)(1)), (bb)(2), or (dd) of this chapter, as a means of mitigating interstate transport of ozone and nitrogen oxides.

CAIR NOX source means a source that includes one or more CAIR NOX units.

CAIR NOX unit means a unit that is subject to the CAIR NOX Annual Trading Program under §97.104 and, except for purposes of §97.105 and subpart EE of this part, a CAIR NOX opt-in unit under subpart II of this part.

CAIR permit means the legally binding and federally enforceable written document, or portion of such document, issued by the permitting authority under subpart CC of this part, including any permit revisions, specifying the CAIR NOX Annual Trading Program requirements applicable to a CAIR NOX source, to each CAIR NOX unit at the source, and to the owners and operators and the CAIR designated representative of the source and each such unit.

CAIR SO2 source means a source that is subject to the CAIR SO2 Trading Program.

CAIR SO2 Trading Program means a multi-state sulfur dioxide air pollution control and emission reduction program established by the Administrator in accordance with subparts AAA through IIII of this part and §§51.124(r) and 52.36 of this chapter or approved and administered by the Administrator in accordance with subparts AAA through IIII of part 96 of this chapter and §§51.124(o)(1) or (2) of this chapter, as a means of mitigating interstate transport of fine particulates and sulfur dioxide.

Certifying official means:
(1) For a corporation, a president, secretary, treasurer, or vice-president or the corporation in charge of a principal business function or any other person who performs similar policy or decision-making functions for the corporation;
(2) For a partnership or sole proprietorship, a general partner or the proprietor respectively; or
(3) For a local government entity or State, Federal, or other public agency, a principal executive officer or ranking elected official.

Clean Air Act or CAA means the Clean Air Act, 42 U.S.C. 7401, et seq.

Coal means any solid fuel classified as anthracite, bituminous, subbituminous, or lignite.

Coal-derived fuel means any fuel (whether in a solid, liquid, or gaseous state) produced by the mechanical, thermal, or chemical processing of coal.

Coal-fired means:
(1) Except for purposes of subpart EE of this part, combusting any amount of coal or coal-derived fuel, alone or in combination with any amount of any other fuel, during any year; or
(2) For purposes of subpart EE of this part, combusting any amount of coal or coal-derived fuel, alone or in combination with any amount of any other fuel, during a specified year.

Cogeneration unit means a stationary, fossil-fuel-fired boiler or stationary, fossil-fuel-fired combustion turbine:
(1) Having equipment used to produce electricity and useful thermal energy for industrial, commercial, heating, or cooling purposes through the sequential use of energy; and
(2) Producing during the 12-month period starting on the date the unit first produces electricity and during any calendar year after the calendar year in which the unit first produces electricity—
   (i) For a topping-cycle cogeneration unit, (A) Useful thermal energy not less than 5 percent of total energy output; and
   (B) Useful power that, when added to one-half of useful thermal energy produced, is not less than 42.5 percent of total energy input, if useful thermal energy produced is 15 percent or more of total energy input, or if useful thermal energy produced is less than 15 percent of total energy output.
   (ii) For a bottoming-cycle cogeneration unit, useful power not less than 45 percent of total energy input;
(3) Provided that the total energy input under paragraphs (2)(i)(B) and (2)(ii) of this definition shall equal the...
unit’s total energy input from all fuel except biomass if the unit is a boiler.

**Combustion turbine** means:

1. An enclosed device comprising a compressor, a combustor, and a turbine and in which the flue gas resulting from the combustion of fuel in the combustor passes through the turbine, rotating the turbine; and

2. If the enclosed device under paragraph (1) of this definition is combined cycle, any associated duct burner, heat recovery steam generator, and steam turbine.

**Commence commercial operation** means, with regard to a unit:

1. To have begun to produce steam, gas, or other heated medium used to generate electricity for sale or use, including test generation, except as provided in §97.105 and §97.184(h).

   (i) For a unit that is a CAIR NOX unit under §97.104 on the later of November 15, 1990 or the date the unit commences commercial operation as defined in paragraph (1) of this definition and that subsequently undergoes a physical change (other than replacement of the unit by a unit at the same source), such date shall remain the date of commencement of commercial operation of the unit, which shall continue to be treated as the same unit.

   (ii) For a unit that is a CAIR NOX unit under §97.104 on the later of November 15, 1990 or the date the unit commences commercial operation as defined in paragraph (1) of this definition and that is subsequently replaced by a unit at the same source (e.g., repowered), such date shall remain the replaced unit’s date of commencement of commercial operation, and the replacement unit shall be treated as a separate unit with a separate date for commencement of commercial operation as defined in paragraph (1) or (2) of this definition as appropriate.

2. Notwithstanding paragraph (1) of this definition and except as provided in §97.105, for a unit that is not a CAIR NOX unit under §97.104 on the later of November 15, 1990 or the date the unit commences commercial operation as defined in paragraph (1) of this definition, the unit’s date for commencement of commercial operation shall be the date on which the unit becomes a CAIR NOX unit under §97.104.

(i) For a unit with a date for commencement of commercial operation as defined in paragraph (2) of this definition and that subsequently undergoes a physical change (other than replacement of the unit by a unit at the same source), such date shall remain the date of commencement of commercial operation of the unit, which shall continue to be treated as the same unit.

(ii) For a unit with a date for commencement of commercial operation as defined in paragraph (2) of this definition and that is subsequently replaced by a unit at the same source (e.g., repowered), such date shall remain the replaced unit’s date of commencement of commercial operation, and the replacement unit shall be treated as a separate unit with a separate date for commencement of commercial operation as defined in paragraph (1) or (2) of this definition as appropriate.

**Commence operation** means:

1. To have begun any mechanical, chemical, or electronic process, including, with regard to a unit, start-up of a unit’s combustion chamber, except as provided in §97.184(h).

2. For a unit that undergoes a physical change (other than replacement of the unit by a unit at the same source) after the date the unit commences operation as defined in paragraph (1) of this definition, such date shall remain the date of commencement of operation of the unit, which shall continue to be treated as the same unit.

3. For a unit that is replaced by a unit at the same source (e.g., repowered) after the date the unit commences operation as defined in paragraph (1) of this definition, such date shall remain the replaced unit’s date of commencement of operation, and the replacement unit shall be treated as a separate unit with a separate date for commencement of operation as defined in paragraph (1), (2), or (3) of this definition as appropriate, except as provided in §97.184(h).

**Common stack** means a single flue through which emissions from 2 or more units are exhausted.

**Compliance account** means a CAIR NOX Allowance Tracking System account, established by the Administrator for a CAIR NOX source under subpart FF or II of this part, in which
any CAIR NO\textsubscript{X} allowance allocations for the CAIR NO\textsubscript{X} units at the source are initially recorded and in which are held any CAIR NO\textsubscript{X} allowances available for use for a control period in order to meet the source’s CAIR NO\textsubscript{X} emissions limitation in accordance with §97.154.

Continuous emission monitoring system or CEMS means the equipment required under subpart HH of this part to sample, analyze, measure, and provide, by means of readings recorded at least once every 15 minutes (using an automated data acquisition and handling system (DAHS)), a permanent record of nitrogen oxides emissions, stack gas volumetric flow rate, stack gas moisture content, and oxygen or carbon dioxide concentration (as applicable), in a manner consistent with part 75 of this chapter. The following systems are the principal types of continuous emission monitoring systems required under subpart HH of this part:

(1) A flow monitoring system, consisting of a stack flow rate monitor and an automated data acquisition and handling system and providing a permanent, continuous record of stack gas volumetric flow rate, in standard cubic feet per hour (scfh);

(2) A nitrogen oxides concentration monitoring system, consisting of a NO\textsubscript{X} pollutant concentration monitor and an automated data acquisition and handling system and providing a permanent, continuous record of NO\textsubscript{X} emissions, in parts per million (ppm);

(3) A nitrogen oxides emission rate (or NO\textsubscript{X}-diluent) monitoring system, consisting of a NO\textsubscript{X} pollutant concentration monitor, a diluent gas (CO\textsubscript{2} or O\textsubscript{2}) monitor, and an automated data acquisition and handling system and providing a permanent, continuous record of NO\textsubscript{X} concentration, in parts per million (ppm), diluent gas concentration, in percent CO\textsubscript{2} or O\textsubscript{2}, and NO\textsubscript{X} emission rate, in pounds per million British thermal units (lb/mmBtu);

(4) A moisture monitoring system, as defined in §75.11(b)(2) of this chapter and providing a permanent, continuous record of the stack gas moisture content, in percent H\textsubscript{2}O;

(5) A carbon dioxide monitoring system, consisting of a CO\textsubscript{2} pollutant concentration monitor (or an oxygen monitor plus suitable mathematical equations from which the CO\textsubscript{2} concentration is derived) and an automated data acquisition and handling system and providing a permanent, continuous record of CO\textsubscript{2} emissions, in percent CO\textsubscript{2}; and

(6) An oxygen monitoring system, consisting of an O\textsubscript{2} concentration monitor and an automated data acquisition and handling system and providing a permanent, continuous record of O\textsubscript{2}, in percent O\textsubscript{2}.

Control period means the period beginning January 1 of a calendar year, except as provided in §97.106(c)(2), and ending on December 31 of the same year, inclusive.

Emissions means air pollutants exhausted from a unit or source into the atmosphere, as measured, recorded, and reported to the Administrator by the CAIR designated representative and as determined by the Administrator in accordance with subpart HH of this part.

Excess emissions means any ton of nitrogen oxides emitted by the CAIR NO\textsubscript{X} units at a CAIR NO\textsubscript{X} source during a control period that exceeds the CAIR NO\textsubscript{X} emissions limitation for the source.

Fossil fuel means natural gas, petroleum, coal, or any form of solid, liquid, or gaseous fuel derived from such material.

Fossil-fuel-fired means, with regard to a unit, combusting any amount of fossil fuel in any calendar year.

Fuel oil means any petroleum-based fuel (including diesel fuel or petroleum derivatives such as oil tar) and any recycled or blended petroleum products or petroleum by-products used as a fuel whether in a liquid, solid, or gaseous state.

General account means a CAIR NO\textsubscript{X} Allowance Tracking System account, established under subpart FF of this part, that is not a compliance account.

Generator means a device that produces electricity.

Gross electrical output means, with regard to a cogeneration unit, electricity made available for use, including any such electricity used in the power production process (which process includes, but is not limited to, any onsite processing or treatment of fuel
combusted at the unit and any on-site emission controls).

Heat input means, with regard to a specified period of time, the product (in mmBtu/time) of the gross calorific value of the fuel (in Btu/lb) divided by 1,000,000 Btu/mmBtu and multiplied by the fuel feed rate into a combustion device (in lb of fuel/time), as measured, recorded, and reported to the Administrator by the CAIR designated representative and determined by the Administrator in accordance with subpart HH of this part and excluding the heat derived from preheated combustion air, recirculated flue gases, or exhaust from other sources.

Heat input rate means the amount of heat input (in mmBtu) divided by unit operating time (in hr) or, with regard to a specific fuel, the amount of heat input attributed to the fuel (in mmBtu) divided by the unit operating time (in hr) during which the unit combusts the fuel.

Hg Budget Trading Program means a multi-state Hg air pollution control and emission reduction program approved and administered by the Administrator in accordance subpart HHHH of part 60 of this chapter and §60.24(h)(6), or established by the Administrator under section 111 of the Clean Air Act, as a means of reducing national Hg emissions.

Life-of-the-unit, firm power contractual arrangement means a unit participation power sales agreement under which a utility or industrial customer reserves, or is entitled to receive, a specified amount or percentage of nameplate capacity and associated energy generated by any specified unit and pays its proportional amount of such unit’s total costs, pursuant to a contract:

1. For the life of the unit;
2. For a cumulative term of no less than 30 years, including contracts that permit an election for early termination; or
3. For a period no less than 25 years or 70 percent of the economic useful life of the unit determined as of the time the unit is built, with option rights to purchase or release some portion of the nameplate capacity and associated energy generated by the unit at the end of the period.

Maximum design heat input means the maximum amount of fuel per hour (in Btu/hr) that a unit is capable of combusting on a steady state basis as of the initial installation of the unit as specified by the manufacturer of the unit.

Monitoring system means any monitoring system that meets the requirements of subpart HH of this part, including a continuous emissions monitoring system, an alternative monitoring system, or an excepted monitoring system under part 75 of this chapter.

Most stringent State or Federal NOX emissions limitation means, with regard to a unit, the lowest NOX emissions limitation (in terms of lb/mmBtu) that is applicable to the unit under State or Federal law, regardless of the averaging period to which the emissions limitation applies.

Nameplate capacity means, starting from the initial installation of a generator, the maximum electrical generating output (in MWe) that the generator is capable of producing on a steady state basis and during continuous operation (when not restricted by seasonal or other deratings) as of such installation as specified by the manufacturer of the generator or, starting from the completion of any subsequent physical change in the generator resulting in an increase in the maximum electrical generating output (in MWe) that the generator is capable of producing on a steady state basis and during continuous operation (when not restricted by seasonal or other deratings), such increased maximum amount as of such completion as specified by the person conducting the physical change.

Oil-fired means, for purposes of subpart EE of this part, combusting fuel oil for more than 15.0 percent of the annual heat input in a specified year and not qualifying as coal-fired.

Operator means any person who operates, controls, or supervises a CAIR NOX unit or a CAIR NOX source and shall include, but not be limited to, any holding company, utility system, or plant manager of such a unit or source.

Owner means any of the following persons:
(1) With regard to a CAIR NO\textsubscript{X} source or a CAIR NO\textsubscript{X} unit at a source, respectively:

(i) Any holder of any portion of the legal or equitable title in a CAIR NO\textsubscript{X} unit at the source or the CAIR NO\textsubscript{X} unit;

(ii) Any holder of a leasehold interest in a CAIR NO\textsubscript{X} unit at the source or the CAIR NO\textsubscript{X} unit; or

(iii) Any purchaser of power from a CAIR NO\textsubscript{X} unit at the source or the CAIR NO\textsubscript{X} unit under a life-of-the-unit, firm power contractual arrangement; provided that, unless expressly provided for in a leasehold agreement, owner shall not include a passive lessor, or a person who has an equitable interest through such lessor, whose rental payments are not based (either directly or indirectly) on the revenues or income from such CAIR NO\textsubscript{X} unit; or

(2) With regard to any general account, any person who has an ownership interest with respect to the CAIR NO\textsubscript{X} allowances held in the general account and who is subject to the binding agreement for the CAIR authorized account representative to represent the person’s ownership interest with respect to CAIR NO\textsubscript{X} allowances.

Permitting authority means the State air pollution control agency, local agency, other State agency, or other agency authorized by the Administrator to issue or revise permits to meet the requirements of the CAIR NO\textsubscript{X} Annual Trading Program or, if no such agency has been so authorized, the Administrator.

Potential electrical output capacity means 33 percent of a unit’s maximum design heat input, divided by 3,413 Btu/kWh, divided by 1,000 kWh/MWh, and multiplied by 8,760 hr/yr.

Receive or receipt of means, when referring to the permitting authority or the Administrator, to come into possession of a document, information, or correspondence (whether sent in hard copy or by authorized electronic transmission), as indicated in an official log, or by a notation made on the document, information, or correspondence, by the permitting authority or the Administrator in the regular course of business.

Recordation, record, or recorded means, with regard to CAIR NO\textsubscript{X} allowances, the movement of CAIR NO\textsubscript{X} allowances by the Administrator into or between CAIR NO\textsubscript{X} Allowance Tracking System accounts, for purposes of allocation, transfer, or deduction.

Reference method means any direct test method of sampling and analyzing for an air pollutant as specified in §75.22 of this chapter.

Replacement, replace, or replaced means, with regard to a unit, the demolishing of a unit, or the permanent shutdown and permanent disabling of a unit, and the construction of another unit (the replacement unit) to be used instead of the demolished or shutdown unit (the replaced unit).

Repowered means, with regard to a unit, replacement of a coal-fired boiler with one of the following coal-fired technologies at the same source as the coal-fired boiler:

(1) Atmospheric or pressurized fluidized bed combustion;

(2) Integrated gasification combined cycle;

(3) Magnetohydrodynamics;

(4) Direct and indirect coal-fired turbines;

(5) Integrated gasification fuel cells; or

(6) As determined by the Administrator in consultation with the Secretary of Energy, a derivative of one or more of the technologies under paragraphs (1) through (5) of this definition and any other coal-fired technology capable of controlling multiple combustion emissions simultaneously with improved boiler or generation efficiency and with significantly greater waste reduction relative to the performance of technology in widespread commercial use as of January 1, 2005.

Sequential use of energy means:

(1) For a topping-cycle cogeneration unit, the use of reject heat from electricity production in a useful thermal energy application or process; or

(2) For a bottoming-cycle cogeneration unit, the use of reject heat from useful thermal energy application or process in electricity production.

Serial number means, for a CAIR NO\textsubscript{X} allowance, the unique identification number assigned to each CAIR NO\textsubscript{X} allowance by the Administrator.

Solid waste incineration unit means a stationary, fossil-fuel-fired boiler or
stationary, fossil-fuel-fired combustion turbine that is a “solid waste incineration unit” as defined in section 129(g)(1) of the Clean Air Act.

Source means all buildings, structures, or installations located in one or more contiguous or adjacent properties under common control of the same person or persons. For purposes of section 502(c) of the Clean Air Act, a “source,” including a “source” with multiple units, shall be considered a single “facility.”

State means one of the States or the District of Columbia that is subject to the CAIR NOX Annual Trading Program pursuant to §52.35 of this chapter.

Submit or serve means to send or transmit a document, information, or correspondence to the person specified in accordance with the applicable regulation:
(1) In person;
(2) By United States Postal Service; or
(3) By other means of dispatch or transmission and delivery. Compliance with any “submission” or “service” deadline shall be determined by the date of dispatch, transmission, or mailing and not the date of receipt.

Title V operating permit means a permit issued under title V of the Clean Air Act and part 70 or part 71 of this chapter.

Title V operating permit regulations means the regulations that the Administrator has approved or issued as meeting the requirements of title V of the Clean Air Act and part 70 or 71 of this chapter.

Ton means 2,000 pounds. For the purpose of determining compliance with the CAIR NOX emissions limitation, total tons of nitrogen oxides emissions for a control period shall be calculated as the sum of all recorded hourly emissions (or the mass equivalent of the recorded hourly emission rates) in accordance with subpart HH of this part, but with any remaining fraction of a ton equal to or greater than 0.50 tons deemed to equal one ton and any remaining fraction of a ton less than 0.50 tons deemed to equal zero tons.

Topping-cycle cogeneration unit means a cogeneration unit in which the energy input to the unit is first used to produce useful power, including electricity, and at least some of the reject heat from the electricity production is then used to provide useful thermal energy.

Total energy input means, with regard to a cogeneration unit, total energy of all forms supplied to the cogeneration unit, excluding energy produced by the cogeneration unit itself. Each form of energy supplied shall be measured by the lower heating value of that form of energy calculated as follows:

\[ \text{LHV} = \text{HHV} - 10.55(W + 9H) \]

Where:
\[ \text{LHV} = \text{lower heating value of fuel in Btu/lb}, \]
\[ \text{HHV} = \text{higher heating value of fuel in Btu/lb}, \]
\[ W = \text{Weight \% of moisture in fuel}, \]
\[ H = \text{Weight \% of hydrogen in fuel}. \]

Total energy output means, with regard to a cogeneration unit, the sum of useful power and useful thermal energy produced by the cogeneration unit.

Unit means a stationary, fossil-fuel-fired boiler or combustion turbine or other stationary, fossil-fuel-fired combustion device.

Unit operating day means a calendar day in which a unit combusts any fuel.

Unit operating hour or hour of unit operation means an hour in which a unit combusts any fuel.

Useful power means, with regard to a cogeneration unit, electricity or mechanical energy made available for use, excluding any such energy used in the power production process (which process includes, but is not limited to, any on-site processing or treatment of fuel combusted at the unit and any on-site emission controls).

Useful thermal energy means, with regard to a cogeneration unit, thermal energy that is:
(1) Made available to an industrial or commercial process (not a power production process), excluding any heat contained in condensate return or makeup water;
(2) Used in a heating application (e.g., space heating or domestic hot water heating); or
(3) Used in a space cooling application (i.e., thermal energy used by an absorption chiller).

Utility power distribution system means the portion of an electricity grid owned
or operated by a utility and dedicated to delivering electricity to customers.

§ 97.103 Measurements, abbreviations, and acronyms.

Measurements, abbreviations, and acronyms used in this subpart and subparts BB through II are defined as follows:

Btu—British thermal unit

CO$_2$—carbon dioxide

H$_2$O—water

Hg—mercury

hr—hour

kW—kilowatt electrical

kWh—kilowatt hour

lb—pound

mmBtu—million Btu

MWe—megawatt electrical

MWh—megawatt hour

NO$_X$—nitrogen oxides

O$_2$—oxygen

ppm—parts per million

scfh—standard cubic feet per hour

SO$_2$—sulfur dioxide

yr—year

§ 97.104 Applicability

(a) Except as provided in paragraph (b) of this section:

(1) The following units in a State shall be CAIR NO$_X$ units, and any source that includes one or more such units shall be a CAIR NO$_X$ source, subject to the requirements of this subpart and subparts BB through HH of this part: any stationary, fossil-fuel-fired boiler or stationary, fossil-fuel-fired combustion turbine serving at any time, since the later of November 15, 1990 or the start-up of the unit’s combustion chamber, a generator with nameplate capacity of more than 25 MWe producing electricity for sale.

(b) The units in a State that meet the requirements set forth in paragraph (b)(1)(i), (b)(2)(i), or (b)(2)(ii) of this section shall not be CAIR NO$_X$ units:

(1)(i) Any unit that is a CAIR NO$_X$ unit under paragraph (a)(1) or (2) of this section:

(A) Qualifying as a cogeneration unit during the 12-month period starting on the date the unit first produces electricity and continuing to qualify as a cogeneration unit; and

(B) Not serving at any time, since the later of November 15, 1990 or the start-up of the unit’s combustion chamber, a generator with nameplate capacity of more than 25 MWe supplying in any calendar year more than one-third of the unit’s potential electric output capacity or 219,000 MWh, whichever is greater, to any utility power distribution system for sale.

(ii) If a unit qualifies as a cogeneration unit during the 12-month period starting on the date the unit first produces electricity and meets the requirements of paragraphs (b)(1)(i) of this section for at least one calendar year, but subsequently no longer meets all such requirements, the unit shall become a CAIR NO$_X$ unit starting on the earlier of January 1 after the first calendar year during which the unit first no longer qualifies as a cogeneration unit or January 1 after the first calendar year during which the unit no longer meets the requirements of paragraph (b)(1)(i)(B) of this section.

(2)(i) Any unit that is a CAIR NO$_X$ unit under paragraph (a)(1) or (2) of this section commencing operation before January 1, 1985:

(A) Qualifying as a solid waste incineration unit; and

(B) Not with an average annual fuel consumption of non-fossil fuel for 1985–1987 exceeding 80 percent (on a Btu basis) and an average annual fuel consumption of non-fossil fuel for any 3 consecutive calendar years after 1990 exceeding 80 percent (on a Btu basis).

(ii) Any unit that is a CAIR NO$_X$ unit under paragraph (a)(1) or (2) of this section commencing operation on or after January 1, 1985:

(A) Qualifying as a solid waste incineration unit; and
(B) With an average annual fuel consumption of non-fossil fuel for the first 3 calendar years of operation exceeding 80 percent (on a Btu basis) and an average annual fuel consumption of non-fossil fuel for any 3 consecutive calendar years after 1990 exceeding 80 percent (on a Btu basis).

(iii) If a unit qualifies as a solid waste incineration unit and meets the requirements of paragraph (b)(2)(i) or (ii) of this section for at least 3 consecutive calendar years, but subsequently no longer meets all such requirements, the unit shall become a CAIR NO\textsubscript{X} unit starting on the earlier of January 1 after the first calendar year during which the unit first no longer qualifies as a solid waste incineration unit or January 1 after the first 3 consecutive calendar years after 1990 for which the unit has an average annual fuel consumption of fossil fuel of 20 percent or more.

(c) A certifying official of an owner or operator of any unit may petition the Administrator at any time for a determination concerning the applicability, under paragraphs (a) and (b) of this section, of the CAIR NO\textsubscript{X} Annual Trading Program to the unit.

(1) Petition content. The petition shall be in writing and include the identification of the unit and the relevant facts about the unit. The petition and any other documents provided to the Administrator in connection with the petition shall include the following certification statement, signed by the certifying official: “I am authorized to make this submission on behalf of the owners and operators of the unit for which the submission is made. I certify under penalty of law that I have personally examined, and am familiar with, the statements and information submitted in this document and all its attachments. Based on my inquiry of those individuals with primary responsibility for obtaining the information, I certify that the statements and information are to the best of my knowledge and belief true, accurate, and complete. I am aware that there are significant penalties for submitting false statements and information or omitting required statements and information, including the possibility of fine or imprisonment.”

(2) Submission. The petition and any other documents provided in connection with the petition shall be submitted to the Director of the Clean Air Markets Division (or its successor), U.S. Environmental Protection Agency, who will act on the petition as the Administrator’s duly authorized representative.

(3) Response. The Administrator will issue a written response to the petition and may request supplemental information relevant to such petition. The Administrator’s determination concerning the applicability, under paragraphs (a) and (b) of this section, of the CAIR NO\textsubscript{X} Annual Trading Program to the unit shall be binding on the permitting authority unless the petition or other information or documents provided in connection with the petition are found to have contained significant, relevant errors or omissions.

§ 97.105 Retired unit exemption.

(a)(1) Any CAIR NO\textsubscript{X} unit that is permanently retired and is not a CAIR NO\textsubscript{X} opt-in unit under subpart II of this part shall be exempt from the CAIR NO\textsubscript{X} Annual Trading Program, except for the provisions of this section, §§97.102, 97.103, 97.104, 97.106(c)(4) through (7), 97.107, 97.108, and subparts BB and EE through GG of this part.

(2) The exemption under paragraph (a)(1) of this section shall become effective the day on which the CAIR NO\textsubscript{X} unit is permanently retired. Within 30 days of the unit’s permanent retirement, the CAIR designated representative shall submit a statement to the permitting authority otherwise responsible for administering any CAIR permit for the unit and shall submit a copy of the statement to the Administrator. The statement shall state, in a format prescribed by the permitting authority, that the unit was permanently retired on a specific date and will comply with the requirements of paragraph (b) of this section.

(3) After receipt of the statement under paragraph (a)(2) of this section, the permitting authority will amend any permit under subpart CC of this part covering the source at which the unit is located to add the provisions and requirements of the exemption.
under paragraphs (a)(1) and (b) of this section.

(b) Special provisions. (1) A unit exempt under paragraph (a) of this section shall not emit any nitrogen oxides, starting on the date that the exemption takes effect.

(2) The Administrator or the permitting authority will allocate CAIR NOx allowances under subpart EE of this part to a unit exempt under paragraph (a) of this section.

(3) For a period of 5 years from the date the records are created, the owners and operators of a unit exempt under paragraph (a) of this section shall retain, at the source that includes the unit, records demonstrating that the unit is permanently retired. The 5-year period for keeping records may be extended for cause, at any time before the end of the period, in writing by the permitting authority or the Administrator. The owners and operators bear the burden of proof that the unit is permanently retired.

(4) The owners and operators and, to the extent applicable, the CAIR designated representative of a unit exempt under paragraph (a) of this section shall comply with the requirements of the CAIR NOx Annual Trading Program concerning all periods for which the exemption is not in effect, even if such requirements arise, or must be complied with, after the exemption takes effect.

(5) A unit exempt under paragraph (a) of this section and located at a source that is required, or but for this exemption would be required, to have a Title V operating permit shall not resume operation unless the CAIR designated representative of the source submits a complete CAIR permit application under §97.122 for the unit not less than 18 months (or such lesser time provided by the permitting authority) before the later of January 1, 2009 or the date on which the unit resumes operation.

(6) On the earlier of the following dates, a unit exempt under paragraph (a) of this section shall lose its exemption:

(1) The date on which the CAIR designated representative submits a CAIR permit application for the unit under paragraph (b)(5) of this section;

(ii) The date on which the CAIR designated representative is required under paragraph (b)(5) of this section to submit a CAIR permit application for the unit; or

(iii) The date on which the unit resumes operation, if the CAIR designated representative is not required to submit a CAIR permit application for the unit.

(7) For the purpose of applying monitoring, reporting, and recordkeeping requirements under subpart HH of this part, a unit that loses its exemption under paragraph (a) of this section shall be treated as a unit that commences commercial operation on the first date on which the unit resumes operation.

§ 97.106 Standard requirements.

(a) Permit requirements. (1) The CAIR designated representative of each CAIR NOx source required to have a Title V operating permit and each CAIR NOx unit required to have a Title V operating permit at the source shall:

(i) Submit to the permitting authority a complete CAIR permit application under §97.122 in accordance with the deadlines specified in §97.121; and

(ii) Submit in a timely manner any supplemental information that the permitting authority determines is necessary in order to review a CAIR permit application and issue or deny a CAIR permit.

(2) The owners and operators of each CAIR NOx source required to have a Title V operating permit and each CAIR NOx unit required to have a Title V operating permit at the source shall have a CAIR permit issued by the permitting authority under subpart CC of this part for the source and operate the source and the unit in compliance with such CAIR permit.

(3) Except as provided in subpart II of this part, the owners and operators of a CAIR NOx source that is not otherwise required to have a Title V operating permit and each CAIR NOx unit that is not otherwise required to have a Title V operating permit are not required to submit a CAIR permit application, and to have a CAIR permit, under subpart CC of this part for such CAIR NOx source and such CAIR NOx unit.
(b) Monitoring, reporting, and recordkeeping requirements. (1) The owners and operators, and the CAIR designated representative, of each CAIR NO\(_X\) source and each CAIR NO\(_X\) unit at the source shall comply with the monitoring, reporting, and recordkeeping requirements of subpart HH of this part.

(2) The emissions measurements recorded and reported in accordance with subpart HH of this part shall be used to determine compliance by each CAIR NO\(_X\) source with the CAIR NO\(_X\) emissions limitation under paragraph (c) of this section.

(c) Nitrogen oxides emission requirements. (1) As of the allowance transfer deadline for a control period, the owners and operators of each CAIR NO\(_X\) source and each CAIR NO\(_X\) unit at the source shall hold, in the source’s compliance account, CAIR NO\(_X\) allowances available for compliance deductions for the control period under §97.154(a) in an amount not less than the tons of total nitrogen oxides emissions for the control period from all CAIR NO\(_X\) units at the source, as determined in accordance with subpart HH of this part.

(2) A CAIR NO\(_X\) unit shall be subject to the requirements under paragraph (c)(1) of this section for the control period starting on the later of January 1, 2009 or the deadline for meeting the unit’s monitor certification requirements under §97.170(b)(1), (2), or (5) and for each control period thereafter.

(3) A CAIR NO\(_X\) allowance shall not be deducted, for compliance with the requirements under paragraph (c)(1) of this section, for a control period in a calendar year before the year for which the CAIR NO\(_X\) allowance was allocated.

(4) CAIR NO\(_X\) allowances shall be held in, deducted from, or transferred into or among CAIR NO\(_X\) Allowance Tracking System accounts in accordance with subparts EE, FF, GG, and II of this part.

(5) A CAIR NO\(_X\) allowance is a limited authorization to emit one ton of nitrogen oxides in accordance with the CAIR NO\(_X\) Annual Trading Program. No provision of the CAIR NO\(_X\) Annual Trading Program, the CAIR permit application, the CAIR permit, or an exemption under §97.105 and no provision of law shall be construed to limit the authority of the United States to terminate or limit such authorization.

(6) A CAIR NO\(_X\) allowance does not constitute a property right.

(7) Upon recordation by the Administrator under subpart EE, FF, GG, or II of this part, every allocation, transfer, or deduction of a CAIR NO\(_X\) allowance to or from a CAIR NO\(_X\) source’s compliance account is incorporated automatically in any CAIR permit of the source.

(d) Excess emissions requirements. If a CAIR NO\(_X\) source emits nitrogen oxides during any control period in excess of the CAIR NO\(_X\) emissions limitation, then:

(1) The owners and operators of the source and each CAIR NO\(_X\) unit at the source shall surrender the CAIR NO\(_X\) allowances required for deduction under §97.154(d)(1) and pay any fine, penalty, or assessment or comply with any other remedy imposed, for the same violations, under the Clean Air Act or applicable State law; and

(2) Each ton of such excess emissions and each day of such control period shall constitute a separate violation of this subpart, the Clean Air Act, and applicable State law.

(e) Recordkeeping and reporting requirements. (1) Unless otherwise provided, the owners and operators of the CAIR NO\(_X\) source and each CAIR NO\(_X\) unit at the source shall keep on site at the source each of the following documents that demonstrate the truth of the statements in the certificate of representation; provided that the certificate and documents shall be retained on site at the source beyond such 5-year period until such documents are superseded because of the submission of a new certificate of representation under §97.113 changing the CAIR designated representative.

(i) The certificate of representation under §97.113 for the CAIR designated representative for the source and each CAIR NO\(_X\) unit at the source and all documents that demonstrate the truth of the statements in the certificate of representation; provided that the certificate and documents shall be retained on site at the source beyond such 5-year period until such documents are superseded because of the submission of a new certificate of representation under §97.113 changing the CAIR designated representative.

(ii) All emissions monitoring information, in accordance with subpart HH
§ 97.107 Computation of time.

(a) Unless otherwise stated, any time period scheduled, under the CAIR NOX Annual Trading Program, to begin on the occurrence of an act or event shall begin on the day the act or event occurs.

(b) Unless otherwise stated, any time period scheduled, under the CAIR NOX Annual Trading Program, to begin before the occurrence of an act or event shall be computed so that the period ends the day before the act or event occurs.

(c) Unless otherwise stated, if the final day of any time period, under the CAIR NOX Annual Trading Program, falls on a weekend or a State or Federal holiday, the time period shall be extended to the next business day.

§ 97.108 Appeal procedures.

The appeal procedures for decisions of the Administrator under the CAIR NOX Annual Trading Program are set forth in part 78 of this chapter.

Subpart BB—CAIR Designated Representative for CAIR NOX Sources

§ 97.110 Authorization and responsibilities of CAIR designated representative.

(a) Except as provided under §97.111, each CAIR NOX source, including all CAIR NOX units at the source, shall have one and only one CAIR designated representative, with regard to all matters under the CAIR NOX Annual Trading Program concerning the source or any CAIR NOX unit at the source.

(b) Any provision of the CAIR NOX Annual Trading Program that applies to a CAIR NOX source or the CAIR designated representative of a CAIR NOX source shall also apply to the owners and operators of such source and of the CAIR NOX units at the source.

(c) Any provision of the CAIR NOX Annual Trading Program that applies to a CAIR NOX unit or the CAIR designated representative of a CAIR NOX unit shall also apply to the owners and operators of such unit.

(g) Effect on other authorities. No provision of the CAIR NOX Annual Trading Program, a CAIR permit application, a CAIR permit, or an exemption under §97.105 shall be construed as exempting or excluding the owners and operators, and the CAIR designated representative, of a CAIR NOX source or CAIR NOX unit from compliance with any other provision of the applicable, approved State implementation plan, a federally enforceable permit, or the Clean Air Act.

§ 97.107 Computation of time.

(a) Unless otherwise stated, any time period scheduled, under the CAIR NOX Annual Trading Program, to begin on the occurrence of an act or event shall begin on the day the act or event occurs.

(b) Unless otherwise stated, any time period scheduled, under the CAIR NOX Annual Trading Program, to begin before the occurrence of an act or event shall be computed so that the period ends the day before the act or event occurs.

(c) Unless otherwise stated, if the final day of any time period, under the CAIR NOX Annual Trading Program, falls on a weekend or a State or Federal holiday, the time period shall be extended to the next business day.

§ 97.110 Authorization and responsibilities of CAIR designated representative.

(a) Except as provided under §97.111, each CAIR NOX source, including all CAIR NOX units at the source, shall have one and only one CAIR designated representative, with regard to all matters under the CAIR NOX Annual Trading Program concerning the source or any CAIR NOX unit at the source.

(b) Any provision of the CAIR NOX Annual Trading Program that applies to a CAIR NOX source or the CAIR designated representative of a CAIR NOX source shall also apply to the owners and operators of such source and of the CAIR NOX units at the source.

(c) Any provision of the CAIR NOX Annual Trading Program that applies to a CAIR NOX unit or the CAIR designated representative of a CAIR NOX unit shall also apply to the owners and operators of such unit.

(g) Effect on other authorities. No provision of the CAIR NOX Annual Trading Program, a CAIR permit application, a CAIR permit, or an exemption under §97.105 shall be construed as exempting or excluding the owners and operators, and the CAIR designated representative, of a CAIR NOX source or CAIR NOX unit from compliance with any other provision of the applicable, approved State implementation plan, a federally enforceable permit, or the Clean Air Act.
between the CAIR designated representative and such owners and operators. The owners and operators shall be bound by any decision or order issued to the CAIR designated representative by the permitting authority, the Administrator, or a court regarding the source or unit.

(d) No CAIR permit will be issued, no emissions data reports will be accepted, and no CAIR NO\textsubscript{X} Allowance Tracking System account will be established for a CAIR NO\textsubscript{X} unit at a source, until the Administrator has received a complete certificate of representation under §97.113 for a CAIR designated representative of the source and the CAIR NO\textsubscript{X} units at the source.

(e)(1) Each submission under the CAIR NO\textsubscript{X} Annual Trading Program shall be submitted, signed, and certified by the CAIR designated representative for each CAIR NO\textsubscript{X} source on behalf of which the submission is made. Each such submission shall include the following certification statement by the CAIR designated representative: “I am authorized to make this submission on behalf of the owners and operators of the source or units for which the submission is made. I certify under penalty of law that I have personally examined, and am familiar with, the statements and information submitted in this document and all its attachments. Based on my inquiry of those individuals with primary responsibility for obtaining the information, I certify that the statements and information are to the best of my knowledge and belief true, accurate, and complete. I am aware that there are significant penalties for submitting false statements and information or omitting required statements and information, including the possibility of fine or imprisonment.”

(2) The permitting authority and the Administrator will accept or act on a submission made on behalf of owner or operators of a CAIR NO\textsubscript{X} source or a CAIR NO\textsubscript{X} unit only if the submission has been made, signed, and certified in accordance with paragraph (e)(1) of this section.

§97.112 Changing CAIR designated representative and alternate CAIR designated representative; changes in owners and operators.

(a) Changing CAIR designated representative. The CAIR designated representative may be changed at any time upon receipt by the Administrator of a superseding complete certificate of representation under §97.113. Notwithstanding any such change, all representations, actions, inactions, and submissions by the previous CAIR designated representative before the time and date when the Administrator receives the superseding certificate of representation shall be binding on the new CAIR designated representative and the owners and operators of the CAIR NO\textsubscript{X} source and the CAIR NO\textsubscript{X} units at the source.

(b) Changing alternate CAIR designated representative. The alternate CAIR designated representative may be changed at any time upon receipt by the Administrator of a superseding complete certificate of representation under
§ 97.113 Certificate of representation.

(a) A complete certificate of representation for a CAIR designated representative or an alternate CAIR designated representative shall include the following elements in a format prescribed by the Administrator:

(1) Identification of the CAIR NO\textsubscript{X} source, and each CAIR NO\textsubscript{X} unit at the source, for which the certificate of representation is submitted, including identification and nameplate capacity of each generator served by each such unit.

(2) The name, address, e-mail address (if any), telephone number, and facsimile transmission number (if any) of the CAIR designated representative and any alternate CAIR designated representative.

(3) A list of the owners and operators of the CAIR NO\textsubscript{X} source and of each CAIR NO\textsubscript{X} unit at the source.

(4) The following certification statements by the CAIR designated representative and any alternate CAIR designated representative:

(i) “I certify that I was selected as the CAIR designated representative or alternate CAIR designated representative, as applicable, by an agreement binding on the owners and operators of the source and each CAIR NO\textsubscript{X} unit at the source.”

(ii) “I certify that I have all the necessary authority to carry out my duties and responsibilities under the CAIR NO\textsubscript{X} Annual Trading Program on behalf of the owners and operators of the source and each CAIR NO\textsubscript{X} unit at the source and that each such owner and operator shall be fully bound by my representations, actions, inactions, or submissions.”

(iii) “I certify that the owners and operators of the source and of each CAIR NO\textsubscript{X} unit at the source shall be bound by any order issued to me by the Administrator, the permitting authority, or a court regarding the source or unit.”

(iv) Where there are multiple holders of a legal or equitable title to, or a leasehold interest in, a CAIR NO\textsubscript{X} unit, or where a utility or industrial customer purchases power from a CAIR NO\textsubscript{X} unit under a life-of-the-unit, firm power contractual arrangement, I certify that: I have given a written notice of my selection as the ‘CAIR designated representative’ or ‘alternate CAIR designated representative’, as applicable, and of the agreement by which I was selected to each owner and operator of the source and of each CAIR NO\textsubscript{X} unit at the source; and CAIR NO\textsubscript{X} allowances and proceeds of transactions involving CAIR NO\textsubscript{X} allowances will be deemed to be held or distributed in proportion to each holder’s legal, equitable, leasehold, or contractual reservation or entitlement, except that, if such multiple holders have expressly provided for a different distribution of CAIR NO\textsubscript{X} allowances by contract, CAIR NO\textsubscript{X} allowances and proceeds of
transactions involving CAIR NO\(_x\) allowances will be deemed to be held or distributed in accordance with the contract.”

(5) The signature of the CAIR designated representative and any alternate CAIR designated representative and the dates signed.

(b) Unless otherwise required by the permitting authority or the Administrator, documents of agreement referred to in the certificate of representation shall not be submitted to the permitting authority or the Administrator. Neither the permitting authority nor the Administrator shall be under any obligation to review or evaluate the sufficiency of such documents, if submitted.

§ 97.114 Objections concerning CAIR designated representative.

(a) Once a complete certificate of representation under §97.113 has been submitted and received, the permitting authority and the Administrator will rely on the certificate of representation unless and until a superseding complete certificate of representation under §97.113 is received by the Administrator.

(b) Except as provided in §97.112(a) or (b), no objection or other communication submitted to the permitting authority or the Administrator concerning the authorization, or any representation, action, inaction, or submission, of the CAIR designated representative shall affect any representation, action, inaction, or submission of the CAIR designated representative or the finality of any decision or order by the permitting authority or the Administrator under the CAIR NO\(_x\) Annual Trading Program.

(c) Neither the permitting authority nor the Administrator will adjudicate any private legal dispute concerning the authorization or any representation, action, inaction, or submission of any CAIR designated representative, including private legal disputes concerning the proceeds of CAIR NO\(_x\) allowance transfers.

§ 97.115 Delegation by CAIR designated representative and alternate CAIR designated representative.

(a) A CAIR designated representative may delegate, to one or more natural persons, his or her authority to make an electronic submission to the Administrator provided for or required under this part.

(b) An alternate CAIR designated representative may delegate, to one or more natural persons, his or her authority to make an electronic submission to the Administrator provided for or required under this part.

(c) In order to delegate authority to make an electronic submission to the Administrator in accordance with paragraph (a) or (b) of this section, the CAIR designated representative or alternate CAIR designated representative, as appropriate, must submit to the Administrator a notice of delegation, in a format prescribed by the Administrator, that includes the following elements:

(1) The name, address, e-mail address, telephone number, and facsimile transmission number (if any) of such CAIR designated representative or alternate CAIR designated representative;

(2) The name, address, e-mail address, telephone number, and facsimile transmission number (if any) of each such natural person (referred to as an “agent”);

(3) For each such natural person, a list of the type or types of electronic submissions under paragraph (a) or (b) of this section for which authority is delegated to him or her; and

(4) The following certification statements by such CAIR designated representative or alternate CAIR designated representative:

(i) “I agree that any electronic submission to the Administrator that is by an agent identified in this notice of delegation and of a type listed for such agent in this notice of delegation and that is made when I am a CAIR designated representative or alternate CAIR designated representative, as appropriate, and before this notice of delegation is superseded by another notice of delegation under 40 CFR §97.115(d) shall be deemed to be an electronic submission by me.”
(ii) "Until this notice of delegation is superseded by another notice of delegation under 40 CFR 97.115(d), I agree to maintain an e-mail account and to notify the Administrator immediately of any change in my e-mail address unless all delegation of authority by me under 40 CFR 97.115 is terminated."

(d) A notice of delegation submitted under paragraph (c) of this section shall be effective, with regard to the CAIR designated representative or alternate CAIR designated representative identified in such notice, upon receipt of such notice by the Administrator and until receipt by the Administrator of a superseding notice of delegation submitted by such CAIR designated representative or alternate CAIR designated representative, as appropriate. The superseding notice of delegation may replace any previously identified agent, add a new agent, or eliminate entirely any delegation of authority.

(e) Any electronic submission covered by the certification in paragraph (c)(4)(i) of this section and made in accordance with a notice of delegation effective under paragraph (d) of this section shall be deemed to be an electronic submission by the CAIR designated representative or alternate CAIR designated representative submitting such notice of delegation.

Subpart CC—Permits

§ 97.120 General CAIR NOX Annual Trading Program permit requirements.

(a) For each CAIR NOX source required to have a title V operating permit or required, under subpart II of this part, to have a title V operating permit or other federally enforceable permit, such permit shall include a CAIR permit administered by the permitting authority for the title V operating permit or the federally enforceable permit as applicable. The CAIR portion of the title V permit or other federally enforceable permit as applicable shall be administered in accordance with the permitting authority’s title V operating permits regulations promulgated under part 70 or 71 of this chapter or the permitting authority’s regulations for other federally enforceable permits as applicable, except as provided otherwise by §97.105, this subpart, and subpart II of this part.

(b) Each CAIR permit shall contain, with regard to the CAIR NOX source and the CAIR NOX units at the source covered by the CAIR permit, all applicable CAIR NOX Annual Trading Program, CAIR NOX Ozone Season Trading Program, and CAIR SO2 Trading Program requirements and shall be a complete and separable portion of the title V operating permit or other federally enforceable permit under paragraph (a) of this section.

§ 97.121 Submission of CAIR permit applications.

(a) Duty to apply. The CAIR designated representative of any CAIR NOX source required to have a title V operating permit shall submit to the permitting authority a complete CAIR permit application under §97.122 for the source covering each CAIR NOX unit at the source at least 18 months (or such lesser time provided by the permitting authority) before the later of January 1, 2009 or the date on which the CAIR NOX unit commences commercial operation, except as provided in §97.183(a).

(b) Duty to reapply. For a CAIR NOX source required to have a title V operating permit, the CAIR designated representative shall submit a complete CAIR permit application under §97.122 for the source covering each CAIR NOX unit at the source to renew the CAIR permit in accordance with the permitting authority’s title V operating permits regulations addressing permit renewal, except as provided in §97.183(b).

§ 97.122 Information requirements for CAIR permit applications.

A complete CAIR permit application shall include the following elements concerning the CAIR NOX source for which the application is submitted, in a format prescribed by the permitting authority:

(a) Identification of the CAIR NOX source;

(b) Identification of each CAIR NOX unit at the CAIR NOX source; and

(c) The standard requirements under §97.106.
§ 97.123 CAIR permit contents and term.

(a) Each CAIR permit will contain, in a format prescribed by the permitting authority, all elements required for a complete CAIR permit application under § 97.122.

(b) Each CAIR permit is deemed to incorporate automatically the definitions of terms under § 97.102 and, upon recordation by the Administrator under subpart EE, FF, GG, or II of this part, every allocation, transfer, or deduction of a CAIR NO\textsubscript{X} allowance to or from the compliance account of the CAIR NO\textsubscript{X} source covered by the permit.

(c) The term of the CAIR permit will be set by the permitting authority, as necessary to facilitate coordination of the renewal of the CAIR permit with issuance, revision, or renewal of the CAIR NO\textsubscript{X} source’s title V operating permit or other federally enforceable permit as applicable.

§ 97.124 CAIR permit revisions.

Except as provided in § 97.123(b), the permitting authority will revise the CAIR permit, as necessary, in accordance with the permitting authority’s title V operating permits regulations or the permitting authority’s regulations for other federally enforceable permits as applicable addressing permit revisions.

Subpart DD [Reserved]

Subpart EE—CAIR NO\textsubscript{X} Allowance Allocations

§ 97.140 State trading budgets.

The State trading budgets for annual allocations of CAIR NO\textsubscript{X} allowances for the control periods in 2009 through 2014 and in 2015 and thereafter are respectively as follows:

<table>
<thead>
<tr>
<th>State</th>
<th>State trading budget for 2009–2014 (tons)</th>
<th>State trading budget for 2015 and thereafter (tons)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Alabama</td>
<td>69,020</td>
<td>57,517</td>
</tr>
<tr>
<td>Delaware</td>
<td>4,166</td>
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<td>Florida</td>
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<td>Illinois</td>
<td>76,230</td>
<td>63,525</td>
</tr>
<tr>
<td>Indiana</td>
<td>108,935</td>
<td>90,779</td>
</tr>
</tbody>
</table>

§ 97.141 Timing requirements for CAIR NO\textsubscript{X} allowance allocations.

(a) The Administrator will determine by order the CAIR NO\textsubscript{X} allowance allocations, in accordance with § 97.142(a) and (b), for the control periods in 2009, 2010, 2011, 2012, 2013, and 2014.

(b) By July 31, 2011 and July 31 of each year thereafter, the Administrator will determine by order the CAIR NO\textsubscript{X} allowance allocations, in accordance with § 97.142(a) and (b), for the control period in the fourth year after the year of the applicable deadline for determination under this paragraph.

(c) By July 31, 2009 and July 31 of each year thereafter, the Administrator will determine by order the CAIR NO\textsubscript{X} allowance allocations, in accordance with § 97.142(a), (c), and (d), for the control period in the year of the applicable deadline for determination under this paragraph.

(d) The Administrator will make available to the public each determination of CAIR NO\textsubscript{X} allowances under paragraph (a), (b), or (c) of this section and will provide an opportunity for submission of objections to the determination. Objections shall be limited to addressing whether the determination is in accordance with § 97.142. Based on any such objections, the Administrator will adjust each determination to the extent necessary to ensure that it is in accordance with § 97.142.
§ 97.142 CAIR NO\textsubscript{X} allowance allocations.

(a)(1) The baseline heat input (in mmBtu) used with respect to CAIR NO\textsubscript{X} allowance allocations under paragraph (b) of this section for each CAIR NO\textsubscript{X} unit will be:

(i) For units commencing operation before January 1, 2001 the average of the 3 highest amounts of the unit’s adjusted control period heat input for 2000 through 2004, with the adjusted control period heat input for each year calculated as follows:

(A) If the unit is coal-fired during the year, the unit’s control period heat input for such year is multiplied by 100 percent;  
(B) If the unit is oil-fired during the year, the unit’s control period heat input for such year is multiplied by 60 percent; and 
(C) If the unit is not subject to paragraph (a)(1)(i)(A) or (B) of this section, the unit’s control period heat input for such year is multiplied by 40 percent.

(ii) For units commencing operation on or after January 1, 2001 and operating each calendar year during a period of 5 or more consecutive calendar years, the average of the 3 highest amounts of the unit’s total converted control period heat input over the first such 5 years.

(2)(i) A unit’s control period heat input, and a unit’s status as coal-fired or oil-fired, for a calendar year under paragraph (a)(1)(i)(A) or (B) of this section, the unit’s control period heat input for such year is multiplied by 40 percent; and

(ii) For units commencing operation on or after January 1, 2001 and operating each calendar year during a period of 5 or more consecutive calendar years, the average of the 3 highest amounts of the unit’s total converted control period heat input over the first such 5 years.

(3) The Administrator will determine what data are the best available data under paragraph (a)(2) of this section by weighing the likelihood that data are accurate and reliable and giving greater weight to data submitted to a governmental entity in compliance with legal requirements or substantiated by an independent entity.

(b)(1) For each control period in 2009 and thereafter, the Administrator will allocate to all CAIR NO\textsubscript{X} units in a State that have a baseline heat input of the generator or generators served by the unit multiplied by 7,900 Btu/kWh, if the unit is coal-fired for the year, or 6,675 Btu/kWh, if the unit is not coal-fired for the year, and divided by 1,000,000 Btu/mmBtu, provided that if a generator is served by 2 or more units, then the gross electrical output of the generator will be attributed to each unit in proportion to the unit’s share of the total control period heat input of such units for the year;

(B) For a unit that is a boiler and has equipment used to produce electricity and useful thermal energy for industrial, commercial, heating, or cooling purposes through the sequential use of energy, the total heat energy (in Btu) of the steam produced by the boiler during the control period, divided by 0.8 and by 1,000,000 Btu/mmBtu; or

(C) For a unit that is a combustion turbine and has equipment used to produce electricity and useful thermal energy for industrial, commercial, heating, or cooling purposes through the sequential use of energy, the control period gross electrical output of the enclosed device comprising the compressor, combustor, and turbine multiplied by 3,413 Btu/kWh, plus the total heat energy (in Btu) of the steam produced by any associated heat recovery steam generator during the control period divided by 0.8, and with the sum divided by 1,000,000 Btu/mmBtu.

(iii) Gross electrical output and total heat energy under paragraph (a)(2)(ii) of this section will be determined based on the best available data reported to the Administrator for the unit (in a format prescribed by the Administrator).

(3) The Administrator will determine what data are the best available data under paragraph (a)(2) of this section by weighing the likelihood that data are accurate and reliable and giving greater weight to data submitted to a governmental entity in compliance with legal requirements or substantiated by an independent entity.

(b)(1) For each control period in 2009 and thereafter, the Administrator will allocate to all CAIR NO\textsubscript{X} units in a State that have a baseline heat input of the generator or generators served by the unit multiplied by 7,900 Btu/kWh, if the unit is coal-fired for the year, or 6,675 Btu/kWh, if the unit is not coal-fired for the year, and divided by 1,000,000 Btu/mmBtu, provided that if a generator is served by 2 or more units, then the gross electrical output of the generator will be attributed to each unit in proportion to the unit’s share of the total control period heat input of such units for the year.

(B) For a unit that is a boiler and has equipment used to produce electricity and useful thermal energy for industrial, commercial, heating, or cooling purposes through the sequential use of energy, the total heat energy (in Btu) of the steam produced by the boiler during the control period, divided by 0.8 and by 1,000,000 Btu/mmBtu; or

(C) For a unit that is a combustion turbine and has equipment used to produce electricity and useful thermal energy for industrial, commercial, heating, or cooling purposes through the sequential use of energy, the control period gross electrical output of the enclosed device comprising the compressor, combustor, and turbine multiplied by 3,413 Btu/kWh, plus the total heat energy (in Btu) of the steam produced by any associated heat recovery steam generator during the control period divided by 0.8, and with the sum divided by 1,000,000 Btu/mmBtu.
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a control period during 2009 through 2014, and 97 percent for a control period during 2015 and thereafter, of the tons of NOx emissions in the applicable State trading budget under §97.140 (except as provided in paragraphs (d) and (e) of this section).

(2) The Administrator will allocate CAIR NOx allowances to each CAIR NOx unit under paragraph (b)(1) of this section in an amount determined by multiplying the total amount of CAIR NOx allowances allocated under paragraph (b)(1) of this section by the ratio of the baseline heat input of such CAIR NOx unit to the total amount of baseline heat input of all such CAIR NOx units in the State and rounding to the nearest whole allowance as appropriate.

(c) For each control period in 2009 and thereafter, the Administrator will allocate CAIR NOx allowances to CAIR NOx units in a State that are not allocated CAIR NOx allowances under paragraph (b) of this section because the units do not yet have a baseline heat input under paragraph (a) of this section or because the units have a baseline heat input but all CAIR NOx allowances available under paragraph (b) of this section for the control period are already allocated, in accordance with the following procedures:

(1) The Administrator will establish a separate new unit set-aside for each control period. Each new unit set-aside will be allocated CAIR NOx allowances equal to 5 percent for a control period in 2009 through 2014, and 3 percent for a control period in 2015 and thereafter, of the amount of tons of NOx emissions in the applicable State trading budget under §97.140.

(2) The CAIR designated representative of such a CAIR NOx unit may submit to the Administrator a request, in a format specified by the Administrator, to be allocated CAIR NOx allowances, starting with the later of the control period in 2009 or the first control period after the control period in which the CAIR NOx unit commences commercial operation and until the first control period for which the unit is allocated CAIR NOx allowances under paragraph (b) of this section. A separate CAIR NOx allowance allocation request for each control period for which CAIR NOx allowances are sought must be submitted on or before May 1 of such control period and after the date on which the CAIR NOx unit commences commercial operation.

(3) In a CAIR NOx allowance allocation request under paragraph (c)(2) of this section, the CAIR designated representative may request for a control period CAIR NOx allowances in an amount not exceeding the CAIR NOx unit’s total tons of NOx emissions during the calendar year immediately before such control period.

(4) The Administrator will review each CAIR NOx allowance allocation request under paragraph (c)(2) of this section and will allocate CAIR NOx allowances for each control period pursuant to such request as follows:

(i) The Administrator will accept an allowance allocation request only if the request meets, or is adjusted by the Administrator as necessary to meet, the requirements of paragraphs (c)(2) and (3) of this section.

(ii) On or after May 1 of the control period, the Administrator will determine the sum of the CAIR NOx allowances requested (as adjusted under paragraph (c)(4)(i) of this section) in all allowance allocation requests accepted under paragraph (c)(4)(i) of this section for the control period.

(iii) If the amount of CAIR NOx allowances in the new unit set-aside for the control period is greater than or equal to the sum under paragraph (c)(4)(i) of this section, then the Administrator will allocate the amount of CAIR NOx allowances requested (as adjusted under paragraph (c)(4)(i) of this section) to each CAIR NOx unit covered by an allowance allocation request accepted under paragraph (c)(4)(i) of this section.

(iv) If the amount of CAIR NOx allowances in the new unit set-aside for the control period is less than the sum under paragraph (c)(4)(ii) of this section, then the Administrator will allocate to each CAIR NOx unit covered by an allowance allocation request accepted under paragraph (c)(4)(i) of this section the amount of the CAIR NOx allowances requested (as adjusted under paragraph (c)(4)(i) of this section), multiplied by the amount of CAIR NOx allowances in the new unit set-aside for
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the control period, divided by the sum determined under paragraph (c)(4)(i) of this section, and rounded to the nearest whole allowance as appropriate.

(v) The Administrator will notify each CAIR designated representative that submitted an allowance allocation request of the amount of CAIR NOX allowances (if any) allocated for the control period to the CAIR NOX unit covered by the request.

(d) If, after completion of the procedures under paragraph (c)(4) of this section for a control period, any unallocated CAIR NOX allowances remain in the new unit set-aside under paragraph (c) of this section for a State for the control period, the Administrator will allocate to each CAIR NOX unit that was allocated CAIR NOX allowances under paragraph (b) of this section in the State an amount of CAIR NOX allowances equal to the total amount of such remaining unallocated CAIR NOX allowances, multiplied by the unit's allocation under paragraph (b) of this section, divided by 95 percent for a control period during 2009 through 2014, and 97 percent for a control period during 2015 and thereafter, of the amount of tons of NOx emissions in the applicable State trading budget under §97.140 and rounded to the nearest whole allowance as appropriate.

(e) If the Administrator determines that CAIR NOX allowances were allocated under paragraphs (a) and (b) of this section, paragraphs (a) and (c) of this section, or paragraph (d) of this section for a control period and that the recipient of the allocation is not actually a CAIR NOX unit under §97.104 in such control period, then the Administrator will notify the CAIR designated representative and will act in accordance with the following procedures:

1. Except as provided in paragraph (e)(2) or (3) of this section, the Administrator will not record such CAIR NOX allowances under §97.153.

2. If the Administrator already recorded such CAIR NOX allowances under §97.153 and if the Administrator makes such determination after making deductions for the source that includes such recipient under §97.154(b) for the control period, then the Administrator will apply paragraph (e)(1) or (2) of this section, as appropriate, to any subsequent control period for which CAIR NOX allowances were allocated to such recipient.

(4) The Administrator will transfer the CAIR NOX allowances that are not recorded, or that are deducted, in accordance with paragraphs (e)(1), (2), and (3) of this section to a new unit set-aside for the State in which such recipient is located.

§ 97.143 Compliance supplement pool.

(a) In addition to the CAIR NOX allowances allocated under §97.142, the Administrator may allocate for the control period in 2009 up to the following amount of CAIR NOX allowances to CAIR NOX units in the respective State:

<table>
<thead>
<tr>
<th>State</th>
<th>Compliance supplement pool</th>
</tr>
</thead>
<tbody>
<tr>
<td>Alabama</td>
<td>10,166</td>
</tr>
<tr>
<td>Delaware</td>
<td>843</td>
</tr>
<tr>
<td>District of Columbia</td>
<td>0</td>
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<tr>
<td>Florida</td>
<td>8,335</td>
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<tr>
<td>Georgia</td>
<td>12,397</td>
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<tr>
<td>Illinois</td>
<td>11,299</td>
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<tr>
<td>Indiana</td>
<td>20,155</td>
</tr>
<tr>
<td>Iowa</td>
<td>6,978</td>
</tr>
<tr>
<td>Kentucky</td>
<td>14,935</td>
</tr>
<tr>
<td>Louisiana</td>
<td>2,251</td>
</tr>
<tr>
<td>Maryland</td>
<td>4,670</td>
</tr>
<tr>
<td>Michigan</td>
<td>8,347</td>
</tr>
<tr>
<td>Minnesota</td>
<td>6,528</td>
</tr>
<tr>
<td>Mississippi</td>
<td>3,066</td>
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<tr>
<td>Missouri</td>
<td>9,044</td>
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<tr>
<td>New Jersey</td>
<td>660</td>
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<tr>
<td>New York</td>
<td>0</td>
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<td>North Carolina</td>
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<td>Ohio</td>
<td>25,037</td>
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<tr>
<td>Pennsylvania</td>
<td>16,009</td>
</tr>
<tr>
<td>South Carolina</td>
<td>2,600</td>
</tr>
</tbody>
</table>
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(b) For any CAIR NO\textsubscript{X} unit in a State, if the unit’s average annual NO\textsubscript{X} emission rate for 2007 or 2008 is less than 0.25 lb/mmBtu and, where such unit is included in a NO\textsubscript{X} averaging plan under §76.11 of this chapter under the Acid Rain Program for such year, the unit’s NO\textsubscript{X} averaging plan has an actual weighted average NO\textsubscript{X} emission rate for such year equal to or less than the actual weighted average NO\textsubscript{X} emission rate for the year before such year and if the unit achieves NO\textsubscript{X} emission reductions in 2007 and 2008, the CAIR designated representative of the unit may request early reduction credits, in accordance with the following:

(1) The owners and operators of such CAIR NO\textsubscript{X} unit shall monitor and report the NO\textsubscript{X} emissions rate and the heat input of the unit in accordance with subpart HH of this part in each control period for which early reduction credits are requested.

(2) The CAIR designated representative of such CAIR NO\textsubscript{X} unit shall submit to the Administrator by May 1, 2009 a request, in a format specified by the Administrator, for allocation of an amount of CAIR NO\textsubscript{X} allowances from the compliance supplement pool not exceeding the minimum amount of CAIR NO\textsubscript{X} allowances necessary to remove such undue risk to the reliability of electricity supply.

(c) For any CAIR NO\textsubscript{X} unit in a State whose compliance with the CAIR NO\textsubscript{X} emissions limitation for the control period in 2009 would create an undue risk to the reliability of electricity supply during such control period, the CAIR designated representative of the unit may request the allocation of CAIR NO\textsubscript{X} allowances from the compliance supplement pool under paragraph (a) of this section, in accordance with the following:

(1) The CAIR designated representative of such CAIR NO\textsubscript{X} unit shall submit to the Administrator by May 1, 2009 a request, in a format specified by the Administrator, for allocation of an amount of CAIR NO\textsubscript{X} allowances from the compliance supplement pool not exceeding the minimum amount of CAIR NO\textsubscript{X} allowances necessary to remove such undue risk to the reliability of electricity supply.

(2) In the request under paragraph (c)(1) of this section, the CAIR designated representative of such CAIR NO\textsubscript{X} unit shall demonstrate that, in the absence of allocation to the unit of the amount of CAIR NO\textsubscript{X} allowances requested, the unit’s compliance with the CAIR NO\textsubscript{X} emissions limitation for the control period in 2009 would create an undue risk to the reliability of electricity supply during such control period. This demonstration must include a showing that it would not be feasible for the owners and operators of the unit to:

(i) Obtain a sufficient amount of electricity from other electricity generation facilities, during the installation of control technology at the unit for compliance with the CAIR NO\textsubscript{X} emissions limitation, to prevent such undue risk; or

(ii) Obtain under paragraphs (b) and (d) of this section, or otherwise obtain, a sufficient amount of CAIR NO\textsubscript{X} allowances to prevent such undue risk.

(d) The Administrator will review each request under paragraph (b) or (c) of this section submitted by May 1, 2009 and will allocate CAIR NO\textsubscript{X} allowances for the control period in 2009 to CAIR NO\textsubscript{X} units in a State and covered by such request as follows:

<table>
<thead>
<tr>
<th>State</th>
<th>Compliance supplement pool</th>
</tr>
</thead>
<tbody>
<tr>
<td>Tennessee</td>
<td>8,944</td>
</tr>
<tr>
<td>Texas</td>
<td>772</td>
</tr>
<tr>
<td>Virginia</td>
<td>5,134</td>
</tr>
<tr>
<td>West Virginia</td>
<td>16,929</td>
</tr>
<tr>
<td>Wisconsin</td>
<td>4,898</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td><strong>199,997</strong></td>
</tr>
</tbody>
</table>
§ 97.144 Alternative of allocation of CAIR NO\textsubscript{X} allowances and compliance supplement pool by permitting authority.

(a) Notwithstanding §§97.141, 97.142, and 97.153 if a State submits, and the Administrator approves, a State implementation plan revision in accordance with §51.123(p)(2) of this chapter providing for allocation of CAIR NO\textsubscript{X} allowances by the permitting authority, then the permitting authority shall make such allocations in accordance with such approved State implementation plan revision, the Administrator will not make allocations under §§97.141 and 97.142 for the CAIR NO\textsubscript{X} units in the State, and under §97.153, the Administrator will record the allocations made under such approved State implementation plan revision instead of allocations made under §§97.141 and 97.142.

(b) Notwithstanding §97.143, if a State submits, and the Administrator approves, a State implementation plan revision in accordance with §51.123(p)(2) of this chapter providing for allocation of the State’s compliance supplement pool by the permitting authority, then the permitting authority shall make such allocations in accordance with such approved State implementation plan revision, the Administrator will not make allocations under §§97.141 and 97.142 for the CAIR NO\textsubscript{X} units in the State, and under §97.153, the Administrator will record the allocations made under such approved State implementation plan revision instead of allocations made under §§97.141 and 97.142.
under such approved State implementation plan revision instead of allocations made under §97.143(d)(4).

(c)(1) In implementing paragraph (a) of this section and §§97.141, 97.142, and 97.153, the Administrator will ensure that the total amount of CAIR NO\textsubscript{X} allowances allocated, under such provisions and under a State’s State implementation plan revision approved in accordance with §51.123(p)(1) of this chapter, for a control period for CAIR NO\textsubscript{X} sources in the State or for other entities specified by the permitting authority will not exceed the State’s State trading budget for the year of the control period.

(2) In implementing paragraph (b) of this section and §97.143, the Administrator will ensure that the total amount of CAIR NO\textsubscript{X} allowances allocated, under such provisions and under a State’s State implementation plan revision approved in accordance with §51.123(p)(2), for CAIR NO\textsubscript{X} sources in the State will not exceed the State’s compliance supplement pool.

[65 FR 2727, Jan. 18, 2000, as amended at 71 FR 74795, Dec. 13, 2006]

APPENDIX A TO SUBPART EE OF PART 97—STATES WITH APPROVED STATE IMPLEMENTATION PLAN REVISIONS CONCERNING ALLOCATIONS

1. The following States have State Implementation Plan revisions under §51.123(p)(1) of this chapter approved by the Administrator and providing for allocation of CAIR NO\textsubscript{X} allowances by the permitting authority under §97.144(a):
   - Indiana
   - Louisiana
   - Michigan
   - New Jersey
   - North Carolina
   - Ohio
   - South Carolina
   - Tennessee
   - Texas (for control periods 2009–2014)
   - West Virginia (for control periods 2009–2014)
   - Wisconsin

2. The following States have State Implementation Plan revisions under §51.123(p)(2) of this chapter approved by the Administrator and providing for allocation of the Compliance Supplement Pool by the permitting authority under §97.144(b):
   - Indiana
   - Michigan
   - New Jersey
   - Ohio
   - South Carolina
   - Texas


Subpart FF—CAIR NO\textsubscript{X} Allowance Tracking System

§97.150 [Reserved]

§97.151 Establishment of accounts.

(a) Compliance accounts. Except as provided in §97.184(e), upon receipt of a complete certificate of representation under §97.113, the Administrator will establish a compliance account for the CAIR NO\textsubscript{X} source for which the certificate of representation was submitted, unless the source already has a compliance account.

(b) General accounts—(1) Application for general account. (i) Any person may apply to open a general account for the purpose of holding and transferring CAIR NO\textsubscript{X} allowances. An application for a general account may designate one and only one CAIR authorized account representative and one and only one alternate CAIR authorized account representative who may act on behalf of the CAIR authorized account representative. The agreement by which the alternate CAIR authorized account representative is selected shall include a procedure for authorizing the alternate CAIR authorized account representative to act in lieu of the CAIR authorized account representative.

(ii) A complete application for a general account shall be submitted to the Administrator and shall include the following elements in a format prescribed by the Administrator:
   (A) Name, mailing address, e-mail address (if any), telephone number, and facsimile transmission number (if any) of the CAIR authorized account representative and any alternate CAIR authorized account representative; and
   (B) Organization name and type of organization, if applicable;
   (C) A list of all persons subject to a binding agreement for the CAIR authorized account representative and
any alternate CAIR authorized account representative to represent their ownership interest with respect to the CAIR NO\textsubscript{X} allowances held in the general account;

(D) The following certification statement by the CAIR authorized account representative or the alternate CAIR authorized account representative, as applicable, by an agreement that is binding on all persons who have an ownership interest with respect to CAIR NO\textsubscript{X} allowances held in the general account:

I certify that I was selected as the CAIR authorized account representative or the alternate CAIR authorized account representative, and that each such person shall be fully bound by my representations, actions, inactions, or submissions and by any order or decision issued to me by the Administrator or a court regarding the general account.

(E) The signature of the CAIR authorized account representative and any alternate CAIR authorized account representative and the dates signed.

(iii) Unless otherwise required by the permitting authority or the Administrator, documents of agreement referred to in the application for a general account shall not be submitted to the permitting authority or the Administrator. Neither the permitting authority nor the Administrator shall be under any obligation to review or evaluate the sufficiency of such documents, if submitted.

(2) Authorization of CAIR authorized account representative and alternate CAIR authorized account representative.

(i) Upon receipt by the Administrator of a complete application for a general account under paragraph (b)(1) of this section:

(A) The Administrator will establish a general account for the person or persons for whom the application is submitted.

(B) The CAIR authorized account representative and any alternate CAIR authorized account representative for the general account shall represent and, by his or her representations, actions, inactions, or submissions, legally bind each person who has an ownership interest with respect to CAIR NO\textsubscript{X} allowances held in the general account in all matters pertaining to the CAIR NO\textsubscript{X} Annual Trading Program, notwithstanding any agreement between the CAIR authorized account representative or any alternate CAIR authorized account representative and such person. Any such person shall be bound by any order or decision issued to the CAIR authorized account representative or any alternate CAIR authorized account representative by the Administrator or a court regarding the general account.

(C) Any representation, action, inaction, or submission by any alternate CAIR authorized account representative shall be deemed to be a representation, action, inaction, or submission by the CAIR authorized account representative.

(ii) Each submission concerning the general account shall be submitted, signed, and certified by the CAIR authorized account representative or any alternate CAIR authorized account representative for the persons having an ownership interest with respect to CAIR NO\textsubscript{X} allowances held in the general account. Each such submission shall include the following certification statement by the CAIR authorized account representative or any alternate CAIR authorized account representative: "I am authorized to make this submission on behalf of the persons having an ownership interest with respect to the CAIR NO\textsubscript{X} allowances held in the general account. I certify under penalty of law that I have personally examined, and am familiar with, the statements and information submitted in this document and all its attachments. Based on my inquiry of those individuals with primary responsibility for obtaining the information, I certify that the statements and information are to the best of my knowledge and belief true, accurate, and complete. I am aware that there are significant penalties for submitting false statements and information or omitting required statements and information, including the possibility of fine or imprisonment."

(iii) The Administrator will accept or act on a submission concerning the
general account only if the submission has been made, signed, and certified in accordance with paragraph (b)(2)(ii) of this section.

(3) Changing CAIR authorized account representative and alternate CAIR authorized account representative; changes in persons with ownership interest. (i) The CAIR authorized account representative for a general account may be changed at any time upon receipt by the Administrator of a superseding complete application for a general account under paragraph (b)(1) of this section. Notwithstanding any such change, all representations, actions, inactions, and submissions by the previous CAIR authorized account representative before the time and date when the Administrator receives the superseding application for a general account shall be binding on the new CAIR authorized account representative and the persons with an ownership interest with respect to the CAIR NO\textsubscript{X} allowances in the general account.

(ii) The alternate CAIR authorized account representative for a general account may be changed at any time upon receipt by the Administrator of a superseding complete application for a general account under paragraph (b)(1) of this section. Notwithstanding any such change, all representations, actions, inactions, and submissions by the previous alternate CAIR authorized account representative before the time and date when the Administrator receives the superseding application for a general account shall be binding on the new alternate CAIR authorized account representative and the persons with an ownership interest with respect to the CAIR NO\textsubscript{X} allowances in the general account.

(iii)(A) In the event a person having an ownership interest with respect to CAIR NO\textsubscript{X} allowances in the general account is not included in the list of such persons in the application for a general account, such person shall be deemed to be subject to and bound by the application for a general account, the representation, actions, inactions, and submissions of the CAIR authorized account representative and any alternate CAIR authorized account representative of the account, and the decisions and orders of the Administrator or a court, as if the person were included in such list.

(B) Within 30 days following any change in the persons having an ownership interest with respect to CAIR NO\textsubscript{X} allowances in the general account, including the addition of a new person, the CAIR authorized account representative or any alternate CAIR authorized account representative shall submit a revision to the application for a general account amending the list of persons having an ownership interest with respect to the CAIR NO\textsubscript{X} allowances in the general account to include the change.

(4) Objections concerning CAIR authorized account representative and alternate CAIR authorized account representative. (i) Once a complete application for a general account under paragraph (b)(1) of this section has been submitted and received, the Administrator will rely on the application unless and until a superseding complete application for a general account under paragraph (b)(1) of this section is received by the Administrator.

(ii) Except as provided in paragraph (b)(3)(i) or (ii) of this section, no objection or other communication submitted to the Administrator concerning the authorization, or any representation, action, inaction, or submission of the CAIR authorized account representative or any alternate CAIR authorized account representative for a general account shall affect any representation, action, inaction, or submission of the CAIR authorized account representative or any alternate CAIR authorized account representative or the finality of any decision or order by the Administrator under the CAIR NO\textsubscript{X} Annual Trading Program.

(iii) The Administrator will not adjudicate any private legal dispute concerning the authorization or any representation, action, inaction, or submission of the CAIR authorized account representative or any alternate CAIR authorized account representative or the finality of any decision or order by the Administrator under the CAIR NO\textsubscript{X} Annual Trading Program.

(5) Delegation by CAIR authorized account representative and alternate CAIR authorized account representative. (i) A
CAIR authorized account representative may delegate, to one or more natural persons, his or her authority to make an electronic submission to the Administrator provided for or required under subparts FF and GG of this part.

(ii) An alternate CAIR authorized account representative may delegate, to one or more natural persons, his or her authority to make an electronic submission to the Administrator provided for or required under subparts FF and GG of this part.

(iii) In order to delegate authority to make an electronic submission to the Administrator in accordance with paragraph (b)(5)(i) or (ii) of this section, the CAIR authorized account representative or alternate CAIR authorized account representative, as appropriate, must submit to the Administrator a notice of delegation, in a format prescribed by the Administrator, that includes the following elements:

(A) The name, address, e-mail address, telephone number, and facsimile transmission number (if any) of such CAIR authorized account representative or alternate CAIR authorized account representative;

(B) The name, address, e-mail address, telephone number, and facsimile transmission number (if any) of each such natural person (referred to as an "agent");

(C) For each such natural person, a list of the type or types of electronic submissions under paragraph (b)(5)(i) or (ii) of this section for which authority is delegated to him or her;

(D) The following certification statement by such CAIR authorized account representative or alternate CAIR authorized account representative: "I agree that any electronic submission to the Administrator that is by an agent identified in this notice of delegation and of a type listed for such agent in this notice of delegation and that is made when I am a CAIR authorized account representative or alternate CAIR authorized representative, as appropriate, and before this notice of delegation is superseded by another notice of delegation under 40 CFR 97.151(b)(5)(iv), I agree to maintain an e-mail account and to notify the Administrator immediately of any change in my e-mail address unless all delegation of authority by me under 40 CFR 97.151(b)(5) is terminated.",

(iv) A notice of delegation submitted under paragraph (b)(5)(iii) of this section shall be effective, with regard to the CAIR authorized account representative or alternate CAIR authorized account representative identified in such notice, upon receipt of such notice by the Administrator and until receipt by the Administrator of a superseding notice of delegation submitted by such CAIR authorized account representative or alternate CAIR authorized account representative, as appropriate. The superseding notice of delegation may replace any previously identified agent, add a new agent, or eliminate entirely any delegation of authority.

(v) Any electronic submission covered by the certification in paragraph (b)(5)(iii)(D) of this section and made in accordance with a notice of delegation effective under paragraph (b)(5)(iv) of this section shall be deemed to be an electronic submission by the CAIR designated representative or alternate CAIR designated representative submitting such notice of delegation.

(c) Account identification. The Administrator will assign a unique identifying number to each account established under paragraph (a) or (b) of this section.

§ 97.152 Responsibilities of CAIR authorized account representative.

Following the establishment of a CAIR NOX Allowance Tracking System account, all submissions to the Administrator pertaining to the account, including, but not limited to, submissions concerning the deduction or transfer of CAIR NOX allowances in the account, shall be made only by the CAIR authorized account representative for the account.
§ 97.153 Recordation of CAIR NO\textsubscript{X} allowance allocations.

(a) By September 30, 2007, the Administrator will record in the CAIR NO\textsubscript{X} source’s compliance account the CAIR NO\textsubscript{X} allowances allocated for the CAIR NO\textsubscript{X} units at the source in accordance with § 97.142(a) and (b) for the control period in 2007.

(b) By September 30, 2008, the Administrator will record in the CAIR NO\textsubscript{X} source’s compliance account the CAIR NO\textsubscript{X} allowances allocated for the CAIR NO\textsubscript{X} units at the source in accordance with § 97.142(a) and (b) for the control period in 2008.

(c) By September 30, 2009, the Administrator will record in the CAIR NO\textsubscript{X} source’s compliance account the CAIR NO\textsubscript{X} allowances allocated for the CAIR NO\textsubscript{X} units at the source in accordance with § 97.142(a) and (b) for the control periods in 2011, 2012, and 2013.

(d) By December 1, 2010 and December 1 of each year thereafter, the Administrator will record in the CAIR NO\textsubscript{X} source’s compliance account the CAIR NO\textsubscript{X} allowances allocated for the CAIR NO\textsubscript{X} units at the source in accordance with § 97.142(a) and (b) for the control period in the fourth year after the year of the applicable deadline for recordation under this paragraph.

(e) By December 1, 2009 and December 1 of each year thereafter, the Administrator will record in the CAIR NO\textsubscript{X} source’s compliance account the CAIR NO\textsubscript{X} allowances allocated for the CAIR NO\textsubscript{X} units at the source in accordance with § 97.142(a) and (b) for the control period in the year of the applicable deadline for recordation under this paragraph.

(f) Serial numbers for allocated CAIR NO\textsubscript{X} allowances. When recording the allocation of CAIR NO\textsubscript{X} allowances for a CAIR NO\textsubscript{X} unit in a compliance account, the Administrator will assign each CAIR NO\textsubscript{X} allowance a unique identification number that will include digits identifying the year of the control period for which the CAIR NO\textsubscript{X} allowance is allocated.

§ 97.154 Compliance with CAIR NO\textsubscript{X} emissions limitation.

(a) Allowance transfer deadline. The CAIR NO\textsubscript{X} allowances are available to be deducted for compliance with a source’s CAIR NO\textsubscript{X} emissions limitation for a control period in a given calendar year only if the CAIR NO\textsubscript{X} allowances:

1. Were allocated for the control period in the year or a prior year; and
2. Are held in the compliance account as of the allowance transfer deadline for the control period or are transferred into the compliance account by a CAIR NO\textsubscript{X} allowance transfer correctly submitted for recordation under §§ 97.160 and 97.161 by the allowance transfer deadline for the control period.

(b) Deductions for compliance. Following the recordation, in accordance with § 97.161, of CAIR NO\textsubscript{X} allowance transfers submitted for recordation in a source’s compliance account by the allowance transfer deadline for a control period, the Administrator will deduct from the compliance account CAIR NO\textsubscript{X} allowances available under paragraph (a) of this section in order to determine whether the source meets the CAIR NO\textsubscript{X} emissions limitation for the control period, as follows:

1. Until the amount of CAIR NO\textsubscript{X} allowances deducted equals the number of tons of total nitrogen oxides emissions, determined in accordance with subpart HH of this part, from all CAIR NO\textsubscript{X} units at the source for the control period; or
2. If there are insufficient CAIR NO\textsubscript{X} allowances to complete the deductions in paragraph (b)(1) of this section, until no more CAIR NO\textsubscript{X} allowances available under paragraph (a) of this section remain in the compliance account.

(c) Identification of CAIR NO\textsubscript{X} allowances by serial number. The Administrator may request that specific CAIR NO\textsubscript{X} allowances, identified by serial number, in the compliance account be deducted for emissions or excess emissions for a control period in accordance with paragraph (b) or (d) of this section. Such request shall be submitted to the Administrator by the allowance transfer deadline for the control period and include, in a format prescribed by the Administrator, the identification of the CAIR NO\textsubscript{X} source and the appropriate serial numbers.
§ 97.155 Banking.

(a) CAIR NO\textsubscript{X} allowances may be banked for future use or transfer in a compliance account or a general account in accordance with paragraph (b) of this section.

(b) Any CAIR NO\textsubscript{X} allowance that is held in a compliance account or a general account will remain in such account unless and until the CAIR NO\textsubscript{X} allowance is deducted or transferred under §97.142, §97.154, §97.156, or subpart GG or II of this part.

§ 97.156 Account error.

The Administrator may, at his or her sole discretion and on his or her own motion, correct any error in any CAIR NO\textsubscript{X} Allowance Tracking System account. Within 10 business days of making such correction, the Administrator will notify the CAIR authorized account representative for the account.

§ 97.157 Closing of general accounts.

(a) The CAIR authorized account representative of a general account may submit to the Administrator a request to close the account, which shall include a correctly submitted allowance transfer under §§97.160 and 97.161 for any CAIR NO\textsubscript{X} allowances in the account to one or more other CAIR NO\textsubscript{X} Allowance Tracking System accounts.

(b) If a general account has no allowance transfers in or out of the account for a 12-month period or longer and does not contain any CAIR NO\textsubscript{X} allowances, the Administrator may notify the CAIR authorized account representative for the account that the account will be closed following 20 business days after the notice is sent. The account will be closed after the 20-day period unless, before the end of the 20-day period, the Administrator receives a correctly submitted transfer of CAIR NO\textsubscript{X} allowances into the account under §§97.160 and 97.161 or a statement submitted by the CAIR authorized account representative demonstrating to the satisfaction of the Administrator good
cause as to why the account should not be closed.

**Subpart GG—CAIR NO\textsubscript{X} Allowance Transfers**

§ 97.160 Submission of CAIR NO\textsubscript{X} allowance transfers.

A CAIR authorized account representative seeking recordation of a CAIR NO\textsubscript{X} allowance transfer shall submit the transfer to the Administrator. To be considered correctly submitted, the CAIR NO\textsubscript{X} allowance transfer shall include the following elements, in a format specified by the Administrator:

(a) The account numbers for both the transferor and transferee accounts;

(b) The serial number of each CAIR NO\textsubscript{X} allowance that is in the transferor account and is to be transferred; and

(c) The name and signature of the CAIR authorized account representative of the transferor account and the date signed.

§ 97.161 EPA recordation.

(a) Within 5 business days (except as provided in paragraph (b) of this section) of receiving a CAIR NO\textsubscript{X} allowance transfer, the Administrator will record a CAIR NO\textsubscript{X} allowance transfer by moving each CAIR NO\textsubscript{X} allowance from the transferor account to the transferee account as specified by the request, provided that:

(1) The transfer is correctly submitted under § 97.160; and

(2) The transferor account includes each CAIR NO\textsubscript{X} allowance identified by serial number in the transfer.

(b) A CAIR NO\textsubscript{X} allowance transfer that is submitted for recordation after the allowance transfer deadline for a control period and that includes any CAIR NO\textsubscript{X} allowances allocated for any control period before such allowance transfer deadline will not be recorded until after the Administrator completes the deductions under § 97.154 for the control period immediately before such allowance transfer deadline.

(c) Where a CAIR NO\textsubscript{X} allowance transfer submitted for recordation fails to meet the requirements of paragraph (a) of this section, the Administrator will not record such transfer.

§ 97.162 Notification.

(a) Notification of recordation. Within 5 business days of recordation of a CAIR NO\textsubscript{X} allowance transfer under § 97.161, the Administrator will notify the CAIR authorized account representatives of both the transferor and transferee accounts.

(b) Notification of non-recordation. Within 10 business days of receipt of a CAIR NO\textsubscript{X} allowance transfer that fails to meet the requirements of § 97.161(a), the Administrator will notify the CAIR authorized account representatives of both accounts subject to the transfer of:

(1) A decision not to record the transfer, and

(2) The reasons for such non-recordation.

(c) Nothing in this section shall preclude the submission of a CAIR NO\textsubscript{X} allowance transfer for recordation following notification of non-recordation.

**Subpart HH—Monitoring and Reporting**

§ 97.170 General requirements.

The owners and operators, and to the extent applicable, the CAIR designated representative, of a CAIR NO\textsubscript{X} unit, shall comply with the monitoring, recordkeeping, and reporting requirements as provided in this subpart and in subpart H of part 75 of this chapter. For purposes of complying with such requirements, the definitions in § 97.102 and in § 72.2 of this chapter shall apply, and the terms “affected unit,” “designated representative,” and “continuous emission monitoring system” or “CEMS”) in part 75 of this chapter shall be deemed to refer to the terms “CAIR NO\textsubscript{X} unit,” “CAIR designated representative,” and “continuous emission monitoring system” (or “CEMS”) respectively, as defined in § 97.102. The owner or operator of a unit that is not a CAIR NO\textsubscript{X} unit but that is monitored under § 75.72(b)(2)(ii) of this chapter shall comply with the same monitoring, recordkeeping, and reporting requirements as a CAIR NO\textsubscript{X} unit.

(a) Requirements for installation, certification, and data accounting. The owner or operator of each CAIR NO\textsubscript{X} unit shall:
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(1) Install all monitoring systems required under this subpart for monitoring NO\textsubscript{X} mass emissions and individual unit heat input (including all systems required to monitor NO\textsubscript{X} emission rate, NO\textsubscript{X} concentration, stack gas moisture content, stack gas flow rate, CO\textsubscript{2} or O\textsubscript{2} concentration, and fuel flow rate, as applicable, in accordance with §§75.71 and 75.72 of this chapter);

(2) Successfully complete all certification tests required under §97.171 and meet all other requirements of this subpart and part 75 of this chapter applicable to the monitoring systems under paragraph (a)(1) of this section; and

(3) Record, report, and quality assures the data from the monitoring systems under paragraph (a)(1) of this section.

(b) Compliance deadlines. Except as provided in paragraph (e) of this section, the owner or operator shall meet the monitoring system certification and other requirements of paragraphs (a)(1) and (2) of this section on or before the following dates. The owner or operator shall record, report, and quality-assure the data from the monitoring systems under paragraph (a)(1) of this section on and after the following dates.

(1) For the owner or operator of a CAIR NO\textsubscript{X} unit that commences commercial operation before July 1, 2007, by January 1, 2008.

(2) For the owner or operator of a CAIR NO\textsubscript{X} unit that commences commercial operation on or after July 1, 2007, by the later of the following dates:

(i) January 1, 2008; or

(ii) 90 unit operating days or 180 calendar days, whichever occurs first, after the date on which the unit commences commercial operation.

(3) For the owner or operator of a CAIR NO\textsubscript{X} unit for which construction of a new stack or flue or installation of add-on NO\textsubscript{X} emission controls is completed after the applicable deadline under paragraph (b)(1), (2), (4), or (5) of this section, by 90 unit operating days or 180 calendar days, whichever occurs first, after the date on which emissions first exit to the atmosphere through the new stack or flue or add-on NO\textsubscript{X} emissions controls.

(4) Notwithstanding the dates in paragraphs (b)(1) and (2) of this section, for the owner or operator of a unit for which a CAIR opt-in permit application is submitted and not withdrawn and a CAIR opt-in permit is not yet issued or denied under subpart II of this part, by the date specified in §97.184(b).

(5) Notwithstanding the dates in paragraphs (b)(1) and (2) of this section, for the owner or operator of a CAIR NO\textsubscript{X} opt-in unit under subpart II of this part, by the date on which the CAIR NO\textsubscript{X} opt-in unit enters the CAIR NO\textsubscript{X} Annual Trading Program as provided in §97.184(g).

(c) Reporting data. The owner or operator of a CAIR NO\textsubscript{X} unit that does not meet the applicable compliance date set forth in paragraph (b) of this section for any monitoring system under paragraph (a)(1) of this section shall, for each such monitoring system, determine, record, and report maximum potential (or, as appropriate, minimum potential) values for NO\textsubscript{X} concentration, NO\textsubscript{X} emission rate, stack gas flow rate, stack gas moisture content, fuel flow rate, and any other parameters required to determine NO\textsubscript{X} mass emissions and heat input in accordance with §75.31(b)(2) or (c)(3) of this chapter, section 2.4 of appendix D to part 75 of this chapter, or section 2.5 of appendix E to part 75 of this chapter, as applicable.

(d) Prohibitions. (1) No owner or operator of a CAIR NO\textsubscript{X} unit shall use any alternative monitoring system, alternative reference method, or any other alternative to any requirement of this subpart without having obtained prior written approval in accordance with §97.175.

(2) No owner or operator of a CAIR NO\textsubscript{X} unit shall operate the unit so as to discharge, or allow to be discharged, NO\textsubscript{X} emissions to the atmosphere without accounting for all such emissions in accordance with the applicable provisions of this subpart and part 75 of this chapter.

(3) No owner or operator of a CAIR NO\textsubscript{X} unit shall disrupt the continuous emission monitoring system, any portion thereof, or any other approved emission monitoring method, and thereby avoid monitoring and recording NO\textsubscript{X} mass emissions discharged.
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§ 97.171 Initial certification and recertification procedures.

(a) The owner or operator of a CAIR NO\textsubscript{X} unit shall be exempt from the initial certification requirements of this section for a monitoring system under §97.170(a)(1) if the following conditions are met:

1. The monitoring system has been previously certified in accordance with part 75 of this chapter; and
2. The applicable quality-assurance and quality-control requirements of §75.21 of this chapter and appendix B, appendix D, and appendix E to part 75 of this chapter are fully met for the certified monitoring system described in paragraph (a)(1) of this section.

(b) The recertification provisions of this section shall apply to a monitoring system under §97.170(a)(1) exempt from initial certification requirements under paragraph (a) of this section.

(c) If the Administrator has previously approved a petition under §75.17(a) or (b) of this section for apportioning the NO\textsubscript{X} emission rate measured in a common stack or a petition under §75.66 of this chapter for an alternative to a requirement in §75.12 or §75.17 of this chapter, the CAIR designated representative shall resubmit the petition to the Administrator under §97.175 to determine whether the approval applies under the CAIR NO\textsubscript{X} Annual Trading Program.

(d) Except as provided in paragraph (a) of this section, the owner or operator of a CAIR NO\textsubscript{X} unit shall comply with the following initial certification and recertification procedures for a continuous monitoring system (i.e., a continuous emission monitoring system and an excepted monitoring system under appendices D and E to part 75 of this chapter) under §97.170(a)(1).

The owner or operator of a unit that qualifies to use the low mass emissions excepted monitoring methodology under §75.19 of this chapter or that qualifies to use an alternative monitoring system under subpart E of part 75 of this chapter shall comply with the procedures in paragraph (e) or (f) of this section respectively.

1. Requirements for initial certification.

(a) The owner or operator shall ensure that each continuous monitoring system under §97.170(a)(1) (including the automated data acquisition and handling system) successfully completes all of the initial certification testing required under §75.20 of this chapter by the applicable deadline in §97.170(b). In addition, whenever the owner or operator installs a monitoring system to meet the requirements of this subpart in a location where no such monitoring system was previously installed, initial certification in accordance with §75.20 of this chapter is required.

2. Requirements for recertification.

Whenever the owner or operator makes a replacement, modification, or change in any certified continuous emission monitoring system under §97.170(a)(1)
that may significantly affect the ability of the system to accurately measure or record NO\textsubscript{X} mass emissions or heat input rate or to meet the quality-assurance and quality-control requirements of §73.21 of this chapter or appendix B to part 75 of this chapter, the owner or operator shall recertify the monitoring system in accordance with §75.20(b) of this chapter. Furthermore, whenever the owner or operator makes a replacement, modification, or change to the flue gas handling system or the unit’s operation that may significantly change the stack flow or concentration profile, the owner or operator shall recertify each continuous emission monitoring system whose accuracy is potentially affected by the change, in accordance with §75.20(b) of this chapter. Examples of changes to a continuous emission monitoring system that require recertification include replacement of the analyzer, complete replacement of an existing continuous emission monitoring system, or change in location or orientation of the sampling probe or site. Any fuel flowmeter system, and any excepted NO\textsubscript{X} monitoring system under appendix E to part 75 of this chapter, under §97.170(a)(1) are subject to the recertification requirements in §75.20(g)(6) of this chapter.

(3) Approval process for initial certification and recertification. Paragraphs (d)(3)(i) through (iv) of this section apply to both initial certification and recertification of a continuous monitoring system under §97.170(a)(1). For recertifications, replace the words “certification” and “initial certification” with the word “recertification”, and follow the procedures in §§75.20(b)(5) and (g)(7) of this chapter in lieu of the procedures in paragraph (d)(3)(v) of this section.

(i) Notification of certification. The CAIR designated representative shall submit to the appropriate EPA Regional Office and the Administrator written notice of the dates of certification testing, in accordance with §97.173.

(ii) Certification application. The CAIR designated representative shall submit to the Administrator a certification application for each monitoring system. A complete certification application shall include the information specified in §75.63 of this chapter.

(iii) Provisional certification date. The provisional certification date for a monitoring system shall be determined in accordance with §75.20(a)(3) of this chapter. A provisionally certified monitoring system may be used under the CAIR NO\textsubscript{X} Annual Trading Program for a period not to exceed 120 days after receipt by the Administrator of the complete certification application for the monitoring system under paragraph (d)(3)(ii) of this section. Data measured and recorded by the provisionally certified monitoring system, in accordance with the requirements of part 75 of this chapter, will be considered valid quality-assured data (retroactive to the date and time of provisional certification), provided that the Administrator does not invalidate the provisional certification by issuing a notice of disapproval within 120 days of the date of receipt of the complete certification application by the Administrator.

(iv) Certification application approval process. The Administrator will issue a written notice of approval or disapproval of the certification application to the owner or operator within 120 days of receipt of the complete certification application under paragraph (d)(3)(ii) of this section. In the event the Administrator does not issue such a notice within such 120-day period, each monitoring system that meets the applicable performance requirements of part 75 of this chapter and is included in the certification application will be deemed certified for use under the CAIR NO\textsubscript{X} Annual Trading Program.

(A) Approval notice. If the certification application is complete and shows that each monitoring system meets the applicable performance requirements of part 75 of this chapter, then the Administrator will issue a written notice of approval of the certification application within 120 days of receipt.

(B) Incomplete application notice. If the certification application is not complete, then the Administrator will issue a written notice of incompleteness that sets a reasonable date by
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which the CAIR designated representative must submit the additional information required to complete the certification application. If the CAIR designated representative does not comply with the notice of incompleteness by the specified date, then the Administrator may issue a notice of disapproval under paragraph (d)(3)(iv)(C) of this section. The 120-day review period shall not begin before receipt of a complete certification application.

(C) Disapproval notice. If the certification application shows that any monitoring system does not meet the performance requirements of part 75 of this chapter or if the certification application is incomplete and the requirement for disapproval under paragraph (d)(3)(iv)(B) of this section is met, then the Administrator will issue a written notice of disapproval of the certification application. Upon issuance of such notice of disapproval, the provisional certification is invalidated by the Administrator and the data measured and recorded by each uncertified monitoring system shall not be considered valid quality-assured data beginning with the date and hour of provisional certification (as defined under § 75.20(a)(4)(iii), § 75.20(g)(7), or § 75.21(e) of this chapter). The owner or operator shall follow the procedures for loss of certification in paragraph (d)(3)(v) of this section for each monitoring system that is disapproved for initial certification.

(D) Audit decertification. The Administrator may issue a notice of disapproval of the certification status of a monitor in accordance with § 97.172(b).

(v) Procedures for loss of certification. If the Administrator issues a notice of disapproval of a certification application under paragraph (d)(3)(iv)(C) of this section or a notice of disapproval of certification status under paragraph (d)(3)(iv)(D) of this section, then:

(A) The owner or operator shall substitute the following values, for each disapproved monitoring system, for each hour of unit operation during the period of invalid data specified under § 75.20(a)(4)(ii), § 75.20(g)(7), or § 75.21(e) of this chapter and continuing until the applicable date and hour specified under § 75.20(a)(5)(i) or (g)(7) of this chapter:

(1) For a disapproved NOX emission rate (i.e., NOX-diluent) system, the maximum potential NOX emission rate, as defined in § 72.2 of this chapter.

(2) For a disapproved NOX pollutant concentration monitor and disapproved flow monitor, respectively, the maximum potential concentration of NOX and the maximum potential flow rate, as defined in sections 2.1.2.1 and 2.1.4.1 of appendix A to part 75 of this chapter.

(3) For a disapproved moisture monitoring system and disapproved diluent gas monitoring system, respectively, the minimum potential moisture percentage and either the maximum potential CO2 concentration or the minimum potential O2 concentration (as applicable), as defined in sections 2.1.5, 2.1.3.1, and 2.1.3.2 of appendix A to part 75 of this chapter.

(4) For a disapproved fuel flowmeter system, the maximum potential fuel flow rate, as defined in section 2.4.2.1 of appendix D to part 75 of this chapter.

(5) For a disapproved excepted NOX monitoring system under appendix E to part 75 of this chapter, the fuel-specific maximum potential NOX emission rate, as defined in § 72.2 of this chapter.

(B) The CAIR designated representative shall submit a notification of certification retest dates and a new certification application in accordance with paragraphs (d)(3)(i) and (ii) of this section.

(C) The owner or operator shall repeat all certification tests or other requirements that were failed by the monitoring system, as indicated in the Administrator’s notice of disapproval, no later than 30 unit operating days after the date of issuance of the notice of disapproval.

(e) Initial certification and recertification procedures for units using the low mass emission excepted methodology under § 75.19 of this chapter. The owner or operator of a unit qualified to use the low mass emissions (LME) excepted methodology under § 75.19 of this chapter shall meet the applicable certification and recertification requirements in §§ 75.19(a)(2) and 75.20(h) of this chapter. If the owner or operator of such a unit elects to certify a fuel flowmeter system for heat input determination, the owner or operator shall
§ 97.172 Out of control periods.

(a) Whenever any monitoring system fails to meet the quality-assurance and quality-control requirements or data validation requirements of part 75 of this chapter, data shall be substituted using the applicable missing data procedures in subpart D or subpart H of, or appendix D or appendix E to, part 75 of this chapter.

(b) Audit decertification. Whenever both an audit of a monitoring system and a review of the initial certification or recertification application reveal that any monitoring system should not have been certified or recertified because it did not meet a particular performance specification or other requirement under §97.171 or the applicable provisions of part 75 of this chapter, both at the time of the initial certification or recertification application submission and at the time of the audit, the Administrator will issue a notice of disapproval of the certification status of such monitoring system. For the purposes of this paragraph, an audit shall be either a field audit or an audit of any information submitted to the permitting authority or the Administrator. By issuing the notice of disapproval, the Administrator revokes prospectively the certification status of the monitoring system. The data measured and recorded by the monitoring system shall not be considered valid quality-assured data from the date of issuance of the notification of the revoked certification status until the date and time that the owner or operator completes subsequently approved initial certification or recertification tests for the monitoring system. The owner or operator shall follow the applicable initial certification or recertification procedures in §97.171 for each disapproved monitoring system.

§ 97.173 Notifications.

The CAIR designated representative for a CAIR NOX unit shall submit written notice to the Administrator in accordance with §75.61 of this chapter.

§ 97.174 Recordkeeping and reporting.

(a) General provisions. The CAIR designated representative shall comply with all recordkeeping and reporting requirements in this section, the applicable recordkeeping and reporting requirements under §75.73 of this chapter, and the requirements of §97.10(e)(1).

(b) Monitoring plans. The owner or operator of a CAIR NOX unit shall comply with requirements of §75.73(c) and (e) of this chapter and, for a unit for which a CAIR opt-in permit application is submitted and not withdrawn and a CAIR opt-in permit is not yet issued or denied under subpart II of this part, §§97.183 and 97.184(a).

(c) Certification applications. The CAIR designated representative shall submit an application to the Administrator within 45 days after completing all initial certification or recertification tests required under §97.171, including the information required under §75.63 of this chapter.

(d) Quarterly reports. The CAIR designated representative shall submit quarterly reports, as follows:

(i) The CAIR designated representative shall report the NOX mass emissions data and heat input data for the CAIR NOX unit, in an electronic quarterly report in a format prescribed by the Administrator, for each calendar quarter beginning with:

(ii) For a unit that commences commercial operation before July 1, 2007, the calendar quarter covering January 1, 2008 through March 31, 2008.

(iii) For a unit that commences commercial operation on or after July 1, 2007, the calendar quarter corresponding to the earlier of the date of provisional certification or the applicable deadline for initial certification under §97.170(b), unless that quarter is the third or fourth quarter of 2007, in which case reporting shall commence...
in the quarter covering January 1, 2008 through March 31, 2008:

(iii) Notwithstanding paragraphs (d)(1)(i) and (ii) of this section, for a unit for which a CAIR opt-in permit application is submitted and not withdrawn and a CAIR opt-in permit is not yet issued or denied under subpart II of this part, the calendar quarter corresponding to the date specified in §97.184(b); and

(iv) Notwithstanding paragraphs (d)(1)(i) and (ii) of this section, for a CAIR NO\textsubscript{X} opt-in unit under subpart II of this part, the calendar quarter corresponding to the date on which the CAIR NO\textsubscript{X} opt-in unit enters the CAIR NO\textsubscript{X} Annual Trading Program as provided in §97.184(g).

(2) The CAIR designated representative shall submit each quarterly report to the Administrator within 30 days following the end of the calendar quarter covered by the report. Quarterly reports shall be submitted in the manner specified in §75.73(f) of this chapter.

(3) For CAIR NO\textsubscript{X} units that are also subject to an Acid Rain emissions limitation or the CAIR NO\textsubscript{X} Ozone Season Trading Program, CAIR SO\textsubscript{2} Trading Program, or Hg Budget Trading Program, quarterly reports shall include the applicable data and information required by subparts F through I of part 75 of this chapter as applicable, in addition to the NO\textsubscript{X} mass emission data, heat input data, and other information required by this subpart.

(e) Compliance certification. The CAIR designated representative shall submit to the Administrator a compliance certification (in a format prescribed by the Administrator) in support of each quarterly report based on reasonable inquiry of those persons with primary responsibility for ensuring that all of the unit’s emissions are correctly and fully monitored. The certification shall state that:

(1) The monitoring data submitted were recorded in accordance with the applicable requirements of this subpart and part 75 of this chapter, including the quality assurance procedures and specifications; and

(2) For a unit with add-on NO\textsubscript{X} emission controls and for all hours where NO\textsubscript{X} data are substituted in accordance with §75.34(a)(1) of this chapter, the add-on emission controls were operating within the range of parameters listed in the quality assurance/quality control program under appendix B to part 75 of this chapter and the substitute data values do not systematically underestimate NO\textsubscript{X} emissions.

§97.175 Petitions.

The CAIR designated representative of a CAIR NO\textsubscript{X} unit may submit a petition under §75.66 of this chapter to the Administrator requesting approval to apply an alternative to any requirement of this subpart. Application of an alternative to any requirement of this subpart is in accordance with this subpart only to the extent that the petition is approved in writing by the Administrator, in consultation with the permitting authority.

Subpart II—CAIR NO\textsubscript{X} Opt-In Units

§97.180 Applicability.

A CAIR NO\textsubscript{X} opt-in unit must be a unit that:

(a) Is located in a State that submits, and for which the Administrator approves, a State implementation plan revision in accordance with §51.123(p)(3)(i), (ii), or (iii) of this chapter establishing procedures concerning CAIR opt-in units;

(b) Is not a CAIR NO\textsubscript{X} unit under §97.104 and is not covered by a retired unit exemption under §97.105 that is in effect;

(c) Is not covered by a retired unit exemption under §72.8 of this chapter that is in effect;

(d) Has or is required or qualified to have a title V operating permit or other federally enforceable permit; and

(e) Vents all of its emissions to a stack and can meet the monitoring, recordkeeping, and reporting requirements of subpart HH of this part.

§97.181 General.

(a) Except as otherwise provided in §§97.101 through 97.104, §§97.106 through 97.108, and subparts BB and CC and subparts FF through HH of this part, a CAIR NO\textsubscript{X} opt-in unit shall be treated as a CAIR NO\textsubscript{X} unit for purposes of applying such sections and subparts of this part.
§ 97.182 CAIR designated representative.

Any CAIR NOX opt-in unit, and any unit for which a CAIR opt-in permit application is submitted and not withdrawn and a CAIR opt-in permit is not yet issued or denied under this subpart, located at the same source as one or more CAIR NOX units shall have the same CAIR designated representative and alternate CAIR designated representative as such CAIR NOX units.

§ 97.183 Applying for CAIR opt-in permit.

(a) Applying for initial CAIR opt-in permit. The CAIR designated representative of a unit meeting the requirements for a CAIR NOX opt-in unit in § 97.180 may apply for an initial CAIR opt-in permit at any time, except as provided under § 97.186(f) and (g), and, in order to apply, must submit the following:

(1) A complete CAIR permit application under § 97.122;
(2) A certification, in a format specified by the permitting authority, that the unit:
   (i) Is not a CAIR NOX unit under § 97.104 and is not covered by a retired unit exemption under § 97.105 that is in effect;
   (ii) Is not covered by a retired unit exemption under § 72.8 of this chapter that is in effect;
   (iii) Vents all of its emissions to a stack; and
   (iv) Has documented heat input for more than 876 hours during the 6 months immediately preceding submission of the CAIR permit application under § 97.122;
(3) A monitoring plan in accordance with subpart HH of this part;
(4) A complete certificate of representation under § 97.113 consistent with § 97.182, if no CAIR designated representative has been previously designated for the source that includes the unit; and
(5) A statement, in a format specified by the permitting authority, whether the CAIR designated representative requests that the unit be allocated CAIR NOX allowances under § 97.188(b) or § 97.188(c) (subject to the conditions in §§ 97.184(h) and 97.186(g)), to the extent such allocation is provided in a State implementation plan revision submitted in accordance with §§ 51.123(p)(3)(i), (ii), or (iii) of this chapter and approved by the Administrator. If allocation under § 97.188(c) is requested, this statement shall include a statement that the owners and operators of the unit intend to repower the unit before January 1, 2015 and that they will provide, upon request, documentation demonstrating such intent.

(b) Duty to reapply. (1) The CAIR designated representative of a CAIR NOX opt-in unit shall submit a complete CAIR permit application under § 97.122 to renew the CAIR opt-in unit permit in accordance with the permitting authority’s regulations for title V operating permits, or the permitting authority’s regulations for other federally enforceable permits if applicable, addressing permit renewal.

(2) Unless the permitting authority issues a notification of acceptance of withdrawal of the CAIR NOX opt-in unit from the CAIR NOX Annual Trading Program in accordance with § 97.186 or the unit becomes a CAIR NOX unit under § 97.104, the CAIR NOX opt-in unit shall remain subject to the requirements for a CAIR NOX opt-in unit, even if the CAIR designated representative for the CAIR NOX opt-in unit fails to submit a CAIR permit application that is required for renewal of the CAIR opt-in permit under paragraph (b)(1) of this section.

§ 97.184 Opt-in process.

The permitting authority will issue or deny a CAIR opt-in permit for a unit for which an initial application for a CAIR opt-in permit under § 97.183 is submitted in accordance with the following, to the extent provided in a State implementation plan revision submitted in accordance with §§ 51.123(p)(3)(i), (ii), or (iii) of this chapter and approved by the Administrator:
Environmental Protection Agency

§ 97.184

(a) Interim review of monitoring plan. The permitting authority and the Administrator will determine, on an interim basis, the sufficiency of the monitoring plan accompanying the initial application for a CAIR opt-in permit under § 97.183. A monitoring plan is sufficient, for purposes of interim review, if the plan appears to contain information demonstrating that the NO\textsubscript{X} emissions rate and heat input of the unit and all other applicable parameters are monitored and reported in accordance with subpart HH of this part. A determination of sufficiency shall not be construed as acceptance or approval of the monitoring plan.

(b) Monitoring and reporting. (1)(i) If the permitting authority and the Administrator determine that the monitoring plan is sufficient under paragraph (a) of this section, the owner or operator shall monitor and report the NO\textsubscript{X} emissions rate and heat input of the unit and all other applicable parameters, in accordance with subpart HH of this part, starting on the date of certification of the appropriate monitoring systems under subpart HH of this part and continuing until a CAIR opt-in permit is denied under § 97.184(f) or, if a CAIR opt-in permit is issued, the date and time when the unit is withdrawn from the CAIR NO\textsubscript{X} Annual Trading Program in accordance with § 97.186.

(ii) The monitoring and reporting under paragraph (b)(1)(i) of this section shall include the entire control period immediately before the date on which the unit enters the CAIR NO\textsubscript{X} Annual Trading Program under § 97.184(g), during which period monitoring system availability must not be less than 90 percent under subpart HH of this part and the unit must be in full compliance with any applicable State or Federal emissions or emissions-related requirements.

(2) To the extent the NO\textsubscript{X} emissions rate and heat input of the unit are monitored and reported in accordance with subpart HH of this part for one or more control periods, in addition to the control period under paragraph (b)(1)(i) of this section, during which control periods monitoring system availability is not less than 90 percent under subpart HH of this part and the

unit is in full compliance with any applicable State or Federal emissions or emissions-related requirements and which control periods begin not more than 3 years before the unit enters the CAIR NO\textsubscript{X} Annual Trading Program under § 97.184(g), such information shall be used as provided in paragraphs (c) and (d) of this section.

(c) Baseline heat input. The unit’s baseline heat input shall equal:

(1) If the unit’s NO\textsubscript{X} emissions rate and heat input are monitored and reported for only one control period, in accordance with paragraph (b)(1) of this section, the unit’s total heat input (in mmBtu) for the control period; or

(2) If the unit’s NO\textsubscript{X} emissions rate and heat input are monitored and reported for more than one control period, in accordance with paragraphs (b)(1) and (2) of this section, the average of the amounts of the unit’s total heat input (in mmBtu) for the control periods under paragraphs (b)(1)(i) and (2) of this section.

(d) Baseline NO\textsubscript{X} emission rate. The unit’s baseline NO\textsubscript{X} emission rate shall equal:

(1) If the unit’s NO\textsubscript{X} emissions rate and heat input are monitored and reported for only one control period, in accordance with paragraph (b)(1) of this section, the unit’s NO\textsubscript{X} emissions rate (in lb/mmBtu) for the control period;

(2) If the unit’s NO\textsubscript{X} emissions rate and heat input are monitored and reported for more than one control period, in accordance with paragraphs (b)(1) and (2) of this section, and the unit does not have add-on NO\textsubscript{X} emission controls during any such control periods, the average of the amounts of the unit’s NO\textsubscript{X} emissions rate (in lb/mmBtu) for the control periods under paragraphs (b)(1)(ii) and (2) of this section; or

(3) If the unit’s NO\textsubscript{X} emissions rate and heat input are monitored and reported for more than one control period, in accordance with paragraphs (b)(1) and (2) of this section, and the unit has add-on NO\textsubscript{X} emission controls during any such control periods, the average of the amounts of the unit’s NO\textsubscript{X} emissions rate (in lb/mmBtu) for such control periods during which the unit has add-on NO\textsubscript{X} emission controls.
(e) Issuance of CAIR opt-in permit. After calculating the baseline heat input and the baseline NO\textsubscript{X} emissions rate for the unit under paragraphs (c) and (d) of this section and if the permitting authority determines that the CAIR designated representative shows that the unit meets the requirements for a CAIR NO\textsubscript{X} opt-in unit in §97.180 and meets the elements certified in §97.183(a)(2), the permitting authority will issue a CAIR opt-in permit. The permitting authority will provide a copy of the CAIR opt-in permit to the Administrator, who will then establish a compliance account for the source that includes the CAIR NO\textsubscript{X} opt-in unit unless the source already has a compliance account.

(f) Issuance of denial of CAIR opt-in permit. Notwithstanding paragraphs (a) through (e) of this section, if at any time before issuance of a CAIR opt-in permit for the unit, the permitting authority determines that the CAIR designated representative fails to show that the unit meets the requirements for a CAIR NO\textsubscript{X} opt-in unit in §97.180 or meets the elements certified in §97.183(a)(2), the permitting authority will issue a denial of a CAIR opt-in permit for the unit.

(g) Date of entry into CAIR NO\textsubscript{X} Annual Trading Program. A unit for which an initial CAIR opt-in permit is issued by the permitting authority shall become a CAIR NO\textsubscript{X} opt-in unit, and a CAIR NO\textsubscript{X} unit, as of the later of January 1, 2009 or January 1 of the first control period during which such CAIR opt-in permit is issued.

(h) Repowered CAIR NO\textsubscript{X} opt-in unit. (1) If CAIR designated representative requests, and the permitting authority issues a CAIR opt-in permit providing for, allocation to a CAIR NO\textsubscript{X} opt-in unit of CAIR NO\textsubscript{X} allowances under §97.188(c) and such unit is repowered after its date of entry into the CAIR NO\textsubscript{X} Annual Trading Program under paragraph (g) of this section, the repowered unit shall be treated as a CAIR NO\textsubscript{X} opt-in unit replacing the original CAIR NO\textsubscript{X} opt-in unit, as of the date of start-up of the repowered unit’s combustion chamber.

(2) Notwithstanding paragraphs (c) and (d) of this section, as of the date of start-up under paragraph (h)(1) of this section, the repowered unit shall be deemed to have the same date of commencement of operation, date of commencement of commercial operation, baseline heat input, and baseline NO\textsubscript{X} emission rate as the original CAIR NO\textsubscript{X} opt-in unit, and the original CAIR NO\textsubscript{X} opt-in unit shall no longer be treated as a CAIR NO\textsubscript{X} opt-in unit or a CAIR NO\textsubscript{X} unit.

[65 FR 2727, Jan. 18, 2000, as amended at 71 FR 74795, Dec. 13, 2006]

§97.185 CAIR opt-in permit contents.

(a) Each CAIR opt-in permit will contain:

(1) All elements required for a complete CAIR permit application under §97.122;

(2) The certification in §97.183(a)(2);

(3) The unit’s baseline heat input under §97.184(c);

(4) The unit’s baseline NO\textsubscript{X} emission rate under §97.184(d);

(5) A statement whether the unit is to be allocated CAIR NO\textsubscript{X} allowances under §97.188(b) or §97.188(c) (subject to the conditions in §§97.184(h) and 97.186(g));

(6) A statement that the unit may withdraw from the CAIR NO\textsubscript{X} Annual Trading Program only in accordance with §97.186; and

(7) A statement that the unit is subject to, and the owners and operators of the unit must comply with, the requirements of §97.187.

(b) Each CAIR opt-in permit is deemed to incorporate automatically the definitions of terms under §97.102 and, upon recordation by the Administrator under subpart FF or GG of this part or this subpart, every allocation, transfer, or deduction of CAIR NO\textsubscript{X} allowances to or from the compliance account of the source that includes a CAIR NO\textsubscript{X} opt-in unit covered by the CAIR opt-in permit.

(c) The CAIR opt-in permit shall be included, in a format specified by the permitting authority, in the CAIR permit for the source where the CAIR NO\textsubscript{X} opt-in unit is located and in a title V operating permit or other federally enforceable permit for the source.
§ 97.186 Withdrawal from CAIR NOx Annual Trading Program.

Except as provided under paragraph (g) of this section, a CAIR NOx opt-in unit may withdraw from the CAIR NOx Annual Trading Program, but only if the permitting authority issues a notification to the CAIR designated representative of the CAIR NOx opt-in unit of the acceptance of the withdrawal of the CAIR NOx opt-in unit in accordance with paragraph (d) of this section.

(a) Requesting withdrawal. In order to withdraw a CAIR NOx opt-in unit from the CAIR NOx Annual Trading Program, the CAIR designated representative of the CAIR NOx opt-in unit shall submit to the permitting authority a request to withdraw effective as of midnight of December 31 of a specified calendar year, which date must be at least 4 years after December 31 of the year of entry into the CAIR NOx Annual Trading Program under §97.184(g).

The request must be submitted no later than 90 days before the requested effective date of withdrawal.

(b) Conditions for withdrawal. Before a CAIR NOx opt-in unit covered by a request under paragraph (a) of this section may withdraw from the CAIR NOx Annual Trading Program and the CAIR opt-in permit may be terminated under paragraph (e) of this section, the following conditions must be met:

(1) For the control period ending on the date on which the withdrawal is to be effective, the source that includes the CAIR NOx opt-in unit must meet the requirements to hold CAIR NOx allowances under §97.106(c) and cannot have any excess emissions.

(2) After the requirement for withdrawal under paragraph (b)(1) of this section is met, the Administrator will deduct from the compliance account of the source that includes the CAIR NOx opt-in unit CAIR NOx allowances equal in amount to and allocated for the same or a prior control period as any CAIR NOx allowances allocated to the CAIR NOx opt-in unit under §97.188 for any control period for which the withdrawal is to be effective. If there are no remaining CAIR NOx units at the source, the Administrator will close the compliance account, and the owners and operators of the CAIR NOx opt-

in unit may submit a CAIR NOx allowance transfer for any remaining CAIR NOx allowances to another CAIR NOx Allowance Tracking System in accordance with subpart GG of this part.

(c) Notification. (1) After the requirements for withdrawal under paragraphs (a) and (b) of this section are met (including deduction of the full amount of CAIR NOx allowances required), the permitting authority will issue a notification to the CAIR designated representative of the CAIR NOx opt-in unit of the acceptance of the withdrawal of the CAIR NOx opt-in unit as of midnight on December 31 of the calendar year for which the withdrawal was requested.

(2) If the requirements for withdrawal under paragraphs (a) and (b) of this section are not met, the permitting authority will issue a notification to the CAIR designated representative of the CAIR NOx opt-in unit that the CAIR NOx opt-in unit’s request to withdraw is denied. Such CAIR NOx opt-in unit shall continue to be a CAIR NOx opt-in unit.

(d) Permit amendment. After the permitting authority issues a notification under paragraph (c)(1) of this section that the requirements for withdrawal have been met, the permitting authority will revise the CAIR permit covering the CAIR NOx opt-in unit to terminate the CAIR opt-in permit for such unit as of the effective date specified under paragraph (c)(1) of this section.

The unit shall continue to be a CAIR NOx opt-in unit until the effective date of the termination and shall comply with all requirements under the CAIR NOx Annual Trading Program concerning any control periods for which the unit is a CAIR NOx opt-in unit, even if such requirements arise or must be complied with after the withdrawal takes effect.

(e) Reapplication upon failure to meet conditions of withdrawal. If the permitting authority denies the CAIR NOx opt-in unit’s request to withdraw, the CAIR designated representative may submit another request to withdraw in accordance with paragraphs (a) and (b) of this section.

(f) Ability to reapply to the CAIR NOx Annual Trading Program. Once a CAIR NOx opt-in unit withdraws from the
§ 97.187 Change in regulatory status.

(a) Notification. If a CAIR NO\textsubscript{X} opt-in unit becomes a CAIR NO\textsubscript{X} unit under §97.104, then the CAIR designated representative shall notify in writing the permitting authority of such change in the CAIR NO\textsubscript{X} opt-in unit’s regulatory status, within 30 days of such change.

(b) Permitting authority’s and Administrator’s actions. (1) If a CAIR NO\textsubscript{X} opt-in unit becomes a CAIR NO\textsubscript{X} unit under §97.104, the permitting authority will revise the CAIR NO\textsubscript{X} opt-in unit’s CAIR NO\textsubscript{X} opt-in permit to meet the requirements of a CAIR permit under §97.123, and remove the CAIR opt-in permit provisions, as of the date on which the CAIR NO\textsubscript{X} opt-in unit becomes a CAIR NO\textsubscript{X} unit under §97.104.

(2)(i) The Administrator will deduct from the compliance account of the source that includes the CAIR NO\textsubscript{X} opt-in unit that becomes a CAIR NO\textsubscript{X} unit under §97.104, CAIR NO\textsubscript{X} allowances equal in amount to and allocated for the same or a prior control period as:

(A) Any CAIR NO\textsubscript{X} allowances allocated to the CAIR NO\textsubscript{X} opt-in unit under §97.188 for any control period after the date on which the CAIR NO\textsubscript{X} opt-in unit becomes a CAIR NO\textsubscript{X} unit under §97.104; and

(B) If the date on which the CAIR NO\textsubscript{X} opt-in unit becomes a CAIR NO\textsubscript{X} unit under §97.104 is not December 31, the CAIR NO\textsubscript{X} allowances allocated to the CAIR NO\textsubscript{X} opt-in unit under §97.188 for the control period that includes the date on which the CAIR NO\textsubscript{X} opt-in unit becomes a CAIR NO\textsubscript{X} unit under §97.104, multiplied by the ratio of the number of days, in the control period, starting with the date on which the CAIR NO\textsubscript{X} opt-in unit becomes a CAIR NO\textsubscript{X} unit under §97.104 divided by the total number of days in the control period and rounded to the nearest whole allowance as appropriate.

(ii) If the date on which the CAIR NO\textsubscript{X} opt-in unit becomes a CAIR NO\textsubscript{X} unit under §97.104 is not December 31, contains the CAIR NO\textsubscript{X} allowances necessary for completion of the deduction under paragraph (b)(2)(i) of this section.

(3)(i) For every control period after the date on which the CAIR NO\textsubscript{X} opt-in unit becomes a CAIR NO\textsubscript{X} unit under §97.104, the CAIR NO\textsubscript{X} opt-in unit will be allocated CAIR NO\textsubscript{X} allowances under §97.142.

(ii) If the date on which the CAIR NO\textsubscript{X} opt-in unit becomes a CAIR NO\textsubscript{X} unit under §97.104 is not December 31, the following amount of CAIR NO\textsubscript{X} allowances will be allocated to the CAIR NO\textsubscript{X} opt-in unit (as a CAIR NO\textsubscript{X} unit) under §97.142 for the control period that includes the date on which the CAIR NO\textsubscript{X} opt-in unit becomes a CAIR NO\textsubscript{X} unit under §97.104:

(A) The amount of CAIR NO\textsubscript{X} allowances otherwise allocated to the CAIR NO\textsubscript{X} opt-in unit (as a CAIR NO\textsubscript{X} unit) under §97.142 for the control period multiplied by:

(B) The ratio of the number of days, in the control period, starting with the date on which the CAIR NO\textsubscript{X} opt-in unit becomes a CAIR NO\textsubscript{X} unit under §97.104, divided by the total number of days in the control period; and

(C) Rounded to the nearest whole allowance as appropriate.

§ 97.188 CAIR NO\textsubscript{x} allowance allocations to CAIR NO\textsubscript{x} opt-in units.

(a) Timing requirements. (1) When the CAIR opt-in permit is issued under §97.184(e), the permitting authority will allocate CAIR NO\textsubscript{x} allowances to the CAIR NO\textsubscript{x} opt-in unit, and submit to the Administrator the allocation for the control period in which a CAIR NO\textsubscript{x} opt-in unit enters the CAIR NO\textsubscript{x} Annual Trading Program under §97.184(g), in accordance with paragraph (b) or (c) of this section.

(2) By no later than October 31 of the control period after the control period in which a CAIR NO\textsubscript{x} opt-in unit enters the CAIR NO\textsubscript{x} Annual Trading Program under §97.184(g) and October 31 of each year thereafter, the permitting authority will allocate CAIR NO\textsubscript{x} allowances to the CAIR NO\textsubscript{x} opt-in unit, and submit to the Administrator the allocation for the control period that includes such submission deadline and in which the unit is a CAIR NO\textsubscript{x} opt-in unit, in accordance with paragraph (b) or (c) of this section.

(b) Calculation of allocation. For each control period for which a CAIR NO\textsubscript{x} opt-in unit is to be allocated CAIR NO\textsubscript{x} allowances, the permitting authority will allocate in accordance with the following procedures, if provided in a State implementation plan revision submitted in accordance with §51.123(p)(3)(i), (ii), or (iii) of this chapter and approved by the Administrator:

(1) The heat input (in mmBtu) used for calculating CAIR NO\textsubscript{x} allowance allocation will be the lesser of:

(i) The CAIR NO\textsubscript{x} opt-in unit’s baseline heat input determined under §97.184(c); or

(ii) The CAIR NO\textsubscript{x} opt-in unit’s heat input, as determined in accordance with subpart HH of this part, for the immediately prior control period, except when the allocation is being calculated for the control period in which the CAIR NO\textsubscript{x} opt-in unit enters the CAIR NO\textsubscript{x} Annual Trading Program under §97.184(g).

(2) The NO\textsubscript{x} emission rate (in lb/mmBtu) used for calculating CAIR NO\textsubscript{x} allowance allocations will be the lesser of:

(i) The CAIR NO\textsubscript{x} opt-in unit’s baseline NO\textsubscript{x} emissions rate (in lb/mmBtu) determined under §97.184(d) and multiplied by 70 percent; or

(ii) The most stringent State or Federal NO\textsubscript{x} emissions limitation applicable to the CAIR NO\textsubscript{x} opt-in unit at any time during the control period for which CAIR NO\textsubscript{x} allowances are to be allocated.

(3) The permitting authority will allocate CAIR NO\textsubscript{x} allowances to the CAIR NO\textsubscript{x} opt-in unit in an amount equaling the heat input under paragraph (b)(1) of this section, multiplied by the NO\textsubscript{x} emission rate under paragraph (b)(2) of this section, divided by 2,000 lb/ton, and rounded to the nearest whole allowance as appropriate.

(c) Notwithstanding paragraph (b) of this section and if the CAIR designated representative requests, and the permitting authority issues a CAIR opt-in permit (based on a demonstration of the intent to repower stated under §97.183(a)(5)) providing for, allocation to a CAIR NO\textsubscript{x} opt-in unit of CAIR NO\textsubscript{x} allowances under this paragraph (subject to the conditions in §§97.184(h) and 97.186(g)), the permitting authority will allocate to the CAIR NO\textsubscript{x} opt-in unit as follows, if provided in a State implementation plan revision submitted in accordance with §51.123(p)(3)(i), (ii), or (iii) of this chapter and approved by the Administrator:

(1) For each control period in 2009 through 2014 for which the CAIR NO\textsubscript{x} opt-in unit is to be allocated CAIR NO\textsubscript{x} allowances,

(i) The heat input (in mmBtu) used for calculating CAIR NO\textsubscript{x} allowance allocations will be determined as described in paragraph (b)(1) of this section.

(ii) The NO\textsubscript{x} emission rate (in lb/mmBtu) used for calculating CAIR NO\textsubscript{x} allowance allocations will be the lesser of:

(A) The CAIR NO\textsubscript{x} opt-in unit’s baseline NO\textsubscript{x} emissions rate (in lb/mmBtu) determined under §97.184(d); or

(B) The most stringent State or Federal NO\textsubscript{x} emissions limitation applicable to the CAIR NO\textsubscript{x} opt-in unit at any time during the control period in which the CAIR NO\textsubscript{x} opt-in unit enters the CAIR NO\textsubscript{x} Annual Trading Program under §97.184(g).

(iii) The permitting authority will allocate CAIR NO\textsubscript{x} allowances to the
CAIR NO\textsubscript{X} opt-in unit in an amount equaling the heat input under paragraph (c)(1)(i) of this section, multiplied by the NO\textsubscript{X} emission rate under paragraph (c)(1)(ii) of this section, divided by 2,000 lb/ton, and rounded to the nearest whole allowance as appropriate.

(2) For each control period in 2015 and thereafter for which the CAIR NO\textsubscript{X} opt-in unit is to be allocated CAIR NO\textsubscript{X} allowances,

(i) The heat input (in mmBtu) used for calculating the CAIR NO\textsubscript{X} allowance allocations will be determined as described in paragraph (b)(1) of this section.

(ii) The NO\textsubscript{X} emission rate (in lb/mmBtu) used for calculating the CAIR NO\textsubscript{X} allowance allocation will be the lesser of:

(A) 0.15 lb/mmBtu;

(B) The CAIR NO\textsubscript{X} opt-in unit’s baseline NO\textsubscript{X} emissions rate (in lb/mmBtu) determined under §97.184(d); or

(C) The most stringent State or Federal NO\textsubscript{X} emissions limitation applicable to the CAIR NO\textsubscript{X} opt-in unit at any time during the control period for which CAIR NO\textsubscript{X} allowances are to be allocated.

(iii) The permitting authority will allocate CAIR NO\textsubscript{X} allowances to the CAIR NO\textsubscript{X} opt-in unit in an amount equaling the heat input under paragraph (c)(2)(i) of this section, multiplied by the NO\textsubscript{X} emission rate under paragraph (c)(2)(ii) of this section, divided by 2,000 lb/ton, and rounded to the nearest whole allowance as appropriate.

(d) Recordation. If provided in a State implementation plan revision submitted in accordance with §51.123(p)(3)(i), (ii), or (iii) of this chapter and approved by the Administrator:

(1) The Administrator will record, in the compliance account of the source that includes the CAIR NO\textsubscript{X} opt-in unit, the CAIR NO\textsubscript{X} allowances allocated by the permitting authority to the CAIR NO\textsubscript{X} opt-in unit under paragraph (a)(2) of this section.

APPENDIX A TO SUBPART II OF PART 97—STATES WITH APPROVED STATE IMPLEMENTATION PLAN REVISIONS CONCERNING CAIR NO\textsubscript{X} OPT-IN UNITS

1. The following States have State Implementation Plan revisions under §51.123(p)(3) of this chapter approved by the Administrator and establishing procedures for allocation of CAIR NO\textsubscript{X} allowances to such units under §97.188(b):

Indiana
Michigan
North Carolina
Ohio
South Carolina
Tennessee

2. The following States have State Implementation Plan revisions under §51.123(p)(3) of this chapter approved by the Administrator and establishing procedures for allocation of CAIR NO\textsubscript{X} allowances to such units under §97.188(c):

Indiana
Michigan
Ohio
North Carolina
South Carolina
Tennessee


Subpart AAA—CAIR SO\textsubscript{2} Trading Program General Provisions

§97.201 Purpose.

This subpart and subparts BBB through III set forth the general provisions and the designated representative, permitting, allowance, monitoring, and opt-in provisions for the Federal Clean Air Interstate Rule (CAIR) SO\textsubscript{2} Trading Program, under section 110 of the Clean Air Act and §52.36 of this chapter, as a means of mitigating interstate transport of fine particulates and sulfur dioxide.

§97.202 Definitions.

The terms used in this subpart and subparts BBB through III shall have
Account number means the identification number given by the Administrator to each CAIR SO\textsubscript{2} Allowance Tracking System account.

Acid Rain emissions limitation means a limitation on emissions of sulfur dioxide or nitrogen oxides under the Acid Rain Program.

Acid Rain Program means a multi-state sulfur dioxide and nitrogen oxides air pollution control and emission reduction program established by the Administrator under title IV of the CAA and parts 72 through 78 of this chapter.

Administrator means the Administrator of the United States Environmental Protection Agency or the Administrator's duly authorized representative.

Allocate or allocation means, with regard to CAIR SO\textsubscript{2} allowances issued under the Acid Rain Program, the determination by the Administrator of the amount of such CAIR SO\textsubscript{2} allowances to be initially credited to a CAIR SO\textsubscript{2} unit or other entity and, with regard to CAIR SO\textsubscript{2} allowances issued under § 97.288 or provisions of a State implementation plan that are approved under § 51.124(o)(1) or (2) or (r) of this chapter, the determination by a permitting authority of the amount of such CAIR SO\textsubscript{2} allowances to be initially credited to a CAIR SO\textsubscript{2} unit or other entity.

Allowance transfer deadline means, for a control period, midnight of March 1 (if it is a business day), or midnight of the first business day thereafter (if March 1 is not a business day), immediately following the control period and is the deadline by which a CAIR SO\textsubscript{2} allowance transfer must be submitted for recordation in a CAIR SO\textsubscript{2} source's compliance account in order to be used to meet the source's CAIR SO\textsubscript{2} emissions limitation for such control period in accordance with § 97.234.

Alternate CAIR designated representative means, for a CAIR SO\textsubscript{2} source and each CAIR SO\textsubscript{2} unit at the source, the natural person who is authorized by the owners and operators of the source and all such units at the source, in accordance with subparts BBB and III of this part, to act on behalf of the CAIR designated representative in matters pertaining to the CAIR SO\textsubscript{2} Trading Program. If the CAIR SO\textsubscript{2} source is also a CAIR NO\textsubscript{X} source, then this natural person shall be the same person as the alternate CAIR designated representative under the CAIR NO\textsubscript{X} Annual Trading Program. If the CAIR SO\textsubscript{2} source is also a CAIR NO\textsubscript{X} Ozone Season source, then this natural person shall be the same person as the alternate CAIR designated representative under the CAIR NO\textsubscript{X} Ozone Season Trading Program. If the CAIR SO\textsubscript{2} source is also subject to the Hg Budget Trading Program, then this natural person shall be the same person as the alternate Hg designated representative under the Hg Budget Trading Program.

Automated data acquisition and handling system or DAHS means that component of the continuous emission monitoring system, or other emissions monitoring system approved for use under subpart HHH of this part, designed to interpret and convert individual output signals from pollutant concentration monitors, flow monitors, diluent gas monitors, and other component parts of the monitoring system to produce a continuous record of the measured parameters in the measurement units required by subpart HHH of this part.

Biomass means—

(1) Any organic material grown for the purpose of being converted to energy;

(2) Any organic byproduct of agriculture that can be converted into energy; or

(3) Any material that can be converted into energy and is nonmerchantable for other purposes, that is segregated from other nonmerchantable material, and that is:

(i) A forest-related organic resource, including mill residues, precommercial thinnings, slash, brush, or byproduct from conversion of trees to merchantable material; or

(ii) A wood material, including pallets, crates, dunnage, manufacturing and construction materials (other than...
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pressure-treated, chemically-treated, or painted wood products), and landscape or right-of-way tree trimmings.

*Boiler* means an enclosed fossil- or other-fuel-fired combustion device used to produce heat and to transfer heat to recirculating water, steam, or other medium.

*Bottoming-cycle cogeneration unit* means a cogeneration unit in which the energy input to the unit is first used to produce useful thermal energy and at least some of the reject heat from the useful thermal energy application or process is then used for electricity production.

*CAIR authorized account representative* means, with regard to a general account, a responsible natural person who is authorized, in accordance with subparts BBB, FFF, and III of this part, to transfer and otherwise dispose of CAIR SO₂ allowances held in the general account and, with regard to a compliance account, the CAIR designated representative of the source.

*CAIR designated representative* means, for a CAIR SO₂ source and each CAIR SO₂ unit at the source, the natural person who is authorized by the owners and operators of the source and all such units at the source, in accordance with subparts BBB and III of this part, to represent and legally bind each owner and operator in matters pertaining to the CAIR SO₂ Trading Program. If the CAIR SO₂ source is also a CAIR NOₓ source, then this natural person shall be the same as the CAIR designated representative under the CAIR NOₓ Annual Trading Program. If the CAIR SO₂ source is also a CAIR NOₓ Ozone Season source, then this natural person shall be the same as the CAIR designated representative under the CAIR NOₓ Ozone Season Trading Program. If the CAIR SO₂ source is also subject to the Acid Rain Program, then this natural person shall be the same as the designated representative under the Acid Rain Program.

*CAIR NOₓ Annual Trading Program* means a multi-state nitrogen oxides air pollution control and emission reduction program established by the Administrator in accordance with subparts AA through II of this part and §51.123(p) and 52.35 of this chapter or approved and administered by the Administrator in accordance with subparts AA through II of part 96 of this chapter and §51.123(o)(1) or (2) of this chapter, as a means of mitigating interstate transport of fine particulates and nitrogen oxides.

*CAIR NOₓ Ozone Season source* means a source that is subject to the CAIR NOₓ Ozone Season Trading Program.

*CAIR NOₓ Ozone Season Trading Program* means a multi-state nitrogen oxides air pollution control and emission reduction program established by the Administrator in accordance with subparts AAAA through IIII of this part and §51.123(aa)(1) or (2) (and (bb)(1)), (bb)(2), or (dd) of this chapter, as a means of mitigating interstate transport of ozone and nitrogen oxides.

*CAIR NOₓ source* means a source that is subject to the CAIR NOₓ Annual Trading Program.

*CAIR permit* means the legally binding and federally enforceable written document, or portion of such document, issued by the permitting authority under subpart CCC of this part, including any permit revisions, specifying the CAIR SO₂ Trading Program requirements applicable to a CAIR SO₂ source, to each CAIR SO₂ unit at the source, and to the owners and operators and the CAIR designated representative of the source and each such unit.

*CAIR SO₂ allowance* means a limited authorization issued by the Administrator under the Acid Rain Program, by a permitting authority under §97.288, or by a permitting authority under provisions of a State implementation plan that are approved under §51.124(o)(1) or (2) or (r) of this chapter, to emit sulfur dioxide during the control period of the specified calendar year for which the authorization is allocated or of any calendar year thereafter under the CAIR SO₂ Trading Program as follows:
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(1) For one CAIR SO₂ allowance allocated for a control period in a year before 2010, one ton of sulfur dioxide, except as provided in §97.254(b);

(2) For one CAIR SO₂ allowance allocated for a control period in 2010 through 2014, 0.50 ton of sulfur dioxide, except as provided in §97.254(b); and

(3) For one CAIR SO₂ allowance allocated for a control period in 2015 or later, 0.35 ton of sulfur dioxide, except as provided in §97.254(b).

(4) An authorization to emit sulfur dioxide that is not issued under the Acid Rain Program, §97.288, or provisions of a State implementation plan that are approved under §51.124(o)(1) or (2) or (r) of this chapter shall not be a CAIR SO₂ allowance.

CAIR SO₂ allowance deduction or deduction CAIR SO₂ allowances means the permanent withdrawal of CAIR SO₂ allowances by the Administrator from a compliance account, e.g., in order to account for a specified number of tons of total sulfur dioxide emissions from all CAIR SO₂ units at a CAIR SO₂ source for a control period, determined in accordance with subpart HHH of this part, or to account for excess emissions.

CAIR SO₂ Allowance Tracking System means the system by which the Administrator records allocations, deductions, and transfers of CAIR SO₂ allowances under the CAIR SO₂ Trading Program. This is the same system as the Allowance Tracking System under §72.2 of this chapter by which the Administrator records allocations, deductions, and transfers of Acid Rain SO₂ allowances under the Acid Rain Program.

CAIR SO₂ Allowance Tracking System account means an account in the CAIR SO₂ Allowance Tracking System established by the Administrator for purposes of recording the allocation, holding, transferring, or deducting of CAIR SO₂ allowances. Such allowances will be allocated, held, deducted, or transferred only as whole allowances.

CAIR SO₂ allowances held or hold CAIR SO₂ allowances means the CAIR SO₂ allowances recorded by the Administrator, or submitted to the Administrator for recordation, in accordance with subparts FFF, GGG, and HHH of this part or part 73 of this chapter, in a CAIR SO₂ Allowance Tracking System account.

CAIR SO₂ emissions limitation means, for a CAIR SO₂ source, the tonnage equivalent, in SO₂ emissions in a control period, of the CAIR SO₂ allowances available for deduction for the source under §97.254(a) and (b) for the control period.

CAIR SO₂ source means a source that includes one or more CAIR SO₂ units.

CAIR SO₂ Trading Program means a multi-state sulfur dioxide air pollution control and emission reduction program established by the Administrator in accordance with subparts AAA through III of this part and §§51.124(r) and 52.36 of this chapter or approved and administered by the Administrator in accordance with subparts AAA through III of part 96 of this chapter and §51.124(o) (1) or (2) of this chapter, as a means of mitigating interstate transport of fine particulates and sulfur dioxide.

CAIR SO₂ unit means a unit that is subject to the CAIR SO₂ Trading Program under §97.204 and, except for purposes of §97.205, a CAIR SO₂ opt-in unit under subpart III of this part.

Certifying official means:

(1) For a corporation, a president, secretary, treasurer, or vice-president or the corporation in charge of a principal business function or any other person who performs similar policy or decision-making functions for the corporation;

(2) For a partnership or sole proprietorship, a general partner or the proprietor respectively; or

(3) For a local government entity or State, Federal, or other public agency, a principal executive officer or ranking elected official.

Clean Air Act orCAA means the Clean Air Act, 42 U.S.C. 7401, et seq.

Coal means any solid fuel classified as anthracite, bituminous, subbituminous, or lignite.

Coal-derived fuel means any fuel (whether in a solid, liquid, or gaseous state) produced by the mechanical, thermal, or chemical processing of coal.

Coal-fired means combusting any amount of coal or coal-derived fuel, alone, or in combination with any amount of any other fuel.
Cogeneration unit means a stationary, fossil-fuel-fired boiler or stationary, fossil-fuel-fired combustion turbine:

(1) Having equipment used to produce electricity and useful thermal energy for industrial, commercial, heating, or cooling purposes through the sequential use of energy; and

(2) Producing during the 12-month period starting on the date the unit first produces electricity and during any calendar year after the calendar year in which the unit first produces electricity—

(i) For a topping-cycle cogeneration unit,

(A) Useful thermal energy not less than 5 percent of total energy output; and

(B) Useful power that, when added to one-half of useful thermal energy produced, is not less than 42.5 percent of total energy input, if useful thermal energy produced is 15 percent or more of total energy output, or not less than 45 percent of total energy input, if useful thermal energy produced is less than 15 percent of total energy output.

(ii) For a bottoming-cycle cogeneration unit, useful power not less than 45 percent of total energy input;

(3) Provided that the total energy input under paragraphs (2)(i)(B) and (2)(ii) of this definition shall equal the unit’s total energy input from all fuel except biomass if the unit is a boiler.

Combustion turbine means:

(1) An enclosed device comprising a compressor, a combustor, and a turbine and in which the flue gas resulting from the combustion of fuel in the combustor passes through the turbine, rotating the turbine; and

(2) If the enclosed device under paragraph (1) of this definition is combined cycle, any associated duct burner, heat recovery steam generator, and steam turbine.

Commence commercial operation means, with regard to a unit:

(1) To have begun to produce steam, gas, or other heated medium used to generate electricity for sale or use, including test generation, except as provided in §97.205 and §97.284(h).

(i) For a unit that is a CAIR SO₂ unit under §97.204 on the later of November 15, 1990 or the date the unit commences commercial operation as defined in paragraph (1) of this definition and that is subsequently replaced by a unit at the same source (e.g., repowered), such date shall remain the replaced unit’s date of commencement of commercial operation, and the replacement unit shall be treated as a separate unit with a separate date for commencement of commercial operation as defined in paragraph (1) or (2) of this definition as appropriate.

(ii) Notwithstanding paragraph (1) of this definition and except as provided in §97.205, for a unit that is not a CAIR SO₂ unit under §97.204 on the later of November 15, 1990 or the date the unit commences commercial operation as defined in paragraph (1) of this definition, the unit’s date for commencement of commercial operation shall be the date on which the unit becomes a CAIR SO₂ unit under §97.204.

(i) For a unit with a date for commencement of commercial operation as defined in paragraph (2) of this definition and that subsequently undergoes a physical change (other than replacement of the unit by a unit at the same source), such date shall remain the date of commencement of commercial operation of the unit, which shall continue to be treated as the same unit.

(ii) For a unit with a date for commencement of commercial operation as defined in paragraph (2) of this definition and that is subsequently replaced by a unit at the same source (e.g., repowered), such date shall remain the replaced unit’s date of commencement of commercial operation, and the replacement unit shall be treated as a separate unit with a separate date for commencement of commercial operation as defined in paragraph (1) or (2) of this definition as appropriate.

Commence operation means:
(1) To have begun any mechanical, chemical, or electronic process, including, with regard to a unit, start-up of a unit’s combustion chamber, except as provided in §97.284(h).

(2) For a unit that undergoes a physical change (other than replacement of the unit by a unit at the same source) after the date the unit commences operation as defined in paragraph (1) of this definition, such date shall remain the date of commencement of operation of the unit, which shall continue to be treated as the same unit.

(3) For a unit that is replaced by a unit at the same source (e.g., repowered) after the date the unit commences operation as defined in paragraph (1) of this definition, such date shall remain the replaced unit’s date of commencement of operation, and the replacement unit shall be treated as a separate unit with a separate date for commencement of operation as defined in paragraph (1), (2), or (3) of this definition as appropriate, except as provided in §97.284(h).

Common stack means a single flue through which emissions from 2 or more units are exhausted.

Compliance account means a CAIR SO\(_2\) Allowance Tracking System account, established by the Administrator for a CAIR SO\(_2\) source subject to an Acid Rain emissions limitations under §73.31(a) or (b) of this chapter or for any other CAIR SO\(_2\) source under subpart FFF or III of this part, in which any CAIR SO\(_2\) allowance allocations for the CAIR SO\(_2\) units at the source are initially recorded and in which are held any CAIR SO\(_2\) allowances available for use for a control period in order to meet the source’s CAIR SO\(_2\) emissions limitation in accordance with §97.254.

Continuous emission monitoring system or CEMS means the equipment required under subpart HHH of this part to sample, analyze, measure, and provide, by means of readings recorded at least once every 15 minutes (using an automated data acquisition and handling system (DAHS)), a permanent record of sulfur dioxide emissions, stack gas volumetric flow rate, stack gas moisture content, and oxygen or carbon dioxide concentration (as applicable), in a manner consistent with part 75 of this chapter. The following systems are the principal types of continuous emission monitoring systems required under subpart HHH of this part:

(1) A flow monitoring system, consisting of a stack flow rate monitor and an automated data acquisition and handling system and providing a permanent, continuous record of stack gas volumetric flow rate, in standard cubic feet per hour (scfh);

(2) A sulfur dioxide monitoring system, consisting of a SO\(_2\) pollutant concentration monitor and an automated data acquisition and handling system and providing a permanent, continuous record of SO\(_2\) emissions, in parts per million (ppm);

(3) A moisture monitoring system, as defined in §75.11(b)(2) of this chapter and providing a permanent, continuous record of the stack gas moisture content, in percent H\(_2\)O;

(4) A carbon dioxide monitoring system, consisting of a CO\(_2\) pollutant concentration monitor (or an oxygen monitor plus suitable mathematical equations from which the CO\(_2\) concentration is derived) and an automated data acquisition and handling system and providing a permanent, continuous record of CO\(_2\) emissions, in percent CO\(_2\); and

(5) An oxygen monitoring system, consisting of an O\(_2\) concentration monitor and an automated data acquisition and handling system and providing a permanent, continuous record of O\(_2\) in percent O\(_2\).

Control period means the period beginning January 1 of a calendar year, except as provided in §97.206(c)(2), and ending on December 31 of the same year, inclusive.

Emissions means air pollutants exhausted from a unit or source into the atmosphere, as measured, recorded, and reported to the Administrator by the CAIR designated representative and as determined by the Administrator in accordance with subpart HHH of this part.

Excess emissions means any ton, or portion of a ton, of sulfur dioxide emitted by the CAIR SO\(_2\) units at a CAIR SO\(_2\) source during a control period that exceeds the CAIR SO\(_2\) emissions limitation for the source, provided that any portion of a ton of excess emissions
shall be treated as one ton of excess emissions.

Fossil fuel means natural gas, petroleum, coal, or any form of solid, liquid, or gaseous fuel derived from such material.

Fossil-fuel-fired means, with regard to a unit, combusting any amount of fossil fuel in any calendar year.

General account means a CAIR SO\(_2\) Allowance Tracking System account, established under subpart FFF of this part, that is not a compliance account.

Generator means a device that produces electricity.

Heat input means, with regard to a specified period of time, the product (in mmBtu/time) of the gross calorific value of the fuel (in Btu/lb) divided by 1,000,000 Btu/mmBtu and multiplied by the fuel feed rate into a combustion device (in lb of fuel/time), as measured, recorded, and reported to the Administrator by the CAIR designated representative and determined by the Administrator in accordance with subpart HHH of this part and excluding the heat derived from preheated combustion air, recirculated flue gases, or exhaust from other sources.

Heat input rate means the amount of heat input (in mmBtu) divided by unit operating time (in hr) or, with regard to a specific fuel, the amount of heat input attributed to the fuel (in mmBtu) divided by the unit operating time (in hr) during which the unit combusts the fuel.

Hg Budget Trading Program means a multi-state Hg air pollution control and emission reduction program approved and administered by the Administrator in accordance with subpart HHHH of part 60 of this chapter and §60.29(h)(6), or established by the Administrator under section 111 of the Clean Air Act, as a means of reducing national Hg emissions.

Life-of-the-unit, firm power contractual arrangement means a unit participation power sales agreement under which a utility or industrial customer reserves, or is entitled to receive, a specified amount or percentage of nameplate capacity and associated energy generated by any specified unit and pays its proportional amount of such unit’s total costs, pursuant to a contract:

1. For the life of the unit;
2. For a cumulative term of no less than 30 years, including contracts that permit an election for early termination; or
3. For a period no less than 25 years or 70 percent of the economic useful life of the unit determined as of the time the unit is built, with option rights to purchase or release some portion of the nameplate capacity and associated energy generated by the unit at the end of the period.

Maximum design heat input means the maximum amount of fuel per hour (in Btu/hr) that a unit is capable of combusting on a steady state basis as of the initial installation of the unit as specified by the manufacturer of the unit.

Monitoring system means any monitoring system that meets the requirements of subpart HHH of this part, including a continuous emissions monitoring system, an alternative monitoring system, or an excepted monitoring system under part 75 of this chapter.

Most stringent State or Federal SO\(_2\) emissions limitation means, with regard to a unit, the lowest SO\(_2\) emissions limitation (in terms of lb/mmBtu) that is applicable to the unit under State or Federal law, regardless of the averaging period to which the emissions limitation applies.

Nameplate capacity means, starting from the initial installation of a generator, the maximum electrical generating output (in MWe) that the generator is capable of producing on a steady state basis and during continuous operation (when not restricted by seasonal or other deratings) as of such installation as specified by the manufacturer of the generator or, starting from the completion of any subsequent physical change in the generator resulting in an increase in the maximum electrical generating output (in MWe) that the generator is capable of producing on a steady state basis and during continuous operation (when not restricted by seasonal or other deratings), such increased maximum amount as of such completion as specified by the person conducting the physical change.

Operator means any person who operates, controls, or supervises a CAIR
SO\textsubscript{2} unit or a CAIR SO\textsubscript{2} source and shall include, but not be limited to, any holding company, utility system, or plant manager of such a unit or source.

Owner means any of the following persons:

(1) With regard to a CAIR SO\textsubscript{2} source or a CAIR SO\textsubscript{2} unit at a source, respectively:

(i) Any holder of any portion of the legal or equitable title in a CAIR SO\textsubscript{2} unit at the source or the CAIR SO\textsubscript{2} unit;

(ii) Any holder of a leasehold interest in a CAIR SO\textsubscript{2} unit at the source or the CAIR SO\textsubscript{2} unit; or

(iii) Any purchaser of power from a CAIR SO\textsubscript{2} unit at the source or the CAIR SO\textsubscript{2} unit under a life-of-the-unit, firm power contractual arrangement; provided that, unless expressly provided for in a leasehold agreement, owner shall not include a passive lessor, or a person who has an equitable interest through such lessor, whose rental payments are not based (either directly or indirectly) on the revenues or income from such CAIR SO\textsubscript{2} unit; or

(2) With regard to any general account, any person who has an ownership interest with respect to the CAIR SO\textsubscript{2} allowances held in the general account and who is subject to the binding agreement for the CAIR authorized account representative to represent the person’s ownership interest with respect to CAIR SO\textsubscript{2} allowances.

Permitting authority means the State air pollution control agency, local agency, other State agency, or other agency authorized by the Administrator to issue or revise permits to meet the requirements of the CAIR SO\textsubscript{2} Trading Program or, if no such agency has been so authorized, the Administrator.

Potential electrical output capacity means 33 percent of a unit’s maximum design heat input, divided by 3,413 Btu/kWh, divided by 1,000 kWh/MWh, and multiplied by 8,760 hr/yr.

Receive or receipt of means, when referring to the permitting authority or the Administrator, to come into possession of a document, information, or correspondence (whether sent in hard copy or by authorized electronic transmission), as indicated in an official log, or by a notation made on the document, information, or correspondence, by the permitting authority or the Administrator in the regular course of business.

Recordation, record, or recorded means, with regard to CAIR SO\textsubscript{2} allowances, the movement of CAIR SO\textsubscript{2} allowances by the Administrator into or between CAIR SO\textsubscript{2} Allowance Tracking System accounts, for purposes of allocation, transfer, or deduction.

Reference method means any direct test method of sampling and analyzing for an air pollutant as specified in §75.22 of this chapter.

Replacement, replace, or replaced means, with regard to a unit, the demolishing of a unit, or the permanent shutdown and permanent disabling of a unit, and the construction of another unit (the replacement unit) to be used instead of the demolished or shutdown unit (the replaced unit).

Repowered means, with regard to a unit, replacement of a coal-fired boiler with one of the following coal-fired technologies at the same source as the coal-fired boiler:

(1) Atmospheric or pressurized fluidized bed combustion;

(2) Integrated gasification combined cycle;

(3) Magnetohydrodynamics;

(4) Direct and indirect coal-fired turbines;

(5) Integrated gasification fuel cells; or

(6) As determined by the Administrator in consultation with the Secretary of Energy, a derivative of one or more of the technologies under paragraphs (1) through (5) of this definition and any other coal-fired technology capable of controlling multiple combustion emissions simultaneously with improved boiler or generation efficiency and with significantly greater waste reduction relative to the performance of technology in widespread commercial use as of January 1, 2005.

Sequential use of energy means:

(1) For a topping-cycle cogeneration unit, the use of reject heat from electricity production in a useful thermal energy application or process; or

(2) For a bottoming-cycle cogeneration unit, the use of reject heat from
useful thermal energy application or process in electricity production.

**Serial number** means, for a CAIR SO₂ allowance, the unique identification number assigned to each CAIR SO₂ allowance by the Administrator.

**Solid waste incineration unit** means a stationary, fossil-fuel-fired boiler or stationary, fossil-fuel-fired combustion turbine that is a “solid waste incineration unit” as defined in section 129(g)(1) of the Clean Air Act.

**Source** means all buildings, structures, or installations located in one or more contiguous or adjacent properties under common control of the same person or persons. For purposes of section 502(c) of the Clean Air Act, a “source,” including a “source” with multiple units, shall be considered a single “facility.”

**State** means one of the States or the District of Columbia that is subject to the CAIR SO₂ Trading Program pursuant to §52.35 of this chapter.

**Submit or serve** means to send or transmit a document, information, or correspondence to the person specified in accordance with the applicable regulation:

1. In person;
2. By United States Postal Service; or
3. By other means of dispatch or transmission and delivery. Compliance with any “submission” or “service” deadline shall be determined by the date of dispatch, transmission, or mailing and not the date of receipt.

**Title V operating permit** means a permit issued under title V of the Clean Air Act and part 70 or part 71 of this chapter.

**Title V operating permit regulations** means the regulations that the Administrator has approved or issued as meeting the requirements of title V of the Clean Air Act and part 70 or 71 of this chapter.

**Ton** means 2,000 pounds. For the purpose of determining compliance with the CAIR SO₂ emissions limitation, total tons of sulfur dioxide emissions for a control period shall be calculated as the sum of all recorded hourly emissions (or the mass equivalent of the recorded hourly emission rates) in accordance with subpart HHH of this part, but with any remaining fraction of a ton equal to or greater than 0.50 tons deemed to equal one ton and any remaining fraction of a ton less than 0.50 tons deemed to equal zero tons.

**Topping-cycle cogeneration unit** means a cogeneration unit in which the energy input to the unit is first used to produce useful power, including electricity, and at least some of the reject heat from the electricity production is then used to provide useful thermal energy.

**Total energy input** means, with regard to a cogeneration unit, total energy of all forms supplied to the cogeneration unit, excluding energy produced by the cogeneration unit itself. Each form of energy supplied shall be measured by the lower heating value of that form of energy calculated as follows:

\[
LHV = HHV - 10.55(W + 9H)
\]

Where:

- \(LHV\) = lower heating value of fuel in Btu/lb,
- \(HHV\) = higher heating value of fuel in Btu/lb,
- \(W\) = Weight % of moisture in fuel,
- \(H\) = Weight % of hydrogen in fuel.

**Total energy output** means, with regard to a cogeneration unit, the sum of useful power and useful thermal energy produced by the cogeneration unit.

**Unit** means a stationary, fossil-fuel-fired boiler or combustion turbine or other stationary, fossil-fuel-fired combustion device. **Unit operating day** means a calendar day in which a unit combusts any fuel.

**Unit operating hour or hour of unit operation** means an hour in which a unit combusts any fuel.

**Useful power** means, with regard to a cogeneration unit, electricity or mechanical energy made available for use, excluding any such energy used in the power production process (which process includes, but is not limited to, any on-site processing or treatment of fuel combusted at the unit and any on-site emission controls).

**Useful thermal energy** means, with regard to a cogeneration unit, thermal energy that is:

1. Made available to an industrial or commercial process (not a power production process), excluding any heat contained in condensate return or makeup water;
(2) Used in a heating application (e.g., space heating or domestic hot water heating); or
(3) Used in a space cooling application (i.e., thermal energy used by an absorption chiller).

Utility power distribution system means the portion of an electricity grid owned or operated by a utility and dedicated to delivering electricity to customers.

[65 FR 2727, Jan 18, 2000, as amended by 71 FR 74795, Dec. 13, 2006; 72 FR 59207, Oct. 19, 2007]

§ 97.203 Measurements, abbreviations, and acronyms.

Measurements, abbreviations, and acronyms used in this subpart and subparts BBB through III are defined as follows:

Btu—British thermal unit.
CO_2—carbon dioxide.
H_2O—water.
Hg—mercury.
h—hour.
kW—kilowatt electrical.
kWh—kilowatt hour.
lb—pound.
mmBtu—million Btu.
MWe—megawatt electrical.
MWh—megawatt hour.
NO_X—nitrogen oxides.
O_2—oxygen.
ppm—parts per million.
scfh—standard cubic feet per hour.
SO_2—sulfur dioxide.
yr—year.

§ 97.204 Applicability.

(a) Except as provided in paragraph (b) of this section:

(1) The following units in a State shall be CAIR SO_2 units, and any source that includes one or more such units shall be a CAIR SO_2 source, subject to the requirements of this subpart and subparts BBB through HHH of this part: any stationary, fossil-fuel-fired boiler or stationary, fossil-fuel-fired combustion turbine serving at any time, since the later of November 15, 1990 or the start-up of the unit’s combustion chamber, a generator with nameplate capacity of more than 25 MWe producing electricity for sale, the unit shall become a CAIR SO_2 unit as provided in paragraph (a)(1) of this section on the first date on which it both combusts fossil fuel and serves such generator.

(b) The units in a State that meet the requirements set forth in paragraph (b)(1)(i), (b)(2)(i), or (b)(2)(ii) of this section shall not be CAIR SO_2 units:

(1)(i) Any unit that is a CAIR SO_2 unit under paragraph (a)(1) or (2) of this section:

(A) Qualifying as a cogeneration unit during the 12-month period starting on the date the unit first produces electricity and continuing to qualify as a cogeneration unit; and

(B) Not serving at any time, since the later of November 15, 1990 or the start-up of the unit’s combustion chamber, a generator with nameplate capacity of more than 25 MWe supplying in any calendar year more than one-third of the unit’s potential electric output capacity or 219,000 MWh, whichever is greater, to any utility power distribution system for sale.

(ii) If a unit qualifies as a cogeneration unit during the 12-month period starting on the date the unit first produces electricity and meets the requirements of paragraphs (b)(1)(i) of this section for at least one calendar year, but subsequently no longer meets all such requirements, the unit shall become a CAIR SO_2 unit starting on the earlier of January 1 after the first calendar year during which the unit first no longer qualifies as a cogeneration unit or January 1 after the first calendar year during which the unit no longer meets the requirements of paragraph (b)(1)(i)(B) of this section.

(2)(i) Any unit that is a CAIR SO_2 unit under paragraph (a)(1) or (2) of this section commencing operation before January 1, 1985:

(A) Qualifying as a solid waste incineration unit; and

(B) With an average annual fuel consumption of non-fossil fuel for 1985–1987 exceeding 80 percent (on a Btu basis) and an average annual fuel consumption of non-fossil fuel for any 3 consecutive calendar years after 1990 exceeding 80 percent (on a Btu basis).
(ii) Any unit that is a CAIR SO\textsubscript{2} unit under paragraph (a)(1) or (2) of this section commencing operation on or after January 1, 1985:

(A) Qualifying as a solid waste incineration unit; and

(B) With an average annual fuel consumption of non-fossil fuel for the first 3 calendar years of operation exceeding 80 percent (on a Btu basis) and an average annual fuel consumption of non-fossil fuel for any 3 consecutive calendar years after 1990 exceeding 80 percent (on a Btu basis).

(iii) If a unit qualifies as a solid waste incineration unit and meets the requirements of paragraph (b)(2)(i) or (ii) of this section for at least 3 consecutive calendar years, but subsequently no longer meets all such requirements, the unit shall become a CAIR SO\textsubscript{2} unit starting on the earlier of January 1 after the first calendar year during which the unit first no longer qualifies as a solid waste incineration unit or January 1 after the first 3 consecutive calendar years after 1990 for which the unit has an average annual fuel consumption of fossil fuel of 20 percent or more.

(c) A certifying official of an owner or operator of any unit may petition the Administrator at any time for a determination concerning the applicability, under paragraphs (a) and (b) of this section, of the CAIR SO\textsubscript{2} Trading Program to the unit.

(1) Petition content. The petition shall be in writing and include the identification of the unit and the relevant facts about the unit. The petition and any other documents provided to the Administrator in connection with the petition shall include the following certification statement, signed by the certifying official: “I am authorized to make this submission on behalf of the owners and operators of the unit for which the submission is made. I certify under penalty of law that I have personally examined, and am familiar with, the statements and information submitted in this document and all its attachments. Based on my inquiry of those individuals with primary responsibility for obtaining the information, I certify that the statements and information are to the best of my knowledge and belief true, accurate, and complete. I am aware that there are significant penalties for submitting false statements and information or omitting required statements and information, including the possibility of fine or imprisonment.”

(2) Submission. The petition and any other documents provided in connection with the petition shall be submitted to the Director of the Clean Air Markets Division (or its successor), U.S. Environmental Protection Agency, who will act on the petition as the Administrator’s duly authorized representative.

(3) Response. The Administrator will issue a written response to the petition and may request supplemental information relevant to such petition. The Administrator’s determination concerning the applicability, under paragraphs (a) and (b) of this section, of the CAIR SO\textsubscript{2} Trading Program to the unit shall be binding on the permitting authority unless the petition or other information or documents provided in connection with the petition are found to have contained significant, relevant errors or omissions.

§ 97.205 Retired unit exemption.

(a)(1) Any CAIR SO\textsubscript{2} unit that is permanently retired and is not a CAIR SO\textsubscript{2} opt-in unit under subpart III of this part shall be exempt from the CAIR SO\textsubscript{2} Trading Program, except for the provisions of this section, §§97.202, 97.203, 97.204, 97.206(c)(4) through (7), 97.207, 97.208, and subparts BBB, PPP, and GGG of this part.

(2) The exemption under paragraph (a)(1) of this section shall become effective the day on which the CAIR SO\textsubscript{2} unit is permanently retired. Within 30 days of the unit’s permanent retirement, the CAIR designated representative shall submit a statement to the permitting authority otherwise responsible for administering any CAIR permit for the unit and shall submit a copy of the statement to the Administrator. The statement shall state, in a format prescribed by the permitting authority, that the unit was permanently retired on a specific date and will comply with the requirements of paragraph (b) of this section.

(3) After receipt of the statement under paragraph (a)(2) of this section,
the permitting authority will amend any permit under subpart CCC of this part covering the source at which the unit is located to add the provisions and requirements of the exemption under paragraphs (a)(1) and (b) of this section.

(b) Special provisions. (1) A unit exempt under paragraph (a) of this section shall not emit any sulfur dioxide, starting on the date that the exemption takes effect.

(2) For a period of 5 years from the date the records are created, the owners and operators of a unit exempt under paragraph (a) of this section shall retain, at the source that includes the unit, records demonstrating that the unit is permanently retired. The 5-year period for keeping records may be extended for cause, at any time before the end of the period, in writing by the permitting authority or the Administrator. The owners and operators bear the burden of proof that the unit is permanently retired.

(3) The owners and operators and, to the extent applicable, the CAIR designated representative of a unit exempt under paragraph (a) of this section shall comply with the requirements of the CAIR SO₂ Trading Program concerning all periods for which the exemption is not in effect, even if such requirements arise, or must be complied with, after the exemption takes effect.

(4) A unit exempt under paragraph (a) of this section and located at a source that is required, or but for this exemption would be required, to have a title V operating permit shall not resume operation unless the CAIR designated representative of the source submits a complete CAIR permit application under §97.222 for the unit not less than 18 months (or such lesser time provided by the permitting authority) before the later of January 1, 2010 or the date on which the unit resumes operation.

(5) On the earlier of the following dates, a unit exempt under paragraph (a) of this section shall lose its exemption:

(i) The date on which the CAIR designated representative submits a CAIR permit application for the unit under paragraph (b)(4) of this section;

(ii) The date on which the CAIR designated representative is required under paragraph (b)(4) of this section to submit a CAIR permit application for the unit; or

(iii) The date on which the unit resumes operation, if the CAIR designated representative is not required to submit a CAIR permit application for the unit.

(6) For the purpose of applying monitoring, reporting, and recordkeeping requirements under subpart HHH of this part, a unit that loses its exemption under paragraph (a) of this section shall be treated as a unit that commences commercial operation on the first date on which the unit resumes operation.

§97.206 Standard requirements.

(a) Permit requirements. (1) The CAIR designated representative of each CAIR SO₂ source required to have a title V operating permit and each CAIR SO₂ unit required to have a title V operating permit at the source shall:

(i) Submit to the permitting authority a complete CAIR permit application under §97.222 in accordance with the deadlines specified in §97.221; and

(ii) Submit in a timely manner any supplemental information that the permitting authority determines is necessary in order to review a CAIR permit application and issue or deny a CAIR permit.

(2) The owners and operators of each CAIR SO₂ source required to have a title V operating permit and each CAIR SO₂ unit required to have a title V operating permit at the source shall have a CAIR permit issued by the permitting authority under subpart CCC of this part for the source and operate the source and the unit in compliance with such CAIR permit.

(3) Except as provided in subpart III of this part, the owners and operators of a CAIR SO₂ source that is not otherwise required to have a title V operating permit and each CAIR SO₂ unit that is not otherwise required to have a title V operating permit are not required to submit a CAIR permit application, and to have a CAIR permit, under subpart CCC of this part for such CAIR SO₂ source and such CAIR SO₂ unit.
(b) Monitoring, reporting, and recordkeeping requirements. (1) The owners and operators, and the CAIR designated representative, of each CAIR SO₂ source and each CAIR SO₂ unit at the source shall comply with the monitoring, reporting, and recordkeeping requirements of subpart HHH of this part.

(2) The emissions measurements recorded and reported in accordance with subpart HHH of this part shall be used to determine compliance by each CAIR SO₂ source with the CAIR SO₂ emissions limitation under paragraph (c) of this section.

(c) Sulfur dioxide emission requirements. (1) As of the allowance transfer deadline for a control period, the owners and operators of each CAIR SO₂ source and each CAIR SO₂ unit at the source shall hold, in the source’s compliance account, a tonnage equivalent in CAIR SO₂ allowances available for compliance deductions for the control period, as determined in accordance with §97.254(a) and (b), not less than the tons of total sulfur dioxide emissions for the control period from all CAIR SO₂ units at the source, as determined in accordance with subpart HHH of this part.

(2) A CAIR SO₂ unit shall be subject to the requirements under paragraph (c)(1) of this section for the control period starting on the later of January 1, 2010 or the deadline for meeting the unit(s) monitor certification requirements under §97.270(b)(1), (2), or (5) and for each control period thereafter.

(3) A CAIR SO₂ allowance shall not be deducted for compliance with the requirements under paragraph (c)(1) of this section, for a control period in a calendar year before the year for which the CAIR SO₂ allowance was allocated.

(4) CAIR SO₂ allowances shall be held in, deducted from, or transferred into or among CAIR SO₂ Allowance Tracking System accounts in accordance with subparts FFF, GGG, and III of this part.

(5) A CAIR SO₂ allowance is a limited authorization to emit sulfur dioxide in accordance with the CAIR SO₂ Trading Program. No provision of the CAIR SO₂ Trading Program, the CAIR permit, or an exemption under §97.205 and no provision of law shall be construed to limit the authority of the United States to terminate or limit such authorization.

(6) A CAIR SO₂ allowance does not constitute a property right.

(7) Upon recordation by the Administrator under subpart FFF, GGG, or III of this part, every allocation, transfer, or deduction of a CAIR SO₂ allowance to or from a CAIR SO₂ source’s compliance account is incorporated automatically in any CAIR permit of the source.

(d) Excess emissions requirements. If a CAIR SO₂ source emits sulfur dioxide during any control period in excess of the CAIR SO₂ emissions limitation, then:

(1) The owners and operators of the source and each CAIR SO₂ unit at the source shall surrender the CAIR SO₂ allowances required for deduction under §97.254(d)(1) and pay any fine, penalty, or assessment or comply with any other remedy imposed, for the same violations, under the Clean Air Act or applicable State law; and

(2) Each ton of such excess emissions and each day of such control period shall constitute a separate violation of this subpart, the Clean Air Act, and applicable State law.

(e) Recordkeeping and reporting requirements. (1) Unless otherwise provided, the owners and operators of the CAIR SO₂ source and each CAIR SO₂ unit at the source shall keep on site at the source each of the following documents for a period of 5 years from the date the document is created. This period may be extended for cause, at any time before the end of 5 years, in writing by the permitting authority or the Administrator.

(1) The certificate of representation under §97.213 for the CAIR designated representative for the source and each CAIR SO₂ unit at the source and all documents that demonstrate the truth of the statements in the certificate of representation; provided that the certificate and documents shall be retained on site at the source beyond such 5-year period until such documents are superseded because of the submission of a new certificate of representation under §97.213 changing the CAIR designated representative.

(ii) All emissions monitoring information, in accordance with subpart
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§ 97.210 Authorization and responsibilities of CAIR designated representative.

(a) Except as provided under §97.211, each CAIR SO\textsubscript{2} source, including all CAIR SO\textsubscript{2} units at the source, shall have one and only one CAIR designated representative, with regard to all matters under the CAIR SO\textsubscript{2} Trading Program concerning the source or any CAIR SO\textsubscript{2} unit at the source.

(b) The CAIR designated representative of the CAIR SO\textsubscript{2} source shall be selected by an agreement binding on the owners and operators of the source and all CAIR SO\textsubscript{2} units at the source and the CAIR designated representative of a CAIR SO\textsubscript{2} unit shall also apply to the owners and operators of such unit.

(g) Effect on other authorities. No provision of the CAIR SO\textsubscript{2} Trading Program, a CAIR permit application, a CAIR permit, or an exemption under §97.205 shall be construed as exempting or excluding the owners and operators, and the CAIR designated representative, of a CAIR SO\textsubscript{2} source or CAIR SO\textsubscript{2} unit from compliance with any other provision of the applicable, approved State implementation plan, a federally enforceable permit, or the Clean Air Act.

§ 97.207 Computation of time.

(a) Unless otherwise stated, any time period scheduled, under the CAIR SO\textsubscript{2} Trading Program, to begin on the occurrence of an act or event shall begin on the day the act or event occurs.

(b) Unless otherwise stated, any time period scheduled, under the CAIR SO\textsubscript{2} Trading Program, to begin before the occurrence of an act or event shall be computed so that the period ends the day before the act or event occurs.

(c) Unless otherwise stated, if the final day of any time period, under the CAIR SO\textsubscript{2} Trading Program, falls on a weekend or a State or Federal holiday, the time period shall be extended to the next business day.

§ 97.208 Appeal procedures.

The appeal procedures for decisions of the Administrator under the CAIR SO\textsubscript{2} Trading Program are set forth in part 78 of this chapter.
§ 97.211 Alternate CAIR designated representative.

(a) A certificate of representation under §97.213 may designate one and only one alternate CAIR designated representative, who may act on behalf of the CAIR designated representative.

§ 97.212 Changing CAIR designated representative and alternate CAIR designated representative; changes in owners and operators.

(a) Changing CAIR designated representative. The CAIR designated representative may be changed at any time upon receipt by the Administrator of a superseding complete certificate of representation under §97.213. Notwithstanding any such change, all representations, actions, inactions, and submissions by the previous CAIR designated representative before the time and date when the Administrator receives the superseding certificate of representation shall be binding on the new CAIR designated representative and the owners and operators of the CAIR SO₂ source and the CAIR SO₂ units at the source.

(b) Changing alternate CAIR designated representative. The alternate CAIR designated representative may be changed at any time upon receipt by the Administrator of a superseding complete certificate of representation under §97.213. Notwithstanding any such change, all representations, actions, inactions, and submissions by the previous alternate CAIR designated representative before the time and date when the Administrator receives the superseding certificate of representation shall be binding on the new alternate CAIR designated representative and the owners and operators of the CAIR SO₂ source and the CAIR SO₂ units at the source.

§ 97.211 Alternate CAIR designated representative.

(a) A certificate of representation under §97.213 may designate one and only one alternate CAIR designated representative, who may act on behalf of the CAIR designated representative.

The agreement by which the alternate CAIR designated representative is selected shall include a procedure for authorizing the alternate CAIR designated representative to act in lieu of the CAIR designated representative.

(d) No CAIR permit will be issued, no emissions data reports will be accepted, and no CAIR SO₂ Allowance Tracking System account will be established for a CAIR SO₂ unit at a source, until the Administrator has received a complete certificate of representation under §97.213 for a CAIR designated representative of the source and the CAIR SO₂ units at the source.

(e)(1) Each submission under the CAIR SO₂ Trading Program shall be submitted, signed, and certified by the CAIR designated representative for each CAIR SO₂ source on behalf of which the submission is made. Each such submission shall include the following certification statement by the CAIR designated representative: "I am authorized to make this submission on behalf of the owners and operators of the source or units for which the submission is made. I certify under penalty of law that I have personally examined, and am familiar with, the statements and information submitted in this document and all its attachments. Based on my inquiry of those individuals with primary responsibility for obtaining the information, I certify that the statements and information are to the best of my knowledge and belief true, accurate, and complete. I am aware that there are significant penalties for submitting false statements and information or omitting required statements and information, including the possibility of fine or imprisonment."

(2) The permitting authority and the Administrator will accept or act on a submission made on behalf of owner or operators of a CAIR SO₂ source or a CAIR SO₂ unit only if the submission has been made, signed, and certified in accordance with paragraph (e)(1) of this section.

§ 97.212 Changing CAIR designated representative and alternate CAIR designated representative; changes in owners and operators.

(a) Changing CAIR designated representative. The CAIR designated representative may be changed at any time upon receipt by the Administrator of a superseding complete certificate of representation under §97.213. Notwithstanding any such change, all representations, actions, inactions, and submissions by the previous CAIR designated representative before the time and date when the Administrator receives the superseding certificate of representation shall be binding on the new CAIR designated representative and the owners and operators of the CAIR SO₂ source and the CAIR SO₂ units at the source.

(b) Changing alternate CAIR designated representative. The alternate CAIR designated representative may be changed at any time upon receipt by the Administrator of a superseding complete certificate of representation under §97.213. Notwithstanding any such change, all representations, actions, inactions, and submissions by the previous alternate CAIR designated representative before the time and date when the Administrator receives the superseding certificate of representation shall be binding on the new alternate CAIR designated representative and the owners and operators of the CAIR SO₂ source and the CAIR SO₂ units at the source.
superseding certificate of representation shall be binding on the new alternate CAIR designated representative and the owners and operators of the CAIR SO\textsubscript{2} source and the CAIR SO\textsubscript{2} units at the source.

(c) Changes in owners and operators. 

(1) In the event an owner or operator of a CAIR SO\textsubscript{2} source or a CAIR SO\textsubscript{2} unit is not included in the list of owners and operators in the certificate of representation under §97.213, such owner or operator shall be deemed to be subject to and bound by the certificate of representation, the representations, actions, inactions, and submissions of the CAIR designated representative and any alternate CAIR designated representative of the source or unit, and the decisions and orders of the permitting authority, the Administrator, or a court, as if the owner or operator were included in such list.

(2) Within 30 days following any change in the owners and operators of a CAIR SO\textsubscript{2} source or a CAIR SO\textsubscript{2} unit, including the addition of a new owner or operator, the CAIR designated representative and any alternate CAIR designated representative shall submit a revision to the certificate of representation under §97.213 amending the list of owners and operators to include the change.

§ 97.213 Certificate of representation.

(a) A complete certificate of representation for a CAIR designated representative or an alternate CAIR designated representative shall include the following elements in a format prescribed by the Administrator:

(1) Identification of the CAIR SO\textsubscript{2} source, and each CAIR SO\textsubscript{2} unit at the source, for which the certificate of representation is submitted, including identification and nameplate capacity of each generator served by each such unit.

(2) The name, address, e-mail address (if any), telephone number, and facsimile transmission number (if any) of the CAIR designated representative and any alternate CAIR designated representative.

(3) A list of the owners and operators of the CAIR SO\textsubscript{2} source and of each CAIR SO\textsubscript{2} unit at the source.

(4) The following certification statements by the CAIR designated representative and any alternate CAIR designated representative—

(i) “I certify that I was selected as the CAIR designated representative or alternate CAIR designated representative, as applicable, by an agreement binding on the owners and operators of the source and each CAIR SO\textsubscript{2} unit at the source.”

(ii) “I certify that I have all the necessary authority to carry out my duties and responsibilities under the CAIR SO\textsubscript{2} Trading Program on behalf of the owners and operators of the source and of each CAIR SO\textsubscript{2} unit at the source and that each such owner and operator shall be fully bound by my representations, actions, inactions, or submissions.”

(iii) “I certify that the owners and operators of the source and of each CAIR SO\textsubscript{2} unit at the source shall be bound by any order issued to me by the Administrator, the permitting authority, or a court regarding the source or unit.”

(iv) “Where there are multiple holders of a legal or equitable title to, or a leasehold interest in, a CAIR SO\textsubscript{2} unit, or where a utility or industrial customer purchases power from a CAIR SO\textsubscript{2} unit under a life-of-the-unit, firm power contractual arrangement, I certify that: I have given a written notice of my selection as the ‘CAIR designated representative’ or ‘alternate CAIR designated representative’, as applicable, and of the agreement by which I was selected to each owner and operator of the source and of each CAIR SO\textsubscript{2} unit; and CAIR SO\textsubscript{2} allowances and proceeds of transactions involving CAIR SO\textsubscript{2} allowances will be deemed to be held or distributed in proportion to each holder’s legal, equitable, leasehold, or contractual reservation or entitlement, except that, if such multiple holders have expressly provided for a different distribution of CAIR SO\textsubscript{2} allowances by contract, CAIR SO\textsubscript{2} allowances and proceeds of transactions involving CAIR SO\textsubscript{2} allowances will be deemed to be held or distributed in accordance with the contract.”
(5) The signature of the CAIR designated representative and any alternate CAIR designated representative and the dates signed.

(b) Unless otherwise required by the permitting authority or the Administrator, documents of agreement referred to in the certificate of representation shall not be submitted to the permitting authority or the Administrator. Neither the permitting authority nor the Administrator shall be under any obligation to review or evaluate the sufficiency of such documents, if submitted.

§ 97.214 Objections concerning CAIR designated representative.

(a) Once a complete certificate of representation under §97.213 has been submitted and received, the permitting authority and the Administrator will rely on the certificate of representation unless and until a superseding complete certificate of representation under §97.213 is received by the Administrator.

(b) Except as provided in §97.212(a) or (b), no objection or other communication submitted to the permitting authority or the Administrator concerning the authorization, or any representation, action, inaction, or submission, of the CAIR designated representative shall affect any representation, action, inaction, or submission of the CAIR designated representative or the finality of any decision or order by the permitting authority or the Administrator under the CAIR SO\textsubscript{2} Trading Program.

(c) Neither the permitting authority nor the Administrator will adjudicate any private legal dispute concerning the authorization or any representation, action, inaction, or submission of any CAIR designated representative, including private legal disputes concerning the proceeds of CAIR SO\textsubscript{2} allowance transfers.

§ 97.215 Delegation by CAIR designated representative and alternate CAIR designated representative.

(a) A CAIR designated representative may delegate, to one or more natural persons, his or her authority to make an electronic submission to the Administrator provided for or required under this part.

(b) An alternate CAIR designated representative may delegate, to one or more natural persons, his or her authority to make an electronic submission to the Administrator provided for or required under this part.

(c) In order to delegate authority to make an electronic submission to the Administrator in accordance with paragraph (a) or (b) of this section, the CAIR designated representative or alternate CAIR designated representative, as appropriate, must submit to the Administrator a notice of delegation, in a format prescribed by the Administrator, that includes the following elements:

(1) The name, address, e-mail address, telephone number, and facsimile transmission number (if any) of such CAIR designated representative or alternate CAIR designated representative;

(2) The name, address, e-mail address, telephone number, and facsimile transmission number (if any) of each such natural person (referred to as an “agent”);

(3) For each such natural person, a list of the type or types of electronic submissions under paragraph (a) or (b) of this section for which authority is delegated to him or her; and

(4) The following certification statements by such CAIR designated representative or alternate CAIR designated representative:

(i) “I agree that any electronic submission to the Administrator that is by an agent identified in this notice of delegation and of a type listed for such agent in this notice of delegation and that is made when I am a CAIR designated representative or alternate CAIR designated representative, as appropriate, and before this notice of delegation is superseded by another notice of delegation under 40 CFR 97.215(d) shall be deemed to be an electronic submission by me.”

(ii) “Until this notice of delegation is superseded by another notice of delegation under 40 CFR 97.215(d), I agree to maintain an e-mail account and to notify the Administrator immediately of any change in my e-mail address unless all delegation of authority by me under 40 CFR 97.215 is terminated.”
(d) A notice of delegation submitted under paragraph (c) of this section shall be effective, with regard to the CAIR designated representative or alternate CAIR designated representative identified in such notice, upon receipt of such notice by the Administrator and until receipt by the Administrator of a superseding notice of delegation submitted by such CAIR designated representative or alternate CAIR designated representative, as appropriate. The superseding notice of delegation may replace any previously identified agent, add a new agent, or eliminate entirely any delegation of authority.

(e) Any electronic submission covered by the certification in paragraph (c)(4)(i) of this section and made in accordance with a notice of delegation effective under paragraph (d) of this section shall be deemed to be an electronic submission by the CAIR designated representative or alternate CAIR designated representative submitting such notice of delegation.

Subpart CCC—Permits

§ 97.220 General CAIR SO\textsubscript{2} Trading Program permit requirements.

(a) For each CAIR SO\textsubscript{2} source required to have a title V operating permit or required, under subpart III of this part, to have a title V operating permit or other federally enforceable permit, such permit shall include a CAIR permit administered by the permitting authority for the title V operating permit or the federally enforceable permit as applicable. The CAIR portion of the title V permit or other federally enforceable permit as applicable shall be administered in accordance with the permitting authority’s title V operating permits regulations promulgated under part 70 or 71 of this chapter or the permitting authority’s regulations for other federally enforceable permits as applicable, except as provided otherwise by §97.205, this subpart, and subpart III of this part.

(b) Each CAIR permit shall contain, with regard to the CAIR SO\textsubscript{2} source and the CAIR SO\textsubscript{2} units at the source covered by the CAIR permit, all applicable CAIR SO\textsubscript{2} Trading Program, CAIR NO\textsubscript{x} Annual Trading Program, and CAIR NO\textsubscript{x} Ozone Season Trading Program requirements and shall be a complete and separable portion of the title V operating permit or other federally enforceable permit under paragraph (a) of this section.

§ 97.221 Submission of CAIR permit applications.

(a) Duty to apply. The CAIR designated representative of any CAIR SO\textsubscript{2} source required to have a title V operating permit shall submit to the permitting authority a complete CAIR permit application under §97.222 for the source covering each CAIR SO\textsubscript{2} unit at the source at least 18 months (or such lesser time provided by the permitting authority) before the later of January 1, 2010 or the date on which the CAIR SO\textsubscript{2} unit commences commercial operation, except as provided in §97.233(a).

(b) Duty to reapply. For a CAIR SO\textsubscript{2} source required to have a title V operating permit, the CAIR designated representative shall submit a complete CAIR permit application under §97.222 for the source covering each CAIR SO\textsubscript{2} unit at the source to renew the CAIR permit in accordance with the permitting authority’s title V operating permits regulations addressing permit renewal, except as provided in §97.233(b).

§ 97.222 Information requirements for CAIR permit applications.

A complete CAIR permit application shall include the following elements concerning the CAIR SO\textsubscript{2} source for which the application is submitted, in a format prescribed by the permitting authority:

(a) Identification of the CAIR SO\textsubscript{2} source;

(b) Identification of each CAIR SO\textsubscript{2} unit at the CAIR SO\textsubscript{2} source; and

(c) The standard requirements under §97.206.

§ 97.223 CAIR permit contents and term.

(a) Each CAIR permit will contain, in a format prescribed by the permitting authority, all elements required for a complete CAIR permit application under §97.222.

(b) Each CAIR permit is deemed to incorporate automatically the definitions of terms under §97.202 and, upon
§ 97.224 CAIR permit revisions.

Except as provided in §97.223(b), the permitting authority will revise the CAIR permit, as necessary, in accordance with the permitting authority’s title V operating permits regulations or the permitting authority’s regulations for other federally enforceable permits as applicable addressing permit revisions.

Subparts DDD—EEE [Reserved]

Subpart FFF—CAIR SO\(_2\) Allowance Tracking System

§ 97.250 [Reserved]

§ 97.251 Establishment of accounts.

(a) Compliance accounts. Except as provided in §97.284(e), upon receipt of a complete certificate of representation under §97.213, the Administrator will establish a compliance account for the CAIR SO\(_2\) source for which the certificate of representation was submitted, unless the source already has a compliance account.

(b) General accounts—(1) Application for general account. (i) Any person may apply to open a general account for the purpose of holding and transferring CAIR SO\(_2\) allowances. An application for a general account may designate one and only one CAIR authorized account representative and one and only one alternate CAIR authorized account representative who may act on behalf of the CAIR authorized account representative. The agreement by which the alternate CAIR authorized account representative is selected shall include a procedure for authorizing the alternate CAIR authorized account representative to act in lieu of the CAIR authorized account representative.

(ii) A complete application for a general account shall be submitted to the Administrator and shall include the following elements in a format prescribed by the Administrator:

(A) Name, mailing address, e-mail address (if any), telephone number, and facsimile transmission number (if any) of the CAIR authorized account representative and any alternate CAIR authorized account representative.

(B) Organization name and type of organization, if applicable;

(C) A list of all persons subject to a binding agreement for the CAIR authorized account representative and any alternate CAIR authorized account representative to represent their ownership interest with respect to the CAIR SO\(_2\) allowances held in the general account;

(D) The following certification statement by the CAIR authorized account representative and any alternate CAIR authorized account representative: “I certify that I was selected as the CAIR authorized account representative or the alternate CAIR authorized account representative, as applicable, by an agreement that is binding on all persons who have an ownership interest with respect to CAIR SO\(_2\) allowances held in the general account. I certify that I have all the necessary authority to carry out my duties and responsibilities under the CAIR SO\(_2\) Trading Program on behalf of such persons and that each such person shall be fully bound by my representations, actions, inactions, or submissions and by any order or decision issued to me by the Administrator or a court regarding the general account.”

(E) The signature of the CAIR authorized account representative and any alternate CAIR authorized account representative and the dates signed.

(iii) Unless otherwise required by the permitting authority or the Administrator, documents of agreement referred to in the application for a general account shall not be submitted to the permitting authority or the Administrator. Neither the permitting authority nor the Administrator shall be under any obligation to review or
evaluate the sufficiency of such documents, if submitted.

(2) Authorization of CAIR authorized account representative and alternate CAIR authorized account representative.

(i) Upon receipt by the Administrator of a complete application for a general account under paragraph (b)(1) of this section:

(A) The Administrator will establish a general account for the person or persons for whom the application is submitted.

(B) The CAIR authorized account representative and any alternate CAIR authorized account representative for the general account shall represent and, by his or her representations, actions, inactions, or submissions, legally bind each person who has an ownership interest with respect to CAIR SO\textsubscript{2} allowances held in the general account in all matters pertaining to the CAIR SO\textsubscript{2} Trading Program, notwithstanding any agreement between the CAIR authorized account representative or any alternate CAIR authorized account representative and such person. Any such person shall be bound by any order or decision issued to the CAIR authorized account representative or any alternate CAIR authorized account representative by the Administrator or a court regarding the general account.

(C) Any representation, action, inaction, or submission by any alternate CAIR authorized account representative shall be deemed to be a representation, action, inaction, or submission by the CAIR authorized account representative.

(ii) Each submission concerning the general account shall be submitted, signed, and certified by the CAIR authorized account representative or any alternate CAIR authorized account representative for the persons having an ownership interest with respect to CAIR SO\textsubscript{2} allowances held in the general account. Each such submission shall include the following certification statement by the CAIR authorized account representative or any alternate CAIR authorized account representative: "I am authorized to make this submission on behalf of the persons having an ownership interest with respect to the CAIR SO\textsubscript{2} allowances held in the general account. I certify under penalty of law that I have personally examined, and am familiar with, the statements and information submitted in this document and all its attachments. Based on my inquiry of those individuals with primary responsibility for obtaining the information, I certify that the statements and information are to the best of my knowledge and belief true, accurate, and complete. I am aware that there are significant penalties for submitting false statements and information or omitting required statements and information, including the possibility of fine or imprisonment."

(iii) The Administrator will accept or act on a submission concerning the general account only if the submission has been made, signed, and certified in accordance with paragraph (b)(2)(ii) of this section.

(3) Changing CAIR authorized account representative and alternate CAIR authorized account representative; changes in persons with ownership interest.

(i) The CAIR authorized account representative for a general account may be changed at any time upon receipt by the Administrator of a superseding complete application for a general account under paragraph (b)(1) of this section. Notwithstanding any such change, all representations, actions, inactions, and submissions by the previous CAIR authorized account representative before the time and date when the Administrator receives the superseding application for a general account shall be binding on the new CAIR authorized account representative and the persons with an ownership interest with respect to the CAIR SO\textsubscript{2} allowances in the general account.

(ii) The alternate CAIR authorized account representative for a general account may be changed at any time upon receipt by the Administrator of a superseding complete application for a general account under paragraph (b)(1) of this section. Notwithstanding any such change, all representations, actions, inactions, and submissions by the previous alternate CAIR authorized account representative before the time and date when the Administrator receives the superseding application for a general account shall be binding on the new alternate CAIR authorized account representative and the persons with an ownership interest with respect to the CAIR SO\textsubscript{2} allowances in the general account.
representative and the persons with an ownership interest with respect to the CAIR SO\textsubscript{2} allowances in the general account.

(iii)(A) In the event a person having an ownership interest with respect to CAIR SO\textsubscript{2} allowances in the general account is not included in the list of such persons in the application for a general account, such person shall be deemed to be subject to and bound by the application for a general account, the representation, actions, inactions, and submissions of the CAIR authorized account representative and any alternate CAIR authorized account representative of the account, and the decisions and orders of the Administrator or a court, as if the person were included in such list.

(B) Within 30 days following any change in the persons having an ownership interest with respect to CAIR SO\textsubscript{2} allowances in the general account, including the addition of a new person, the CAIR authorized account representative or any alternate CAIR authorized account representative shall submit a revision to the application for a general account amending the list of persons having an ownership interest with respect to the CAIR SO\textsubscript{2} allowances in the general account to include the change.

(4) Objections concerning CAIR authorized account representative and alternate CAIR authorized account representative. (i) Once a complete application for a general account under paragraph (b)(1) of this section has been submitted and received, the Administrator will rely on the application unless and until a superseding complete application for a general account under paragraph (b)(1) of this section is received by the Administrator.

(ii) Except as provided in paragraph (b)(3)(i) or (ii) of this section, no objection or other communication submitted to the Administrator concerning the authorization or any representation, action, inaction, or submission of the CAIR authorized account representative or any alternate CAIR authorized account representative for a general account shall affect any representation, action, inaction, or submission of the CAIR authorized account representative or any alternate CAIR authorized account representative or the finality of any decision or order by the Administrator under the CAIR SO\textsubscript{2} Trading Program.

(iii) The Administrator will not adjudicate any private legal dispute concerning the authorization or any representation, action, inaction, or submission of the CAIR authorized account representative or any alternate CAIR authorized account representative for a general account, including private legal disputes concerning the proceeds of CAIR SO\textsubscript{2} allowance transfers.

(5) Delegation by CAIR authorized account representative and alternate CAIR authorized account representative. (i) A CAIR authorized account representative may delegate, to one or more natural persons, his or her authority to make an electronic submission to the Administrator provided for or required under subparts FFF and GGG of this part.

(ii) An alternate CAIR authorized account representative may delegate, to one or more natural persons, his or her authority to make an electronic submission to the Administrator provided for or required under subparts FFF and GGG of this part.

(iii) In order to delegate authority to make an electronic submission to the Administrator in accordance with paragraph (b)(5)(i) or (ii) of this section, the CAIR authorized account representative or alternate CAIR authorized account representative, as appropriate, must submit to the Administrator a notice of delegation, in a format prescribed by the Administrator, that includes the following elements:

(A) The name, address, e-mail address, telephone number, and facsimile transmission number (if any) of each such natural person (referred to as an "agent");

(B) The name, address, e-mail address, telephone number, and facsimile transmission number (if any) of each such natural person (referred to as an "agent");

(C) For each such natural person, a list of the type or types of electronic submissions under paragraph (b)(5)(i) or (ii) of this section for which authority is delegated to him or her;
(D) The following certification statement by such CAIR authorized account representative or alternate CAIR authorized account representative: "I agree that any electronic submission to the Administrator that is by an agent identified in this notice of delegation and of a type listed for such agent in this notice of delegation and that is made when I am a CAIR authorized account representative or alternate CAIR authorized representative, as appropriate, and before this notice of delegation is superseded by another notice of delegation under 40 CFR 97.251(b)(5)(iv) shall be deemed to be an electronic submission by me."; and

(E) The following certification statement by such CAIR authorized account representative or alternate CAIR authorized account representative: "Until this notice of delegation is superseded by another notice of delegation under 40 CFR 97.251(b)(5)(iv), I agree to maintain an e-mail account and to notify the Administrator immediately of any change in my e-mail address, unless all delegation of authority by me under 40 CFR 97.251(b)(5) is terminated.".

(iv) A notice of delegation submitted under paragraph (b)(5)(iii) of this section shall be effective, with regard to the CAIR authorized account representative or alternate CAIR authorized account representative identified in such notice, upon receipt of such notice by the Administrator and until receipt by the Administrator of a superseding notice of delegation submitted by such CAIR authorized account representative or alternate CAIR authorized account representative, as appropriate. The superseding notice of delegation may replace any previously identified agent, add a new agent, or eliminate entirely any delegation of authority.

(v) Any electronic submission covered by the certification in paragraph (b)(5)(iii)(D) of this section and made in accordance with a notice of delegation effective under paragraph (b)(5)(iv) of this section shall be deemed to be an electronic submission by the CAIR designated representative or alternate CAIR designated representative submitting such notice of delegation.

(c) Account identification. The Administrator will assign a unique identifying number to each account established under paragraph (a) or (b) of this section.

§ 97.252 Responsibilities of CAIR authorized account representative.

Following the establishment of a CAIR SO_2 Allowance Tracking System account, all submissions to the Administrator pertaining to the account, including, but not limited to, submissions concerning the deduction or transfer of CAIR SO_2 allowances in the account, shall be made only by the CAIR authorized account representative for the account.

§ 97.253 Recordation of CAIR SO_2 allowances.

(a)(1) After a compliance account is established under §97.251(a) or §73.31(a) or (b) of this chapter, the Administrator will record in the compliance account any CAIR SO_2 allowance allocated to any CAIR SO_2 unit at the source for each of the 30 years starting the later of 2010 or the year in which the compliance account is established, and any CAIR SO_2 allowance allocated for each of the 30 years starting the later of 2010 or the year in which the compliance account is established and transferred to the source in accordance with subpart GGG of this part or subpart D of part 73 of this chapter.

(2) In 2011 and each year thereafter, after Administrator has completed all deductions under §97.254(b), the Administrator will record in the compliance account any CAIR SO_2 allowance allocated to any CAIR SO_2 unit at the source for the new 30th year (i.e., the year that is 30 years after the calendar year for which such deductions are or could be made) and any CAIR SO_2 allowance allocated for the new 30th year and transferred to the source in accordance with subpart GGG of this part or subpart D of part 73 of this chapter.

(b)(1) After a general account is established under §97.251(b) or §73.31(c) of this chapter, the Administrator will record in the general account any CAIR SO_2 allowance allocated for each of the 30 years starting the later of 2010 or the year in which the general account is established and transferred to the general account in accordance with
subpart GGG of this part or subpart D of part 73 of this chapter.

(2) In 2011 and each year thereafter, after Administrator has completed all deductions under §97.254(b), the Administrator will record in the general account any CAIR SO\(_2\) allowance allocated for the new 30th year (i.e., the year that is 30 years after the calendar year for which such deductions are or could be made) and transferred to the general account in accordance with subpart GGG of this part or subpart D of part 73 of this chapter.

(c) Serial numbers for allocated CAIR SO\(_2\) allowances. When recording the allocation of CAIR SO\(_2\) allowances issued by a permitting authority under §97.288, the Administrator will assign each such CAIR SO\(_2\) allowance a unique identification number that will include digits identifying the year of the control period for which the CAIR SO\(_2\) allowance is allocated.

§97.254 Compliance with CAIR SO\(_2\) emissions limitation.

(a) Allowance transfer deadline. The CAIR SO\(_2\) allowances are available to be deducted for compliance with a source’s CAIR SO\(_2\) emissions limitation for a control period in a given calendar year only if the CAIR SO\(_2\) allowances:

(1) Were allocated for the control period in the year or a prior year; and

(2) Are held in the compliance account as of the allowance transfer deadline for the control period or are transferred into the compliance account by a CAIR SO\(_2\) allowance transfer correctly submitted for recordation under §§97.260 and 97.261 by the allowance transfer deadline for the control period.

(b) Deductions for compliance. Following the recordation, in accordance with §97.261, of CAIR SO\(_2\) allowance transfers submitted for recordation in a source’s compliance account by the allowance transfer deadline for a control period, the Administrator will deduct from the compliance account CAIR SO\(_2\) allowances available under paragraph (a) of this section in order to determine whether the source meets the CAIR SO\(_2\) emissions limitation for the control period as follows:

(1) For a CAIR SO\(_2\) source subject to an Acid Rain emissions limitation, the Administrator will, in the following order:

(i) Deduct the amount of CAIR SO\(_2\) allowances, available under paragraph (a) of this section and not issued by a permitting authority under §97.288, that is required under §§73.35(b) and (c) of this part. If there are sufficient CAIR SO\(_2\) allowances to complete this deduction, the deduction will be treated as satisfying the requirements of §§73.35(b) and (c) of this chapter.

(ii) Deduct the amount of CAIR SO\(_2\) allowances, not issued by a permitting authority under §97.288, that is required under §§73.35(d) and 77.5 of this part. If there are sufficient CAIR SO\(_2\) allowances to complete this deduction, the deduction will be treated as satisfying the requirements of §§73.35(d) and 77.5 of this chapter.

(iii) Treating the CAIR SO\(_2\) allowances deducted under paragraph (b)(1)(i) of this section as also being deducted under this paragraph (b)(1)(ii), deduct CAIR SO\(_2\) allowances available under paragraph (a) of this section (including any issued by a permitting authority under §97.288) in order to determine whether the source meets the CAIR SO\(_2\) emissions limitation for the control period, as follows:

(A) Until the tonnage equivalent of the CAIR SO\(_2\) allowances deducted equals, or exceeds in accordance with paragraphs (c)(1) and (2) of this section, the number of tons of total sulfur dioxide emissions, determined in accordance with subpart HHH of this part, from all CAIR SO\(_2\) units at the source for the control period; or

(B) If there are insufficient CAIR SO\(_2\) allowances to complete the deductions in paragraph (b)(1)(ii)(A) of this section, until no more CAIR SO\(_2\) allowances available under paragraph (a) of this section (including any issued by a permitting authority under §97.288) remain in the compliance account.

(2) For a CAIR SO\(_2\) source not subject to an Acid Rain emissions limitation, the Administrator will deduct CAIR SO\(_2\) allowances available under paragraph (a) of this section (including any issued by a permitting authority under §97.288) in order to determine whether the source meets the CAIR SO\(_2\) emissions limitation for the control period, as follows:
(i) Until the tonnage equivalent of the CAIR SO\textsubscript{2} allowances deducted equals, or exceeds in accordance with paragraphs (c)(1) and (2) of this section, the number of tons of total sulfur dioxide emissions, determined in accordance with subpart HH of this part, from all CAIR SO\textsubscript{2} units at the source for the control period; or

(ii) If there are insufficient CAIR SO\textsubscript{2} allowances to complete the deductions in paragraph (b)(2)(i) of this section, until no more CAIR SO\textsubscript{2} allowances available under paragraph (a) of this section (including any issued by a permitting authority under §97.288) remain in the compliance account.

(c)(1) Identification of CAIR SO\textsubscript{2} allowances by serial number. The CAIR authorized account representative for a source’s compliance account may request that specific CAIR SO\textsubscript{2} allowances, identified by serial number, in the compliance account be deducted for emissions or excess emissions for a control period in accordance with paragraph (b) or (d) of this section. Such request shall be submitted to the Administrator by the allowance transfer deadline for the control period and include, in a format prescribed by the Administrator, the identification of the CAIR SO\textsubscript{2} source and the appropriate serial numbers.

(2) First-in, first-out. The Administrator will deduct CAIR SO\textsubscript{2} allowances under paragraph (b) or (d) of this section from the source’s compliance account, in the absence of an identification or in the case of a partial identification of CAIR SO\textsubscript{2} allowances by serial number under paragraph (c)(1) of this section, on a first-in, first-out (FIFO) accounting basis in the following order:

(i) Any CAIR SO\textsubscript{2} allowances that were allocated to the units at the source for a control period before 2010, in the order of recordation;

(ii) Any CAIR SO\textsubscript{2} allowances that were allocated to any entity for a control period before 2010 and transferred and recorded in the compliance account pursuant to subpart GGG of this part or subpart D of part 73 of this chapter, in the order of recordation;

(iii) Any CAIR SO\textsubscript{2} allowances that were allocated to the units at the source for a control period during 2010 through 2014, in the order of recordation;

(iv) Any CAIR SO\textsubscript{2} allowances that were allocated to any entity for a control period during 2010 through 2014 and transferred and recorded in the compliance account pursuant to subpart GGG of this part or subpart D of part 73 of this chapter, in the order of recordation;

(v) Any CAIR SO\textsubscript{2} allowances that were allocated to the units at the source for a control period in 2015 or later, in the order of recordation; and

(vi) Any CAIR SO\textsubscript{2} allowances that were allocated to any entity for a control period in 2015 or later and transferred and recorded in the compliance account pursuant to subpart GGG of this part or subpart D of part 73 of this chapter, in the order of recordation.

(d) Deductions for excess emissions. (1) After making the deductions for compliance under paragraph (b) of this section for a control period in a calendar year in which the CAIR SO\textsubscript{2} source has excess emissions, the Administrator will deduct from the source’s compliance account the tonnage equivalent in CAIR SO\textsubscript{2} allowances, allocated for the control period in the immediately following calendar year (including any issued by a permitting authority under §97.288), equal to, or exceeding in accordance with paragraphs (c)(1) and (2) of this section 3 times the following amount: the number of tons of the source’s excess emissions minus, if the source is subject to an Acid Rain emissions limitation, the amount of the CAIR SO\textsubscript{2} allowances required to be deducted under paragraph (b)(1)(ii) of this section.

(2) Any allowance deduction required under paragraph (d)(1) of this section shall not affect the liability of the owners and operators of the CAIR SO\textsubscript{2} source or the CAIR SO\textsubscript{2} units at the source for any fine, penalty, or assessment, or their obligation to comply with any other remedy, for the same violations, as ordered under the Clean Air Act or applicable State law.

(e) Recordation of deductions. The Administrator will record in the appropriate compliance account all deductions from such an account under paragraphs (b) and (d) of this section and subpart III.
§ 97.255 Administrator's action on submissions.

(1) The Administrator may review and conduct independent audits concerning any submission under the CAIR SO₂ Trading Program and make appropriate adjustments of the information in the submissions.

(2) The Administrator may deduct CAIR SO₂ allowances from or transfer CAIR SO₂ allowances to a source's compliance account based on the information in the submissions, as adjusted under paragraph (f)(1) of this section, and record such deductions and transfers.

§ 97.255 Banking.

(a) CAIR SO₂ allowances may be banked for future use or transfer in a compliance account or a general account in accordance with paragraph (b) of this section.

(b) Any CAIR SO₂ allowance that is held in a compliance account or a general account will remain in such account unless and until the CAIR SO₂ allowance is deducted or transferred under §97.254, §97.256, or subpart GGG or III of this part.

§ 97.256 Account error.

The Administrator may, at his or her sole discretion and on his or her own motion, correct any error in any CAIR SO₂ Allowance Tracking System account. Within 10 business days of making such correction, the Administrator will notify the CAIR authorized account representative for the account.

§ 97.257 Closing of general accounts.

(a) The CAIR authorized account representative of a general account may submit to the Administrator a request to close the account, which shall include a correctly submitted allowance transfer under §§97.260 and 97.261 for any CAIR SO₂ allowances in the account to one or more other CAIR SO₂ Allowance Tracking System accounts.

(b) If a general account has no allowance transfers in or out of the account for a 12-month period or longer and does not contain any CAIR SO₂ allowances, the Administrator may notify the CAIR authorized account representative for the account that the account will be closed after the 20-day period unless, before the end of the 20-day period, the Administrator receives a correctly submitted transfer of CAIR SO₂ allowances into the account under §§97.260 and 97.261 or a statement submitted by the CAIR authorized account representative demonstrating to the satisfaction of the Administrator good cause as to why the account should not be closed.

Subpart GGG—CAIR SO₂ Allowance Transfers

§ 97.260 Submission of CAIR SO₂ allowance transfers.

(a) A CAIR authorized account representative seeking recordation of a CAIR SO₂ allowance transfer shall submit the transfer to the Administrator. To be considered correctly submitted, the CAIR SO₂ allowance transfer shall include the following elements, in a format specified by the Administrator:

(1) The account numbers of both the transferor and transferee accounts;

(2) The serial number of each CAIR SO₂ allowance that is in the transferor account and is to be transferred;

(3) The name and signature of the CAIR authorized account representatives of the transferor and transferee accounts and the dates signed.

(b)(1) The CAIR authorized account representative for the transferee account can meet the requirements in paragraph (a)(3) of this section by submitting, in a format prescribed by the Administrator, a statement signed by the CAIR authorized account representative and identifying each account into which any transfer of allowances, submitted on or after the date on which the Administrator receives such statement, is authorized. Such authorization shall be binding on any CAIR authorized account representative for such account and shall apply to all transfers into the account that are submitted on or after such date of receipt, unless and until the Administrator receives a statement signed by the CAIR authorized account representative retracting the authorization for the account.

(2) The statement under paragraph (b)(1) of this section shall include the
following: “By this signature I authorize any transfer of allowances into each account listed herein, except that I do not waive any remedies under State or Federal law to obtain correction of any erroneous transfers into such accounts. This authorization shall be binding on any CAIR authorized account representative for such account unless and until a statement signed by the CAIR authorized account representative retracting this authorization for the account is received by the Administrator.”

§ 97.261 EPA recordation.

(a) Within 5 business days (except as necessary to perform a transfer in perpetuity of CAIR SO₂ allowances allocated to a CAIR SO₂ unit or as provided in paragraph (b) of this section) of receiving a CAIR SO₂ allowance transfer, the Administrator will record a CAIR SO₂ allowance transfer by moving each CAIR SO₂ allowance from the transferor account to the transferee account as specified by the request, provided that:

(1) The transfer is correctly submitted under § 97.260;
(2) The transferor account includes each CAIR SO₂ allowance identified by serial number in the transfer; and
(3) The transfer is in accordance with the limitation on transfer under § 74.42 of this chapter and § 74.47(c) of this chapter, as applicable.

(b) A CAIR SO₂ allowance transfer that is submitted for recordation after the allowance transfer deadline for a control period and that includes any CAIR SO₂ allowances allocated for any control period before such allowance transfer deadline will not be recorded until after the Administrator completes the deductions under § 97.254 for the control period immediately before such allowance transfer deadline.

(c) Where a CAIR SO₂ allowance transfer submitted for recordation fails to meet the requirements of paragraph (a) of this section, the Administrator will not record such transfer.

§ 97.262 Notification.

(a) Notification of recordation. Within 5 business days of recordation of a CAIR SO₂ allowance transfer under § 97.261, the Administrator will notify the CAIR authorized account representatives of both the transferor and transferee accounts.

(b) Notification of non-recordation. Within 10 business days of receipt of a CAIR SO₂ allowance transfer that fails to meet the requirements of § 97.261(a), the Administrator will notify the CAIR authorized account representatives of both accounts subject to the transfer of:

(1) A decision not to record the transfer, and
(2) The reasons for such non-recordation.

(c) Nothing in this section shall preclude the submission of a CAIR SO₂ allowance transfer for recordation following notification of non-recordation.

Subpart HHH—Monitoring and Reporting

§ 97.270 General requirements.

The owners and operators, and to the extent applicable, the CAIR designated representative, of a CAIR SO₂ unit, shall comply with the monitoring, recordkeeping, and reporting requirements as provided in this subpart and in subparts F and G of part 75 of this chapter. For purposes of complying with such requirements, the definitions in § 97.202 and in § 72.2 of this chapter shall apply, and the terms “affected unit,” “designated representative,” and “continuous emission monitoring system” (or “CEMS”) in part 75 of this chapter shall be deemed to refer to the terms “CAIR SO₂ unit,” “CAIR designated representative,” and “continuous emission monitoring system” or (“CEMS”) respectively, as defined in § 97.202. The owner or operator of a unit that is not a CAIR SO₂ unit but that is monitored under § 75.16(b)(2) of this chapter shall comply with the same monitoring, recordkeeping, and reporting requirements as a CAIR SO₂ unit.

(a) Requirements for installation, certification, and data accounting. The owner or operator of each CAIR SO₂ unit shall:

(1) Install all monitoring systems required under this subpart for monitoring SO₂ mass emissions and individual unit heat input (including all
systems required to monitor SO\textsubscript{2} concentration, stack gas moisture content, stack gas flow rate, CO\textsubscript{2} or O\textsubscript{2} concentration, and fuel flow rate, as applicable, in accordance with §§75.11 and 75.16 of this chapter;

(2) Successfully complete all certification tests required under §97.271 and meet all other requirements of this subpart and part 75 of this chapter applicable to the monitoring systems under paragraph (a)(1) of this section; and

(3) Record, report, and quality-assure the data from the monitoring systems under paragraph (a)(1) of this section.

(b) Compliance deadlines. Except as provided in paragraph (e) of this section, the owner or operator shall meet the monitoring system certification and other requirements of paragraphs (a)(1) and (2) of this section on or before the following dates. The owner or operator shall record, report, and quality-assure the data from the monitoring systems under paragraph (a)(1) of this section on and after the following dates.

(1) For the owner or operator of a CAIR SO\textsubscript{2} unit that commences commercial operation before July 1, 2008, by January 1, 2009.

(2) For the owner or operator of a CAIR SO\textsubscript{2} unit that commences commercial operation on or after July 1, 2008, by the later of the following dates:

(i) January 1, 2009; or

(ii) 90 unit operating days or 180 calendar days, whichever occurs first, after the date on which the unit commences commercial operation.

(3) For the owner or operator of a CAIR SO\textsubscript{2} unit for which construction of a new stack or flue or installation of add-on SO\textsubscript{2} emission controls is completed after the applicable deadline under paragraph (b)(1), (2), (4), or (5) of this section, by 90 unit operating days or 180 calendar days, whichever occurs first, after the date on which emissions first exit to the atmosphere through the new stack or flue or add-on SO\textsubscript{2} emissions controls.

(4) Notwithstanding the dates in paragraphs (b)(1) and (2) of this section, for the owner or operator of a unit for which a CAIR opt-in permit application is submitted and not withdrawn and a CAIR opt-in permit is not yet issued or denied under subpart III of this part, by the date specified in §97.284(b).

(5) Notwithstanding the dates in paragraphs (b)(1) and (2) of this section, for the owner or operator of a CAIR SO\textsubscript{2} opt-in unit under subpart III of this part, by the date on which the CAIR SO\textsubscript{2} opt-in unit enters the CAIR SO\textsubscript{2} Trading Program as provided in §97.284(g).

(c) Reporting data. The owner or operator of a CAIR SO\textsubscript{2} unit that does not meet the applicable compliance date set forth in paragraph (b) of this section for any monitoring system under paragraph (a)(1) of this section shall, for each such monitoring system under paragraph (a)(1) of this section on or after the following dates.

(1) For the owner or operator of a CAIR SO\textsubscript{2} unit that commences commercial operation before July 1, 2008, by January 1, 2009.

(2) For the owner or operator of a CAIR SO\textsubscript{2} unit that commences commercial operation on or after July 1, 2008, by the later of the following dates:

(i) January 1, 2009; or

(ii) 90 unit operating days or 180 calendar days, whichever occurs first, after the date on which emissions first exit to the atmosphere through the new stack or flue or add-on SO\textsubscript{2} emissions controls.

(d) Prohibitions. (1) No owner or operator of a CAIR SO\textsubscript{2} unit shall use any alternative monitoring system, alternative reference method, or any other alternative to any requirement of this subpart without having obtained prior written approval in accordance with §97.275.

(2) No owner or operator of a CAIR SO\textsubscript{2} unit shall operate the unit so as to discharge, or allow to be discharged, SO\textsubscript{2} emissions to the atmosphere without accounting for all such emissions in accordance with the applicable provisions of this subpart and part 75 of this chapter.

(3) No owner or operator of a CAIR SO\textsubscript{2} unit shall disrupt the continuous emission monitoring system, any portion thereof, or any other approved emission monitoring method, and thereby avoid monitoring and recording SO\textsubscript{2} mass emissions discharged into the atmosphere or heat input, except for periods of recertification or periods when calibration, quality assurance testing, or maintenance is performed in accordance with the applicable provisions of this subpart and part 75 of this chapter.
(4) No owner or operator of a CAIR SO₂ unit shall retire or permanently discontinue use of the continuous emission monitoring system, any component thereof, or any other approved monitoring system under this subpart, except under any one of the following circumstances:

(i) During the period that the unit is covered by an exemption under §97.205 that is in effect;

(ii) The owner or operator is monitoring emissions from the unit with another certified monitoring system approved, in accordance with the applicable provisions of this subpart and part 75 of this chapter, by the Administrator for use at that unit that provides emission data for the same pollutant or parameter as the retired or discontinued monitoring system; or

(iii) The CAIR designated representative submits notification of the date of certification testing of a replacement monitoring system for the retired or discontinued monitoring system in accordance with §97.271(d)(3)(i).

(e) Long-term cold storage. The owner or operator of a CAIR SO₂ unit is subject to the applicable provisions of part 75 of this chapter concerning units in long-term cold storage.

§97.271 Initial certification and recertification procedures.

(a) The owner or operator of a CAIR SO₂ unit shall be exempt from the initial certification requirements of this section for a monitoring system under §97.270(a)(1) if the following conditions are met:

(1) The monitoring system has been previously certified in accordance with part 75 of this chapter; and

(2) The applicable quality-assurance and quality-control requirements of §75.21 of this chapter and appendix B to part 75 of this chapter are fully met for the certified monitoring system described in paragraph (a)(1) of this section.

(b) The recertification provisions of this section shall apply to a monitoring system under §97.270(a)(1) exempt from initial certification requirements under paragraph (a) of this section.

(c) [Reserved]

(d) Except as provided in paragraph (a) of this section, the owner or operator of a CAIR SO₂ unit shall comply with the following initial certification and recertification procedures, for a continuous monitoring system (i.e., a continuous emission monitoring system and an excepted monitoring system under appendix D to part 75 of this chapter) under §97.270(a)(1). The owner or operator of a unit that qualifies to use the low mass emissions excepted monitoring methodology under §75.19 of this chapter or that qualifies to use an alternative monitoring system under subpart E of part 75 of this chapter shall comply with the procedures in paragraph (e) or (f) of this section respectively.

(1) Requirements for initial certification. The owner or operator shall ensure that each continuous monitoring system under §97.270(a)(1) (including the automated data acquisition and handling system) successfully completes all of the initial certification testing required under §75.20 of this chapter by the applicable deadline in §97.270(b). In addition, whenever the owner or operator installs a monitoring system to meet the requirements of this subpart in a location where no such monitoring system was previously installed, initial certification in accordance with §75.20 of this chapter is required.

(2) Requirements for recertification. Whenever the owner or operator makes a replacement, modification, or change in any certified continuous emission monitoring system under §97.270(a)(1) that may significantly affect the ability of the system to accurately measure or record SO₂ mass emissions or heat input rate or to meet the quality-assurance and quality-control requirements of §75.21 of this chapter or appendix B to part 75 of this chapter, the owner or operator shall recertify the monitoring system in accordance with §75.20(b) of this chapter. Furthermore, whenever the owner or operator makes a replacement, modification, or change to the flue gas handling system or the unit’s operation that may significantly change the stack flow or concentration

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profile, the owner or operator shall re-certify each continuous emission monitoring system whose accuracy is potentially affected by the change, in accordance with §75.20(b) of this chapter. Examples of changes to a continuous emission monitoring system that require recertification include: replacement of the analyzer, complete replacement of an existing continuous emission monitoring system, or change in location or orientation of the sampling probe or site. Any fuel flowmeter system under §97.270(a)(1) is subject to the recertification requirements in §75.20(g)(6) of this chapter.

(3) Approval process for initial certification and recertification. Paragraphs (d)(3)(i) through (iv) of this section apply to both initial certification and recertification of a continuous monitoring system under §97.270(a)(1). For recertifications, replace the words “certification” and “initial certification” with the word “recertification”, replace the word “certified” with the word “recertified,” and follow the procedures in §§75.20(b)(5) and (g)(7) of this chapter in lieu of the procedures in paragraph (d)(3)(v) of this section.

(i)Notification of certification. The CAIR designated representative shall submit to the appropriate EPA Regional Office and the Administrator written notice of the dates of certification testing, in accordance with §97.273.

(ii) Certification application. The CAIR designated representative shall submit to the Administrator a certification application for each monitoring system. A complete certification application shall include the information specified in §75.63 of this chapter.

(iii) Provisional certification date. The provisional certification date for a monitoring system shall be determined in accordance with §75.20(a)(3) of this chapter. A provisionally certified monitoring system may be used under the CAIR SO₂ Trading Program for a period not to exceed 120 days after receipt by the Administrator of the complete certification application for the monitoring system under paragraph (d)(3)(ii) of this section. Data measured and recorded by the provisionally certified monitoring system, in accordance with the requirements of part 75 of this chapter, will be considered valid quality-assured data (retroactive to the date and time of provisional certification), provided that the Administrator does not invalidate the provisional certification by issuing a notice of disapproval within 120 days of the date of receipt of the complete certification application by the Administrator.

(iv) Certification application approval process. The Administrator will issue a written notice of approval or disapproval of the certification application to the owner or operator within 120 days of receipt of the complete certification application under paragraph (d)(3)(ii) of this section. In the event the Administrator does not issue such a notice within such 120-day period, each monitoring system that meets the applicable performance requirements of part 75 of this chapter and is included in the certification application will be deemed certified for use under the CAIR SO₂ Trading Program.

(A) Approval notice. If the certification application is complete and shows that each monitoring system meets the applicable performance requirements of part 75 of this chapter, then the Administrator will issue a written notice of approval of the certification application within 120 days of receipt.

(B) Incomplete application notice. If the certification application is not complete, then the Administrator will issue a written notice of incompleteness that sets a reasonable date by which the CAIR designated representative must submit the additional information required to complete the certification application. If the CAIR designated representative does not comply with the notice of incompleteness by the specified date, then the Administrator may issue a notice of disapproval under paragraph (d)(3)(iv)(C) of this section. The 120-day review period shall not begin before receipt of a complete certification application.

(C) Disapproval notice. If the certification application shows that any monitoring system does not meet the performance requirements of part 75 of
this chapter or if the certification application is incomplete and the requirement for disapproval under paragraph (d)(3)(iv)(B) of this section is met, then the Administrator will issue a written notice of disapproval of the certification application. Upon issuance of such notice of disapproval, the provisional certification is invalidated by the Administrator and the data measured and recorded by each uncertified monitoring system shall not be considered valid quality-assured data beginning with the date and hour of provisional certification (as defined under §75.20(a)(3) of this chapter). The owner or operator shall follow the procedures for loss of certification in paragraph (d)(3)(v) of this section for each monitoring system that is disapproved for initial certification.

(D) Audit decertification. The Administrator may issue a notice of disapproval of the certification status of a monitor in accordance with §97.272(b).

(v) Procedures for loss of certification. If the Administrator issues a notice of disapproval of a certification application under paragraph (d)(3)(iv)(C) of this section or a notice of disapproval of certification status under paragraph (d)(3)(iv)(D) of this section, then:

(A) The owner or operator shall substitute the following values, for each disapproved monitoring system, for each hour of unit operation during the period of invalid data specified under §75.20(a)(4)(iii), §75.20(g)(7), or §75.21(e) of this chapter and continuing until the applicable date and hour specified under §75.20(a)(5)(i) or (g)(7) of this chapter:

(1) For a disapproved SO\textsubscript{2} pollutant concentration monitor and disapproved flow monitor, respectively, the maximum potential concentration of SO\textsubscript{2} and the maximum potential flow rate, as defined in sections 2.1.1.1 and 2.1.4.1 of appendix A to part 75 of this chapter.

(2) For a disapproved moisture monitoring system and disapproved diluent gas monitoring system, respectively, the minimum potential moisture percentage and either the maximum potential CO\textsubscript{2} concentration or the minimum potential O\textsubscript{2} concentration (as applicable), as defined in sections 2.1.5, 2.1.3.1, and 2.1.3.2 of appendix A to part 75 of this chapter.

(B) The CAIR designated representative shall submit a notification of certification retest dates and a new certification application in accordance with paragraphs (d)(3)(i) and (ii) of this section.

(C) The owner or operator shall repeat all certification tests or other requirements that were failed by the monitoring system, as indicated in the Administrator's notice of disapproval, no later than 30 unit operating days after the date of issuance of the notice of disapproval.

(e) Initial certification and recertification procedures for units using the low mass emission excepted methodology under §75.19 of this chapter. The owner or operator of a unit qualified to use the low mass emissions (LME) excepted methodology under §75.19 of this chapter shall meet the applicable certification and recertification requirements in §§75.19(a)(2) and 75.20(h) of this chapter. If the owner or operator of such a unit elects to certify a fuel flowmeter system for heat input determination, the owner or operator shall also meet the certification and recertification requirements in §75.20(g) of this chapter.

(f) Certification/recertification procedures for alternative monitoring systems. The CAIR designated representative of each unit for which the owner or operator intends to use an alternative monitoring system approved by the Administrator under subpart E of part 75 of this chapter shall comply with the applicable notification and application procedures of §75.20(f) of this chapter.
§ 97.273 Notifications.

The CAIR designated representative for a CAIR SO₂ unit shall submit written notice to the Administrator in accordance with §75.61 of this chapter. §97.274 Recordkeeping and reporting.

(a) General provisions. The CAIR designated representative shall comply with all recordkeeping and reporting requirements in this section, the applicable recordkeeping and reporting requirements in subparts F and G of part 75 of this chapter, and the requirements of §97.218(e)(1).

(b) Monitoring Plans. The owner or operator of a CAIR SO₂ unit shall comply with requirements of §75.62 of this chapter and, for a unit for which a CAIR opt-in permit application is submitted and not withdrawn and a CAIR opt-in permit is not yet issued or denied under subpart III of this part, §§97.283 and 97.284(a).

(c) Certification Applications. The CAIR designated representative shall submit an application to the Administrator within 45 days after completing all initial certification or recertification tests required under §97.271, including the information required under §75.63 of this chapter.

(d) Quarterly reports. The CAIR designated representative shall submit quarterly reports, as follows:

1. The CAIR designated representative shall report the SO₂ mass emissions data and heat input data for the CAIR SO₂ unit, in an electronic quarterly report in a format prescribed by the Administrator, for each calendar quarter beginning with:
   (i) For a unit that commences commercial operation before July 1, 2008, the calendar quarter covering January 1, 2009 through March 31, 2009;
   (ii) For a unit that commences commercial operation on or after July 1, 2008, the calendar quarter corresponding to the earlier of the date of provisional certification or the applicable deadline for initial certification under §97.270(b), unless that quarter is the third or fourth quarter of 2008, in which case reporting shall commence in the quarter covering January 1, 2009 through March 31, 2009;
   (iii) Notwithstanding paragraphs (d)(1)(i) and (ii) of this section, for a unit for which a CAIR opt-in permit application is submitted and not withdrawn and a CAIR opt-in permit is not yet issued or denied under subpart III of this part, the calendar quarter corresponding to the date specified in §97.284(b); and
   (iv) Notwithstanding paragraphs (d)(1)(i) and (ii) of this section, for a CAIR SO₂ opt-in unit under subpart III of this part, the calendar quarter corresponding to the date on which the CAIR SO₂ opt-in unit enters the CAIR SO₂ Trading Program as provided in §97.284(g).

2. The CAIR designated representative shall submit each quarterly report to the Administrator within 30 days following the end of the calendar quarter covered by the report. Quarterly reports shall be submitted in the manner specified in §75.64 of this chapter.
(3) For CAIR SO\textsubscript{2} units that are also subject to an Acid Rain emissions limitation or the CAIR NO\textsubscript{X} Annual Trading Program, CAIR NO\textsubscript{X} Ozone Season Trading Program, or Hg Budget Trading Program, quarterly reports shall include the applicable data and information required by subparts F through I of part 75 of this chapter as applicable, in addition to the SO\textsubscript{2} mass emission data, heat input data, and other information required by this subpart.

(e) Compliance certification. The CAIR designated representative shall submit to the Administrator a compliance certification (in a format prescribed by the Administrator) in support of each quarterly report based on reasonable inquiry of those persons with primary responsibility for ensuring that all of the unit’s emissions are correctly and fully monitored. The certification shall state that:

(1) The monitoring data submitted were recorded in accordance with the applicable requirements of this subpart and part 75 of this chapter, including the quality assurance procedures and specifications; and

(2) For a unit with add-on SO\textsubscript{2} emission controls and for all hours where SO\textsubscript{2} data are substituted in accordance with §75.34(a)(1) of this chapter, the add-on emission controls were operating within the range of parameters listed in the quality assurance/quality control program under appendix B to part 75 of this chapter and the substitute data values do not systematically underestimate SO\textsubscript{2} emissions.

§ 97.275 Petitions.

The CAIR designated representative of a CAIR SO\textsubscript{2} unit may submit a petition under §75.66 of this chapter to the Administrator requesting approval to apply an alternative to any requirement of this subpart. Application of an alternative to any requirement of this subpart is in accordance with this subpart only to the extent that the petition is approved in writing by the Administrator, in consultation with the permitting authority.

§ 97.280 Applicability.

A CAIR SO\textsubscript{2} opt-in unit must be a unit that:

(a) Is located in a State that submits, and for which the Administrator approves, a State implementation plan revision in accordance with §51.124(r)(1), (2), or (3) of this chapter establishing procedures concerning CAIR opt-in units;

(b) Is not a CAIR SO\textsubscript{2} unit under §97.204 and is not covered by a retired unit exemption under §97.205 that is in effect;

(c) Is not covered by a retired unit exemption under §72.8 of this chapter that is in effect and is not an opt-in source under part 74 of this chapter;

(d) Has or is required or qualified to have a title V operating permit or other federally enforceable permit; and

(e) Vents all of its emissions to a stack and can meet the monitoring, recordkeeping, and reporting requirements of subpart HH of this part.

§ 97.281 General.

(a) Except as otherwise provided in §§97.201 through 97.204, §§97.206 through 97.208, and subparts BBB and CCC and subparts FFF through HHH of this part, a CAIR SO\textsubscript{2} opt-in unit shall be treated as a CAIR SO\textsubscript{2} unit for purposes of applying such sections and subparts of this part.

(b) Solely for purposes of applying, as provided in this subpart, the requirements of subpart HHH of this part to a unit for which a CAIR opt-in permit application is submitted and not withdrawn and a CAIR opt-in permit is not yet issued or denied under this subpart, such unit shall be treated as a CAIR SO\textsubscript{2} unit before issuance of a CAIR opt-in permit for such unit.

§ 97.282 CAIR designated representative.

Any CAIR SO\textsubscript{2} opt-in unit, and any unit for which a CAIR opt-in permit application is submitted and not withdrawn and a CAIR opt-in permit is not yet issued or denied under this subpart, located at the same source as one or more CAIR SO\textsubscript{2} units shall have the same CAIR designated representative.
§ 97.283 Applying for CAIR opt-in permit.

(a) Applying for initial CAIR opt-in permit. The CAIR designated representative of a unit meeting the requirements for a CAIR SO₂ opt-in unit in §97.280 may apply for an initial CAIR opt-in permit at any time, except as provided under §97.286(f) and (g), and, in order to apply, must submit the following:

(1) A complete CAIR permit application under §97.222;

(2) A certification, in a format specified by the permitting authority, that the unit:

(i) Is not a CAIR SO₂ unit under §97.204 and is not covered by a retired unit exemption under §97.205 that is in effect;

(ii) Is not covered by a retired unit exemption under §72.8 of this chapter that is in effect;

(iii) Is not and, so long as the unit is a CAIR SO₂ opt-in unit, will not become, an opt-in source under part 74 of this chapter;

(iv) Vents all of its emissions to a stack; and

(v) Has documented heat input for more than 876 hours during the 6 months immediately preceding submission of the CAIR permit application under §97.222;

(3) A monitoring plan in accordance with subpart HHH of this part;

(4) A complete certificate of representation under §97.213 consistent with §97.282, if no CAIR designated representative has been previously designated for the source that includes the unit; and

(5) A statement, in a format specified by the permitting authority, whether the CAIR designated representative requests that the unit be allocated CAIR SO₂ allowances under §97.288(b) or §97.288(c) (subject to the conditions in §§97.284(h) and 97.286(g)), to the extent such allocation is provided in a State implementation plan revision submitted in accordance with §51.124(r)(1), (2), or (3) of this chapter and approved by the Administrator. If allocation under §97.288(c) is requested, this statement shall include a statement that the owners and operators of the unit intend to repower the unit before January 1, 2015 and that they will provide, upon request, documentation demonstrating such intent.

(b) Duty to reapply. (1) The CAIR designated representative of a CAIR SO₂ opt-in unit shall submit a complete CAIR permit application under §97.222 to renew the CAIR opt-in unit permit in accordance with the permitting authority’s regulations for title V operating permits, or the permitting authority’s regulations for other federally enforceable permits if applicable, addressing permit renewal.

(2) Unless the permitting authority issues a notification of acceptance of withdrawal of the CAIR SO₂ opt-in unit from the CAIR SO₂ Trading Program in accordance with §97.286 or the unit becomes a CAIR SO₂ unit under §97.204, the CAIR SO₂ opt-in unit shall remain subject to the requirements for a CAIR SO₂ opt-in unit, even if the CAIR designated representative for the CAIR SO₂ opt-in unit fails to submit a CAIR permit application that is required for renewal of the CAIR opt-in permit under paragraph (b)(1) of this section.

[65 FR 2727, Jan 18, 2000, as amended by 71 FR 74795, Dec. 13, 2006]

§ 97.284 Opt-in process.

The permitting authority will issue or deny a CAIR opt-in permit for a unit for which an initial application for a CAIR opt-in permit under §97.283 is submitted in accordance with the following, to the extent provided in a State implementation plan revision submitted in accordance with §51.124(r)(1), (2), or (3) of this chapter and approved by the Administrator:

(a) Interim review of monitoring plan.

The permitting authority and the Administrator will determine, on an interim basis, the sufficiency of the monitoring plan accompanying the initial application for a CAIR opt-in permit under §97.283. A monitoring plan is sufficient, for purposes of interim review, if the plan appears to contain information demonstrating that the SO₂ emissions rate and heat input of the unit and all other applicable parameters are monitored and reported in accordance with subpart HHH of this part. A determination of sufficiency shall not be
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 construed as acceptance or approval of the monitoring plan.

(b) Monitoring and reporting. (1)(i) If the permitting authority and the Administrator determine that the monitoring plan is sufficient under paragraph (a) of this section, the owner or operator shall monitor and report the SO₂ emissions rate and the heat input of the unit and all other applicable parameters, in accordance with subpart HHH of this part, starting on the date of certification of the appropriate monitoring system under subpart HHH of this part, and continuing until a CAIR opt-in permit is issued, the date and time when the unit is withdrawn from the CAIR SO₂ Trading Program in accordance with §97.280, or, if a CAIR opt-in permit is issued, the date and time when the unit does not have add-on SO₂ emission controls during any such control periods, the average of the amounts of the unit’s total heat input (in mmBtu) for the control periods under paragraphs (b)(1)(ii) and (2) of this section.

(2) If the unit’s SO₂ emissions rate and heat input are monitored and reported for more than one control period, in accordance with paragraphs (b)(1) and (2) of this section, the average of the amounts of the unit’s total heat input (in mmBtu) for the control periods under paragraphs (b)(1)(ii) and (2) of this section.

(d) Baseline SO₂ emission rate. The unit’s baseline SO₂ emission rate shall equal:

(1) If the unit’s SO₂ emissions rate and heat input are monitored and reported for only one control period, in accordance with paragraph (b)(1) of this section, the unit’s SO₂ emissions rate (in lb/mmBtu) for the control period;

(2) If the unit’s SO₂ emissions rate and heat input are monitored and reported for more than one control period, in accordance with paragraphs (b)(1) and (2) of this section, and the unit does not have add-on SO₂ emission controls during any such control periods, the average of the amounts of the unit’s total heat input (in lb/mmBtu) for the control periods under paragraphs (b)(1)(ii) and (2) of this section; or

(3) If the unit’s SO₂ emissions rate and heat input are monitored and reported for more than one control period, in accordance with paragraphs (b)(1) and (2) of this section, and the unit has add-on SO₂ emission controls during any such control periods, the average of the amounts of the unit’s SO₂ emission rate (in lb/mmBtu) for such control periods during which the unit has add-on SO₂ emission controls.

(e) Issuance of CAIR opt-in permit. After calculating the baseline heat input and the baseline SO₂ emissions rate for the unit under paragraphs (c) and (d) of this section and if the permitting authority determines that the CAIR designated representative shows that the unit meets the requirements for a CAIR SO₂ opt-in unit in §97.280 and meets the elements certified in §97.283(a)(2), the permitting authority will issue a CAIR opt-in permit. The permitting authority will provide a copy of the CAIR opt-in permit to the Administrator, who will then establish a compliance account for the source that includes the CAIR SO₂ opt-in unit.
unless the source already has a compliance account.

(f) Issuance of denial of CAIR opt-in permit. Notwithstanding paragraphs (a) through (e) of this section, if at any time before issuance of a CAIR opt-in permit for the unit, the permitting authority determines that the CAIR designated representative fails to show that the unit meets the requirements for a CAIR SO\textsubscript{2} opt-in unit in §97.280 or meets the elements certified in §97.283(a)(2), the permitting authority will issue a denial of a CAIR opt-in permit for the unit.

(g) Date of entry into CAIR SO\textsubscript{2} Trading Program. A unit for which an initial CAIR opt-in permit is issued by the permitting authority shall become a CAIR SO\textsubscript{2} opt-in unit, and a CAIR SO\textsubscript{2} unit, as of the later of January 1, 2010 or January 1 of the first control period during which such CAIR opt-in permit is issued.

(h) Repowered CAIR SO\textsubscript{2} opt-in unit. (1) If CAIR designated representative requests, and the permitting authority issues a CAIR opt-in permit providing for, allocation to a CAIR SO\textsubscript{2} opt-in unit of CAIR SO\textsubscript{2} allowances under §97.288(c) and such unit is repowered after its date of entry into the CAIR SO\textsubscript{2} Trading Program under paragraph (g) of this section, the repowered unit shall be treated as a CAIR SO\textsubscript{2} opt-in unit replacing the original CAIR SO\textsubscript{2} opt-in unit, as of the date of start-up of the repowered unit’s combustion chamber.

(2) Notwithstanding paragraphs (c) and (d) of this section, as of the date of start-up under paragraph (h)(1) of this section, the repowered unit shall be deemed to have the same date of commencement of operation, date of commencement of commercial operation, baseline heat input, and baseline SO\textsubscript{2} emission rate as the original CAIR SO\textsubscript{2} opt-in unit, and the original CAIR SO\textsubscript{2} opt-in unit shall no longer be treated as a CAIR SO\textsubscript{2} opt-in unit or a CAIR SO\textsubscript{2} unit.

§97.285 CAIR opt-in permit contents.

(a) Each CAIR opt-in permit will contain:

(1) All elements required for a complete CAIR permit application under §97.222;
(2) The certification in §97.283(a)(2);
(3) The unit’s baseline heat input under §97.284(c);
(4) The unit’s baseline SO\textsubscript{2} emission rate under §97.284(d);
(5) A statement whether the unit is to be allocated CAIR SO\textsubscript{2} allowances under §97.288(b) or §97.288(c) (subject to the conditions in §§97.284(h) and 97.286(g));
(6) A statement that the unit may withdraw from the CAIR SO\textsubscript{2} Trading Program only in accordance with §97.286; and
(7) A statement that the unit is subject to, and the owners and operators of the unit must comply with, the requirements of §97.287.

(b) Each CAIR opt-in permit is deemed to incorporate automatically the definitions of terms under §97.202 and, upon recordation by the Administrator under subpart FFF or GGG of this part or this subpart, every allocation, transfer, or deduction of CAIR SO\textsubscript{2} allowances to or from the compliance account of the source that includes a CAIR SO\textsubscript{2} opt-in unit covered by the CAIR opt-in permit.

§97.286 Withdrawal from CAIR SO\textsubscript{2} Trading Program.

Except as provided under paragraph (g) of this section, a CAIR SO\textsubscript{2} opt-in unit may withdraw from the CAIR SO\textsubscript{2} Trading Program, but only if the permitting authority issues a notification to the CAIR designated representative of the CAIR SO\textsubscript{2} opt-in unit of the acceptance of the withdrawal of the CAIR SO\textsubscript{2} opt-in unit in accordance with paragraph (d) of this section.

(a) Requesting withdrawal. In order to withdraw a CAIR SO\textsubscript{2} opt-in unit from the CAIR SO\textsubscript{2} Trading Program, the CAIR designated representative of the CAIR SO\textsubscript{2} opt-in unit shall submit to the permitting authority a request to withdraw effective as of midnight of
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December 31 of a specified calendar year, which date must be at least 4 years after December 31 of the year of entry into the CAIR SO\textsubscript{2} Trading Program under §97.284(g). The request must be submitted no later than 90 days before the requested effective date of withdrawal.

(b) Conditions for withdrawal. Before a CAIR SO\textsubscript{2} opt-in unit covered by a request under paragraph (a) of this section may withdraw from the CAIR SO\textsubscript{2} Trading Program and the CAIR opt-in permit may be terminated under paragraph (e) of this section, the following conditions must be met:

1. For the control period ending on the date on which the withdrawal is to be effective, the source that includes the CAIR SO\textsubscript{2} opt-in unit must meet the requirement to hold CAIR SO\textsubscript{2} allowances under §97.206(c) and cannot have any excess emissions.

2. After the requirement for withdrawal under paragraph (b)(1) of this section is met, the Administrator will deduct from the compliance account of the source that includes the CAIR SO\textsubscript{2} opt-in unit CAIR SO\textsubscript{2} allowances equal in amount to and allocated for the same or a prior control period as any CAIR SO\textsubscript{2} allowances allocated to the CAIR SO\textsubscript{2} opt-in unit under §97.206 for any control period for which the withdrawal is to be effective. If there are no remaining CAIR SO\textsubscript{2} units at the source, the Administrator will close the compliance account, and the owners and operators of the CAIR SO\textsubscript{2} opt-in unit may submit a CAIR SO\textsubscript{2} allowance transfer for any remaining CAIR SO\textsubscript{2} allowances to another CAIR SO\textsubscript{2} Allowance Tracking System in accordance with subpart GGG of this part.

(c) Notification. (1) After the requirements for withdrawal under paragraphs (a) and (b) of this section are met, the permitting authority will issue a notification to the CAIR designated representative of the CAIR SO\textsubscript{2} opt-in unit that the CAIR SO\textsubscript{2} opt-in unit’s request to withdraw is denied. Such CAIR SO\textsubscript{2} opt-in unit shall continue to be a CAIR SO\textsubscript{2} opt-in unit.

(d) Permit amendment. After the permitting authority issues a notification under paragraph (c)(1) of this section that the requirements for withdrawal have been met, the permitting authority will revise the CAIR permit covering the CAIR SO\textsubscript{2} opt-in unit to terminate the CAIR opt-in permit for such unit as of the effective date specified under paragraph (c)(1) of this section. The unit shall continue to be a CAIR SO\textsubscript{2} opt-in unit until the effective date of the termination and shall comply with all requirements under the CAIR SO\textsubscript{2} Trading Program concerning any control periods for which the unit is a CAIR SO\textsubscript{2} opt-in unit, even if such requirements arise or must be complied with after the withdrawal takes effect.

(e) Reapplication upon failure to meet conditions of withdrawal. If the permitting authority denies the CAIR SO\textsubscript{2} opt-in unit’s request to withdraw, the CAIR designated representative may submit another request to withdraw in accordance with paragraphs (a) and (b) of this section.

(f) Ability to reapply to the CAIR SO\textsubscript{2} Trading Program. Once a CAIR SO\textsubscript{2} opt-in unit withdraws from the CAIR SO\textsubscript{2} Trading Program and its CAIR opt-in permit is terminated under this section, the CAIR designated representative may not submit another application for a CAIR opt-in permit under §97.204 for such CAIR SO\textsubscript{2} opt-in unit before the date that is 4 years after the date on which the withdrawal became effective. Such new application for a CAIR opt-in permit will be treated as an initial application for a CAIR opt-in permit under §97.284.

(g) Inability to withdraw. Notwithstanding paragraphs (a) through (f) of this section, a CAIR SO\textsubscript{2} opt-in unit shall not be eligible to withdraw from the CAIR SO\textsubscript{2} Trading Program if the CAIR designated representative of the CAIR SO\textsubscript{2} opt-in unit requests, and the permitting authority issues a CAIR opt-in permit providing for, allocation
§ 97.287 Change in regulatory status.

(a) Notification. If a CAIR SO₂ opt-in unit becomes a CAIR SO₂ unit under §97.204, then the CAIR designated representative shall notify in writing the permitting authority and the Administrator of such change in the CAIR SO₂ opt-in unit’s regulatory status, within 30 days of such change.

(b) Permitting authority’s and Administrator’s actions. (1) If a CAIR SO₂ opt-in unit becomes a CAIR SO₂ unit under §97.204, the permitting authority will revise the CAIR SO₂ opt-in unit’s CAIR opt-in permit to meet the requirements of a CAIR permit under §97.223, and remove the CAIR opt-in permit provisions, as of the date on which the CAIR SO₂ opt-in unit becomes a CAIR SO₂ unit under §97.204.

(2)(i) The Administrator will deduct from the compliance account of the source that includes the CAIR SO₂ opt-in unit that becomes a CAIR SO₂ unit under §97.204. CAIR SO₂ allowances equal in amount to and allocated for the same or a prior control period as:

(A) Any CAIR SO₂ allowances allocated to the CAIR SO₂ opt-in unit under §97.288 for any control period after the date on which the CAIR SO₂ opt-in unit becomes a CAIR SO₂ unit under §97.204; and

(B) If the date on which the CAIR SO₂ opt-in unit becomes a CAIR SO₂ unit under §97.204 is not December 31, the CAIR SO₂ allowances allocated to the CAIR SO₂ opt-in unit under §97.288 for the control period that includes the date on which the CAIR SO₂ opt-in unit becomes a CAIR SO₂ unit under §97.204, multiplied by the ratio of the number of days, in the control period, starting with the date on which the CAIR SO₂ opt-in unit becomes a CAIR SO₂ unit under §97.204 and rounded to the nearest whole allowance as appropriate.

(ii) The CAIR designated representative shall ensure that the compliance account of the source that includes the CAIR SO₂ opt-in unit that becomes a CAIR SO₂ unit under §97.204 contains the CAIR SO₂ allowances necessary for completion of the deduction under paragraph (b)(2)(i) of this section.

§ 97.288 CAIR SO₂ allowance allocations to CAIR SO₂ opt-in units.

(a) Timing requirements. (1) When the CAIR opt-in permit is issued under §97.284(e), the permitting authority will allocate CAIR SO₂ allowances to the CAIR SO₂ opt-in unit, and submit to the Administrator the allocation for the control period in which a CAIR SO₂ opt-in unit enters the CAIR SO₂ Trading Program under §97.284(g), in accordance with paragraph (b) or (c) of this section.

(2) By no later than October 31 of the control period after the control period in which a CAIR SO₂ opt-in unit enters the CAIR SO₂ Trading Program under §97.284(g) and October 31 of each year thereafter, the permitting authority will allocate CAIR SO₂ allowances to the CAIR SO₂ opt-in unit, and submit to the Administrator the allocation for the control period that includes such submission deadline and in which the unit is a CAIR SO₂ opt-in unit, in accordance with paragraph (b) or (c) of this section.

(b) Calculation of allocation. For each control period for which a CAIR SO₂ opt-in unit is to be allocated CAIR SO₂ allowances, the permitting authority will allocate in accordance with the following procedures, if provided in a State implementation plan revision submitted in accordance with §51.124(r)(1), (2), or (3) of this chapter and approved by the Administrator:

(1) The heat input (in mmBtu) used for calculating the CAIR SO₂ allowance allocation will be the lesser of:

(i) The CAIR SO₂ opt-in unit’s base-line heat input determined under §97.284(c); or

(ii) The CAIR SO₂ opt-in unit’s heat input, as determined in accordance with subpart HHH of this part, for the immediately prior control period, except when the allocation is being calculated for the control period in which the CAIR SO₂ opt-in unit enters the CAIR SO₂ Trading Program under §97.284(g).

(2) The SO₂ emission rate (in lb/ mmBtu) used for calculating CAIR SO₂
allowance allocations will be the lesser of:

(i) The CAIR SO₂ opt-in unit’s baseline SO₂ emissions rate (in lb/mmBtu) determined under §97.284(d) and multiplied by 70 percent; or

(ii) The most stringent State or Federal SO₂ emissions limitation applicable to the CAIR SO₂ opt-in unit at any time during the control period for which CAIR SO₂ allowances are to be allocated.

(3) The permitting authority will allocate CAIR SO₂ allowances to the CAIR SO₂ opt-in unit with a tonnage equivalent equal to, or less than by the smallest possible amount, the heat input under paragraph (b)(1) of this section, multiplied by the SO₂ emission rate under paragraph (b)(2) of this section, and divided by 2,000 lb/ton.

(c) Notwithstanding paragraph (b) of this section and if the CAIR designated representative requests, and the permitting authority issues a CAIR opt-in permit (based on a demonstration of the intent to repower stated under §97.283(a)(5)) providing for, allocation to a CAIR SO₂ opt-in unit of CAIR SO₂ allowances under this paragraph (subject to the conditions in §§97.284(h) and 97.286(g)), the permitting authority will allocate to the CAIR SO₂ opt-in unit as follows, if provided in a State implementation plan revision submitted in accordance with §51.124(r)(1), (2), or (3) of this chapter and approved by the Administrator:

(1) For each control period in 2010 through 2014 for which the CAIR SO₂ opt-in unit is to be allocated CAIR SO₂ allowances,

(i) The heat input (in mmBtu) used for calculating CAIR SO₂ allowance allocations will be determined as described in paragraph (b)(1) of this section.

(ii) The SO₂ emission rate (in lb/mmBtu) used for calculating the CAIR SO₂ allowance includes, the compliance account, the most stringent State or Federal SO₂ emissions limitation applicable to the CAIR SO₂ opt-in unit at any time during the control period for which CAIR SO₂ allowances are to be allocated.

(iii) The permitting authority will allocate CAIR SO₂ allowances to the CAIR SO₂ opt-in unit with a tonnage equivalent equal to, or less than by the smallest possible amount, the heat input under paragraph (c)(1)(i) of this section, multiplied by the SO₂ emission rate under paragraph (c)(1)(ii) of this section, and divided by 2,000 lb/ton.

(2) For each control period in 2015 and thereafter for which the CAIR SO₂ opt-in unit is to be allocated CAIR SO₂ allowances,

(i) The heat input (in mmBtu) used for calculating the CAIR SO₂ allowance allocations will be determined as described in paragraph (b)(1) of this section.

(ii) The SO₂ emission rate (in lb/mmBtu) used for calculating the CAIR SO₂ allowance allocation will be the lesser of:

(A) The CAIR SO₂ opt-in unit’s baseline SO₂ emissions rate (in lb/mmBtu) determined under §97.284(d) multiplied by 10 percent; or

(B) The most stringent State or Federal SO₂ emissions limitation applicable to the CAIR SO₂ opt-in unit at any time during the control period for which CAIR SO₂ allowances are to be allocated.

(iii) The permitting authority will allocate CAIR SO₂ allowances to the CAIR SO₂ opt-in unit with a tonnage equivalent equal to, or less than by the smallest possible amount, the heat input under paragraph (c)(2)(i) of this section, multiplied by the SO₂ emission rate under paragraph (c)(2)(ii) of this section, and divided by 2,000 lb/ton.

(d) Recordation. If provided in a State implementation plan revision submitted in accordance with §51.124(r)(1), (2), or (3) of this chapter and approved by the Administrator:

(1) The Administrator will record, in the compliance account of the source that includes the CAIR SO₂ opt-in unit, the CAIR SO₂ allowances allocated by the permitting authority to the CAIR SO₂ opt-in unit under paragraph (a)(1) of this section.

(2) By December 1 of the control period in which a CAIR SO₂ opt-in unit enters the CAIR SO₂ Trading Program under §97.284(g) and December 1 of each
year thereafter, the Administrator will record, in the compliance account of the source that includes the CAIR SO\textsubscript{2} opt-in unit, the CAIR SO\textsubscript{2} allowances allocated by the permitting authority to the CAIR SO\textsubscript{2} opt-in unit under paragraph (a)(2) of this section.

APPENDIX A TO SUBPART III OF PART 97—STATES WITH APPROVED STATE IMPLEMENTATION PLAN REVISIONS CONCERNING CAIR SO\textsubscript{2} OPT-IN UNITS

1. The following States have State Implementation Plan revisions under §51.124(r) of this chapter approved by the Administrator and establishing procedures providing for CAIR SO\textsubscript{2} opt-in units under subpart III of this part and allocation of CAIR SO\textsubscript{2} allowances to such units under §97.288(b):

   Indiana
   North Carolina
   Ohio
   South Carolina
   Tennessee

2. The following States have State Implementation Plan revisions under §51.124(r) of this chapter approved by the Administrator and establishing procedures providing for CAIR SO\textsubscript{2} opt-in units under subpart III of this part and allocation of CAIR SO\textsubscript{2} allowances to such units under §97.288(c):

   Indiana
   North Carolina
   Ohio
   South Carolina
   Tennessee


Subpart AAAA—CAIR NO\textsubscript{X} Ozone Season Trading Program General Provisions

§ 97.302 Definitions.

The terms used in this subpart and subparts BBBB through IIII shall have the meanings set forth in this section as follows:

Account number means the identification number given by the Administrator to each CAIR NO\textsubscript{X} Ozone Season Allowance Tracking System account.

Acid Rain emissions limitation means a limitation on emissions of sulfur dioxide or nitrogen oxides under the Acid Rain Program.

Acid Rain Program means a multi-state sulfur dioxide and nitrogen oxides air pollution control and emission reduction program established by the Administrator under title IV of the CAA and parts 72 through 78 of this chapter.

Administrator means the Administrator of the United States Environmental Protection Agency or the Administrator’s duly authorized representative.

Allocate or allocation means, with regard to CAIR NO\textsubscript{X} Ozone Season allowances, the determination by a permitting authority or the Administrator of the amount of such CAIR NO\textsubscript{X} Ozone Season allowances to be initially credited to a CAIR NO\textsubscript{X} Ozone Season unit, a new unit set-aside, or other entity.

Allotment transfer deadline means, for a control period, midnight of November 30 (if it is a business day), or midnight of the first business day thereafter (if November 30 is not a business day), immediately following the control period and is the deadline by which a CAIR NO\textsubscript{X} Ozone Season allowance transfer must be submitted for recordation in a CAIR NO\textsubscript{X} Ozone Season source’s compliance account in order to be used to meet the source’s CAIR NO\textsubscript{X} Ozone Season emissions limitation for such control period in accordance with §97.354.

Alternate CAIR designated representative means, for a CAIR NO\textsubscript{X} Ozone Season source and each CAIR NO\textsubscript{X} Ozone Season unit at the source, the natural person who is authorized by the owners and operators of the source and all such units at the source, in accordance with subparts BBBB and IIII of this part, to act on behalf of the CAIR designated representative in matters pertaining to the CAIR NO\textsubscript{X} Ozone Season Trading Program. If the CAIR NO\textsubscript{X}
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Ozone Season source is also a CAIR NO\textsubscript{X} source, then this natural person shall be the same person as the alternate CAIR designated representative under the CAIR NO\textsubscript{X} Annual Trading Program. If the CAIR NO\textsubscript{X} Ozone Season source is also a CAIR SO\textsubscript{2} source, then this natural person shall be the same person as the alternate CAIR designated representative under the CAIR SO\textsubscript{2} Trading Program. If the CAIR NO\textsubscript{X} Ozone Season source is also subject to the Acid Rain Program, then this natural person shall be the same person as the CAIR designated representative under the Acid Rain Program. If the CAIR NO\textsubscript{X} Ozone Season source is also subject to the Hg Budget Trading Program, then this natural person shall be the same person as the Hg designated representative under the Hg Budget Trading Program.

Automated data acquisition and handling system or DAHS means that component of the continuous emission monitoring system, or other emissions monitoring system approved for use under subpart HHHH of this part, designed to interpret and convert individual output signals from pollutant concentration monitors, flow monitors, diluent gas monitors, and other component parts of the monitoring system to produce a continuous record of the measured parameters in the measurement units required by subpart HHHH of this part.

Biomass means—

(1) Any organic material grown for the purpose of being converted to energy;

(2) Any organic byproduct of agriculture that can be converted into energy; or

(3) Any material that can be converted into energy and is nonmerchantable for other purposes, that is segregated from other nonmerchantable material, and that is:

(i) A forest-related organic resource, including mill residues, precommercial thinnings, slash, brush, or byproduct from conversion of trees to merchantable material; or

(ii) A wood material, including pallets, crates, dunnage, manufacturing and construction materials (other than pressure-treated, chemically-treated, or painted wood products), and landscape or right-of-way tree trimmings.

Boiler means an enclosed fossil-or other-fuel-fired combustion device used to produce heat and to transfer heat to recirculating water, steam, or other medium.

Bottoming-cycle cogeneration unit means a cogeneration unit in which the energy input to the unit is first used to produce useful thermal energy and at least some of the reject heat from the useful thermal energy application or process is then used for electricity production.

CAIR authorized account representative means, with regard to a general account, a responsible natural person who is authorized, in accordance with subparts BBBB, FFFF, and IIII of this part, to transfer and otherwise dispose of CAIR NO\textsubscript{X} Ozone Season allowances held in the general account and, with regard to a compliance account, the CAIR designated representative of the source.

CAIR designated representative means, for a CAIR NO\textsubscript{X} Ozone Season source and each CAIR NO\textsubscript{X} Ozone Season unit at the source, the natural person who is authorized by the owners and operators of the source and all such units at the source, in accordance with subparts BBBB and IIII of this part, to represent and legally bind each owner and operator in matters pertaining to the CAIR NO\textsubscript{X} Ozone Season Trading Program. If the CAIR NO\textsubscript{X} Ozone Season source is also a CAIR NO\textsubscript{X} source, then this natural person shall be the same person as the CAIR designated representative under the CAIR NO\textsubscript{X} Annual Trading Program. If the CAIR NO\textsubscript{X} Ozone Season source is also a CAIR SO\textsubscript{2} source, then this natural person shall be the same person as the CAIR designated representative under the CAIR SO\textsubscript{2} Trading Program. If the CAIR NO\textsubscript{X} Ozone Season source is also subject to the Acid Rain Program, then this natural person shall be the same person as the designated representative under the Acid Rain Program. If the CAIR NO\textsubscript{X} Ozone Season source is also subject to the Hg Budget Trading Program, then this natural person shall be the same person as the Hg designated representative under the Hg Budget Trading Program.
CAIR NO\textsubscript{X} Annual Trading Program means a multi-state nitrogen oxides air pollution control and emission reduction program established by the Administrator in accordance with subparts AA through II of this part and §§51.123(p) and 52.35 of this chapter or approved and administered by the Administrator in accordance with subparts AA through II of part 96 of this chapter and §51.123(o)(1) or (2) of this chapter, as a means of mitigating interstate transport of fine particulates and nitrogen oxides.

CAIR NO\textsubscript{X} Ozone Season allowance means a limited authorization issued by a permitting authority or the Administrator under subpart EEEE of this part, §97.388, or provisions of a State implementation plan that are approved under §51.123(aa)(1) or (2) (and (bb)(1)), (bb)(2), (dd), or (ee) of this chapter, to emit one ton of nitrogen oxides during a control period of the specified calendar year for which the authorization is allocated or of any calendar year thereafter under the CAIR NO\textsubscript{X} Ozone Season Trading Program or a limited authorization issued by a permitting authority for a control period during 2003 through 2008 under the NO\textsubscript{X} Budget Trading Program in accordance with §51.121(p) of this chapter, to emit one ton of nitrogen oxides during a control period, provided that the provision in §51.121(i)(2)(ii)(E) of this chapter shall not be used in applying this definition and the limited authorization shall not have been used to meet the allowance-holding requirement under the NO\textsubscript{X} Budget Trading Program. An authorization to emit nitrogen oxides that is not issued under subpart EEEE of this part, §97.388, or provisions of a State implementation plan that are approved under §51.123(aa)(1) or (2) (and (bb)(1)), (bb)(2), (dd), or (ee) of this chapter or under the NO\textsubscript{X} Budget Trading Program as described in the prior sentence shall not be a CAIR NO\textsubscript{X} Ozone Season allowance.

CAIR NO\textsubscript{X} Ozone Season allowance deduction or deduct CAIR NO\textsubscript{X} Ozone Season allowances means the permanent withdrawal of CAIR NO\textsubscript{X} Ozone Season allowances by the Administrator from a compliance account, e.g., in order to account for a specified number of tons of total nitrogen oxides emissions from all CAIR NO\textsubscript{X} Ozone Season units at a CAIR NO\textsubscript{X} Ozone Season source for a control period, determined in accordance with subpart HHHH of this part, or to account for excess emissions.

CAIR NO\textsubscript{X} Ozone Season Allowance Tracking System account means an account in the CAIR NO\textsubscript{X} Ozone Season Allowance Tracking System established by the Administrator for purposes of recording the allocation, holding, transferring, or deducting of CAIR NO\textsubscript{X} Ozone Season allowances.

CAIR NO\textsubscript{X} Ozone Season allowances held or hold CAIR NO\textsubscript{X} Ozone Season allowances means the CAIR NO\textsubscript{X} Ozone Season allowances recorded by the Administrator, or submitted to the Administrator for recordation, in accordance with subparts FFFF, GGGG, and IIII of this part, in a CAIR NO\textsubscript{X} Ozone Season Allowance Tracking System account.

CAIR NO\textsubscript{X} Ozone Season emissions limitation means, for a CAIR NO\textsubscript{X} Ozone Season source, the tonnage equivalent, in NO\textsubscript{X} emissions in a control period, of the CAIR NO\textsubscript{X} Ozone Season allowances available for deduction for the source under §97.354(a) and (b) for the control period.

CAIR NO\textsubscript{X} Ozone Season source means a source that includes one or more CAIR NO\textsubscript{X} Ozone Season units.

CAIR NO\textsubscript{X} Ozone Season Trading Program means a multi-state nitrogen oxides air pollution control and emission reduction program established by the Administrator in accordance with subparts AAAA through IIII of part 96 of this part and §§51.123(ee) and 52.35 of this chapter or approved and administered by the Administrator in accordance with subparts AAAA through IIII and §51.123(aa)(1) or (2) of this chapter, as a means of mitigating interstate transport of nitrogen oxides air pollution control and emission reduction program established by the Administrator in accordance with subpart HHHH of this part, or to account for excess emissions.
CAIR NO\textsubscript{X} Ozone Season unit means a unit that is subject to the CAIR NO\textsubscript{X} Ozone Season Trading Program under §97.304 and, except for purposes of §97.305 and subpart EEEE of this part, a CAIR NO\textsubscript{X} Ozone Season opt-in unit under subpart IIII of this part.

CAIR NO\textsubscript{X} source means a source that is subject to the CAIR NO\textsubscript{X} Annual Trading Program.

CAIR permit means the legally binding and federally enforceable written document, or portion of such document, issued by the permitting authority under subpart CCC of this part, including any permit revisions, specifying the CAIR NO\textsubscript{X} Ozone Season Trading Program requirements applicable to a CAIR NO\textsubscript{X} Ozone Season source, to each CAIR NO\textsubscript{X} Ozone Season unit at the source, and to the owners and operators and the CAIR designated representative of the source and each such unit.

CAIR SO\textsubscript{2} source means a source that is subject to the CAIR SO\textsubscript{2} Trading Program.

CAIR SO\textsubscript{2} Trading Program means a multi-state sulfur dioxide air pollution control and emission reduction program established by the Administrator in accordance with subparts AAA through IIII of this part and §§51.124(r) and 52.36 of this chapter or approved and administered by the Administrator in accordance with subparts AAA through IIII of part 96 of this chapter and §51.124(o)(1) or (2) of this chapter, as a means of mitigating interstate transport of fine particulates and sulfur dioxide.

Certifying official means:
(1) For a corporation, a president, secretary, treasurer, or vice-president or the corporation in charge of a principal business function or any other person who performs similar policy or decision-making functions for the corporation;
(2) For a partnership or sole proprietorship, a general partner or the proprietor respectively; or
(3) For a local government entity or State, Federal, or other public agency, a principal executive officer or ranking elected official.

Clean Air Act or CAA means the Clean Air Act, 42 U.S.C. 7401, et seq.

Coal means any solid fuel classified as anthracite, bituminous, subbituminous, or lignite.

Coal-derived fuel means any fuel (whether in a solid, liquid, or gaseous state) produced by the mechanical, thermal, or chemical processing of coal.

Coal-fired means:
(1) Except for purposes of subpart EEEE of this part, combusting any amount of coal or coal-derived fuel, alone or in combination with any amount of any other fuel, during any year; or
(2) For purposes of subpart EEEE of this part, combusting any amount of coal or coal-derived fuel, alone or in combination with any amount of any other fuel, during a specified year.

Cogeneration unit means a stationary, fossil-fuel-fired boiler or stationary, fossil-fuel-fired combustion turbine:
(1) Having equipment used to produce electricity and useful thermal energy for industrial, commercial, heating, or cooling purposes through the sequential use of energy; and
(2) Producing during the 12-month period starting on the date the unit first produces electricity and during any calendar year after the calendar year in which the unit first produces electricity—
   (i) For a topping-cycle cogeneration unit, useful thermal energy not less than 5 percent of total energy output; and
   (B) Useful power that, when added to one-half of useful thermal energy produced, is not less than 42.5 percent of total energy output, or not less than 45 percent of total energy input, if useful thermal energy produced is less than 15 percent of total energy output.
(ii) For a bottoming-cycle cogeneration unit, useful power not less than 45 percent of total energy input;
(3) Provided that the total energy input under paragraphs (2)(i)(B) and (2)(ii) of this definition shall equal the unit’s total energy input from all fuel except biomass if the unit is a boiler.

Combustion turbine means:
(1) An enclosed device comprising a compressor, a combustor, and a turbine
and in which the flue gas resulting from the combustion of fuel in the combustor passes through the turbine, rotating the turbine; and

(2) If the enclosed device under paragraph (1) of this definition is combined cycle, any associated duct burner, heat recovery steam generator, and steam turbine.

Commence commercial operation means, with regard to a unit:

(1) To have begun to produce steam, gas, or other heated medium used to generate electricity for sale or use, including test generation, except as provided in §97.305 and §97.384(h).

(i) For a unit that is a CAIR NO\textsubscript{X} Ozone Season unit under §97.304 on the later of November 15, 1990 or the date the unit commences commercial operation as defined in paragraph (1) of this definition and that subsequently undergoes a physical change (other than replacement of the unit by a unit at the same source), such date shall remain the date of commencement of commercial operation of the unit, which shall continue to be treated as the same unit.

(ii) For a unit with a date for commencement of commercial operation as defined in paragraph (2) of this definition and that is subsequently replaced by a unit at the same source (e.g., repowered), such date shall remain the replaced unit’s date of commencement of commercial operation, and the replacement unit shall be treated as a separate unit with a separate date for commencement of commercial operation as defined in paragraph (1), (2), or (3) of this definition as appropriate.

(2) Notwithstanding paragraph (1) of this definition and except as provided in §97.305, for a unit that is not a CAIR NO\textsubscript{X} Ozone Season unit under §97.304 on the later of November 15, 1990 or the date the unit commences commercial operation as defined in paragraph (1) of this definition, the unit’s date of commencement of commercial operation of the unit, which shall continue to be treated as the same unit.

(ii) For a unit that undergoes a physical change (other than replacement of the unit by a unit at the same source) after the date the unit commences operation as defined in paragraph (1) of this definition, such date shall remain the date of commencement of operation of the unit, which shall continue to be treated as the same unit.

(ii) For a unit that is replaced by a unit at the same source (e.g., repowered) after the date the unit commences operation as defined in paragraph (1) of this definition, such date shall remain the date of commencement of operation of the unit, which shall continue to be treated as the same unit.

Commence operation means:

(1) To have begun any mechanical, chemical, or electronic process, including, with regard to a unit, start-up of a unit’s combustion chamber, except as provided in §97.384(h).

(i) For a unit that undergoes a physical change (other than replacement of the unit by a unit at the same source) after the date the unit commences operation as defined in paragraph (1) of this definition, such date shall remain the date of commencement of operation of the unit, which shall continue to be treated as the same unit.

(ii) For a unit that is replaced by a unit at the same source (e.g., repowered) after the date the unit commences operation as defined in paragraph (1) of this definition, such date shall remain the date of commencement of operation of the unit, which shall continue to be treated as the same unit.

(2) Notwithstanding paragraph (1) of this definition and solely for purposes of subpart HHHH of this part, for a unit at the same source (e.g., repowered) after the date the unit commences operation as defined in paragraph (1) of this definition, such date shall remain the date of commencement of operation of the unit, which shall continue to be treated as the same unit.
that is not a CAIR NO$_x$ Ozone Season unit under §97.304(d) on the later of November 15, 1990 or the date the unit commences operation as defined in paragraph (1) of this definition and subsequently becomes such a CAIR NO$_x$ Ozone Season unit, the unit’s date for commencement of operation shall be the date on which the unit becomes a CAIR NO$_x$ Ozone Season unit under §97.304(d).

(i) For a unit with a date for commencement of operation as defined in paragraph (2) of this definition and that subsequently undergoes a physical change (other than replacement of the unit by a unit at the same source), such date shall remain the date of commencement of operation of the unit, which shall continue to be treated as the same unit.

(ii) For a unit with a date for commencement of operation as defined in paragraph (2) of this definition and that is subsequently replaced by a unit at the same source (e.g., repowered), such date shall remain the replaced unit’s date of commencement of operation, and the replacement unit shall be treated as a separate unit with a separate date for commencement of operation as defined in paragraph (1) or (2) of this definition as appropriate.

Common stack means a single flue through which emissions from 2 or more units are exhausted.

Compliance account means a CAIR NO$_x$ Ozone Season Allowance Tracking System account, established by the Administrator for a CAIR NO$_x$ Ozone Season source under subpart FFFF or IIII of this part, in which any CAIR NO$_x$ Ozone Season allowance allocations for the CAIR NO$_x$ Ozone Season units at the source are initially recorded and in which are held any CAIR NO$_x$ Ozone Season allowances available for use for a control period in order to meet the source’s CAIR NO$_x$ Ozone Season emissions limitation in accordance with §97.354.

Continuous emission monitoring system or CEMS means the equipment required under subpart HHHH of this part to sample, analyze, measure, and provide, by means of readings recorded at least once every 15 minutes (using an automated data acquisition and handling system (DAHS)), a permanent record of nitrogen oxides emissions, stack gas volumetric flow rate, stack gas moisture content, and oxygen or carbon dioxide concentration (as applicable), in a manner consistent with part 75 of this chapter.

The following systems are the principal types of continuous emission monitoring systems required under subpart HHHH of this part:

(1) A flow monitoring system, consisting of a stack flow rate monitor and an automated data acquisition and handling system and providing a permanent, continuous record of stack gas volumetric flow rate, in standard cubic feet per hour (scfh);

(2) A nitrogen oxides concentration monitoring system, consisting of a NO$_x$ pollutant concentration monitor and an automated data acquisition and handling system and providing a permanent, continuous record of NO$_x$ emissions, in parts per million (ppm);

(3) A nitrogen oxides emission rate (or NO$_x$-diluent) monitoring system, consisting of a NO$_x$ pollutant concentration monitor, a diluent gas (CO$_2$ or O$_2$) monitor, and an automated data acquisition and handling system and providing a permanent, continuous record of NO$_x$ concentration, in parts per million (ppm), diluent gas concentration, in percent CO$_2$ or O$_2$, and NO$_x$ emission rate, in pounds per million British thermal units (lb/mmBtu);

(4) A moisture monitoring system, as defined in §75.11(b)(2) of this chapter and providing a permanent, continuous record of the stack gas moisture content, in percent H$_2$O;

(5) A carbon dioxide monitoring system, consisting of a CO$_2$ pollutant concentration monitor (or an oxygen monitor plus suitable mathematical equations from which the CO$_2$ concentration is derived) and an automated data acquisition and handling system and providing a permanent, continuous record of CO$_2$ emissions, in percent CO$_2$; and

(6) An oxygen monitoring system, consisting of an O$_2$ concentration monitor and an automated data acquisition and handling system and providing a permanent, continuous record of O$_2$, in percent O$_2$.

Control period or ozone season means the period beginning May 1 of a calendar year, except as provided in
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§ 97.306(c)(2) and ending on September 30 of the same year, inclusive.

Emissions means air pollutants exhausted from a unit or source into the atmosphere, as measured, recorded, and reported to the Administrator by the CAIR designated representative and as determined by the Administrator in accordance with subpart HHHH of this part.

Excess emissions means any ton of nitrogen oxides emitted by the CAIR NOX Ozone Season units at a CAIR NOX Ozone Season source during a control period that exceeds the CAIR NOX Ozone Season emissions limitation for the source.

Fossil fuel means natural gas, petroleum, coal, or any form of solid, liquid, or gaseous fuel derived from such material.

Fossil-fuel-fired means, with regard to a unit, combusting any amount of fossil fuel in any calendar year.

Fuel oil means any petroleum-based fuel (including diesel fuel or petroleum derivatives such as oil tar) and any recycled or blended petroleum products or petroleum by-products used as a fuel whether in a liquid, solid, or gaseous state.

General account means a CAIR NOX Ozone Season Allowance Tracking System account, established under subpart FFFF of this part, that is not a compliance account.

Generator means a device that produces electricity.

Gross electrical output means, with regard to a cogeneration unit, electricity made available for use, including any such electricity used in the power production process (which process includes, but is not limited to, any on-site processing or treatment of fuel combusted at the unit and any on-site emission controls).

Heat input means, with regard to a specified period of time, the product (in mmBtu/hour) of the gross calorific value of the fuel (in Btu/lb) divided by 1,000,000 Btu/mmBtu and multiplied by the fuel feed rate into a combustion device (in lb of fuel/time), as measured, recorded, and reported to the Administrator by the CAIR designated representative and determined by the Administrator in accordance with subpart HHHH of this part and excluding the heat derived from preheated combustion air, recirculated flue gases, or exhaust from other sources.

Heat input rate means the amount of heat input (in mmBtu) divided by unit operating time (in hr) or, with regard to a specific fuel, the amount of heat input attributed to the fuel (in mmBtu) divided by the unit operating time (in hr) during which the unit combusts the fuel.

Hg Budget Trading Program means a multi-state Hg air pollution control and emission reduction program approved and administered by the Administrator in accordance subpart HHHH of part 60 of this chapter and §60.24(h)(6), or established by the Administrator under section 111 of the Clean Air Act, as a means of reducing national Hg emissions.

Life-of-the-unit, firm power contractual arrangement means a unit participation power sales agreement under which a utility or industrial customer reserves, or is entitled to receive, a specified amount or percentage of nameplate capacity and associated energy generated by any specified unit and pays its proportional amount of such unit's total costs, pursuant to a contract:

(1) For the life of the unit;
(2) For a cumulative term of no less than 30 years, including contracts that permit an election for early termination; or
(3) For a period no less than 25 years or 70 percent of the economic useful life of the unit determined as of the time the unit is built, with option rights to purchase or release some portion of the nameplate capacity and associated energy generated by the unit at the end of the period.

Maximum design heat input means the maximum amount of fuel per hour (in Btu/hr) that a unit is capable of combusting on a steady state basis as of the initial installation of the unit as specified by the manufacturer of the unit.

Monitoring system means any monitoring system that meets the requirements of subpart HHHH of this part, including a continuous emissions monitoring system, an alternative monitoring system, or an excepted monitoring system under part 75 of this chapter.
Most stringent State or Federal NO\textsubscript{X} emissions limitation means, with regard to a unit, the lowest NO\textsubscript{X} emissions limitation (in terms of lb/mmBtu) that is applicable to the unit under State or Federal law, regardless of the averaging period to which the emissions limitation applies.

Nameplate capacity means, starting from the initial installation of a generator, the maximum electrical generating output (in MWe) that the generator is capable of producing on a steady state basis and during continuous operation (when not restricted by seasonal or other deratings) as of such installation as specified by the manufacturer of the generator or, starting from the completion of any subsequent physical change in the generator resulting in an increase in the maximum electrical generating output (in MWe) that the generator is capable of producing on a steady state basis and during continuous operation (when not restricted by seasonal or other deratings), such increased maximum amount as of such completion as specified by the person conducting the physical change.

Oil-fired means, for purposes of subpart EEEE of this part, combusting fuel oil for more than 15.0 percent of the annual heat input in a specified year and not qualifying as coal-fired.

Operator means any person who operates, controls, or supervises a CAIR NO\textsubscript{X} Ozone Season unit or a CAIR NO\textsubscript{X} Ozone Season source and shall include, but not be limited to, any holding company, utility system, or plant manager of such a unit or source.

Owner means any of the following persons:

(1) With regard to a CAIR NO\textsubscript{X} Ozone Season source or a CAIR NO\textsubscript{X} Ozone Season unit at a source, respectively:

(i) Any holder of any portion of the legal or equitable title in a CAIR NO\textsubscript{X} Ozone Season unit at the source or the CAIR NO\textsubscript{X} Ozone Season source;

(ii) Any holder of a leasehold interest in a CAIR NO\textsubscript{X} Ozone Season unit at the source or the CAIR NO\textsubscript{X} Ozone Season unit;

(iii) Any purchaser of power from a CAIR NO\textsubscript{X} Ozone Season unit at the source or the CAIR NO\textsubscript{X} Ozone Season unit under a life-of-the-unit, firm power contractual arrangement; provided that, unless expressly provided for in a leasehold agreement, owner shall not include a passive lessor, or a person who has an equitable interest through such lessor, whose rental payments are not based (either directly or indirectly) on the revenues or income from such CAIR NO\textsubscript{X} Ozone Season unit; or

(2) With regard to any general account, any person who has an ownership interest with respect to the CAIR NO\textsubscript{X} Ozone Season allowances held in the general account and who is subject to the binding agreement for the CAIR authorized account representative to represent the person’s ownership interest with respect to CAIR NO\textsubscript{X} Ozone Season allowances.

Permitting authority means the State air pollution control agency, local agency, other State agency, or other agency authorized by the Administrator to issue or revise permits to meet the requirements of the CAIR NO\textsubscript{X} Ozone Season Trading Program or, if no such agency has been so authorized, the Administrator.

Potential electrical output capacity means 33 percent of a unit’s maximum design heat input, divided by 3,413 Btu/kWh, divided by 1,000 kWh/MWh, and multiplied by 8,760 hr/yr.

Receive or receipt of means, when referring to the permitting authority or the Administrator, to come into possession of a document, information, or correspondence (whether sent in hard copy or by authorized electronic transmission), as indicated in an official log, or by a notation made on the document, information, or correspondence, by the permitting authority or the Administrator in the regular course of business.

Recordation, record, or recorded means, with regard to CAIR NO\textsubscript{X} Ozone Season allowances, the movement of CAIR NO\textsubscript{X} Ozone Season allowances by the Administrator into or between CAIR NO\textsubscript{X} Ozone Season Allowance Tracking System accounts, for purposes of allocation, transfer, or deduction.

Reference method means any direct test method of sampling and analyzing for an air pollutant as specified in §75.22 of this chapter.
Replacement, replace, or replaced means, with regard to a unit, the demolishing of a unit, or the permanent shutdown and permanent disabling of a unit, and the construction of another unit (the replacement unit) to be used instead of the demolished or shutdown unit (the replaced unit).

Repowered means, with regard to a unit, replacement of a coal-fired boiler with one of the following coal-fired technologies at the same source as the coal-fired boiler:

1. Atmospheric or pressurized fluidized bed combustion;
2. Integrated gasification combined cycle;
3. Magnetohydrodynamics;
4. Direct and indirect coal-fired turbines;
5. Integrated gasification fuel cells; or
6. As determined by the Administrator in consultation with the Secretary of Energy, a derivative of one or more of the technologies under paragraphs (1) through (5) of this definition and any other coal-fired technology capable of controlling multiple combustion emissions simultaneously with improved boiler or generation efficiency and with significantly greater waste reduction relative to the performance of technology in widespread commercial use as of January 1, 2005.

Sequential use of energy means:

1. For a topping-cycle cogeneration unit, the use of reject heat from electricity production in a useful thermal energy application or process; or
2. For a bottoming-cycle cogeneration unit, the use of reject heat from useful thermal energy application or process in electricity production.

Serial number means, for a CAIR NOX Ozone Season allowance, the unique identification number assigned to each CAIR NOX Ozone Season allowance by the Administrator.

Solid waste incineration unit means a stationary, fossil-fuel-fired boiler or stationary, fossil-fuel-fired combustion turbine that is a “solid waste incineration unit” as defined in section 129(g)(1) of the Clean Air Act.

Source means all buildings, structures, or installations located in one or more contiguous or adjacent properties under common control of the same person or persons. For purposes of section 502(c) of the Clean Air Act, a “source” including a “source” with multiple units, shall be considered a single “facility.”

State means one of the States or the District of Columbia that is subject to the CAIR NOX Ozone Season Trading Program pursuant to §52.35 of this chapter.

Submit or serve means to send or transmit a document, information, or correspondence to the person specified in accordance with the applicable regulation:

1. In person;
2. By United States Postal Service; or
3. By other means of dispatch or transmission and delivery. Compliance with any “submission” or “service” deadline shall be determined by the date of dispatch, transmission, or mailing and not the date of receipt.

Title V operating permit means a permit issued under title V of the Clean Air Act and part 70 or part 71 of this chapter.

Title V operating permit regulations means the regulations that the Administrator has approved or issued as meeting the requirements of title V of the Clean Air Act and part 70 or 71 of this chapter.

Ton means 2,000 pounds. For the purpose of determining compliance with the CAIR NOX Ozone Season emissions limitation, total tons of nitrogen oxides emissions for a control period shall be calculated as the sum of all recorded hourly emissions (or the mass equivalent of the recorded hourly emission rates) in accordance with subpart HHHH of this part, but with any remaining fraction of a ton equal to or greater than 0.50 tons deemed to equal one ton and any remaining fraction of a ton less than 0.50 tons deemed to equal zero tons.

Topping-cycle cogeneration unit means a cogeneration unit in which the energy input to the unit is first used to produce useful power, including electricity, and at least some of the reject heat from the electricity production is then used to provide useful thermal energy.

Total energy input means, with regard to a cogeneration unit, total energy of...
all forms supplied to the cogeneration unit, excluding energy produced by the cogeneration unit itself. Each form of energy supplied shall be measured by the lower heating value of that form of energy calculated as follows:

\[ LHV = HHV - 10.55(W + 9H) \]

Where:
- \( LHV \) = lower heating value of fuel in Btu/lb,
- \( HHV \) = higher heating value of fuel in Btu/lb,
- \( W \) = Weight % of moisture in fuel, and
- \( H \) = Weight % of hydrogen in fuel.

Total energy output means, with regard to a cogeneration unit, the sum of useful power and useful thermal energy produced by the cogeneration unit.

Unit means a stationary, fossil-fuel-fired boiler or combustion turbine or other stationary, fossil-fuel-fired combustion device.

Unit operating day means a calendar day in which a unit combusts any fuel.

Unit operating hour or hour of unit operation means an hour in which a unit combusts any fuel.

Useful power means, with regard to a cogeneration unit, electricity or mechanical energy made available for use, excluding any such energy used in the power production process (which process includes, but is not limited to, any on-site processing or treatment of fuel combusted at the unit and any on-site emission controls).

Useful thermal energy means, with regard to a cogeneration unit, thermal energy that is:

1. Made available to an industrial or commercial process (not a power production process), excluding any heat contained in condensate return or makeup water;
2. Used in a heating application (e.g., space heating or domestic hot water heating); or
3. Used in a space cooling application (i.e., thermal energy used by an absorption chiller).

Utility power distribution system means the portion of an electricity grid owned or operated by a utility and dedicated to delivering electricity to customers.

§ 97.304 Applicability.

(a) Except as provided in paragraph (b) of this section:

1. The following units in a State shall be CAIR NO\(_X\) Ozone Season units, and any source that includes one or more such units shall be a CAIR NO\(_X\) Ozone Season source, subject to the requirements of this subpart and subparts BBBBB through HHHHH of this part: any stationary, fossil-fuel-fired boiler or stationary, fossil-fuel-fired combustion turbine serving at any time, since the later of November 15, 1990 or the start-up of the unit's combustion chamber, a generator with nameplate capacity of more than 25 MWe producing electricity for sale.

(b) The units in a State that meet the requirements set forth in paragraph (b)(1)(i), (b)(2)(i), or (b)(2)(ii) of this section shall not be CAIR NO\(_X\) Ozone Season units:

§ 97.303 Measurements, abbreviations, and acronyms.

Measurements, abbreviations, and acronyms used in this subpart and subparts BBBBB through HHHHH are defined as follows:

- Btu—British thermal unit.
- CO\(_2\)—carbon dioxide.
- H\(_2\)O—water.
- Hg—mercury.
- hr—hour.
- kW—kilowatt electrical.
- kWh—kilowatt hour.
- lb—pound.
- mmBtu—million Btu.
- MWe—megawatt electrical.
- MWh—megawatt hour.
- NO\(_X\)—nitrogen oxides.
- O\(_2\)—oxygen.
- ppm—parts per million.
- scfh—standard cubic feet per hour.
- SO\(_2\)—sulfur dioxide.
- yr—year.
§ 97.304

(1)(i) Any unit that is a CAIR NO\textsubscript{X} Ozone Season unit under paragraph (a)(1) or (2) of this section:

(A) Qualifying as a cogeneration unit during the 12-month period starting on the date the unit first produces electricity and continuing to qualify as a cogeneration unit; and

(B) Not serving at any time, since the later of November 15, 1990 or the start-up of the unit’s combustion chamber, a generator with nameplate capacity of more than 25 MWe supplying in any calendar year more than one-third of the unit’s potential electric output capacity or 219,000 MWh, whichever is greater, to any utility power distribution system for sale.

(ii) If a unit qualifies as a cogeneration unit during the 12-month period starting on the date the unit first produces electricity and meets the requirements of paragraphs (b)(1)(i) of this section for at least one calendar year, but subsequently no longer meets all such requirements, the unit shall become a CAIR NO\textsubscript{X} Ozone Season unit starting on the earlier of January 1 after the first calendar year during which the unit first no longer qualifies as a cogeneration unit or January 1 after the first 3 consecutive calendar years after 1990 for which the unit has an average annual fuel consumption of fossil fuel of 20 percent or more.

(c) A certifying official of an owner or operator of any unit may petition the Administrator at any time for a determination concerning the applicability, under paragraphs (a) and (b) of this section, of the CAIR NO\textsubscript{X} Ozone Season Trading Program to the unit.

(1) Petition content. The petition shall be in writing and include the identification of the unit and the relevant facts about the unit. The petition and any other documents provided to the Administrator in connection with the petition shall include the following certification statement, signed by the certifying official: ‘‘I am authorized to make this submission on behalf of the owners and operators of the unit for which the submission is made. I certify under penalty of law that I have personally examined, and am familiar with, the statements and information submitted in this document and all its attachments. Based on my inquiry of those individuals with primary responsibility for obtaining the information, I certify that the statements and information are to the best of my knowledge and belief true, accurate, and complete. I am aware that there are significant penalties for submitting false statements and information or omitting required statements and information, including the possibility of fine or imprisonment.’’

(2) Submission. The petition and any other documents provided in connection with the petition shall be submitted to the Director of the Clean Air Markets Division (or its successor),
§ 97.305 Retired unit exemption.

(a)(1) Any CAIR NO\textsubscript{X} Ozone Season unit that is permanently retired and is not a CAIR NO\textsubscript{X} Ozone Season opt-in unit under subpart III of this part shall be exempt from the CAIR NO\textsubscript{X} Ozone Season Trading Program, except for the provisions of this section, §§97.302, 97.303, 97.304, 97.306(c)(4) through (7), 97.307, 97.308, and subparts BBBB and EEEE through GGGG of this part.

(2) The exemption under paragraph (a)(1) of this section shall become effective the day on which the CAIR NO\textsubscript{X} Ozone Season unit is permanently retired. Within 30 days of the unit’s permanent retirement, the CAIR designated representative shall submit a statement to the permitting authority otherwise responsible for administering any CAIR permit for the unit and shall submit a copy of the statement to the Administrator. The statement shall state, in a format prescribed by the permitting authority, that the unit was permanently retired on a specific date and will comply with the requirements of paragraph (b) of this section.

(3) After receipt of the statement under paragraph (a)(2) of this section, the permitting authority will amend any permit under subpart CCCC of this part covering the source at which the unit is located to add the provisions and requirements of the exemption under paragraphs (a)(1) and (b) of this section.

(b) Special provisions.

(1) A unit exempt under paragraph (a) of this section shall not emit any nitrogen oxides, starting on the date that the exemption takes effect.

(2) The Administrator or the permitting authority will allocate CAIR NO\textsubscript{X} Ozone Season allowances under subpart EEEE of this part to a unit exempt under paragraph (a) of this section.

(3) For a period of 5 years from the date the records are created, the owners and operators of a unit exempt under paragraph (a) of this section shall retain at the source that includes the unit, records demonstrating that the unit is permanently retired. The 5-year period for keeping records may be extended for cause, at any time before the end of the period, in writing by the permitting authority or the Administrator. The owners and operators bear the burden of proof that the unit is permanently retired.

(4) The owners and operators and, to the extent applicable, the CAIR designated representative of a unit exempt under paragraph (a) of this section shall comply with the requirements of the CAIR NO\textsubscript{X} Ozone Season Trading Program concerning all periods for which the exemption is not in effect, even if such requirements arise, or must be complied with, after the exemption takes effect.

(5) A unit exempt under paragraph (a) of this section and located at a source that is required, or but for this exemption would be required, to have a Title V operating permit shall not resume...
§ 97.306 Standard requirements.

(a) Permit requirements. (1) The CAIR designated representative of each CAIR NO\textsubscript{X} Ozone Season source required to have a title V operating permit and each CAIR NO\textsubscript{X} Ozone Season unit required to have a title V operating permit at the source shall have a CAIR permit issued by the permitting authority under subpart CCCC of this part for the source and operate the source and the unit in compliance with such CAIR permit.

(2) The owners and operators of each CAIR NO\textsubscript{X} Ozone Season source that is not otherwise required to have a title V operating permit and each CAIR NO\textsubscript{X} Ozone Season unit that is not otherwise required to have a title V operating permit are not required to submit a CAIR permit application, and to have a CAIR permit, under subpart CCCC of this part for such CAIR NO\textsubscript{X} Ozone Season source and such CAIR NO\textsubscript{X} Ozone Season unit.

(b) Monitoring, reporting, and recordkeeping requirements. (1) The owners and operators, and the CAIR designated representative, of each CAIR NO\textsubscript{X} Ozone Season source and each CAIR NO\textsubscript{X} Ozone Season unit at the source shall comply with the monitoring, reporting, and recordkeeping requirements of subpart HHHH of this part.

(2) The emissions measurements recorded and reported in accordance with subpart HHHH of this part shall be used to determine compliance by each CAIR NO\textsubscript{X} Ozone Season source with the CAIR NO\textsubscript{X} Ozone Season emissions limitation under paragraph (c) of this section.

(c) Nitrogen oxides ozone season emission requirements. (1) As of the allowance transfer deadline for a control period, the owners and operators of each CAIR NO\textsubscript{X} Ozone Season source required to hold, in the source’s compliance account, CAIR NO\textsubscript{X} Ozone Season allowances available for compliance deductions for the control period under §97.354(a) in an amount not less than the tons of total nitrogen oxides emissions for the control period from all CAIR NO\textsubscript{X} Ozone Season units at the source, as determined in accordance with subpart HHHH of this part.

(2) A CAIR NO\textsubscript{X} Ozone Season unit shall be subject to the requirements under paragraph (c)(1) of this section for the control period starting on the later of May 1, 2009 or the deadline for meeting the unit’s monitor certification requirements under §97.370(b)(1),
(2), (3), or (7) and for each control period thereafter.

(3) A CAIR NOx Ozone Season allowance shall not be deducted, for compliance with the requirements under paragraph (c)(1) of this section, for a control period in a calendar year before the year for which the CAIR NOx Ozone Season allowance was allocated.

(4) CAIR NOx Ozone Season allowances shall be held in, deducted from, or transferred into or among CAIR NOx Ozone Season Allowance Tracking System accounts in accordance with subparts EEEE, FFFF, GGGG, and IIII of this part.

(5) A CAIR NOx Ozone Season allowance is a limited authorization to emit one ton of nitrogen oxides in accordance with the CAIR NOx Ozone Season Trading Program. No provision of the CAIR NOx Ozone Season Trading Program, the CAIR permit application, the CAIR permit, or an exemption under §97.305 and no provision of law shall be construed to limit the authority of the United States to terminate or limit such authorization.

(6) A CAIR NOx Ozone Season allowance does not constitute a property right.

(7) Upon recordation by the Administrator under subpart EEEE, FFFF, GGGG, or IIII of this part, every allocation, transfer, or deduction of a CAIR NOx Ozone Season allowance to or from a CAIR NOx Ozone Season source’s compliance account is incorporated automatically in any CAIR permit of the source.

(d) Excess emissions requirements. If a CAIR NOx Ozone Season source emits nitrogen oxides during any control period in excess of the CAIR NOx Ozone Season emissions limitation, then:

(1) The owners and operators of the source and each CAIR NOx Ozone Season unit at the source shall surrender the CAIR NOx Ozone Season allowances required for deduction under §97.354(d)(1) and pay any fine, penalty, or assessment or comply with any other remedy imposed, for the same violations, under the Clean Air Act or applicable State law; and

(2) Each ton of such excess emissions and each day of such control period shall constitute a separate violation of this subpart, the Clean Air Act, and applicable State law.

(e) Recordkeeping and reporting requirements. (1) Unless otherwise provided, the owners and operators of the CAIR NOx Ozone Season source and each CAIR NOx Ozone Season unit at the source shall keep on site at the source each of the following documents for a period of 5 years from the date the document is created. This period may be extended for cause, at any time before the end of 5 years, in writing by the permitting authority or the Administrator.

(i) The certificate of representation under §97.313 for the CAIR designated representative for the source and each CAIR NOx Ozone Season unit at the source and all documents that demonstrate the truth of the statements in the certificate of representation; provided that the certificate and documents shall be retained on site at the source beyond such 5-year period until such documents are superseded because of the submission of a new certificate of representation under §97.313 changing the CAIR designated representative.

(ii) All emissions monitoring information, in accordance with subpart HHHH of this part, provided that to the extent that subpart HHHH of this part provides for a 3-year period for recordkeeping, the 3-year period shall apply.

(iii) Copies of all reports, compliance certifications, and other submissions and all records made or required under the CAIR NOx Ozone Season Trading Program.

(iv) Copies of all documents used to complete a CAIR permit application and any other submission under the CAIR NOx Ozone Season Trading Program or to demonstrate compliance with the requirements of the CAIR NOx Ozone Season Trading Program.

(2) The CAIR designated representative of a CAIR NOx Ozone Season source and each CAIR NOx Ozone Season unit at the source shall submit the reports required under the CAIR NOx Ozone Season Trading Program, including those under subpart HHHH of this part.

(f) Liability. (1) Each CAIR NOx Ozone Season source and each CAIR NOx
§ 97.307 Computation of time.

(a) Unless otherwise stated, any time period scheduled, under the CAIR NO\textsubscript{X} Ozone Season Trading Program, to begin on the occurrence of an act or event shall begin on the day the act or event occurs.

(b) Unless otherwise stated, any time period scheduled, under the CAIR NO\textsubscript{X} Ozone Season Trading Program, to begin before the occurrence of an act or event shall be computed so that the period ends the day before the act or event occurs.

(c) Unless otherwise stated, if the final day of any time period, under the CAIR NO\textsubscript{X} Ozone Season Trading Program, falls on a weekend or a State or Federal holiday, the time period shall be extended to the next business day.

§ 97.308 Appeal procedures.

The appeal procedures for decisions of the Administrator under the CAIR NO\textsubscript{X} Ozone Season Trading Program are set forth in part 78 of this chapter.
§ 97.311 Alternate CAIR designated representative.

(a) A certificate of representation under §97.313 may designate one and only one alternate CAIR designated representative, who may act on behalf of the CAIR designated representative. The agreement by which the alternate CAIR designated representative is selected shall include a procedure for authorizing the alternate CAIR designated representative to act in lieu of the CAIR designated representative.

(b) Upon receipt by the Administrator of a complete certificate of representation under §97.313, any representation, action, inaction, or submission by the alternate CAIR designated representative shall be deemed to be a representation, action, inaction, or submission by the CAIR designated representative.

(c) Except in this section and §§97.302, 97.310(a) and (d), 97.312, 97.313, 97.315, 97.351, and 97.382, whenever the term “CAIR designated representative” is used in subparts AAAAA through III of this part, the term shall be construed to include the CAIR designated representative or any alternate CAIR designated representative.

§ 97.312 Changing CAIR designated representative and alternate CAIR designated representative; changes in owners and operators.

(a) Changing CAIR designated representative. The CAIR designated representative may be changed at any time upon receipt by the Administrator of a superseding complete certificate of representation under §97.313. Notwithstanding any such change, all representations, actions, inactions, and submissions by the previous CAIR designated representative before the time and date when the Administrator receives the superseding certificate of representation shall be binding on the new CAIR designated representative and the owners and operators of the CAIR NOx Ozone Season source and the CAIR NOx Ozone Season units at the source.

(b) Changing alternate CAIR designated representative. The alternate CAIR designated representative may be changed at any time upon receipt by the Administrator of a superseding complete
§ 97.313 Certificate of representation.

(a) A complete certificate of representation for a CAIR designated representative or an alternate CAIR designated representative shall include the following elements in a format prescribed by the Administrator:

(1) Identification of the CAIR NO\textsubscript{X} Ozone Season source, and each CAIR NO\textsubscript{X} Ozone Season unit at the source, for which the certificate of representation is submitted, including identification and nameplate capacity of each generator served by each such unit.

(2) The name, address, e-mail address (if any), telephone number, and facsimile transmission number (if any) of the CAIR designated representative and any alternate CAIR designated representative.

(3) A list of the owners and operators of the CAIR NO\textsubscript{X} Ozone Season source and of each CAIR NO\textsubscript{X} Ozone Season unit at the source.

(c) Changes in owners and operators.

(1) In the event an owner or operator of a CAIR NO\textsubscript{X} Ozone Season source or a CAIR NO\textsubscript{X} Ozone Season unit is not included in the list of owners and operators in the certificate of representation under §97.313, such owner or operator shall be deemed to be subject to and bound by the certificate of representation, the representations, actions, inactions, and submissions of the CAIR designated representative and any alternate CAIR designated representative of the source or unit, and the decisions and orders of the permitting authority, the Administrator, or a court, as if the owner or operator were included in such list.

(2) Within 30 days following any change in the owners and operators of a CAIR NO\textsubscript{X} Ozone Season source or a CAIR NO\textsubscript{X} Ozone Season unit, including the addition of a new owner or operator, the CAIR designated representative or any alternate CAIR designated representative shall submit a revision to the certificate of representation under §97.313 amending the list of owners and operators to include the change.

§ 97.313 Certificate of representation.

Notwithstanding any such change, all representations, actions, inactions, and submissions by the previous alternate CAIR designated representative before the time and date when the Administrator receives the superseding certificate of representation shall be binding on the new alternate CAIR designated representative and the owners and operators of the CAIR NO\textsubscript{X} Ozone Season source and the CAIR NO\textsubscript{X} Ozone Season units at the source.

(2) The name, address, e-mail address (if any), telephone number, and facsimile transmission number (if any) of the CAIR designated representative and any alternate CAIR designated representative.

(3) A list of the owners and operators of the CAIR NO\textsubscript{X} Ozone Season source and of each CAIR NO\textsubscript{X} Ozone Season unit at the source.

(4) The following certification statements by the CAIR designated representative and any alternate CAIR designated representative—

(i) “I certify that I was selected as the CAIR designated representative or alternate CAIR designated representative, as applicable, by an agreement binding on the owners and operators of the source and each CAIR NO\textsubscript{X} Ozone Season unit at the source.”

(ii) “I certify that I have all the necessary authority to carry out my duties and responsibilities under the CAIR NO\textsubscript{X} Ozone Season Trading Program on behalf of the owners and operators of the source and each CAIR NO\textsubscript{X} Ozone Season unit at the source and that each such owner and operator shall be fully bound by my representations, actions, inactions, or submissions.”

(iii) “I certify that the owners and operators of the source and each CAIR NO\textsubscript{X} Ozone Season unit at the source shall be bound by any order issued to me by the Administrator, the permitting authority, or a court regarding the source or unit.”

(iv) “Where there are multiple holders of a legal or equitable title to, or a leasehold interest in, a CAIR NO\textsubscript{X} Ozone Season unit, or where a utility or industrial customer purchases power from a CAIR NO\textsubscript{X} Ozone Season unit under a life-of-the-unit, firm power contractual arrangement, I certify that: I have given a written notice of my selection as the ‘CAIR designated representative’ or ‘alternate CAIR designated representative’, as applicable, and of the agreement by which I was selected to each owner and operator of the source and of each CAIR NO\textsubscript{X} Ozone Season unit at the source; and CAIR NO\textsubscript{X} Ozone Season allowances and proceeds of transactions involving CAIR NO\textsubscript{X} Ozone Season allowances will be
deemed to be held or distributed in proportion to each holder's legal, equitable, leasehold, or contractual reservation or entitlement, except that, if such multiple holders have expressly provided for a different distribution of CAIR \(\text{NO}_x\) Ozone Season allowances by contract, CAIR \(\text{NO}_x\) Ozone Season allowances and proceeds of transactions involving CAIR \(\text{NO}_x\) Ozone Season allowances will be deemed to be held or distributed in accordance with the contract.''

(5) The signature of the CAIR designated representative and any alternate CAIR designated representative and the dates signed.

(b) Unless otherwise required by the permitting authority or the Administrator, documents of agreement referred to in the certificate of representation shall not be submitted to the permitting authority or the Administrator. Neither the permitting authority nor the Administrator shall be under any obligation to review or evaluate the sufficiency of such documents, if submitted.

§ 97.314 Objections concerning CAIR designated representative.

(a) Once a complete certificate of representation under §97.313 has been submitted and received, the permitting authority and the Administrator will rely on the certificate of representation unless and until a superseding complete certificate of representation under §97.313 is received by the Administrator.

(b) Except as provided in §97.312(a) or (b), no objection or other communication submitted to the permitting authority or the Administrator concerning the authorization, or any representation, action, inaction, or submission, of the CAIR designated representative shall affect any representation, action, inaction, or submission of the CAIR designated representative or the finality of any decision or order by the permitting authority or the Administrator under the CAIR \(\text{NO}_x\) Ozone Season Trading Program.

(c) Neither the permitting authority nor the Administrator will adjudicate any private legal dispute concerning the authorization or any representation, action, inaction, or submission of any CAIR designated representative, including private legal disputes concerning the proceeds of CAIR \(\text{NO}_x\) Ozone Season allowance transfers.

§ 97.315 Delegation by CAIR designated representative and alternate CAIR designated representative.

(a) A CAIR designated representative may delegate, to one or more natural persons, his or her authority to make an electronic submission to the Administrator provided for or required under this part.

(b) An alternate CAIR designated representative may delegate, to one or more natural persons, his or her authority to make an electronic submission to the Administrator provided for or required under this part.

(c) In order to delegate authority to make an electronic submission to the Administrator, in a format prescribed by the Administrator, a notice of delegation, in a format prescribed by the Administrator, that includes the following elements:

(1) The name, address, e-mail address, telephone number, and facsimile transmission number (if any) of each such natural person (referred to as an "agent");

(2) For each such natural person, a list of the type or types of electronic submissions under paragraph (a) or (b) of this section for which authority is delegated to him or her; and

(4) The following certification statements by such CAIR designated representative or alternate CAIR designated representative:

(i) "I agree that any electronic submission to the Administrator that is by an agent identified in this notice of delegation and of a type listed for such agent in this notice of delegation and that is made when I am a CAIR designated representative or alternate..."
CAIR designated representative, as appropriate, and before this notice of delegation is superseded by another notice of delegation under 40 CFR 97.315(d) shall be deemed to be an electronic submission by me."

(ii) "Until this notice of delegation is superseded by another notice of delegation under 40 CFR 97.315(d), I agree to maintain an e-mail account and to notify the Administrator immediately of any change in my e-mail address unless all delegation of authority by me under 40 CFR 97.315 is terminated."

(d) A notice of delegation submitted under paragraph (c) of this section shall be effective, with regard to the CAIR designated representative or alternate CAIR designated representative identified in such notice, upon receipt of such notice by the Administrator and until receipt by the Administrator of a superseding notice of delegation submitted by such CAIR designated representative or alternate CAIR designated representative. The superseding notice of delegation may replace any previously identified agent, add a new agent, or eliminate entirely any delegation of authority.

(e) Any electronic submission covered by the certification in paragraph (c)(4)(i) of this section and made in accordance with a notice of delegation effective under paragraph (d) of this section shall be deemed to be an electronic submission by the CAIR designated representative or alternate CAIR designated representative submitting such notice of delegation.

Subpart CCCC—Permits

§ 97.320 General CAIR NO
X Ozone Season Trading Program permit requirements.

(a) For each CAIR NO
X Ozone Season source required to have a title V operating permit or required, under subpart III of this part, to have a title V operating permit or other federally enforceable permit, such permit shall include a CAIR permit administered by the permitting authority for the title V operating permit or the federally enforceable permit as applicable. The CAIR portion of the title V permit or other federally enforceable permit as applicable shall be administered in accordance with the permitting authority’s title V operating permits regulations promulgated under part 70 or 71 of this chapter or the permitting authority’s regulations for other federally enforceable permits as applicable, except as provided otherwise by § 97.365, this subpart, and subpart III of this part.

(b) Each CAIR permit shall contain, with regard to the CAIR NO
X Ozone Season source and the CAIR NO
X Ozone Season units at the source covered by the CAIR permit, all applicable CAIR NO
X Ozone Season Trading Program, CAIR NO
X Annual Trading Program, and CAIR SO
2 Trading Program requirements and shall be a complete and separable portion of the title V operating permit or other federally enforceable permit under paragraph (a) of this section.

§ 97.321 Submission of CAIR permit applications.

(a) Duty to apply. The CAIR designated representative of any CAIR NO
X Ozone Season source required to have a title V operating permit shall submit to the permitting authority a complete CAIR permit application under § 97.322 for the source covering each CAIR NO
X Ozone Season unit at the source at least 18 months (or such lesser time provided by the permitting authority) before the later of January 1, 2009 or the date on which the CAIR NO
X Ozone Season unit commences commercial operation, except as provided in § 97.383(a).

(b) Duty to reapply. For a CAIR NO
X Ozone Season source required to have a title V operating permit, the CAIR designated representative shall submit a complete CAIR permit application under § 97.322 for the source covering each CAIR NO
X Ozone Season unit at the source to renew the CAIR permit in accordance with the permitting authority’s title V operating permits regulations addressing permit renewal, except as provided in § 97.383(b).

§ 97.322 Information requirements for CAIR permit applications.

A complete CAIR permit application shall include the following elements concerning the CAIR NO
X Ozone Season source for which the application is
Environmental Protection Agency § 97.341

submitted, in a format prescribed by the permitting authority:
(a) Identification of the CAIR NOx Ozone Season source;
(b) Identification of each CAIR NOx Ozone Season unit at the CAIR NOx Ozone Season source; and
(c) The standard requirements under § 97.306.

§ 97.323 CAIR permit contents and term.
(a) Each CAIR permit will contain, in a format prescribed by the permitting authority, all elements required for a complete CAIR permit application under §97.322.
(b) Each CAIR permit is deemed to incorporate automatically the definitions of terms under §97.302 and, upon recordation by the Administrator under subpart EEEE, FFFF, GGGG, or IIII of this part, every allocation, transfer, or deduction of a CAIR NOx Ozone Season allowance to or from the compliance account of the CAIR NOx Ozone Season source covered by the permit.
(c) The term of the CAIR permit will be set by the permitting authority, as necessary to facilitate coordination of the renewal of the CAIR permit with issuance, revision, or renewal of the CAIR NOx Ozone Season source’s title V operating permit or other federally enforceable permit as applicable.

§ 97.324 CAIR permit revisions.
Except as provided in §97.323(b), the permitting authority will revise the CAIR permit, as necessary, in accordance with the permitting authority’s title V operating permits regulations or the permitting authority’s regulations for other federally enforceable permits as applicable addressing permit revisions.

Subpart DDDD [Reserved]

Subpart EEEE—CAIR NOx Ozone Season Allowance Allocations
§ 97.340 State trading budgets.
(a) Except as provided in paragraph (b) of this section, the State trading budgets for annual allocations of CAIR NOx Ozone Season allowances for the control periods in 2009 through 2014 and in 2015 and thereafter are respectively as follows:

<table>
<thead>
<tr>
<th>State</th>
<th>State trading budget for 2009-2014 (tons)</th>
<th>State trading budget for 2015 and thereafter (tons)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Alabama</td>
<td>32,182</td>
<td>26,818</td>
</tr>
<tr>
<td>Arkansas</td>
<td>11,515</td>
<td>9,597</td>
</tr>
<tr>
<td>Connecticut</td>
<td>2,569</td>
<td>2,569</td>
</tr>
<tr>
<td>Delaware</td>
<td>2,226</td>
<td>1,855</td>
</tr>
<tr>
<td>District of Columbia</td>
<td>112</td>
<td>94</td>
</tr>
<tr>
<td>Florida</td>
<td>47,912</td>
<td>39,926</td>
</tr>
<tr>
<td>Illinois</td>
<td>30,701</td>
<td>28,981</td>
</tr>
<tr>
<td>Indiana</td>
<td>45,952</td>
<td>39,273</td>
</tr>
<tr>
<td>Iowa</td>
<td>14,236</td>
<td>11,886</td>
</tr>
<tr>
<td>Kentucky</td>
<td>36,045</td>
<td>30,587</td>
</tr>
<tr>
<td>Louisiana</td>
<td>17,085</td>
<td>14,238</td>
</tr>
<tr>
<td>Maryland</td>
<td>12,834</td>
<td>10,695</td>
</tr>
<tr>
<td>Massachusetts</td>
<td>7,551</td>
<td>6,293</td>
</tr>
<tr>
<td>Michigan</td>
<td>28,971</td>
<td>24,142</td>
</tr>
<tr>
<td>Mississippi</td>
<td>8,714</td>
<td>7,262</td>
</tr>
<tr>
<td>Missouri</td>
<td>26,678</td>
<td>22,231</td>
</tr>
<tr>
<td>New Jersey</td>
<td>6,654</td>
<td>5,545</td>
</tr>
<tr>
<td>New York</td>
<td>20,632</td>
<td>17,193</td>
</tr>
<tr>
<td>North Carolina</td>
<td>28,392</td>
<td>23,660</td>
</tr>
<tr>
<td>Ohio</td>
<td>45,664</td>
<td>39,945</td>
</tr>
<tr>
<td>Pennsylvania</td>
<td>42,171</td>
<td>35,143</td>
</tr>
<tr>
<td>South Carolina</td>
<td>15,249</td>
<td>12,707</td>
</tr>
<tr>
<td>Tennessee</td>
<td>22,842</td>
<td>19,035</td>
</tr>
<tr>
<td>Virginia</td>
<td>15,994</td>
<td>13,328</td>
</tr>
<tr>
<td>West Virginia</td>
<td>26,859</td>
<td>26,625</td>
</tr>
<tr>
<td>Wisconsin</td>
<td>17,997</td>
<td>14,989</td>
</tr>
</tbody>
</table>

(b) Upon approval by the Administrator of a State’s State implementation plan revision under §51.123(ee)(1) of this chapter providing for the inclusion in the CAIR NOx Ozone Season Trading Program of all units that are not otherwise CAIR NOx Ozone Season units under §97.304(a) and (b) and that are NOx Budget units covered by the State’s emissions trading program approved under §51.121(p), the amount in the State trading budget for a control period in a calendar year will be the sum of the amount set forth for the State and for the year in paragraph (a) of this section and the amount of additional CAIR NOx Ozone Season allowance allocations issued under §51.123(ee)(1)(ii)(A) of this chapter for the year.

§ 97.341 Timing requirements for CAIR NOx Ozone Season allowance allocations.
(a) The Administrator will determine by order the CAIR NOx Ozone Season allowance allocations, in accordance with §97.342(a) and (b), for the control periods in 2009, 2010, 2011, 2012, 2013, and 2014.
§ 97.342 CAIR NOX Ozone Season allowance allocations.

(a)(1) The baseline heat input (in mmBtu) used with respect to CAIR NOX Ozone Season allowance allocations under paragraph (b) of this section for each CAIR NOX Ozone Season unit will be:

(i) For units commencing operation before January 1, 2001, the average of the 3 highest amounts of the unit’s adjusted control period heat input for 2000 through 2004, with the adjusted control period heat input for each year calculated as follows:

(A) If the unit is coal-fired during the year, the unit’s control period heat input for such year is multiplied by 100 percent;

(B) If the unit is oil-fired during the year, the unit’s control period heat input for such year is multiplied by 60 percent; and

(C) If the unit is not subject to paragraph (a)(1)(i)(A) or (B) of this section, the unit’s control period heat input for such year is multiplied by 40 percent.

(ii) For units commencing operation on or after January 1, 2001 and operating each calendar year during a period of 5 or more consecutive calendar years, the average of the 3 highest amounts of the unit’s total converted control period heat input over the first such 5 years.

(2)(i) A unit’s control period heat input, and a unit’s status as coal-fired or oil-fired, for a calendar year under paragraph (a)(1)(i) of this section, and a unit’s total tons of NOX emissions during a control period in a calendar year under paragraph (c)(3) of this section, will be determined in accordance with §97.342. Based on any such objections, the Administrator will adjust each determination to the extent necessary to ensure that it is in accordance with §97.342.

(ii) A unit’s converted control period heat input for a calendar year specified under paragraph (a)(1)(ii) of this section equals:

(A) Except as provided in paragraph (a)(2)(ii)(B) or (C) of this section, the control period gross electrical output of the generator or generators served by the unit multiplied by 7,900 Btu/kWh, if the unit is coal-fired for the year, or 6,675 Btu/kWh, if the unit is not coal-fired for the year, and divided by 1,000,000 Btu/mmBtu, provided that if a generator is served by 2 or more units, then the gross electrical output of the generator will be attributed to each unit in proportion to the unit’s share of the total control period heat input of such units for the year;

(B) For a unit that is a boiler and has equipment used to produce electricity and useful thermal energy for industrial, commercial, heating, or cooling purposes through the sequential use of energy, the total heat energy (in Btu) of the steam produced by the boiler during the control period, divided by 0.8 and by 1,000,000 Btu/mmBtu; or

(C) For a unit that is a combustion turbine and has equipment used to produce electricity and useful thermal
energy for industrial, commercial, heating, or cooling purposes through the sequential use of energy, the control period gross electrical output of the enclosed device comprising the compressor, combustor, and turbine multiplied by 3,413 Btu/kWh, plus the total heat energy (in Btu) of the steam produced by any associated heat recovery steam generator during the control period divided by 0.8, and with the sum divided by 1,000,000 Btu/mmBtu.

(iii) Gross electrical output and total heat energy under paragraph (a)(2)(ii) of this section will be determined based on the best available data reported to the Administrator for the unit (in a format prescribed by the Administrator).

(3) The Administrator will determine what data are the best available data under paragraph (a)(2) of this section by weighing the likelihood that data are accurate and reliable and giving greater weight to data submitted to a governmental entity in compliance with legal requirements or substantiated by an independent entity.

(b)(1) For each control period in 2009 and thereafter, the Administrator will allocate to all CAIR NO\textsubscript{X} Ozone Season units in a State that have a baseline heat input (as determined under paragraph (a) of this section) a total amount of CAIR NO\textsubscript{X} Ozone Season allowances equal to 95 percent for a control period during 2009 through 2014, and 97 percent for a control period during 2015 and thereafter, of the tons of NO\textsubscript{X} emissions in the applicable State trading budget under §97.340 (except as provided in paragraphs (d) and (e) of this section).

(2) The Administrator will allocate CAIR NO\textsubscript{X} Ozone Season allowances to each CAIR NO\textsubscript{X} Ozone Season unit under paragraph (b)(1) of this section in an amount determined by multiplying the total amount of CAIR NO\textsubscript{X} Ozone Season allowances allocated under paragraph (b)(1) of this section by the ratio of the baseline heat input of such CAIR NO\textsubscript{X} Ozone Season unit to the total amount of baseline heat input of all such CAIR NO\textsubscript{X} Ozone Season units in the State and rounding to the nearest whole allowance as appropriate.

(c) For each control period in 2009 and thereafter, the Administrator will allocate CAIR NO\textsubscript{X} Ozone Season allowances to CAIR NO\textsubscript{X} Ozone Season units in a State that are not allocated CAIR NO\textsubscript{X} Ozone Season allowances under paragraph (b) of this section because the units do not yet have a baseline heat input under paragraph (a) of this section or because the units have a baseline heat input but all CAIR NO\textsubscript{X} Ozone Season allowances available under paragraph (b) of this section for the control period are already allocated, in accordance with the following procedures:

(1) The Administrator will establish a separate new unit set-aside for each control period. Each new unit set-aside will be allocated CAIR NO\textsubscript{X} Ozone Season allowances equal to 5 percent for a control period in 2009 through 2014, and 3 percent for a control period in 2015 and thereafter, of the amount of tons of NO\textsubscript{X} emissions in the applicable State trading budget under §97.340.

(2) The CAIR designated representative of such a CAIR NO\textsubscript{X} Ozone Season unit may submit to the Administrator a request, in a format specified by the Administrator, to be allocated CAIR NO\textsubscript{X} Ozone Season allowances, starting with the later of the control period in 2009 or the first control period after the control period in which the CAIR NO\textsubscript{X} Ozone Season unit commences commercial operation and until the first control period for which the unit is allocated CAIR NO\textsubscript{X} Ozone Season allowances under paragraph (b) of this section. A separate CAIR NO\textsubscript{X} Ozone Season allowance allocation request for each control period for which CAIR NO\textsubscript{X} Ozone Season allowances are sought must be submitted on or before February 1 before such control period and after the date on which the CAIR NO\textsubscript{X} Ozone Season unit commences commercial operation.

(3) In a CAIR NO\textsubscript{X} Ozone Season allowance allocation request under paragraph (c)(2) of this section, the CAIR designated representative may request for a control period CAIR NO\textsubscript{X} Ozone Season allowances in an amount not exceeding the CAIR NO\textsubscript{X} Ozone Season unit’s total tons of NO\textsubscript{X} emissions during the control period immediately before such control period.
(4) The Administrator will review each CAIR NOX Ozone Season allowance allocation request under paragraph (c)(2) of this section and will allocate CAIR NOX Ozone Season allowances for each control period pursuant to such request as follows:

(i) The Administrator will accept an allowance allocation request only if the request meets, or is adjusted by the Administrator as necessary to meet, the requirements of paragraphs (c)(2) and (3) of this section.

(ii) On or after February 1 before the control period, the Administrator will determine the sum of the CAIR NOX Ozone Season allowances requested (as adjusted under paragraph (c)(4)(i) of this section) in all allowance allocation requests accepted under paragraph (c)(4)(i) of this section for the control period.

(iii) If the amount of CAIR NOX Ozone Season allowances in the new unit set-aside for the control period is greater than or equal to the sum under paragraph (c)(4)(ii) of this section, then the Administrator will allocate the amount of CAIR NOX Ozone Season allowances requested (as adjusted under paragraph (c)(4)(i) of this section) to each CAIR NOX Ozone Season unit covered by an allowance allocation request accepted under paragraph (c)(4)(i) of this section.

(iv) If the amount of CAIR NOX Ozone Season allowances in the new unit set-aside for the control period is less than the sum under paragraph (c)(4)(ii) of this section, then the Administrator will allocate to each CAIR NOX Ozone Season unit covered by an allowance allocation request accepted under paragraph (c)(4)(i) of this section the amount of the CAIR NOX Ozone Season allowances requested (as adjusted under paragraph (c)(4)(i) of this section), multiplied by the amount of CAIR NOX Ozone Season allowances in the new unit set-aside for the control period, divided by the sum determined under paragraph (c)(4)(ii) of this section, and rounded to the nearest whole allowance as appropriate.

(v) The Administrator will notify each CAIR designated representative that submitted an allowance allocation request of the amount of CAIR NOX Ozone Season allowances (if any) allocated for the control period to the CAIR NOX Ozone Season unit covered by the request.

(d) If, after completion of the procedures under paragraph (c)(4) of this section for a control period, any unallocated CAIR NOX Ozone Season allowances remain in the new unit set-aside under paragraph (c) of this section for a State for the control period, the Administrator will allocate to each CAIR NOX Ozone Season unit that was allocated CAIR NOX Ozone Season allowances under paragraph (b) of this section in the State an amount of CAIR NOX Ozone Season allowances equal to the total amount of such remaining unallocated CAIR NOX Ozone Season allowances, multiplied by the unit’s allocation under paragraph (b) of this section, divided by 85 percent for a control period during 2009 through 2014, and 97 percent for a control period during 2015 and thereafter, of the amount of tons of NOX emissions in the applicable State trading budget under §97.340, and rounded to the nearest whole allowance as appropriate.

(e) If the Administrator determines that CAIR NOX Ozone Season allowances were allocated under paragraphs (a) and (b) of this section, paragraphs (a) and (c) of this section, or paragraph (d) of this section for a control period and that the recipient of the allocation is not actually a CAIR NOX Ozone Season unit under §97.304 in such control period, then the Administrator will notify the CAIR designated representative and will act in accordance with the following procedures:

(1) Except as provided in paragraph (e)(2) or (3) of this section, the Administrator will not record such CAIR NOX Ozone Season allowances under §97.353.

(2) If the Administrator already recorded such CAIR NOX Ozone Season allowances under §97.353 and if the Administrator makes such determinations before making deductions for the source that includes such recipient under §97.354(b) for the control period, then the Administrator will deduct from the account in which such CAIR NOX Ozone Season allowances were recorded under §97.353 an amount of CAIR NOX Ozone Season allowances allocated for the same or a prior control
§ 97.351 Establishment of accounts.

(a) Compliance accounts. Except as provided in §97.384(e), upon receipt of a complete certificate of representation under §97.313, the Administrator will establish a compliance account for the CAIR NO\textsubscript{X} Ozone Season source for the purpose of holding and transferring CAIR NO\textsubscript{X} Ozone Season allowances.

(b) General accounts—(1) Application for general account. (i) Any person may apply to open a general account for the purpose of holding and transferring CAIR NO\textsubscript{X} Ozone Season allowances.

Appendix A to Subpart EEEE of Part 97—States With Approved State Implementation Plan Revisions Concerning Allocations

The following States have State Implementation Plan revisions under §51.123(ee)(2) of this chapter approved by the Administrator and providing for allocation of CAIR NO\textsubscript{X} Ozone Season allowances by the permitting authority under §97.343(a):

- Indiana
- Louisiana
- Michigan
- New Jersey
- North Carolina
- Ohio
- South Carolina
- Tennessee
- West Virginia (for control periods 2009–2014)
- Wisconsin

one and only one alternate CAIR authorized account representative who may act on behalf of the CAIR authorized account representative. The agreement by which the alternate CAIR authorized account representative is selected shall include a procedure for authorizing the alternate CAIR authorized account representative to act in lieu of the CAIR authorized account representative.

(ii) A complete application for a general account shall be submitted to the Administrator and shall include the following elements in a format prescribed by the Administrator:

(A) Name, mailing address, e-mail address (if any), telephone number, and facsimile transmission number (if any) of the CAIR authorized account representative and any alternate CAIR authorized account representative;

(B) Organization name and type of organization, if applicable;

(C) A list of all persons subject to a binding agreement for the CAIR authorized account representative and any alternate CAIR authorized account representative to represent their ownership interest with respect to CAIR NO\textsubscript{X} Ozone Season allowances held in the general account;

(D) The following certification statement by the CAIR authorized account representative and any alternate CAIR authorized account representative: “I certify that I was selected as the CAIR authorized account representative or the alternate CAIR authorized account representative, as applicable, by an agreement that is binding on all persons who have an ownership interest with respect to CAIR NO\textsubscript{X} Ozone Season allowances held in the general account;

(E) The following certification statement by the CAIR authorized account representative and any alternate CAIR authorized account representative: “I certify that I have all the necessary authority to carry out my duties and responsibilities under the CAIR NO\textsubscript{X} Ozone Season Trading Program on behalf of such persons and that each such person shall be fully bound by my representations, actions, inactions, or submissions and by any order or decision issued to me by the Administrator or a court regarding the general account.’’

(E) The signature of the CAIR authorized account representative and any alternate CAIR authorized account representative and the dates signed.

(iii) Unless otherwise required by the permitting authority or the Administrator, documents of agreement referred to in the application for a general account shall not be submitted to the permitting authority or the Administrator. Neither the permitting authority nor the Administrator shall be under any obligation to review or evaluate the sufficiency of such documents, if submitted.

(2) Authorization of CAIR authorized account representative and alternate CAIR authorized account representative.

(i) Upon receipt by the Administrator of a complete application for a general account under paragraph (b)(1) of this section:

(A) The Administrator will establish a general account for the person or persons for whom the application is submitted.

(B) The CAIR authorized account representative and any alternate CAIR authorized account representative for the general account shall represent and, by his or her representations, actions, inactions, or submissions, legally bind each person who has an ownership interest with respect to CAIR NO\textsubscript{X} Ozone Season allowances held in the general account in all matters pertaining to the CAIR NO\textsubscript{X} Ozone Season Trading Program, notwithstanding any agreement between the CAIR authorized account representative or any alternate CAIR authorized account representative and such person. Any such person shall be bound by any order or decision issued to the CAIR authorized account representative or any alternate CAIR authorized account representative by the Administrator or a court regarding the general account.

(C) Any representation, action, inaction, or submission by any alternate CAIR authorized account representative shall be deemed to be a representation, action, inaction, or submission by the CAIR authorized account representative.
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held in the general account. Each such submission shall include the following certification statement by the CAIR authorized account representative or any alternate CAIR authorized account representative: “I am authorized to make this submission on behalf of the persons having an ownership interest with respect to the CAIR NO\textsubscript{X} Ozone Season allowances held in the general account. I certify under penalty of law that I have personally examined, and am familiar with, the statements and information submitted in this document and all its attachments. Based on my inquiry of those individuals with primary responsibility for obtaining the information, I certify that the statements and information are to the best of my knowledge and belief true, accurate, and complete. I am aware that there are significant penalties for submitting false statements and information or omitting required statements and information, including the possibility of fine or imprisonment.”

(iii) The Administrator will accept or act on a submission concerning the general account only if the submission has been made, signed, and certified in accordance with paragraph (b)(2)(ii) of this section.

(3) Changing CAIR authorized account representative and alternate CAIR authorized account representative; changes in persons with ownership interest. (i) The CAIR authorized account representative for a general account may be changed at any time upon receipt by the Administrator of a superseding complete application for a general account under paragraph (b)(1) of this section. Notwithstanding any such change, all representations, actions, inactions, and submissions by the previous CAIR authorized account representative before the time and date when the Administrator receives the superseding application for a general account shall be binding on the new CAIR authorized account representative and the persons with an ownership interest with respect to the CAIR NO\textsubscript{X} Ozone Season allowances in the general account.

(iii)(A) In the event a person having an ownership interest with respect to CAIR NO\textsubscript{X} Ozone Season allowances in the general account is not included in the list of such persons in the application for a general account, such person shall be deemed to be subject to and bound by the application for a general account, the representation, actions, inactions, and submissions of the CAIR authorized account representative and any alternate CAIR authorized account representative of the account, and the decisions and orders of the Administrator or a court, as if the person were included in such list.

(B) Within 30 days following any change in the persons having an ownership interest with respect to CAIR NO\textsubscript{X} Ozone Season allowances in the general account, including the addition of a new person, the CAIR authorized account representative or any alternate CAIR authorized account representative shall submit a revision to the application for a general account amending the list of persons having an ownership interest with respect to the CAIR NO\textsubscript{X} Ozone Season allowances in the general account to include the change.

(4) Objections concerning CAIR authorized account representative and alternate CAIR authorized account representative. (i) Once a complete application for a general account under paragraph (b)(1) of this section has been submitted and received, the Administrator will rely on the application unless and until a superseding complete application for a general account under paragraph (b)(1) of this section is received by the Administrator.
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(ii) Except as provided in paragraph (b)(3)(i) or (ii) of this section, no objection or other communication submitted to the Administrator concerning the authorization, or any representation, action, inaction, or submission of the CAIR authorized account representative or any alternate CAIR authorized account representative for a general account shall affect any representation, action, inaction, or submission of the CAIR authorized account representative or any alternate CAIR authorized account representative or the finality of any decision or order by the Administrator under the CAIR NOX Ozone Season Trading Program.

(iii) The Administrator will not adjudicate any private legal dispute concerning the authorization or any representation, action, inaction, or submission of the CAIR authorized account representative or any alternate CAIR authorized account representative for a general account, including private legal disputes concerning the proceeds of CAIR NOX Ozone Season allowance transfers.

(5) Delegation by CAIR authorized account representative and alternate CAIR authorized account representative. (i) A CAIR authorized account representative may delegate, to one or more natural persons, his or her authority to make an electronic submission to the Administrator provided for or required under subparts FFFF and GGGG of this part.

(ii) An alternate CAIR authorized account representative may delegate, to one or more natural persons, his or her authority to make an electronic submission to the Administrator provided for or required under subparts FFFF and GGGG of this part.

(iii) In order to delegate authority to make an electronic submission to the Administrator in accordance with paragraph (b)(5)(i) or (ii) of this section, the CAIR authorized account representative or alternate CAIR authorized account representative, as appropriate, must submit to the Administrator a notice of delegation, in a format prescribed by the Administrator, that includes the following elements:

(A) The name, address, e-mail address, telephone number, and facsimile transmission number (if any) of such CAIR authorized account representative or alternate CAIR authorized account representative;

(B) The name, address, e-mail address, telephone number, and facsimile transmission number (if any) of each such natural person (referred to as an "agent");

(C) For each such natural person, a list of the type or types of electronic submissions under paragraph (b)(5)(i) or (ii) of this section for which authority is delegated to him or her;

(D) The following certification statement by such CAIR authorized account representative or alternate CAIR authorized account representative: "I agree that any electronic submission to the Administrator that is by an agent identified in this notice of delegation and of a type listed for such agent in this notice of delegation and that is made when I am a CAIR authorized account representative or alternate CAIR authorized representative, as appropriate, and before this notice of delegation is superseded by another notice of delegation under 40 CFR 97.351(b)(5)(iv) shall be deemed to be an electronic submission by me.");

(E) The following certification statement by such CAIR authorized account representative or alternate CAIR authorized account representative: Until this notice of delegation is superseded by another notice of delegation under 40 CFR 97.351(b)(5)(iv), I agree to maintain an e-mail account and to notify the Administrator immediately of any change in my e-mail address unless all delegation of authority by me under 40 CFR 97.351(b)(5) is terminated.

(iv) A notice of delegation submitted under paragraph (b)(5)(iii) of this section shall be effective, with regard to the CAIR authorized account representative or alternate CAIR authorized account representative identified in such notice, upon receipt of such notice by the Administrator and until receipt by the Administrator of a superseding notice of delegation submitted by such CAIR authorized account representative or alternate CAIR authorized account representative, as appropriate. The superseding notice of delegation may replace any previously identified agent, add a new agent, or
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eliminate entirely any delegation of authority.

(v) Any electronic submission covered by the certification in paragraph (b)(5)(iii)(D) of this section and made in accordance with a notice of delegation effective under paragraph (b)(5)(iv) of this section shall be deemed to be an electronic submission by the CAIR designated representative or alternate CAIR designated representative submitting such notice of delegation.

(c) Account identification. The Administrator will assign a unique identifying number to each account established under paragraph (a) or (b) of this section.

§ 97.352 Responsibilities of CAIR authorized account representative.

Following the establishment of a CAIR NOx Ozone Season Allowance Tracking System account, all submissions to the Administrator pertaining to the account, including, but not limited to, submissions concerning the deduction or transfer of CAIR NOx Ozone Season allowances in the account, shall be made only by the CAIR authorized account representative for the account.

§ 97.353 Recordation of CAIR NOx Ozone Season allowance allocations.

(a) By September 30, 2007, the Administrator will record in the CAIR NOx Ozone Season sources compliance account the CAIR NOx Ozone Season allowances allocated for the CAIR NOx Ozone Season units at the source in accordance with §97.342(a) and (b) for the control period in 2009.

(b) By September 30, 2006, the Administrator will record in the CAIR NOx Ozone Season source’s compliance account the CAIR NOx Ozone Season allowances allocated for the CAIR NOx Ozone Season units at the source in accordance with §97.342(a) and (b) for the control period in 2010.

(c) By September 30, 2009, the Administrator will record in the CAIR NOx Ozone Season source’s compliance account the CAIR Ozone Season NOx allowances allocated for the CAIR NOx Ozone Season units at the source in accordance with §97.342(a) and (b) for the control periods in 2011, 2012, and 2013.

(d) By December 1, 2010 and December 1 of each year thereafter, the Administrator will record in the CAIR NOx Ozone Season source’s compliance account the CAIR NOx Ozone Season allowances allocated for the CAIR NOx Ozone Season units at the source in accordance with §97.342(a) and (b) for the control period in the fourth year after the year of the applicable deadline for recordation under this paragraph.

(e) By September 1, 2009 and September 1 of each year thereafter, the Administrator will assign a unique identification number to each CAIR NOx Ozone Season allowance allocated for the CAIR NOx Ozone Season units at the source in accordance with §97.342(a) and (c) for the control period in the year of the applicable deadline for recordation under this paragraph.

(f) Serial numbers for allocated CAIR NOx Ozone Season allowances. When recording the allocation of CAIR NOx Ozone Season allowances for a CAIR NOx Ozone Season unit in a compliance account, the Administrator will assign each CAIR NOx Ozone Season allowance a unique identification number that will include digits identifying the year of the control period for which the CAIR NOx Ozone Season allowance is allocated.

§ 97.354 Compliance with CAIR NOx emissions limitation.

(a) Allowance transfer deadline. The CAIR NOx Ozone Season allowances are available to be deducted for compliance with a source’s CAIR NOx Ozone Season emissions limitation for a control period in a given calendar year only if the CAIR NOx Ozone Season allowances:

(1) Were allocated for the control period in the year or a prior year; and

(2) Are held in the compliance account as of the allowance transfer deadline for the control period or are transferred into the compliance account by a CAIR NOx Ozone Season allowance transfer correctly submitted for recordation under §§97.360 and 97.361 by the allowance transfer deadline for the control period.

(b) Deductions for compliance. Following the recordation, in accordance with §97.361, of CAIR NOx Ozone Season
allowance transfers submitted for recordation in a source’s compliance account by the allowance transfer deadline for a control period, the Administrator will deduct from the compliance account CAIR NOX Ozone Season allowances available under paragraph (a) of this section in order to determine whether the source meets the CAIR NOX Ozone Season emissions limitation for the control period, as follows:

(1) Until the amount of CAIR NOX Ozone Season allowances deducted equals the number of tons of total nitrogen oxides emissions, determined in accordance with subpart HHHH of this part, from all CAIR NOX Ozone Season units at the source for the control period; or

(2) If there are insufficient CAIR NOX Ozone Season allowances to complete the deductions in paragraph (b)(1) of this section, until no more CAIR NOX Ozone Season allowances available under paragraph (a) of this section remain in the compliance account.

(c)(1) Identification of CAIR NOX Ozone Season allowances by serial number. The CAIR authorized account representative for a source’s compliance account may request that specific CAIR NOX Ozone Season allowances, identified by serial number, in the compliance account be deducted for emissions or excess emissions for a control period in accordance with paragraph (b) or (d) of this section. Such request shall be submitted to the Administrator by the allowance transfer deadline for the control period and include, in a format prescribed by the Administrator, the identification of the CAIR NOX Ozone Season source and the appropriate serial numbers.

(2) First-in, first-out. The Administrator will deduct CAIR NOX Ozone Season allowances under paragraph (b) or (d) of this section from the source’s compliance account, in the absence of an identification or in the case of a partial identification of CAIR NOX Ozone Season allowances by serial number under paragraph (c)(1) of this section, on a first-in, first-out (FIFO) accounting basis in the following order:

(i) Any CAIR NOX Ozone Season allowances that were allocated to the units at the source, in the order of recordation; and then

(ii) Any CAIR NOX Ozone Season allowances that were allocated to any entity and transferred and recorded in the compliance account pursuant to subpart GGGG of this part, in the order of recordation.

(d) Deductions for excess emissions. (1) After making the deductions for compliance under paragraph (b) of this section for a control period in a calendar year in which the CAIR NOX Ozone Season source has excess emissions, the Administrator will deduct from the source’s compliance account an amount of CAIR NOX Ozone Season allowances, allocated for the control period in the immediately following calendar year, equal to 3 times the number of tons of the source’s excess emissions.

(2) Any allowance deduction required under paragraph (d)(1) of this section shall not affect the liability of the owners and operators of the CAIR NOX Ozone Season source or the CAIR NOX Ozone Season units at the source for any fine, penalty, or assessment, or their obligation to comply with any other remedy, for the same violations, as ordered under the Clean Air Act or applicable State law.

(e) Recordation of deductions. The Administrator will record in the appropriate compliance account all deductions from such an account under paragraphs (b) and (d) of this section and subpart III.

(f) Administrator’s action on submissions. (1) The Administrator may review and conduct independent audits concerning any submission under the CAIR NOX Ozone Season Trading Program and make appropriate adjustments of the information in the submissions.

(2) The Administrator may deduct CAIR NOX Ozone Season allowances from or transfer CAIR NOX Ozone Season allowances to a source’s compliance account based on the information in the submissions, as adjusted under paragraph (f)(1) of this section, and record such deductions and transfers.

§ 97.355 Banking.

(a) CAIR NOX Ozone Season allowances may be banked for future use or transfer in a compliance account or a
general account in accordance with paragraph (b) of this section.

(b) Any CAIR NOX Ozone Season allowance that is held in a compliance account or a general account will remain in such account unless and until the CAIR NOX Ozone Season allowance is deducted or transferred under §97.342, §97.354, §97.356, or subpart GGGG or IIII of this part.

§ 97.356 Account error.

The Administrator may, at his or her sole discretion and on his or her own motion, correct any error in any CAIR NOX Ozone Season Allowance Tracking System account. Within 10 business days of making such correction, the Administrator will notify the CAIR authorized account representative for the account.

§ 97.357 Closing of general accounts.

(a) The CAIR authorized account representative of a general account may submit to the Administrator a request to close the account, which shall include a correctly submitted allowance transfer under §§97.360 and 97.361 for any CAIR NOX Ozone Season allowances in the account to one or more other CAIR NOX Ozone Season Allowance Tracking System accounts.

(b) If a general account has no allowance transfers in or out of the account for a 12-month period or longer and does not contain any CAIR NOX Ozone Season allowances, the Administrator may notify the CAIR authorized account representative for the account that the account will be closed following 20 business days after the notice is sent. The account will be closed after the 20-day period unless, before the end of the 20-day period, the Administrator receives a correctly submitted transfer of CAIR NOX Ozone Season allowances into the account under §§97.360 and 97.361 or a statement submitted by the CAIR authorized account representative demonstrating to the satisfaction of the Administrator good cause as to why the account should not be closed.

Subpart GGGG—CAIR NOX Ozone Season Allowance Transfers

§ 97.360 Submission of CAIR NOX Ozone Season allowance transfers.

A CAIR authorized account representative seeking recording of a CAIR NOX Ozone Season allowance transfer shall submit the transfer to the Administrator. To be considered correctly submitted, the CAIR NOX Ozone Season allowance transfer shall include the following elements, in a format specified by the Administrator:

(a) The account numbers for both the transferor and transferee accounts;

(b) The serial number of each CAIR NOX Ozone Season allowance that is in the transferor account and is to be transferred; and

(c) The name and signature of the CAIR authorized account representative of the transferor account and the date signed.

§ 97.361 EPA recordation.

(a) Within 5 business days (except as provided in paragraph (b) of this section) of receiving a CAIR NOX Ozone Season allowance transfer, the Administrator will record a CAIR NOX Ozone Season allowance transfer by moving each CAIR NOX Ozone Season allowance from the transferor account to the transferee account as specified by the request, provided that:

(1) The transfer is correctly submitted under §97.360; and

(2) The transferor account includes each CAIR NOX Ozone Season allowance identified by serial number in the transfer.

(b) A CAIR NOX Ozone Season allowance transfer that is submitted for recording after the allowance transfer deadline for a control period and that includes any CAIR NOX Ozone Season allowances allocated for any control period before such allowance transfer deadline will not be recorded until after the Administrator completes the deductions under §97.354 for the control period immediately before such allowance transfer deadline.

(c) Where a CAIR NOX Ozone Season allowance transfer submitted for recording fails to meet the requirements
§ 97.362 Notification.

(a) Notification of recordation. Within 5 business days of recordation of a CAIR NO<sub>X</sub> Ozone Season allowance transfer under §97.361, the Administrator will notify the CAIR authorized account representatives of both the transferor and transferee accounts.

(b) Notification of non-recordation. Within 10 business days of receipt of a CAIR NO<sub>X</sub> Ozone Season allowance transfer that fails to meet the requirements of §97.361(a), the Administrator will notify the CAIR authorized account representatives of both accounts subject to the transfer of:

(1) A decision not to record the transfer, and

(2) The reasons for such non-recordation.

(c) Nothing in this section shall preclude the submission of a CAIR NO<sub>X</sub> Ozone Season allowance transfer for recordation following notification of non-recordation.

Subpart HHHH—Monitoring and Reporting

§ 97.370 General requirements.

The owners and operators, and to the extent applicable, the CAIR designated representative, of a CAIR NO<sub>X</sub> Ozone Season unit, shall comply with the monitoring, recordkeeping, and reporting requirements as provided in this subpart and in subpart H of part 75 of this chapter. For purposes of complying with such requirements, the definitions in §97.302 and in §72.2 of this chapter shall apply, and the terms “affected unit,” “designated representative,” and “continuous emission monitoring system” (or “CEMS”) in part 75 of this chapter shall be deemed to refer to the terms “CAIR NO<sub>X</sub> Ozone Season unit,” “CAIR designated representative,” and “continuous emission monitoring system” (or “CEMS”) respectively, as defined in §97.302. The owner or operator of a unit that is not a CAIR NO<sub>X</sub> Ozone Season unit but that is monitored under §75.72(b)(2)(i) of this chapter shall comply with the same monitoring, recordkeeping, and reporting requirements as a CAIR NO<sub>X</sub> Ozone Season unit.

(a) Requirements for installation, certification, and data accounting. The owner or operator of each CAIR NO<sub>X</sub> Ozone Season unit shall:

(1) Install all monitoring systems required under this subpart for monitoring NO<sub>X</sub> mass emissions and individual unit heat input (including all systems required to monitor NO<sub>X</sub> emission rate, NO<sub>X</sub> concentration, stack gas moisture content, stack gas flow rate, CO<sub>2</sub> or O<sub>2</sub> concentration, and fuel flow rate, as applicable, in accordance with §§75.71 and 75.72 of this chapter);

(2) Successfully complete all certification tests required under §97.371 and meet all other requirements of this subpart and part 75 of this chapter applicable to the monitoring systems under paragraph (a)(1) of this section; and

(3) Record, report, and quality-assure the data from the monitoring systems under paragraph (a)(1) of this section.

(b) Compliance deadlines. Except as provided in paragraph (e) of this section, the owner or operator shall meet the monitoring system certification and other requirements of paragraphs (a)(1) and (2) of this section on or before the following dates. The owner or operator shall record, report, and quality-assure the data from the monitoring systems under paragraph (a)(1) of this section on and after the following dates.

(1) For the owner or operator of a CAIR NO<sub>X</sub> Ozone Season unit that commences commercial operation before July 1, 2007, by May 1, 2008.

(2) For the owner or operator of a CAIR NO<sub>X</sub> Ozone Season unit that commences commercial operation on or after July 1, 2007 and that reports on an annual basis under §97.374(d), by the later of the following dates:

(i) 90 unit operating days or 180 calendar days, whichever occurs first, after the date on which the unit commences commercial operation; or

(ii) May 1, 2008.

(3) For the owner or operator of a CAIR NO<sub>X</sub> Ozone Season unit that commences commercial operation on or after July 1, 2007 and that reports on a control period basis under
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§ 97.374(d)(2)(ii), by the later of the following dates:

(i) 90 unit operating days or 180 calendar days, whichever occurs first, after the date on which the unit commences commercial operation; or

(ii) If the compliance date under paragraph (b)(3)(i) of this section is not during a control period, May 1 immediately following the compliance date under paragraph (b)(3)(i) of this section.

(4) For the owner or operator of a CAIR NOₓ Ozone Season unit for which construction of a new stack or flue or installation of add-on NOₓ emission controls is completed after the applicable deadline under paragraph (b)(1), (2), (6), or (7) of this section and that reports on an annual basis under §97.374(d), by 90 unit operating days or 180 calendar days, whichever occurs first, after the date on which emissions first exit to the atmosphere through the new stack or flue or add-on NOₓ emissions controls.

(5) For the owner or operator of a CAIR NOₓ Ozone Season unit for which construction of a new stack or flue or installation of add-on NOₓ emission controls is completed after the applicable deadline under paragraph (b)(1), (3), (6), or (7) of this section and that reports on a control period basis under §97.374(d)(2)(ii), by the later of the following dates:

(i) 90 unit operating days or 180 calendar days, whichever occurs first, after the date on which emissions first exit to the atmosphere through the new stack or flue or add-on NOₓ emissions controls; or

(ii) If the compliance date under paragraph (b)(5)(i) of this section is not during a control period, May 1 immediately following the compliance date under paragraph (b)(5)(i) of this section.

(6) Notwithstanding the dates in paragraphs (b)(1), (2), and (3) of this section, for the owner or operator of a CAIR NOₓ Ozone Season opt-in unit under subpart III of this part, by the date on which the CAIR NOₓ Ozone Season opt-in unit enters the CAIR NOₓ Ozone Season Trading Program as provided in §97.384(g).

(c) Reporting data. The owner or operator of a CAIR NOₓ Ozone Season unit that does not meet the applicable compliance date set forth in paragraph (b) of this section for any monitoring system under paragraph (a)(1) of this section shall, for each such monitoring system, determine, record, and report maximum potential (or, as appropriate, minimum potential) values for NOₓ concentration, NOₓ emission rate, stack gas flow rate, stack gas moisture content, fuel flow rate, and any other parameters required to determine NOₓ mass emissions and heat input in accordance with §75.31(b)(2) or (c)(3) of this chapter, section 2.4 of appendix D to part 75 of this chapter, or section 2.5 of appendix E to part 75 of this chapter, as applicable.

(d) Prohibitions. (1) No owner or operator of a CAIR NOₓ Ozone Season unit shall use any alternative monitoring system, alternative reference method, or any other alternative to any requirement of this subpart without having obtained prior written approval in accordance with §97.375.

(2) No owner or operator of a CAIR NOₓ Ozone Season unit shall operate the unit so as to discharge, or allow to be discharged, NOₓ emissions to the atmosphere without accounting for all such emissions in accordance with the applicable provisions of this subpart and part 75 of this chapter.

(3) No owner or operator of a CAIR NOₓ Ozone Season unit shall disrupt the continuous emission monitoring system, any portion thereof, or any other approved emission monitoring method, and thereby avoid monitoring and recording NOₓ mass emissions discharged into the atmosphere or heat input, except for periods of recertification or periods when calibration, quality assurance testing, or maintenance is performed in accordance with the applicable provisions of this subpart and part 75 of this chapter.

(4) No owner or operator of a CAIR NOₓ Ozone Season unit shall retire or
§ 97.371 Initial certification and recertification procedures.

(a) The owner or operator of a CAIR NOX Ozone Season unit shall be exempt from the initial certification requirements of this section for a monitoring system under §97.370(a)(1) if the following conditions are met:

(1) The monitoring system has been previously certified in accordance with part 75 of this chapter; and

(2) The applicable quality-assurance and quality-control requirements of §75.21 of this chapter and appendix B, appendix D, and appendix E to part 75 of this chapter are fully met for the certified monitoring system described in paragraph (a)(1) of this section.

(b) The recertification provisions of this section shall apply to a monitoring system under §97.370(a)(1) except from initial certification requirements under paragraph (a) of this section.

(c) If the Administrator has previously approved a petition under §75.17(a) or (b) of this chapter for apportioning the NOX emission rate measured in a common stack or a petition under §75.66 of this chapter for an alternative to a requirement in §75.12 or §75.17 of this chapter, the CAIR designated representative shall resubmit the petition to the Administrator under §97.375 to determine whether the approval applies under the CAIR NOX Ozone Season Trading Program.

(d) Except as provided in paragraph (a) of this section, the owner or operator of a CAIR NOX Ozone Season unit shall comply with the following initial certification and recertification procedures for a continuous monitoring system (i.e., a continuous emission monitoring system and an excepted monitoring system under appendices D and E to part 75 of this chapter) under §97.370(a)(1). The owner or operator of a unit that qualifies to use the low mass emissions excepted monitoring methodology under §75.19 of this chapter or that qualifies to use an alternative monitoring system under subpart E of part 75 of this chapter shall comply with the procedures in paragraph (e) or (f) of this section respectively.

(1) Requirements for initial certification. The owner or operator shall ensure that each continuous monitoring system under §97.370(a)(1) (including the automated data acquisition and handling system) successfully completes all of the initial certification testing required under §75.20 of this chapter by the applicable deadline in §97.370(b). In addition, whenever the owner or operator installs a monitoring system to meet the requirements of this subpart in a location where no such monitoring system was previously installed, initial certification in accordance with §75.20 of this chapter is required.

(2) Requirements for recertification. Whenever the owner or operator makes a replacement, modification, or change in any certified continuous emission monitoring system under §97.370(a)(1) that may significantly affect the ability of the system to accurately measure or record NOX mass emissions or heat input rate or to meet the quality-assurance and quality-control requirements of §75.21 of this chapter or appendix B to part 75 of this chapter, the owner or operator shall recertify the monitoring system in accordance with
§ 75.20(b) of this chapter. Furthermore, whenever the owner or operator makes a replacement, modification, or change to the flue gas handling system or the unit’s operation that may significantly change the stack flow or concentration profile, the owner or operator shall recertify each continuous emission monitoring system whose accuracy is potentially affected by the change, in accordance with §75.20(b) of this chapter. Examples of changes to a continuous emission monitoring system that require recertification include: replacement of the analyzer, complete replacement of an existing continuous emission monitoring system, or change in location or orientation of the sampling probe or site. Any fuel flowmeter systems, and any excepted NO\textsubscript{X} monitoring system under appendix E to part 75 of this chapter, under §97.370(a)(1) are subject to the recertification requirements in §75.20(g)(6) of this chapter.

(3) Approval process for initial certification and recertification. Paragraphs (d)(3)(i) through (iv) of this section apply to both initial certification and recertification of a continuous monitoring system under §97.370(a)(1). For recertifications, replace the words “certification” and “initial certification” with the word “recertification”, replace the word “certified” with the word “recertified,” and follow the procedures in §§75.20(b)(5) and (g)(7) of this chapter in lieu of the procedures in paragraph (d)(3)(v) of this section.

(i) Notification of certification. The CAIR designated representative shall submit to the appropriate EPA Regional Office and the Administrator written notice of the dates of certification testing, in accordance with §97.373.

(ii) Certification application. The CAIR designated representative shall submit to the Administrator a certification application for each monitoring system. A complete certification application shall include the information specified in §75.63 of this chapter.

(iii) Provisional certification date. The provisional certification date for a monitoring system shall be determined in accordance with §75.20(a)(3) of this chapter. A provisionally certified monitoring system may be used under the CAIR NO\textsubscript{X} Ozone Season Trading Program for a period not to exceed 120 days after receipt by the Administrator of the complete certification application for the monitoring system under paragraph (d)(3)(ii) of this section. Data measured and recorded by the provisionally certified monitoring system, in accordance with the requirements of part 75 of this chapter, will be considered valid quality-assured data (retroactive to the date and time of provisional certification), provided that the Administrator does not invalidate the provisional certification by issuing a notice of disapproval within 120 days of the date of receipt of the complete certification application by the Administrator.

(iv) Certification application approval process. The Administrator will issue a written notice of approval or disapproval of the certification application to the owner or operator within 120 days of receipt of the complete certification application under paragraph (d)(3)(ii) of this section. In the event the Administrator does not issue such a notice within such 120-day period, each monitoring system that meets the applicable performance requirements of part 75 of this chapter and is included in the certification application will be deemed certified for use under the CAIR NO\textsubscript{X} Ozone Season Trading Program.

(A) Approval notice. If the certification application is complete and shows that each monitoring system meets the applicable performance requirements of part 75 of this chapter, then the Administrator will issue a written notice of approval of the certification application within 120 days of receipt.

(B) Incomplete application notice. If the certification application is not complete, then the Administrator will issue a written notice of incompleteness that sets a reasonable date by which the CAIR designated representative must submit the additional information required to complete the certification application. If the CAIR designated representative does not comply with the notice of incompleteness by the specified date, then the Administrator may issue a notice of disapproval under paragraph (d)(3)(iv)(C)
of this section. The 120-day review period shall not begin before receipt of a complete certification application.

(C) Disapproval notice. If the certification application shows that any monitoring system does not meet the performance requirements of part 75 of this chapter or if the certification application is incomplete and the requirement for disapproval under paragraph (d)(3)(iv)(B) of this section is met, then the Administrator will issue a written notice of disapproval of the certification application. Upon issuance of such notice of disapproval, the provisional certification is invalidated by the Administrator and the data measured and recorded by each uncertified monitoring system shall not be considered valid quality-assured data beginning with the date and hour of provisional certification (as defined under §75.20(a)(3) of this chapter). The owner or operator shall follow the procedures for loss of certification in paragraph (d)(3)(v) of this section for each monitoring system that is disapproved for initial certification.

(D) Audit decertification. The Administrator may issue a notice of disapproval of the certification status of a monitor in accordance with §97.372(b).

(v) Procedures for loss of certification. If the Administrator issues a notice of disapproval of a certification application under paragraph (d)(3)(iv)(C) of this section or a notice of disapproval of certification status under paragraph (d)(3)(iv)(D) of this section, then:

(A) The owner or operator shall substitute the following values, for each disapproved monitoring system, for each hour of unit operation during the period of invalid data specified under §75.20(a)(4)(iii), §75.20(g)(7), or §75.21(e) of this chapter and continuing until the applicable date and hour specified under §75.20(a)(5)(i) or (g)(7) of this chapter:

1. For a disapproved NOx emission rate (i.e., NOx-diluent) system, the maximum potential NOx emission rate, as defined in (72.2 of this chapter.

2. For a disapproved NOx pollutant concentration monitor and disapproved flow monitor, respectively, the maximum potential concentration of NOx and the maximum potential flow rate, as defined in sections 2.1.2.1 and 2.1.4.1 of appendix A to part 75 of this chapter.

3. For a disapproved moisture monitoring system and disapproved diluent gas monitoring system, respectively, the minimum potential moisture percentage and either the maximum potential CO2 concentration or the minimum potential O2 concentration (as applicable), as defined in sections 2.1.5, 2.1.3.1, and 2.1.3.2 of appendix A to part 75 of this chapter.

4. For a disapproved fuel flowmeter system, the maximum potential fuel flow rate, as defined in section 2.4.2.1 of appendix D to part 75 of this chapter.

5. For a disapproved excepted NOx monitoring system under appendix E to part 75 of this chapter, the fuel-specific maximum potential NOx emission rate, as defined in (72.2 of this chapter.

(B) The CAIR designated representative shall submit a notification of certification retest dates and a new certification application in accordance with paragraphs (d)(3)(i) and (ii) of this section.

(C) The owner or operator shall repeat all certification tests or other requirements that were failed by the monitoring system, as indicated in the Administrator’s notice of disapproval, no later than 30 unit operating days after the date of issuance of the notice of disapproval.

(e) Initial certification and recertification procedures for units using the low mass emission excepted methodology under §75.19 of this chapter. The owner or operator of a unit qualified to use the low mass emissions (LME) excepted methodology under §75.19 of this chapter shall meet the applicable certification and recertification requirements in §§75.19(a)(2) and 75.20(b) of this chapter. If the owner or operator of such a unit elects to certify a fuel flowmeter system for heat input determination, the owner or operator shall also meet the certification and recertification requirements in §75.20(g) of this chapter.

(f) Certification/recertification procedures for alternative monitoring systems. The CAIR designated representative of each unit for which the owner or operator intends to use an alternative monitoring system approved by the Administrator under subpart E of part 75 of
§ 97.372 Out of control periods.

(a) Whenever any monitoring system fails to meet the quality-assurance and quality-control requirements or data validation requirements of part 75 of this chapter, data shall be substituted using the applicable missing data procedures in subpart D or subpart H of, or appendix D or appendix E to, part 75 of this chapter.

(b) Audit decertification. Whenever both an audit of a monitoring system and a review of the initial certification or recertification application reveal that any monitoring system should not have been certified or recertified because it did not meet a particular performance specification or other requirement under § 97.371 or the applicable provisions of part 75 of this chapter, both at the time of the initial certification or recertification application submission and at the time of the audit, the Administrator will issue a notice of disapproval of the certification status of such monitoring system. The data measured and recorded by the monitoring system shall not be considered valid quality-assured data from the date of issuance of the notice of the revoked certification status until the date and time that the owner or operator completes subsequently approved initial certification or recertification tests for the monitoring system.

§ 97.373 Notifications.

The CAIR designated representative for a CAIR NO\textsubscript{X} Ozone Season unit shall submit written notice to the Administrator in accordance with § 75.61 of this chapter.

§ 97.374 Recordkeeping and reporting.

(a) General provisions. The CAIR designated representative shall comply with all recordkeeping and reporting requirements in this section, the applicable recordkeeping and reporting requirements under § 75.73 of this chapter, and the requirements of § 97.310(e)(1).

(b) Monitoring Plans. The owner or operator of a CAIR NO\textsubscript{X} Ozone Season unit shall comply with requirements of § 75.73 (c) and (e) of this chapter and, for a unit for which a CAIR opt-in permit application is submitted and not withdrawn and a CAIR opt-in permit is not yet issued or denied under subpart III of this part, §§ 97.383 and 97.384(a).

(c) Certification Applications. The CAIR designated representative shall submit an application to the Administrator within 45 days after completing all initial certification or recertification tests required under § 97.371, including the information required under § 75.63 of this chapter.

(d) Quarterly reports. The CAIR designated representative shall submit quarterly reports, as follows:

(1) If the CAIR NO\textsubscript{X} Ozone Season unit is subject to an Acid Rain emissions limitation or a CAIR NO\textsubscript{X} emissions limitation or if the owner or operator of such unit chooses to report on an annual basis under this subpart, the CAIR designated representative shall meet the requirements of subpart H of part 75 of this chapter (concerning monitoring of NO\textsubscript{X} mass emissions) for such unit for the entire year and shall report the NO\textsubscript{X} mass emissions data and heat input data for such unit, in an electronic quarterly report in a format prescribed by the Administrator, for each calendar quarter beginning with:

(i) For a unit that commences commercial operation before July 1, 2007, the calendar quarter covering May 1, 2008 through June 30, 2008; and

(ii) For a unit that commences commercial operation on or after July 1, 2007, the calendar quarter corresponding to the earlier of the date of provisional certification or the applicable deadline for initial certification under § 97.370(b), unless that quarter is
the third or fourth quarter of 2007 or
the first quarter of 2008, in which case
reporting shall commence in the quar-
ter covering May 1, 2008 through June
30, 2008;

(iii) Notwithstanding paragraphs (d)(1) (i) and (ii) of this section, for a
unit for which a CAIR opt-in permit
application is submitted and not with-
drawn and a CAIR opt-in permit is not
yet issued or denied under subpart III
of this part, the calendar quarter cor-
responding to the date specified in
§97.384(b); and

(iv) Notwithstanding paragraphs (d)(1) (i) and (ii) of this section, for a
CAIR NO\textsubscript{X} Ozone Season opt-in unit under subpart III of this part, the
calendar quarter corresponding to the
date on which the CAIR NO\textsubscript{X} Ozone
Season opt-in unit enters the CAIR
NO\textsubscript{X} Ozone Season Trading Program as
provided in §97.384(g).

(2) If the CAIR NO\textsubscript{X} Ozone Season
unit is not subject to an Acid Rain
emissions limitation or a CAIR NO\textsubscript{X}
emissions limitation, then the CAIR
designated representative shall either:

(i) Meet the requirements of subpart H of part 75 (concerning monitoring of
NO\textsubscript{X} mass emissions) for such unit for
the entire year and report the NO\textsubscript{X}
mass emissions data and heat input
data for such unit in accordance with
paragraph (d)(1) of this section; or

(ii) Meet the requirements of subpart H of part 75 for the control period (in-
cluding the requirements in §75.74(c) of
this chapter) and report NO\textsubscript{X} mass
emissions data and heat input data (in-
cluding the data described in
§75.74(c)(6) of this chapter) for such
unit only for the control period of each
year and report, in an electronic quar-
terly report in a format prescribed by
the Administrator, for each calendar
quarter beginning with:

(A) For a unit that commences com-
mmercial operation before July 1, 2007,
the calendar quarter covering May 1,
2008 through June 30, 2008;

(B) For a unit that commences com-
mmercial operation on or after July 1,
2007, the calendar quarter cor-
responding to the earlier of the date of
provisional certification or the applica-
bility deadline for initial certification
under §97.370(b), unless that date is not
during a control period, in which case
reporting shall commence in the quar-
ter that includes May 1 through June
30 of the first control period after such
date;

(C) Notwithstanding paragraphs (d)(2)(ii)(A) and (2)(ii)(B) of this sec-
section, for a unit for which a CAIR opt-
in permit application is submitted and
not withdrawn and a CAIR opt-in per-
mit is not yet issued or denied under
subpart III of this part, the calendar
quarter corresponding to the date spec-
ified in §97.384(b); and

(D) Notwithstanding paragraphs (d)(2)(ii)(A) and (2)(ii)(B) of this sec-
section, for a CAIR NO\textsubscript{X} Ozone Season opt-
in unit under subpart III of this part,
the calendar quarter corresponding to
the date on which the CAIR NO\textsubscript{X} Ozone
Season opt-in unit enters the CAIR
NO\textsubscript{X} Ozone Season Trading Program as
provided in §97.384(g).

(3) The CAIR designated representa-
tive shall submit each quarterly report
to the Administrator within 30 days
following the end of the calendar quar-
ter covered by the report. Quarterly re-
ports shall be submitted in the manner
specified in §75.73(f) of this chapter.

(4) For CAIR NO\textsubscript{X} Ozone Season units
that are also subject to an Acid Rain
emissions limitation or the CAIR NO\textsubscript{X}
Annual Trading Program, CAIR SO\textsubscript{2}
Trading Program, or Hg Budget Trad-
ing Program, quarterly reports shall
include the applicable data and infor-
mation required by subparts F through
I of part 75 of this chapter as applica-
table, in addition to the NO\textsubscript{X} mass emis-
sion data, heat input data, and other
information required by this subpart.

(e) Compliance certification. The CAIR
designated representative shall submit
to the Administrator a compliance cer-
tificate (in a format prescribed by
the Administrator) in support of each
quarterly report based on reasonable
inquiry of those persons with primary
responsibility for ensuring that all of
the unit’s emissions are correctly and
fully monitored. The certification shall
state that:

(1) The monitoring data submitted
were recorded in accordance with the
applicable requirements of this subpart
and part 75 of this chapter, including
the quality assurance procedures and
specifications;
(2) For a unit with add-on NOX emission controls and for all hours where NOX data are substituted in accordance with §75.34(a)(1) of this chapter, the add-on emission controls were operating within the range of parameters listed in the quality assurance/quality control program under appendix B to part 75 of this chapter and the substitute data values do not systematically underestimate NOX emissions; and

(3) For a unit that is reporting on a control period basis under paragraph (d)(2)(ii) of this section, the NOX emission rate and NOX concentration values substituted for missing data under subpart D of part 75 of this chapter are calculated using only values from a control period and do not systematically underestimate NOX emissions.

§ 97.383 Applying for CAIR opt-in permit.

(a) Applying for initial CAIR opt-in permit. The CAIR designated representative of a unit meeting the requirements for a CAIR NOX Ozone Season opt-in unit in §97.380 may apply for an initial CAIR opt-in permit at any time, except as provided under §§97.386 (f) and (g), and, in order to apply, must submit the following:

(1) A complete CAIR permit application under §97.322;

(2) A certification, in a format specified by the permitting authority, that the unit:

(d) Has or is required or qualified to have a title V operating permit or other federally enforceable permit; and

(e) Vents all of its emissions to a stack and can meet the monitoring, recordkeeping, and reporting requirements of subpart HHHH of this part.

(b) Solely for purposes of applying, as provided in this subpart, the requirements of subpart HHHH of this part to a unit for which a CAIR opt-in permit application is submitted and not withdrawn and a CAIR opt-in permit is not yet issued or denied under this subpart, such unit shall be treated as a CAIR NOX Ozone Season unit before issuance of a CAIR opt-in permit for such unit.
(i) Is not a CAIR NO\textsubscript{X} Ozone Season unit under §97.304 and is not covered by a retired unit exemption under §97.305 that is in effect;
(ii) Is not covered by a retired unit exemption under §72.8 of this chapter that is in effect;
(iii) Vents all of its emissions to a stack; and
(iv) Has documented heat input for more than 876 hours during the 6 months immediately preceding submission of the CAIR permit application under §97.322;
(3) A monitoring plan in accordance with subpart HHHH of this part;
(4) A complete certificate of representation under §97.313 consistent with §97.382, if no CAIR designated representative has been previously designated for the source that includes the unit; and
(5) A statement, in a format specified by the permitting authority, whether the CAIR designated representative requests that the unit be allocated CAIR NO\textsubscript{X} Ozone Season allowances under §97.380(b) or §97.388(c) (subject to the conditions in §§97.384(h) and 97.386(g)), to the extent such allocation is provided in a State implementation plan revision submitted in accordance with §51.123(ee)(3)(i), (ii), or (iii) of this chapter and approved by the Administrator.
§97.384 Opt-in process.

The permitting authority will issue or deny a CAIR opt-in permit for a unit for which an initial application for a CAIR opt-in permit under §97.383 is submitted in accordance with the following, to the extent provided in a State implementation plan revision submitted in accordance with §51.123(ee)(3)(i), (ii), or (iii) of this chapter and approved by the Administrator:
(a) Interim review of monitoring plan.

The permitting authority and the Administrator will determine, on an interim basis, the sufficiency of the monitoring plan accompanying the initial application for a CAIR opt-in permit under §97.383. A monitoring plan is sufficient, for purposes of interim review, if the plan appears to contain information demonstrating that the NO\textsubscript{X} emissions rate and heat input of the unit and all other applicable parameters are monitored and reported in accordance with subpart HHHH of this part. A determination of sufficiency shall not be construed as acceptance or approval of the monitoring plan.

(b) Duty to reapply. (1) The CAIR designated representative of a CAIR NO\textsubscript{X} Ozone Season opt-in unit shall submit a complete CAIR permit application under §97.322 to renew the CAIR opt-in unit permit in accordance with the permitting authority's regulations for title V operating permits, or the permitting authority's regulations for other federally enforceable permits if applicable, addressing permit renewal.
(2) Unless the permitting authority issues a notification of acceptance of withdrawal of the CAIR NO\textsubscript{X} Ozone Season opt-in unit from the CAIR NO\textsubscript{X} Ozone Season Trading Program in accordance with §97.386, the CAIR NO\textsubscript{X} Ozone Season opt-in unit shall remain subject to the requirements for a CAIR NO\textsubscript{X} Ozone Season opt-in unit, even if the CAIR designated representative for the CAIR NO\textsubscript{X} Ozone Season opt-in unit fails to submit a CAIR permit application that is required for renewal of the CAIR opt-in permit under paragraph (b)(1) of this section.
(i) The monitoring and reporting under paragraph (b)(1)(i) of this section shall include the entire control period immediately before the date on which the unit enters the CAIR NO\textsubscript{X} Ozone Season Trading Program under \$97.384(g), during which period monitoring system availability must not be less than 90 percent under subpart HHHH of this part and the unit must be in full compliance with any applicable State or Federal emissions or emissions-related requirements.

(2) To the extent the NO\textsubscript{X} emissions rate and the heat input of the unit are monitored and reported in accordance with subpart HHHH of this part for one or more control periods, in addition to the control period under paragraph (b)(1)(ii) of this section, during which control periods monitoring system availability is not less than 90 percent under subpart HHHH of this part and the unit is in full compliance with any applicable State or Federal emissions or emissions-related requirements and which control periods begin not more than 3 years before the unit enters the CAIR NO\textsubscript{X} Ozone Season Trading Program under \$97.384(g), such information shall be used as provided in paragraphs (c) and (d) of this section.

(c) Baseline heat input. The unit’s baseline heat input shall equal:

(1) If the unit’s NO\textsubscript{X} emissions rate and heat input are monitored and reported for only one control period, in accordance with paragraph (b)(1) of this section, the unit’s total heat input (in mmBtu) for the control period; or

(2) If the unit’s NO\textsubscript{X} emissions rate and heat input are monitored and reported for more than one control period, in accordance with paragraphs (b)(1) and (2) of this section, and the unit does not have add-on NO\textsubscript{X} emission controls during any such control periods, the average of the amounts of the unit’s NO\textsubscript{X} emissions rate (in lb/mmBtu) for the control periods under paragraphs (b)(1)(ii) and (2) of this section; or

(3) If the unit’s NO\textsubscript{X} emissions rate and heat input are monitored and reported for more than one control period, in accordance with paragraphs (b)(1) and (2) of this section, and the unit has add-on NO\textsubscript{X} emission controls during any such control periods, the average of the amounts of the unit’s NO\textsubscript{X} emissions rate (in lb/mmBtu) for such control periods during which the unit has add-on NO\textsubscript{X} emission controls.

(e) Issuance of CAIR opt-in permit. After calculating the baseline heat input and the baseline NO\textsubscript{X} emissions rate for the unit under paragraphs (c) and (d) of this section and if the permitting authority determines that the CAIR designated representative shows that the unit meets the requirements for a CAIR NO\textsubscript{X} Ozone Season opt-in unit in \$97.380 and meets the elements certified in \$97.383(a)(2), the permitting authority will issue a CAIR opt-in permit. The permitting authority will provide a copy of the CAIR opt-in permit to the Administrator, who will then establish a compliance account for the source that includes the CAIR NO\textsubscript{X} Ozone Season opt-in unit unless the source already has a compliance account.

(f) Issuance of denial of CAIR opt-in permit. Notwithstanding paragraphs (a) through (e) of this section, if at any time before issuance of a CAIR opt-in permit for the unit, the permitting authority determines that the CAIR designated representative fails to show that the unit meets the requirements for a CAIR NO\textsubscript{X} Ozone Season opt-in unit in \$97.380 or meets the elements certified in \$97.383(a)(2), the permitting authority will issue a denial of a CAIR opt-in permit for the unit.

(g) Date of entry into CAIR NO\textsubscript{X} Ozone Season Trading Program. A unit for which an initial CAIR opt-in permit is
§ 97.385 CAIR opt-in permit contents.

(a) Each CAIR opt-in permit will contain:

(1) All elements required for a complete CAIR permit application under §97.322;

(2) The certification in §97.383(a)(2);

(3) The unit’s baseline heat input under §97.384(c);

(4) The unit’s baseline NO\textsubscript{X} emission rate as the original CAIR NO\textsubscript{X} Ozone Season opt-in unit, and the original CAIR NO\textsubscript{X} Ozone Season opt-in unit shall no longer be treated as a CAIR NO\textsubscript{X} Ozone Season opt-in unit or a CAIR NO\textsubscript{X} Ozone Season unit.

(5) A statement whether the unit is to be allocated CAIR NO\textsubscript{X} Ozone Season allowances under §97.388(b) or §97.388(c) (subject to the conditions in §§97.384(h) and 97.386(g));

(6) A statement that the unit may withdraw from the CAIR NO\textsubscript{X} Ozone Season Trading Program only in accordance with §97.386; and

(7) A statement that the unit is subject to, and the owners and operators of the unit must comply with, the requirements of §97.387.

(b) Each CAIR opt-in permit is deemed to incorporate automatically the definitions of terms under §97.302 and, upon recordation by the Administrator under subpart FFF or GGGG of this part or this subpart, every allocation, transfer, or deduction of CAIR NO\textsubscript{X} Ozone Season allowances to or from the compliance account of the source that includes a CAIR NO\textsubscript{X} Ozone Season opt-in unit covered by the CAIR opt-in permit.

(c) The CAIR opt-in permit shall be included, in a format specified by the permitting authority, in the CAIR permit for the source where the CAIR NO\textsubscript{X} Ozone Season opt-in unit is located and in a title V operating permit or other federally enforceable permit for the source.

§ 97.386 Withdrawal from CAIR NO\textsubscript{X} Ozone Season Trading Program.

Except as provided under paragraph (g) of this section, a CAIR NO\textsubscript{X} Ozone Season opt-in unit may withdraw from the CAIR NO\textsubscript{X} Ozone Season Trading Program, but only if the permitting authority issues a notification to the CAIR designated representative of the CAIR NO\textsubscript{X} Ozone Season opt-in unit of the acceptance of the withdrawal of the CAIR NO\textsubscript{X} Ozone Season opt-in unit in accordance with paragraph (d) of this section.

(a) Requesting withdrawal. In order to withdraw a CAIR NO\textsubscript{X} Ozone Season opt-in unit from the CAIR NO\textsubscript{X} Ozone Season Trading Program, the CAIR designated representative of the CAIR NO\textsubscript{X} Ozone Season opt-in unit shall submit to the permitting authority a request to withdraw effective as of midnight of September 30 of a specified calendar year, which date must be at least 4 years after September 30 of the year of entry into the CAIR NO\textsubscript{X} Ozone Season Trading Program under §97.384(g). The request must be submitted no later than 90 days before the requested effective date of withdrawal.

(b) Conditions for withdrawal. Before a CAIR NO\textsubscript{X} Ozone Season opt-in unit
covered by a request under paragraph (a) of this section may withdraw from the CAIR NO\textsubscript{X} Ozone Season Trading Program and the CAIR opt-in permit may be terminated under paragraph (e) of this section, the following conditions must be met:

(1) For the control period ending on the date on which the withdrawal is to be effective, the source that includes the CAIR NO\textsubscript{X} Ozone Season opt-in unit must meet the requirement to hold CAIR NO\textsubscript{X} Ozone Season allowances equal in amount to and allocated for the same or a prior control period as any CAIR NO\textsubscript{X} Ozone Season allowances allocated to the CAIR NO\textsubscript{X} Ozone Season opt-in unit under §97.386 for any control period for which the withdrawal is to be effective. If there are no remaining CAIR NO\textsubscript{X} Ozone Season units at the source, the Administrator will deduct from the compliance account of the source that includes the CAIR NO\textsubscript{X} Ozone Season opt-in unit CAIR NO\textsubscript{X} Ozone Season allowances equal in amount to and allocated for the same or a prior control period as any CAIR NO\textsubscript{X} Ozone Season allowances allocated to the CAIR NO\textsubscript{X} Ozone Season opt-in unit under §97.386 for any control period for which the withdrawal is to be effective.

(2) After the requirement for withdrawal under paragraph (b)(1) of this section is met, the Administrator will deduct from the compliance account of the source that includes the CAIR NO\textsubscript{X} Ozone Season opt-in unit the CAIR NO\textsubscript{X} Ozone Season allowance transfer for any remaining CAIR NO\textsubscript{X} Ozone Season allowances to another CAIR NO\textsubscript{X} Ozone Season Allowance Tracking System in accordance with subpart GGGG of this part.

(c) Notification. (1) After the requirements for withdrawal under paragraphs (a) and (b) of this section are met (including deduction of the full amount of CAIR NO\textsubscript{X} Ozone Season allowances required), the permitting authority will issue a notification to the CAIR designated representative of the CAIR NO\textsubscript{X} Ozone Season opt-in unit of the acceptances of the withdrawal of the CAIR NO\textsubscript{X} Ozone Season opt-in unit as of midnight on September 30 of the calendar year for which the withdrawal was requested.

(2) If the requirements for withdrawal under paragraphs (a) and (b) of this section are not met, the permitting authority will issue a notification to the CAIR designated representative of the CAIR NO\textsubscript{X} Ozone Season opt-in unit that the CAIR NO\textsubscript{X} Ozone Season opt-in unit’s request to withdraw is denied. Such CAIR NO\textsubscript{X} Ozone Season opt-in unit shall continue to be a CAIR NO\textsubscript{X} Ozone Season opt-in unit.

(d) Permit amendment. After the permitting authority issues a notification under paragraph (c)(1) of this section that the requirements for withdrawal have been met, the permitting authority will revise the CAIR permit covering the CAIR NO\textsubscript{X} Ozone Season opt-in unit to terminate the CAIR opt-in permit for such unit as of the effective date specified under paragraph (c)(1) of this section. The unit shall continue to be a CAIR NO\textsubscript{X} Ozone Season opt-in unit until the effective date of the termination and shall comply with all requirements under the CAIR NO\textsubscript{X} Ozone Season Trading Program concerning any control periods for which the unit is a CAIR NO\textsubscript{X} Ozone Season opt-in unit, even if such requirements arise or must be complied with after the withdrawal takes effect.

(e) Reapplication upon failure to meet conditions of withdrawal. If the permitting authority denies the CAIR NO\textsubscript{X} Ozone Season opt-in unit’s request to withdraw, the CAIR designated representative may submit another request to withdraw in accordance with paragraphs (a) and (b) of this section.

(f) Ability to reapply to the CAIR NO\textsubscript{X} Ozone Season Trading Program. Once a CAIR NO\textsubscript{X} Ozone Season opt-in unit withdraws, the CAIR designated representative may submit another application for a CAIR opt-in permit under §97.383 for such CAIR NO\textsubscript{X} Ozone Season opt-in unit before the date that is 4 years after the date on which the withdrawal became effective. Such new application for a CAIR opt-in permit will be treated as an initial application for a CAIR opt-in permit under §97.384.

(g) Inability to withdraw. Notwithstanding paragraphs (a) through (f) of this section, a CAIR NO\textsubscript{X} Ozone Season opt-in unit shall not be eligible to withdraw from the CAIR NO\textsubscript{X} Ozone Season Trading Program if the CAIR designated representative of the CAIR NO\textsubscript{X} Ozone Season opt-in unit requests,
§ 97.387 Change in regulatory status.

(a) Notification. If a CAIR NO\textsubscript{X} Ozone Season opt-in unit becomes a CAIR NO\textsubscript{X} Ozone Season unit under §97.304, then the CAIR designated representative shall notify in writing the permitting authority and the Administrator of such change in the CAIR NO\textsubscript{X} Ozone Season opt-in unit’s regulatory status, within 30 days of such change.

(b) Permitting authority’s and Administrator’s actions. (1) If a CAIR NO\textsubscript{X} Ozone Season opt-in unit becomes a CAIR NO\textsubscript{X} Ozone Season unit under §97.304, the permitting authority will revise the CAIR NO\textsubscript{X} Ozone Season opt-in unit’s CAIR opt-in permit to meet the requirements of a CAIR permit under §97.323, and remove the CAIR opt-in permit provisions, as of the date on which the CAIR NO\textsubscript{X} Ozone Season opt-in unit becomes a CAIR NO\textsubscript{X} Ozone Season unit under §97.304.

(2)(i) The Administrator will deduct from the compliance account of the source that includes the CAIR NO\textsubscript{X} Ozone Season opt-in unit that becomes a CAIR NO\textsubscript{X} Ozone Season unit under §97.304, CAIR NO\textsubscript{X} Ozone Season allowances equal in amount to and allocated for the same or a prior control period as:

(A) Any CAIR NO\textsubscript{X} Ozone Season allowances allocated to the CAIR NO\textsubscript{X} Ozone Season opt-in unit under §97.388 for any control period after the date on which the CAIR NO\textsubscript{X} Ozone Season opt-in unit becomes a CAIR NO\textsubscript{X} Ozone Season unit under §97.304; and

(B) If the date on which the CAIR NO\textsubscript{X} Ozone Season opt-in unit becomes a CAIR NO\textsubscript{X} Ozone Season unit under §97.304 is not September 30, the CAIR NO\textsubscript{X} Ozone Season allowances allocated to the CAIR NO\textsubscript{X} Ozone Season opt-in unit under §97.388 for the control period that includes the date on which the CAIR NO\textsubscript{X} Ozone Season opt-in unit becomes a CAIR NO\textsubscript{X} Ozone Season unit under §97.304, multiplied by the ratio of the number of days, in the control period, starting with the date on which the CAIR NO\textsubscript{X} Ozone Season opt-in unit becomes a CAIR NO\textsubscript{X} Ozone Season unit under §97.304 divided by the total number of days in the control period and rounded to the nearest whole allowance as appropriate.

(ii) The CAIR designated representative shall ensure that the compliance account of the source that includes the CAIR NO\textsubscript{X} Ozone Season opt-in unit that becomes a CAIR NO\textsubscript{X} Ozone Season unit under §97.304 contains the CAIR NO\textsubscript{X} Ozone Season allowances necessary for completion of the deduction under paragraph (b)(2)(i) of this section.

(3)(i) For every control period after the date on which the CAIR NO\textsubscript{X} Ozone Season opt-in unit becomes a CAIR NO\textsubscript{X} Ozone Season unit under §97.304, the CAIR NO\textsubscript{X} Ozone Season opt-in unit will be allocated CAIR NO\textsubscript{X} Ozone Season allowances under §97.342.

(ii) If the date on which the CAIR NO\textsubscript{X} Ozone Season opt-in unit becomes a CAIR NO\textsubscript{X} Ozone Season unit under §97.304 is not September 30, the following amount of CAIR NO\textsubscript{X} Ozone Season allowances will be allocated to the CAIR NO\textsubscript{X} Ozone Season opt-in unit (as a CAIR NO\textsubscript{X} Ozone Season unit) under §97.342 for the control period that includes the date on which the CAIR NO\textsubscript{X} Ozone Season opt-in unit becomes a CAIR NO\textsubscript{X} Ozone Season unit under §97.304:

(A) The amount of CAIR NO\textsubscript{X} Ozone Season allowances otherwise allocated to the CAIR NO\textsubscript{X} Ozone Season opt-in unit (as a CAIR NO\textsubscript{X} Ozone Season unit) under §97.342 for the control period multiplied by:

(B) The ratio of the number of days, in the control period, starting with the date on which the CAIR NO\textsubscript{X} Ozone Season opt-in unit becomes a CAIR NO\textsubscript{X} Ozone Season unit under §97.304, divided by the total number of days in the control period; and

(C) Rounded to the nearest whole allowance as appropriate.


§ 97.388 CAIR NO\textsubscript{X} Ozone Season allowance allocations to CAIR NO\textsubscript{X} Ozone Season opt-in units.

(a) Timing requirements. (1) When the CAIR opt-in permit is issued under §97.384(e), the permitting authority
will allocate CAIR NO\textsubscript{X} Ozone Season allowances to the CAIR NO\textsubscript{X} Ozone Season opt-in unit, and submit to the Administrator the allocation for the control period in which a CAIR NO\textsubscript{X} Ozone Season opt-in unit enters the CAIR NO\textsubscript{X} Ozone Season Trading Program under §97.384(g). In accordance with paragraph (b) or (c) of this section.

(2) By no later than July 31 of the control period after the control period in which a CAIR NO\textsubscript{X} Ozone Season opt-in unit enters the CAIR NO\textsubscript{X} Ozone Season Trading Program under §97.384(g) and July 31 of each year thereafter, the permitting authority will allocate CAIR NO\textsubscript{X} Ozone Season allowances to the CAIR NO\textsubscript{X} Ozone Season opt-in unit, and submit to the Administrator the allocation for the control period that includes such submission deadline and in which the unit is a CAIR NO\textsubscript{X} Ozone Season opt-in unit, in accordance with paragraph (b) or (c) of this section.

(b) Calculation of allocation. For each control period for which a CAIR NO\textsubscript{X} Ozone Season opt-in unit is to be allocated CAIR NO\textsubscript{X} Ozone Season allowances, the permitting authority will allocate in accordance with the following procedures, if provided in a State implementation plan revision submitted in accordance with §51.123(ee)(3)(i), (ii), or (iii) of this chapter and approved by the Administrator:

(1) The heat input (in mmBtu) used for calculating the CAIR NO\textsubscript{X} Ozone Season allowance allocation will be the lesser of:

(i) The CAIR NO\textsubscript{X} Ozone Season opt-in unit’s baseline NO\textsubscript{X} emissions rate (in lb/mmBtu) determined under §97.384(d) and multiplied by 70 percent; or

(ii) The most stringent State or Federal NO\textsubscript{X} emissions limitation applicable to the CAIR NO\textsubscript{X} Ozone Season opt-in unit at any time during the control period for which CAIR NO\textsubscript{X} Ozone Season allowances are to be allocated.

(3) The permitting authority will allocate CAIR NO\textsubscript{X} Ozone Season allowances to the CAIR NO\textsubscript{X} Ozone Season opt-in unit in an amount equaling the heat input under paragraph (b)(1) of this section, multiplied by the NO\textsubscript{X} emission rate under paragraph (b)(2) of this section, divided by 2,000 lb/ton, and rounded to the nearest whole allowance as appropriate.

(c) Notwithstanding paragraph (b) of this section and if the CAIR designated representative requests, and the permitting authority issues a CAIR opt-in permit (based on a demonstration of the intent to repower stated under §97.383 (a)(5)) providing for, allocation to a CAIR NO\textsubscript{X} Ozone Season opt-in unit of CAIR NO\textsubscript{X} Ozone Season allowances under this paragraph (subject to the conditions in §§97.384(h) and 97.386(g)), the permitting authority will allocate to the CAIR NO\textsubscript{X} Ozone Season opt-in unit as follows, if provided in a State implementation plan revision submitted in accordance with §51.123(ee)(3)(i), (ii), or (iii) of this chapter and approved by the Administrator:

(1) For each control period in 2009 through 2014 for which the CAIR NO\textsubscript{X} Ozone Season opt-in unit is to be allocated CAIR NO\textsubscript{X} Ozone Season allowances,

(i) The heat input (in mmBtu) used for calculating CAIR NO\textsubscript{X} Ozone Season allowance allocations will be the lesser of:

(i) The CAIR NO\textsubscript{X} Ozone Season opt-in unit’s baseline NO\textsubscript{X} emissions rate (in lb/mmBtu) determined under §97.384(d); or

(ii) The most stringent State or Federal NO\textsubscript{X} emissions limitation applicable to the CAIR NO\textsubscript{X} Ozone Season opt-in unit at any time during the control period for which CAIR NO\textsubscript{X} Ozone Season allowances are to be allocated.

(ii) The NO\textsubscript{X} emission rate (in lb/mmBtu) used for calculating CAIR NO\textsubscript{X} Ozone Season allowance allocations will be the lesser of:

(A) The CAIR NO\textsubscript{X} Ozone Season opt-in unit’s baseline NO\textsubscript{X} emissions rate (in lb/mmBtu) determined under §97.384(d); or
(B) The most stringent State or Federal NO\textsubscript{X} emissions limitation applicable to the CAIR NO\textsubscript{X} Ozone Season opt-in unit at any time during the control period in which the CAIR NO\textsubscript{X} Ozone Season opt-in unit enters the CAIR NO\textsubscript{X} Ozone Season Trading Program under §97.384(g).

(iii) The permitting authority will allocate CAIR NO\textsubscript{X} Ozone Season allowances to the CAIR NO\textsubscript{X} Ozone Season opt-in unit in an amount equaling the heat input under paragraph (c)(1)(i) of this section, multiplied by the NO\textsubscript{X} emission rate under paragraph (c)(1)(ii) of this section, divided by 2,000 lb/ton, and rounded to the nearest whole allowance as appropriate.

(2) For each control period in 2015 and thereafter for which the CAIR NO\textsubscript{X} Ozone Season opt-in unit is to be allocated CAIR NO\textsubscript{X} Ozone Season allowances,

(i) The heat input (in mmBtu) used for calculating the CAIR NO\textsubscript{X} Ozone Season allowance allocations will be determined as described in paragraph (b)(1) of this section.

(ii) The NO\textsubscript{X} emission rate (in lb/mmBtu) used for calculating the CAIR NO\textsubscript{X} Ozone Season allowance allocation will be the lesser of:

(A) 0.15 lb/mmBtu;

(B) The CAIR NO\textsubscript{X} Ozone Season opt-in unit’s baseline NO\textsubscript{X} emissions rate (in lb/mmBtu) determined under §97.384(d); or

(C) The most stringent State or Federal NO\textsubscript{X} emissions limitation applicable to the CAIR NO\textsubscript{X} Ozone Season opt-in unit at any time during the control period for which CAIR NO\textsubscript{X} Ozone Season allowances are to be allocated.

(iii) The permitting authority will allocate CAIR NO\textsubscript{X} Ozone Season allowances to the CAIR NO\textsubscript{X} Ozone Season opt-in unit in an amount equaling the heat input under paragraph (c)(2)(i) of this section, multiplied by the NO\textsubscript{X} emission rate under paragraph (c)(2)(ii) of this section, divided by 2,000 lb/ton, and rounded to the nearest whole allowance as appropriate.

(d) Recordation. If provided in a State implementation plan revision submitted in accordance with §51.123(ee)(3)(i), (ii), or (iii) of this chapter and approved by the Administrator:

(1) The Administrator will record, in the compliance account of the source that includes the CAIR NO\textsubscript{X} Ozone Season opt-in unit, the CAIR NO\textsubscript{X} Ozone Season allowances allocated by the permitting authority to the CAIR NO\textsubscript{X} Ozone Season opt-in unit under paragraph (a)(1) of this section.

(2) By September 1 of the control period in which a CAIR NO\textsubscript{X} Ozone Season opt-in unit enters the CAIR NO\textsubscript{X} Ozone Season Trading Program under §97.384(g) and September 1 of each year thereafter, the Administrator will record, in the compliance account of the source that includes the CAIR NO\textsubscript{X} Ozone Season opt-in unit, the CAIR NO\textsubscript{X} Ozone Season allowances allocated by the permitting authority to the CAIR NO\textsubscript{X} Ozone Season opt-in unit under paragraph (a)(2) of this section.

APPENDIX A TO SUBPART IIII OF PART 97—STATES WITH APPROVED STATE IMPLEMENTATION PLAN REVISIONS CONCERNING CAIR NO\textsubscript{X} OZONE SEASON OPT-IN UNITS

1. The following States have State Implementation Plan revisions under §51.123(ee)(3) of this chapter approved by the Administrator and establishing procedures providing for CAIR NO\textsubscript{X} Ozone Season opt-in units under subpart IIII of this part and allocation of CAIR NO\textsubscript{X} Ozone Season allowances to such units under §97.388(b):

   Indiana
   Michigan
   North Carolina
   Ohio
   South Carolina
   Tennessee

2. The following States have State Implementation Plan revisions under §51.123(ee)(3) of this chapter approved by the Administrator and establishing procedures providing for CAIR NO\textsubscript{X} Ozone Season opt-in units under subpart IIII of this part and allocation of CAIR NO\textsubscript{X} Ozone Season allowances to such units under §97.388(c):

   Indiana
   Michigan
   North Carolina
   Ohio
   South Carolina
   Tennessee

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Subpart AAAAA—TR NO\textsubscript{X} Annual Trading Program

Source: 76 FR 48379, Aug. 8, 2011, unless otherwise noted.

§ 97.401 Purpose.

This subpart sets forth the general, designated representative, allowance, and monitoring provisions for the Transport Rule (TR) NO\textsubscript{X} Annual Trading Program, under section 110 of the Clean Air Act and § 52.38 of this chapter, as a means of mitigating interstate transport of fine particulates and nitrogen oxides.

§ 97.402 Definitions.

The terms used in this subpart shall have the meanings set forth in this section as follows:

\textit{Acid Rain Program} means a multi-state SO\textsubscript{2} and NO\textsubscript{X} air pollution control and emission reduction program established by the Administrator under title IV of the Clean Air Act and parts 72 through 78 of this chapter.

\textit{Administrator} means the Administrator of the United States Environmental Protection Agency or the Director of the Clean Air Markets Division (or its successor determined by the Administrator) of the United States Environmental Protection Agency, the Administrator’s duly authorized representative under this subpart.

\textit{Allocate} or \textit{allocation} means, with regard to TR NO\textsubscript{X} Annual allowances, the determination by the Administrator, State, or permitting authority, in accordance with this subpart and any SIP revision submitted by the State and approved by the Administrator under § 52.38(a)(3), (4), or (5) of this chapter, of the amount of such TR NO\textsubscript{X} Annual allowances to be initially credited, at no cost to the recipient, to:

1. A TR NO\textsubscript{X} Annual unit;
2. A new unit set-aside;
3. An Indian country new unit set-aside;
4. An entity not listed in paragraphs (1) through (3) of this definition;
5. Provided that, if the Administrator, State, or permitting authority initially credits, to a TR NO\textsubscript{X} Annual unit qualifying for an initial credit, a credit in the amount of zero TR NO\textsubscript{X} Annual allowances, the TR NO\textsubscript{X} Annual unit will be treated as being allocated an amount (i.e., zero) of TR NO\textsubscript{X} Annual allowances.

\textit{Allowable NO\textsubscript{X} emission rate} means, for a unit, the most stringent State or federal NO\textsubscript{X} emission rate limit (in lb/MWhr or, if in lb/mmBtu, converted to lb/MWhr by multiplying it by the unit’s heat rate in mmBtu/MWhr) that is applicable to the unit and covers the longest averaging period not exceeding one year.

\textit{Allowance Management System} means the system by which the Administrator records allocations, deductions, and transfers of TR NO\textsubscript{X} Annual allowances under the TR NO\textsubscript{X} Annual Trading Program. Such allowances are allocated, recorded, held, deducted, or transferred only as whole allowances.

\textit{Allowance Management System account} means an account in the Allowance Management System established by the Administrator for purposes of recording the allocation, holding, transfer, or deduction of TR NO\textsubscript{X} Annual allowances.

\textit{Allowance transfer deadline} means, for a control period in a given year, midnight of March 1 (if it is a business day), or midnight of the first business day thereafter (if March 1 is not a business day), immediately after such control period and is the deadline by which a TR NO\textsubscript{X} Annual allowance transfer must be submitted for recordation in a TR NO\textsubscript{X} Annual source’s compliance account in order to be available for use in complying with the source’s TR NO\textsubscript{X} Annual emissions limitation for such control period in accordance with §§ 97.406 and 97.424.

\textit{Alternate designated representative} means, for a TR NO\textsubscript{X} Annual source and each TR NO\textsubscript{X} Annual unit at the source, the natural person who is authorized by the owners and operators of the source and all such units at the source, in accordance with this subpart, to act on behalf of the designated representative in matters pertaining to the TR NO\textsubscript{X} Annual Trading Program. If the TR NO\textsubscript{X} Annual source is also subject to the Acid Rain Program, TR NO\textsubscript{X} Ozone Season Trading Program, TR SO\textsubscript{2} Group 1 Trading Program, or TR SO\textsubscript{2} Group 2 Trading Program, then this natural person shall be the same.
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natural person as the alternate designated representative, as defined in the respective program.

Assurance account means an Allowance Management System account, established by the Administrator under §97.425(b)(3) for certain owners and operators of a group of one or more TR NOX Annual sources and units in a given State (and Indian country within the borders of such State), in which are held TR NOX Annual allowances available for use for a control period in a given year in complying with the TR NOX Annual assurance provisions in accordance with §§97.406 and 97.425.

Authorized account representative means, for a general account, the natural person who is authorized, in accordance with this subpart, to transfer and otherwise dispose of TR NOX Annual allowances held in the general account and, for a TR NOX Annual source’s compliance account, the designated representative of the source.

Automated data acquisition and handling system or DAHS means the component of the continuous emission monitoring system, or other emissions monitoring system approved for use under this subpart, designed to interpret and convert individual output signals from pollutant concentration monitors, flow monitors, diluent gas monitors, and other component parts of the monitoring system to produce a continuous record of the measured parameters in the measurement units required by this subpart.

Biomass means—

(1) Any organic material grown for the purpose of being converted to energy;

(2) Any organic byproduct of agriculture that can be converted into energy; or

(3) Any material that can be converted into energy and is nonmerchantable for other purposes, that is segregated from other material that is nonmerchantable for other purposes, and that is:

(i) A forest-related organic resource, including mill residues, precommercial thinnings, slash, brush, or byproduct from conversion of trees to merchantable material; or

(ii) A wood material, including pallets, crates, dunnage, manufacturing and construction materials (other than pressure-treated, chemically-treated, or painted wood products), and landscape or right-of-way tree trimmings.

Boiler means an enclosed fossil- or other-fuel-fired combustion device used to produce heat and to transfer heat to recirculating water, steam, or other medium.

Bottoming-cycle unit means a unit in which the energy input to the unit is first used to produce useful thermal energy, where at least some of the reject heat from the useful thermal energy application or process is then used for electricity production.

Business day means a day that does not fall on a weekend or a federal holiday.

Certifying official means a natural person who is:

(1) For a corporation, a president, secretary, treasurer, or vice-president of the corporation in charge of a principal business function or any other person who performs similar policy- or decision-making functions for the corporation;

(2) For a partnership or sole proprietorship, a general partner or the proprietor respectively; or

(3) For a local government entity or State, federal, or other public agency, a principal executive officer or ranking elected official.

Clean Air Act means the Clean Air Act, 42 U.S.C. 7401, et seq.

Coal means “coal” as defined in §72.2 of this chapter.

Coal-derived fuel means any fuel (whether in a solid, liquid, or gaseous state) produced by the mechanical, thermal, or chemical processing of coal.

Cogeneration system means an integrated group, at a source, of equipment (including a boiler, or combustion turbine, and a steam turbine generator) designed to produce useful thermal energy for industrial, commercial, heating, or cooling purposes and electricity through the sequential use of energy.

Cogeneration unit means a stationary, fossil-fuel-fired boiler or stationary, fossil-fuel-fired combustion turbine that is a topping-cycle unit or a bottoming-cycle unit:

(1) Operating as part of a cogeneration system; and
(2) Producing on an annual average basis—
   (i) For a topping-cycle unit,
       (A) Useful thermal energy not less than 5 percent of total energy output; and
       (B) Useful power that, when added to one-half of useful thermal energy produced, is not less than 42.5 percent of total energy input, if useful thermal energy produced is 15 percent or more of total energy output, or not less than 45 percent of total energy input, if useful thermal energy produced is less than 15 percent of total energy output.
   (ii) For a bottoming-cycle unit, useful power not less than 45 percent of total energy input;
   (3) Provided that the requirements in paragraph (2) of this definition shall not apply to a calendar year referenced in paragraph (2) of this definition during which the unit did not operate at all;
   (4) Provided that the total energy input under paragraphs (2)(i)(B) and (2)(ii) of this definition shall equal the unit’s total energy input from all fuel, except biomass if the unit is a boiler; and
   (5) Provided that, if, throughout its operation during the 12-month period or a calendar year referenced in paragraph (2) of this definition, a unit is operated as part of a cogeneration system and the cogeneration system meets on a system-wide basis the requirement in paragraph (2)(i)(B) or (2)(ii) of this definition, the unit shall be deemed to meet such requirement during that 12-month period or calendar year.

Combustion turbine means an enclosed device comprising:
   (1) If the device is simple cycle, a compressor, a combustor, and a turbine and in which the flue gas resulting from the combustion of fuel in the combustor passes through the turbine, rotating the turbine; and
   (2) If the device is combined cycle, the equipment described in paragraph (1) of this definition and any associated duct burner, heat recovery steam generator, and steam turbine.

Commence commercial operation means, with regard to a unit:
   (1) To have begun to produce steam, gas, or other heated medium used to generate electricity for sale or use, excluding test generation, except as provided in §97.405.
   (i) For a unit that is a TR NOX Annual unit under §97.404 on the later of January 1, 2005 or the date the unit commences commercial operation as defined in the introductory text of paragraph (1) of this definition and that subsequently undergoes a physical change or is moved to a new location or source, such date shall remain the date of commencement of commercial operation of the unit, which shall continue to be treated as the same unit.
   (ii) For a unit that is a TR NOX Annual unit under §97.404 on the later of January 1, 2005 or the date the unit commences commercial operation as defined in the introductory text of paragraph (1) of this definition and that is subsequently replaced by a unit at the same or a different source, such date shall remain the replaced unit’s date of commencement of commercial operation, and the replacement unit shall be treated as a separate unit with a separate date for commencement of commercial operation as defined in paragraph (1) or (2) of this definition as appropriate.
   (2) Notwithstanding paragraph (1) of this definition and except as provided in §97.405, for a unit that is not a TR NOX Annual unit under §97.404 on the later of January 1, 2005 or the date the unit commences commercial operation as defined in introductory text of paragraph (1) of this definition, the unit’s date for commencement of commercial operation shall be the date on which the unit becomes a TR NOX Annual unit under §97.404.
   (i) For a unit with a date for commencement of commercial operation as defined in the introductory text of paragraph (2) of this definition and that subsequently undergoes a physical change or is moved to a different location or source, such date shall remain the date of commencement of commercial operation of the unit, which shall continue to be treated as the same unit.
   (ii) For a unit with a date for commencement of commercial operation as defined in the introductory text of paragraph (2) of this definition and that is subsequently replaced by a unit at the same or a different source, such
date shall remain the replaced unit’s date of commencement of commercial operation, and the replacement unit shall be treated as a separate unit with a separate date for commencement of commercial operation as defined in paragraph (1) or (2) of this definition as appropriate.

Common designated representative means, with regard to a control period in a given year, a designated representative where, as of April 1 immediately after the allowance transfer deadline for such control period, the same natural person is authorized under §§97.413(a) and 97.415(a) as the designated representative for a group of one or more TR NOX Annual sources and units located in a State (and Indian country within the borders of such State).

Common designated representative’s assurance level means, with regard to a specific common designated representative and a State (and Indian country within the borders of such State) and control period in a given year for which the State assurance level is exceeded as described in §97.406(c)(2)(iii), the common designated representative’s share of the State NOX Annual trading budget with the variability limit for the State for such control period.

Common designated representative’s share means, with regard to a specific common designated representative for a control period in a given year:

(1) With regard to a total amount of NOX emissions from all TR NOX Annual units in a State (and Indian country within the borders of such State) during such control period, the total tonnage of NOX emissions during such control period from a group of one or more TR NOX Annual units located in such State (and such Indian country) and having the common designated representative for such control period;

(2) With regard to a State NOX Annual trading budget with the variability limit for such control period, the amount (rounded to the nearest allowance) equal to the sum of the total amount of TR NOX Annual allowances allocated for such control period to a group of one or more TR NOX Annual units located in the State (and Indian country within the borders of such State) and having the common designated representative for such control period and of the total amount of TR NOX Annual allowances purchased by an owner or operator of such TR NOX Annual units in an auction for such control period and submitted by the State or the permitting authority to the Administrator for recordation in the compliance accounts for such TR NOX Annual units in accordance with the TR NOX Annual allowance auction provisions in a SIP revision approved by the Administrator under §52.36(a)(4) or (5) of this chapter, multiplied by the sum of the State NOX Annual trading budget under §97.410(a) and the State’s variability limit under §97.410(b) for such control period and divided by such State NOX Annual trading budget;

(3) Provided that, in the case of a unit that operates during, but has no allowances for such control period, the unit shall be treated, solely for purposes of this definition, as being allocated an amount (rounded to the nearest allowance) of TR NOX Annual allowances for such control period equal to the unit’s allowable NOX emission rate applicable to such control period, multiplied by a capacity factor of 0.85 (if the unit is a boiler combusting any amount of coal or coal-derived fuel during such control period), 0.24 (if the unit is a simple combustion turbine during such control period), 0.67 (if the unit is a combined cycle turbine during such control period), 0.74 (if the unit is an integrated coal gasification combined cycle unit during such control period), or 0.36 (for any other unit), multiplied by the unit’s maximum hourly load as reported in accordance with this subpart and by 8,760 hours/control period, and divided by 2,000 lb/ton.

Common stack means a single flue through which emissions from 2 or more units are exhausted.

Compliance account means an Allowance Management System account, established by the Administrator for a TR NOX Annual source under this subpart, in which any TR NOX Annual allowance allocations to the TR NOX Annual units at the source are recorded and in which are held any TR NOX Annual allowances available for use for a
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control period in a given year in complying with the source’s TR NOX Annual emissions limitation in accordance with §§97.406 and 97.424.

Continuous emission monitoring system or CEMS means the equipment required under this subpart to sample, analyze, measure, and provide, by means of readings recorded at least once every 15 minutes and using an automated data acquisition and handling system (DAHS), a permanent record of NOX emissions, stack gas volumetric flow rate, stack gas moisture content, and O2 or CO2 concentration (as applicable), in a manner consistent with part 75 of this chapter and §§97.430 through 97.435. The following systems are the principal types of continuous emission monitoring systems:

1. A flow monitoring system, consisting of a stack flow rate monitor and an automated data acquisition and handling system and providing a permanent, continuous record of stack gas volumetric flow rate, in standard cubic feet per hour (scfh);

2. A NOX concentration monitoring system, consisting of a NOX pollutant concentration monitor and an automated data acquisition and handling system and providing a permanent, continuous record of NOX emissions, in parts per million (ppm);

3. A NOX emission rate (or NOX-diluent) monitoring system, consisting of a NOX pollutant concentration monitor, a diluent gas (CO2 or O2) monitor, and an automated data acquisition and handling system and providing a permanent, continuous record of NOX concentration, in parts per million (ppm), diluent gas concentration, in percent CO2 or O2, and NOX emission rate, in pounds per million British thermal units (lb/mmBtu);

4. A moisture monitoring system, as defined in §75.11(b)(2) of this chapter and providing a permanent, continuous record of the stack gas moisture content, in percent H2O;

5. A CO2 monitoring system, consisting of a CO2 pollutant concentration monitor (or an O2 monitor plus suitable mathematical equations from which the CO2 concentration is derived) and an automated data acquisition and handling system and providing a permanent, continuous record of CO2 emissions, in percent CO2; and

6. An O2 monitoring system, consisting of an O2 concentration monitor and an automated data acquisition and handling system and providing a permanent, continuous record of O2, in percent O2.

Control period means the period starting January 1 of a calendar year, except as provided in §97.406(c)(3), and ending on December 31 of the same year, inclusive.

Designated representative means, for a TR NOX Annual source and each TR NOX Annual unit at the source, the natural person who is authorized by the owners and operators of the source and all such units at the source, in accordance with this subpart, to represent and legally bind each owner and operator in matters pertaining to the TR NOX Annual Trading Program. If the TR NOX Annual source is also subject to the Acid Rain Program, TR NOX Ozone Season Trading Program, TR SO2 Group 1 Trading Program, or TR SO2 Group 2 Trading Program, then this natural person shall be the same natural person as the designated representative, as defined in the respective program.

Emissions means air pollutants exhausted from a unit or source into the atmosphere, as measured, recorded, and reported to the Administrator by the designated representative, and as modified by the Administrator:

1. In accordance with this subpart; and

2. With regard to a period before the unit or source is required to measure, record, and report such air pollutants in accordance with this subpart, in accordance with part 75 of this chapter.

Excess emissions means any ton of emissions from the TR NOX Annual units at a TR NOX Annual source during a control period in a given year that exceeds the TR NOX Annual emissions limitation for the source for such control period.

Fossil fuel means—

1. Natural gas, petroleum, coal, or any form of solid, liquid, or gaseous fuel derived from such material; or

2. For purposes of applying the limitation on “average annual fuel consumption of fossil fuel” in
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§§ 97.404(b)(2)(i)(B) and (ii), natural gas, petroleum, coal, or any form of solid, liquid, or gaseous fuel derived from such material for the purpose of creating useful heat.

Fossil-fuel-fired means, with regard to a unit, combusting any amount of fossil fuel in 2005 or any calendar year thereafter.

General account means an Allowance Management System account, established under this subpart, that is not a compliance account or an assurance account.

Generator means a device that produces electricity.

Gross electrical output means, for a unit, electricity made available for use, including any such electricity used in the power production process (which process includes, but is not limited to, any on-site processing or treatment of fuel combusted at the unit and any on-site emission controls).

Heat input means, for a unit for a specified period of time, the product (in mmBtu/time) of the gross calorific value of the fuel (in mmBtu/lb) fed into the unit multiplied by the fuel feed rate (in lb of fuel/time), as measured, recorded, and reported to the Administrator by the designated representative and as modified by the Administrator in accordance with this subpart and excluding the heat derived from preheated combustion air, recirculated flue gases, or exhaust.

Heat input rate means, for a unit, the amount of heat input (in mmBtu) divided by unit operating time (in hr) or, for a unit and a specific fuel, the amount of heat input attributed to the fuel (in mmBtu) divided by the unit operating time (in hr) during which the unit combusts the fuel.

Heat rate means, for a unit, the unit’s maximum design heat input (in Btu/hr), divided by the product of 1,000,000 Btu/mmBtu and the unit’s maximum hourly load.

Indian country means “Indian country” as defined in 18 U.S.C. 1151.

Life-of-the-unit, firm power contractual arrangement means a unit participation power sales agreement under which a utility or industrial customer reserves, or is entitled to receive, a specified amount or percentage of nameplate capacity and associated energy generated by any specified unit and pays its proportional amount of such unit’s total costs, pursuant to a contract:

1. For the life of the unit;
2. For a cumulative term of no less than 30 years, including contracts that permit an election for early termination; or
3. For a period no less than 25 years or 70 percent of the economic useful life of the unit determined as of the time the unit is built, with option rights to purchase or release some portion of the nameplate capacity and associated energy generated by the unit at the end of the period.

Maximum design heat input means, for a unit, the maximum amount of fuel per hour (in Btu/hr) that the unit is capable of combusting on a steady state basis as of the initial installation of the unit as specified by the manufacturer of the unit.

Monitoring system means any monitoring system that meets the requirements of this subpart, including a continuous emission monitoring system, an alternative monitoring system, or an excepted monitoring system under part 75 of this chapter.

Nameplate capacity means, starting from the initial installation of a generator, the maximum electrical generating output (in MWe, rounded to the nearest tenth) that the generator is capable of producing on a steady state basis and during continuous operation (when not restricted by seasonal or other deratings) as of such installation as specified by the manufacturer of the generator or, starting from the completion of any subsequent physical change in the generator resulting in an increase in the maximum electrical generating output that the generator is capable of producing on a steady state basis and during continuous operation (when not restricted by seasonal or other deratings), such increased maximum amount (in MWe, rounded to the nearest tenth) as of such completion as specified by the person conducting the physical change.

Natural gas means “natural gas” as defined in §72.2 of this chapter.

Newly affected TR NOX Annual unit means a unit that was not a TR NOX Annual unit when it began operating.
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but that thereafter becomes a TR NOX Annual unit.

Operate or operation means, with regard to a unit, to combust fuel.

Operator means, for a TR NOX Annual source or a TR NOX Annual unit at a source respectively, any person who operates, controls, or supervises a TR NOX Annual unit at the source or the TR NOX Annual unit and shall include, but not be limited to, any holding company, utility system, or plant manager of such source or unit.

Owner means, for a TR NOX Annual source or a TR NOX Annual unit at a source respectively, any person who operates, controls, or supervises a TR NOX Annual unit at the source or the TR NOX Annual unit and shall include, but not be limited to, any holding company, utility system, or plant manager of such source or unit.

Receive or receipt of means, when referring to the Administrator, to come into possession of a document, information, or correspondence, by the Administrator in the regular course of business.

Recordation, record, or recorded means, with regard to TR NOX Annual allowances, the moving of TR NOX Annual allowances by the Administrator into, out of, or between Allowance Management System accounts, for purposes of allocation, auction, transfer, or deduction.

Reference method means any direct test method of sampling and analyzing for an air pollutant as specified in §75.22 of this chapter.

Replacement, replace, or replaced means, with regard to a unit, the demolishing of a unit, or the permanent retirement and permanent disabling of a unit, and the construction of another unit (the replacement unit) to be used instead of the demolished or retired unit (the replaced unit).

Sequential use of energy means:

(1) The use of reject heat from electricity production in a useful thermal energy application or process; or

(2) The use of reject heat from useful thermal energy application or process in electricity production.

Serial number means, for a TR NOX Annual allowance, the unique identification number assigned to each TR NOX Annual allowance by the Administrator.

Solid waste incineration unit means a stationary, fossil-fuel-fired boiler or stationary, fossil-fuel-fired combustion turbine that is a “solid waste incineration unit” as defined in section 129(g)(1) of the Clean Air Act.

Source means all buildings, structures, or installations located in one or more contiguous or adjacent properties under common control of the same person or persons. This definition does not change or otherwise affect the definition of “major source”, “stationary source”, or “source” as set forth and implemented in a title V operating permit program or any other program under the Clean Air Act.

State means one of the States that is subject to the TR NOX Annual Trading Program pursuant to §52.38(a) of this chapter.

Submit or serve means to send or transmit a document, information, or correspondence to the person specified.
in accordance with the applicable regulation:
(1) In person;
(2) By United States Postal Service; or
(3) By other means of dispatch or transmission and delivery;
(4) Provided that compliance with any “submission” or “service” deadline shall be determined by the date of dispatch, transmission, or mailing and not the date of receipt.

* Topping-cycle unit * means a unit in which the energy input to the unit is first used to produce useful power, including electricity, where at least some of the reject heat from the electricity production is then used to provide useful thermal energy.

* Total energy input * means, for a unit, total energy of all forms supplied to the unit, excluding energy produced by the unit. Each form of energy supplied shall be measured by the lower heating value of that form of energy calculated as follows:

\[
LHV = HHV - 10.55(W + 9H)
\]

where:
- \( LHV \) = lower heating value of the form of energy in Btu/lb,
- \( HHV \) = higher heating value of the form of energy in Btu/lb,
- \( W \) = weight % of moisture in the form of energy, and
- \( H \) = weight % of hydrogen in the form of energy.

* Total energy output * means, for a unit, the sum of useful power and useful thermal energy produced by the unit.

* TR NO\(_X\) Annual allowance * means a limited authorization issued and allocated or auctioned by the Administrator under this subpart, or by a State or permitting authority under a SIP revision approved by the Administrator under §52.38(a)(3), (4), or (5) of this chapter, to emit one ton of NO\(_X\) during a control period of the specified calendar year for which the authorization is allocated or auctioned or of any calendar year thereafter under the TR NO\(_X\) Annual Trading Program.

* TR NO\(_X\) Annual allowance deduction or deduct TR NO\(_X\) Annual allowances * means the permanent withdrawal of TR NO\(_X\) Annual allowances by the Administrator from a compliance account (e.g., in order to account for compliance with the TR NO\(_X\) Annual emissions limitation) or from an assurance account (e.g., in order to account for compliance with the assurance provisions under §§97.406 and 97.425).

* TR NO\(_X\) Annual allowances held or hold TR NO\(_X\) Annual allowances * means the TR NO\(_X\) Annual allowances treated as included in an Allowance Management System account as of a specified point in time because at that time they:
(1) Have been recorded by the Administrator in the account or transferred into the account by a correctly submitted, but not yet recorded, TR NO\(_X\) Annual allowance transfer in accordance with this subpart; and
(2) Have not been transferred out of the account by a correctly submitted, but not yet recorded, TR NO\(_X\) Annual allowance transfer in accordance with this subpart.

* TR NO\(_X\) Annual emissions limitation * means, for a TR NO\(_X\) Annual source, the tonnage of NO\(_X\) emissions authorized in a control period in a given year by the TR NO\(_X\) Annual allowances available for deduction for the source under §97.424(a) for such control period.

* TR NO\(_X\) Annual source * means a source that includes one or more TR NO\(_X\) Annual units.

* TR NO\(_X\) Annual Trading Program * means a multi-state NO\(_X\) air pollution control and emission reduction program established in accordance with this subpart and §52.38(a) of this chapter (including such a program that is revised in a SIP revision approved by the Administrator under §52.38(a)(3) or (4) of this chapter or that is established in a SIP revision approved by the Administrator under §52.38(a)(5) of this chapter), as a means of mitigating interstate transport of fine particulates and NO\(_X\).

* TR NO\(_X\) Annual unit * means a unit that is subject to the TR NO\(_X\) Annual Trading Program.

* TR NO\(_X\) Ozone Season Trading Program * means a multi-state NO\(_X\) air pollution control and emission reduction program established in accordance with subpart BBBB of this part and §52.38(b) of this chapter (including such a program that is revised in a SIP revision approved by the Administrator under §52.38(b)(3) or (4) of this chapter or that is established in a SIP revision.
approved by the Administrator under §52.38(b)(5) of this chapter, as a means of mitigating interstate transport of ozone and NOx.

TR SO\textsubscript{2} Group 1 Trading Program means a multi-state SO\textsubscript{2} air pollution control and emission reduction program established in accordance with subpart CCCC of this part and §52.39(a), (b), (d) through (f), (j), and (k) of this chapter (including such a program that is revised in a SIP revision approved by the Administrator under §52.39(f) of this chapter), as a means of mitigating interstate transport of fine particulates and SO\textsubscript{2}.

TR SO\textsubscript{2} Group 2 Trading Program means a multi-state SO\textsubscript{2} air pollution control and emission reduction program established in accordance with subpart DDDD of this part and §52.39(a), (c), and (g) through (k) of this chapter (including such a program that is revised in a SIP revision approved by the Administrator under §52.39(h) of this chapter), as a means of mitigating interstate transport of fine particulates and SO\textsubscript{2}.

Unit means a stationary, fossil-fuel-fired boiler, stationary, fossil-fuel-fired combustion turbine, or other stationary, fossil-fuel-fired combustion device. A unit that undergoes a physical change or is moved to a different location or source shall continue to be treated as the same unit. A unit (the replaced unit) that is replaced by another unit (the replacement unit) at the same or a different source shall continue to be treated as the same unit, and the replacement unit shall be treated as a separate unit.

Unit operating day means, with regard to a unit, a calendar day in which the unit combusts any fuel.

Unit operating hour or hour of unit operation means, with regard to a unit, an hour in which the unit combusts any fuel.

Useful power means, with regard to a unit, electricity or mechanical energy that the unit makes available for use, excluding any such energy used in the power production process (which process includes, but is not limited to, any on-site processing or treatment of fuel combusted at the unit and any on-site emission controls).

Useful thermal energy means thermal energy that is:

(1) Made available to an industrial or commercial process (not a power production process), excluding any heat contained in condensate return or makeup water;

(2) Used in a heating application (e.g., space heating or domestic hot water heating); or

(3) Used in a space cooling application (i.e., in an absorption chiller).

Utility power distribution system means the portion of an electricity grid owned or operated by a utility and dedicated to delivering electricity to customers.

§ 97.403 Measurements, abbreviations, and acronyms.

Measurements, abbreviations, and acronyms used in this subpart are defined as follows:

- Btu—British thermal unit
- CO\textsubscript{2}—carbon dioxide
- H\textsubscript{2}O—water
- hr—hour
- kW—kilowatt electrical
- kWh—kilowatt hour
- lb—pound
- mmBtu—million Btu
- MWe—megawatt electrical
- MWh—megawatt hour
- NO\textsubscript{x}—nitrogen oxides
- O\textsubscript{2}—oxygen
- ppm—parts per million
- scfh—standard cubic feet per hour
- SO\textsubscript{2}—sulfur dioxide
- yr—year

§ 97.404 Applicability.

(a) Except as provided in paragraph (b) of this section:

(1) The following units in a State (and Indian country within the borders of such State) shall be TR NO\textsubscript{x} Annual units, and any source that includes one or more such units shall be a TR NO\textsubscript{x} Annual source, subject to the requirements of this subpart: any stationary, fossil-fuel-fired boiler or stationary, fossil-fuel-fired combustion turbine serving at any time, on or after January 1, 2005, a generator with nameplate capacity of more than 25 MWe producing electricity for sale.

(2) If a stationary boiler or stationary combustion turbine that, under
paragraph (a)(1) of this section, is not a
TR NO\textsubscript{X} Annual unit begins to combust
fossil fuel or to serve a generator with
nameplate capacity of more than 25
MWe producing electricity for sale, the
unit shall become a TR NO\textsubscript{X} Annual
unit as provided in paragraph (a)(1) of
this section on the first date on which
it both combusts fossil fuel and serves
such generator.

(b) Any unit in a State (and Indian
country within the borders of such
State) that otherwise is a TR NO\textsubscript{X} An-
nual unit under paragraph (a) of this
section and that meets the require-
ments set forth in paragraph (b)(1)(i) or
(2)(i) of this section shall not be a TR
NO\textsubscript{X} Annual unit:

(1)(i) Any unit:
(A) Qualifying as a cogeneration unit
throughout the later of 2005 or the 12-
month period starting on the date the
unit first produces electricity and con-
tinuing to qualify as a cogeneration
unit throughout each calendar year
ending after the later of 2005 or such 12-
month period; and
(B) Not supplying in 2005 or any cal-
endar year thereafter more than one-
third of the unit’s potential electric
output capacity or 219,000 MWh, which-
ever is greater, to any utility power
distribution system for sale.

(ii) If, after qualifying under para-
graph (b)(2)(i) of this section as not
being a TR NO\textsubscript{X} Annual unit, a unit
subsequently no longer meets all the
requirements of paragraph (b)(1)(i) of
this section, the unit shall become a
TR NO\textsubscript{X} Annual unit starting on the
earlier of January 1 after the first cal-
endar year during which the unit first
no longer qualifies as a solid waste in-
cineration unit or January 1 after the
first 3 consecutive calendar years after
2005 for which the unit has an average
annual fuel consumption of fossil fuel
of 20 percent or more. The unit shall
thereafter continue to be a TR NO\textsubscript{X}
Annual unit.

(c) A certifying official of an owner
or operator of any unit or other equip-
ment may submit a petition (including
any supporting documents) to the Ad-
ministrator at any time for a deter-
mination concerning the applicability,
under paragraphs (a) and (b) of this sec-
tion or a SIP revision approved under
§52.38(a)(4) or (5) of this chapter, of the
TR NO\textsubscript{X} Annual Trading Program to
the unit or other equipment.

(1) Petition content. The petition
shall be in writing and include the
identification of the unit or other equip-
ment and the relevant facts about
the unit or other equipment. The peti-
tion and any other documents provided
to the Administrator in connection
with the petition shall include the fol-
lowing certification statement, signed
by the certifying official: “I am au-
thorized to make this submission on
behalf of the owners and operators of
the unit or other equipment for which
the submission is made. I certify under
penalty of law that I have personally
examined, and am familiar with, the
statements and information submitted
in this document and all its attach-
ments. Based on my inquiry of those
individuals with primary responsibility
for obtaining the information, I certify
that the statements and information
are to the best of my knowledge and belief true, accurate, and complete. I am aware that there are significant penalties for submitting false statements and information or omitting required statements and information, including the possibility of fine or imprisonment."

(2) Response. The Administrator will issue a written response to the petition and may request supplemental information determined by the Administrator to be relevant to such petition. The Administrator’s determination concerning the applicability, under paragraphs (a) and (b) of this section, of the TR NO\textsubscript{X} Annual Trading Program to the unit or other equipment shall be binding on any State or permitting authority unless the Administrator determines that the petition or other documents or information provided in connection with the petition contained significant, relevant errors or omissions.

§97.405 Retired unit exemption.

(a)(1) Any TR NO\textsubscript{X} Annual unit that is permanently retired shall be exempt from §§97.406(b) and (c)(1), §97.424, and §§97.430 through 97.435.

(2) The exemption under paragraph (a)(1) of this section shall become effective the day on which the TR NO\textsubscript{X} Annual unit is permanently retired. Within 30 days of the unit’s permanent retirement, the designated representative shall submit a statement to the Administrator. The statement shall state, in a format prescribed by the Administrator, that the unit was permanently retired on a specified date and will comply with the requirements of paragraph (b) of this section.

(b) Special provisions. (1) A unit exempt under paragraph (a) of this section shall lose its exemption on the first date on which the unit resumes operation. Such unit shall be treated, for purposes of applying allocation, monitoring, reporting, and recordkeeping requirements under this subpart, as a unit that commences commercial operation on the first date on which the unit resumes operation.

§97.406 Standard requirements.

(a) Designated representative requirements. The owners and operators shall comply with the requirement to have a designated representative, and may have an alternate designated representative, in accordance with §§97.413 through 97.418.

(b) Emissions monitoring, reporting, and recordkeeping requirements.

(1) The owners and operators, and the designated representative, of each TR NO\textsubscript{X} Annual source and each TR NO\textsubscript{X} Annual unit at the source shall comply with the monitoring, reporting, and recordkeeping requirements of §§97.430 through 97.435.

(2) The emissions data determined in accordance with §§97.430 through 97.435 shall be used to calculate allocations of TR NO\textsubscript{X} Annual allowances under §§97.411(a)(2) and (b) and 97.412 and to determine compliance with the TR NO\textsubscript{X} Annual emissions limitation and assurance provisions under paragraph (c) of this section, provided that, for each monitoring location from which mass emissions are reported, the mass emissions amount used for the monitoring location determined in accordance with §§97.430
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through 97.435 and rounded to the nearest ton, with any fraction of a ton less than 0.50 being deemed to be zero.

(c) $NO_x$ emissions requirements. (1) TR $NO_x$ Annual emissions limitation. (i) As of the allowance transfer deadline for a control period in a given year, the owners and operators of each TR $NO_x$ Annual source and each TR $NO_x$ Annual unit at the source shall hold, in the source’s compliance account, TR $NO_x$ Annual allowances available for deduction for such control period under § 97.424(a) in an amount not less than the tons of total $NO_x$ emissions for such control period from all TR $NO_x$ Annual units at the source.

(ii) If total $NO_x$ emissions during a control period in a given year from the TR $NO_x$ Annual units at a TR $NO_x$ Annual source are in excess of the TR $NO_x$ Annual emissions limitation set forth in paragraph (c)(1)(i) of this section, then:

(A) The owners and operators of the source and each TR $NO_x$ Annual unit at the source shall hold the TR $NO_x$ Annual allowances required for deduction under § 97.424(d); and

(B) The owners and operators of the source and each TR $NO_x$ Annual unit at the source shall pay any fine, penalty, or assessment or comply with any other remedy imposed, for the same violations, under the Clean Air Act, and each ton of such excess emissions and each day of such control period shall constitute a separate violation of this subpart and the Clean Air Act.

(2) TR $NO_x$ Annual assurance provisions. (i) If total $NO_x$ emissions during a control period in a given year from all TR $NO_x$ Annual units at TR $NO_x$ Annual sources in a State (and Indian country within the borders of such State) exceed the State assurance level, then the owners and operators of such sources and units in each group of one or more sources and units having a common designated representative for such control period, where the common designated representative’s share of such $NO_x$ emissions during such control period exceeds the common designated representative’s assurance level for the State and such control period, shall hold (in the assurance account established for the owners and operators of such group) TR $NO_x$ Annual allowances available for deduction for such control period under § 97.425(a) in an amount equal to two times the product (rounded to the nearest whole number), as determined by the Administrator in accordance with § 97.425(b), of multiplying—

(A) The quotient of the amount by which the common designated representative’s share of such $NO_x$ emissions exceeds the common designated representative’s assurance level divided by the sum of the amounts, determined for all common designated representatives for such sources and units in the State (and Indian country within the borders of such State) for such control period, by which each common designated representative’s share of such $NO_x$ emissions exceeds the respective common designated representative’s assurance level; and

(B) The amount by which total $NO_x$ emissions from all TR $NO_x$ Annual units at TR $NO_x$ Annual sources in the State (and Indian country within the borders of such State) for such control period exceed the State assurance level.

(ii) The owners and operators shall hold the TR $NO_x$ Annual allowances required under paragraph (c)(2)(i) of this section, as of midnight of November 1 (if it is a business day), or midnight of the first business day thereafter (if November 1 is not a business day), immediately after such control period.

(iii) Total $NO_x$ emissions from all TR $NO_x$ Annual units at TR $NO_x$ Annual sources in a State (and Indian country within the borders of such State) during a control period in a given year exceed the State assurance level if such total $NO_x$ emissions exceed the sum, for such control period, of the State $NO_x$ Annual trading budget under § 97.410(a) and the State’s variability limit under § 97.410(b).

(iv) It shall not be a violation of this subpart or of the Clean Air Act if total $NO_x$ emissions from all TR $NO_x$ Annual units at TR $NO_x$ Annual sources in a State (and Indian country within the borders of such State) during a control period exceed the State assurance level or if a common designated representative’s share of total $NO_x$ emissions from the TR $NO_x$ Annual units at TR
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NO\textsubscript{X} Annual sources in a State (and Indian country within the borders of such State) during a control period exceeds the common designated representative's assurance level.

(v) To the extent the owners and operators fail to hold TR NO\textsubscript{X} Annual allowances for a control period in a given year in accordance with paragraphs (c)(2)(i) through (iii) of this section,

(A) The owners and operators shall pay any fine, penalty, or assessment or comply with any other remedy imposed under the Clean Air Act; and

(B) Each TR NO\textsubscript{X} Annual allowance that the owners and operators fail to hold for such control period in accordance with paragraphs (c)(2)(i) through (iii) of this section and each day of such control period shall constitute a separate violation of this subpart and the Clean Air Act.

(3) Compliance periods.—(i) A TR NO\textsubscript{X} Annual unit shall be subject to the requirements under paragraph (c)(1) of this section for the control period starting on the later of January 1, 2012 or the deadline for meeting the unit's monitor certification requirements under § 97.430(b) and for each control period thereafter.

(ii) A TR NO\textsubscript{X} Annual unit shall be subject to the requirements under paragraph (c)(2) of this section for the control period starting on the later of January 1, 2014 or the deadline for meeting the unit's monitor certification requirements under § 97.430(b) and for each control period thereafter.

(4) Vintage of allowances held for compliance. (i) A TR NO\textsubscript{X} Annual allowance held for compliance with the requirements under paragraph (c)(1)(i) of this section for a control period in a given year must be a TR NO\textsubscript{X} Annual allowance that was allocated for such control period or a control period in a prior year.

(ii) A TR NO\textsubscript{X} Annual allowance held for compliance with the requirements under paragraphs (c)(1)(ii)(A) and (2)(i) through (iii) of this section for a control period in a given year must be a TR NO\textsubscript{X} Annual allowance that was allocated for a control period in a prior year or the control period in the given year or in the immediately following year.

(5) Allowance Management System requirements. Each TR NO\textsubscript{X} Annual allowance shall be held in, deducted from, or transferred into, out of, or between Allowance Management System accounts in accordance with this subpart.

(6) Limited authorization. A TR NO\textsubscript{X} Annual allowance is a limited authorization to emit one ton of NO\textsubscript{X} during the control period in one year. Such authorization is limited in its use and duration as follows:

(i) Such authorization shall only be used in accordance with the TR NO\textsubscript{X} Annual Trading Program; and

(ii) Notwithstanding any other provision of this subpart, the Administrator has the authority to terminate or limit the use and duration of such authorization to the extent the Administrator determines is necessary or appropriate to implement any provision of the Clean Air Act.

(7) Property right. A TR NO\textsubscript{X} Annual allowance does not constitute a property right.

(d) Title V permit requirements. (1) No title V permit revision shall be required for any allocation, holding, deduction, or transfer of TR NO\textsubscript{X} Annual allowances in accordance with this subpart.

(2) A description of whether a unit is required to monitor and report NO\textsubscript{X} emissions using a continuous emission monitoring system (under subpart H of part 75 of this chapter), an excepted monitoring system (under appendices D and E to part 75 of this chapter), a low mass emissions excepted monitoring methodology (under § 75.19 of this chapter), or an alternative monitoring system (under subpart E of part 75 of this chapter) in accordance with §§ 97.430 through 97.435 may be added to, or changed in, a title V permit using minor permit modification procedures in accordance with §§70.7(e)(2) and 71.7(e)(1) of this chapter, provided that the requirements applicable to the described monitoring and reporting (as added or changed, respectively) are already incorporated in such permit. This paragraph explicitly provides that the addition of, or change to, a unit's description as described in the prior sentence is eligible for minor permit modification procedures in accordance
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with §§ 70.7(e)(2)(I)(B) and 71.7(e)(1)(I)(B) of this chapter.

(e) Additional recordkeeping and reporting requirements. (1) Unless otherwise provided, the owners and operators of each TR NOX Annual source and each TR NOX Annual unit at the source shall keep on site at the source each of the following documents (in hardcopy or electronic format) for a period of 5 years from the date the document is created. This period may be extended for cause, at any time before the end of 5 years, in writing by the Administrator.

(i) The certificate of representation under §97.416 for the designated representative for the source and each TR NOX Annual unit at the source and all documents that demonstrate the truth of the statements in the certificate of representation; provided that the certificate and documents shall be retained on site at the source beyond such 5-year period until such certificate of representation and documents are superseded because of the submission of a new certificate of representation under §97.416 changing the designated representative.

(ii) All emissions monitoring information, in accordance with this subpart.

(iii) Copies of all reports, compliance certifications, and other submissions and all records made or required under, or to demonstrate compliance with the requirements of, the TR NOX Annual Trading Program.

(2) The designated representative of a TR NOX Annual source and each TR NOX Annual unit at the source shall make all submissions required under the TR NOX Annual Trading Program, except as provided in §97.418. This requirement does not change, create an exemption from, or otherwise affect the responsible official submission requirements under a title V operating permit program in parts 70 and 71 of this chapter.

(f) Liability. (1) Any provision of the TR NOX Annual Trading Program that applies to a TR NOX Annual source or the designated representative of a TR NOX Annual source shall also apply to the owners and operators of such source and of the TR NOX Annual units at the source.

(2) Any provision of the TR NOX Annual Trading Program that applies to a TR NOX Annual unit or the designated representative of a TR NOX Annual unit shall also apply to the owners and operators of such unit.

(g) Effect on other authorities. No provision of the TR NOX Annual Trading Program or exemption under §97.405 shall be construed as exempting or excluding the owners and operators, and the designated representative, of a TR NOX Annual source or TR NOX Annual unit from compliance with any other provision of the applicable, approved State implementation plan, a federally enforceable permit, or the Clean Air Act.

[76 FR 48379, Aug. 8, 2011, as amended at 77 FR 10334, Feb. 21, 2012]

§ 97.407 Computation of time.

(a) Unless otherwise stated, any time period scheduled, under the TR NOX Annual Trading Program, to begin on the occurrence of an act or event shall begin on the day the act or event occurs.

(b) Unless otherwise stated, any time period scheduled, under the TR NOX Annual Trading Program, to begin before the occurrence of an act or event shall be computed so that the period ends the day before the act or event occurs.

(c) Unless otherwise stated, if the final day of any time period, under the TR NOX Annual Trading Program, is not a business day, the time period shall be extended to the next business day.

§ 97.408 Administrative appeal procedures.

The administrative appeal procedures for decisions of the Administrator under the TR NOX Annual Trading Program are set forth in part 78 of this chapter.
§ 97.410 State NO\textsubscript{X} Annual trading budgets, new unit set-asides, Indian country new unit set-aside, and variability limits.

(a) The State NO\textsubscript{X} Annual trading budgets, new unit set-asides, and Indian country new unit set-asides for allocations of TR NO\textsubscript{X} Annual allowances for the control periods in 2012 and thereafter are as follows:

1. **Alabama.** (i) The NO\textsubscript{X} annual trading budget for 2012 and 2013 is 72,691 tons.
   (ii) The NO\textsubscript{X} annual new unit set-aside for 2012 and 2013 is 1,454 tons.
   (iii) [Reserved]
   (iv) The NO\textsubscript{X} annual trading budget for 2014 and thereafter is 71,962 tons.
   (v) The NO\textsubscript{X} annual new unit set-aside for 2014 and thereafter is 1,439 tons.
   (vi) [Reserved]

2. **Georgia.** (i) The NO\textsubscript{X} annual trading budget for 2012 and 2013 is 62,010 tons.
   (ii) The NO\textsubscript{X} annual new unit set-aside for 2012 and 2013 is 1,240 tons.
   (iii) [Reserved]
   (iv) The NO\textsubscript{X} annual trading budget for 2014 and thereafter is 40,540 tons.
   (v) The NO\textsubscript{X} annual new unit set-aside for 2014 and thereafter is 811 tons.
   (vi) [Reserved]

3. **Illinois.** (i) The NO\textsubscript{X} annual trading budget for 2012 and 2013 is 47,872 tons.
   (ii) The NO\textsubscript{X} annual new unit set-aside for 2012 and 2013 is 3,830 tons.
   (iii) [Reserved]
   (iv) The NO\textsubscript{X} annual trading budget for 2014 and thereafter is 47,872 tons.
   (v) The NO\textsubscript{X} annual new unit set-aside for 2014 and thereafter is 3,830 tons.
   (vi) [Reserved]

4. **Indiana.** (i) The NO\textsubscript{X} annual trading budget for 2012 and 2013 is 109,726 tons.
   (ii) The NO\textsubscript{X} annual new unit set-aside for 2012 and 2013 is 3,292 tons.
   (iii) [Reserved]
   (iv) The NO\textsubscript{X} annual trading budget for 2014 and thereafter is 108,424 tons.
   (v) The NO\textsubscript{X} annual new unit set-aside for 2014 and thereafter is 3,253 tons.
   (vi) [Reserved]

5. **Iowa.** (i) The NO\textsubscript{X} annual trading budget for 2012 and 2013 is 38,335 tons.
   (ii) The NO\textsubscript{X} annual new unit set-aside for 2012 and 2013 is 729 tons.
   (iii) [Reserved]
   (iv) The NO\textsubscript{X} annual new unit set-aside for 2012 and 2013 is 38 tons.
   (v) The NO\textsubscript{X} annual trading budget for 2014 and thereafter is 37,498 tons.
   (vi) The NO\textsubscript{X} annual new unit set-aside for 2014 and thereafter is 712 tons.

6. **Kansas.** (i) The NO\textsubscript{X} annual trading budget for 2012 and 2013 is 30,714 tons.
   (ii) The NO\textsubscript{X} annual new unit set-aside for 2012 and 2013 is 583 tons.
   (iii) [Reserved]
   (iv) The NO\textsubscript{X} annual new unit set-aside for 2014 and thereafter is 485 tons.
   (v) The NO\textsubscript{X} annual new unit set-aside for 2014 and thereafter is 26 tons.

7. **Kentucky.** (i) The NO\textsubscript{X} annual trading budget for 2012 and 2013 is 85,086 tons.
   (ii) The NO\textsubscript{X} annual new unit set-aside for 2012 and 2013 is 3,403 tons.
   (iii) [Reserved]
   (iv) The NO\textsubscript{X} annual new unit set-aside for 2014 and thereafter is 3,090 tons.
   (v) The NO\textsubscript{X} annual new unit set-aside for 2014 and thereafter is 26 tons.

8. **Maryland.** (i) The NO\textsubscript{X} annual trading budget for 2012 and 2013 is 16,633 tons.
   (ii) The NO\textsubscript{X} annual new unit set-aside for 2012 and 2013 is 333 tons.
   (iii) [Reserved]
   (iv) The NO\textsubscript{X} annual new unit set-aside for 2014 and thereafter is 331 tons.
   (v) [Reserved]

9. **Michigan.** (i) The NO\textsubscript{X} annual trading budget for 2012 and 2013 is 65,421 tons.
   (ii) The NO\textsubscript{X} annual new unit set-aside for 2012 and 2013 is 1,243 tons.
   (iii) [Reserved]
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(iv) The NO\textsubscript{X} annual trading budget for 2014 and thereafter is 63,940 tons.

(v) The NO\textsubscript{X} annual new unit set-aside for 2014 and thereafter is 1,198 tons.

(vi) The NO\textsubscript{X} annual Indian country new unit set-aside for 2014 and thereafter is 63 tons.

(10) Minnesota. (i) The NO\textsubscript{X} annual trading budget for 2012 and 2013 is 29,572 tons.

(ii) The NO\textsubscript{X} annual new unit set-aside for 2012 and 2013 is 561 tons.

(iii) The NO\textsubscript{X} annual Indian country new unit set-aside for 2012 and 2013 is 30 tons.

(iv) The NO\textsubscript{X} annual trading budget for 2014 and thereafter is 29,572 tons.

(v) The NO\textsubscript{X} annual new unit set-aside for 2014 and thereafter is 561 tons.

(vi) The NO\textsubscript{X} annual Indian country new unit set-aside for 2014 and thereafter is 30 tons.

(11) Missouri. (i) The NO\textsubscript{X} annual trading budget for 2012 and 2013 is 52,374 tons.

(ii) The NO\textsubscript{X} annual new unit set-aside for 2012 and 2013 is 1,571 tons.

(iii) The NO\textsubscript{X} annual Indian country new unit set-aside for 2012 and 2013 is 30 tons.

(iv) The NO\textsubscript{X} annual trading budget for 2014 and thereafter is 48,717 tons.

(v) The NO\textsubscript{X} annual new unit set-aside for 2014 and thereafter is 1,462 tons.

(vi) [Reserved]

(12) Nebraska. (i) The NO\textsubscript{X} annual trading budget for 2012 and 2013 is 30,039 tons.

(ii) The NO\textsubscript{X} annual new unit set-aside for 2012 and 2013 is 1,772 tons.

(iii) The NO\textsubscript{X} annual Indian country new unit set-aside for 2012 and 2013 is 30 tons.

(iv) The NO\textsubscript{X} annual trading budget for 2014 and thereafter is 30,039 tons.

(v) The NO\textsubscript{X} annual new unit set-aside for 2014 and thereafter is 1,772 tons.

(vi) The NO\textsubscript{X} annual Indian country new unit set-aside for 2014 and thereafter is 30 tons.

(13) New Jersey. (i) The NO\textsubscript{X} annual trading budget for 2012 and 2013 is 7,945 tons.

(ii) The NO\textsubscript{X} annual new unit set-aside for 2012 and 2013 is 164 tons.

(iii) [Reserved]

(iv) The NO\textsubscript{X} annual trading budget for 2014 and thereafter is 7,945 tons.

(v) The NO\textsubscript{X} annual new unit set-aside for 2014 and thereafter is 159 tons.

(vi) [Reserved]

(14) New York. (i) The NO\textsubscript{X} annual trading budget for 2012 and 2013 is 21,028 tons.

(ii) The NO\textsubscript{X} annual new unit set-aside for 2012 and 2013 is 400 tons.

(iii) The NO\textsubscript{X} annual Indian country new unit set-aside for 2012 and 2013 is 21 tons.

(iv) The NO\textsubscript{X} annual trading budget for 2014 and thereafter is 21,028 tons.

(v) The NO\textsubscript{X} annual new unit set-aside for 2014 and thereafter is 400 tons.

(vi) The NO\textsubscript{X} annual Indian country new unit set-aside for 2014 and thereafter is 21 tons.

(15) North Carolina. (i) The NO\textsubscript{X} annual trading budget for 2012 and 2013 is 50,587 tons.

(ii) The NO\textsubscript{X} annual new unit set-aside for 2012 and 2013 is 2,984 tons.

(iii) The NO\textsubscript{X} annual Indian country new unit set-aside for 2012 and 2013 is 51 tons.

(iv) The NO\textsubscript{X} annual trading budget for 2014 and thereafter is 41,553 tons.

(v) The NO\textsubscript{X} annual new unit set-aside for 2014 and thereafter is 2,451 tons.

(vi) The NO\textsubscript{X} annual Indian country new unit set-aside for 2014 and thereafter is 42 tons.

(16) Ohio. (i) The NO\textsubscript{X} annual trading budget for 2012 and 2013 is 92,703 tons.

(ii) The NO\textsubscript{X} annual new unit set-aside for 2012 and 2013 is 1,854 tons.

(iii) [Reserved]

(iv) The NO\textsubscript{X} annual trading budget for 2014 and thereafter is 87,493 tons.

(v) The NO\textsubscript{X} annual new unit set-aside for 2014 and thereafter is 1,750 tons.

(vi) [Reserved]

(17) Pennsylvania. (i) The NO\textsubscript{X} annual trading budget for 2012 and 2013 is 119,986 tons.

(ii) The NO\textsubscript{X} annual new unit set-aside for 2012 and 2013 is 2,400 tons.

(iii) [Reserved]

(iv) The NO\textsubscript{X} annual trading budget for 2014 and thereafter is 119,986 tons.

(v) The NO\textsubscript{X} annual new unit set-aside for 2014 and thereafter is 2,384 tons.

(vi) [Reserved]
(18) South Carolina. (i) The NO\textsubscript{X} annual trading budget for 2012 and 2013 is 32,498 tons.
(ii) The NO\textsubscript{X} annual new unit set-aside for 2012 and 2013 is 617 tons.
(iii) The NO\textsubscript{X} annual Indian country new unit set-aside for 2012 and 2013 is 33 tons.
(iv) The NO\textsubscript{X} annual trading budget for 2014 and thereafter is 32,498 tons.
(v) The NO\textsubscript{X} annual new unit set-aside for 2014 and thereafter is 617 tons.
(vi) The NO\textsubscript{X} annual Indian country new unit set-aside for 2014 and thereafter is 33 tons.

(19) Tennessee. (i) The NO\textsubscript{X} annual trading budget for 2012 and 2013 is 35,703 tons.
(ii) The NO\textsubscript{X} annual new unit set-aside for 2012 and 2013 is 714 tons.
(iii) The NO\textsubscript{X} annual new unit set-aside for 2014 and thereafter is 387 tons.
(iv) The NO\textsubscript{X} annual trading budget for 2014 and thereafter is 19,337 tons.
(v) The NO\textsubscript{X} annual new unit set-aside for 2014 and thereafter is 387 tons.
(vi) The NO\textsubscript{X} annual Indian country new unit set-aside for 2014 and thereafter is 33 tons.

(20) Texas. (i) The NO\textsubscript{X} annual trading budget for 2012 and 2013 is 134,970 tons.
(ii) The NO\textsubscript{X} annual new unit set-aside for 2012 and 2013 is 5,264 tons.
(iii) The NO\textsubscript{X} annual Indian country new unit set-aside for 2012 and 2013 is 135 tons.
(iv) The NO\textsubscript{X} annual trading budget for 2014 and thereafter is 134,970 tons.
(v) The NO\textsubscript{X} annual new unit set-aside for 2014 and thereafter is 5,264 tons.
(vi) The NO\textsubscript{X} annual Indian country new unit set-aside for 2014 and thereafter is 135 tons.

(21) Virginia. (i) The NO\textsubscript{X} annual trading budget for 2012 and 2013 is 33,242 tons.
(ii) The NO\textsubscript{X} annual new unit set-aside for 2012 and 2013 is 1,662 tons.
(iii) [Reserved]
(iv) The NO\textsubscript{X} annual trading budget for 2014 and thereafter is 33,242 tons.
(v) The NO\textsubscript{X} annual new unit set-aside for 2014 and thereafter is 1,662 tons.
(vi) [Reserved]

(22) West Virginia. (i) The NO\textsubscript{X} annual trading budget for 2012 and 2013 is 361 tons.
(ii) The NO\textsubscript{X} annual new unit set-aside for 2012 and 2013 is 2,974 tons.
(iii) [Reserved]

(b) The States’ variability limits for the State NO\textsubscript{X} Annual trading budgets for the control periods in 2014 and thereafter are as follows:

(1) The NO\textsubscript{X} annual variability limit for Alabama is 12,953 tons.
(2) The NO\textsubscript{X} annual variability limit for Georgia is 7,297 tons.
(3) The NO\textsubscript{X} annual variability limit for Illinois is 8,617 tons.
(4) The NO\textsubscript{X} annual variability limit for Indiana is 19,516 tons.
(5) The NO\textsubscript{X} annual variability limit for Iowa is 6,750 tons.
(6) The NO\textsubscript{X} annual variability limit for Kansas is 4,601 tons.
(7) The NO\textsubscript{X} annual variability limit for Kentucky is 13,903 tons.
(8) The NO\textsubscript{X} annual variability limit for Maryland is 2,983 tons.
(9) The NO\textsubscript{X} annual variability limit for Michigan is 11,347 tons.
(10) The NO\textsubscript{X} annual variability limit for Minnesota is 5,323 tons.
(11) The NO\textsubscript{X} annual variability limit for Missouri is 8,769 tons.
(12) The NO\textsubscript{X} annual variability limit for Nebraska is 5,407 tons.
(13) The NO\textsubscript{X} annual variability limit for New Jersey is 1,430 tons.
(14) The NO\textsubscript{X} annual variability limit for New York is 3,785 tons.
(15) The NO\textsubscript{X} annual variability limit for North Carolina is 7,480 tons.
(16) The NO\textsubscript{X} annual variability limit for Ohio is 15,749 tons.
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(17) The NO\textsubscript{X} annual variability limit for Pennsylvania is 21,455 tons.
(18) The NO\textsubscript{X} annual variability limit for South Carolina is 5,850 tons.
(19) The NO\textsubscript{X} annual variability limit for Tennessee is 3,481 tons.
(20) The NO\textsubscript{X} annual variability limit for Texas is 24,295 tons.
(21) The NO\textsubscript{X} annual variability limit for Virginia is 5,984 tons.
(22) The NO\textsubscript{X} annual variability limit for West Virginia is 9,825 tons.
(23) The NO\textsubscript{X} annual variability limit for Wisconsin is 5,917 tons.

(c) Each NO\textsubscript{X} annual trading budget identified in this section includes any tons in a new unit set aside or Indian country new unit set aside, but does not include any tons in a variability limit.

[77 FR 10334, Feb. 21, 2012]

EFFECTIVE DATE NOTE: At 77 FR 34844, June 12, 2012, § 97.410 was amended by revising paragraphs (a)(2)(iv) and (a)(2)(v); revising paragraphs (a)(6), (a)(11), (a)(14), (a)(16), and (a)(20); and revising paragraphs (b)(2), (b)(6), (b)(11), (b)(14), (b)(16) and (b)(20), effective Aug. 13, 2012. For the convenience of the user, the revised text is set forth as follows:

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State NO\textsubscript{X} Annual trading budgets, new unit set-asides, Indian country new unit set-aside, and variability limits.

(a) * * *

(2) The NO\textsubscript{X} annual trading budget for 2014 and thereafter is 53,738 tons.

(iv) The NO\textsubscript{X} annual trading budget for 2014 and thereafter is 53,738 tons.

(v) The NO\textsubscript{X} annual new unit set-aside for 2014 and thereafter is 1,975 tons.

* * * * *

(6) Kansas. (i) The NO\textsubscript{X} annual trading budget for 2012 and 2013 is 31,354 tons.

(ii) The NO\textsubscript{X} annual new unit set-aside for 2012 and 2013 is 596 tons.

(iii) The NO\textsubscript{X} annual Indian country new unit set-aside for 2012 and 2013 is 31 tons.

(iv) The NO\textsubscript{X} annual trading budget for 2014 and thereafter is 31,354 tons.

(v) The NO\textsubscript{X} annual new unit set-aside for 2014 and thereafter is 596 tons.

(vi) The NO\textsubscript{X} annual Indian country new unit set-aside for 2014 and thereafter is 31 tons.

* * * * *

(11) Missouri. (i) The NO\textsubscript{X} annual trading budget for 2012 and 2013 is 52,400 tons.

(ii) The NO\textsubscript{X} annual new unit set-aside for 2012 is 1,572 tons and for 2013 is 3,144 tons.

(iii) [Reserved]

(iv) The NO\textsubscript{X} annual variability limit for Georgia is 9,673 tons.

* * * * *

(16) Ohio. (i) The NO\textsubscript{X} annual trading budget for 2012 and 2013 is 95,488 tons.

(ii) The NO\textsubscript{X} annual new unit set-aside for 2012 and 2013 is 1,909 tons.

(iii) [Reserved]

(iv) The NO\textsubscript{X} annual trading budget for 2014 and thereafter is 90,258 tons.

(v) The NO\textsubscript{X} annual new unit set-aside for 2014 and thereafter is 1,865 tons.

* * * * *

(20) Texas. (i) The NO\textsubscript{X} annual trading budget for 2012 and 2013 is 137,701 tons.

(ii) The NO\textsubscript{X} annual new unit set-aside for 2012 and 2013 is 5,370 tons.

(iii) The NO\textsubscript{X} annual Indian country new unit set-aside for 2012 and 2013 is 138 tons.

(iv) The NO\textsubscript{X} annual trading budget for 2014 and thereafter is 137,701 tons.

(v) The NO\textsubscript{X} annual new unit set-aside for 2014 and thereafter is 5,370 tons.

(vi) The NO\textsubscript{X} annual Indian country new unit set-aside for 2014 and thereafter is 138 tons.

* * * * *

(b) * * *

(2) The NO\textsubscript{X} annual variability limit for Georgia is 9,673 tons.

* * * * *

(6) The NO\textsubscript{X} annual variability limit for Kansas is 5,644 tons.

* * * * *

(11) The NO\textsubscript{X} annual variability limit for Missouri is 8,774 tons.

* * * * *
§ 97.411 Timing requirements for TR NO\textsubscript{X} Annual allowance allocations.

(a) Existing units. (1) TR NO\textsubscript{X} Annual allowances are allocated, for the control periods in 2012 and each year thereafter, as provided in a notice of data availability issued by the Administrator. Providing an allocation to a unit in such notice does not constitute a determination that the unit is a TR NO\textsubscript{X} Annual unit, and not providing an allocation to a unit in such notice does not constitute a determination that the unit is not a TR NO\textsubscript{X} Annual unit.

(2) Notwithstanding paragraph (a)(1) of this section, if a unit provided an allocation in the notice of data availability issued under paragraph (a)(1) of this section does not operate, starting after 2011, during the control period in two consecutive years, such unit will not be allocated the TR NO\textsubscript{X} Annual allowances provided in such notice for the unit for the control periods in the fifth year after the first such year and in each year after that fifth year. All TR NO\textsubscript{X} Annual allowances that would otherwise have been allocated to such unit will be allocated to the new unit set-aside for the State where such unit is located and for the respective years involved. If such unit resumes operation, the Administrator will allocate TR NO\textsubscript{X} Annual allowances to the unit in accordance with paragraph (b) of this section.

(b) New units. (1) New unit set-asides. (i) By June 1, 2012 and June 1 of each year thereafter, the Administrator will calculate the TR NO\textsubscript{X} Annual allowance allocation to each TR NO\textsubscript{X} Annual unit in a State, in accordance with §97.412(a)(2) through (7) and (12), for the control period in the year of the applicable calculation deadline under this paragraph and will promulgate a notice of data availability of the results of the calculations.

(ii) For each notice of data availability required in paragraph (b)(1)(i) of this section, the Administrator will provide an opportunity for submission of objections to the calculations referenced in such notice.

(A) Objections shall be submitted by the deadline specified in each notice of data availability required in paragraph (b)(1)(i) of this section and shall be limited to addressing whether the calculations (including the identification of the TR NO\textsubscript{X} Annual units) are in accordance with §97.412(a)(2) through (7) and (12) and §§97.406(b)(2) and 97.430 through 97.435.

(B) The Administrator will adjust the calculations to the extent necessary to ensure that they are in accordance with the provisions referenced in paragraph (b)(1)(i)(A) of this section. By August 1 immediately after the promulgation of each notice of data availability required in paragraph (b)(1)(i) of this section, the Administrator will promulgate a notice of data availability of any adjustments that the Administrator determines to be necessary with regard to allocations under §97.412(a)(2) through (7) and (12) and the reasons for accepting or rejecting any objections submitted in accordance with paragraph (b)(1)(ii)(A) of this section.

(iii) If the new unit set-aside for such control period contains any TR NO\textsubscript{X} Annual allowances that have not been allocated in the applicable notice of data availability required in paragraph (b)(1)(ii) of this section, the Administrator will promulgate, by December 15 immediately after such notice, a notice of data availability that identifies any TR NO\textsubscript{X} Annual units that commenced commercial operation during the period starting January 1 of the year before the year of such control period and ending November 30 of year of such control period.

(iv) For each notice of data availability required in paragraph (b)(1)(iii) of this section, the Administrator will provide an opportunity for submission of objections to the identification of TR NO\textsubscript{X} annual units in such notice.
(A) Objections shall be submitted by the deadline specified in each notice of data availability required in paragraph (b)(1)(iii) of this section and shall be limited to addressing whether the identification of TR NO\textsubscript{X} annual units in such notice is in accordance with paragraph (b)(1)(iii) of this section.

(B) The Administrator will adjust the identification of TR NO\textsubscript{X} Annual units in the each notice of data availability required in paragraph (b)(1)(iii) of this section to the extent necessary to ensure that it is in accordance with paragraph (b)(1)(iii) of this section and will calculate the TR NO\textsubscript{X} Annual allowance allocation to each TR NO\textsubscript{X} Annual unit in accordance with §97.412(a)(9), (10), and (12) and §§97.406(b)(2) and 97.430 through 97.435. By February 15 immediately after the promulgation of each notice of data availability required in paragraph (b)(1)(iii) of this section, the Administrator will promulgate a notice of data availability of any adjustments that the Administrator determines to be necessary, the reasons for accepting or rejecting any objections submitted in accordance with paragraph (b)(1)(iv)(A) of this section, and the results of such calculations.

(v) To the extent any TR NO\textsubscript{X} Annual allowances are added to the new unit set-aside after promulgation of each notice of data availability required in paragraph (b)(1)(iii) of this section, the Administrator will promulgate additional notices of data availability, as deemed appropriate, of the allocation of such TR NO\textsubscript{X} Annual allowances in accordance with §97.412(a)(10).

(2) Indian country new unit set-asides. (i) By June 1, 2012 and June 1 of each year thereafter, the Administrator will calculate the TR NO\textsubscript{X} Annual allowance allocation to each TR NO\textsubscript{X} Annual unit in Indian country within the borders of a State, in accordance with §97.412(b)(2) through (7) and (12), for the control period in the year of the applicable calculation deadline under this paragraph and will promulgate a notice of data availability of the results of the calculations.

(ii) For each notice of data availability required in paragraph (b)(2)(i) of this section, the Administrator will provide an opportunity for submission of objections to the calculations referenced in such notice.

(A) Objections shall be submitted by the deadline specified in each notice of data availability required in paragraph (b)(2)(i) of this section and shall be limited to addressing whether the calculations (including the identification of the TR NO\textsubscript{X} Annual units) are in accordance with §§97.412(b)(2) through (7) and (12) and §§97.406(b)(2) and 97.430 through 97.435.

(B) The Administrator will adjust the calculations to the extent necessary to ensure that they are in accordance with the provisions referenced in paragraph (b)(2)(ii)(A) of this section. By August 1 immediately after the promulgation of each notice of data availability required in paragraph (b)(2)(i) of this section, the Administrator will promulgate a notice of data availability of any adjustments that the Administrator determines to be necessary with regard to allocations under §97.412(b)(2) through (7) and (12) and the reasons for accepting or rejecting any objections submitted in accordance with paragraph (b)(2)(ii)(A) of this section.

(iii) If the Indian country new unit set-aside for such control period contains any TR NO\textsubscript{X} Annual allowances that have not been allocated in the applicable notice of data availability required in paragraph (b)(2)(ii) of this section, the Administrator will promulgate, by December 15 immediately after such notice, a notice of data availability that identifies any TR NO\textsubscript{X} Annual units that commenced commercial operation during the period starting January 1 of the year before the year of such control period and ending November 30 of year of such control period.

(iv) For each notice of data availability required in paragraph (b)(2)(iii) of this section, the Administrator will provide an opportunity for submission of objections to the identification of TR NO\textsubscript{X} annual units in such notice.

(A) Objections shall be submitted by the deadline specified in each notice of data availability required in paragraph (b)(2)(iii) of this section and shall be limited to addressing whether the identification of TR NO\textsubscript{X} annual units in
such notice is in accordance with paragraph (b)(2)(iii) of this section.

(B) The Administrator will adjust the identification of TR NO\textsubscript{X} Annual units in each notice of data availability required in paragraph (b)(2)(iii) of this section to the extent necessary to ensure that it is in accordance with paragraph (b)(2)(iii) of this section and will calculate the TR NO\textsubscript{X} Annual allowance allocation to each TR NO\textsubscript{X} Annual unit in accordance with §97.412(b)(9), (10), and (12) and §§97.406(b)(2) and 97.430 through 97.435. By February 15 immediately after the promulgation of each notice of data availability required in paragraph (b)(2)(iii) of this section, the Administrator will promulgate a notice of data availability of any adjustments of the identification of TR NO\textsubscript{X} Annual units that the Administrator determines to be necessary, the reasons for accepting or rejecting any objections submitted in accordance with paragraph (b)(2)(iv)(A) of this section, and the results of such calculations.

(v) To the extent any TR NO\textsubscript{X} Annual allowances are added to the Indian country new unit set-aside after promulgation of each notice of data availability required in paragraph (b)(2)(iii) of this section, the Administrator will promulgate additional notices of data availability, as deemed appropriate, of the allocation of such TR NO\textsubscript{X} Annual allowances in accordance with §97.412(b)(10).

(c) Units incorrectly allocated TR NO\textsubscript{X} Annual allowances. (1) For each control period in 2012 and thereafter, if the Administrator determines that TR NO\textsubscript{X} Annual allowances were allocated under paragraph (a) of this section, or under a provision of a SIP revision approved under §52.38(a)(3), (4), or (5) of this chapter, where such control period and the recipient are covered by the provisions of paragraph (c)(1)(i) of this section or were allocated under §97.412(a)(2) through (7), (9), and (12) and (b)(2) through (7), (9), and (12), or under a provision of a SIP revision approved under §52.38(a)(4) or (5) of this chapter, where such control period and the recipient are covered by the provisions of paragraph (c)(1)(i) of this section, the Administrator will notify the designated representative of the recipient and will act in accordance with the procedures set forth in paragraphs (c)(2) through (5) of this section:

(i)(A) The recipient is not actually a TR NO\textsubscript{X} Annual unit under §97.404 as of January 1, 2012 and is allocated TR NO\textsubscript{X} Annual allowances for such control period or, in the case of an allocation under a provision of a SIP revision approved under §52.38(a)(3), (4), or (5) of this chapter, the recipient is not actually a TR NO\textsubscript{X} Annual unit as of January 1, 2012 and is allocated TR NO\textsubscript{X} Annual allowances for such control period that the SIP revision provides should be allocated only to recipients that are TR NO\textsubscript{X} Annual units as of January 1, 2012; or

(ii) The recipient is not located as of January 1 of the control period in the State from whose NO\textsubscript{X} Annual trading budget the TR NO\textsubscript{X} Annual allowances allocated under paragraph (a) of this section, or under a provision of a SIP revision approved under §52.38(a)(3), (4), or (5) of this chapter, were allocated for such control period.

(ii) The recipient is not actually a TR NO\textsubscript{X} Annual unit under §97.404 as of January 1 of such control period and is allocated TR NO\textsubscript{X} Annual allowances for such control period or, in the case of an allocation under a provision of a SIP revision approved under §52.38(a)(3), (4), or (5) of this chapter, the recipient is not actually a TR NO\textsubscript{X} Annual unit as of January 1 of such control period and is allocated TR NO\textsubscript{X} Annual allowances for such control period that the SIP revision provides should be allocated only to recipients that are TR NO\textsubscript{X} Annual units as of January 1 of such control period.

(2) Except as provided in paragraph (c)(3) or (4) of this section, the Administrator will not record such TR NO\textsubscript{X} Annual allowances under §97.421.

(3) If the Administrator already recorded such TR NO\textsubscript{X} Annual allowances under §97.421 and if the Administrator makes the determination under paragraph (c)(1) of this section before making deductions for the source that includes such recipient under §97.424(b) for such control period, then the Administrator will deduct from the account in which such TR NO\textsubscript{X} Annual allowances were recorded an amount of
§ 97.412 TR NO\textsubscript{x} Annual allowances allocations to new units.

(a) For each control period in 2012 and thereafter and for the TR NO\textsubscript{x} Annual units in each State, the Administrator will allocate TR NO\textsubscript{x} Annual allowances to the TR NO\textsubscript{x} Annual units as follows:

1. The TR NO\textsubscript{x} Annual allowances will be allocated to the following TR NO\textsubscript{x} Annual units, except as provided in paragraph (a)(10) of this section:
   (i) TR NO\textsubscript{x} Annual units that are not allocated an amount of TR NO\textsubscript{x} Annual allowances in the notice of data availability issued under §97.411(a)(1);
   (ii) TR NO\textsubscript{x} Annual units whose allocation of an amount of TR NO\textsubscript{x} Annual allowances for such control period in the notice of data availability issued under §97.411(a)(1) is covered by §97.411(c)(2) or (3);
   (iii) TR NO\textsubscript{x} Annual units that are allocated an amount of TR NO\textsubscript{x} Annual allowances for such control period in the notice of data availability issued under §97.411(a)(1), which allocation is terminated for such control period pursuant to §97.411(a)(2), and that operate during the control period immediately preceding such control period; or
   (iv) For purposes of paragraph (a)(9) of this section, TR NO\textsubscript{x} Annual units under §97.411(c)(1)(i) whose allocation of an amount of TR NO\textsubscript{x} Annual allowances for such control period in the notice of data availability issued under §97.411(b)(1) is covered by §97.411(c)(2) or (3).

(2) The Administrator will establish a separate new unit set-aside for the State for each such control period.
Each such new unit set-aside will be allocated TR NO\textsubscript{X} Annual allowances in an amount equal to the applicable amount of tons of NO\textsubscript{X} emissions as set forth in §97.410(a) and will be allocated additional TR NO\textsubscript{X} Annual allowances (if any) in accordance with §§97.411(a)(2) and (c)(5) and paragraph (b)(10) of this section.

(3) The Administrator will determine, for each TR NO\textsubscript{X} Annual unit described in paragraph (a)(1) of this section, an allocation of TR NO\textsubscript{X} Annual allowances for the later of the following control periods and for each subsequent control period:

(i) The control period in 2012;
(ii) The first control period after the control period in which the TR NO\textsubscript{X} Annual unit commences commercial operation;
(iii) For a unit described in paragraph (a)(1)(ii) of this section, the first control period in which the TR NO\textsubscript{X} Annual unit operates in the State after operating in another jurisdiction and for which the unit is not already allocated one or more TR NO\textsubscript{X} Annual allowances; and
(iv) For a unit described in paragraph (a)(1)(iii) of this section, the first control period after the control period in which the unit resumes operation.

(4)(i) The allocation to each TR NO\textsubscript{X} annual unit described in paragraph (a)(1)(i) through (iii) of this section and for each control period described in paragraph (a)(3) of this section will be an amount equal to the unit’s total tons of NO\textsubscript{X} emissions during the immediately preceding control period.

(ii) The Administrator will adjust the allocation amount in paragraph (a)(4)(i) in accordance with paragraphs (a)(5) through (12) of this section.

(5) The Administrator will calculate the sum of the TR NO\textsubscript{X} Annual allowances determined for all such TR NO\textsubscript{X} Annual units under paragraph (a)(4)(i) of this section in the State for such control period.

(6) If the amount of TR NO\textsubscript{X} Annual allowances in the new unit set-aside for the State for such control period is greater than or equal to the sum under paragraph (a)(5) of this section, then the Administrator will allocate the amount of TR NO\textsubscript{X} Annual allowances determined for each such TR NO\textsubscript{X} Annual unit under paragraph (a)(4)(i) of this section.

(7) If the amount of TR NO\textsubscript{X} Annual allowances in the new unit set-aside for the State for such control period is less than the sum under paragraph (a)(5) of this section, then the Administrator will allocate to each such TR NO\textsubscript{X} Annual unit the amount of the TR NO\textsubscript{X} Annual allowances determined under paragraph (a)(4)(i) of this section for the unit, multiplied by the amount of TR NO\textsubscript{X} Annual allowances in the new unit set-aside for such control period, divided by the sum under paragraph (a)(5) of this section, and rounded to the nearest allowance.

(8) The Administrator will notify the public, through the promulgation of the notices of data availability described in §97.411(b)(1)(i) and (ii), of the amount of TR NO\textsubscript{X} Annual allowances allocated under paragraphs (a)(2) through (7) and (12) of this section for such control period to each TR NO\textsubscript{X} Annual unit eligible for such allocation.

(9) If, after completion of the procedures under paragraphs (a)(5) through (8) of this section for such control period, any unallocated TR NO\textsubscript{X} Annual allowances remain in the new unit set-aside for the State for such control period, the Administrator will allocate such TR NO\textsubscript{X} Annual allowances as follows—

(i) The Administrator will determine, for each unit described in paragraph (a)(1) of this section that commenced commercial operation during the period starting January 1 of the year before the year of such control period and ending November 30 of year of such control period, the positive difference (if any) between the unit’s emissions during such control period and the amount of TR NO\textsubscript{X} Annual allowances referenced in the notice of data availability required under §97.411(b)(1)(ii) for the unit for such control period;
(ii) The Administrator will determine the sum of the positive differences determined under paragraph (a)(9)(i) of this section;
(iii) If the amount of unallocated TR NO\textsubscript{X} Annual allowances remaining in the new unit set-aside for the State for such control period is greater than or
equal to the sum determined under paragraph (a)(9)(i) of this section, then the Administrator will allocate the amount of TR NOx Annual allowances determined for each such TR NOx Annual unit under paragraph (a)(9)(i) of this section; and

(iv) If the amount of unallocated TR NOx Annual allowances remaining in the new unit set-aside for the State for such control period is less than the sum under paragraph (a)(9)(i) of this section, then the Administrator will allocate to each such TR NOx Annual unit the amount of the TR NOx Annual allowances determined under paragraph (a)(9)(i) of this section for the unit, multiplied by the amount of unallocated TR NOx Annual allowances remaining in the new unit set-aside for such control period, divided by the sum under paragraph (a)(9)(i) of this section, and rounded to the nearest allowance.

(10) If, after completion of the procedures under paragraphs (a)(9) and (12) of this section for such control period, any unallocated TR NOx Annual allowances remain in the new unit set-aside for the State for such control period, the Administrator will allocate to each TR NOx Annual unit that is in the State, is allocated an amount of TR NOx Annual allowances in the notice of data availability issued under §97.411(a)(1), and continues to be allocated TR NOx Annual allowances for such control period in accordance with §97.411(a)(2), an amount of TR NOx Annual allowances equal to the following: the total amount of such remaining unallocated TR NOx Annual allowances in such new unit set-aside, multiplied by the unit’s allocation under §97.411(a) for such control period, divided by the remainder of the amount of tons in the applicable State NOx Annual trading budget minus the sum of the amounts of tons in such new unit set-aside and the Indian country new unit set-aside for the State for such control period, and rounded to the nearest allowance.

(11) The Administrator will notify the public, through the promulgation of the notices of data availability described in §97.411(b)(1)(iii), (iv), and (v), of the amount of TR NOx Annual allowances allocated under paragraphs (a)(9), (10), and (12) of this section for such control period to each TR NOx Annual unit eligible for such allocation.

(12)(i) Notwithstanding the requirements of paragraphs (a)(2) through (11) of this section, if the calculations of allocations of a new unit set-aside for a control period in a given year under paragraph (a)(7) of this section, paragraphs (a)(6) and (9)(iv) of this section, or paragraphs (a)(6), (9)(iii), and (10) of this section would otherwise result in total allocations of such new unit set-aside exceeding the total amount of such new unit set-aside, then the Administrator will adjust the results of the calculations under paragraph (a)(7), (9)(iv), or (10) of this section, as applicable, as follows. The Administrator will list the TR NOx Annual units in descending order based on the amount of such units’ allocations under paragraph (a)(7), (9)(iv), or (10) of this section, as applicable, and, in cases of equal allocation amounts, in alphabetical order of the relevant source’s name and numerical order of the relevant unit’s identification number, and will reduce each unit’s allocation under paragraph (a)(7), (9)(iv), or (10) of this section, as applicable, by one TR NOx Annual allowance (but not below zero) in the order in which the units are listed and will repeat this reduction process as necessary, until the total allocations of such new unit set-aside equal the total amount of such new unit set-aside.

(ii) Notwithstanding the requirements of paragraphs (a)(10) and (11) of this section, if the calculations of allocations of a new unit set-aside for a control period in a given year under paragraphs (a)(6), (9)(ii), and (10) of this section would otherwise result in a total allocations of such new unit set-aside less than the total amount of such new unit set-aside, then the Administrator will adjust the results of the calculations under paragraph (a)(10) of this section, as follows. The Administrator will list the TR NOx Annual units in descending order based on the amount of such units’ allocations under paragraph (a)(10) of this section and, in cases of equal allocation amounts, in alphabetical order of the relevant source’s name and numerical
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order of the relevant unit’s identification number, and will increase each unit’s allocation under paragraph (a)(10) of this section by one TR NO\textsubscript{X} Annual allowance in the order in which the units are listed and will repeat this increase process as necessary, until the total allocations of such new unit set-aside equal the total amount of such new unit set-aside.

(b) For each control period in 2012 and thereafter and for the TR NO\textsubscript{X} Annual units located in Indian country within the borders of each State, the Administrator will allocate TR NO\textsubscript{X} Annual allowances to the TR NO\textsubscript{X} Annual units as follows:

(1) The TR NO\textsubscript{X} Annual allowances will be allocated to the following TR NO\textsubscript{X} Annual units, except as provided in paragraph (b)(10) of this section:

(i) TR NO\textsubscript{X} Annual units that are not allocated an amount of TR NO\textsubscript{X} Annual allowances in the notice of data availability issued under §97.411(a)(1); or

(ii) For purposes of paragraph (b)(9) of this section, TR NO\textsubscript{X} Annual units under §97.411(c)(1)(i) whose allocation of an amount of TR NO\textsubscript{X} Annual allowances for such control period in the notice of data availability issued under §97.411(b)(2)(ii)(B) is covered by §97.411(c)(2) or (3).

(2) The Administrator will establish a separate Indian country new unit set-aside for the State for each such control period. Each such Indian country new unit set-aside will be allocated TR NO\textsubscript{X} Annual allowances in an amount equal to the applicable amount of tons of NO\textsubscript{X} emissions as set forth in §97.410(a) and will be allocated additional TR NO\textsubscript{X} Annual allowances (if any) in accordance with §97.411(c)(5).

(3) The Administrator will determine, for each TR NO\textsubscript{X} Annual unit described in paragraph (b)(1) of this section, an allocation of TR NO\textsubscript{X} Annual allowances for the later of the following control periods and for each subsequent control period:

(i) The control period in 2012; and

(ii) The first control period after the control period in which the TR NO\textsubscript{X} Annual unit commences commercial operation.

(4)(i) The allocation to each TR NO\textsubscript{X} annual unit described in paragraph (b)(1)(i) of this section and for each control period described in paragraph (b)(3) of this section will be an amount equal to the unit’s total tons of NO\textsubscript{X} emissions during the immediately preceding control period.

(ii) The Administrator will adjust the allocation amount in accordance with paragraphs (b)(5) through (7) and (12) of this section.

(5) The Administrator will calculate the sum of the TR NO\textsubscript{X} Annual allowances determined for all such TR NO\textsubscript{X} Annual units under paragraph (b)(4)(i) of this section in Indian country within the borders of the State for such control period.

(6) If the amount of TR NO\textsubscript{X} Annual allowances in the Indian country new unit set-aside for the State for such control period is greater than or equal to the amount of TR NO\textsubscript{X} Annual allowances determined for each such TR NO\textsubscript{X} Annual unit under paragraph (b)(4)(i) of this section, then the Administrator will allocate the amount of TR NO\textsubscript{X} Annual allowances determined for each such TR NO\textsubscript{X} Annual unit under paragraph (b)(4)(i) of this section.

(7) If the amount of TR NO\textsubscript{X} Annual allowances in the Indian country new unit set-aside for the State for such control period is less than the amount under paragraph (b)(5) of this section, then the Administrator will allocate to each such TR NO\textsubscript{X} Annual unit the amount of the TR NO\textsubscript{X} Annual allowances determined under paragraph (b)(4)(i) of this section for the unit, multiplied by the amount of TR NO\textsubscript{X} Annual allowances in the Indian country new unit set-aside for such control period, divided by the sum of the TR NO\textsubscript{X} Annual allowances determined under paragraphs (b)(5) through (7) and (12) of this section for such control period, and rounded to the nearest nearest allowance.

(8) The Administrator will notify the public, through the promulgation of the notices of data availability described in §97.411(b)(2)(i) and (ii), of the amount of TR NO\textsubscript{X} Annual allowances allocated under paragraphs (b)(2) through (7) and (12) of this section for such control period to each TR NO\textsubscript{X} Annual unit eligible for such allocation.

(9) If, after completion of the procedures under paragraphs (b)(5) through (8) of this section for such control period, any unallocated TR NO\textsubscript{X} Annual allowances remain in the Indian country new unit set-aside for the State for
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such control period, the Administrator will allocate such TR NO\textsubscript{X} Annual allowances as follows—

(i) The Administrator will determine, for each unit described in paragraph (b)(1) of this section that commenced commercial operation during the period starting January 1 of the year before the year of such control period and ending November 30 of year of such control period, the positive difference (if any) between the unit’s emissions during such control period and the amount of TR NO\textsubscript{X} Annual allowances referenced in the notice of data availability required under § 97.411(b)(2)(ii) for the unit for such control period;

(ii) The Administrator will determine the sum of the positive differences determined under paragraph (b)(9)(i) of this section;

(iii) If the amount of unallocated TR NO\textsubscript{X} Annual allowances remaining in the Indian country new unit set-aside for the State for such control period is greater than or equal to the sum determined under paragraph (b)(9)(ii) of this section, then the Administrator will allocate the amount of TR NO\textsubscript{X} Annual allowances determined for each such TR NO\textsubscript{X} Annual unit under paragraph (b)(9)(i) of this section; and

(iv) If the amount of unallocated TR NO\textsubscript{X} Annual allowances remaining in the Indian country new unit set-aside for the State for such control period is less than the sum under paragraph (b)(9)(ii) of this section, then the Administrator will allocate to each such TR NO\textsubscript{X} Annual unit the amount of the TR NO\textsubscript{X} Annual allowances determined under paragraph (b)(9)(i) of this section for the unit, multiplied by the amount of unallocated TR NO\textsubscript{X} Annual allowances remaining in the Indian country new unit set-aside for such control period, divided by the sum under paragraph (b)(9)(ii) of this section, and rounded to the nearest allowance.

(10) If, after completion of the procedures under paragraphs (b)(9) and (12) of this section for such control period, any unallocated TR NO\textsubscript{X} Annual allowances remain in the Indian country new unit set-aside for the State for such control period, the Administrator will:

(i) Transfer such unallocated TR NO\textsubscript{X} Annual allowances to the new unit set-aside for the State for such control period; or

(ii) If the State has a SIP revision approved under § 52.38(a)(4) or (5) covering such control period, include such unallocated TR NO\textsubscript{X} Annual allowances in the portion of the State NO\textsubscript{X} Annual trading budget that may be allocated for such control period in accordance with such SIP revision.

(11) The Administrator will notify the public, through the promulgation of the notices of data availability described in § 97.411(b)(2)(iii), (iv), and (v), of the amount of TR NO\textsubscript{X} Annual allowances allocated under paragraphs (b)(9), (10), and (12) of this section for such control period to each TR NO\textsubscript{X} Annual unit eligible for such allocation.

(12)(i) Notwithstanding the requirements of paragraphs (b)(2) through (11) of this section, if the calculations of allocations of an Indian country new unit set-aside for a control period in a given year under paragraph (b)(7) of this section, paragraphs (b)(6) and (9)(iv) of this section, or paragraphs (b)(6), (9)(i), and (10) of this section would otherwise result in total allocations of such Indian country new unit set-aside exceeding the total amount of such Indian country new unit set-aside, then the Administrator will adjust the results of the calculations under paragraph (b)(7), (9)(iv), or (10) of this section, as applicable, as follows. The Administrator will list the TR NO\textsubscript{X} Annual units in descending order based on the amount of such units’ allocations under paragraph (b)(7), (9)(iv), or (10) of this section, as applicable, and, in cases of equal allocation amounts, in alphabetical order of the relevant source’s name and numerical order of the relevant unit’s identification number, and will reduce each unit’s allocation under paragraph (b)(7), (9)(iv), or (10) of this section, as applicable, by one TR NO\textsubscript{X} Annual allowance (but not below zero) in the order in which the units are listed and will repeat this reduction process as necessary, until the total allocations of such Indian country new unit set-aside equal the total amount of such Indian country new unit set-aside.

(ii) Notwithstanding the requirements of paragraphs (b)(10) and (11) of
this section, if the calculations of allocations of an Indian country new unit set-aside for a control period in a given year under paragraphs (b)(6), (9)(iii), and (10) of this section would otherwise result in a total allocations of such Indian country new unit set-aside less than the total amount of such Indian country new unit set-aside, then the Administrator will adjust the results of the calculations under paragraph (b)(10) of this section, as follows. The Administrator will list the TR NO\textsubscript{X} Annual units in descending order based on the amount of such units’ allocations under paragraph (b)(10) of this section and, in cases of equal allocation amounts, in alphabetical order of the relevant source’s name and numerical order of the relevant unit’s identification number, and will increase each unit’s allocation under paragraph (b)(10) of this section by one TR NO\textsubscript{X} Annual allowance in the order in which the units are listed and will repeat this increase process as necessary, until the total allocations of such Indian country new unit set-aside equal the total amount of such Indian country new unit set-aside.

§ 97.413 Authorization of designated representative and alternate designated representative.

(a) Except as provided under §97.415, each TR NO\textsubscript{X} Annual source, including all TR NO\textsubscript{X} Annual units at the source, shall have one and only one designated representative, with regard to all matters under the TR NO\textsubscript{X} Annual Trading Program.

(1) The designated representative shall be selected by an agreement binding on the owners and operators of the source and all TR NO\textsubscript{X} Annual units at the source and shall act in accordance with the certification statement in §97.416(a)(4)(iii).

(2) Upon and after receipt by the Administrator of a complete certificate of representation under §97.416:

(i) The alternate designated representative shall be authorized;

(ii) Any representation, action, inaction, or submission by the alternate designated representative shall be deemed to be a representation, action, inaction, or submission by the designated representative; and

(iii) The owners and operators of the source and each TR NO\textsubscript{X} Annual unit at the source shall act in accordance with the certification statement in §97.416(a)(4)(iii).

(b) Except as provided under §97.415, each TR NO\textsubscript{X} Annual source may have one and only one alternate designated representative, who may act on behalf of the designated representative. The agreement by which the alternate designated representative is selected shall include a procedure for authorizing the alternate designated representative to act in lieu of the designated representative.

(1) The alternate designated representative shall be selected by an agreement binding on the owners and operators of the source and all TR NO\textsubscript{X} Annual units at the source and shall act in accordance with the certification statement in §97.416(a)(4)(iii).

(2) Upon and after receipt by the Administrator of a complete certificate of representation under §97.416:

(i) The alternate designated representative shall be authorized;

(ii) Any representation, action, inaction, or submission by the alternate designated representative shall be deemed to be a representation, action, inaction, or submission by the designated representative; and

(iii) The owners and operators of the source and each TR NO\textsubscript{X} Annual unit at the source shall be bound by any decision or order issued to the alternate designated representative by the Administrator regarding the source or any such unit.

(c) Except in this section, §§97.402 and §§97.414 through 97.418, whenever the term “designated representative” (as distinguished from the term “common designated representative”) is used in this subpart, the term shall be construed to include the designated representative or any alternate designated representative.
§ 97.414 Responsibilities of designated representative and alternate designated representative.

(a) Except as provided under §97.418 concerning delegation of authority to make submissions, each submission under the TR NO\textsubscript{X} Annual Trading Program shall be made, signed, and certified by the designated representative or alternate designated representative for each TR NO\textsubscript{X} Annual source and TR NO\textsubscript{X} Annual unit for which the submission is made. Each such submission shall include the following certification statement by the designated representative or alternate designated representative: “I am authorized to make this submission on behalf of the owners and operators of the source or units for which the submission is made. I certify under penalty of law that I have personally examined, and am familiar with, the statements and information submitted in this document and all its attachments. Based on my inquiry of those individuals with primary responsibility for obtaining the information, I certify that the statements and information are to the best of my knowledge and belief true, accurate, and complete. I am aware that there are significant penalties for submitting false statements and information or omitting required statements and information, including the possibility of fine or imprisonment.”

(b) The Administrator will accept or act on a submission made for a TR NO\textsubscript{X} Annual source or a TR NO\textsubscript{X} Annual unit only if the submission has been made, signed, and certified in accordance with paragraph (a) of this section and §97.418.

§ 97.415 Changing designated representative and alternate designated representative; changes in owners and operators; changes in units at the source.

(a) Changing designated representative. The designated representative may be changed at any time upon receipt by the Administrator of a superseding complete certificate of representation under §97.416. Notwithstanding any such change, all representations, actions, inactions, and submissions by the previous designated representative before the time and date when the Administrator receives the superseding certificate of representation shall be binding on the new designated representative and the owners and operators of the TR NO\textsubscript{X} Annual source and the TR NO\textsubscript{X} Annual units at the source.

(b) Changing alternate designated representative. The alternate designated representative may be changed at any time upon receipt by the Administrator of a superseding complete certificate of representation under §97.416. Notwithstanding any such change, all representations, actions, inactions, and submissions by the previous alternate designated representative before the time and date when the Administrator receives the superseding certificate of representation shall be binding on the new alternate designated representative, the designated representative, and the owners and operators of the TR NO\textsubscript{X} Annual source and the TR NO\textsubscript{X} Annual units at the source.

(c) Changes in owners and operators.

(1) In the event an owner or operator of a TR NO\textsubscript{X} Annual source or a TR NO\textsubscript{X} Annual unit at the source is not included in the list of owners and operators in the certificate of representation under §97.416, such owner or operator shall be deemed to be subject to and bound by the certificate of representation, the representations, actions, inactions, and submissions of the designated representative and any alternate designated representative of the source or unit, and the decisions and orders of the Administrator, as if the owner or operator were included in such list.

(2) Within 30 days after any change in the owners and operators of a TR NO\textsubscript{X} Annual source or a TR NO\textsubscript{X} Annual unit at the source, including the addition or removal of an owner or operator, the designated representative or any alternate designated representative shall submit a revision to the certificate of representation under §97.416 amending the list of owners and operators to reflect the change.

(d) Changes in units at the source. Within 30 days of any change in which units are located at a TR NO\textsubscript{X} Annual source (including the addition or removal of a unit), the designated representative or any alternate designated representative...
representative shall submit a certificate of representation under §97.416 amending the list of units to reflect the change.

(1) If the change is the addition of a unit that operated (other than for purposes of testing by the manufacturer before initial installation) before being located at the source, then the certificate of representation shall identify, in a format prescribed by the Administrator, the entity from whom the unit was purchased or otherwise obtained (including name, address, telephone number, and facsimile number (if any)), the date on which the unit was purchased or otherwise obtained, and the date on which the unit became located at the source.

(2) If the change is the removal of a unit, then the certificate of representation shall identify, in a format prescribed by the Administrator, the entity to which the unit was sold or otherwise obtained (including name, address, telephone number, and facsimile number (if any)), the date on which the unit was sold or otherwise obtained, and the date on which the unit became no longer located at the source.

§ 97.416 Certificate of representation.

(a) A complete certificate of representation for a designated representative or an alternate designated representative shall include the following elements in a format prescribed by the Administrator:

(1) Identification of the TR NOx Annual source, and each TR NOx Annual unit at the source, for which the certificate of representation is submitted, including source name, source category and NAICS code (or, in the absence of a NAICS code, an equivalent code), State, plant code, county, latitude and longitude, unit identification number and type, identification number and nameplate capacity (in MWe, rounded to the nearest tenth) of each generator served by each such unit, actual or projected date of commencement of commercial operation, and a statement of whether such source is located in Indian Country. If a projected date of commencement of commercial operation is provided, the actual date of commencement of commercial operation shall be provided when such information becomes available.

(2) The name, address, e-mail address (if any), telephone number, and facsimile transmission number (if any) of the designated representative and any alternate designated representative.

(3) A list of the owners and operators of the TR NOx Annual source and of each TR NOx Annual unit at the source.

(4) The following certification statements by the designated representative and any alternate designated representative—

(i) “I certify that I was selected as the designated representative or alternate designated representative, as applicable, by an agreement binding on the owners and operators of the source and each TR NOx Annual unit at the source.”

(ii) “I certify that I have all the necessary authority to carry out my duties and responsibilities under the TR NOx Annual Trading Program on behalf of the owners and operators of the source and of each TR NOx Annual unit at the source and that each such owner and operator shall be fully bound by my representations, actions, inactions, or submissions and by any decision or order issued to me by the Administrator regarding the source or unit.”

(iii) “Where there are multiple holders of a legal or equitable title to, or a leasehold interest in, a TR NOx Annual unit, or where a utility or industrial customer purchases power from a TR NOx Annual unit under a life-of-the-unit, firm power contractual arrangement, I certify that: I have given a written notice of my selection as the ‘designated representative’ or ‘alternate designated representative’, as applicable, and of the agreement by which I was selected to each owner and operator of the source and of each TR NOx Annual unit at the source; and TR NOx Annual allowances and proceeds of transactions involving TR NOx Annual allowances will be deemed to be held or distributed in proportion to each holder’s legal, equitable, leasehold, or contractual reservation or entitlement, except that, if such multiple holders have expressly provided for a different
distribution of TR NO\textsubscript{X} Annual allowances by contract, TR NO\textsubscript{X} Annual allowances and proceeds of transactions involving TR NO\textsubscript{X} Annual allowances will be deemed to be held or distributed in accordance with the contract.

(5) The signature of the designated representative and any alternate designated representative and the dates signed.

(b) Unless otherwise required by the Administrator, documents of agreement referred to in the certificate of representation shall not be submitted to the Administrator. The Administrator shall not be under any obligation to review or evaluate the sufficiency of such documents, if submitted.

§ 97.417 Objections concerning designated representative and alternate designated representative.

(a) Once a complete certificate of representation under §97.416 has been submitted and received, the Administrator will rely on the certificate of representation unless and until a superseding complete certificate of representation under §97.416 is received by the Administrator.

(b) Except as provided in paragraph (a) of this section, no objection or other communication submitted to the Administrator concerning the authorization, or any representation, action, inaction, or submission, of a designated representative or alternate designated representative shall affect any representation, action, inaction, or submission of the designated representative or alternate designated representative or the finality of any decision or order by the Administrator under the TR NO\textsubscript{X} Annual Trading Program.

(c) The Administrator will not adjudicate any private legal dispute concerning the authorization or any representation, action, inaction, or submission of any designated representative or alternate designated representative, including private legal disputes concerning the proceeds of TR NO\textsubscript{X} Annual allowance transfers.

§ 97.418 Delegation by designated representative and alternate designated representative.

(a) A designated representative may delegate, to one or more natural persons, his or her authority to make an electronic submission to the Administrator provided for or required under this subpart.

(b) An alternate designated representative may delegate, to one or more natural persons, his or her authority to make an electronic submission to the Administrator provided for or required under this subpart.

(c) In order to delegate authority to a natural person to make an electronic submission to the Administrator in accordance with paragraph (a) or (b) of this section, the designated representative or alternate designated representative, as appropriate, must submit to the Administrator a notice of delegation, in a format prescribed by the Administrator, that includes the following elements:

(1) The name, address, e-mail address, telephone number, and facsimile transmission number (if any) of such designated representative or alternate designated representative;

(2) The name, address, e-mail address, telephone number, and facsimile transmission number (if any) of each such natural person (referred to in this section as an “agent”);

(3) For each such natural person, a list of the type or types of electronic submissions under paragraph (a) or (b) of this section for which authority is delegated to him or her; and

(4) The following certification statements by such designated representative or alternate designated representative:

(i) “I agree that any electronic submission to the Administrator that is made by an agent identified in this notice of delegation and of a type listed for such agent in this notice of delegation and that is made when I am a designated representative or alternate designated representative, as appropriate, and before this notice of delegation is superseded by another notice of delegation under 40 CFR 97.418(d) shall be deemed to be an electronic submission by me.”

(ii) “Until this notice of delegation is superseded by another notice of delegation under 40 CFR 97.418(d), I agree to maintain an e-mail account and to notify the Administrator immediately of any change in my e-mail address unless
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all delegation of authority by me under 40 CFR 97.418 is terminated.”

(d) A notice of delegation submitted under paragraph (c) of this section shall be effective, with regard to the designated representative or alternate designated representative identified in such notice, upon receipt of such notice by the Administrator and until receipt by the Administrator of a superseding notice of delegation submitted by such designated representative or alternate designated representative, as appropriate. The superseding notice of delegation may replace any previously identified agent, add a new agent, or eliminate entirely any delegation of authority.

(e) Any electronic submission covered by the certification in paragraph (c)(4)(i) of this section and made in accordance with a notice of delegation effective under paragraph (d) of this section shall be deemed to be an electronic submission by the designated representative or alternate designated representative submitting such notice of delegation.

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§ 97.420 Establishment of compliance accounts, assurance accounts, and general accounts.

(a) Compliance accounts. Upon receipt of a complete certificate of representation under §97.416, the Administrator will establish a compliance account for the TR NOx Annual source for which the certificate of representation was submitted, unless the source already has a compliance account. The designated representative and any alternate designated representative of the source shall be the authorized account representative and the alternate authorized account representative respectively of the compliance account.

(b) Assurance accounts. The Administrator will establish assurance accounts for certain owners and operators and States in accordance with §97.425(b)(3).

(c) General accounts. (1) Application for general account. (i) Any person may apply to open a general account, for the purpose of holding and transferring TR NOx Annual allowances, by submitting to the Administrator a complete application for a general account. Such application shall designate one and only one authorized account representative and may designate one and only one alternate authorized account representative who may act on behalf of the authorized account representative.

(A) The authorized account representative and alternate authorized account representative shall be selected by an agreement binding on the persons who have an ownership interest with respect to TR NOx Annual allowances held in the general account.

(B) The agreement by which the alternate authorized account representative is selected shall include a procedure for authorizing the alternate authorized account representative to act in lieu of the authorized account representative.

(ii) A complete application for a general account shall include the following elements in a format prescribed by the Administrator:

(A) Name, mailing address, e-mail address (if any), telephone number, and facsimile transmission number (if any) of the authorized account representative and any alternate authorized account representative;

(B) An identifying name for the general account;

(C) A list of all persons subject to a binding agreement for the authorized account representative and any alternate authorized account representative to represent their ownership interest with respect to the TR NOx Annual allowances held in the general account;

(D) The following certification statement by the authorized account representative and any alternate authorized account representative: "I certify that I was selected as the authorized account representative or the alternate authorized account representative, as applicable, by an agreement that is binding on all persons who have an ownership interest with respect to TR NOx Annual allowances held in the general account. I certify that I have all the necessary authority to carry out my duties and responsibilities under the TR NOx Annual Trading Program on behalf of such persons and that each such person shall be fully bound by my representations, actions, inactions, or submissions and by any
decision or order issued to me by the Administrator regarding the general account."

(E) The signature of the authorized account representative and any alternate authorized account representative and the dates signed.

(iii) Unless otherwise required by the Administrator, documents of agreement referred to in the application for a general account shall not be submitted to the Administrator. The Administrator shall not be under any obligation to review or evaluate the sufficiency of such documents, if submitted.

(2) Authorization of authorized account representative and alternate authorized account representative. (i) Upon receipt by the Administrator of a complete application for a general account under paragraph (b)(1) of this section, the Administrator will establish a general account for the person or persons for whom the application is submitted, and upon and after such receipt by the Administrator:

(A) The authorized account representative of the general account shall be authorized and shall represent and, by his or her representations, actions, inactions, or submissions, legally bind each person who has an ownership interest with respect to TR NO\textsubscript{X} Annual allowances held in the general account in all matters pertaining to the TR NO\textsubscript{X} Annual Trading Program, notwithstanding any agreement between the authorized account representative and such person.

(B) Any alternate authorized account representative shall be authorized, and any representation, action, inaction, or submission by any alternate authorized account representative shall be deemed to be a representation, action, inaction, or submission by the authorized account representative.

(C) Each person who has an ownership interest with respect to TR NO\textsubscript{X} Annual allowances held in the general account shall be bound by any decision or order issued to the authorized account representative or alternate authorized account representative by the Administrator regarding the general account.

(ii) Except as provided in paragraph (c)(5) of this section concerning delegation of authority to make submissions, each submission concerning the general account shall be made, signed, and certified by the authorized account representative or any alternate authorized account representative for the persons having an ownership interest with respect to TR NO\textsubscript{X} Annual allowances held in the general account. Each such submission shall include the following certification statement by the authorized account representative or any alternate authorized account representative: "I am authorized to make this submission on behalf of the persons having an ownership interest with respect to the TR NO\textsubscript{X} Annual allowances held in the general account. I certify under penalty of law that I have personally examined, and am familiar with, the statements and information submitted in this document and all its attachments. Based on my inquiry of those individuals with primary responsibility for obtaining the information, I certify that the statements and information are to the best of my knowledge and belief true, accurate, and complete. I am aware that there are significant penalties for submitting false statements and information or omitting required statements and information, including the possibility of fine or imprisonment."

(iii) Except in this section, whenever the term "authorized account representative" is used in this subpart, the term shall be construed to include the authorized account representative or any alternate authorized account representative.

(3) Changing authorized account representative and alternate authorized account representative; changes in persons with ownership interest. (i) The authorized account representative of a general account may be changed at any time upon receipt by the Administrator of a superseding complete application for a general account under paragraph (c)(1) of this section. Notwithstanding any such change, all representations, actions, inactions, and submissions by the previous authorized account representative before the time and date when the Administrator receives the superseding application for a general account shall be binding on the new authorized account representative.
and the persons with an ownership interest with respect to the TR NO\textsubscript{X} Annual allowances in the general account.

(ii) The alternate authorized account representative of a general account may be changed at any time upon receipt by the Administrator of a superseding complete application for a general account under paragraph (c)(1) of this section. Notwithstanding any such change, all representations, actions, inactions, and submissions by the previous alternate authorized account representative before the time and date when the Administrator receives the superseding application for a general account shall be binding on the new alternate authorized account representative, the authorized account representative, and the persons with an ownership interest with respect to the TR NO\textsubscript{X} Annual allowances in the general account.

(iii)(A) In the event a person having an ownership interest with respect to TR NO\textsubscript{X} Annual allowances in the general account is not included in the list of such persons in the application for a general account, such person shall be deemed to be subject to and bound by the application for a general account, the representation, actions, inactions, and submissions of the authorized account representative and any alternate authorized account representative of the account, and the decisions and orders of the Administrator, as if the person were included in such list.

(B) Within 30 days after any change in the persons having an ownership interest with respect to NO\textsubscript{X} Annual allowances in the general account, including the addition or removal of a person, the authorized account representative or any alternate authorized account representative shall submit a revision to the application for a general account amending the list of persons having an ownership interest with respect to the TR NO\textsubscript{X} Annual allowance transfers.

(4) Objections concerning authorized account representative and alternate authorized account representative. (i) Once a complete application for a general account under paragraph (c)(1) of this section has been submitted and received, the Administrator will rely on the application unless and until a superseding complete application for a general account under paragraph (b)(1) of this section is received by the Administrator.

(ii) Except as provided in paragraph (c)(4)(i) of this section, no objection or other communication submitted to the Administrator concerning the authorization, or any representation, action, inaction, or submission of the authorized account representative or any alternate authorized account representative of a general account shall affect any representation, action, inaction, or submission of the authorized account representative or any alternate authorized account representative or the finality of any decision or order by the Administrator under the TR NO\textsubscript{X} Annual Trading Program.

(iii) The Administrator will not adjudicate any private legal dispute concerning the authorization or any representation, action, inaction, or submission of the authorized account representative or any alternate authorized account representative of a general account, including private legal disputes concerning the proceeds of TR NO\textsubscript{X} Annual allowance transfers.

(5) Delegation by authorized account representative and alternate authorized account representative. (i) An authorized account representative of a general account may delegate, to one or more natural persons, his or her authority to make an electronic submission to the Administrator provided for or required under this subpart.

(ii) An alternate authorized account representative of a general account may delegate, to one or more natural persons, his or her authority to make an electronic submission to the Administrator provided for or required under this subpart.

(iii) In order to delegate authority to a natural person to make an electronic submission to the Administrator in accordance with paragraph (c)(5)(i) or (ii) of this section, the authorized account representative or alternate authorized account representative, as appropriate, must submit to the Administrator a notice of delegation, in a format prescribed by the Administrator, that includes the following elements:
(A) The name, address, e-mail address, telephone number, and facsimile transmission number (if any) of such authorized account representative or alternate authorized account representative;

(B) The name, address, e-mail address, telephone number, and facsimile transmission number (if any) of each such natural person (referred to in this section as an “agent”);

(C) For each such natural person, a list of the type or types of electronic submissions under paragraph (c)(5)(i) or (ii) of this section for which authority is delegated to him or her;

(D) The following certification statement by such authorized account representative or alternate authorized account representative: “I agree that any electronic submission to the Administrator that is made by an agent identified in this notice of delegation and of a type listed for such agent in this notice of delegation and that is made when I am an authorized account representative or alternate authorized representative, as appropriate, and before this notice of delegation is superseded by another notice of delegation under 40 CFR 97.420(c)(5)(iv) shall be deemed to be an electronic submission by me.”; and

(E) The following certification statement by such authorized account representative or alternate authorized account representative: “Until this notice of delegation is superseded by another notice of delegation under 40 CFR 97.420(c)(5)(iv), I agree to maintain an e-mail account and to notify the Administrator immediately of any change in my e-mail address unless all delegation of authority by me under 40 CFR 97.420(c)(5) is terminated.”.

(iv) A notice of delegation submitted under paragraph (c)(5)(iii) of this section shall be effective, with regard to the authorized account representative or alternate authorized account representative identified in such notice, upon receipt of such notice by the Administrator and until receipt by the Administrator of a superseding notice of delegation submitted by such authorized account representative or alternate authorized account representative, as appropriate. The superseding notice of delegation may replace any previously identified agent, add a new agent, or eliminate entirely any delegation of authority.

(v) Any electronic submission covered by the certification in paragraph (c)(5)(i)(D) of this section and made in accordance with a notice of delegation effective under paragraph (c)(5)(iv) of this section shall be deemed to be an electronic submission by the designated representative or alternate designated representative submitting such notice of delegation.

(6) Closing a general account. (i) The authorized account representative or alternate authorized account representative of a general account may submit to the Administrator a request to close the account. Such request shall include a correctly submitted TR NOx Annual allowance transfer under §97.422 for any TR NOx Annual allowances in the account to one or more other Allowance Management System accounts.

(ii) If a general account has no TR NOx Annual allowance transfers to or from the account for a 12-month period or longer and does not contain any TR NOx Annual allowances, the Administrator may notify the authorized account representative for the account that the account will be closed after 30 days after the notice is sent. The account will be closed after the 30-day period unless, before the end of the 30-day period, the Administrator receives a correctly submitted TR NOx Annual allowance transfer under §97.422 to the account or a statement submitted by the authorized account representative or alternate authorized account representative demonstrating to the satisfaction of the Administrator good cause as to why the account should not be closed.

(d) Account identification. The Administrator will assign a unique identifying number to each account established under paragraph (a), (b), or (c) of this section.

(e) Responsibilities of authorized account representative and alternate authorized account representative. After the establishment of a compliance account or general account, the Administrator will accept or act on a submission pertaining to the account, including, but not limited to, submissions
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concerning the deduction or transfer of TR NOX Annual allowances in the account, only if the submission has been made, signed, and certified in accordance with §§97.414(a) and 97.418 or paragraphs (c)(2)(i) and (c)(5) of this section.

§ 97.421 Recordation of TR NOX Annual allowance allocations and auction results.

(a) By November 7, 2011, the Administrator will record in each TR NOX Annual source’s compliance account the TR NOX Annual allowances allocated to the TR NOX Annual units at the source in accordance with §97.411(a) for the control period in 2012.

(b) By November 7, 2011, the Administrator will record in each TR NOX Annual source’s compliance account the TR NOX Annual allowances allocated to the TR NOX Annual units at the source in accordance with §97.411(a) for the control period in 2013, unless the State in which the source is located notifies the Administrator in writing by October 17, 2011 of the State’s intent to submit to the Administrator a complete SIP revision by April 1, 2012 meeting the requirements of §52.38(a)(3)(i) through (iv) of this chapter.

(1) If, by April 1, 2012, the State does not submit to the Administrator such complete SIP revision, the Administrator will record by April 15, 2012 in each TR NOX Annual source’s compliance account the TR NOX Annual allowances allocated to the TR NOX Annual units at the source in accordance with §97.411(a) for the control period in 2013.

(2) If the State submits to the Administrator by April 1, 2012, and the Administrator approves by October 1, 2012, such complete SIP revision, the Administrator will record by October 1, 2012 in each TR NOX Annual source’s compliance account the TR NOX Annual allowances allocated to the TR NOX Annual units at the source in accordance with §97.411(a) for the control period in 2013.

(c) By July 1, 2013, the Administrator will record in each TR NOX Annual source’s compliance account the TR NOX Annual allowances allocated to the TR NOX Annual units at the source, or in each appropriate Allowance Management System account the TR NOX Annual allowances auctioned to TR NOX Annual units, in accordance with §97.411(a), or with a SIP revision approved under §52.38(a)(4) or (5) of this chapter, for the control period in 2014 and 2015.

(d) By July 1, 2014, the Administrator will record in each TR NOX Annual source’s compliance account the TR NOX Annual allowances allocated to the TR NOX Annual units at the source, or in each appropriate Allowance Management System account the TR NOX Annual allowances auctioned to TR NOX Annual units, in accordance with §97.411(a), or with a SIP revision approved under §52.38(a)(4) or (5) of this chapter, for the control period in 2016 and 2017.

(e) By July 1, 2015, the Administrator will record in each TR NOX Annual source’s compliance account the TR NOX Annual allowances allocated to the TR NOX Annual units at the source, or in each appropriate Allowance Management System account the TR NOX Annual allowances auctioned to TR NOX Annual units, in accordance with §97.411(a), or with a SIP revision approved under §52.38(a)(4) or (5) of this chapter, for the control period in 2018 and 2019.

(f) By July 1, 2016 and July 1 of each year thereafter, the Administrator will record in each TR NOX Annual source’s compliance account the TR NOX Annual allowances allocated to the TR NOX Annual units at the source, or in each appropriate Allowance Management System account the TR NOX Annual allowances auctioned to TR NOX Annual units, in accordance with §97.411(a), or with a SIP revision approved under §52.38(a)(4) or (5) of this chapter, for the control period in the
§ 97.422 Submission of TR NOx Annual allowance transfers.

(a) An authorized account representative seeking recordation of a TR NOx Annual allowance transfer shall submit the transfer to the Administrator.

(b) A TR NOx Annual allowance transfer shall be correctly submitted if:

(i) The transfer includes the following elements, in a format prescribed by the Administrator:

(ii) The serial number of each TR NOx Annual allowance that is in the transferor account and is to be transferred; and

(iii) The name and signature of the authorized account representative of the transferor account and the date signed; and

(j) By the date on which any allocation or auction results, other than an allocation or auction results described in paragraphs (a) through (i) of this section, of TR NOx Annual allowances to a recipient is made by or are submitted to the Administrator in accordance with §97.411 or §97.412 or with a SIP revision approved under §52.38(a)(4) or (5) of this chapter, for the control period in the year of the applicable recordation deadline under this paragraph.

(k) When recording the allocation or auction of TR NOx Annual allowances to a TR NOx Annual unit or other entity in an Allowance Management System account, the Administrator will assign each TR NOx Annual allowance a unique identification number that will include digits identifying the year of the control period for which the TR NOx Annual allowance is allocated or auctioned.

§ 97.423 Recordation of TR NOx Annual allowance transfers.

(a) Within 5 business days (except as provided in paragraph (b) of this section) of receiving a TR NOx Annual allowance transfer that is correctly submitted under §97.422, the Administrator will record a TR NOx Annual allowance transfer by moving each TR NOx Annual allowance from the transferor account to the transferee account as specified in the transfer.

(b) A TR NOx Annual allowance transfer to or from a compliance account that is submitted for recordation after the allowance transfer deadline for a control period and that includes any TR NOx Annual allowances allocated for any control period before such allowance transfer deadline will not be recorded until after the Administrator completes the deductions from such compliance account under §97.424.
§ 97.424 Compliance with TR NOX Annual emissions limitation.

(a) Availability for deduction for compliance. TR NOX Annual allowances are available to be deducted for compliance with a source’s TR NOX Annual emissions limitation for a control period in a given year only if the TR NOX Annual allowances:

1. Were allocated for such control period or a control period in a prior year; and
2. Are held in the source’s compliance account as of the allowance transfer deadline for such control period.

(b) Deductions for compliance. After the recordation, in accordance with §97.423, of TR NOX Annual allowance transfers submitted by the allowance transfer deadline for a control period in a given year, the Administrator will deduct from each source’s compliance account TR NOX Annual allowances available under paragraph (a) of this section in order to determine whether the source meets the TR NOX Annual emissions limitation for such control period, as follows:

1. Until the amount of TR NOX Annual allowances deducted equals the number of tons of total NOX emissions from all TR NOX Annual units at the source for such control period; or
2. If there are insufficient TR NOX Annual allowances to complete the deductions in paragraph (b)(1) of this section, until no more TR NOX Annual allowances available under paragraph (a) of this section remain in the compliance account.

(c) Identification of TR NOX Annual allowances by serial number. The authorized account representative for a source’s compliance account may request that specific TR NOX Annual allowances, identified by serial number, in the compliance account be deducted for emissions or excess emissions for a control period in a given year in accordance with paragraph (b) or (d) of this section. In order to be complete, such request shall be submitted to the Administrator by the allowance transfer deadline for such control period and include, in a format prescribed by the Administrator, the identification of the TR NOX Annual source and the appropriate serial numbers.

(c)(1) First-in, first-out. The Administrator will deduct TR NOX Annual allowances under paragraph (b) or (d) of this section from the source’s compliance account in accordance with a complete request under paragraph (c)(1) of this section or, in the absence of such request or in the case of identification of an insufficient amount of TR NOX Annual allowances in such request, on a first-in, first-out accounting basis in the following order:

1. Any TR NOX Annual allowances that were allocated to the units at the source and not transferred out of the compliance account, in the order of recordation; and then
2. Any TR NOX Annual allowances that were allocated to any unit and transferred to and recorded in the compliance account pursuant to this subpart, in the order of recordation.

(d) Deductions for excess emissions. After making the deductions for compliance under paragraph (b) of this section for a control period in a year in which the TR NOX Annual source has excess emissions, the Administrator will deduct from the source’s compliance account an amount of TR NOX Annual allowances, allocated for a control period in a prior year or the control period in the year of the excess emissions or in the immediately following year,
equal to two times the number of tons of the source’s excess emissions.

(e) Recordation of deductions. The Administrator will record in the appropriate compliance account all deductions from such an account under paragraphs (b) and (d) of this section.

§ 97.425 Compliance with TR NO\textsubscript{X} Annual assurance provisions.

(a) Availability for deduction. TR NO\textsubscript{X} Annual allowances are available to be deducted for compliance with the TR NO\textsubscript{X} Annual assurance provisions for a control period in a given year by the owners and operators of a group of one or more TR NO\textsubscript{X} Annual sources and units in a State (and Indian country within the borders of such State) only if the TR NO\textsubscript{X} Annual allowances:

1. Were allocated for a control period in a prior year or the control period in the given year or in the immediately following year; and

2. Are held in the assurance account, established by the Administrator for such owners and operators of such group of TR NO\textsubscript{X} Annual sources and units in such State (and Indian country within the borders of such State) under paragraph (b)(3) of this section, as of the deadline established in paragraph (b)(4) of this section.

(b) Deductions for compliance. The Administrator will deduct TR NO\textsubscript{X} Annual allowances available under paragraph (a) of this section for compliance with the TR NO\textsubscript{X} Annual assurance provisions for a State for a control period in a given year in accordance with the following procedures:

1. By June 1, 2015 and June 1 of each year thereafter, the Administrator will:
   1. Calculate, for each State (and Indian country within the borders of such State), the total NO\textsubscript{X} emissions from all TR NO\textsubscript{X} Annual units at TR NO\textsubscript{X} Annual sources in the State (and Indian country within the borders of such State) during the control period in the year before the year of this calculation deadline and the amount, if any, by which such total NO\textsubscript{X} emissions exceed the State assurance level as described in §97.406(c)(2)(iii); and
   2. Promulgate a notice of data availability of the results of these calculations required in paragraph (b)(1)(i) of this section, including separate calculations of the NO\textsubscript{X} emissions from each TR NO\textsubscript{X} Annual source.

2. For each notice of data availability required in paragraph (b)(1)(ii) of this section and for any State (and Indian country within the borders of such State) identified in such notice as having TR NO\textsubscript{X} Annual units with total NO\textsubscript{X} emissions exceeding the State assurance level for a control period in a given year, as described in §97.406(c)(2)(iii):
   1. By July 1 immediately after the promulgation of such notice, the designated representative of each TR NO\textsubscript{X} Annual source in each such State (and Indian country within the borders of such State) shall submit a statement, in a format prescribed by the Administrator, providing for each TR NO\textsubscript{X} Annual unit (if any) at the source that operates during, but is not allocated an amount of TR NO\textsubscript{X} Annual allowances for, such control period, the unit’s allowable NO\textsubscript{X} emission rate for such control period and, if such rate is expressed in lb per mmBtu, the unit’s heat rate.

   2. By August 1 immediately after the promulgation of such notice, the Administrator will calculate, for each such State (and Indian country within the borders of such State), the total NO\textsubscript{X} emissions from all TR NO\textsubscript{X} Annual units at TR NO\textsubscript{X} Annual sources in the State (and Indian country within the borders of such State), the common designated representative’s share of the total NO\textsubscript{X} emissions from all TR NO\textsubscript{X} Annual units at TR NO\textsubscript{X} Annual sources in the State (and Indian country within the borders of such State), the common designated representative’s assurance level, and the amount (if any) of TR NO\textsubscript{X} Annual allowances that the owners and operators of such group of sources and units must hold in accordance with the calculation formula in §97.406(c)(2)(i) and will promulgate a notice of data availability of the results of these calculations.

   3. The Administrator will provide an opportunity for submission of objections to the calculations referenced by the notice of data availability required in paragraph (b)(2)(ii) of this section.
and the calculations referenced by the relevant notice of data availability required in paragraph (b)(1)(i) of this section.

(A) Objections shall be submitted by the deadline specified in such notice and shall be limited to addressing whether the calculations referenced in the relevant notice required under paragraph (b)(1)(ii) of this section and referenced in the notice required under paragraph (b)(2)(ii) of this section are in accordance with §97.406(c)(2)(iii), §§97.406(b) and 97.430 through 97.435, the definitions of “common designated representative”, “common designated representative’s assurance level”, and “common designated representative’s share” in §97.402, and the calculation formula in §97.406(c)(2)(i).

(B) The Administrator will adjust the calculations to the extent necessary to ensure that they are in accordance with the provisions referenced in paragraph (b)(2)(iii)(A) of this section. By October 1 immediately after the promulgation of such notice, the Administrator will promulgate a notice of data availability of any adjustments that the Administrator determines to be necessary and the reasons for accepting or rejecting any objections submitted in accordance with paragraph (b)(2)(iii)(A) of this section.

(3) For any State (and Indian country within the territories of such State) referenced in each notice of data availability required in paragraph (b)(2)(iii)(B) of this section as having TR NO\(_X\) Annual units with total NO\(_X\) emissions exceeding the State assurance level for a control period in a given year, the Administrator will establish one assurance account for each set of owners and operators referenced in the notice of data availability required under paragraph (b)(2)(iii)(B) of this section, as all of the owners and operators of a group of TR NO\(_X\) Annual units in the State (and Indian country within the territories of such State) having a common designated representative for such control period and as being required to hold TR NO\(_X\) Annual allowances.

(4)(i) As of midnight of November 1 immediately after the promulgation of each notice of data availability required in paragraph (b)(2)(iii)(B) of this section, the owners and operators described in paragraph (b)(3) of this section shall hold in the assurance account established for the them and for the appropriate TR NO\(_X\) Annual sources, TR NO\(_X\) Annual units, and State (and Indian country within the territories of such State) under paragraph (b)(3) of this section a total amount of TR NO\(_X\) Annual allowances, available for deduction under paragraph (a) of this section, equal to the amount such owners and operators are required to hold with regard to such sources, units and State (and Indian country within the territories of such State) as calculated by the Administrator and referenced in such notice.

(ii) Notwithstanding the allowance-holding deadline specified in paragraph (b)(4)(i) of this section, if November 1 is not a business day, then such allowance-holding deadline shall be midnight of the first business day thereafter.

(5) After November 1 (or the date described in paragraph (b)(4)(i) of this section) immediately after the promulgation of each notice of data availability required in paragraph (b)(2)(iii)(B) of this section and after the recordation, in accordance with §97.423, of TR NO\(_X\) Annual allowance transfers submitted by midnight of such date, the Administrator will determine whether the owners and operators described in paragraph (b)(3) of this section hold, in the assurance account for the appropriate TR NO\(_X\) Annual sources, TR NO\(_X\) Annual units, and State (and Indian country within the territories of such State) established under paragraph (b)(3) of this section, the amount of TR NO\(_X\) Annual allowances available under paragraph (a) of this section that the owners and operators are required to hold with regard to such sources, units, and State (and Indian country within the territories of such State) as calculated by the Administrator and referenced in the notice required in paragraph (b)(2)(iii)(B) of this section.

(6) Notwithstanding any other provision of this subpart and any revision, made by or submitted to the Administrator after the promulgation of the notice of data availability required in paragraph (b)(2)(iii)(B) of this section...
for a control period in a given year, of any data used in making the calculations referenced in such notice, the amounts of TR NO\textsubscript{X} Annual allowances that the owners and operators are required to hold in accordance with §97.406(c)(2)(i) for such control period shall continue to be such amounts as calculated by the Administrator and referenced in such notice required in paragraph (b)(2)(iii)(B) of this section, except as follows:

(i) If any such data are revised by the Administrator as a result of a decision in or settlement of litigation concerning such data on appeal under part 78 of this chapter of such notice, or on appeal under section 307 of the Clean Air Act of a decision rendered under part 78 of this chapter on appeal of such notice, then the Administrator will use the data as so revised to recalculate the amounts of TR NO\textsubscript{X} Annual allowances that owners and operators are required to hold in accordance with the calculation formula in §97.406(c)(2)(i) for such control period with regard to the TR NO\textsubscript{X} Annual sources, TR NO\textsubscript{X} Annual units, and State (and Indian country within the borders of such State) involved, provided that such litigation under part 78 of this chapter was initiated no later than 30 days after promulgation of such notice required in paragraph (b)(2)(iii)(B) of this section.

(ii) If any such data are revised by the owners and operators of a TR NO\textsubscript{X} Annual source and TR NO\textsubscript{X} Annual unit whose designated representative submitted such data under paragraph (b)(2)(i) of this section, as a result of a decision in or settlement of litigation concerning such submission, then the Administrator will use the data as so revised to recalculate the amounts of TR NO\textsubscript{X} Annual allowances that owners and operators are required to hold in accordance with the calculation formula in §97.406(c)(2)(i) for such control period with regard to the TR NO\textsubscript{X} Annual sources, TR NO\textsubscript{X} Annual units, and State (and Indian country within the borders of such State) involved, provided that such litigation was initiated no later than 30 days after promulgation of such notice required in paragraph (b)(2)(iii)(B) of this section.

(iii) If the revised data are used to recalculate, in accordance with paragraphs (b)(6)(i) and (ii) of this section, the amount of TR NO\textsubscript{X} Annual allowances that the owners and operators are required to hold for such control period with regard to the TR NO\textsubscript{X} Annual sources, TR NO\textsubscript{X} Annual units, and State (and Indian country within the borders of such State) involved—

(A) Where the amount of TR NO\textsubscript{X} Annual allowances that the owners and operators are required to hold increases as a result of the use of all such revised data, the Administrator will establish a new, reasonable deadline on which the owners and operators shall hold the additional amount of TR NO\textsubscript{X} Annual allowances in the assurance account established by the Administrator for the appropriate TR NO\textsubscript{X} Annual sources, TR NO\textsubscript{X} Annual units, and State (and Indian country within the borders of such State) under paragraph (b)(3) of this section. The owners’ and operators’ failure to hold such additional amount, as required, before the new deadline shall not be a violation of the Clean Air Act. The owners’ and operators’ failure to hold such additional amount, as required, as of the new deadline shall be a violation of the Clean Air Act. Each TR NO\textsubscript{X} Annual allowance that the owners and operators fail to hold as required as of the new deadline, and each day in such control period, shall be a separate violation of the Clean Air Act.

(B) For the owners and operators for which the amount of TR NO\textsubscript{X} Annual allowances required to be held decreases as a result of the use of all such revised data, the Administrator will record, in all accounts from which TR NO\textsubscript{X} Annual allowances were transferred by such owners and operators for such control period to the assurance account established by the Administrator for the appropriate at TR NO\textsubscript{X} Annual sources, TR NO\textsubscript{X} Annual units, and State (and Indian country within the borders of such State) under paragraph (b)(3) of this section, a total amount of the TR NO\textsubscript{X} Annual allowances held in such assurance account equal to the amount of the decrease. If
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§ 97.430 General monitoring, record-keeping, and reporting requirements.

The owners and operators, and to the extent applicable, the designated representative, of a TR NO\textsubscript{X} Annual unit, shall comply with the monitoring, record-keeping, and reporting requirements as provided in this subpart and subpart H of part 75 of this chapter.

For purposes of applying such requirements, the definitions in §97.402 and in §72.2 of this chapter shall apply, the terms “affected unit”, “designated representative,” and “continuous emission monitoring system” (or “CEMS”) in part 75 of this chapter shall be deemed to refer to the terms “TR NO\textsubscript{X} Annual unit”, “designated representative,” and “continuous emission monitoring system” (or “CEMS”) respectively as defined in §97.402, and the term “newly affected unit” shall be deemed to mean “newly affected TR NO\textsubscript{X} Annual unit”. The owner or operator of a unit that is not a TR NO\textsubscript{X} Annual unit but that is monitored under §75.72(b)(2)(ii) of this chapter shall comply with the same monitoring, record-keeping, and reporting requirements as a TR NO\textsubscript{X} Annual unit.

(a) Requirements for installation, certification, and data accounting. The owner or operator of each TR NO\textsubscript{X} Annual unit shall:

(1) Install all monitoring systems required under this subpart for monitoring NO\textsubscript{X} mass emissions and individual unit heat input (including all systems required to monitor NO\textsubscript{X} emission rate, NO\textsubscript{X} concentration, stack gas moisture content, stack gas flow rate, CO\textsubscript{2} or O\textsubscript{2} concentration, and fuel flow rate, as applicable, in accordance with §§75.71 and 75.72 of this chapter);

(2) Successfully complete all certification tests required under §97.431 and meet all other requirements of this subpart and part 75 of this chapter applicable to the monitoring systems under paragraph (a)(1) of this section; and

§ 97.428 Administrator’s action on submissions.

(a) The Administrator may review and conduct independent audits concerning any submission under the TR NO\textsubscript{X} Annual Trading Program and make appropriate adjustments of the information in the submission.

(b) The Administrator may deduct TR NO\textsubscript{X} Annual allowances from or transfer TR NO\textsubscript{X} Annual allowances to a compliance account or an assurance account, based on the information in a submission, as adjusted under paragraph (a)(1) of this section, and record such deductions and transfers.

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(3) Record, report, and quality-assure the data from the monitoring systems under paragraph (a)(1) of this section.

(b) Compliance deadlines. Except as provided in paragraph (e) of this section, the owner or operator shall meet the monitoring system certification and other requirements of paragraphs (a)(1) and (2) of this section on or before the following dates and shall record, report, and quality-assure the data from the monitoring systems under paragraph (a)(1) of this section on and after the following dates.

(1) For the owner or operator of a TR NOX Annual unit that commences commercial operation before July 1, 2011, January 1, 2012.

(2) For the owner or operator of a TR NOX Annual unit that commences commercial operation on or after July 1, 2011, the later of the following:

(i) January 1, 2012; or

(ii) 180 calendar days after the date on which the unit commences commercial operation;

(3) The owner or operator of a TR NOX Annual unit for which construction of a new stack or flue or installation of add-on NOX emission controls is completed after the applicable deadline under paragraph (b)(1) or (2) of this section shall meet the requirements of §§ 75.4(e)(1) through (e)(4) of this chapter, except that:

(i) Such requirements shall apply to the monitoring systems required under §97.430 through §97.435, rather than the monitoring systems required under part 75 of this chapter;

(ii) NOX emission rate, NOX concentration, stack gas volumetric flow rate, and O2 or CO2 concentration data shall be determined and reported, rather than the data listed in §75.4(e)(2) of this chapter; and

(iii) Any petition for another procedure under §75.4(e)(2) of this chapter shall be submitted under §97.435, rather than §75.66.

(c) Reporting data. The owner or operator of a TR NOX Annual unit that does not meet the applicable compliance date set forth in paragraph (b) of this section for any monitoring system under paragraph (a)(1) of this section shall, for each such monitoring system, determine, record, and report maximum potential (or, as appropriate, minimum potential) values for NOX concentration, NOX emission rate, stack gas flow rate, stack gas moisture content, fuel flow rate, and any other parameters required to determine NOX mass emissions and heat input in accordance with §75.31(b)(2) or (c)(3) of this chapter, section 2.4 of appendix D to part 75 of this chapter, or section 2.5 of appendix E to part 75 of this chapter, as applicable.

(d) Prohibitions. (1) No owner or operator of a TR NOX Annual unit shall use any alternative monitoring system, alternative reference method, or any other alternative to any requirement of this subpart without having obtained prior written approval in accordance with §97.435.

(2) No owner or operator of a TR NOX Annual unit shall operate the unit so as to discharge, or allow to be discharged, NOX to the atmosphere without accounting for all such NOX in accordance with the applicable provisions of this subpart and part 75 of this chapter.

(3) No owner or operator of a TR NOX Annual unit shall disrupt the continuous emission monitoring system, any portion thereof, or any other approved emission monitoring method, and thereby avoid monitoring and recording NOX mass discharged into the atmosphere or heat input, except for periods of recertification or periods when calibration, quality assurance testing, or maintenance is performed in accordance with the applicable provisions of this subpart and part 75 of this chapter.

(4) No owner or operator of a TR NOX Annual unit shall retire or permanently discontinue use of the continuous emission monitoring system, any component thereof, or any other approved monitoring system under this subpart, except under any one of the following circumstances:

(i) During the period that the unit is covered by an exemption under §97.405 that is in effect;

(ii) The owner or operator is monitoring emissions from the unit with another certified monitoring system approved, in accordance with the applicable provisions of this subpart and part...
§ 97.431 Initial monitoring system certification and recertification procedures.

(a) The owner or operator of a TR NOX Annual unit shall be exempt from the initial certification requirements of this section for a monitoring system under § 97.430(a)(1) if the following conditions are met:

(1) The monitoring system has been previously certified in accordance with part 75 of this chapter; and

(2) The applicable quality-assurance and quality-control requirements of § 75.21 of this chapter and appendices B, D, and E to part 75 of this chapter are fully met for the certified monitoring system described in paragraph (a)(1) of this section.

(b) The recertification provisions of this section shall apply to a monitoring system under § 97.430(a)(1) that is exempt from initial certification requirements under paragraph (a) of this section.

(c) If the Administrator has previously approved a petition under § 75.19(a) or (b) of this chapter for apportioning the NOX emission rate measured in a common stack or a petition under § 75.66 of this chapter for an alternative to a requirement in § 75.12 or § 75.17 of this chapter, the designated representative shall resubmit the petition to the Administrator under § 97.435 to determine whether the approval applies under the TR NOX Annual Trading Program.

(d) Except as provided in paragraph (a) of this section, the owner or operator of a TR NOX Annual unit shall comply with the following initial certification and recertification procedures for a continuous monitoring system (i.e., a continuous emission monitoring system and an excepted monitoring system under appendices D and E to part 75 of this chapter) under § 97.430(a)(1). The owner or operator of a unit that qualifies to use the low mass emissions excepted monitoring methodology under § 75.19 of this chapter or that qualifies to use an alternative monitoring system under part 75 of this chapter shall comply with the procedures in paragraph (e) or (f) of this section respectively.

(1) Requirements for initial certification. The owner or operator shall ensure that each continuous monitoring system under § 97.430(a)(1) (including the automated data acquisition and handling system) successfully completes all of the initial certification testing required under § 75.20 of this chapter by the applicable deadline in § 97.430(b). In addition, whenever the owner or operator installs a monitoring system to meet the requirements of this subpart in a location where no such monitoring system was previously installed, initial certification in accordance with § 75.20 of this chapter is required.

(2) Requirements for recertification. Whenever the owner or operator makes a replacement, modification, or change in any certified continuous emission monitoring system under § 97.430(a)(1) that may significantly affect the ability of the system to accurately measure or record NOX mass emissions or heat input rate or to meet the quality-assurance and quality-control requirements of § 75.21 of this chapter, the owner or operator shall recertify the monitoring system in accordance with § 75.20(b) of this chapter. Furthermore, whenever the owner or operator makes a replacement, modification, or change to the flue gas handling system or the unit’s operation that may significantly change the stack flow or concentration profile, the owner or operator shall recertify each continuous emission monitoring system whose accuracy is potentially affected by the change, in accordance with § 75.20(b) of this chapter. Examples of changes to a continuous
emission monitoring system that require recertification include replacement of the analyzer, complete replacement of an existing continuous emission monitoring system, or change in location or orientation of the sampling probe or site. Any fuel flowmeter system, and any excepted NO\textsubscript{X} monitoring system under appendix E to part 75 of this chapter, under §97.430(a)(1) are subject to the recertification requirements in §75.20(g)(6) of this chapter.

(3) Approval process for initial certification and recertification. For initial certification of a continuous monitoring system under §97.430(a)(1), paragraphs (d)(3)(i) through (v) of this section apply. For recertifications of such monitoring systems, paragraphs (d)(3)(i) through (iv) of this section and the procedures in §§75.20(b)(5) and (g)(7) of this chapter (in lieu of the procedures in paragraph (d)(3)(v) of this section) apply, provided that in applying paragraphs (d)(3)(i) through (iv) of this section, the word “certification” and “initial certification” are replaced by the word “recertification” and the word “certified” is replaced by with the word “recertified”.

(i) Notification of certification. The designated representative shall submit to the appropriate EPA Regional Office and the Administrator written notice of the dates of certification testing, in accordance with §97.433.

(ii) Certification application. The designated representative shall submit to the Administrator a certification application for each monitoring system. A complete certification application shall include the information specified in §75.63 of this chapter.

(iii) Provisional certification date. The provisional certification date for a monitoring system shall be determined in accordance with §75.20(a)(3) of this chapter. A provisionally certified monitoring system may be used under the TR NO\textsubscript{X} Annual Trading Program for a period not to exceed 120 days after receipt by the Administrator of the complete certification application for the monitoring system under paragraph (d)(3)(ii) of this section. Data measured and recorded by the provisionally certified monitoring system, in accordance with the requirements of part 75 of this chapter, will be considered valid quality-assured data (retroactive to the date and time of provisional certification), provided that the Administrator does not invalidate the provisional certification by issuing a notice of disapproval within 120 days of the date of receipt of the complete certification application by the Administrator.

(iv) Certification application approval process. The Administrator will issue a written notice of approval or disapproval of the certification application to the owner or operator within 120 days of receipt of the complete certification application under paragraph (d)(3)(ii) of this section. In the event the Administrator does not issue such a notice within such 120-day period, each monitoring system that meets the applicable performance requirements of part 75 of this chapter and is included in the certification application will be deemed certified for use under the TR NO\textsubscript{X} Annual Trading Program.

(A) Approval notice. If the certification application is complete and shows that each monitoring system meets the applicable performance requirements of part 75 of this chapter, then the Administrator will issue a written notice of approval of the certification application within 120 days of receipt.

(B) Incomplete application notice. If the certification application is not complete, then the Administrator will issue a written notice of approval of the certification application within 120 days of receipt.

(C) Disapproval notice. If the certification application shows that any monitoring system does not meet the performance requirements of part 75 of this chapter or if the certification application is incomplete and the requirement for disapproval under paragraph (d)(3)(iv)(C) of this section is met, then the Administrator will issue a written notice of disapproval of the...
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certification application. Upon issuance of such notice of disapproval, the provisional certification is invalidated by the Administrator and the data measured and recorded by each uncertified monitoring system shall not be considered valid quality-assured data beginning with the date and hour of provisional certification (as defined under §75.20(a)(3) of this chapter).

(D) Audit decertification. The Administrator may issue a notice of disapproval of the certification status of a monitor in accordance with §97.432(b).

(v) Procedures for loss of certification. If the Administrator issues a notice of disapproval of a certification application under paragraph (d)(3)(iv)(C) of this section or a notice of disapproval of certification status under paragraph (d)(3)(iv)(D) of this section, then:

(A) The owner or operator shall substitute the following values, for each disapproved monitoring system, for each hour of unit operation during the period of invalid data specified under §75.20(a)(4)(iii), §75.20(g)(7), or §75.21(e) of this chapter and continuing until the applicable date and hour specified under §75.20(a)(5)(i) or (g)(7) of this chapter:

1) For a disapproved NOX emission rate (i.e., NOX-diluent) system, the maximum potential NOX emission rate, as defined in §72.2 of this chapter.

2) For a disapproved NOX pollutant concentration monitor and disapproved flow monitor, respectively, the maximum potential concentration of NOX and the maximum potential flow rate, as defined in sections 2.1.2.1 and 2.1.4.1 of appendix A to part 75 of this chapter.

3) For a disapproved moisture monitoring system and disapproved diluent gas monitoring system, respectively, the minimum potential moisture percentage and either the maximum potential CO2 concentration or the minimum potential O2 concentration (as applicable), as defined in sections 2.1.3.1, and 2.1.3.2 of appendix A to part 75 of this chapter.

4) For a disapproved fuel flowmeter system, the maximum potential fuel flow rate, as defined in section 2.4.2.1 of appendix D to part 75 of this chapter.

5) For a disapproved excepted NOX monitoring system under appendix E to part 75 of this chapter, the fuel-specific maximum potential NOX emission rate, as defined in §72.2 of this chapter.

(B) The designated representative shall submit a notification of certification retest dates and a new certification application in accordance with paragraphs (d)(3)(i) and (ii) of this section.

(C) The owner or operator shall repeat all certification tests or other requirements that were failed by the monitoring system, as indicated in the Administrator’s notice of disapproval, no later than 30 unit operating days after the date of issuance of the notice of disapproval.

(e) If the owner or operator of a unit qualified to use the low mass emissions (LME) excepted methodology under §75.19 of this chapter shall meet the applicable certification and recertification requirements in §§75.19(a)(2) and 75.20(h) of this chapter. If the owner or operator of such a unit elects to certify a fuel flowmeter system for heat input determination, the owner or operator shall also meet the certification and recertification requirements in §75.20(g) of this chapter.

(f) The designated representative of each unit for which the owner or operator intends to use an alternative monitoring system approved by the Administrator under subpart E of part 75 of this chapter shall comply with the applicable notification and application procedures of §75.20(f) of this chapter.

§97.432 Monitoring system out-of-control periods.

(a) General provisions. Whenever any monitoring system fails to meet the quality-assurance and quality-control requirements or data validation requirements of part 75 of this chapter, data shall be substituted using the applicable missing data procedures in subpart D or subpart H of, or appendix D or appendix E to, part 75 of this chapter.

(b) Audit decertification. Whenever both an audit of a monitoring system and a review of the initial certification or recertification application reveal that any monitoring system should not
have been certified or recertified because it did not meet a particular performance specification or other requirement under §97.431 or the applicable provisions of part 75 of this chapter, both at the time of the initial certification or recertification application submission and at the time of the audit, the Administrator will issue a notice of disapproval of the certification status of such monitoring system. For the purposes of this paragraph, an audit shall be either a field audit or an audit of any information submitted to the Administrator or any State or permitting authority. By issuing the notice of disapproval, the Administrator revokes prospectively the certification status of the monitoring system. The data measured and recorded by the monitoring system shall not be considered valid quality-assured data from the date of issuance of the notification of the revoked certification status until the date and time that the owner or operator completes subsequently approved initial certification or recertification tests for the monitoring system. The owner or operator shall follow the applicable initial certification or recertification procedures in §97.431 for each disapproved monitoring system.

§ 97.433 Notifications concerning monitoring.

The designated representative of a TR NOx Annual unit shall submit written notice to the Administrator in accordance with §75.61 of this chapter.

§ 97.434 Recordkeeping and reporting.

(a) General provisions. The designated representative shall comply with all recordkeeping and reporting requirements in paragraphs (b) through (e) of this section, the applicable recordkeeping and reporting requirements under §75.73 of this chapter, and the requirements of §97.414(a).

(b) Monitoring plans. The owner or operator of a TR NOx Annual unit shall comply with requirements of §75.73(c) and (e) of this chapter.

(c) Certification applications. The designated representative shall submit an application to the Administrator within 45 days after completing all initial certification or recertification tests required under §97.431, including the information required under §75.63 of this chapter.

(d) Quarterly reports. The designated representative shall submit quarterly reports, as follows:

(1) The designated representative shall report the NOx mass emissions data and heat input data for the TR NOx Annual unit, in an electronic quarterly report in a format prescribed by the Administrator, for each calendar quarter beginning with:

(i) For a unit that commences commercial operation before July 1, 2011, the calendar quarter covering January 1, 2012 through March 31, 2012; or

(ii) For a unit that commences commercial operation on or after July 1, 2011, the calendar quarter corresponding to the earlier of the date of provisional certification or the applicable deadline for initial certification under §97.430(b), unless that quarter is the third or fourth quarter of 2011, in which case reporting shall commence in the quarter covering January 1, 2012 through March 31, 2012.

(2) The designated representative shall submit each quarterly report to the Administrator within 30 days after the end of the calendar quarter covered by the report. Quarterly reports shall be submitted in the manner specified in §75.73(f) of this chapter.

(3) For TR NOx Annual units that are also subject to the Acid Rain Program, TR NOx Ozone Season Trading Program, TR SO2 Group 1 Trading Program, or TR SO2 Group 2 Trading Program, quarterly reports shall include the applicable data and information required by subparts F through H of part 75 of this chapter as applicable, in addition to the NOx mass emission data, heat input data, and other information required by this subpart.

(4) The Administrator may review and conduct independent audits of any quarterly report in order to determine whether the quarterly report meets the requirements of this subpart and part 75 of this chapter, including the requirement to use substitute data.

(i) The Administrator will notify the designated representative of any determination that the quarterly report fails to meet any such requirements and specify in such notification any
corrections that the Administrator believes are necessary to make through resubmission of the quarterly report and a reasonable time period within which the designated representative must respond. Upon request by the designated representative, the Administrator may specify reasonable extensions of such time period. Within the time period (including any such extensions) specified by the Administrator, the designated representative shall resubmit the quarterly report with the corrections specified by the Administrator, except to the extent the designated representative provides information demonstrating that a specified correction is not necessary because the quarterly report already meets the requirements of this subpart and part 75 of this chapter that are relevant to the specified correction.

(ii) Any resubmission of a quarterly report shall meet the requirements applicable to the submission of a quarterly report under this subpart and part 75 of this chapter, except for the deadline set forth in paragraph (d)(2) of this section.

(e) Compliance certification. The designated representative shall submit to the Administrator a compliance certification (in a format prescribed by the Administrator) in support of each quarterly report based on reasonable inquiry of those persons with primary responsibility for ensuring that all of the unit’s emissions are correctly and fully monitored. The certification shall state that:

1. The monitoring data submitted were recorded in accordance with the applicable requirements of this subpart and part 75 of this chapter, including the quality assurance procedures and specifications; and

2. For a unit with add-on NO\textsubscript{X} emission controls and for all hours where NO\textsubscript{X} data are substituted in accordance with §75.34(a)(1) of this chapter, the add-on emission controls were operating within the range of parameters listed in the quality assurance/quality control program under appendix B to part 75 of this chapter and the substitute data values do not systematically underestimate NO\textsubscript{X} emissions.

§97.435 Petitions for alternatives to monitoring, recordkeeping, or reporting requirements.

(a) The designated representative of a TR NO\textsubscript{X} Annual unit may submit a petition under §75.66 of this chapter to the Administrator, requesting approval to apply an alternative to any requirement of §§97.430 through 97.434.

(b) A petition submitted under paragraph (a) of this section shall include sufficient information for the evaluation of the petition, including, at a minimum, the following information:

(i) Identification of each unit and source covered by the petition;

(ii) A detailed explanation of why the proposed alternative is being suggested in lieu of the requirement;

(iii) A description and diagram of any equipment and procedures used in the proposed alternative;

(iv) A demonstration that the proposed alternative is consistent with the purposes of the requirement for which the alternative is proposed and with the purposes of this subpart and part 75 of this chapter and that any adverse effect of approving the alternative will be de minimis; and

(v) Any other relevant information that the Administrator may require.

(c) Use of an alternative to any requirement referenced in paragraph (a) of this section is in accordance with this subpart only to the extent that the petition is approved in writing by the Administrator and that such use is in accordance with such approval.

Subpart BBBBB—TR NO\textsubscript{X} Ozone Season Trading Program

SOURCE: 76 FR 48406, Aug. 8, 2011, unless otherwise noted.

§97.501 Purpose.

This subpart sets forth the general, designated representative, allowance, and monitoring provisions for the Transport Rule (TR) NO\textsubscript{X} Ozone Season Trading Program, under section 110 of the Clean Air Act and §52.38 of this chapter, as a means of mitigating interstate transport of ozone and nitrogen oxides.
§ 97.502 Definitions.

The terms used in this subpart shall have the meanings set forth in this section as follows:

Acid Rain Program means a multi-state SO₂ and NOₓ air pollution control and emission reduction program established by the Administrator under title IV of the Clean Air Act and parts 72 through 78 of this chapter.

Administrator means the Administrator of the United States Environmental Protection Agency or the Director of the Clean Air Markets Division (or its successor determined by the Administrator) of the United States Environmental Protection Agency, the Administrator’s duly authorized representative under this subpart.

Allocate or allocation means, with regard to TR NOₓ Ozone Season allowances, the determination by the Administrator, State, or permitting authority, in accordance with this subpart and any SIP revision submitted by the State and approved by the Administrator under §52.38(b)(3), (4), or (5) of this chapter, of the amount of such TR NOₓ Ozone Season allowances to be initially credited, at no cost to the recipient, to:

(1) A TR NOₓ Ozone Season unit;
(2) A new unit set-aside;
(3) An Indian country new unit set-aside; or
(4) An entity not listed in paragraphs (1) through (3) of this definition;

Provided that, if the Administrator, State, or permitting authority initially credits, to a TR NOₓ Ozone Season unit qualifying for an initial credit, a credit in the amount of zero TR NOₓ Ozone Season allowances, the TR NOₓ Ozone Season unit will be treated as being allocated an amount (i.e., zero) of TR NOₓ Ozone Season allowances.

Allowable NOₓ emission rate means, for a unit, the most stringent State or federal NOₓ emission rate limit (in lb/MMWhr or, if in lb/mmBtu, converted to lb/MMWhr by multiplying it by the unit’s heat rate in mmBtu/MMWhr) that is applicable to the unit and covers the longest averaging period not exceeding one year.

Allowance Management System means the system by which the Administrator records allocations, deductions, and transfers of TR NOₓ Ozone Season allowances under the TR NOₓ Ozone Season Trading Program. Such allowances are allocated, recorded, held, deducted, or transferred only as whole allowances.

Allowance Management System account means an account in the Allowance Management System established by the Administrator for purposes of recording the allocation, holding, transfer, or deduction of TR NOₓ Ozone Season allowances.

Allowance transfer deadline means, for a control period in a given year, midnight of December 1 (if it is a business day), or midnight of the first business day thereafter (if December 1 is not a business day), immediately after such control period and is the deadline by which a TR NOₓ Ozone Season allowance transfer must be submitted for recordation in a TR NOₓ Ozone Season source’s compliance account in order to be available for use in complying with the source’s TR NOₓ Ozone Season emissions limitation for such control period in accordance with §§97.506 and 97.524.

Alternate designated representative means, for a TR NOₓ Ozone Season source and each TR NOₓ Ozone Season unit at the source, the natural person who is authorized by the owners and operators of the source and all such units at the source, in accordance with this subpart, to act on behalf of the designated representative in matters pertaining to the TR NOₓ Ozone Season Trading Program. If the TR NOₓ Ozone Season source is also subject to the Acid Rain Program, TR NOₓ Annual Trading Program, TR SO₂ Group 1 Trading Program, or TR SO₂ Group 2 Trading Program, then this natural person shall be the same natural person as the alternate designated representative, as defined in the respective program.

Assurance account means an Allowance Management System account, established by the Administrator under §97.525(b)(3) for certain owners and operators of a group of one or more TR NOₓ Ozone Season sources and units in a given State (and Indian country within the borders of such State), in which are held TR NOₓ Ozone Season allowances.
allowances available for use for a control period in a given year in complying with the TR NOx Ozone Season assurance provisions in accordance with §§97.506 and 97.525.

Authorized account representative means, for a general account, the natural person who is authorized, in accordance with this subpart, to transfer and otherwise dispose of TR NOx Ozone Season allowances held in the general account and, for a TR NOx Ozone Season source’s compliance account, the designated representative of the source.

Automated data acquisition and handling system or DAHS means the component of the continuous emission monitoring system, or other emissions monitoring system approved for use under this subpart, designed to interpret and convert individual output signals from pollutant concentration monitors, flow monitors, diluent gas monitors, and other component parts of the monitoring system to produce a continuous record of the measured parameters in the measurement units required by this subpart.

Biomass means—
(1) Any organic material grown for the purpose of being converted to energy;
(2) Any organic byproduct of agriculture that can be converted into energy; or
(3) Any material that can be converted into energy and is nonmerchantable for other purposes, that is segregated from other material that is nonmerchantable for other purposes, and that is:
   (i) A forest-related organic resource, including mill residues, precommercial thinnings, slash, brush, or byproduct from conversion of trees to merchantable material; or
   (ii) A wood material, including pallets, crates, dunnage, manufacturing and construction materials (other than pressure-treated, chemically-treated, or painted wood products), and landscape or right-of-way tree trimmings.

Boiler means an enclosed fossil- or other-fuel-fired combustion device used to produce heat and to transfer heat to recirculating water, steam, or other medium.

Botoming-cycle unit means a unit in which the energy input to the unit is first used to produce useful thermal energy, where at least some of the reject heat from the useful thermal energy application or process is then used for electricity production.

Business day means a day that does not fall on a weekend or a federal holiday.

Certifying official means a natural person who is:
(1) For a corporation, a president, secretary, treasurer, or vice-president of the corporation in charge of a principal business function or any other person who performs similar policy- or decision-making functions for the corporation;
(2) For a partnership or sole proprietorship, a general partner or the proprietor respectively; or
(3) For a local government entity or State, federal, or other public agency, a principal executive officer or ranking elected official.

Clean Air Act means the Clean Air Act, 42 U.S.C. 7401, et seq.

Coal means “coal” as defined in §72.2 of this chapter.

Coal-derived fuel means any fuel (whether in a solid, liquid, or gaseous state) produced by the mechanical, thermal, or chemical processing of coal.

Cogeneration system means an integrated group, at a source, of equipment (including a boiler, or combustion turbine, and a steam turbine generator) designed to produce useful thermal energy for industrial, commercial, heating, or cooling purposes and electricity through the sequential use of energy.

Cogeneration unit means a stationary, fossil-fuel-fired boiler or stationary, fossil-fuel-fired combustion turbine that is a topping-cycle unit or a bottoming-cycle unit:
(1) Operating as part of a cogeneration system; and
(2) Producing on an annual average basis—
   (i) For a topping-cycle unit,
      (A) Useful thermal energy not less than 5 percent of total energy output; and
      (B) Useful power that, when added to one-half of useful thermal energy produced, is not less than 42.5 percent of
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total energy input, if useful thermal energy produced is 15 percent or more of total energy output, or not less than 45 percent of total energy input, if useful thermal energy produced is less than 15 percent of total energy output.

(ii) For a bottoming-cycle unit, useful power not less than 45 percent of total energy input;

(iii) Provided that the requirements in paragraph (2) of this definition shall not apply to a calendar year referenced in paragraph (2) of this definition during which the unit did not operate at all;

(iv) Provided that the total energy input under paragraphs (2)(i)(B) and (2)(ii) of this definition shall equal the unit’s total energy input from all fuel, except biomass if the unit is a boiler; and

(v) Provided that, if, throughout its operation during the 12-month period or a calendar year referenced in paragraph (2) of this definition, a unit is operated as part of a cogeneration system and the cogeneration system meets on a system-wide basis the requirement in paragraph (2)(i)(B) or (2)(ii) of this definition, the unit shall be deemed to meet such requirement during that 12-month period or calendar year.

Combustion turbine means an enclosed device comprising:

(1) If the device is simple cycle, a compressor, a combustor, and a turbine and in which the flue gas resulting from the combustion of fuel in the combustor passes through the turbine, rotating the turbine; and

(2) If the device is combined cycle, the equipment described in paragraph (1) of this definition and any associated duct burner, heat recovery steam generator, and steam turbine.

Commence commercial operation means, with regard to a unit:

(1) To have begun to produce steam, gas, or other heated medium used to generate electricity for sale or use, including test generation, except as provided in §97.505.

(i) For a unit that is a TR NOX Ozone Season unit under §97.504 on the later of January 1, 2005 or the date the unit commences commercial operation as defined in the introductory text of paragraph (1) of this definition and that subsequently undergoes a physical change or is moved to a new location or source, such date shall remain the date of commencement of commercial operation of the unit, which shall continue to be treated as the same unit.

(ii) For a unit that is a TR NOX Ozone Season unit under §97.504 on the later of January 1, 2005 or the date the unit commences commercial operation as defined in the introductory text of paragraph (1) of this definition and that is subsequently replaced by a unit at the same or a different source, such date shall remain the replaced unit’s date of commencement of commercial operation, and the replacement unit shall be treated as a separate unit with a separate date for commencement of commercial operation as defined in paragraph (1) or (2) of this definition as appropriate.

(2) Notwithstanding paragraph (1) of this definition and except as provided in §97.505, for a unit that is not a TR NOX Ozone Season unit under §97.504 on the later of January 1, 2005 or the date the unit commences commercial operation as defined in introductory text of paragraph (1) of this definition, the unit’s date for commencement of commercial operation shall be the date on which the unit becomes a TR NOX Ozone Season unit under §97.504.

(i) For a unit with a date for commencement of commercial operation as defined in the introductory text of paragraph (2) of this definition and that subsequently undergoes a physical change or is moved to a different location or source, such date shall remain the date of commencement of commercial operation of the unit, which shall continue to be treated as the same unit.

(ii) For a unit with a date for commencement of commercial operation as defined in the introductory text of paragraph (2) of this definition and that is subsequently replaced by a unit at the same or a different source, such date shall remain the replaced unit’s date of commencement of commercial operation, and the replacement unit shall be treated as a separate unit with a separate date for commencement of commercial operation as defined in paragraph (1) or (2) of this definition as appropriate.
Common designated representative means, with regard to a control period in a given year, a designated representative where, as of April 1 immediately after the allowance transfer deadline for such control period, the same natural person is authorized under §§97.513(a) and 97.515(a) as the designated representative for a group of one or more TR NOX Ozone Season sources and units located in a State (and Indian country within the borders of such State).

Common designated representative’s assurance level means, with regard to a specific common designated representative and a State (and Indian country within the borders of such State) and control period in a given year for which the State assurance level is exceeded as described in §97.506(c)(2)(iii), the common designated representative’s share of the State NOX Ozone Season trading budget with the variability limit for the State for such control period.

Common designated representative’s share means, with regard to a specific common designated representative for a control period in a given year:

(1) With regard to a total amount of NOX emissions from all TR NOX Ozone Season units in a State (and Indian country within the borders of such State) during such control period, the total tonnage of NOX emissions during such control period from a group of one or more TR NOX Ozone Season units located in such State (and such Indian country) and having the common designated representative for such control period;

(2) With regard to a State NOX Ozone Season trading budget with the variability limit for such control period, the amount (rounded to the nearest allowance) equal to the sum of the total amount of TR NOX Ozone Season allowances allocated for such control period to a group of one or more TR NOX Ozone Season units located in the State (and Indian country within the borders of such State) and having the common designated representative for such control period and of the total amount of TR NOX Ozone Season allowances purchased by an owner or operator of such TR NOX Ozone Season units in an auction for such control period and submitted by the State or the permitting authority to the Administrator for recordation in the compliance accounts for such TR NOX Ozone Season units in accordance with the TR NOX Ozone Season allowance auction provisions in a SIP revision approved by the Administrator under §52.38(b)(4) or (5) of this chapter, multiplied by the sum of the State NOX Ozone Season trading budget under §97.510(a) and the State’s variability limit under §97.510(b) for such control period and divided by such State NOX Ozone Season trading budget;

(3) Provided that, in the case of a unit that operates during, but has no amount of TR NOX Ozone Season allowances allocated under §§97.511 and 97.512 for, such control period, the unit shall be treated, solely for purposes of this definition, as being allocated an amount (rounded to the nearest allowance) of TR NOX Ozone Season allowances for such control period equal to the unit’s allowable NOX emission rate applicable to such control period, multiplied by a capacity factor of 0.92 (if the unit is a boiler combusting any amount of coal or coal-derived fuel during such control period), 0.32 (if the unit is a simple combustion turbine during such control period), 0.71 (if the unit is a combined cycle turbine during such control period), 0.73 (if the unit is an integrated coal gasification combined cycle unit during such control period), or 0.44 (for any other unit), multiplied by the unit’s maximum hourly load as reported in accordance with this subpart and by 3,672 hours/control period, and divided by 2,000 lb/ton.

Common stack means a single flue through which emissions from 2 or more units are exhausted.

Compliance account means an Allowance Management System account, established by the Administrator for a TR NOX Ozone Season source under this subpart, in which any TR NOX Ozone Season allowance allocations to the TR NOX Ozone Season units at the source are recorded and in which are held any TR NOX Ozone Season allowances available for use for a control period in a given year in complying with the source’s TR NOX Ozone Season
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emissions limitation in accordance with §§97.506 and 97.524.

Continuous emission monitoring system or CEMS means the equipment required under this subpart to sample, analyze, measure, and provide, by means of readings recorded at least once every 15 minutes and using an automated data acquisition and handling system (DAHS), a permanent record of NO\textsubscript{x} emissions, stack gas volumetric flow rate, stack gas moisture content, and \textit{O}_2 or CO\textsubscript{2} concentration (as applicable), in a manner consistent with part 75 of this chapter and §§97.530 through 97.535.

The following systems are the principal types of continuous emission monitoring systems:

(1) A flow monitoring system, consisting of a stack flow rate monitor and an automated data acquisition and handling system and providing a permanent, continuous record of stack gas volumetric flow rate, in standard cubic feet per hour (scfh);

(2) A NO\textsubscript{x} concentration monitoring system, consisting of a NO\textsubscript{x} pollutant concentration monitor and an automated data acquisition and handling system and providing a permanent, continuous record of stack gas volumetric flow rate, in parts per million (ppm);

(3) A NO\textsubscript{x} emission rate (or NO\textsubscript{x}-diluent) monitoring system, consisting of a NO\textsubscript{x} pollutant concentration monitor, a diluent gas (CO\textsubscript{2} or \textit{O}_2) monitor, and an automated data acquisition and handling system and providing a permanent, continuous record of NO\textsubscript{x} concentration, in parts per million (ppm), diluent gas concentration, in percent CO\textsubscript{2} or \textit{O}_2, and NO\textsubscript{x} emission rate, in pounds per million British thermal units (lb/mmBtu);

(4) A moisture monitoring system, as defined in §75.11(b)(2) of this chapter and providing a permanent, continuous record of the stack gas moisture content, in percent H\textsubscript{2}O;

(5) A CO\textsubscript{2} monitoring system, consisting of a CO\textsubscript{2} pollutant concentration monitor (or an \textit{O}_2 monitor plus suitable mathematical equations from which the CO\textsubscript{2} concentration is derived) and an automated data acquisition and handling system and providing a permanent, continuous record of CO\textsubscript{2} emissions, in percent CO\textsubscript{2}; and

(6) An \textit{O}_2 monitoring system, consisting of an \textit{O}_2 concentration monitor and an automated data acquisition and handling system and providing a permanent, continuous record of \textit{O}_2, in percent \textit{O}_2.

Control period means the period starting May 1 of a calendar year, except as provided in §97.506(c)(3), and ending on September 30 of the same year, inclusive.

Designated representative means, for a TR NO\textsubscript{x} Ozone Season source and each TR NO\textsubscript{x} Ozone Season unit at the source, the natural person who is authorized by the owners and operators of the source and all such units at the source, in accordance with this subpart, to represent and legally bind each owner and operator in matters pertaining to the TR NO\textsubscript{x} Ozone Season Trading Program. If the TR NO\textsubscript{x} Ozone Season source is also subject to the Acid Rain Program, TR NO\textsubscript{x} Annual Trading Program, TR SO\textsubscript{2} Group 1 Trading Program, or TR SO\textsubscript{2} Group 2 Trading Program, then this natural person shall be the same natural person as the designated representative, as defined in the respective program.

Emissions means air pollutants exhausted from a unit or source into the atmosphere, as measured, recorded, and reported to the Administrator by the designated representative, and as modified by the Administrator:

(1) In accordance with this subpart; and

(2) With regard to a period before the unit or source is required to measure, record, and report such air pollutants in accordance with this subpart, in accordance with part 75 of this chapter.

Excess emissions means any ton of emissions from the TR NO\textsubscript{x} Ozone Season units at a TR NO\textsubscript{x} Ozone Season source during a control period in a given year that exceeds the TR NO\textsubscript{x} Ozone Season emissions limitation for the source for such control period.

Fossil fuel means—

(1) Natural gas, petroleum, coal, or any form of solid, liquid, or gaseous fuel derived from such material; or

(2) For purposes of applying the limitation on “average annual fuel consumption of a fossil fuel” in §§97.504(b)(2)(i)(B) and (ii). natural gas, petroleum, coal, or any form of solid,
liquid, or gaseous fuel derived from such material for the purpose of creating useful heat.

Fossil-fuel-fired means, with regard to a unit, combusting any amount of fossil fuel in 2005 or any calendar year thereafter.

General account means an Allowance Management System account, established under this subpart, that is not a compliance account or an assurance account.

Generator means a device that produces electricity.

Gross electrical output means, for a unit, electricity made available for use, including any such electricity used in the power production process (which process includes, but is not limited to, any on-site processing or treatment of fuel combusted at the unit and any on-site emission controls).

Heat input means, for a unit for a specified period of time, the product (in mmBtu/time) of the gross calorific value of the fuel (in mmBtu/lb) fed into the unit multiplied by the fuel feed rate (in lb of fuel/time), as measured, recorded, and reported to the Administrator by the designated representative and as modified by the Administrator in accordance with this subpart and excluding the heat derived from preheated combustion air, recirculated flue gases, or exhaust.

Heat input rate means, for a unit, the amount of heat input (in mmBtu) divided by unit operating time (in hr) or, for a unit and a specific fuel, the amount of heat input attributed to the fuel (in mmBtu) divided by the unit operating time (in hr) during which the unit combusted the fuel.

Heat rate means, for a unit, the unit’s maximum design heat input (in Btu/hr), divided by the product of 1,000,000 Btu/mmBtu and the unit’s maximum hourly load.

Indian country means “Indian country” as defined in 18 U.S.C. 1151.

Life-of-the-unit, firm power contractual arrangement means a unit participation power sales agreement under which a utility or industrial customer reserves, or is entitled to receive, a specified amount or percentage of nameplate capacity and associated energy generated by any specified unit and pays its proportional amount of such unit’s total costs, pursuant to a contract:

1. For the life of the unit;
2. For a cumulative term of no less than 30 years, including contracts that permit an election for early termination; or
3. For a period no less than 25 years or 70 percent of the economic useful life of the unit determined as of the time the unit is built, with option rights to purchase or release some portion of the nameplate capacity and associated energy generated by the unit at the end of the period.

Maximum design heat input means, for a unit, the maximum amount of fuel per hour (in Btu/hr) that the unit is capable of combusting on a steady state basis as of the initial installation of the unit as specified by the manufacturer of the unit.

Monitoring system means any monitoring system that meets the requirements of this subpart, including a continuous emission monitoring system, an alternative monitoring system, or an excepted monitoring system under part 75 of this chapter.

Nameplate capacity means, starting from the initial installation of a generator, the maximum electrical generating output (in MWe, rounded to the nearest tenth) that the generator is capable of producing on a steady state basis and during continuous operation (when not restricted by seasonal or other deratings) as of such installation as specified by the manufacturer of the generator or, starting from the completion of any subsequent physical change in the generator resulting in an increase in the maximum electrical generating output that the generator is capable of producing on a steady state basis and during continuous operation (when not restricted by seasonal or other deratings), such increased maximum amount (in MWe, rounded to the nearest tenth) as of such completion as specified by the person conducting the physical change.

Natural gas means “natural gas” as defined in §72.2 of this chapter.

Newly affected TR NOx Ozone Season unit means a unit that was not a TR NOx Ozone Season unit when it began operating but that thereafter becomes a TR NOx Ozone Season unit.
Operate or operation means, with regard to a unit, to combust fuel.

Operator means, for a TR NO\textsubscript{X} Ozone Season source or a TR NO\textsubscript{X} Ozone Season unit at a source respectively, any person who operates, controls, or supervises a TR NO\textsubscript{X} Ozone Season unit at the source or the TR NO\textsubscript{X} Ozone Season unit and shall include, but not be limited to, any holding company, utility system, or plant manager of such source or unit.

Operator means, for a TR NO\textsubscript{X} Ozone Season source or a TR NO\textsubscript{X} Ozone Season unit at a source respectively, any person who operates, controls, or supervises a TR NO\textsubscript{X} Ozone Season unit at the source or the TR NO\textsubscript{X} Ozone Season unit and shall include, but not be limited to, any holding company, utility system, or plant manager of such source or unit.

Owner means, for a TR NO\textsubscript{X} Ozone Season source or a TR NO\textsubscript{X} Ozone Season unit at a source respectively, any of the following persons:

1. Any holder of any portion of the legal or equitable title in a TR NO\textsubscript{X} Ozone Season unit at the source or the TR NO\textsubscript{X} Ozone Season unit;
2. Any holder of a leasehold interest in a TR NO\textsubscript{X} Ozone Season unit at the source or the TR NO\textsubscript{X} Ozone Season unit, provided that, unless expressly provided for in a leasehold agreement, “owner” shall not include a passive lessor, or a person who has an equitable interest through such lessor, whose rental payments are not based (either directly or indirectly) on the revenues or income from such TR NO\textsubscript{X} Ozone Season unit; and
3. Any purchaser of power from a TR NO\textsubscript{X} Ozone Season unit at the source or the TR NO\textsubscript{X} Ozone Season unit under a life-of-the-unit, firm power contractual arrangement.

Permanently retired means, with regard to a unit, a unit that is unavailable for service and that the unit’s owners and operators do not expect to return to service in the future.

Permitting authority means “permitting authority” as defined in §§70.2 and 71.2 of this chapter.

Potential electrical output capacity means, for a unit, 33 percent of the unit’s maximum design heat input, divided by 3,413 Btu/kWh, divided by 1,000 kWh/MWh, and multiplied by 8,760 hr/yr.

Receive or receipt of means, when referring to the Administrator, to come into possession of a document, information, or correspondence (whether sent in hard copy or by authorized electronic transmission), as indicated in an official log, or by a notation made on the document, information, or correspondence, by the Administrator in the regular course of business.

Recordation, record, or recorded means, with regard to TR NO\textsubscript{X} Ozone Season allowances, the moving of TR NO\textsubscript{X} Ozone Season allowances by the Administrator into, out of, or between Allowance Management System accounts, for purposes of allocation, auction, transfer, or deduction.

Reference method means any direct test method of sampling and analyzing for an air pollutant as specified in §75.22 of this chapter.

Replacement, replace, or replaced means, with regard to a unit, the demolishing of a unit, or the permanent retirement and permanent disabling of a unit, and the construction of another unit (the replacement unit) to be used instead of the demolished or retired unit (the replaced unit).

Sequential use of energy means:

1. The use of reject heat from electricity production in a useful thermal energy application or process; or
2. The use of reject heat from useful thermal energy application or process in electricity production.

Serial number means, for a TR NO\textsubscript{X} Ozone Season allowance, the unique identification number assigned to each TR NO\textsubscript{X} Ozone Season allowance by the Administrator.

Solid waste incineration unit means a stationary, fossil-fuel-fired boiler or stationary, fossil-fuel-fired combustion turbine that is a “solid waste incineration unit” as defined in section 129(g)(1) of the Clean Air Act.

Source means all buildings, structures, or installations located in one or more contiguous or adjacent properties under common control of the same person or persons. This definition does not change or otherwise affect the definition of “major source”, “stationary source”, or “source” as set forth and implemented in a title V operating permit program or any other program under the Clean Air Act.

State means one of the States that is subject to the TR NO\textsubscript{X} Ozone Season Trading Program pursuant to §52.38(b) of this chapter.

Submit or serve means to send or transmit a document, information, or correspondence to the person specified
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in accordance with the applicable regulation:

1. In person;
2. By United States Postal Service; or
3. By other means of dispatch or transmission and delivery;
4. Provided that compliance with any “submission” or “service” deadline shall be determined by the date of dispatch, transmission, or mailing and not the date of receipt.

_Topping-cycle unit_ means a unit in which the energy input to the unit is first used to produce useful power, including electricity, where at least some of the reject heat from the electricity production is then used to provide useful thermal energy.

_Total energy input_ means, for a unit, total energy of all forms supplied to the unit, excluding energy produced by the unit. Each form of energy supplied shall be measured by the lower heating value of that form of energy calculated as follows:

\[ \text{LHV} = \text{HHV} - 10.55 \left( W + 9H \right) \]

where:

_LHV_ = lower heating value of the form of energy in Btu/lb,

_HHV_ = higher heating value of the form of energy in Btu/lb,

_W_ = weight % of moisture in the form of energy, and

_H_ = weight % of hydrogen in the form of energy.

_Total energy output_ means, for a unit, the sum of useful power and useful thermal energy produced by the unit.

_TR NO_x Annual Trading Program_ means a multi-state NO_x air pollution control and emission reduction program established in accordance with subpart AAAAA of this part and §52.38(a) of this chapter (including such a program that is revised in a SIP revision approved by the Administrator under §52.38(a)(3) or (4) of this chapter, or that is established in a SIP revision approved by the Administrator under §52.38(b)(5) of this chapter, to emit one ton of NO_x during a control period of the specified calendar year for which the authorization is allocated or auctioned or of any calendar year thereafter under the TR NO_x Ozone Season Trading Program.

_TR NO_x Ozone Season allowance deduction or deduct TR NO_x Ozone Season allowances_ means the permanent withdrawal of TR NO_x Ozone Season allowances by the Administrator from a compliance account (e.g., in order to account for compliance with the TR NO_x Ozone Season emissions limitation) or from an assurance account (e.g., in order to account for compliance with the assurance provisions under §§97.506 and 97.525).

_TR NO_x Ozone Season allowances held or hold TR NO_x Ozone Season allowances_ means the TR NO_x Ozone Season allowances treated as included in an Allowance Management System account as of a specified point in time because at that time they:

1. Have been recorded by the Administrator in the account or transferred into the account by a correctly submitted, but not yet recorded, TR NO_x Ozone Season allowance transfer in accordance with this subpart; and
2. Have not been transferred out of the account by a correctly submitted, but not yet recorded, TR NO_x Ozone Season allowance transfer in accordance with this subpart.

_TR NO_x Ozone Season emissions limitation_ means, for a TR NO_x Ozone Season source, the tonnage of NO_x emissions authorized in a control period in a given year by the TR NO_x Ozone Season allowances available for deduction for the source under §97.524(a) for such control period.

_TR NO_x Ozone Season source_ means a source that includes one or more TR NO_x Ozone Season units.

_TR NO_x Ozone Season Trading Program_ means a multi-state NO_x air pollution control and emission reduction program established in accordance with this subpart and §52.38(b) of this chapter (including such a program that is revised in a SIP revision approved by the Administrator under §52.38(b)(3) or (4) of this chapter, or that is established in a SIP revision approved by the Administrator under §52.38(b)(5) of this chapter, to emit one ton of NO_x during a control period of the specified calendar year for which the authorization is allocated or auctioned or of any calendar year thereafter under the TR NO_x Ozone Season Trading Program.
§ 97.503 Measurements, abbreviations, and acronyms.

Measurements, abbreviations, and acronyms used in this subpart are defined as follows:

<table>
<thead>
<tr>
<th>Symbol</th>
<th>Description</th>
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<tbody>
<tr>
<td>Btu</td>
<td>British thermal unit</td>
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<tr>
<td>CO₂</td>
<td>Carbon dioxide</td>
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<tr>
<td>H₂O</td>
<td>Water</td>
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<td>hr</td>
<td>Hour</td>
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<tr>
<td>kW</td>
<td>Kilowatt electrical</td>
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<td>kWh</td>
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<tr>
<td>MWh</td>
<td>Megawatt hour</td>
</tr>
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</tr>
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<td>Standard cubic feet per hour</td>
</tr>
<tr>
<td>SO₂</td>
<td>Sulfur dioxide</td>
</tr>
<tr>
<td>yr</td>
<td>Year</td>
</tr>
</tbody>
</table>

§ 97.504 Applicability.

(a) Except as provided in paragraph (b) of this section:

1. The following units in a State (and Indian country within the borders of such State) shall be TR NOₓ Ozone Season units, and any source that includes one or more such units shall be a TR NOₓ Ozone Season source, subject to the requirements of this subpart:
   - any stationary, fossil-fuel-fired boiler or stationary, fossil-fuel-fired combustion turbine serving at any time, on or after January 1, 2005, a generator with nameplate capacity of more than 25 MWe producing electricity for sale.

2. If a stationary boiler or stationary combustion turbine that, under
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paragraph (a)(1) of this section, is not a TR NO\textsubscript{X} Ozone Season unit begins to combust fossil fuel or to serve a generator with nameplate capacity of more than 25 MWe producing electricity for sale, the unit shall become a TR NO\textsubscript{X} Ozone Season unit as provided in paragraph (a)(1) of this section on the first date on which it both combusts fossil fuel and serves such generator.

(b) Any unit in a State (and Indian country within the borders of such State) that otherwise is a TR NO\textsubscript{X} Ozone Season unit under paragraph (a) of this section and that meets the requirements set forth in paragraph (b)(1)(i) or (2)(i) of this section shall not be a TR NO\textsubscript{X} Ozone Season unit:

(1)(i) Any unit:
(A) Qualifying as a cogeneration unit throughout the later of 2005 or the 12-month period starting on the date the unit first produces electricity and continuing to qualify as a cogeneration unit throughout each calendar year ending after the later of 2005 or such 12-month period; and
(B) Not supplying in 2005 or any calendar year thereafter more than one-third of the unit’s potential electric output capacity or 219,000 MWh, whichever is greater, to any utility power distribution system for sale.

(ii) If, after qualifying under paragraph (b)(2)(i) of this section as not being a TR NO\textsubscript{X} Ozone Season unit, a unit subsequently no longer meets all the requirements of paragraph (b)(1)(i) of this section, the unit shall become a TR NO\textsubscript{X} Ozone Season unit starting on the earlier of January 1 after the first calendar year during which the unit first no longer qualifies as a solid waste incineration unit or January 1 after the first 3 consecutive calendar years after 2005 for which the unit has an average annual fuel consumption of fossil fuel of 20 percent or more. The unit shall thereafter continue to be a TR NO\textsubscript{X} Ozone Season unit.

(2)(i) Any unit:
(A) Qualifying as a solid waste incineration unit throughout the later of 2005 or the 12-month period starting on the date the unit first produces electricity and continuing to qualify as a solid waste incineration unit throughout each calendar year ending after the later of 2005 or such 12-month period; and
(B) With an average annual fuel consumption of fossil fuel for the first 3 consecutive calendar years of operation starting no earlier than 2005 of less than 20 percent (on a Btu basis) and an average annual fuel consumption of fossil fuel for any 3 consecutive calendar years thereafter of less than 20 percent (on a Btu basis).

(ii) If, after qualifying under paragraph (b)(2)(i) of this section as not being a TR NO\textsubscript{X} Ozone Season unit, a unit subsequently no longer meets all the requirements of paragraph (b)(2)(i) of this section, the unit shall become a TR NO\textsubscript{X} Ozone Season unit starting on the earlier of January 1 after the first calendar year during which the unit first no longer qualifies as a solid waste incineration unit or January 1 after the first 3 consecutive calendar years after 2005 for which the unit has an average annual fuel consumption of fossil fuel of 20 percent or more. The unit shall thereafter continue to be a TR NO\textsubscript{X} Ozone Season unit.

(c) A certifying official of an owner or operator of any unit or other equipment may submit a petition (including any supporting documents) to the Administrator at any time for a determination concerning the applicability, under paragraphs (a) and (b) of this section or a SIP revision approved under § 52.38(b)(4) or (5) of this chapter, of the TR NO\textsubscript{X} Ozone Season Trading Program to the unit or other equipment.

(1) Petition content. The petition shall be in writing and include the identification of the unit or other equipment and the relevant facts about the unit or other equipment. The petition and any other documents provided to the Administrator in connection with the petition shall include the following certification statement, signed by the certifying official: "I am authorized to make this submission on behalf of the owners and operators of the unit or other equipment for which the submission is made. I certify under penalty of law that I have personally examined, and am familiar with, the statements and information submitted in this document and all its attachments. Based on my inquiry of those individuals with primary responsibility for obtaining the information, I certify that the statements and information..."
§ 97.505 Retired unit exemption.

(a)(1) Any TR NOx Ozone Season unit that is permanently retired shall be exempt from §§97.506(b) and (c)(1), §97.524, and §§97.530 through 97.535.

(2) The exemption under paragraph (a)(1) of this section shall become effective the day on which the TR NOx Ozone Season unit is permanently retired. Within 30 days of the unit’s permanent retirement, the designated representative shall submit a statement to the Administrator. The statement shall state, in a format prescribed by the Administrator, that the unit was permanently retired on a specified date and will comply with the requirements of paragraph (b) of this section.

(b) Special provisions. (1) A unit exempt under paragraph (a) of this section shall not emit any NOx, starting on the date that the exemption takes effect.

(2) For a period of 5 years from the date the records are created, the owners and operators of a unit exempt under paragraph (a) of this section shall retain, at the source that includes the unit, records demonstrating that the unit is permanently retired. The 5-year period for keeping records may be extended for cause, at any time before the end of the period, by the Administrator. The owners and operators bear the burden of proof that the unit is permanently retired.

(3) The owners and operators and, to the extent applicable, the designated representative of a unit exempt under paragraph (a) of this section shall comply with the requirements of the TR NOx Ozone Season Trading Program concerning all periods for which the exemption is not in effect, even if such requirements arise, or must be complied with, after the exemption takes effect.

(4) A unit exempt under paragraph (a) of this section shall lose its exemption on the first date on which the unit resumes operation. Such unit shall be treated, for purposes of applying allocation, monitoring, reporting, and recordkeeping requirements under this subpart, as a unit that commences commercial operation on the first date on which the unit resumes operation.

§ 97.506 Standard requirements.

(a) Designated representative requirements. The owners and operators shall comply with the requirement to have a designated representative, and may have an alternate designated representative, in accordance with §§97.513 through 97.518.

(b) Emissions monitoring, reporting, and recordkeeping requirements. (1) The owners and operators, and the designated representative, of each TR NOx Ozone Season source and each TR NOx Ozone Season unit at the source shall comply with the monitoring, reporting, and recordkeeping requirements of §§97.530 through 97.535.

(2) The emissions data determined in accordance with §§97.530 through 97.535 shall be used to calculate allocations of TR NOx Ozone Season allowances under §§97.511(a)(2) and (b) and 97.512 and to determine compliance with the TR NOx Ozone Season emissions limitation and assurance provisions under paragraph (c) of this section, provided that, for each monitoring location from which mass emissions are reported, the mass emissions amount used in calculating such allocations and determining such compliance shall be the mass emissions amount for the monitoring location determined in accordance with §§97.530 through 97.535.
and rounded to the nearest ton, with any fraction of a ton less than 0.50 being deemed to be zero.

(c) NOₓ emissions requirements. (1) TR NOₓ Ozone Season emissions limitation. (i) As of the allowance transfer deadline for a control period in a given year, the owners and operators of each TR NOₓ Ozone Season source and each TR NOₓ Ozone Season unit at the source shall hold, in the source’s compliance account, TR NOₓ Ozone Season allowances available for deduction for such control period under §97.524(a) in an amount not less than the tons of total NOₓ emissions for such control period from all TR NOₓ Ozone Season units at the source.

(ii) If total NOₓ emissions during a control period in a given year from the TR NOₓ Ozone Season units at a TR NOₓ Ozone Season source are in excess of the TR NOₓ Ozone Season emissions limitation set forth in paragraph (c)(1)(i) of this section, then:

(A) The owners and operators of the source and each TR NOₓ Ozone Season unit at the source shall hold the TR NOₓ Ozone Season allowances required for deduction under §97.524(d); and

(B) The owners and operators of the source and each TR NOₓ Ozone Season unit at the source shall pay any fine, penalty, or assessment or comply with any other remedy imposed, for the same violations, under the Clean Air Act, and each ton of such excess emissions and each day of such control period shall constitute a separate violation of this subpart and the Clean Air Act.

(2) TR NOₓ Ozone Season assurance provisions. (i) If total NOₓ emissions during a control period in a given year from all TR NOₓ Ozone Season units at TR NOₓ Ozone Season sources in a State (and Indian country within the borders of such State) exceed the State assurance level, then the owners and operators of such sources and units having a common designated representative for such control period, whereby the common designated representative’s share of such NOₓ emissions during such control period exceeds the common designated representative’s assurance level for the State and such control period, shall hold (in the assurance account established for the owners and operators of such group) TR NOₓ Ozone Season allowances available for deduction for such control period under §97.525(a) in an amount equal to two times the product (rounded to the nearest whole number), as determined by the Administrator in accordance with §97.525(b), of multiplying—

(A) The quotient of the amount by which the common designated representative’s share of such NOₓ emissions exceeds the respective common designated representative’s assurance level; and

(B) The amount by which total NOₓ emissions from all TR NOₓ Ozone Season sources in a State (and Indian country within the borders of such State) for such control period exceed the State assurance level.

(ii) The owners and operators shall hold the TR NOₓ Ozone Season allowances required under paragraph (c)(2)(i) of this section, as of midnight of November 1 (if it is a business day), or midnight of the first business day thereafter (if November 1 is not a business day), immediately after such control period.

(iii) Total NOₓ emissions from all TR NOₓ Ozone Season units at TR NOₓ Ozone Season sources in a State (and Indian country within the borders of such State) during a control period in a given year exceed the State assurance level if such total NOₓ emissions exceed the sum, for such control period, of the State NOₓ Ozone Season trading budget under §97.510(a) and the State’s variability limit under §97.510(b).

(iv) It shall not be a violation of this subpart or of the Clean Air Act if total NOₓ emissions from all TR NOₓ Ozone Season sources in a State (and Indian country within the borders of such State) during a control period exceed the State...
assurance level or if a common designated representative’s share of total NOX emissions from the TR NOX Ozone Season units at TR NOX Ozone Season sources in a State (and Indian country within the borders of such State) during a control period exceeds the common designated representative’s assurance level.

(v) To the extent the owners and operators fail to hold TR NOX Ozone Season allowances for a control period in a given year in accordance with paragraphs (c)(2)(i) through (iii) of this section,

(A) The owners and operators shall pay any fine, penalty, or assessment or comply with any other remedy imposed under the Clean Air Act; and

(B) Each TR NOX Ozone Season allowance that the owners and operators fail to hold for such control period in accordance with paragraphs (c)(2)(i) through (iii) of this section and each day of such control period shall constitute a separate violation of this subpart and the Clean Air Act.

(3) Compliance periods.—(i) A TR NOX Ozone Season unit shall be subject to the requirements under paragraph (c)(1) of this section for the control period starting on the later of May 1, 2012 or the deadline for meeting the unit’s monitor certification requirements under §97.530(b) and for each control period thereafter.

(ii) A TR NOX Ozone Season unit shall be subject to the requirements under paragraph (c)(2) of this section for the control period starting on the later of May 1, 2014 or the deadline for meeting the unit’s monitor certification requirements under §§97.530(b) and for each control period thereafter.

(4) Vintage of allowances held for compliance. (i) A TR NOX Ozone Season allowance held for compliance with the requirements under paragraph (c)(1)(i) of this section for a control period in a given year must be a TR NOX Ozone Season allowance that was allocated for a control period in a prior year or the control period in the given year or in the immediately following year.

(ii) Each TR NOX Ozone Season allowance shall be held in, deducted from, or transferred into, out of, or between Allowance Management System accounts in accordance with this subpart.

(6) Limited authorization. A TR NOX Ozone Season allowance is a limited authorization to emit one ton of NOX during the control period in one year. Such authorization is limited in its use and duration as follows:

(i) Such authorization shall only be used in accordance with the TR NOX Ozone Season Trading Program; and

(ii) Notwithstanding any other provision of this subpart, the Administrator has the authority to terminate or limit the use and duration of such authorization to the extent the Administrator determines is necessary or appropriate to implement any provision of the Clean Air Act.

(7) Property right. A TR NOX Ozone Season allowance does not constitute a property right.

(d) Title V permit requirements. (1) No title V permit revision shall be required for any allocation, holding, deduction, or transfer of TR NOX Ozone Season allowances in accordance with this subpart.

(2) A description of whether a unit is required to monitor and report NOX emissions using a continuous emission monitoring system (under subpart H of part 75 of this chapter), an excepted monitoring system (under appendices D and E to part 75 of this chapter), a low mass emissions excepted monitoring methodology (under §75.19 of this chapter), or an alternative monitoring system (under subpart E of part 75 of this chapter) in accordance with §§97.530 through 97.535 may be added to, or changed in, a title V permit using minor permit modification procedures in accordance with §§70.7(e)(2) and 71.7(e)(1) of this chapter, provided that the requirements applicable to the described monitoring and reporting (as added or changed, respectively) are already incorporated in such permit. This paragraph explicitly provides that
the addition of, or change to, a unit’s description as described in the prior sentence is eligible for minor permit modification procedures in accordance with §§70.7(e)(2)(i)(B) and 71.7(e)(1)(i)(B) of this chapter.

(e) Additional recordkeeping and reporting requirements. (1) Unless otherwise provided, the owners and operators of each TR NOX Ozone Season source and each TR NOX Ozone Season unit at the source shall keep on site at the source each of the following documents (in hardcopy or electronic format) for a period of 5 years from the date the document is created. This period may be extended for cause, at any time before the end of 5 years, in writing by the Administrator.

(i) The certificate of representation under §97.516 for the designated representative for the source and each TR NOX Ozone Season unit at the source and all documents that demonstrate the truth of the statements in the certificate of representation; provided that the certificate and documents shall be retained on site at the source beyond such 5-year period until such certificate of representation and documents are superseded because of the submission of a new certificate of representation under §97.516 changing the designated representative.

(ii) All emissions monitoring information, in accordance with this subpart.

(iii) Copies of all reports, compliance certifications, and other submissions and all records made or required under, or to demonstrate compliance with the requirements of, the TR NOX Ozone Season Trading Program.

(2) The designated representative of a TR NOX Ozone Season source and each TR NOX Ozone Season unit at the source shall make all submissions required under the TR NOX Ozone Season Trading Program, except as provided in §97.516. This requirement does not change, create an exemption from, or otherwise affect the responsible official submission requirements under a title V operating permit program in parts 70 and 71 of this chapter.

(f) Liability. (1) Any provision of the TR NOX Ozone Season Trading Program that applies to a TR NOX Ozone Season source or the designated representative of a TR NOX Ozone Season source shall also apply to the owners and operators of such source and of the TR NOX Ozone Season units at the source.

(2) Any provision of the TR NOX Ozone Season Trading Program that applies to a TR NOX Ozone Season unit or the designated representative of a TR NOX Ozone Season unit shall also apply to the owners and operators of such unit.

(g) Effect on other authorities. No provision of the TR NOX Ozone Season Trading Program or exemption under §97.505 shall be construed as exempting or excluding the owners and operators, and the designated representative, of a TR NOX Ozone Season source or TR NOX Ozone Season unit from compliance with any other provision of the applicable, approved State implementation plan, a federally enforceable permit, or the Clean Air Act.

[76 FR 48406, Aug. 8, 2011, as amended at 77 FR 10336, Feb. 21, 2012]  
§ 97.507 Computation of time.

(a) Unless otherwise stated, any time period scheduled, under the TR NOX Ozone Season Trading Program, to begin on the occurrence of an act or event shall begin on the day the act or event occurs.

(b) Unless otherwise stated, any time period scheduled, under the TR NOX Ozone Season Trading Program, to begin before the occurrence of an act or event shall be computed so that the period ends the day before the act or event occurs.

(c) Unless otherwise stated, if the final day of any time period, under the TR NOX Ozone Season Trading Program, is not a business day, the time period shall be extended to the next business day.

§ 97.508 Administrative appeal procedures.

The administrative appeal procedures for decisions of the Administrator under the TR NOX Ozone Season Trading Program are set forth in part 78 of this chapter.
§ 97.509  [Reserved]

§ 97.510  State NO\textsubscript{X} Ozone Season trading budgets, new unit set-asides, Indian country new unit set-aside, and variability limits.

(a) The State NO\textsubscript{X} ozone season trading budgets, new unit set-asides, and Indian country new unit-set asides for allocations of TR NO\textsubscript{X} Ozone Season allowances for the control periods in 2012 and thereafter are as follows:

(i) Alabama. (i) The NO\textsubscript{X} ozone season trading budget for 2012 and 2013 is 31,746 tons.

(ii) The NO\textsubscript{X} ozone season new unit set-aside for 2012 and 2013 is 635 tons.

(iii) [Reserved]

(iv) The NO\textsubscript{X} ozone season trading budget for 2014 and thereafter is 31,499 tons.

(v) The NO\textsubscript{X} ozone season new unit set-aside for 2014 and thereafter is 630 tons.

(vi) [Reserved]

(ii) The NO\textsubscript{X} ozone season trading budget for 2012 and 2013 is 15,037 tons.

(ii) The NO\textsubscript{X} ozone season new unit set-aside for 2012 and 2013 is 752 tons.

(iii) [Reserved]

(iv) The NO\textsubscript{X} ozone season trading budget for 2014 and thereafter is 15,037 tons.

(v) The NO\textsubscript{X} ozone season new unit set-aside for 2014 and thereafter is 752 tons.

(vi) [Reserved]

(3) Florida. (i) The NO\textsubscript{X} ozone season trading budget for 2012 and 2013 is 28,644 tons.

(ii) The NO\textsubscript{X} ozone season new unit set-aside for 2012 and 2013 is 544 tons.

(iii) The NO\textsubscript{X} ozone season Indian country new unit set-aside for 2012 and 2013 is 29 tons.

(iv) The NO\textsubscript{X} ozone season trading budget for 2014 and thereafter is 27,825 tons.

(v) The NO\textsubscript{X} ozone season new unit set-aside for 2014 and thereafter is 752 tons.

(vi) [Reserved]

(4) Georgia. (i) The NO\textsubscript{X} ozone season trading budget for 2012 and 2013 is 27,944 tons.

(ii) The NO\textsubscript{X} ozone season new unit set-aside for 2012 and 2013 is 559 tons.

(iii) [Reserved]

(iv) The NO\textsubscript{X} ozone season trading budget for 2014 and thereafter is 18,279 tons.

(v) The NO\textsubscript{X} ozone season new unit set-aside for 2014 and thereafter is 366 tons.

(vi) [Reserved]

(5) Illinois. (i) The NO\textsubscript{X} ozone season trading budget for 2012 and 2013 is 21,208 tons.

(ii) The NO\textsubscript{X} ozone season new unit set-aside for 2012 and 2013 is 1,697 tons.

(iii) [Reserved]

(iv) The NO\textsubscript{X} ozone season trading budget for 2014 and thereafter is 21,208 tons.

(v) The NO\textsubscript{X} ozone season new unit set-aside for 2014 and thereafter is 1,697 tons.

(vi) [Reserved]

(6) Indiana. (i) The NO\textsubscript{X} ozone season trading budget for 2012 and 2013 is 46,876 tons.

(ii) The NO\textsubscript{X} ozone season new unit set-aside for 2012 and 2013 is 1,406 tons.

(iii) [Reserved]

(iv) The NO\textsubscript{X} ozone season trading budget for 2014 and thereafter is 46,175 tons.

(v) The NO\textsubscript{X} ozone season new unit set-aside for 2014 and thereafter is 1,385 tons.

(vi) [Reserved]

(7) Iowa. (i) The NO\textsubscript{X} ozone season trading budget for 2012 and 2013 is 16,532 tons.

(ii) The NO\textsubscript{X} ozone season new unit set-aside for 2012 and 2013 is 314 tons.

(iii) The NO\textsubscript{X} ozone season Indian country new unit set-aside for 2012 and 2013 is 17 tons.

(iv) The NO\textsubscript{X} ozone season trading budget for 2014 and thereafter is 16,207 tons.

(v) The NO\textsubscript{X} ozone season new unit set-aside for 2014 and thereafter is 308 tons.

(vi) The NO\textsubscript{X} ozone season Indian country new unit set-aside for 2014 and thereafter is 16 tons.

(8) Kentucky. (i) The NO\textsubscript{X} ozone season trading budget for 2012 and 2013 is 36,167 tons.

(ii) The NO\textsubscript{X} ozone season new unit set-aside for 2012 and 2013 is 1,447 tons.

(iii) [Reserved]
(iv) The NO\textsubscript{X} ozone season trading budget for 2014 and thereafter is 32,674 tons.
(v) The NO\textsubscript{X} ozone season new unit set-aside for 2014 and thereafter is 1,307 tons.
(vi) [Reserved]

(9) Louisiana. (i) The NO\textsubscript{X} ozone season trading budget for 2012 and 2013 is 18,026 tons.
(ii) The NO\textsubscript{X} ozone season new unit set-aside for 2012 and 2013 is 523 tons.
(iii) The NO\textsubscript{X} ozone season Indian country new unit set-aside for 2012 and 2013 is 18 tons.
(iv) The NO\textsubscript{X} ozone season trading budget for 2014 and thereafter is 18,026 tons.
(v) The NO\textsubscript{X} ozone season new unit set-aside for 2014 and thereafter is 523 tons.
(vi) [Reserved]

(10) Maryland. (i) The NO\textsubscript{X} ozone season trading budget for 2012 and 2013 is 7,179 tons.
(ii) The NO\textsubscript{X} ozone season new unit set-aside for 2012 and 2013 is 144 tons.
(iii) [Reserved]
(iv) The NO\textsubscript{X} ozone season trading budget for 2014 and thereafter is 7,179 tons.
(v) The NO\textsubscript{X} ozone season new unit set-aside for 2014 and thereafter is 144 tons.
(vi) [Reserved]

(11) Michigan. (i) The NO\textsubscript{X} ozone season trading budget for 2012 and 2013 is 28,041 tons.
(ii) The NO\textsubscript{X} ozone season new unit set-aside for 2012 and 2013 is 533 tons.
(iii) The NO\textsubscript{X} ozone season Indian country new unit set-aside for 2012 and 2013 is 28 tons.
(iv) The NO\textsubscript{X} ozone season trading budget for 2014 and thereafter is 27,016 tons.
(v) The NO\textsubscript{X} ozone season new unit set-aside for 2014 and thereafter is 513 tons.
(vi) The NO\textsubscript{X} ozone season Indian country new unit set-aside for 2014 and thereafter is 27 tons.

(12) Mississippi. (i) The NO\textsubscript{X} ozone season trading budget for 2012 and 2013 is 12,314 tons.
(ii) The NO\textsubscript{X} ozone season new unit set-aside for 2012 and 2013 is 234 tons.
(iii) The NO\textsubscript{X} ozone season Indian country new unit set-aside for 2012 and 2013 is 12 tons.
(iv) The NO\textsubscript{X} ozone season trading budget for 2014 and thereafter is 12,314 tons.
(v) The NO\textsubscript{X} ozone season new unit set-aside for 2014 and thereafter is 234 tons.
(vi) The NO\textsubscript{X} ozone season Indian country new unit set-aside for 2014 and thereafter is 12 tons.

(13) Missouri. (i) The NO\textsubscript{X} ozone season trading budget for 2012 and 2013 is 22,762 tons.
(ii) The NO\textsubscript{X} ozone season new unit set-aside for 2012 and 2013 is 683 tons.
(iii) [Reserved]
(iv) The NO\textsubscript{X} ozone season trading budget for 2014 and thereafter is 21,073 tons.
(v) The NO\textsubscript{X} ozone season new unit set-aside for 2014 and thereafter is 632 tons.
(vi) [Reserved]

(14) New Jersey. (i) The NO\textsubscript{X} ozone season trading budget for 2012 and 2013 is 4,128 tons.
(ii) The NO\textsubscript{X} ozone season new unit set-aside for 2012 and 2013 is 83 tons.
(iii) [Reserved]
(iv) The NO\textsubscript{X} ozone season trading budget for 2014 and thereafter is 3,731 tons.
(v) The NO\textsubscript{X} ozone season new unit set-aside for 2014 and thereafter is 75 tons.
(vi) [Reserved]

(15) New York. (i) The NO\textsubscript{X} ozone season trading budget for 2012 and 2013 is 10,242 tons.
(ii) The NO\textsubscript{X} ozone season new unit set-aside for 2012 and 2013 is 195 tons.
(iii) The NO\textsubscript{X} ozone season Indian country new unit set-aside for 2012 and 2013 is 10 tons.
(iv) The NO\textsubscript{X} ozone season trading budget for 2014 and thereafter is 10,242 tons.
(v) The NO\textsubscript{X} ozone season new unit set-aside for 2014 and thereafter is 195 tons.
(vi) The NO\textsubscript{X} ozone season Indian country new unit set-aside for 2014 and thereafter is 10 tons.

(16) North Carolina. (i) The NO\textsubscript{X} ozone season trading budget for 2012 and 2013 is 22,168 tons.
(ii) The NO\textsubscript{X} ozone season new unit set-aside for 2012 and 2013 is 1,308 tons.
(iii) The NO\textsubscript{X} ozone season Indian country new unit set-aside for 2012 and 2013 is 22 tons.
(iv) The NO\textsubscript{X} ozone season trading budget for 2014 and thereafter is 18,455 tons.
(v) The NO\textsubscript{X} ozone season new unit set-aside for 2014 and thereafter is 1,089 tons.
(vi) The NO\textsubscript{X} ozone season Indian country new unit set-aside for 2014 and thereafter is 18 tons.

(17) Ohio. (i) The NO\textsubscript{X} ozone season trading budget for 2012 and 2013 is 40,063 tons.
(ii) The NO\textsubscript{X} ozone season new unit set-aside for 2012 and 2013 is 801 tons.
(iii) [Reserved]
(iv) The NO\textsubscript{X} ozone season trading budget for 2014 and thereafter is 37,792 tons.
(v) The NO\textsubscript{X} ozone season new unit set-aside for 2014 and thereafter is 756 tons.
(vi) [Reserved]

(18) Oklahoma. (i) The NO\textsubscript{X} ozone season trading budget for 2012 is 36,567 and for 2013 is 21,835 tons.
(ii) The NO\textsubscript{X} ozone season new unit set-aside for 2012 is 731 and for 2013 is 437 tons.
(iii) [Reserved]
(iv) The NO\textsubscript{X} ozone season trading budget for 2014 and thereafter is 21,835 tons.
(v) The NO\textsubscript{X} ozone season new unit set-aside for 2014 and thereafter is 437 tons.
(vi) [Reserved]

(19) Pennsylvania. (i) The NO\textsubscript{X} ozone season trading budget for 2012 and 2013 is 52,201 tons.
(ii) The NO\textsubscript{X} ozone season new unit set-aside for 2012 and 2013 is 1,041 tons.
(iii) [Reserved]
(iv) The NO\textsubscript{X} ozone season trading budget for 2014 and thereafter is 51,912 tons.
(v) The NO\textsubscript{X} ozone season new unit set-aside for 2014 and thereafter is 1,038 tons.
(vi) [Reserved]

(20) South Carolina. (i) The NO\textsubscript{X} ozone season trading budget for 2012 and 2013 is 13,908 tons.
(ii) The NO\textsubscript{X} ozone season new unit set-aside for 2012 and 2013 is 264 tons.
(iii) The NO\textsubscript{X} ozone season Indian country new unit set-aside for 2012 and 2013 is 14 tons.
(iv) The NO\textsubscript{X} ozone season trading budget for 2014 and thereafter is 13,909 tons.
(v) The NO\textsubscript{X} ozone season new unit set-aside for 2014 and thereafter is 264 tons.
(vi) The NO\textsubscript{X} ozone season Indian country new unit set-aside for 2014 and thereafter is 14 tons.

(21) Tennessee. (i) The NO\textsubscript{X} ozone season trading budget for 2012 and 2013 is 14,908 tons.
(ii) The NO\textsubscript{X} ozone season new unit set-aside for 2012 and 2013 is 298 tons.
(iii) [Reserved]
(iv) The NO\textsubscript{X} ozone season trading budget for 2014 and thereafter is 8,016 tons.
(v) The NO\textsubscript{X} ozone season new unit set-aside for 2014 and thereafter is 160 tons.
(vi) [Reserved]

(22) Texas. (i) The NO\textsubscript{X} ozone season trading budget for 2012 and 2013 is 64,418 tons.
(ii) The NO\textsubscript{X} ozone season new unit set-aside for 2012 and 2013 is 2,513 tons.
(iii) The NO\textsubscript{X} ozone season Indian country new unit set-aside for 2012 and 2013 is 64 tons.
(iv) The NO\textsubscript{X} ozone season trading budget for 2014 and thereafter is 64,418 tons.
(v) The NO\textsubscript{X} ozone season new unit set-aside for 2014 and thereafter is 2,513 tons.
(vi) The NO\textsubscript{X} ozone season Indian country new unit set-aside for 2014 and thereafter is 64 tons.

(23) Virginia. (i) The NO\textsubscript{X} ozone season trading budget for 2012 and 2013 is 14,452 tons.
(ii) The NO\textsubscript{X} ozone season new unit set-aside for 2012 and 2013 is 723 tons.
(iii) [Reserved]
(iv) The NO\textsubscript{X} ozone season trading budget for 2014 and thereafter is 14,452 tons.
(v) The NO\textsubscript{X} ozone season new unit set-aside for 2014 and thereafter is 723 tons.
(vi) [Reserved]

(24) West Virginia. (i) The NO\textsubscript{X} ozone season trading budget for 2012 and 2013 is 25,283 tons.
(ii) The NO\textsubscript{X} ozone season new unit set-aside for 2012 and 2013 is 1,264 tons.

(iii) [Reserved]

(iv) The NO\textsubscript{X} ozone season trading budget for 2014 and thereafter is 23,291 tons.

(v) The NO\textsubscript{X} ozone season new unit set-aside for 2014 and thereafter is 1,165 tons.

(vi) [Reserved]

(25) Wisconsin. (i) The NO\textsubscript{X} ozone season trading budget for 2012 and 2013 is 14,784 tons.

(ii) The NO\textsubscript{X} ozone season new unit set-aside for 2012 and 2013 is 844 tons.

(iii) The NO\textsubscript{X} ozone season Indian country new unit set-aside for 2012 and 2013 is 14 tons.

(iv) The NO\textsubscript{X} ozone season trading budget for 2014 and thereafter is 14,296 tons.

(v) The NO\textsubscript{X} ozone season new unit set-aside for 2014 and thereafter is 844 tons.

(vi) The NO\textsubscript{X} ozone season Indian country new unit set-aside for 2014 and thereafter is 14 tons.

(b) The States’ variability limits for the State NO\textsubscript{X} ozone season trading budgets for the control periods in 2014 and thereafter are as follows:

(1) The NO\textsubscript{X} ozone season variability limit for Alabama is 6,615 tons.

(2) The NO\textsubscript{X} ozone season variability limit for Arkansas is 3,158 tons.

(3) The NO\textsubscript{X} ozone season variability limit for Florida is 5,813 tons.

(4) The NO\textsubscript{X} ozone season variability limit for Georgia is 3,839 tons.

(5) The NO\textsubscript{X} ozone season variability limit for Illinois is 4,454 tons.

(6) The NO\textsubscript{X} ozone season variability limit for Indiana is 9,697 tons.

(7) The NO\textsubscript{X} ozone season variability limit for Iowa is 3,403 tons.

(8) The NO\textsubscript{X} ozone season variability limit for Kentucky is 6,862 tons.

(9) The NO\textsubscript{X} ozone season variability limit for Louisiana is 3,785 tons.

(10) The NO\textsubscript{X} ozone season variability limit for Maryland is 1,508 tons.

(11) The NO\textsubscript{X} ozone season variability limit for Michigan is 5,673 tons.

(12) The NO\textsubscript{X} ozone season variability limit for Mississippi is 2,586 tons.

(13) The NO\textsubscript{X} ozone season variability limit for Missouri is 4,125 tons.

(14) The NO\textsubscript{X} ozone season variability limit for New Jersey is 784 tons.

(15) The NO\textsubscript{X} ozone season variability limit for New York is 2,151 tons.

(16) The NO\textsubscript{X} ozone season variability limit for North Carolina is 3,876 tons.

(17) The NO\textsubscript{X} ozone season variability limit for Ohio is 7,936 tons.

(18) The NO\textsubscript{X} ozone season variability limit for Oklahoma is 4,585 tons.

(19) The NO\textsubscript{X} ozone season variability limit for Pennsylvania is 10,902 tons.

(20) The NO\textsubscript{X} ozone season variability limit for South Carolina is 2,921 tons.

(21) The NO\textsubscript{X} ozone season variability limit for Tennessee is 1,683 tons.

(22) The NO\textsubscript{X} ozone season variability limit for Texas is 13,528 tons.

(23) The NO\textsubscript{X} ozone season variability limit for Virginia is 3,038 tons.

(24) The NO\textsubscript{X} ozone season variability limit for West Virginia is 4,891 tons.

(25) The NO\textsubscript{X} ozone season variability limit for Wisconsin is 3,002 tons.

(c) Each NO\textsubscript{X} ozone season trading budget in this section includes any tons in a new unit set aside or Indian country new unit set aside, but does not include any tons in a variability limit.

[77 FR 10336, Feb. 21, 2012]

EFFECTIVE DATE NOTE: At 77 FR 34845, June 12, 2012, §97.510 was amended by revising paragraph (a)(2); revising paragraphs (a)(4)(iv) and (a)(4)(v); revising paragraphs (a)(9), (a)(12), (a)(13), (a)(15), (a)(17), (a)(18), and (a)(22); and revising paragraphs (b)(2), (b)(4), (b)(9), (b)(12), (b)(13), (b)(15), (b)(17), (b)(18), and (b)(22), effective Aug. 13, 2012. For the convenience of the user, the revised text is set forth as follows:

§97.510 State NO\textsubscript{X} Ozone Season trading budgets, new unit set-asides, Indian country new unit set-aside, and variability limits.

(a) * * *

(2) Arkansas. (i) The NO\textsubscript{X} ozone season trading budget for 2012 and 2013 is 15,110 tons.

(ii) The NO\textsubscript{X} ozone season new unit set-aside for 2012 and 2013 is 756 tons.

(iii) [Reserved]

(14) The NO\textsubscript{X} ozone season trading budget for 2014 and thereafter is 24,041 tons.

(15) The NO\textsubscript{X} ozone season trading budget for 2014 and thereafter is 15,110 tons.

(16) The NO\textsubscript{X} ozone season new unit set-aside for 2012 and 2013 is 1,264 tons.

(17) The NO\textsubscript{X} ozone season variability limit for Ohio is 7,936 tons.

(18) The NO\textsubscript{X} ozone season variability limit for Oklahoma is 4,585 tons.

(19) The NO\textsubscript{X} ozone season variability limit for Pennsylvania is 10,902 tons.

(20) The NO\textsubscript{X} ozone season variability limit for South Carolina is 2,921 tons.

(21) The NO\textsubscript{X} ozone season variability limit for Tennessee is 1,683 tons.

(22) The NO\textsubscript{X} ozone season variability limit for Texas is 13,528 tons.

(23) The NO\textsubscript{X} ozone season variability limit for Virginia is 3,038 tons.

(24) The NO\textsubscript{X} ozone season variability limit for West Virginia is 4,891 tons.

(25) The NO\textsubscript{X} ozone season variability limit for Wisconsin is 3,002 tons.

(26) The NO\textsubscript{X} ozone season trading budget for 2012 and 2013 is 15 tons.

(27) The NO\textsubscript{X} ozone season variability limit for Iowa is 3,403 tons.

(28) The NO\textsubscript{X} ozone season variability limit for Kentucky is 6,862 tons.

(29) The NO\textsubscript{X} ozone season variability limit for Louisiana is 3,785 tons.

(30) The NO\textsubscript{X} ozone season variability limit for Maryland is 1,508 tons.

(31) The NO\textsubscript{X} ozone season variability limit for Michigan is 5,673 tons.

(32) The NO\textsubscript{X} ozone season variability limit for Mississippi is 2,586 tons.

(33) The NO\textsubscript{X} ozone season variability limit for Missouri is 4,125 tons.

(34) The NO\textsubscript{X} ozone season variability limit for New Jersey is 784 tons.

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(v) The NO\textsubscript{X} ozone season new unit set-aside for 2014 and thereafter is 481 tons.

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(9) Louisiana. (i) The NO\textsubscript{X} ozone season trading budget for 2012 and 2013 is 18,115 tons.
(ii) The NO\textsubscript{X} ozone season new unit set-aside for 2012 and 2013 is 197 tons.
(iii) The NO\textsubscript{X} ozone season Indian country new unit set-aside for 2012 and 2013 is 12 tons.
(iv) The NO\textsubscript{X} ozone season trading budget for 2014 and thereafter is 18,115 tons.
(v) The NO\textsubscript{X} ozone season new unit set-aside for 2014 and thereafter is 18 tons.

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(12) Mississippi. (i) The NO\textsubscript{X} ozone season trading budget for 2012 and 2013 is 12,429 tons.
(ii) The NO\textsubscript{X} ozone season new unit set-aside for 2012 and 2013 is 237 tons.
(iii) The NO\textsubscript{X} ozone season Indian country new unit set-aside for 2012 and 2013 is 12 tons.
(iv) The NO\textsubscript{X} ozone season trading budget for 2014 and thereafter is 12,429 tons.
(v) The NO\textsubscript{X} ozone season new unit set-aside for 2014 and thereafter is 12 tons.

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(15) New York. (i) The NO\textsubscript{X} ozone season trading budget for 2012 and 2013 is 10,369 tons.
(ii) The NO\textsubscript{X} ozone season new unit set-aside for 2012 and 2013 is 197 tons.
(iii) The NO\textsubscript{X} ozone season Indian country new unit set-aside for 2012 and 2013 is 10 tons.
(iv) The NO\textsubscript{X} ozone season trading budget for 2014 and thereafter is 10,369 tons.
(v) The NO\textsubscript{X} ozone season new unit set-aside for 2014 and thereafter is 10 tons.

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(17) Ohio. (i) The NO\textsubscript{X} ozone season trading budget for 2012 and 2013 is 41,284 tons.
(ii) The NO\textsubscript{X} ozone season new unit set-aside for 2012 and 2013 is 826 tons.

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(18) Oklahoma. (i) The NO\textsubscript{X} ozone season trading budget for 2012 is 36,567 tons and for 2013 is 22,694 tons.
(ii) The NO\textsubscript{X} ozone season new unit set-aside for 2012 is 780 tons and for 2013 is 454 tons.
(iii) [Reserved]
(iv) The NO\textsubscript{X} ozone season trading budget for 2014 and thereafter is 36,567 tons and for 2015 is 22,694 tons.
(v) The NO\textsubscript{X} ozone season new unit set-aside for 2014 and thereafter is 780 tons.
(vi) The NO\textsubscript{X} ozone season new unit set-aside for 2014 and thereafter is 454 tons.

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(22) Texas. (i) The NO\textsubscript{X} ozone season trading budget for 2012 and 2013 is 65,560 tons.
(ii) The NO\textsubscript{X} ozone season new unit set-aside for 2012 and 2013 is 2,556 tons.
(iii) The NO\textsubscript{X} ozone season Indian country new unit set-aside for 2012 and 2013 is 66 tons.
(iv) The NO\textsubscript{X} ozone season trading budget for 2014 and thereafter is 65,560 tons.
(v) The NO\textsubscript{X} ozone season new unit set-aside for 2014 and thereafter is 2,556 tons.
(vi) The NO\textsubscript{X} ozone season Indian country new unit set-aside for 2014 and thereafter is 66 tons.

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(b) * * * *

(2) The NO\textsubscript{X} ozone season variability limit for Arkansas is 3,173 tons.

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(4) The NO\textsubscript{X} ozone season variability limit for Georgia is 5,949 tons.

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(9) The NO\textsubscript{X} ozone season variability limit for Louisiana is 4,904 tons.

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(12) The NO\textsubscript{X} ozone season variability limit for Mississippi is 2,610 tons.
(13) The NO\textsubscript{X} ozone season variability limit for Missouri is 4,491 tons.

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(15) The NO\textsubscript{X} ozone season variability limit for New York is 2,177 tons.

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(17) The NO\textsubscript{X} ozone season variability limit for Ohio is 8,193 tons.
(18) The NO\textsubscript{X} ozone season variability limit for Oklahoma is 4,766 tons.

(22) The NO\textsubscript{X} ozone season variability limit for Texas is 13,768 tons.

§ 97.511 Timing requirements for TR NO\textsubscript{X} Ozone Season allowance allocations.

(a) Existing units. (1) TR NO\textsubscript{X} Ozone Season allowances are allocated, for the control periods in 2012 and each year thereafter, as provided in a notice of data availability issued by the Administrator. Providing an allocation to a unit in such notice does not constitute a determination that the unit is a TR NO\textsubscript{X} Ozone Season unit, and not providing an allocation to a unit in such notice does not constitute a determination that the unit is not a TR NO\textsubscript{X} Ozone Season unit.

(2) Notwithstanding paragraph (a)(1) of this section, if a unit provided an allocation in the notice of data availability issued under paragraph (a)(1) of this section does not operate, starting after 2011, during the control period in two consecutive years, such unit will not be allocated the TR NO\textsubscript{X} Ozone Season allowances provided in such notice for the unit for the control periods in the fifth year after the first such year and in each year after that fifth year. All TR NO\textsubscript{X} Ozone Season allowances that would otherwise have been allocated to such unit will be allocated to the new unit set-aside for the State where such unit is located and for the respective years involved. If such unit resumes operation, the Administrator will allocate TR NO\textsubscript{X} Ozone Season allowances to the unit in accordance with paragraph (b) of this section.

(b) New units.—(1) New unit set-asides. (i) By June 1, 2012 and June 1 of each year thereafter, the Administrator will calculate the TR NO\textsubscript{X} Ozone Season allowance allocation to each TR NO\textsubscript{X} Ozone Season unit in a State, in accordance with §97.512(a)(2) through (7) and (12), for the control period in the year of the applicable calculation deadline under this paragraph and will promulgate a notice of data availability of the results of the calculations.

(ii) For each notice of data availability required in paragraph (b)(1)(i) of this section, the Administrator will provide an opportunity for submission of objections to the calculations referenced in such notice.

(A) Objections shall be submitted by the deadline specified in each notice of data availability required in paragraph (b)(1)(i) of this section and shall be limited to addressing whether the calculations (including the identification of the TR NO\textsubscript{X} Ozone Season units) are in accordance with §97.512(a)(2) through (7) and (12) and §§97.506(b)(2) and 97.530 through 97.535.

(B) The Administrator will adjust the calculations to the extent necessary to ensure that they are in accordance with the provisions referenced in paragraph (b)(1)(i) of this section. By August 1 immediately after the promulgation of each notice of data availability required in paragraph (b)(1)(i) of this section, the Administrator will promulgate a notice of data availability of any adjustments that the Administrator determines to be necessary with regard to allocations under §97.512(a)(2) through (7) and (12) and the reasons for accepting or rejecting any objections submitted in accordance with paragraph (b)(1)(ii)(A) of this section.

(iii) If the new unit set-aside for such control period contains any TR NO\textsubscript{X} Ozone Season allowances that have not been allocated in the applicable notice of data availability required in paragraph (b)(1)(i) of this section, the Administrator will promulgate, by September 15 immediately after such notice, a notice of data availability that identifies any TR NO\textsubscript{X} Ozone Season units that commenced commercial operation during the period starting May 1 of the year before the year of such control period and ending August 31 of year of such control period.

(iv) For each notice of data availability required in paragraph (b)(1)(ii) of this section, the Administrator will provide an opportunity for submission of objections to the identification of TR NO\textsubscript{X} Ozone Season units in such notice.

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(A) Objections shall be submitted by the deadline specified in each notice of data availability required in paragraph (b)(1)(iii) of this section and shall be limited to addressing whether the identification of TR NO\textsubscript{X} Ozone Season units in such notice is in accordance with paragraph (b)(1)(iii) of this section.

(B) The Administrator will adjust the identification of TR NO\textsubscript{X} Ozone Season units in the each notice of data availability required in paragraph (b)(1)(iii) of this section to the extent necessary to ensure that it is in accordance with paragraph (b)(1)(iii) of this section and will calculate the TR NO\textsubscript{X} Ozone Season allowance allocation to each TR NO\textsubscript{X} Ozone Season unit in accordance with §97.512(a)(9), (10), and (12) and §§97.506(b)(2) and 97.530 through 97.535. By November 15 immediately after the promulgation of each notice of data availability required in paragraph (b)(1)(iii) of this section, the Administrator will promulgate a notice of data availability of any adjustments of the identification of TR NO\textsubscript{X} Ozone Season units that the Administrator determines to be necessary, the reasons for accepting or rejecting any objections submitted in accordance with paragraph (b)(1)(iv)(A) of this section, and the results of such calculations.

(v) To the extent any TR NO\textsubscript{X} Ozone Season allowances are added to the new unit set-aside after promulgation of each notice of data availability required in paragraph (b)(1)(iv) of this section, the Administrator will promulgate additional notices of data availability, as deemed appropriate, of the allocation of such TR NO\textsubscript{X} Ozone Season allowances in accordance with §97.512(a)(10).

(2) Indian country new unit set-asides. (i) By June 1, 2012 and June 1 of each year thereafter, the Administrator will calculate the TR NO\textsubscript{X} Ozone Season allowance allocation to each TR NO\textsubscript{X} Ozone Season unit in Indian country within the borders of a State, in accordance with §97.512(b)(2) through (7) and (12), for the control period in the year of the applicable calculation deadline under this paragraph and will promulgate a notice of data availability of the results of the calculations.

(ii) For each notice of data availability required in paragraph (b)(2)(i) of this section, the Administrator will provide an opportunity for submission of objections to the calculations referenced in such notice.

(A) Objections shall be submitted by the deadline specified in each notice of data availability required in paragraph (b)(2)(i) of this section and shall be limited to addressing whether the calculations (including the identification of the TR NO\textsubscript{X} Ozone Season units) are in accordance with §97.512(b)(2) through (7) and (12) and §§97.506(b)(2) and 97.530 through 97.535.

(B) The Administrator will adjust the calculations to the extent necessary to ensure that they are in accordance with the provisions referenced in paragraph (b)(2)(ii)(A) of this section. By August 1 immediately after the promulgation of each notice of data availability required in paragraph (b)(2)(i) of this section, the Administrator will promulgate a notice of data availability of any adjustments that the Administrator determines to be necessary with regard to allocations under §97.512(b)(2) through (7) and (12) and the reasons for accepting or rejecting any objections submitted in accordance with paragraph (b)(2)(ii)(A) of this section.

(iii) If the Indian country new unit set-aside for such control period contains any TR NO\textsubscript{X} Ozone Season allowances that have not been allocated in the applicable notice of data availability required in paragraph (b)(2)(ii) of this section, the Administrator will promulgate, by September 15 immediately after such notice, a notice of data availability that identifies any TR NO\textsubscript{X} Ozone Season units that commenced commercial operation during the period starting May 1 of the year before the year of such control period and ending August 31 of year of such control period.

(iv) For each notice of data availability required in paragraph (b)(2)(iii) of this section, the Administrator will provide an opportunity for submission of objections to the identification of TR NO\textsubscript{X} Ozone Season units in such notice.

(A) Objections shall be submitted by the deadline specified in each notice of
(b) The Administrator will adjust the identification of TR NO\textsubscript{X} Ozone Season units in the each notice of data availability required in paragraph (b)(2)(iii) of this section and will calculate the TR NO\textsubscript{X} Ozone Season allowance allocation to each TR NO\textsubscript{X} Ozone Season unit in accordance with §97.512(b)(9), (10), and (12) and §§97.506(b)(2) and 97.530 through 97.535. By November 15 immediately after the promulgation of each notice of data availability required in paragraph (b)(2)(iii) of this section, the Administrator will promulgate a notice of data availability of any adjustments of the identification of TR NO\textsubscript{X} Ozone Season units that the Administrator determines to be necessary, the reasons for accepting or rejecting any objections submitted in accordance with paragraph (b)(2)(iv)(A) of this section, and the results of such calculations.

To the extent any TR NO\textsubscript{X} Ozone Season allowances are added to the Indian country new unit set-aside after promulgation of each notice of data availability required in paragraph (b)(2)(iii) of this section, the Administrator will promulgate additional notices of data availability, as deemed appropriate, of the allocation of such TR NO\textsubscript{X} Ozone Season allowances in accordance with §97.521.

(c) Units incorrectly allocated TR NO\textsubscript{X} Ozone Season allowances. For each control period in 2012 and thereafter, if the Administrator determines that TR NO\textsubscript{X} Ozone Season allowances were allocated under paragraph (a) of this section, or under a provision of a SIP revision approved under §52.38(b)(3), (4), or (5) of this chapter, where such control period and the recipient are covered by the provisions of paragraph (c)(1)(i) of this section or were allocated under §97.512(a)(2) through (7), (9), and (12) and (b)(2) through (7), (9), and (12), or under a provision of a SIP revision approved under §52.38(b)(4) or (5) of this chapter, where such control period and the recipient are covered by the provisions of paragraph (c)(1)(ii) of this section, then the Administrator will notify the designated representative of the recipient and will act in accordance with the procedures set forth in paragraphs (c)(2) through (5) of this section:

(i)(A) The recipient is not actually a TR NO\textsubscript{X} Ozone Season unit under §97.504 as of May 1, 2012 and is allocated TR NO\textsubscript{X} Ozone Season allowances for such control period or, in the case of an allocation under a provision of a SIP revision approved under §52.38(b)(3), (4), or (5) of this chapter, the recipient is not actually a TR NO\textsubscript{X} Ozone Season unit as of May 1, 2012 and is allocated TR NO\textsubscript{X} Ozone Season allowances for such control period that the SIP revision provides should be allocated only to recipients that are TR NO\textsubscript{X} Ozone Season units as of May 1, 2012; or

(ii) The recipient is not located as of May 1 of the control period in the State from whose NO\textsubscript{X} Ozone Season trading budget the TR NO\textsubscript{X} Ozone Season allowances allocated under paragraph (a) of this section, or under a provision of a SIP revision approved under §52.38(b)(3), (4), or (5) of this chapter, were allocated for such control period.

(ii) The recipient is not actually a TR NO\textsubscript{X} Ozone Season unit under §97.504 as of May 1 of such control period and is allocated TR NO\textsubscript{X} Ozone Season allowances for such control period or, in the case of an allocation under a provision of a SIP revision approved under §52.38(b)(3), (4), or (5) of this chapter, the recipient is not actually a TR NO\textsubscript{X} Ozone Season unit as of January 1 of such control period and is allocated TR NO\textsubscript{X} Ozone Season allowances for such control period that the SIP revision provides should be allocated only to recipients that are TR NO\textsubscript{X} Ozone Season units as of January 1 of such control period.

(2) Except as provided in paragraph (c)(3) or (4) of this section, the Administrator will not record such TR NO\textsubscript{X} Ozone Season allowances under §97.521.
(3) If the Administrator already recorded such TR NOx Ozone Season allowances under §97.521 and if the Administrator makes the determination under paragraph (c)(1) of this section before making deductions for the source that includes such recipient under §97.524(b) for such control period, then the Administrator will deduct from the account in which such TR NOx Ozone Season allowances were recorded an amount of TR NOx Ozone Season allowances allocated for the same or a prior control period equal to the amount of such already recorded TR NOx Ozone Season allowances. The authorized account representative shall ensure that there are sufficient TR NOx Ozone Season allowances in such account for completion of the deduction.

(4) If the Administrator already recorded such TR NOx Ozone Season allowances under §97.521 and if the Administrator makes the determination under paragraph (c)(1) of this section after making deductions for the source that includes such recipient under §97.524(b) for such control period, then the Administrator will not make any deduction to take account of such already recorded TR NOx Ozone Season allowances.

(5)(i) With regard to the TR NOx Ozone Season allowances that are not recorded, or that are deducted as an incorrect allocation, in accordance with paragraphs (c)(2) and (3) of this section for a recipient under paragraph (c)(1)(i) of this paragraph, the Administrator will:

(A) Transfer such TR NOx Ozone Season allowances to the new unit set-aside for such control period; or

(B) If the State has a SIP revision approved under §52.38(b)(4) or (5) covering such control period, include such TR NOx Ozone Season allowances in the portion of the State NOx Ozone Season trading budget that may be allocated for such control period in accordance with such SIP revision.

(iii) With regard to the TR NOx Ozone Season allowances that were allocated from the Indian country new unit set-aside for such control period and that are not recorded, or that are deducted as an incorrect allocation, in accordance with paragraphs (c)(2) and (3) of this section for a recipient under paragraph (c)(1)(i) of this paragraph, the Administrator will:

(A) Transfer such TR NOx Ozone Season allowances to the new unit set-aside for such control period; or

(B) If the State has a SIP revision approved under §52.38(b)(4) or (5) covering such control period, include such TR NOx Ozone Season allowances in the portion of the State NOx Ozone Season trading budget that may be allocated for such control period in accordance with such SIP revision.
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Allocation is terminated for such control period pursuant to § 97.511(a)(2), and that operate during the control period immediately preceding such control period; or

(iv) For purposes of paragraph (a)(9) of this section, TR NO\textsubscript{X} Ozone Season units under § 97.511(c)(1)(ii) whose allocation of an amount of TR NO\textsubscript{X} Ozone Season allowances for such control period in the notice of data availability issued under § 97.511(b)(1)(ii)(B) is covered by § 97.511(c)(2) or (3).

(2) The Administrator will establish a separate new unit set-aside for the State for each such control period. Each such new unit set-aside will be allocated TR NO\textsubscript{X} Ozone Season allowances in an amount equal to the applicable amount of tons of NO\textsubscript{X} emissions as set forth in § 97.510(a) and will be allocated additional TR NO\textsubscript{X} Ozone Season allowances (if any) in accordance with §§ 97.511(a)(2) and (c)(5) and paragraph (b)(10) of this section.

(3) The Administrator will determine, for each TR NO\textsubscript{X} Ozone Season unit described in paragraph (a)(1) of this section, an allocation of TR NO\textsubscript{X} Ozone Season allowances for the later of the following control periods and for each subsequent control period:

(i) The control period in 2012;

(ii) The first control period after the control period in which the TR NO\textsubscript{X} Ozone Season unit commences commercial operation;

(iii) For a unit described in paragraph (a)(1)(ii) of this section, the first control period in which the TR NO\textsubscript{X} Ozone Season unit operates in the State after operating in another jurisdiction and for which the unit is not already allocated one or more TR NO\textsubscript{X} Ozone Season allowances; and

(iv) For a unit described in paragraph (a)(1)(iii) of this section, the first control period after the control period in which the unit resumes operation.

(4)(i) The allocation to each TR NO\textsubscript{X} Ozone Season unit described in paragraph (a)(1)(i) through (iii) of this section and for each control period described in paragraph (a)(3) of this section will be an amount equal to the unit's total tons of NO\textsubscript{X} emissions during the immediately preceding control period.

(ii) The Administrator will adjust the allocation amount in paragraph (a)(4)(i) in accordance with paragraphs (a)(5) through (7) and (12) of this section.

(5) The Administrator will calculate the sum of the TR NO\textsubscript{X} Ozone Season allowances determined for all such TR NO\textsubscript{X} Ozone Season units under paragraph (a)(4)(i) of this section in the State for such control period.

(6) If the amount of TR NO\textsubscript{X} Ozone Season allowances in the new unit set-aside for the State for such control period is greater than or equal to the sum under paragraph (a)(5) of this section, then the Administrator will allocate the amount of TR NO\textsubscript{X} Ozone Season allowances determined for each such TR NO\textsubscript{X} Ozone Season unit under paragraph (a)(4)(i) of this section.

(7) If the amount of TR NO\textsubscript{X} Ozone Season allowances in the new unit set-aside for the State for such control period is less than the sum under paragraph (a)(5) of this section, then the Administrator will allocate to each such TR NO\textsubscript{X} Ozone Season unit the amount of the TR NO\textsubscript{X} Ozone Season allowances determined under paragraph (a)(4)(i) of this section for the unit, multiplied by the amount of TR NO\textsubscript{X} Ozone Season allowances in the new unit set-aside for such control period, divided by the sum under paragraph (a)(5) of this section, and rounded to the nearest allowance.

(8) The Administrator will notify the public, through the promulgation of the notices of data availability described in § 97.511(b)(1)(i) and (ii), of the amount of TR NO\textsubscript{X} Ozone Season allowances allocated under paragraphs (a)(2) through (7) and (12) of this section for such control period to each TR NO\textsubscript{X} Ozone Season unit eligible for such allocation.

(9) If, after completion of the procedures under paragraphs (a)(5) through (8) of this section for such control period, any unallocated TR NO\textsubscript{X} Ozone Season allowances remain in the new unit set-aside for the State for such control period, the Administrator will allocate such TR NO\textsubscript{X} Ozone Season allowances as follows—

(i) The Administrator will determine, for each unit described in paragraph (a)(1) of this section that commenced
commercial operation during the period starting May 1 of the year before the year of such control period and ending August 31 of year of such control period, the positive difference (if any) between the unit’s emissions during such control period and the amount of TR NOX Ozone Season allowances referenced in the notice of data availability required under §97.511(b)(1)(ii) for the unit for such control period;

(ii) The Administrator will determine the sum of the positive differences determined under paragraph (a)(9)(i) of this section;

(iii) If the amount of unallocated TR NOX Ozone Season allowances remaining in the new unit set-aside for the State for such control period is greater than or equal to the sum determined under paragraph (a)(9)(ii) of this section, then the Administrator will allocate the amount of TR NOX Ozone Season allowances determined for each such TR NOX Ozone Season unit under paragraph (a)(9)(i) of this section; and

(iv) If the amount of unallocated TR NOX Ozone Season allowances remaining in the new unit set-aside for the State for such control period is less than the sum under paragraph (a)(9)(ii) of this section, then the Administrator will allocate to each such TR NOX Ozone Season unit the amount of the TR NOX Ozone Season allowances determined under paragraph (a)(9)(i) of this section for the unit, multiplied by the amount of unallocated TR NOX Ozone Season allowances remaining in the new unit set-aside for such control period, divided by the sum under paragraph (a)(9)(ii) of this section, and rounded to the nearest allowance.

(10) If, after completion of the procedures under paragraphs (a)(9) and (12) of this section for such control period, any unallocated TR NOX Ozone Season allowances remain in the new unit set-aside for the State for such control period, the Administrator will allocate to each TR NOX Ozone Season unit that is in the State, is allocated an amount of TR NOX Ozone Season allowances in the notice of data availability issued under §97.511(a)(1), and continues to be allocated TR NOX Ozone Season allowances for such control period in accordance with §97.511(a)(2), an amount of TR NOX Ozone Season allowances equal to the following: the total amount of such remaining unallocated TR NOX Ozone Season allowances in such new unit set-aside, multiplied by the unit’s allocation under §97.511(a) for such control period, divided by the remainder of the amount of tons in the applicable State NOX Ozone Season trading budget minus the sum of the amounts of tons in such new unit set-aside and the Indian country new unit set-aside for the State for such control period, and rounded to the nearest allowance.

(11) The Administrator will notify the public, through the promulgation of the notices of data availability described in §97.511(b)(1)(iii), (iv), and (v), of the amount of TR NOX Ozone Season allowances allocated under paragraphs (a)(9), (10), and (12) of this section for such control period to each TR NOX Ozone Season unit eligible for such allocation.

(12)(i) Notwithstanding the requirements of paragraphs (a)(2) through (11) of this section, if the calculations of allocations of a new unit set-aside for a control period in a given year under paragraph (a)(7) of this section, paragraphs (a)(6) and (9)(iv) of this section, or paragraphs (a)(6), (9)(iii), and (10) of this section would otherwise result in total allocations of such new unit set-aside exceeding the total amount of such new unit set-aside, then the Administrator will adjust the results of the calculations under paragraph (a)(7), (9)(iv), or (10) of this section, as applicable, and, in cases of equal allocation amounts, in alphabetical order of the relevant source’s name and numerical order of the relevant unit’s identification number, and will reduce each unit’s allocation under paragraph (a)(7), (9)(iv), or (10) of this section, as applicable, by one TR NOX Ozone Season allowance (but not below zero) in the order in which the units are listed and will repeat this reduction process as necessary, until the total allocations of such new unit set-aside equal the total amount of such new unit set-aside.
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(ii) Notwithstanding the requirements of paragraphs (a)(10) and (11) of this section, if the calculations of allocations of a new unit set-aside for a control period in a given year under paragraphs (a)(6), (9)(iii), and (10) of this section would otherwise result in a total allocations of such new unit set-aside less than the total amount of such new unit set-aside, then the Administrator will adjust the results of the calculations under paragraph (a)(10) of this section, as follows. The Administrator will list the TR NOX Ozone Season units in descending order based on the amount of such units’ allocations under paragraph (a)(10) of this section and, in cases of equal allocation amounts, in alphabetical order of the relevant source’s name and numerical order of the relevant unit’s identification number, and will increase each unit’s allocation under paragraph (a)(10) of this section by one TR NOX Ozone Season allowance in the order in which the units are listed and will repeat this increase process as necessary, until the total allocations of such new unit set-aside equal the total amount of such new unit set-aside.

(b) For each control period in 2012 and thereafter and for the TR NOX Ozone Season units located in Indian country within the borders of each State, the Administrator will allocate TR NOX Ozone Season allowances to the TR NOX Ozone Season units as follows:

(1) The TR NOX Ozone Season allowances will be allocated to the following TR NOX Ozone Season units, except as provided in paragraph (b)(10) of this section:

(i) TR NOX Ozone Season units that are not allocated an amount of TR NOX Ozone Season allowances in the notice of data availability issued under §97.511(a)(1); or

(ii) For purposes of paragraph (b)(9) of this section, TR NOX Ozone Season units under §97.511(c)(1)(ii) whose allocation of an amount of TR NOX Ozone Season allowances for such control period in the notice of data availability issued under §97.511(b)(2)(ii)(B) is covered by §97.511(c)(2) or (3).

(2) The Administrator will establish a separate Indian country new unit set-aside for the State for each such control period. Each such Indian country new unit set-aside will be allocated TR NOX Ozone Season allowances in an amount equal to the applicable amount of tons of NOx emissions as set forth in §97.510(a) and will be allocated additional TR NOX Ozone Season allowances (if any) in accordance with §97.511(c)(5).

(3) The Administrator will determine, for each TR NOX Ozone Season unit described in paragraph (b)(1) of this section, an allocation of TR NOX Ozone Season allowances for the later of the following control periods and for each subsequent control period:

(i) The control period in 2012; and

(ii) The first control period after the control period in which the TR NOX Ozone Season unit commences commercial operation.

(4)(i) The allocation to each TR NOX Ozone Season unit described in paragraph (b)(1) of this section will be an amount equal to the unit’s total tons of NOx emissions during the immediately preceding control period.

(ii) The Administrator will adjust the allocation amount in paragraph (b)(4)(i) in accordance with paragraphs (b)(5) through (7) and (12) of this section.

(5) The Administrator will calculate the sum of the TR NOX Ozone Season allowances determined for all such TR NOX Ozone Season units under paragraph (b)(4)(i) of this section in Indian country within the borders of the State for such control period.

(6) If the amount of TR NOX Ozone Season allowances in the Indian country new unit set-aside for the State for such control period is greater than or equal to the sum under paragraph (b)(5) of this section, then the Administrator will allocate the amount of TR NOX Ozone Season allowances determined for each such TR NOX Ozone Season unit under paragraph (b)(4)(i) of this section.

(7) If the amount of TR NOX Ozone Season allowances in the Indian country new unit set-aside for the State for such control period is less than the
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sum under paragraph (b)(5) of this section, then the Administrator will allocate to each such TR NO\textsubscript{X} Ozone Season unit the amount of the TR NO\textsubscript{X} Ozone Season allowances determined under paragraph (b)(4)(i) of this section for the unit, multiplied by the amount of TR NO\textsubscript{X} Ozone Season allowances in the Indian country new unit set-aside for such control period, divided by the sum under paragraph (b)(5) of this section, and rounded to the nearest allowance.

(8) The Administrator will notify the public, through the promulgation of the notices of data availability described in §97.511(b)(2)(i) and (ii), of the amount of TR NO\textsubscript{X} Ozone Season allowances allocated under paragraphs (b)(2) through (7) and (12) of this section for such control period to each TR NO\textsubscript{X} Ozone Season unit eligible for such allocation.

(9) If, after completion of the procedures under paragraphs (b)(5) through (8) of this section for such control period, any unallocated TR NO\textsubscript{X} Ozone Season allowances remain in the Indian country new unit set-aside for the State for such control period, the Administrator will allocate such TR NO\textsubscript{X} Ozone Season allowances as follows—

(i) The Administrator will determine, for each unit described in paragraph (b)(1) of this section that commenced commercial operation during the period starting May 1 of the year before the year of such control period and ending August 31 of year of such control period, the positive difference (if any) between the unit’s emissions during such control period and the amount of TR NO\textsubscript{X} Ozone Season allowances referenced in the notice of data availability required under §97.511(b)(2)(ii) for the unit for such control period;

(ii) The Administrator will determine the sum of the positive differences determined under paragraph (b)(9)(i) of this section;

(iii) If the amount of unallocated TR NO\textsubscript{X} Ozone Season allowances remaining in the Indian country new unit set-aside for the State for such control period is greater than or equal to the sum determined under paragraph (b)(9)(i) of this section, then the Administrator will allocate the amount of TR NO\textsubscript{X} Ozone Season allowances determined for each such TR NO\textsubscript{X} Ozone Season unit under paragraph (b)(9)(i) of this section; and

(iv) If the amount of unallocated TR NO\textsubscript{X} Ozone Season allowances remaining in the Indian country new unit set-aside for the State for such control period is less than the sum under paragraph (b)(9)(i) of this section, then the Administrator will allocate to each such TR NO\textsubscript{X} Ozone Season unit the amount of the TR NO\textsubscript{X} Ozone Season allowances determined under paragraph (b)(9)(i) of this section for the unit, multiplied by the amount of unallocated TR NO\textsubscript{X} Ozone Season allowances remaining in the Indian country new unit set-aside for such control period, divided by the sum under paragraph (b)(9)(i) of this section, and rounded to the nearest allowance.

(10) If, after completion of the procedures under paragraphs (b)(9) and (12) of this section for such control period, any unallocated TR NO\textsubscript{X} Ozone Season allowances remain in the Indian country new unit set-aside for the State for such control period, the Administrator will:

(i) Transfer such unallocated TR NO\textsubscript{X} Ozone Season allowances to the new unit set-aside for the State for such control period; or

(ii) If the State has a SIP revision approved under §52.38(b)(4) or (5) covering such control period, include such unallocated TR NO\textsubscript{X} Ozone Season allowances in the portion of the State NO\textsubscript{X} Ozone Season trading budget that may be allocated for such control period in accordance with such SIP revision.

(11) The Administrator will notify the public, through the promulgation of the notices of data availability described in §97.511(b)(2)(iii), (iv), and (v), of the amount of TR NO\textsubscript{X} Ozone Season allowances allocated under paragraphs (b)(9), (10), and (12) of this section for such control period to each TR NO\textsubscript{X} Ozone Season unit eligible for such allocation.

(12)(i) Notwithstanding the requirements of paragraphs (b)(2) through (11) of this section, if the calculations of allocations of an Indian country new unit set-aside for a control period in a given year under paragraphs (b)(7) of this section, paragraphs (b)(6) and
(9)(iv) of this section, or paragraphs (b)(6), (9)(iii), and (10) of this section would otherwise result in total allocations of such Indian country new unit set-aside exceeding the total amount of such Indian country new unit set-aside, then the Administrator will adjust the results of the calculations under paragraph (b)(7), (9)(iv), or (10) of this section, as applicable, as follows. The Administrator will list the TR NOx Ozone Season units in descending order based on the amount of such units’ allocations under paragraph (b)(7), (9)(iv), or (10) of this section, as applicable, and, in cases of equal allocation amounts, in alphabetical order of the relevant source’s name and numerical order of the relevant unit’s identification number, and will reduce each unit’s allocation under paragraph (b)(7), (9)(iv), or (10) of this section, as applicable, by one TR NOx Ozone Season allowance (but not below zero) in the order in which the units are listed and will repeat this reduction process as necessary, until the total allocations of such Indian country new unit set-aside equal the total amount of such Indian country new unit set-aside.

§ 97.513 Authorization of designated representative and alternate designated representative.

(a) Except as provided under §97.515, each TR NOx Ozone Season source, including all TR NOx Ozone Season units at the source, shall have one and only one designated representative, with regard to all matters under the TR NOx Ozone Season Trading Program.

(1) The designated representative shall be selected by an agreement binding on the owners and operators of the source and all TR NOx Ozone Season units at the source and shall act in accordance with the certification statement in §97.516(a)(4)(i).

(2) Upon and after receipt by the Administrator of a complete certificate of representation under §97.516:

(i) The designated representative shall be authorized and shall represent and, by his or her representations, actions, inactions, or submissions, legally bind each owner and operator of the source and each TR NOx Ozone Season unit at the source in all matters pertaining to the TR NOx Ozone Season Trading Program, notwithstanding any agreement between the designated representative and such owners and operators; and

(ii) The owners and operators of the source and each TR NOx Ozone Season unit at the source shall be bound by any decision or order issued to the designated representative by the Administrator regarding the source or any such unit.

(b) Except as provided under §97.515, each TR NOx Ozone Season source may have one and only one alternate designated representative, who may act on behalf of the designated representative.

(1) The alternate designated representative shall be selected by an agreement binding on the owners and operators of the source and all TR NOx Ozone Season units at the source and
§ 97.514 Responsibilities of designated representative and alternate designated representative.

(a) Except as provided under §97.518 concerning delegation of authority to make submissions, each submission under the TR NOX Ozone Season Trading Program shall be made, signed, and certified by the designated representative or alternate designated representative for each TR NOX Ozone Season source and TR NOX Ozone Season unit for which the submission is made. Each such submission shall include the following certification statement by the designated representative or alternate designated representative: “I am authorized to make this submission on behalf of the owners and operators of the source or units for which the submission is made. I certify under penalty of law that I have personally examined, and am familiar with, the statements and information submitted in this document and all its attachments. Based on my inquiry of those individuals with primary responsibility for obtaining the information, I certify that the statements and information are to the best of my knowledge and belief true, accurate, and complete. I am aware that there are significant penalties for submitting false statements and information or omitting required statements and information, including the possibility of fine or imprisonment.”

(b) The Administrator will accept or act on a submission made for a TR NOX Ozone Season source or a TR NOX Ozone Season unit only if the submission has been made, signed, and certified in accordance with paragraph (a) of this section and §97.518.

§ 97.515 Changing designated representative and alternate designated representative; changes in owners and operators; changes in units at the source.

(a) Changing designated representative. The designated representative may be changed at any time upon receipt by the Administrator of a superseding complete certificate of representation under §97.516. Notwithstanding any such change, all representations, actions, inactions, and submissions by the previous designated representative before the time and date when the Administrator receives the superseding certificate of representation shall be binding on the new designated representative and the owners and operators of the TR NOX Ozone Season source and the TR NOX Ozone Season units at the source.

(b) Changing alternate designated representative. The alternate designated representative may be changed at any time upon receipt by the Administrator of a superseding complete certificate of representation under §97.516. Notwithstanding any such change, all representations, actions, inactions, and submissions by the previous alternate designated representative before the time and date when the Administrator receives the superseding certificate of representation shall be binding on the new alternate designated representative, the designated representative, and the owners and operators of the TR NOX Ozone Season source and the TR NOX Ozone Season units at the source.

(c) Changes in owners and operators.

(1) In the event an owner or operator of a TR NOX Ozone Season source or a TR NOX Ozone Season unit at the source is
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not included in the list of owners and operators in the certificate of representation under §97.516, such owner or operator shall be deemed to be subject to and bound by the certificate of representation, the representations, actions, inactions, and submissions of the designated representative and any alternate designated representative of the source or unit, and the decisions and orders of the Administrator, as if the owner or operator were included in such list.

(2) Within 30 days after any change in the owners and operators of a TR NOX Ozone Season source or a TR NOX Ozone Season unit at the source, including the addition or removal of an owner or operator, the designated representative or any alternate designated representative shall submit a revision to the certificate of representation under §97.516 amending the list of owners and operators to reflect the change.

(d) Changes in units at the source. Within 30 days of any change in which units are located at a TR NOX Ozone Season source (including the addition or removal of a unit), the designated representative or any alternate designated representative shall submit a certificate of representation under §97.516 amending the list of units to reflect the change.

(1) If the change is the addition of a unit that operated (other than for purposes of testing by the manufacturer before initial installation) before being located at the source, then the certificate of representation shall identify, in a format prescribed by the Administrator, the entity from whom the unit was purchased or otherwise obtained (including name, address, telephone number, and facsimile number (if any)), the date on which the unit was purchased or otherwise obtained, and the date on which the unit became located at the source.

(2) If the change is the removal of a unit, then the certificate of representation shall identify, in a format prescribed by the Administrator, the entity to which the unit was sold or that otherwise obtained the unit (including name, address, telephone number, and facsimile number (if any)), the date on which the unit was sold or otherwise obtained, and the date on which the unit became no longer located at the source.

§ 97.516 Certificate of representation.

(a) A complete certificate of representation for a designated representative or an alternate designated representative shall include the following elements in a format prescribed by the Administrator:

(1) Identification of the TR NOX Ozone Season source, and each TR NOX Ozone Season unit at the source, for which the certificate of representation is submitted, including source name, source category and NAICS code (or, in the absence of a NAICS code, an equivalent code), State, plant code, county, latitude and longitude, unit identification number and type, identification number and nameplate capacity (in MWe, rounded to the nearest tenth) of each generator served by each such unit, actual or projected date of commencement of commercial operation, and a statement of whether such source is located in Indian Country. If a projected date of commencement of commercial operation is provided, the actual date of commencement of commercial operation shall be provided when such information becomes available.

(2) The name, address, e-mail address (if any), telephone number, and facsimile transmission number (if any) of the designated representative and any alternate designated representative.

(3) A list of the owners and operators of the TR NOX Ozone Season source and of each TR NOX Ozone Season unit at the source.

(4) The following certification statements by the designated representative and any alternate designated representative—

(i) “I certify that I was selected as the designated representative or alternate designated representative, as applicable, by an agreement binding on the owners and operators of the source and each TR NOX Ozone Season unit at the source.”

(ii) “I certify that I have all the necessary authority to carry out my duties and responsibilities under the TR NOX Ozone Season Trading Program on behalf of the owners and operators of the source and of each TR NOX Ozone
§ 97.517 Objections concerning designated representative and alternate designated representative.

(a) Once a complete certificate of representation under §97.516 has been submitted and received, the Administrator will rely on the certificate of representation unless and until a superseding complete certificate of representation under §97.516 is received by the Administrator.

(b) Except as provided in paragraph (a) of this section, no objection or other communication submitted to the Administrator concerning the authorization, or any representation, action, inaction, or submission, of a designated representative or alternate designated representative shall affect any representation, action, inaction, or submission of the designated representative or alternate designated representative or the finality of any decision or order by the Administrator under the TR NOx Ozone Season Trading Program.

(c) The Administrator will not adjudicate any private legal dispute concerning the authorization or any representation, action, inaction, or submission of any designated representative or alternate designated representative, including private legal disputes concerning the proceeds of TR NOx Ozone Season allowance transfers.

§ 97.518 Delegation by designated representative and alternate designated representative.

(a) A designated representative may delegate, to one or more natural persons, his or her authority to make an electronic submission to the Administrator provided for or required under this subpart.

(b) An alternate designated representative may delegate, to one or more natural persons, his or her authority to make an electronic submission to the Administrator provided for or required under this subpart.

(c) In order to delegate authority to a natural person to make an electronic submission to the Administrator in accordance with paragraph (a) or (b) of this section, the designated representative or alternate designated representative, as appropriate, must submit to the Administrator a notice of delegation, in a format prescribed by the Administrator, that includes the following elements:
(1) The name, address, e-mail address, telephone number, and facsimile transmission number (if any) of such designated representative or alternate designated representative;
(2) The name, address, e-mail address, telephone number, and facsimile transmission number (if any) of each such natural person (referred to in this section as an “agent”);
(3) For each such natural person, a list of the type or types of electronic submissions under paragraph (a) or (b) of this section for which authority is delegated to him or her; and
(4) The following certification statements by such designated representative or alternate designated representative:

(i) ‘‘I agree that any electronic submission to the Administrator that is made by an agent identified in this notice of delegation and of a type listed for such agent in this notice of delegation and that is made when I am a designated representative or alternate designated representative, as appropriate, and before this notice of delegation is superseded by another notice of delegation under 40 CFR 97.518(d) shall be deemed to be an electronic submission by me.’’

(ii) ‘‘Until this notice of delegation is superseded by another notice of delegation under 40 CFR 97.518(d), I agree to maintain an e-mail account and to notify the Administrator immediately of any change in my e-mail address unless all delegation of authority by me under 40 CFR 97.518 is terminated.’’

(d) A notice of delegation submitted under paragraph (c) of this section shall be effective, with regard to the designated representative or alternate designated representative identified in such notice, upon receipt of such notice by the Administrator and until receipt by the Administrator of a superseding notice of delegation submitted by such designated representative or alternate designated representative, as appropriate. The superseding notice of delegation may replace any previously identified agent, add a new agent, or eliminate entirely any delegation of authority.

(e) Any electronic submission covered by the certification in paragraph (c)(4)(i) of this section and made in accordance with a notice of delegation effective under paragraph (d) of this section shall be deemed to be an electronic submission by the designated representative or alternate designated representative submitting such notice of delegation.

§ 97.519 [Reserved]

§ 97.520 Establishment of compliance accounts, assurance accounts, and general accounts.

(a) Compliance accounts. Upon receipt of a complete certificate of representation under §97.516, the Administrator will establish a compliance account for the TR NOx Ozone Season source for which the certificate of representation was submitted, unless the source already has a compliance account. The designated representative and any alternate designated representative of the source shall be the authorized account representative and the alternate authorized account representative respectively of the compliance account.

(b) Assurance accounts. The Administrator will establish assurance accounts for certain owners and operators and States in accordance with §97.525(b)(3).

(c) General accounts. (1) Application for general account. (i) Any person may apply to open a general account, for the purpose of holding and transferring TR NOx Ozone Season allowances, by submitting to the Administrator a complete application for a general account. Such application shall designate one and only one authorized account representative and may designate one and only one alternate authorized account representative who may act on behalf of the authorized account representative.

(A) The authorized account representative and alternate authorized account representative shall be selected by an agreement binding on the persons who have an ownership interest with respect to TR NOx Ozone Season allowances held in the general account.

(B) The agreement by which the alternate authorized account representative is selected shall include a procedure for authorizing the alternate authorized account representative to act
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in lieu of the authorized account representative.

(ii) A complete application for a general account shall include the following elements in a format prescribed by the Administrator:

(A) Name, mailing address, e-mail address (if any), telephone number, and facsimile transmission number (if any) of the authorized account representative and any alternate authorized account representative;

(B) An identifying name for the general account;

(C) A list of all persons subject to a binding agreement for the authorized account representative and any alternate authorized account representative to represent their ownership interest with respect to TR NO\textsubscript{X} Ozone Season allowances held in the general account;

(D) The following certification statement by the authorized account representative and any alternate authorized account representative, as applicable, by an agreement that is binding on all persons who have an ownership interest with respect to TR NO\textsubscript{X} Ozone Season allowances held in the general account. I certify that I have all the necessary authority to carry out my duties and responsibilities under the TR NO\textsubscript{X} Ozone Season Trading Program on behalf of such persons and that each such person shall be fully bound by my representations, actions, inactions, or submissions and by any decision or order issued to me by the Administrator regarding the general account.

(E) The signature of the authorized account representative and any alternate authorized account representative and the dates signed.

(iii) Unless otherwise required by the Administrator, documents of agreement referred to in the application for a general account shall not be submitted to the Administrator. The Administrator shall not be under any obligation to review or evaluate the sufficiency of such documents, if submitted.

(2) Authorization of authorized account representative. (i) Upon receipt by the Administrator of a complete application for a general account under paragraph (b)(1) of this section, the Administrator will establish a general account for the person or persons for whom the application is submitted, and upon and after such receipt by the Administrator:

(A) The authorized account representative of the general account shall be authorized and shall represent and, by his or her representations, actions, inactions, or submissions, legally bind each person who has an ownership interest with respect to TR NO\textsubscript{X} Ozone Season allowances held in the general account in all matters pertaining to the TR NO\textsubscript{X} Ozone Season Trading Program, notwithstanding any agreement between the authorized account representative and such person.

(B) Any alternate authorized account representative shall be authorized, and any representation, action, inaction, or submission by any alternate authorized account representative shall be deemed to be a representation, action, inaction, or submission by the authorized account representative.

(C) Each person who has an ownership interest with respect to TR NO\textsubscript{X} Ozone Season allowances held in the general account shall be bound by any decision or order issued to the authorized account representative or alternate authorized account representative by the Administrator regarding the general account.

(ii) Except as provided in paragraph (c)(5) of this section concerning delegation of authority to make submissions, each submission concerning the general account shall be made, signed, and certified by the authorized account representative or any alternate authorized account representative for the persons having an ownership interest with respect to TR NO\textsubscript{X} Ozone Season allowances held in the general account. Each such submission shall include the following certification statement by the authorized account representative or any alternate authorized account representative: ‘‘I am authorized to make this submission on behalf of the persons having an ownership interest with respect to the TR NO\textsubscript{X} Ozone Season allowances held in the general account. I certify under penalty of law that I have..."
personally examined, and am familiar with, the statements and information submitted in this document and all its attachments. Based on my inquiry of those individuals with primary responsibility for obtaining the information, I certify that the statements and information are to the best of my knowledge and belief true, accurate, and complete. I am aware that there are significant penalties for submitting false statements and information or omitting required statements and information, including the possibility of fine or imprisonment.

(iii) Except in this section, whenever the term “authorized account representative” is used in this subpart, the term shall be construed to include the authorized account representative or any alternate authorized account representative.

(3) Changing authorized account representative and alternate authorized account representative; changes in persons with ownership interest.

(i) The authorized account representative of a general account may be changed at any time upon receipt by the Administrator of a superseding complete application for a general account under paragraph (c)(1) of this section. Notwithstanding any such change, all representations, actions, inactions, and submissions by the previous authorized account representative before the time and date when the Administrator receives the superseding application for a general account shall be binding on the new authorized account representative and the persons with an ownership interest with respect to the TR NO\textsubscript{X} Ozone Season allowances in the general account.

(ii) The alternate authorized account representative of a general account may be changed at any time upon receipt by the Administrator of a superseding complete application for a general account under paragraph (c)(1) of this section. Notwithstanding any such change, all representations, actions, inactions, and submissions by the previous alternate authorized account representative before the time and date when the Administrator receives the superseding application for a general account shall be binding on the new alternate authorized account representative, the authorized account representative, and the persons with an ownership interest with respect to the TR NO\textsubscript{X} Ozone Season allowances in the general account.

(iii)(A) In the event a person having an ownership interest with respect to TR NO\textsubscript{X} Ozone Season allowances in the general account is not included in the list of such persons in the application for a general account, such person shall be deemed to be subject to and bound by the application for a general account, the representation, actions, inactions, and submissions of the authorized account representative and any alternate authorized account representative of the account, and the decisions and orders of the Administrator, as if the person were included in such list.

(B) Within 30 days after any change in the persons having an ownership interest with respect to NO\textsubscript{X} Ozone Season allowances in the general account, including the addition or removal of a person, the authorized account representative or any alternate authorized account representative shall submit a revision to the application for a general account amending the list of persons having an ownership interest with respect to the TR NO\textsubscript{X} Ozone Season allowances in the general account to include the change.

(4) Objections concerning authorized account representative and alternate authorized account representative.

(i) Once a complete application for a general account under paragraph (c)(1) of this section has been submitted and received, the Administrator will rely on the application unless and until a superseding complete application for a general account under paragraph (b)(1) of this section is received by the Administrator.

(ii) Except as provided in paragraph (c)(4)(i) of this section, no objection or other communication submitted to the Administrator concerning the authorization, or any representation, action, inaction, or submission of the authorized account representative or any alternate authorized account representative of a general account shall affect any representation, action, inaction, or submission of the authorized account representative.
representative or any alternate authorized account representative or the finality of any decision or order by the Administrator under the TR NOx Ozone Season Trading Program.

(iii) The Administrator will not adjudicate any private legal dispute concerning the authorization or any representation, action, inaction, or submission of the authorized account representative or any alternate authorized account representative of a general account, including private legal disputes concerning the proceeds of TR NOx Ozone Season allowance transfers.

(5) Delegation by authorized account representative and alternate authorized account representative. (i) An authorized account representative of a general account may delegate, to one or more natural persons, his or her authority to make an electronic submission to the Administrator provided for or required under this subpart.

(ii) An alternate authorized account representative of a general account may delegate, to one or more natural persons, his or her authority to make an electronic submission to the Administrator provided for or required under this subpart.

(iii) In order to delegate authority to a natural person to make an electronic submission to the Administrator in accordance with paragraph (c)(5)(i) or (ii) of this section, the authorized account representative or alternate authorized account representative, as appropriate, must submit to the Administrator a notice of delegation, in a format prescribed by the Administrator, that includes the following elements:

(A) The name, address, e-mail address, telephone number, and facsimile transmission number (if any) of such authorized account representative or alternate authorized account representative;

(B) The name, address, e-mail address, telephone number, and facsimile transmission number (if any) of each such natural person (referred to in this section as an “agent”);

(C) For each such natural person, a list of the type or types of electronic submissions under paragraph (c)(5)(i) or (ii) of this section for which authority is delegated to him or her;

(D) The following certification statement by such authorized account representative or alternate authorized account representative: “I agree that any electronic submission to the Administrator that is made by an agent identified in this notice of delegation and of a type listed for such agent in this notice of delegation and that is made when I am an authorized account representative or alternate authorized representative, as appropriate, and before this notice of delegation is superseded by another notice of delegation under 40 CFR 97.520(c)(5)(iv) shall be deemed to be an electronic submission by me.”; and

(E) The following certification statement by such authorized account representative or alternate authorized account representative: “Until this notice of delegation is superseded by another notice of delegation under 40 CFR 97.520(c)(5)(iv), I agree to maintain an e-mail account and to notify the Administrator immediately of any change in my e-mail address unless all delegation of authority by me under 40 CFR 97.520(c)(5) is terminated.”.

(iv) A notice of delegation submitted under paragraph (c)(5)(iii) of this section shall be effective, with regard to the authorized account representative or alternate authorized account representative identified in such notice, upon receipt of such notice by the Administrator and until receipt by the Administrator of a superseding notice of delegation submitted by such authorized account representative or alternate authorized account representative, as appropriate. The superseding notice of delegation may replace any previously identified agent, add a new agent, or eliminate entirely any delegation of authority.

(v) Any electronic submission covered by the certification in paragraph (c)(5)(ii)(D) of this section and made in accordance with a notice of delegation effective under paragraph (c)(5)(iv) of this section shall be deemed to be an electronic submission by the designated representative or alternate designated representative submitting such notice of delegation.

(6) Closing a general account. (i) The authorized account representative or
§ 97.521 Recordation of TR NOx Ozone Season allowance allocations and auction results.

(a) By November 7, 2011 or, with regard to units in Iowa, Michigan, Missouri, Oklahoma, and Wisconsin, March 26, 2012, the Administrator will record in each TR NOx Ozone Season source’s compliance account the TR NOx Ozone Season allowances allocated to the TR NOx Ozone Season units at the source in accordance with §97.511(a) for the control period in 2012.

(b) By November 7, 2011 or, with regard to units in Iowa, Michigan, Missouri, Oklahoma, and Wisconsin, March 26, 2012, the Administrator will record in each TR NOx Ozone Season source’s compliance account the TR NOx Ozone Season allowances allocated to the TR NOx Ozone Season units at the source in accordance with §97.511(a) for the control period in 2013, unless the State in which the source is located notifies the Administrator in writing by October 17, 2011 or, with regard to TR NOx Ozone Season units in Iowa, Michigan, Missouri, Oklahoma, and Wisconsin, March 6, 2012 of the State’s intent to submit to the Administrator a complete SIP revision by April 1, 2012 or, with regard to units in Iowa, Michigan, Missouri, Oklahoma, and Wisconsin, October 1, 2012 meeting the requirements of §52.38(b)(3)(i) through (iv) of this chapter.

(1) If, by April 1, 2012 or, with regard to TR NOx Ozone Season units in Iowa, Michigan, Missouri, Oklahoma, and Wisconsin, by October 1, 2012, the State does not submit to the Administrator such complete SIP revision, the Administrator will record by April 15, 2012 or, with regard to units in Iowa, Michigan, Missouri, Oklahoma, and Wisconsin, October 15, 2012 in each TR NOx Ozone Season source’s compliance account the TR NOx Ozone Season allowances allocated to the TR NOx Ozone Season units at the source in accordance with §97.511(a) for the control period in 2013.

(2) If the State submits to the Administrator by April 1, 2012 or, with regard to units in Iowa, Michigan, Missouri, Oklahoma, and Wisconsin, October 1, 2012, and the Administrator approves by October 1, 2012 or, with regard to units in Iowa, Michigan, Missouri, Oklahoma, and Wisconsin, April 1, 2013, such complete SIP revision, the Administrator will record by October 1, 2012 or, with regard to units in Iowa, Michigan, Missouri, Oklahoma, and Wisconsin, April 1, 2013 in each TR NOx...
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Ozone Season source’s compliance account the TR NO\textsubscript{X} Ozone Season allowances allocated to the TR NO\textsubscript{X} Ozone Season units at the source as provided in such approved, complete SIP revision for the control period in 2013.

(3) If the State submits to the Administrator by April 1, 2012 or, with regard to units in Iowa, Michigan, Missouri, Oklahoma, and Wisconsin, October 1, 2012, and the Administrator does not approve by October 1, 2012 or, with regard to units in Iowa, Michigan, Missouri, Oklahoma, and Wisconsin, April 1, 2013, such complete SIP revision, the Administrator will record by October 1, 2012 or, with regard to units in Iowa, Michigan, Missouri, Oklahoma, and Wisconsin, April 1, 2013 in each TR NO\textsubscript{X} Ozone Season source’s compliance account the TR NO\textsubscript{X} Ozone Season allowances allocated to the TR NO\textsubscript{X} Ozone Season units at the source in accordance with §97.511(a) for the control period in 2013.

(c) By July 1, 2013, the Administrator will record in each TR NO\textsubscript{X} Ozone Season source’s compliance account the TR NO\textsubscript{X} Ozone Season allowances allocated to the TR NO\textsubscript{X} Ozone Season units at the source, or in each appropriate Allowance Management System account the TR NO\textsubscript{X} Ozone Season allowances auctioned to TR NO\textsubscript{X} Ozone Season units at the source in accordance with §97.511(a) for the control period in 2013.

(d) By July 1, 2014, the Administrator will record in each TR NO\textsubscript{X} Ozone Season source’s compliance account the TR NO\textsubscript{X} Ozone Season allowances allocated to the TR NO\textsubscript{X} Ozone Season units at the source, or in each appropriate Allowance Management System account the TR NO\textsubscript{X} Ozone Season allowances auctioned to TR NO\textsubscript{X} Ozone Season units at the source, or in each appropriate Allowance Management System account the TR NO\textsubscript{X} Ozone Season allowances auctioned to TR NO\textsubscript{X} Ozone Season units, in accordance with §97.511(a), or with a SIP revision approved under §52.38(b)(4) or (5) of this chapter, for the control period in 2014 and 2015.

(e) By July 1, 2015, the Administrator will record in each TR NO\textsubscript{X} Ozone Season source’s compliance account the TR NO\textsubscript{X} Ozone Season allowances allocated to the TR NO\textsubscript{X} Ozone Season units at the source, or in each appropriate Allowance Management System account the TR NO\textsubscript{X} Ozone Season allowances auctioned to TR NO\textsubscript{X} Ozone Season units, in accordance with §97.511(a), or with a SIP revision approved under §52.38(b)(4) or (5) of this chapter, for the control period in 2016 and 2017.

(f) By July 1, 2016 and July 1 of each year thereafter, the Administrator will record in each TR NO\textsubscript{X} Ozone Season source’s compliance account the TR NO\textsubscript{X} Ozone Season allowances auctioned to TR NO\textsubscript{X} Ozone Season units, in accordance with §97.511(a), or with a SIP revision approved under §52.38(b)(4) or (5) of this chapter, for the control period in 2018 and 2019.

(g) By August 1, 2012 and August 1 of each year thereafter, the Administrator will record in each TR NO\textsubscript{X} Ozone Season source’s compliance account the TR NO\textsubscript{X} Ozone Season allowances allocated to the TR NO\textsubscript{X} Ozone Season units at the source, or in each appropriate Allowance Management System account the TR NO\textsubscript{X} Ozone Season allowances auctioned to TR NO\textsubscript{X} Ozone Season units, in accordance with §97.512(b)(2) through (8) and (12), or with a SIP revision approved under §52.38(b)(4) or (5) of this chapter, for the control period in the fourth year after the year of the applicable recordation deadline under this paragraph.

(h) By August 1, 2012 and August 1 of each year thereafter, the Administrator will record in each TR NO\textsubscript{X} Ozone Season source’s compliance account the TR NO\textsubscript{X} Ozone Season allowances allocated to the TR NO\textsubscript{X} Ozone Season units at the source, or in each appropriate Allowance Management System account the TR NO\textsubscript{X} Ozone Season allowances auctioned to TR NO\textsubscript{X} Ozone Season units, in accordance with §97.512(a)(2) through (8) and (12), or with a SIP revision approved under §52.38(b)(4) or (5) of this chapter, for the control period in the year of the applicable recordation deadline under this paragraph.

(i) By November 15, 2012 and November 15 of each year thereafter, the Administrator will record in each TR NO\textsubscript{X} Ozone Season source’s compliance account the TR NO\textsubscript{X} Ozone Season allowances allocated to the TR NO\textsubscript{X} Ozone Season units at the source, or in each appropriate Allowance Management System account the TR NO\textsubscript{X} Ozone Season allowances auctioned to TR NO\textsubscript{X} Ozone Season units, in accordance with §97.512(a) through (8) and (12), or with a SIP revision approved under §52.38(b)(4) or (5) of this chapter, for the control period in the fourth year after the year of the applicable recordation deadline under this paragraph.
Season units at the source in accordance with §97.512(a)(9) through (12), for the control period in the year of the applicable recordation deadline under this paragraph.

(j) By the date on which any allocation or auction results, other than an allocation or auction results described in paragraphs (a) through (i) of this section, of TR NO\textsubscript{X} Ozone Season allowances to a recipient is made by or are submitted to the Administrator in accordance with §97.511 or §97.512 or with a SIP revision approved under §52.38(b)(4) or (5) of this chapter, the Administrator will record such allocation or auction results in the appropriate Allowance Management System account.

(k) When recording the allocation or auction of TR NO\textsubscript{X} Ozone Season allowances to a TR NO\textsubscript{X} Ozone Season unit or other entity in an Allowance Management System account, the Administrator will assign each TR NO\textsubscript{X} Ozone Season allowance a unique identification number that will include digits identifying the year of the control period for which the TR NO\textsubscript{X} Ozone Season allowance is allocated or auctioned.

[76 FR 48406, Aug. 8, 2011, as amended at 76 FR 80777, Dec. 27, 2011]

§97.522 Submission of TR NO\textsubscript{X} Ozone Season allowance transfers.

(a) An authorized account representative seeking recordation of a TR NO\textsubscript{X} Ozone Season allowance transfer shall submit the transfer to the Administrator.

(b) A TR NO\textsubscript{X} Ozone Season allowance transfer shall be correctly submitted if:

(1) The transfer includes the following elements, in a format prescribed by the Administrator:

(i) The account numbers established by the Administrator for both the transferor and transferee accounts;

(ii) The serial number of each TR NO\textsubscript{X} Ozone Season allowance that is in the transferor account and is to be transferred; and

(iii) The name and signature of the authorized account representative of the transferor account and the date signed; and

(2) When the Administrator attempts to record the transfer, the transferor account includes each TR NO\textsubscript{X} Ozone Season allowance identified by serial number in the transfer.

§97.523 Recordation of TR NO\textsubscript{X} Ozone Season allowance transfers.

(a) Within 5 business days (except as provided in paragraph (b) of this section) of receiving a TR NO\textsubscript{X} Ozone Season allowance transfer that is correctly submitted under §97.522, the Administrator will record a TR NO\textsubscript{X} Ozone Season allowance transfer by moving each TR NO\textsubscript{X} Ozone Season allowance from the transferor account to the transferee account as specified in the transfer.

(b) A TR NO\textsubscript{X} Ozone Season allowance transfer to or from a compliance account that is submitted for recordation after the allowance transfer deadline for a control period and that includes any TR NO\textsubscript{X} Ozone Season allowances allocated for any control period before such allowance transfer deadline will not be recorded until after the Administrator completes the deductions from such compliance account under §97.524 for the control period immediately before such allowance transfer deadline.

(c) Where a TR NO\textsubscript{X} Ozone Season allowance transfer is not correctly submitted under §97.522, the Administrator will not record such transfer.

(d) Within 5 business days of recordation of a TR NO\textsubscript{X} Ozone Season allowance transfer under paragraphs (a) and (b) of the section, the Administrator will notify the authorized account representatives of both the transferor and transferee accounts.

(e) Within 10 business days of receipt of a TR NO\textsubscript{X} Ozone Season allowance transfer that is not correctly submitted under §97.522, the Administrator will notify the authorized account representatives of both accounts subject to the transfer of:

(1) A decision not to record the transfer; and

(2) The reasons for such non-recordation.
§ 97.524 Compliance with TR NOx Ozone Season emissions limitation.

(a) Availability for deduction for compliance. TR NOx Ozone Season allowances are available to be deducted for compliance with a source’s TR NOx Ozone Season emissions limitation for a control period in a given year only if the TR NOx Ozone Season allowances:

(1) Were allocated for such control period or a control period in a prior year; and

(2) Are held in the source’s compliance account as of the allowance transfer deadline for such control period.

(b) Deductions for compliance. After the recordation, in accordance with §97.523, of TR NOx Ozone Season allowances submitted by the allowance transfer deadline for a control period in a given year, the Administrator will deduct from each source’s compliance account TR NOx Ozone Season allowances available under paragraph (a) of this section in order to determine whether the source meets the TR NOx Ozone Season emissions limitation for such control period, as follows:

(1) Until the amount of TR NOx Ozone Season allowances deducted equals the number of tons of total NOx emissions from all TR NOx Ozone Season units at the source for such control period; or

(2) If there are insufficient TR NOx Ozone Season allowances to complete the deductions in paragraph (b)(1) of this section, until no more TR NOx Ozone Season allowances available under paragraph (a) of this section remain in the compliance account.

(c)(1) Identification of TR NOx Ozone Season allowances by serial number. The authorized account representative for a source’s compliance account may request that specific TR NOx Ozone Season allowances, identified by serial number, in the compliance account be deducted for emissions or excess emissions for a control period in a given year in accordance with paragraph (b) or (d) of this section. In order to be complete, such request shall be submitted to the Administrator by the allowance transfer deadline for such control period and include, in a format prescribed by the Administrator, the identification of the TR NOx Ozone Season source and the appropriate serial numbers.

(2) First-in, first-out. The Administrator will deduct TR NOx Ozone Season allowances under paragraph (b) or (d) of this section from the source’s compliance account in accordance with a complete request under paragraph (c)(1) of this section or, in the absence of such request or in the case of identification of an insufficient amount of TR NOx Ozone Season allowances in such request, on a first-in, first-out accounting basis in the following order:

(i) Any TR NOx Ozone Season allowances that were allocated to the units at the source and not transferred out of the compliance account, in the order of recordation; and then

(ii) Any TR NOx Ozone Season allowances that were allocated to any unit and transferred to and recorded in the compliance account pursuant to this subpart, in the order of recordation.

(d) Deductions for excess emissions. After making the deductions for compliance under paragraph (b) of this section for a control period in a year in which the TR NOx Ozone Season source has excess emissions, the Administrator will deduct from the source’s compliance account an amount of TR NOx Ozone Season allowances, allocated for a control period in a prior year or the control period in the year of the excess emissions or in the immediately following year, equal to twice the number of tons of the source’s excess emissions.

(e) Recordation of deductions. The Administrator will record in the appropriate compliance account all deductions from such an account under paragraphs (b) and (d) of this section.

§ 97.525 Compliance with TR NOx Ozone Season assurance provisions.

(a) Availability for deduction. TR NOx Ozone Season allowances are available to be deducted for compliance with the TR NOx Ozone Season assurance provisions for a control period in a given year by the owners and operators of a group of one or more TR NOx Ozone Season sources and units in a State (and Indian country within the borders of such State) only if the TR NOx Ozone Season allowances:
(1) Were allocated for a control period in a prior year or the control period in the given year or in the immediately following year; and

(2) Are held in the assurance account, established by the Administrator for such owners and operators of such group of TR NOX Ozone Season sources and units in such State (and Indian country within the borders of such State) under paragraph (b)(3) of this section, as of the deadline established in paragraph (b)(4) of this section.

(b) Deductions for compliance. The Administrator will deduct TR NOX Ozone Season allowances available under paragraph (a) of this section for compliance with the TR NOX Ozone Season assurance provisions for a State for a control period in a given year in accordance with the following procedures:

(1) By June 1, 2015 and June 1 of each year thereafter, the Administrator will:

(i) Calculate, for each State (and Indian country within the borders of such State), the total NOX emissions from all TR NOX Ozone Season units at TR NOX Ozone Season sources in the State (and Indian country within the borders of such State) during the control period in the year before the year of this calculation deadline and the amount, if any, by which such total NOX emissions exceed the State assurance level as described in §97.506(c)(2)(iii); and

(ii) Promulgate a notice of data availability of the results of the calculations required in paragraph (b)(1)(i) of this section, including separate calculations of the NOX emissions from each TR NOX Ozone Season source.

(2) For each notice of data availability required in paragraph (b)(1)(ii) of this section and for any State (and Indian country within the borders of such State) identified in such notice as having TR NOX Ozone Season units with total NOX emissions exceeding the State assurance level for a control period in a given year, as described in §97.506(c)(2)(iii):

(i) By July 1 immediately after the promulgation of such notice, the designated representative of each TR NOX Ozone Season source in each such State (and Indian country within the borders of such State) shall submit a statement, in a format prescribed by the Administrator, providing for each TR NOX Ozone Season unit (if any) at the source that operates during, but is not allocated an amount of TR NOX Ozone Season allowances for, such control period, the unit’s allowable NOX emission rate for such control period and, if such rate is expressed in lb per mmBtu, the unit’s heat rate.

(ii) By August 1 immediately after the promulgation of such notice, the Administrator will calculate, for each such State (and Indian country within the borders of such State) and such control period and each common designated representative for such control period for a group of one or more TR NOX Ozone Season sources and units in the State (and Indian country within the borders of such State), the common designated representative’s share of the total NOX emissions from all TR NOX Ozone Season units at TR NOX Ozone Season sources in the State (and Indian country within the borders of such State), the common designated representative’s assurance level, and the amount (if any) of TR NOX Ozone Season allowances that the owners and operators of such group of sources and units must hold in accordance with the calculation formula in §97.506(c)(2)(i) and will promulgate a notice of data availability of the results of these calculations.

(iii) The Administrator will provide an opportunity for submission of objections to the calculations referenced by the notice of data availability required in paragraph (b)(2)(ii) of this section and the calculations referenced by the relevant notice of data availability required in paragraph (b)(1)(i) of this section.

(A) Objections shall be submitted by the deadline specified in such notice and shall be limited to addressing whether the calculations referenced in the relevant notice required under paragraph (b)(1)(ii) of this section and referenced in the notice required under paragraph (b)(2)(ii) of this section are in accordance with §97.506(c)(2)(iii), §§97.506(b) and 97.530 through 97.535, the definitions of “common designated representative”, “common designated representative’s assurance level”, and “common designated representative’s
share’’ in §97.502, and the calculation formula in §97.506(c)(2)(i).

(B) The Administrator will adjust the calculations to the extent necessary to ensure that they are in accordance with the provisions referenced in paragraph (b)(2)(iii)(A) of this section. By October 1 immediately after the promulgation of such notice, the Administrator will promulgate a notice of data availability of any adjustments that the Administrator determines to be necessary and the reasons for accepting or rejecting any objections submitted in accordance with paragraph (b)(2)(iii)(A) of this section.

(3) For any State (and Indian country within the borders of such State) referenced in each notice of data availability required in paragraph (b)(2)(iii)(B) of this section as having TR NOX Ozone Season units with total NOX emissions exceeding the State assurance level for a control period in a given year, the Administrator will establish one assurance account for each set of owners and operators referenced, in the notice of data availability required under paragraph (b)(2)(iii)(B) of this section, as all of the owners and operators of a group of TR NOX Ozone Season sources and units in the State (and Indian country within the borders of such State) having a common designated representative for such control period and as being required to hold TR NOX Ozone Season allowances.

(4)(i) As of midnight of November 1 immediately after the promulgation of each notice of data availability required in paragraph (b)(2)(iii)(B) of this section, the owners and operators described in paragraph (b)(3) of this section shall hold in the assurance account established for the them and for the appropriate TR NOX Ozone Season sources, TR NOX Ozone Season units, and State (and Indian country within the borders of such State) as calculated by the Administrator and referenced in the notice required in paragraph (b)(2)(iii)(B) of this section.

(ii) Notwithstanding the allowance-holding deadline specified in paragraph (b)(4)(i) of this section, if November 1 is not a business day, then such allowance-holding deadline shall be midnight of the first business day thereafter.

(5) After November 1 (or the date described in paragraph (b)(4)(ii) of this section) immediately after the promulgation of each notice of data availability required in paragraph (b)(2)(iii)(B) of this section and after the recordation, in accordance with §97.523, of TR NOX Ozone Season allowance transfers submitted by midnight of such date, the Administrator will determine whether the owners and operators described in paragraph (b)(3) of this section hold, in the assurance account for the appropriate TR NOX Ozone Season sources, TR NOX Ozone Season units, and State (and Indian country within the borders of such State) established under paragraph (b)(3) of this section, the amount of TR NOX Ozone Season allowances available under paragraph (a) of this section that the owners and operators are required to hold with regard to such sources, units, and State (and Indian country within the borders of such State) as calculated by the Administrator and referenced in the notice required in paragraph (b)(2)(iii)(B) of this section.

(6) Notwithstanding any other provision of this subpart and any revision, made by or submitted to the Administrator after the promulgation of the notice of data availability required in paragraph (b)(2)(iii)(B) of this section for a control period in a given year, of any data used in making the calculations referenced in such notice, the amounts of TR NOX Ozone Season allowances that the owners and operators are required to hold in accordance with §97.506(c)(2)(i) for such control period shall continue to be such amounts as calculated by the Administrator and referenced in such notice required in paragraph (b)(2)(iii)(B) of this section, except as follows:

(i) If any such data are revised by the Administrator as a result of a decision in or settlement of litigation concerning such data on appeal under part 78 of this chapter of such notice, or on appeal under section 307 of the Clean Air Act, the Administrator will promulgate a notice of data availability of any adjustments that the Administrator determines to be necessary and the reasons for accepting or rejecting any objections submitted in accordance with paragraph (b)(2)(iii)(A) of this section.

(ii) Notwithstanding any other provision of this subpart and any revision, made by or submitted to the Administrator after the promulgation of the notice of data availability required in paragraph (b)(2)(iii)(B) of this section for a control period in a given year, of any data used in making the calculations referenced in such notice, the amounts of TR NOX Ozone Season allowances that the owners and operators are required to hold in accordance with §97.506(c)(2)(i) for such control period shall continue to be such amounts as calculated by the Administrator and referenced in such notice required in paragraph (b)(2)(iii)(B) of this section, except as follows:

(i) If any such data are revised by the Administrator as a result of a decision in or settlement of litigation concerning such data on appeal under part 78 of this chapter of such notice, or on appeal under section 307 of the Clean Air Act, the Administrator will promulgate a notice of data availability of any adjustments that the Administrator determines to be necessary and the reasons for accepting or rejecting any objections submitted in accordance with paragraph (b)(2)(iii)(A) of this section.

(ii) Notwithstanding the allowance-holding deadline specified in paragraph (b)(4)(i) of this section, if November 1 is not a business day, then such allowance-holding deadline shall be midnight of the first business day thereafter.

(5) After November 1 (or the date described in paragraph (b)(4)(ii) of this section) immediately after the promulgation of each notice of data availability required in paragraph (b)(2)(iii)(B) of this section and after the recordation, in accordance with §97.523, of TR NOX Ozone Season allowance transfers submitted by midnight of such date, the Administrator will determine whether the owners and operators described in paragraph (b)(3) of this section hold, in the assurance account for the appropriate TR NOX Ozone Season sources, TR NOX Ozone Season units, and State (and Indian country within the borders of such State) established under paragraph (b)(3) of this section, the amount of TR NOX Ozone Season allowances available under paragraph (a) of this section that the owners and operators are required to hold with regard to such sources, units, and State (and Indian country within the borders of such State) as calculated by the Administrator and referenced in the notice required in paragraph (b)(2)(iii)(B) of this section.

(6) Notwithstanding any other provision of this subpart and any revision, made by or submitted to the Administrator after the promulgation of the notice of data availability required in paragraph (b)(2)(iii)(B) of this section for a control period in a given year, of any data used in making the calculations referenced in such notice, the amounts of TR NOX Ozone Season allowances that the owners and operators are required to hold in accordance with §97.506(c)(2)(i) for such control period shall continue to be such amounts as calculated by the Administrator and referenced in such notice required in paragraph (b)(2)(iii)(B) of this section, except as follows:

(i) If any such data are revised by the Administrator as a result of a decision in or settlement of litigation concerning such data on appeal under part 78 of this chapter of such notice, or on appeal under section 307 of the Clean Air Act, the Administrator will promulgate a notice of data availability of any adjustments that the Administrator determines to be necessary and the reasons for accepting or rejecting any objections submitted in accordance with paragraph (b)(2)(iii)(A) of this section.
Air Act of a decision rendered under part 78 of this chapter on appeal of such notice, then the Administrator will use the data as so revised to recalculate the amounts of TR NOX Ozone Season allowances that owners and operators are required to hold in accordance with the calculation formula in §97.506(c)(2)(i) for such control period with regard to the TR NOX Ozone Season sources, TR NOX Ozone Season units, and State (and Indian country within the borders of such State) involved—

(A) Where the amount of TR NOX Ozone Season allowances that the owners and operators are required to hold increases as a result of the use of all such revised data, the Administrator will establish a new, reasonable deadline on which the owners and operators shall hold the additional amount of TR NOX Ozone Season allowances in the assurance account established by the Administrator for the appropriate TR NOX Ozone Season sources, TR NOX Ozone Season units, and State (and Indian country within the borders of such State) under paragraph (b)(3) of this section. The owners’ and operators’ failure to hold such additional amount, as required, before the new deadline shall not be a violation of the Clean Air Act. The owners’ and operators’ failure to hold such additional amount, as required, after the new deadline shall be a violation of the Clean Air Act. Each TR NOX Ozone Season allowance that the owners and operators fail to hold as required as of the new deadline, and each day in such control period, shall be a separate violation of the Clean Air Act.

(B) For the owners and operators for which the amount of TR NOX Ozone Season allowances required to be held decreases as a result of the use of all such revised data, the Administrator will record, in all accounts from which TR NOX Ozone Season allowances were transferred by such owners and operators for such control period to the assurance account established by the Administrator for the appropriate TR NOX Ozone Season sources, TR NOX Ozone Season units, and State (and Indian country within the borders of such State) involved, provided that such litigation was initiated no later than 30 days after promulgation of such notice required in paragraph (b)(2)(iii)(B) of this section.

(i) If the revised data are used by the owners and operators of a TR NOX Ozone Season source and TR NOX Ozone Season unit whose designated representative submitted such data under paragraph (b)(2)(i) of this section, as a result of a decision in or settlement of litigation concerning such submission, then the Administrator will use the data as so revised to recalculate the amounts of TR NOX Ozone Season allowances that owners and operators are required to hold in accordance with the calculation formula in §97.506(c)(2)(i) for such control period with regard to the TR NOX Ozone Season sources, TR NOX Ozone Season units, and State (and Indian country within the borders of such State) involved, provided that such litigation was initiated no later than 30 days after promulgation of such notice required in paragraph (b)(2)(iii)(B) of this section.

(ii) If any such data are revised by the owners and operators of a TR NOX Ozone Season source and TR NOX Ozone Season unit whose designated representative submitted such data under paragraph (b)(2)(i) of this section, as a result of a decision in or settlement of litigation concerning such submission, then the Administrator will use the data as so revised to recalculate the amounts of TR NOX Ozone Season allowances that owners and operators are required to hold in accordance with the calculation formula in §97.506(c)(2)(i) for such control period with regard to the TR NOX Ozone Season sources, TR NOX Ozone Season units, and State (and Indian country within the borders of such State) involved, provided that such litigation was initiated no later than 30 days after promulgation of such notice required in paragraph (b)(2)(iii)(B) of this section.

(iii) If the revised data are used to recalculate, in accordance with paragraphs (b)(6)(i) and (ii) of this section, the amount of TR NOX Ozone Season allowances that the owners and operators are required to hold for such control period with regard to the TR NOX Ozone Season sources, TR NOX Ozone Season units, and State (and Indian country within the borders of such State) involved—

(A) Where the amount of TR NOX Ozone Season allowances that the owners and operators are required to hold increases as a result of the use of all such revised data, the Administrator will establish a new, reasonable deadline on which the owners and operators shall hold the additional amount of TR NOX Ozone Season allowances in the assurance account established by the Administrator for the appropriate TR NOX Ozone Season sources, TR NOX Ozone Season units, and State (and Indian country within the borders of such State) under paragraph (b)(3) of this section. The owners’ and operators’ failure to hold such additional amount, as required, before the new deadline shall not be a violation of the Clean Air Act. The owners’ and operators’ failure to hold such additional amount, as required, after the new deadline shall be a violation of the Clean Air Act. Each TR NOX Ozone Season allowance that the owners and operators fail to hold as required as of the new deadline, and each day in such control period, shall be a separate violation of the Clean Air Act.

(B) For the owners and operators for which the amount of TR NOX Ozone Season allowances required to be held decreases as a result of the use of all such revised data, the Administrator will record, in all accounts from which TR NOX Ozone Season allowances were transferred by such owners and operators for such control period to the assurance account established by the Administrator for the appropriate TR NOX Ozone Season sources, TR NOX Ozone Season units, and State (and Indian country within the borders of such State) under paragraph (b)(3) of this section, a total amount of the TR NOX Ozone Season allowances held in such assurance account equal to the amount of the decrease. If TR NOX Ozone Season allowances were transferred to such assurance account from more than one account, the amount of TR NOX Ozone Season allowances recorded in each such transferor account will be in proportion to the percentage of the total amount of TR NOX Ozone Season allowances transferred to such assurance account for such control period from such transferor account.

(C) Each TR NOX Ozone Season allowance held under paragraph (b)(6)(iii)(A)
§ 97.526 Banking.

(a) A TR NO\textsubscript{X} Ozone Season allowance may be banked for future use or transfer in a compliance account or a general account in accordance with paragraph (b) of this section.

(b) Any TR NO\textsubscript{X} Ozone Season allowance that is held in a compliance account or a general account will remain in such account unless and until the TR NO\textsubscript{X} Ozone Season allowance is deducted or transferred under §97.511(c), §97.523, §97.524, §97.525, §97.527, or §97.528.

§ 97.527 Account error.

The Administrator may, at his or her sole discretion and on his or her own motion, correct any error in any Allowance Management System account. Within 10 business days of making such correction, the Administrator will notify the authorized account representative for the account.

§ 97.528 Administrator’s action on submissions.

(a) The Administrator may review and conduct independent audits concerning any submission under the TR NO\textsubscript{X} Ozone Season Trading Program and make appropriate adjustments of the information in the submission.

(b) The Administrator may deduct TR NO\textsubscript{X} Ozone Season allowances from or transfer TR NO\textsubscript{X} Ozone Season allowances to a compliance account or an assurance account, based on the information in a submission, as adjusted under paragraph (a)(1) of this section, and record such deductions and transfers.

§ 97.529 [Reserved]

§ 97.530 General monitoring, recordkeeping, and reporting requirements.

The owners and operators, and to the extent applicable, the designated representative, of a TR NO\textsubscript{X} Ozone Season unit, shall comply with the monitoring, recordkeeping, and reporting requirements as provided in this subpart and subpart H of part 75 of this chapter. For purposes of applying such requirements, the definitions in §97.502 and in §72.2 of this chapter shall apply, the terms ‘‘affected unit,’’ ‘‘designated representative,’’ and ‘‘continuous emission monitoring system’’ (or ‘’CEMS’’) in part 75 of this chapter shall be deemed to refer to the terms ‘‘TR NO\textsubscript{X} Ozone Season unit,’’ ‘‘designated representative,’’ and ‘‘continuous emission monitoring system’’ (or ‘’CEMS’’) respectively as defined in §97.502, and the term ‘‘newly affected unit’’ shall be deemed to mean ‘‘newly affected TR NO\textsubscript{X} Ozone Season unit’’. The owner or operator of a unit that is not a TR NO\textsubscript{X} Ozone Season unit but that is monitored under §75.72(b)(2)(ii) of this chapter shall comply with the same monitoring, recordkeeping, and reporting requirements as a TR NO\textsubscript{X} Ozone Season unit.

(a) Requirements for installation, certification, and data accounting. The owner or operator of each TR NO\textsubscript{X} Ozone Season unit shall:

(1) Install all monitoring systems required under this subpart for monitoring NO\textsubscript{X} mass emissions and individual unit heat input (including all systems required to monitor NO\textsubscript{X} emission rate, NO\textsubscript{X} concentration, stack gas moisture content, stack gas flow rate, CO\textsubscript{2} or O\textsubscript{2} concentration, and fuel flow rate, as applicable, in accordance with §§75.71 and 75.72 of this chapter);

(2) Successfully complete all certification tests required under §97.331 and meet all other requirements of this subpart and part 75 of this chapter applicable to the monitoring systems under paragraph (a)(1) of this section; and

(3) Record, report, and quality-assure the data from the monitoring systems under paragraph (a)(1) of this section.
(b) Compliance deadlines. Except as provided in paragraph (e) of this section, the owner or operator shall meet the monitoring system certification and other requirements of paragraphs (a)(1) and (2) of this section on or before the following dates and shall record, report, and quality-assure the data from the monitoring systems under paragraph (a)(1) of this section on and after the following dates.

(1) For the owner or operator of a TR NOx Ozone Season unit that commences commercial operation before July 1, 2011, May 1, 2012.

(2) For the owner or operator of a TR NOx Ozone Season unit that commences commercial operation on or after July 1, 2011 and that reports on an annual basis under §97.534(d), by the later of the following:
   (i) 180 calendar days after the date on which the unit commences commercial operation; or
   (ii) May 1, 2012.

(3) For the owner or operator of a TR NOx Ozone Season unit that commences commercial operation on or after July 1, 2011 and that reports on a control period basis under §97.534(d)(2), by the following date:
   (i) 180 calendar days after the date on which the unit commences commercial operation; or
   (ii) If the compliance date under paragraph (b)(3)(i) of this section is not during a control period, May 1 immediately after the compliance date under paragraph (b)(3)(i) of this section.

(4) The owner or operator of a TR NOx Ozone Season unit for which construction of a new stack or flue or installation of add-on NOx emission controls is completed after the applicable deadline under paragraph (b)(1), (2), or (3) of this section shall meet the requirements of §§75.4(e)(1) through (e)(4) of this chapter, except that:
   (i) Such requirements shall apply to the monitoring systems required under §97.530 through §97.535, rather than the monitoring systems required under part 75 of this chapter;
   (ii) NOx emission rate, NOx concentration, stack gas moisture content, stack gas volumetric flow rate, and O2 or CO2 concentration data shall be determined and reported, rather than the data listed in §75.4(e)(2) of this chapter; and
   (iii) Any petition for another procedure under §75.4(e)(2) of this chapter shall be submitted under §97.535, rather than §75.66.

(c) Reporting data. The owner or operator of a TR NOx Ozone Season unit that does not meet the applicable compliance date set forth in paragraph (b) of this section for any monitoring system under paragraph (a)(1) of this section shall, for each such monitoring system, determine, record, and report maximum potential (or, as appropriate, minimum potential) values for NOx concentration, NOx emission rate, stack gas flow rate, stack gas moisture content, fuel flow rate, and any other parameters required to determine NOx mass emissions and heat input in accordance with §75.31(b)(2) or (c)(3) of this chapter, section 2.4 of appendix D to part 75 of this chapter, or section 2.5 of appendix E to part 75 of this chapter, as applicable.

(d) Prohibitions. (1) No owner or operator of a TR NOx Ozone Season unit shall use any alternative monitoring system, alternative reference method, or any other alternative to any requirement of this subpart without having obtained prior written approval in accordance with §97.535.

(2) No owner or operator of a TR NOx Ozone Season unit shall operate the unit so as to discharge, or allow to be discharged, NOx to the atmosphere without accounting for all such NOx in accordance with the applicable provisions of this subpart and part 75 of this chapter.

(3) No owner or operator of a TR NOx Ozone Season unit shall disrupt the continuous emission monitoring system, any portion thereof, or any other approved emission monitoring method, and thereby avoid monitoring and recording NOx mass discharged into the atmosphere or heat input, except for periods of recertification or periods when calibration, quality assurance testing, or maintenance is performed in accordance with the applicable provisions of this subpart and part 75 of this chapter.
§ 97.531 Initial monitoring system certification and recertification procedures.

(a) The owner or operator of a TR NOX Ozone Season unit shall be exempt from the initial certification requirements of this section for a monitoring system under §97.530(a)(1) if the following conditions are met:

(1) The monitoring system has been previously certified in accordance with part 75 of this chapter; and

(2) The applicable quality-assurance and quality-control requirements of §75.21 of this chapter and appendices B, D, and E to part 75 of this chapter are fully met for the certified monitoring system described in paragraph (a)(1) of this section.

(b) The recertification provisions of this section shall apply to a monitoring system under §97.530(a)(1) that is exempt from initial certification requirements under paragraph (a) of this section.

(c) If the Administrator has previously approved a petition under §75.17(a) or (b) of this chapter for apportioning the NOX emission rate measured in a common stack or a petition under §75.66 of this chapter for an alternative to a requirement in §75.12 or §75.17 of this chapter, the designated representative shall resubmit the petition to the Administrator under §97.535 to determine whether the approval applies under the TR NOX Ozone Season Trading Program.

(d) Except as provided in paragraph (a) of this section, the owner or operator of a TR NOX Ozone Season unit shall comply with the following initial certification and recertification procedures for a continuous monitoring system (i.e., a continuous emission monitoring system and an excepted monitoring system under appendices D and E to part 75 of this chapter) under §97.530(a)(1). The owner or operator of a unit that qualifies to use the low mass emissions excepted monitoring methodology under §75.19 of this chapter or that qualifies to use an alternative monitoring system under subpart E of part 75 of this chapter shall comply with the procedures in paragraph (e) or (f) of this section respectively.

(1) Requirements for initial certification. The owner or operator shall ensure that each continuous monitoring system under §97.530(a)(1) (including the automated data acquisition and handling system) successfully completes all of the initial certification testing required under §75.20 of this chapter by the applicable deadline in §97.530(b). In addition, whenever the owner or operator installs a monitoring system to meet the requirements of this subpart in a location where no such monitoring system was previously installed, initial certification in accordance with §75.20 of this chapter is required.

(2) Requirements for recertification. Whenever the owner or operator makes a replacement, modification, or change in any certified continuous emission monitoring system under §97.530(a)(1) that may significantly affect the ability of the system to accurately measure or record NOX mass emissions or heat input rate or to meet the quality-
assurance and quality-control requirements of §75.21 of this chapter or appendix B to part 75 of this chapter, the owner or operator shall recertify the monitoring system in accordance with §75.20(b) of this chapter. Furthermore, whenever the owner or operator makes a replacement, modification, or change to the flue gas handling system or the unit’s operation that may significantly change the stack flow or concentration profile, the owner or operator shall recertify each continuous emission monitoring system whose accuracy is potentially affected by the change, in accordance with §75.20(b) of this chapter. Examples of changes to a continuous emission monitoring system that require recertification include: replacement of the analyzer, complete replacement of an existing continuous emission monitoring system, or change in location or orientation of the sampling probe or site. Any fuel flowmeter system, and any excepted NOX monitoring system under appendix E to part 75 of this chapter, are subject to the recertification requirements in §75.20(g)(6) of this chapter.

(3) Approval process for initial certification and recertification. For initial certification of a continuous monitoring system under §97.530(a)(1), paragraphs (d)(3)(i) through (v) of this section apply. For recertifications of such monitoring systems, paragraphs (d)(3)(i) through (iv) of this section and the procedures in §§75.20(b)(6) and (g)(7) of this chapter (in lieu of the procedures in paragraph (d)(3)(v) of this section) apply, provided that in applying paragraphs (d)(3)(i) through (iv) of this section, the words “certification” and “initial certification” are replaced by the word “recertification” and the word “certified” is replaced by with the word “recertified”.

(i) Notification of certification. The designated representative shall submit to the appropriate EPA Regional Office and the Administrator written notice of the dates of certification testing, in accordance with §97.533.

(ii) Certification application. The designated representative shall submit to the Administrator a certification application for each monitoring system. A complete certification application shall include the information specified in §75.68 of this chapter.

(iii) Provisional certification date. The provisional certification date for a monitoring system shall be determined in accordance with §75.20(a)(3) of this chapter. A provisionally certified monitoring system may be used under the TR NOX Ozone Season Trading Program for a period not to exceed 120 days after receipt by the Administrator of the complete certification application for the monitoring system under paragraph (d)(3)(i) of this section. Data measured and recorded by the provisionally certified monitoring system, in accordance with the requirements of part 75 of this chapter, will be considered valid quality-assured data (retroactive to the date and time of provisional certification), provided that the Administrator does not invalidate the provisional certification by issuing a notice of disapproval within 120 days of the date of receipt of the complete certification application by the Administrator.

(iv) Certification application approval process. The Administrator will issue a written notice of approval or disapproval of the certification application to the owner or operator within 120 days of receipt of the complete certification application under paragraph (d)(3)(ii) of this section. In the event the Administrator does not issue such a notice within such 120-day period, each monitoring system that meets the applicable performance requirements of part 75 of this chapter and is included in the certification application will be deemed certified for use under the TR NOX Ozone Season Trading Program.

(A) Approval notice. If the certification application is complete and shows that each monitoring system meets the applicable performance requirements of part 75 of this chapter, then the Administrator will issue a written notice of approval of the certification application within 120 days of receipt.

(B) Incomplete application notice. If the certification application is not complete, then the Administrator will issue a written notice of incompleteness that sets a reasonable date by which the designated representative
must submit the additional information required to complete the certification application. If the designated representative does not comply with the notice of incompleteness by the specified date, then the Administrator may issue a notice of disapproval under paragraph (d)(3)(iv)(B) of this section.

(C) Disapproval notice. If the certification application shows that any monitoring system does not meet the performance requirements of part 75 of this chapter or if the certification application is incomplete and the requirement for disapproval under paragraph (d)(3)(iv)(B) of this section is met, then the Administrator will issue a written notice of disapproval of the certification application. Upon issuance of such notice of disapproval, the provisional certification is invalidated by the Administrator and the data measured and recorded by each uncertified monitoring system shall not be considered valid quality-assured data beginning with the date and hour of provisional certification (as defined under §75.20(a)(3) of this chapter).

(D) Audit decertification. The Administrator may issue a notice of disapproval of the certification status of a monitor in accordance with §97.532(b).

(v) Procedures for loss of certification. If the Administrator issues a notice of disapproval of a certification application under paragraph (d)(3)(iv)(C) of this section or a notice of disapproval of certification status under paragraph (d)(3)(iv)(D) of this section, then:

(A) The owner or operator shall substitute the following values, for each disapproved monitoring system, for each hour of unit operation during the period of invalid data specified under §75.20(a)(4)(iii), §75.20(g)(7), or §75.31(e) of this chapter and continuing until the applicable date and hour specified under §75.20(a)(5)(i) or (g)(7) of this chapter:

(1) For a disapproved NOX emission rate (i.e., NOX-diluent) system, the maximum potential NOX emission rate, as defined in §72.2 of this chapter.

(2) For a disapproved NOX pollutant concentration monitor and disapproved flow monitor, respectively, the maximum potential concentration of NOX and the maximum potential flow rate, as defined in sections 2.1.2.1 and 2.1.4.1 of appendix A to part 75 of this chapter.

(3) For a disapproved moisture monitoring system and disapproved diluent gas monitoring system, respectively, the minimum potential moisture percentage and either the maximum potential CO2 concentration or the minimum potential O2 concentration (as applicable), as defined in sections 2.1.5, 2.1.3.1, and 2.1.3.2 of appendix A to part 75 of this chapter.

(4) For a disapproved fuel flowmeter system, the maximum potential fuel flow rate, as defined in section 2.4.2.1 of appendix D to part 75 of this chapter.

(5) For a disapproved excepted NOX monitoring system under appendix E to part 75 of this chapter, the fuel-specific maximum potential NOX emission rate, as defined in §72.2 of this chapter.

(B) The designated representative shall submit a notification of certification retest dates and a new certification application in accordance with paragraphs (d)(3)(i) and (ii) of this section.

(C) The owner or operator shall repeat all certification tests or other requirements that were failed by the monitoring system, as indicated in the Administrator’s notice of disapproval, no later than 30 unit operating days after the date of issuance of the notice of disapproval.

(e) The owner or operator of a unit qualified to use the low mass emissions (LME) excepted methodology under §75.19 of this chapter shall meet the applicable certification and recertification requirements in §§75.19(a)(2) and 75.20(h) of this chapter. If the owner or operator of such a unit elects to certify a fuel flowmeter system for heat input determination, the owner or operator shall also meet the certification and recertification requirements in §75.20(g) of this chapter.

(f) The designated representative of each unit for which the owner or operator intends to use an alternative monitoring system approved by the Administrator under subpart E of part 75 of this chapter shall comply with the applicable notification and application procedures of §75.20(f) of this chapter.
§ 97.532 Monitoring system out-of-control periods.

(a) General provisions. Whenever any monitoring system fails to meet the quality-assurance and quality-control requirements or data validation requirements of part 75 of this chapter, data shall be substituted using the applicable missing data procedures in subpart D or subpart H of, or appendix D or appendix E to, part 75 of this chapter.

(b) Audit decertification. Whenever both an audit of a monitoring system and a review of the initial certification or recertification application reveal that any monitoring system should not have been certified or recertified because it did not meet a particular performance specification or other requirement under §97.531 or the applicable provisions of part 75 of this chapter, both at the time of the initial certification or recertification application submission and at the time of the audit, the Administrator will issue a notice of disapproval of the certification status of such monitoring system. For the purposes of this paragraph, an audit shall be either a field audit or an audit of any information submitted to the Administrator or any State or permitting authority. By issuing the notice of disapproval, the Administrator revokes prospectively the certification status of the monitoring system. The data measured and recorded by the monitoring system shall not be considered valid quality-assured data from the date of issuance of the notification of the revoked certification status until the date and time that the owner or operator completes subsequently approved initial certification or recertification tests for the monitoring system. The data measured and recorded by the monitoring system shall not be considered valid quality-assured data from the date of issuance of the notification of the revoked certification status until the date and time that the owner or operator completes subsequently approved initial certification or recertification tests for the monitoring system. The owner or operator shall follow the applicable initial certification or recertification procedures in §97.531 for each disapproved monitoring system.

§ 97.533 Notifications concerning monitoring.

The designated representative of a TR NOX Ozone Season unit shall submit written notice to the Administrator in accordance with §75.61 of this chapter.

§ 97.534 Recordkeeping and reporting.

(a) General provisions. The designated representative shall comply with all recordkeeping and reporting requirements in paragraphs (b) through (e) of this section, the applicable recordkeeping and reporting requirements under §75.73 of this chapter, and the requirements of §97.514(a).

(b) Monitoring plans. The owner or operator of a TR NOX Ozone Season unit shall comply with requirements of §75.73(c) and (e) of this chapter.

(c) Certification applications. The designated representative shall submit an application to the Administrator within 45 days after completing all initial certification or recertification tests required under §97.531, including the information required under §75.63 of this chapter.

(d) Quarterly reports. The designated representative shall submit quarterly reports, as follows:

(1) If the TR NOX Ozone Season unit is subject to the Acid Rain Program or a TR NOX Annual emissions limitation or if the owner or operator of such unit chooses to report on an annual basis under this subpart, the designated representative shall meet the requirements of subpart H of part 75 of this chapter (concerning monitoring of NOX mass emissions) for such unit for the entire year and shall report the NOX mass emissions data and heat input data for such unit, in an electronic quarterly report in a format prescribed by the Administrator, for each calendar quarter beginning with:

(i) For a unit that commences commercial operation before July 1, 2011, the calendar quarter covering May 1, 2012 through June 30, 2012; or

(ii) For a unit that commences commercial operation on or after July 1, 2011, the calendar quarter corresponding to the earlier of the date of provisional certification or the applicable deadline for initial certification under §97.530(b), unless that quarter is the third or fourth quarter of 2011 or the first quarter of 2012, in which case reporting shall commence in the quarter covering May 1, 2012 through June 30, 2012.

(2) If the TR NOX Ozone Season unit is not subject to the Acid Rain Program or a TR NOX Annual emissions
§ 97.534  Compliance certification. The designated representative shall submit to the Administrator a compliance certification (in a format prescribed by the Administrator) in support of each quarterly report based on reasonable inquiry of those persons with primary responsibility for ensuring that all of the unit’s emissions are correctly and fully monitored. The certification shall state that:

(i) The monitoring data submitted were recorded in accordance with the applicable requirements of this subpart and part 75 of this chapter, including the quality assurance procedures and specifications;

(ii) For a unit with add-on NOX emission controls and for all hours where NOX data are substituted in accordance with §75.34(a)(1) of this chapter, the quarterly report meets the requirements of this subpart and part 75 of this chapter, including the requirement to use substitute data.

(i) The Administrator will notify the designated representative of any determination that the quarterly report fails to meet any such requirements and specify in such notification any corrections that the Administrator believes are necessary to make through resubmission of the quarterly report and a reasonable time period within which the designated representative must respond. Upon request by the designated representative, the Administrator may specify reasonable extensions of such time period. Within the time period (including any such extensions) specified by the Administrator, the designated representative shall resubmit the quarterly report with the corrections specified by the Administrator, except to the extent the designated representative provides information demonstrating that a specified correction is not necessary because the quarterly report already meets the requirements of this subpart and part 75 of this chapter that are relevant to the specified correction.

(e) Compliance certification. The designated representative shall submit to the Administrator a compliance certification (in a format prescribed by the Administrator) in support of each quarterly report based on reasonable inquiry of those persons with primary responsibility for ensuring that all of the unit’s emissions are correctly and fully monitored. The certification shall state that:

(1) The monitoring data submitted were recorded in accordance with the applicable requirements of this subpart and part 75 of this chapter, including the quality assurance procedures and specifications;

(2) For a unit with add-on NOX emission controls and for all hours where NOX data are substituted in accordance with §75.34(a)(1) of this chapter, the

limitation, then the designated representative shall either:

(i) Meet the requirements of subpart H of part 75 (concerning monitoring of NOX mass emissions) for such unit for the entire year and report the NOX mass emissions data and heat input data for such unit in accordance with paragraph (d)(1) of this section; or

(ii) Meet the requirements of subpart H of part 75 for the control period (including the requirements in §75.74(c) of this chapter) and report NOX mass emissions data and heat input data (including the data described in §75.74(c)(6) of this chapter) for such unit only for the control period of each year and report, in an electronic quarterly report in a format prescribed by the Administrator, for each calendar quarter beginning with:

(A) For a unit that commences commercial operation before July 1, 2011, the calendar quarter covering May 1, 2012 through June 30, 2012; or

(B) For a unit that commences commercial operation on or after July 1, 2011, the calendar quarter corresponding to the earlier of the date of provisional certification or the applicable deadline for initial certification under §97.530(b), unless that date is not during a control period, in which case reporting shall commence in the quarter that includes May 1 through June 30 of the first control period after such date.

(3) The designated representative shall submit each quarterly report to the Administrator within 30 days after the end of the calendar quarter covered by the report. Quarterly reports shall be submitted in the manner specified in §75.73(f) of this chapter.

(4) For TR NOx Ozone Season units that are also subject to the Acid Rain Program, TR NOx Annual Trading Program, TR SO2 Group 1 Trading Program, or TR SO2 Group 2 Trading Program, quarterly reports shall include the applicable data and information required by subparts P through H of part 75 of this chapter as applicable, in addition to the NOX mass emission data, heat input data, and other information required by this subpart.

(5) The Administrator may review and conduct independent audits of any quarterly report in order to determine whether the quarterly report meets the requirements of this subpart and part 75 of this chapter, including the requirement to use substitute data.
add-on emission controls were operating within the range of parameters listed in the quality assurance/quality control program under appendix B to part 75 of this chapter and the substitute data values do not systematically underestimate NOX emissions; and

(3) For a unit that is reporting on a control period basis under paragraph (d)(2)(ii) of this section, the NOX emission rate and NOX concentration values substituted for missing data under subpart D of part 75 of this chapter are calculated using only values from a control period and do not systematically underestimate NOX emissions.

§ 97.535 Petitions for alternatives to monitoring, recordkeeping, or reporting requirements.

(a) The designated representative of a TR NOX Ozone Season unit may submit a petition under §75.66 of this chapter to the Administrator, requesting approval to apply an alternative to any requirement of §§97.530 through 97.534.

(b) A petition submitted under paragraph (a) of this section shall include sufficient information for the evaluation of the petition, including, at a minimum, the following information:

(i) Identification of each unit and source covered by the petition;

(ii) A detailed explanation of why the proposed alternative is being suggested in lieu of the requirement;

(iii) A description and diagram of any equipment and procedures used in the proposed alternative;

(iv) A demonstration that the proposed alternative is consistent with the purposes of the requirement for which the alternative is proposed and with the purposes of this subpart and part 75 of this chapter and that any adverse effect of approving the alternative will be de minimis; and

(v) Any other relevant information that the Administrator may require.

(c) Use of an alternative to any requirement referenced in paragraph (a) of this section is in accordance with this subpart only to the extent that the petition is approved in writing by the Administrator and that such use is in accordance with such approval.

Subpart CCCC—TR SO2 Group 1 Trading Program

SOURCE: 76 FR 48432, Aug. 8, 2011, unless otherwise noted.

§ 97.601 Purpose.

This subpart sets forth the general, designated representative, allowance, and monitoring provisions for the Transport Rule (TR) SO2 Group 1 Trading Program, under section 110 of the Clean Air Act and §52.39 of this chapter, as a means of mitigating interstate transport of fine particulates and sulfur dioxide.

§ 97.602 Definitions.

The terms used in this subpart shall have the meanings set forth in this section as follows:

Acid Rain Program means a multi-state SO2 and NOX air pollution control and emission reduction program established by the Administrator under title IV of the Clean Air Act and parts 72 through 78 of this chapter.

Administrator means the Administrator of the United States Environmental Protection Agency or the Director of the Clean Air Markets Division (or its successor determined by the Administrator) of the United States Environmental Protection Agency, the Administrator’s duly authorized representative under this subpart.

Allocate or allocation means, with regard to TR SO2 Group 1 allowances, the determination by the Administrator, State, or permitting authority, in accordance with this subpart and any SIP revision submitted by the State and approved by the Administrator under §52.39(d), (e), or (f) of this chapter, of the amount of such TR SO2 Group 1 allowances to be initially credited, at no cost to the recipient, to:

(1) A TR SO2 Group 1 unit;

(2) A new unit set-aside;

(3) An Indian country new unit set-aside; or

(4) An entity not listed in paragraphs (1) through (3) of this definition;

(5) Provided that, if the Administrator, State, or permitting authority initially credits, to a TR SO2 Group 1 unit qualifying for an initial credit, a credit in the amount of zero TR SO2
§97.602  Group 1 allowances, the TR SO₂ Group 1 unit will be treated as being allocated an amount (i.e., zero) of TR SO₂ Group 1 allowances.

Allowable SO₂ emission rate means, for a unit, the most stringent State or federal SO₂ emission rate limit (in lb/MWhr or, if in lb/mmBtu, converted to lb/MWhr by multiplying it by the unit’s heat rate in mmBtu/MWhr) that is applicable to the unit and covers the longest averaging period not exceeding one year.

Allowance Management System means the system by which the Administrator records allocations, deductions, and transfers of TR SO₂ Group 1 allowances under the TR SO₂ Group 1 Trading Program. Such allowances are allocated, recorded, held, deducted, or transferred only as whole allowances.

Allowance Management System account means an account in the Allowance Management System established by the Administrator for purposes of recording the allocation, holding, transfer, or deduction of TR SO₂ Group 1 allowances.

Allowance transfer deadline means, for a control period in a given year, midnight of March 1 (if it is a business day), or midnight of the first business day thereafter (if March 1 is not a business day), immediately after such control period and is the deadline by which a TR SO₂ Group 1 allowance transfer must be submitted for recordation in a TR SO₂ Group 1 source’s compliance account in order to be available for use in complying with the source’s TR SO₂ Group 1 emissions limitation for such control period in accordance with §§97.606 and 97.624.

Alternate designated representative means, for a TR SO₂ Group 1 source and each TR SO₂ Group 1 unit at the source, the natural person who is authorized by the owners and operators of the source and all such units at the source, in accordance with this subpart, to act on behalf of the designated representative in matters pertaining to the TR SO₂ Group 1 Trading Program.

Automated data acquisition and handling system or DAHS means the component of the continuous emission monitoring system, or other emissions monitoring system approved for use under this subpart, designed to interpret and convert individual output signals from pollutant concentration monitors, flow monitors, diluent gas monitors, and other component parts of the monitoring system to produce a continuous record of the measured parameters in the measurement units required by this subpart.

Biomass means—
(1) Any organic material grown for the purpose of being converted to energy;
(2) Any organic byproduct of agriculture that can be converted into energy; or
(3) Any material that can be converted into energy and is nonmerchantable for other purposes, that is segregated from other material that is nonmerchantable for other purposes, and that is;
   (i) A forest-related organic resource, including mill residues, precommercial thinnings, slash, brush, or byproduct from conversion of trees to merchantable material; or
   (ii) A wood material, including pallets, crates, dunnage, manufacturing and construction materials (other than...
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pressure-treated, chemically-treated, or painted wood products), and landscape or right-of-way tree trimmings.

Boiler means an enclosed fossil- or other-fuel-fired combustion device used to produce heat and to transfer heat to recirculating water, steam, or other medium.

Bottoming-cycle unit means a unit in which the energy input to the unit is first used to produce useful thermal energy, where at least some of the reject heat from the useful thermal energy application or process is then used for electricity production.

Business day means a day that does not fall on a weekend or a federal holiday.

Certifying official means a natural person who is:

(1) For a corporation, a president, secretary, treasurer, or vice-president of the corporation in charge of a principal business function or any other person who performs similar policy- or decision-making functions for the corporation;

(2) For a partnership or sole proprietorship, a general partner or the proprietor respectively; or

(3) For a local government entity or State, federal, or other public agency, a principal executive officer or ranking elected official.

Clean Air Act means the Clean Air Act, 42 U.S.C. 7401, et seq.

Coal means “coal” as defined in §72.2 of this chapter.

Coal-derived fuel means any fuel (whether in a solid, liquid, or gaseous state) produced by the mechanical, thermal, or chemical processing of coal.

Cogeneration system means an integrated group, at a source, of equipment (including a boiler, or combustion turbine, and a steam turbine generator) designed to produce useful thermal energy for industrial, commercial, heating, or cooling purposes and electricity through the sequential use of energy.

Cogeneration unit means a stationary, fossil-fuel-fired boiler or stationary, fossil-fuel-fired combustion turbine that is a topping-cycle unit or a bottoming-cycle unit:

(1) Operating as part of a cogeneration system; and

(2) Producing on an annual average basis—

(i) For a topping-cycle unit,

(A) Useful thermal energy not less than 5 percent of total energy output; and

(B) Useful power that, when added to one-half of useful thermal energy produced, is not less than 42.5 percent of total energy output, if useful thermal energy produced is 15 percent or more of total energy output, or not less than 45 percent of total energy input, if useful thermal energy produced is less than 15 percent of total energy output.

(ii) For a bottoming-cycle unit, useful power not less than 45 percent of total energy input;

(3) Provided that the requirements in paragraph (2) of this definition shall not apply to a calendar year referenced in paragraph (2) of this definition during which the unit did not operate at all;

(4) Provided that the total energy input under paragraphs (2)(i)(B) and (2)(ii) of this definition shall equal the unit’s total energy input from all fuel, except biomass if the unit is a boiler; and

(5) Provided that, if, throughout its operation during the 12-month period or a calendar year referenced in paragraph (2) of this definition, a unit is operated as part of a cogeneration system and the cogeneration system meets on a system-wide basis the requirement in paragraph (2)(i)(B) or (2)(ii) of this definition, the unit shall be deemed to meet such requirement during that 12-month period or calendar year.

Combustion turbine means an enclosed device comprising:

(1) If the device is simple cycle, a compressor, a combustor, and a turbine and in which the flue gas resulting from the combustion of fuel in the combustor passes through the turbine, rotating the turbine; and

(2) If the device is combined cycle, the equipment described in paragraph (1) of this definition and any associated duct burner, heat recovery steam generator, and steam turbine.

Commence commercial operation means, with regard to a unit:

(1) To have begun to produce steam, gas, or other heated medium used to
generate electricity for sale or use, including test generation, except as provided in §97.605.

(i) For a unit that is a TR SO₂ Group 1 unit under §97.604 on the later of January 1, 2005 or the date the unit commences commercial operation as defined in the introductory text of paragraph (1) of this definition and that subsequently undergoes a physical change or is moved to a new location or source, such date shall remain the date of commencement of commercial operation of the unit, which shall continue to be treated as the same unit.

(ii) For a unit that is a TR SO₂ Group 1 unit under §97.604 on the later of January 1, 2005 or the date the unit commences commercial operation as defined in the introductory text of paragraph (1) of this definition and that is subsequently replaced by a unit at the same or a different source, such date shall remain the replaced unit’s date of commencement of commercial operation, and the replacement unit shall be treated as a separate unit with a separate date for commencement of commercial operation as defined in paragraph (1) or (2) of this definition as appropriate.

Common designated representative means, with regard to a control period in a given year, a designated representative where, as of April 1 immediately after the allowance transfer deadline for such control period, the same natural person is authorized under §§97.613(a) and 97.615(a) as the designated representative for a group of one or more TR SO₂ Group 1 sources and units located in a State (and Indian country within the borders of such State).

Common designated representative’s assurance level means, with regard to a specific common designated representative and a State (and Indian country within the borders of such State) and control period in a given year for which the State assurance level is exceeded as described in §97.606(c)(2)(iii), the common designated representative’s share of the State SO₂ Group 1 trading budget with the variability limit for the State for such control period.

Common designated representative’s share means, with regard to a specific common designated representative for a control period in a given year:

(1) With regard to a total amount of SO₂ emissions from all TR SO₂ Group 1 units in a State (and Indian country within the borders of such State) during such control period, the total tonnage of SO₂ emissions during such control period from a group of one or more TR SO₂ Group 1 units located in such State (and such Indian country) and having the common designated representative for such control period;

(2) With regard to a State SO₂ Group 1 trading budget with the variability limit for such control period, the amount (rounded to the nearest allowance) equal to the sum of the total amount of TR SO₂ Group 1 allowances allocated for such control period to a group of one or more TR SO₂ Group 1 units located in the State (and Indian country within the borders of such
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State) and having the common designated representative for such control period and of the total amount of TR SO₂ Group 1 allowances purchased by an owner or operator of such TR SO₂ Group 1 units in an auction for such control period and submitted by the State or the permitting authority to the Administrator for recordation in the compliance accounts for such TR SO₂ Group 1 units in accordance with the TR SO₂ Group 1 allowance auction provisions in a SIP revision approved by the Administrator under § 92.33(e) or (f) of this chapter, multiplied by the sum of the State SO₂ Group 1 trading budget under § 97.610(a) and the State’s variability limit under § 97.610(b) for such control period and divided by such State SO₂ Group 1 trading budget;

(3) Provided that, in the case of a unit that operates during, but has no amount of TR SO₂ Group 1 allowances allocated under §§ 97.611 and 97.612 for such control period, the unit shall be treated, solely for purposes of this definition, as being allocated an amount (rounded to the nearest allowance) of TR SO₂ Group 1 allowances for such control period equal to the unit’s allowable SO₂ emission rate applicable to such control period, multiplied by a capacity factor of 0.85 (if the unit is a boiler combusting any amount of coal or coal-derived fuel during such control period), 0.24 (if the unit is a simple combustion turbine during such control period), 0.67 (if the unit is a combined cycle turbine during such control period), 0.74 (if the unit is an integrated coal gasification combined cycle unit during such control period), or 0.36 (for any other unit), multiplied by the unit’s maximum hourly load as reported in accordance with this subpart and by 8,760 hours/control period, and divided by 2,000 lb/ton.

Common stack means a single flue through which emissions from 2 or more units are exhausted.

Compliance account means an Allowance Management System account, established by the Administrator for a TR SO₂ Group 1 source under this subpart, in which any TR SO₂ Group 1 allowance allocations to the TR SO₂ Group 1 units at the source are recorded and in which are held any TR SO₂ Group 1 allowances available for use for a control period in a given year in complying with the source’s TR SO₂ Group 1 emissions limitation in accordance with §§ 97.606 and 97.624.

Continuous emission monitoring system or CEMS means the equipment required under this subpart to sample, analyze, measure, and provide, by means of readings recorded at least once every 15 minutes and using an automated data acquisition and handling system (DAHS), a permanent record of SO₂ emissions, stack gas volumetric flow rate, stack gas moisture content, and O₂ or CO₂ concentration (as applicable), in a manner consistent with part 75 of this chapter and §§ 97.630 through 97.635. The following systems are the principal types of continuous emission monitoring systems:

(1) A flow monitoring system, consisting of a stack flow rate monitor and an automated data acquisition and handling system and providing a permanent, continuous record of stack gas volumetric flow rate, in standard cubic feet per hour (scfh);

(2) A SO₂ monitoring system, consisting of a SO₂ pollutant concentration monitor and an automated data acquisition and handling system and providing a permanent, continuous record of SO₂ emissions, in parts per million (ppm);

(3) A moisture monitoring system, as defined in § 75.11(b)(2) of this chapter and providing a permanent, continuous record of the stack gas moisture content, in percent H₂O;

(4) A CO₂ monitoring system, consisting of a CO₂ pollutant concentration monitor (or an O₂ monitor plus suitable mathematical equations from which the CO₂ concentration is derived) and an automated data acquisition and handling system and providing a permanent, continuous record of CO₂ emissions, in percent CO₂; and

(5) An O₂ monitoring system, consisting of an O₂ concentration monitor and an automated data acquisition and handling system and providing a permanent, continuous record of O₂, in percent O₂.

Control period means the period starting January 1 of a calendar year, except as provided in §§ 97.606(c)(3), and ending on December 31 of the same year, inclusive.
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Designated representative means, for a TR SO\textsubscript{2} Group 1 source and each TR SO\textsubscript{2} Group 1 unit at the source, the natural person who is authorized by the owners and operators of the source and all such units at the source, in accordance with this subpart, to represent and legally bind each owner and operator in matters pertaining to the TR SO\textsubscript{2} Group 1 Trading Program. If the TR SO\textsubscript{2} Group 1 source is also subject to the Acid Rain Program, TR NO\textsubscript{X} Annual Trading Program, or TR NO\textsubscript{X} Ozone Season Trading Program, then this natural person shall be the same natural person as the designated representative, as defined in the respective program.

Emissions means air pollutants exhausted from a unit or source into the atmosphere, as measured, recorded, and reported to the Administrator by the designated representative, and as modified by the Administrator:

(1) In accordance with this subpart; and

(2) With regard to a period before the unit or source is required to measure, record, and report such air pollutants in accordance with this subpart, in accordance with part 75 of this chapter.

Excess emissions means any ton of emissions from the TR SO\textsubscript{2} Group 1 units at a TR SO\textsubscript{2} Group 1 source during a control period in a given year that exceeds the TR SO\textsubscript{2} Group 1 emissions limitation for the source for such control period.

Fossil fuel means—

(1) Natural gas, petroleum, coal, or any form of solid, liquid, or gaseous fuel derived from such material; or

(2) For purposes of applying the limitation on “average annual fuel consumption of fossil fuel” in §§97.604(b)(2)(i)(B) and (ii), natural gas, petroleum, coal, or any form of solid, liquid, or gaseous fuel derived from such material for the purpose of creating useful heat.

Fossil-fuel-fired means, with regard to a unit, combusting any amount of fossil fuel in 2005 or any calendar year thereafter.

General account means an Allowance Management System account, established under this subpart, that is not a compliance account or an assurance account.

Generator means a device that produces electricity.

Gross electrical output means, for a unit, electricity made available for use, including any such electricity used in the power production process (which process includes, but is not limited to, any on-site processing or treatment of fuel combusted at the unit and any on-site emission controls).

Heat input means, for a unit for a specified period of time, the product (in mmBtu/time) of the gross calorific value of the fuel (in mmBtu/lb) fed into the unit multiplied by the fuel feed rate (in lb of fuel/time), as measured, recorded, and reported to the Administrator by the designated representative and as modified by the Administrator in accordance with this subpart and excluding the heat derived from preheated combustion air, recirculated flue gases, or exhaust.

Heat input rate means, for a unit, the amount of heat input (in mmBtu) divided by unit operating time (in hr) or, for a unit and a specific fuel, the amount of heat input attributed to the fuel (in mmBtu) divided by the unit operating time (in hr) during which the unit combusts the fuel.

Heat rate means, for a unit, the unit’s maximum design heat input (in Btu/hr), divided by the product of 1,000,000 Btu/mmBtu and the unit’s maximum hourly load.

Indian country means “Indian country” as defined in 18 U.S.C. 1151.

Life-of-the-unit, firm power contractual arrangement means a unit participation power sales agreement under which a utility or industrial customer reserves, or is entitled to receive, a specified amount or percentage of nameplate capacity and associated energy generated by any specified unit and pays its proportional amount of such unit’s total costs, pursuant to a contract:

(1) For the life of the unit;

(2) For a cumulative term of no less than 30 years, including contracts that permit an election for early termination; or

(3) For a period no less than 25 years or 70 percent of the economic useful life of the unit determined as of the time the unit is built, with option
rights to purchase or release some portion of the nameplate capacity and associated energy generated by the unit at the end of the period.

*Maximum design heat input* means, for a unit, the maximum amount of fuel per hour (in Btu/hr) that the unit is capable ofcombusting on a steady state basis as of the initial installation of the unit as specified by the manufacturer of the unit.

*Monitoring system* means any monitoring system that meets the requirements of this subpart, including a continuous emission monitoring system, an alternative monitoring system, or an exempted monitoring system under part 75 of this chapter.

*Nameplate capacity* means, starting from the initial installation of a generator, the maximum electrical generating output (in MWe, rounded to the nearest tenth) that the generator is capable of producing on a steady state basis and during continuous operation (when not restricted by seasonal or other deratings) as of such installation as specified by the manufacturer of the generator or, starting from the completion of any subsequent physical change in the generator resulting in an increase in the maximum electrical generating output that the generator is capable of producing on a steady state basis and during continuous operation (when not restricted by seasonal or other deratings), such increased maximum amount (in MWe, rounded to the nearest tenth) as of such completion as specified by the person conducting the physical change.

*Natural gas* means “natural gas” as defined in §72.2 of this chapter.

*Newly affected TR SO₂ Group 1 unit* means a unit that was not a TR SO₂ Group 1 unit when it began operating but that thereafter becomes a TR SO₂ Group 1 unit.

*Operate or operation* means, with regard to a unit, to combust fuel.

*Operator* means, for a TR SO₂ Group 1 source or a TR SO₂ Group 1 unit at a source respectively, any person who operates, controls, or supervises a TR SO₂ Group 1 unit at the source or the TR SO₂ Group 1 unit and shall include, but not be limited to, any holding company, utility system, or plant manager of such source or unit.

*Owner* means, for a TR SO₂ Group 1 source or a TR SO₂ Group 1 unit at a source respectively, any of the following persons:

1. Any holder of any portion of the legal or equitable title in a TR SO₂ Group 1 unit at the source or the TR SO₂ Group 1 unit;
2. Any holder of a leasehold interest in a TR SO₂ Group 1 unit at the source or the TR SO₂ Group 1 unit, provided that, unless expressly provided for in a leasehold agreement, “owner” shall not include a passive lessor, or a person who has an equitable interest through such lessor, whose rental payments are not based (either directly or indirectly) on the revenues or income from such TR SO₂ Group 1 unit; and
3. Any purchaser of power from a TR SO₂ Group 1 unit at the source or the TR SO₂ Group 1 unit under a life-of-the-unit, firm power contractual arrangement.

*Permanently retired* means, with regard to a unit, a unit that is unavailable for service and that the unit’s owners and operators do not expect to return to service in the future.

*Permitting authority* means “permitting authority” as defined in §§70.2 and 71.2 of this chapter.

*Potential electrical output capacity* means, for a unit, 33 percent of the unit’s maximum design heat input, divided by 3,413 Btu/kWh, divided by 1,000 kWh/MWh, and multiplied by 8,760 hr/yr.

*Receive or receipt of* means, when referring to the Administrator, to come into possession of a document, information, or correspondence (whether sent in hard copy or by authorized electronic transmission), as indicated in an official log, or by a notation made on the document, information, or correspondence, by the Administrator in the regular course of business.

*Recordation, record, or recorded* means, with regard to TR SO₂ allowances, the moving of TR SO₂ allowances by the Administrator into, out of, or between Allowance Management System accounts, for purposes of allocation, auction, transfer, or deduction.

*Reference method* means any direct test method of sampling and analyzing...
for an air pollutant as specified in § 75.22 of this chapter.

Replacement, replace, or replaced means, with regard to a unit, the demolishing of a unit, or the permanent retirement and permanent disabling of a unit, and the construction of another unit (the replacement unit) to be used instead of the demolished or retired unit (the replaced unit).

Sequential use of energy means:
(1) The use of reject heat from electricity production in a useful thermal energy application or process; or
(2) The use of reject heat from useful thermal energy application or process in electricity production.

Serial number means, for a TR SO\textsubscript{2} Group 1 allowance, the unique identification number assigned to each TR SO\textsubscript{2} Group 1 allowance by the Administrator.

Solid waste incineration unit means a stationary, fossil-fuel-fired boiler or stationary, fossil-fuel-fired combustion turbine that is a “solid waste incineration unit” as defined in section 129(g)(1) of the Clean Air Act.

Source means all buildings, structures, or installations located in one or more contiguous or adjacent properties under common control of the same person or persons. This definition does not change or otherwise affect the definition of “major source”, “stationary source”, or “source” as set forth and implemented in a title V operating permit program or any other program under the Clean Air Act.

State means one of the States that is subject to the TR SO\textsubscript{2} Group 1 Trading Program pursuant to § 52.38(a), (b), (d), (e), and (f) of this chapter.

Submit or serve means to send or transmit a document, information, or correspondence to the person specified in accordance with the applicable regulation:
(1) In person;
(2) By United States Postal Service;
or
(3) By other means of dispatch or transmission and delivery;
(4) Provided that compliance with any “submission” or “service” deadline shall be determined by the date of dispatch, transmission, or mailing and not the date of receipt.

Total energy input means, for a unit, total energy of all forms supplied to the unit, excluding energy produced by the unit. Each form of energy supplied shall be measured by the lower heating value of that form of energy calculated as follows:

\[
LHV = HHV - 10.55(W + 9H)
\]

where:

\[
LHV = \text{lower heating value of the form of energy in Btu/lb},
\]
\[
HHV = \text{higher heating value of the form of energy in Btu/lb},
\]
\[
W = \text{weight \% of moisture in the form of energy, and}
\]
\[
H = \text{weight \% of hydrogen in the form of energy.}
\]

Total energy output means, for a unit, the sum of useful power and useful thermal energy produced by the unit.

TR NO\textsubscript{X} Annual Trading Program means a multi-state NO\textsubscript{X} air pollution control and emission reduction program established in accordance with subpart AAAAA of this part and § 52.38(a) of this chapter (including such a program that is revised in a SIP revision approved by the Administrator under § 52.38(a)(3) or (4) of this chapter or that is established in a SIP revision approved by the Administrator under § 52.38(a)(5) of this chapter), as a means of mitigating interstate transport of fine particulates and NO\textsubscript{X}.

TR NO\textsubscript{X} Ozone Season Trading Program means a multi-state NO\textsubscript{X} air pollution control and emission reduction program established in accordance with subpart BBBBB of this part and § 52.38(b) of this chapter (including such a program that is revised in a SIP revision approved by the Administrator under § 52.38(b)(3) or (4) of this chapter or that is established in a SIP revision approved by the Administrator under § 52.38(b)(5) of this chapter), as a means of mitigating interstate transport of ozone and NO\textsubscript{X}.

TR SO\textsubscript{2} Group 1 allowance means a limited authorization issued and allocated or auctioned by the Administrator under this subpart, or by a State.
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§ 97.603 Measurements, abbreviations, and acronyms.

Measurements, abbreviations, and acronyms used in this subpart are defined as follows:

Btu—British thermal unit
§ 97.604 Applicability.

(a) Except as provided in paragraph (b) of this section:

(1) The following units in a State (and Indian country within the borders of such State) shall be TR SO\textsubscript{2} Group 1 units, and any source that includes one or more such units shall be a TR SO\textsubscript{2} Group 1 source, subject to the requirements of this subpart: any stationary, fossil-fuel-fired boiler or stationary, fossil-fuel-fired combustion turbine serving at any time, on or after January 1, 2005, a generator with nameplate capacity of more than 25 MWe producing electricity for sale.

(2) If a stationary boiler or stationary combustion turbine that, under paragraph (a)(1) of this section, is not a TR SO\textsubscript{2} Group 1 unit begins to combust fossil fuel or to serve a generator with nameplate capacity of more than 25 MWe producing electricity for sale, the unit shall become a TR SO\textsubscript{2} Group 1 unit as provided in paragraph (a)(1) of this section on the first date on which it both combusts fossil fuel and serves such generator.

(b) Any unit in a State (and Indian country within the borders of such State) that otherwise is a TR SO\textsubscript{2} Group 1 unit under paragraph (a) of this section and that meets the requirements set forth in paragraph (b)(1)(i) or (2)(i) of this section shall not be a TR SO\textsubscript{2} Group 1 unit:

(1)(i) Any unit:

(A) Qualifying as a cogeneration unit throughout the later of 2005 or any calendar year thereafter more than one-third of the unit’s potential electric output capacity or 219,000 MWh, whichever is greater, to any utility power distribution system for sale.

(B) Not supplying in 2005 or any calendar year thereafter more than one-third of the unit’s potential electric output capacity or 219,000 MWh, whichever is greater, to any utility power distribution system for sale.

(ii) If, after qualifying under paragraph (b)(1)(i) of this section as not being a TR SO\textsubscript{2} Group 1 unit, a unit subsequently no longer meets all the requirements of paragraph (b)(1)(i) of this section, the unit shall become a TR SO\textsubscript{2} Group 1 unit starting on the earlier of January 1 after the first calendar year during which the unit no longer qualifies as a cogeneration unit or January 1 after the first calendar year during which the unit no longer meets the requirements of paragraph (b)(1)(i)(B) of this section. The unit shall thereafter continue to be a TR SO\textsubscript{2} Group 1 unit.

(2)(i) Any unit:

(A) Qualifying as a solid waste incineration unit throughout the later of 2005 or the 12-month period starting on the date the unit first produces electricity and continuing to qualify as a solid waste incineration unit throughout each calendar year ending after the later of 2005 or such 12-month period; and

(B) With an average annual fuel consumption of fossil fuel for the first 3 consecutive calendar years of operation starting no earlier than 2005 of less than 20 percent (on a Btu basis) and an average annual fuel consumption of fossil fuel for any 3 consecutive calendar years thereafter of less than 20 percent (on a Btu basis).

(ii) If, after qualifying under paragraph (b)(2)(i) of this section as not being a TR SO\textsubscript{2} Group 1 unit, a unit subsequently no longer meets all the requirements of paragraph (b)(1)(i) of this section, the unit shall become a TR SO\textsubscript{2} Group 1 unit starting on the earlier of January 1 after the first calendar year during which the unit no longer qualifies as a solid waste incineration unit or January 1 after the first 3 consecutive calendar years after 2005 for which the unit has an average annual fuel consumption of fossil fuel of 20 percent or more. The unit shall thereafter continue to be a TR SO\textsubscript{2} Group 1 unit.
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§ 97.605 Retired unit exemption.

(a)(1) Any TR SO₂ Group 1 unit that is permanently retired shall be exempt from §97.606(b) and (c)(1), §97.624, and §§97.630 through 97.635.

(2) The exemption under paragraph (a)(1) of this section shall become effective the day on which the TR SO₂ Group 1 unit is permanently retired. Within 30 days of the unit’s permanent retirement, the designated representative shall submit a statement to the Administrator. The statement shall state, in a format prescribed by the Administrator, that the unit was permanently retired on a specified date and will comply with the requirements of paragraph (b) of this section.

(b) Special provisions. (1) A unit exempt under paragraph (a) of this section shall not emit any SO₂, starting on the date that the exemption takes effect.

(2) For a period of 5 years from the date the records are created, the owners and operators of a unit exempt under paragraph (a) of this section shall retain, at the source that includes the unit, records demonstrating that the unit is permanently retired. The 5-year period for keeping records may be extended for cause, at any time before the end of the period, in writing by the Administrator. The owners and operators bear the burden of proof that the unit is permanently retired.

(3) The owners and operators and, to the extent applicable, the designated representative of a unit exempt under paragraph (a) of this section shall comply with the requirements of the TR SO₂ Group 1 Trading Program concerning all periods for which the exemption is not in effect, even if such requirements arise, or must be complied with, after the exemption takes effect.

(4) A unit exempt under paragraph (a) of this section shall lose its exemption on the first date on which the unit resumes operation. Such unit shall be treated, for purposes of applying allocation, monitoring, reporting, and recordkeeping requirements under this subpart, as a unit that commences commercial operation on the first date on which the unit resumes operation.
§ 97.606 Standard requirements.

(a) Designated representative requirements. The owners and operators shall comply with the requirement to have a designated representative, and may have an alternate designated representative, in accordance with §§97.613 through 97.618.

(b) Emissions monitoring, reporting, and recordkeeping requirements. (1) The owners and operators, and the designated representative, of each TR SO₂ Group 1 source and each TR SO₂ Group 1 unit at the source shall comply with the monitoring, reporting, and recordkeeping requirements of §§97.630 through 97.635.

(2) The emissions data determined in accordance with §§97.630 through 97.635 shall be used to calculate allocations of TR SO₂ Group 1 allowances under §§97.611(a)(2) and (b) and §97.612 and to determine compliance with the TR SO₂ Group 1 emissions limitation and assurance provisions under paragraph (c) of this section, provided that, for each monitoring location from which mass emissions are reported, the mass emissions amount used in calculating such allocations and determining such compliance shall be the mass emissions amount for the monitoring location determined in accordance with §§97.630 through 97.635 and rounded to the nearest ton, with any fraction of a ton less than 0.50 being deemed to be zero.

(c) SO₂ emissions requirements. (1) TR SO₂ Group 1 emissions limitation. (i) As of the allowance transfer deadline for a control period in a given year, the owners and operators of each TR SO₂ Group 1 source and each TR SO₂ Group 1 unit at the source shall hold, in the source’s compliance account, TR SO₂ Group 1 allowances available for deduction for such control period under §97.624(a) in an amount not less than the tons of total SO₂ emissions during such control period from all TR SO₂ Group 1 units at the source.

(ii) If total SO₂ emissions during a control period in a given year from the TR SO₂ Group 1 source are in excess of the TR SO₂ Group 1 emissions limitation set forth in paragraph (c)(1)(i) of this section, then:

(A) The owners and operators of the source and each TR SO₂ Group 1 unit at the source shall hold the TR SO₂ Group 1 allowances required for deduction under §97.624(d); and

(B) The owners and operators of the source and each TR SO₂ Group 1 unit at the source shall pay any fine, penalty, or assessment or comply with any other remedy imposed, for the same violations, under the Clean Air Act, and each ton of such excess emissions and each day of such control period shall constitute a separate violation of this subpart and the Clean Air Act.

(2) TR SO₂ Group 1 assurance provisions. (i) If total SO₂ emissions during a control period in a given year from all TR SO₂ Group 1 units at TR SO₂ Group 1 sources in a State (and Indian country within the borders of such State) exceed the State assurance level, then the owners and operators of such sources and units in each group of one or more sources and units having a common designated representative for such control period, where the common designated representative’s share of such SO₂ emissions during such control period exceeds the common designated representative’s assurance level for the State and such control period, shall hold (in the assurance account established for the owners and operators of such group) TR SO₂ Group 1 allowances available for deduction for such control period under §97.625(a) in an amount equal to two times the product (rounded to the nearest whole number), as determined by the Administrator in accordance with §97.625(b), of multiplying—

(A) The quotient of the amount by which the common designated representative’s share of such SO₂ emissions exceeds the common designated representative’s assurance level divided by the sum of the amounts determined for all common designated representatives for such sources and units in the State (and Indian country within the borders of such State) for such control period, by which each common designated representative’s share of such SO₂ emissions exceeds the respective common designated representative’s assurance level; and

(B) The amount by which total SO₂ emissions from all TR SO₂ Group 1 units at TR SO₂ Group 1 sources in the State (and Indian country within the borders of such State) for such control period exceed the State assurance level.
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period exceed the State assurance level.

(ii) The owners and operators shall hold the TR SO\textsubscript{2} Group 1 allowances required under paragraph (c)(2)(i) of this section, as of midnight of November 1 (if it is a business day), or midnight of the first business day thereafter (if November 1 is not a business day), immediately after such control period.

(iii) Total SO\textsubscript{2} emissions from all TR SO\textsubscript{2} Group 1 units at TR SO\textsubscript{2} Group 1 sources in a State (and Indian country within the borders of such State) during a control period in a given year exceed the State assurance level if such total SO\textsubscript{2} emissions exceed the sum, for such control period, of the State SO\textsubscript{2} Group 1 trading budget under §97.610(a) and the State’s variability limit under §97.610(b).

(iv) It shall not be a violation of this subpart or of the Clean Air Act if total SO\textsubscript{2} emissions from all TR SO\textsubscript{2} Group 1 units at TR SO\textsubscript{2} Group 1 sources in a State (and Indian country within the borders of such State) during a control period in a given year exceed the State assurance level if such total SO\textsubscript{2} emissions exceed the sum, for such control period, of the State SO\textsubscript{2} Group 1 trading budget under §97.610(a) and the State’s variability limit under §97.610(b).

(v) To the extent the owners and operators fail to hold TR SO\textsubscript{2} Group 1 allowances for a control period in a given year in accordance with paragraphs (c)(2)(i) through (iii) of this section,

(A) The owners and operators shall pay any fine, penalty, or assessment or comply with any other remedy imposed under the Clean Air Act; and

(B) Each TR SO\textsubscript{2} Group 1 allowance that the owners and operators fail to hold for a control period in a given year must be a TR SO\textsubscript{2} Group 1 allowance that was allocated for a control period in the given year or in the immediately following year.

(3) Compliance periods.—(i) A TR SO\textsubscript{2} Group 1 unit shall be subject to the requirements under paragraph (c)(1) of this section for the control period starting on the later of January 1, 2014 or the deadline for meeting the unit’s monitor certification requirements under §97.630(b) and for each control period thereafter.

(ii) A TR SO\textsubscript{2} Group 1 unit shall be subject to the requirements under paragraph (c)(2) of this section for the control period starting on the later of January 1, 2014 or the deadline for meeting the unit’s monitor certification requirements under §97.630(b) and for each control period thereafter.

(4) Vintage of allowances held for compliance. (i) A TR SO\textsubscript{2} Group 1 allowance held for compliance with the requirements under paragraph (c)(1)(i) of this section for a control period in a given year must be a TR SO\textsubscript{2} Group 1 allowance that was allocated for such control period or a control period in a prior year.

(ii) A TR SO\textsubscript{2} Group 1 allowance held for compliance with the requirements under paragraphs (c)(1)(ii)(A) and (2)(i) through (iii) of this section for a control period in a given year must be a TR SO\textsubscript{2} Group 1 allowance that was allocated for a control period in a prior year or the control period in the given year or in the immediately following year.

(5) Allowance Management System requirements. Each TR SO\textsubscript{2} Group 1 allowance shall be held in, deducted from, or transferred into, out of, or between Allowance Management System accounts in accordance with this subpart.

(6) Limited authorization. A TR SO\textsubscript{2} Group 1 allowance is a limited authorization to emit one ton of SO\textsubscript{2} during the control period in one year. Such authorization is limited in its use and duration as follows:

(i) Such authorization shall only be used in accordance with the TR SO\textsubscript{2} Group 1 Trading Program; and

(ii) Notwithstanding any other provision of this subpart, the Administrator has the authority to terminate or limit the use and duration of such authorization to the extent the Administrator determines is necessary or appropriate to implement any provision of the Clean Air Act.

(7) Property right. A TR SO\textsubscript{2} Group 1 allowance does not constitute a property right.
§ 97.607 Title V permit requirements.

(d) Title V permit requirements. (1) No title V permit revision shall be required for any allocation, holding, deduction, or transfer of TR SO\textsubscript{2} Group 1 allowances in accordance with this subpart.

(2) A description of whether a unit is required to monitor and report SO\textsubscript{2} emissions using a continuous emission monitoring system (under subpart H of part 75 of this chapter), an excepted monitoring system (under appendices D and E to part 75 of this chapter), a low mass emissions excepted monitoring methodology (under §75.19 of this chapter), or an alternative monitoring system (under subpart E of part 75 of this chapter) in accordance with §§97.630 through 97.635 may be added to, or changed in, a title V permit using minor permit modification procedures in accordance with §§70.7(e)(2) and 71.7(e)(1) of this chapter, provided that the requirements applicable to the described monitoring and reporting (as added or changed, respectively) are already incorporated in such permit. This paragraph explicitly provides that the addition of, or change to, a unit’s description as described in the prior sentence is eligible for minor permit modification procedures in accordance with §§70.7(e)(2) and 71.7(e)(1)(1)(B) of this chapter.

(e) Additional recordkeeping and reporting requirements. (1) Unless otherwise provided, the owners and operators of each TR SO\textsubscript{2} Group 1 source and each TR SO\textsubscript{2} Group 1 unit at the source shall keep on site at the source each of the following documents (in hardcopy or electronic format) for a period of 5 years from the date the document is created. This period may be extended for cause, at any time before the end of 5 years, in writing by the Administrator.

(i) The certificate of representation under §97.616 for the designated representative for the source and each TR SO\textsubscript{2} Group 1 unit at the source and all documents that demonstrate the truth of the statements in the certificate of representation; provided that the certificate and documents shall be retained on site at the source beyond such 5-year period until such certificate of representation and documents are superseded because of the submission of a new certificate of representation under §97.616 changing the designated representative.

(ii) All emissions monitoring information, in accordance with this subpart.

(iii) Copies of all reports, compliance certifications, and other submissions and all records made or required under, or to demonstrate compliance with the requirements of, the TR SO\textsubscript{2} Group 1 Trading Program.

(2) The designated representative of a TR SO\textsubscript{2} Group 1 source and each TR SO\textsubscript{2} Group 1 unit at the source shall make all submissions required under the TR SO\textsubscript{2} Group 1 Trading Program, except as provided in §97.618. This requirement does not change, create an exemption from, or otherwise affect the responsible official submission requirements under a title V operating permit program in parts 70 and 71 of this chapter.

(f) Liability. (1) Any provision of the TR SO\textsubscript{2} Group 1 Trading Program that applies to a TR SO\textsubscript{2} Group 1 source or the designated representative of a TR SO\textsubscript{2} Group 1 source shall also apply to the owners and operators of such source and of the TR SO\textsubscript{2} Group 1 units at the source.

(2) Any provision of the TR SO\textsubscript{2} Group 1 Trading Program that applies to a TR SO\textsubscript{2} Group 1 unit or the designated representative of a TR SO\textsubscript{2} Group 1 unit shall also apply to the owners and operators of such unit.

(g) Effect on other authorities. No provision of the TR SO\textsubscript{2} Group 1 Trading Program or exemption under §97.605 shall be construed as exempting or excluding the owners and operators, and the designated representative, of a TR SO\textsubscript{2} Group 1 source or TR SO\textsubscript{2} Group 1 unit from compliance with any other provision of the applicable, approved State implementation plan, a federally enforceable permit, or the Clean Air Act.

[76 FR 48432, Aug. 8, 2011, as amended at 77 FR 10338, Feb. 21, 2012]

§ 97.607 Computation of time.

(a) Unless otherwise stated, any time period scheduled, under the TR SO\textsubscript{2} Group 1 Trading Program, to begin on the occurrence of an act or event shall
(b) Unless otherwise stated, any time period scheduled, under the TR SO2 Group 1 Trading Program, to begin before the occurrence of an act or event shall be computed so that the period ends the day before the act or event occurs.

(c) Unless otherwise stated, if the final day of any time period, under the TR SO2 Group 1 Trading Program, is not a business day, the time period shall be extended to the next business day.

§ 97.608 Administrative appeal procedures.

The administrative appeal procedures for decisions of the Administrator under the TR SO2 Group 1 Trading Program are set forth in part 78 of this chapter.

§ 97.610 State SO2 Group 1 trading budgets, new unit set-asides, Indian country new unit set-aside, and variability limits.

(a) The State SO2 trading budgets, new unit set-asides, and Indian country new unit set-asides for allocations of TR SO2 Group 1 allowances for the control periods in 2012 and thereafter are as follows:

(i) Illinois. (i) The SO2 trading budget for 2012 and 2013 is 234,889 tons.

(ii) The SO2 new unit set-aside for 2012 and 2013 is 11,744 tons.

(iii) [Reserved]

(iv) The SO2 trading budget for 2014 and thereafter is 124,123 tons.

(v) The SO2 new unit set-aside for 2014 and thereafter is 6,206 tons.

(vi) [Reserved]


(ii) The SO2 new unit set-aside for 2012 and 2013 is 11,744 tons.

(iii) [Reserved]

(iv) The SO2 trading budget for 2014 and thereafter is 161,111 tons.

(v) The SO2 new unit set-aside for 2014 and thereafter is 4,833 tons.

(vi) [Reserved]

(iii) Iowa. (i) The SO2 trading budget for 2012 and 2013 is 107,085 tons.

(ii) The SO2 new unit set-aside for 2012 and 2013 is 2,035 tons.

(iii) The SO2 Indian country new unit set-aside for 2012 and 2013 is 107 tons.

(iv) The SO2 trading budget for 2014 and thereafter is 75,184 tons.

(v) The SO2 new unit set-aside for 2014 and thereafter is 1,429 tons.

(vi) The SO2 Indian country new unit set-aside for 2014 and thereafter is 75 tons.

(iv) Kentucky. (i) The SO2 trading budget for 2012 and 2013 is 232,662 tons.

(ii) The SO2 new unit set-aside for 2012 and 2013 is 13,960 tons.

(iii) [Reserved]

(iv) The SO2 trading budget for 2014 and thereafter is 106,284 tons.

(v) The SO2 new unit set-aside for 2014 and thereafter is 6,377 tons.

(vi) [Reserved]

(5) Maryland. (i) The SO2 trading budget for 2012 and 2013 is 30,120 tons.

(ii) The SO2 new unit set-aside for 2012 and 2013 is 602 tons.

(iii) [Reserved]

(iv) The SO2 trading budget for 2014 and thereafter is 28,203 tons.

(v) The SO2 new unit set-aside for 2014 and thereafter is 564 tons.

(vi) [Reserved]

(6) Michigan. (i) The SO2 trading budget for 2012 and 2013 is 229,303 tons.

(ii) The SO2 new unit set-aside for 2012 and 2013 is 4,357 tons.

(iii) The SO2 Indian country new unit set-aside for 2012 and 2013 is 229 tons.

(iv) The SO2 trading budget for 2014 and thereafter is 143,995 tons.

(v) The SO2 new unit set-aside for 2014 and thereafter is 2,736 tons.

(vi) The SO2 Indian country new unit set-aside for 2014 and thereafter is 144 tons.

(7) Missouri. (i) The SO2 trading budget for 2012 and 2013 is 207,466 tons.

(ii) The SO2 new unit set-aside for 2012 and 2013 is 4,149 tons.

(iii) The SO2 Indian country new unit set-aside for 2012 and 2013 is 229 tons.

(iv) The SO2 trading budget for 2014 and thereafter is 143,995 tons.

(v) The SO2 new unit set-aside for 2014 and thereafter is 2,736 tons.

(vi) The SO2 Indian country new unit set-aside for 2014 and thereafter is 144 tons.

(8) New Jersey. (i) The SO2 trading budget for 2012 and 2013 is 7,670 tons.

(ii) The SO2 new unit set-aside for 2012 and 2013 is 153 tons.

(iii) [Reserved]

(iv) The SO2 trading budget for 2014 and thereafter is 5,574 tons.
(v) The SO$_2$ new unit set-aside for 2014 and thereafter is 111 tons.
(vi) [Reserved]
(9) New York. (i) The SO$_2$ trading budget for 2012 and 2013 is 30,852 tons.
(ii) The SO$_2$ new unit set-aside for 2012 and 2013 is 586 tons.
(iii) The SO$_2$ Indian country new unit set-aside for 2012 and 2013 is 31 tons.
(iv) The SO$_2$ trading budget for 2014 and thereafter is 22,112 tons.
(v) The SO$_2$ new unit set-aside for 2014 and thereafter is 420 tons.
(vi) [Reserved]
(ii) The SO$_2$ new unit set-aside for 2012 and 2013 is 10,613 tons.
(iii) The SO$_2$ Indian country new unit set-aside for 2012 and 2013 is 6,205 tons.
(iv) The SO$_2$ trading budget for 2014 and thereafter is 75,668 tons.
(v) The SO$_2$ new unit set-aside for 2014 and thereafter is 1,177 tons.
(vi) [Reserved]
(11) Ohio. (i) The SO$_2$ trading budget for 2012 and 2013 is 310,230 tons.
(ii) The SO$_2$ new unit set-aside for 2012 and 2013 is 6,205 tons.
(iii) [Reserved]
(iv) The SO$_2$ trading budget for 2014 and thereafter is 22,240 tons.
(v) The SO$_2$ new unit set-aside for 2014 and thereafter is 2,963 tons.
(vi) [Reserved]
(12) Pennsylvania. (i) The SO$_2$ trading budget for 2012 and 2013 is 278,651 tons.
(ii) The SO$_2$ new unit set-aside for 2012 and 2013 is 5,573 tons.
(iii) [Reserved]
(iv) The SO$_2$ trading budget for 2014 and thereafter is 112,021 tons.
(v) The SO$_2$ new unit set-aside for 2014 and thereafter is 1,177 tons.
(vi) [Reserved]
(13) Virginia. (i) The SO$_2$ trading budget for 2012 and 2013 is 70,820 tons.
(ii) The SO$_2$ new unit set-aside for 2012 and 2013 is 2,833 tons.
(iii) [Reserved]
(iv) The SO$_2$ trading budget for 2014 and thereafter is 35,057 tons.
(v) The SO$_2$ new unit set-aside for 2014 and thereafter is 1,402 tons.
(vi) [Reserved]
(14) West Virginia. (i) The SO$_2$ trading budget for 2012 and 2013 is 146,174 tons.
(ii) The SO$_2$ new unit set-aside for 2012 and 2013 is 10,232 tons.
(iii) [Reserved]
(iv) The SO$_2$ trading budget for 2014 and thereafter is 75,668 tons.
(v) The SO$_2$ new unit set-aside for 2014 and thereafter is 5,297 tons.
(vi) [Reserved]
(15) Wisconsin. (i) The SO$_2$ trading budget for 2012 and 2013 is 79,480 tons.
(ii) The SO$_2$ new unit set-aside for 2012 and 2013 is 3,099 tons.
(iii) The SO$_2$ Indian country new unit set-aside for 2012 and 2013 is 80 tons.
(iv) The SO$_2$ trading budget for 2014 and thereafter is 47,883 tons.
(v) The SO$_2$ new unit set-aside for 2014 and thereafter is 1,867 tons.
(vi) The SO$_2$ Indian country new unit set-aside for 2014 and thereafter is 48 tons.
(b) The States’ variability limits for the State SO$_2$ Group 1 trading budgets for the control periods in 2014 and thereafter are as follows:
(1) The SO$_2$ variability limit for Illinois is 22,342 tons.
(2) The SO$_2$ variability limit for Indiana is 29,000 tons.
(3) The SO$_2$ variability limit for Iowa is 13,533 tons.
(4) The SO$_2$ variability limit for Kentucky is 19,131 tons.
(5) The SO$_2$ variability limit for Maryland is 5,077 tons.
(6) The SO$_2$ variability limit for Michigan is 25,919 tons.
(7) The SO$_2$ variability limit for Missouri is 29,869 tons.
(8) The SO$_2$ variability limit for New Jersey is 1,003 tons.
(9) The SO$_2$ variability limit for New York is 3,980 tons.
(10) The SO$_2$ variability limit for North Carolina is 10,372 tons.
(11) The \( \text{SO}_2 \) variability limit for Ohio is 24,674 tons.
(12) The \( \text{SO}_2 \) variability limit for Pennsylvania is 20,164 tons.
(13) The \( \text{SO}_2 \) variability limit for Tennessee is 10,590 tons.
(14) The \( \text{SO}_2 \) variability limit for Virginia is 6,310 tons.
(15) The \( \text{SO}_2 \) variability limit for West Virginia is 13,620 tons.
(16) The \( \text{SO}_2 \) variability limit for Wisconsin is 8,619 tons.

(c) Each \( \text{SO}_2 \) trading budget in this section includes any tons in a new unit set aside or Indian country new unit set-aside, but does not include any tons in a variability limit.

[77 FR 10339, Feb. 21, 2012]

EFFECTIVE DATE NOTE: At 77 FR 34846, June 12, 2012, § 97.610 was amended by revising paragraph (a)(2); paragraphs (a)(7)(ii) and (a)(7)(v); paragraphs (a)(9) and (a)(11); and paragraphs (b)(2), (b)(9), and (b)(11), effective Aug. 13, 2012. For the convenience of the user, the revised text is set forth as follows:

§ 97.610 State \( \text{SO}_2 \) Group 1 trading budgets, new unit set-asides, Indian country new unit set-aside, and variability limits.

(a) * * *
(2) Indiana. (i) The \( \text{SO}_2 \) trading budget for 2012 and 2013 is 290,762 tons.
(ii) The \( \text{SO}_2 \) new unit set-aside for 2012 and 2013 is 8,723 tons.
(iii) [Reserved]
(iv) The \( \text{SO}_2 \) trading budget for 2014 and thereafter is 166,449 tons.
(v) The \( \text{SO}_2 \) new unit set-aside for 2014 and thereafter is 4,993 tons.

* * * * *

(7) * * *
(ii) The \( \text{SO}_2 \) new unit set-aside for 2012 is 4,149 tons and for 2013 is 6,224 tons.

* * * * *

(v) The \( \text{SO}_2 \) new unit set-aside for 2014 and thereafter is 4,978 tons.

* * * * *

(9) New York. (i) The \( \text{SO}_2 \) trading budget for 2012 and 2013 is 36,296 tons.
(ii) The \( \text{SO}_2 \) new unit set-aside for 2012 and 2013 is 690 tons.
(iii) The \( \text{SO}_2 \) Indian country new unit set-aside for 2012 and 2013 is 36 tons.
(iv) The \( \text{SO}_2 \) trading budget for 2014 and thereafter is 27,556 tons.
(v) The \( \text{SO}_2 \) new unit set-aside for 2014 and thereafter is 528 tons.

* * * * *

(vi) The \( \text{SO}_2 \) Indian country new unit set-aside for 2014 and thereafter is 28 tons.

* * * * *

(11) Ohio. (i) The \( \text{SO}_2 \) trading budget for 2012 and 2013 is 315,393 tons.
(ii) The \( \text{SO}_2 \) new unit set-aside for 2012 and 2013 is 6,308 tons.
(iii) [Reserved]
(iv) The \( \text{SO}_2 \) trading budget for 2014 and thereafter is 142,240 tons.
(v) The \( \text{SO}_2 \) new unit set-aside for 2014 and thereafter is 2,845 tons.

* * * * *

(b) * * *
(2) The \( \text{SO}_2 \) variability limit for Indiana is 29,961 tons.

* * * * *

(9) The \( \text{SO}_2 \) variability limit for New York is 4,960 tons.

* * * * *

(11) The \( \text{SO}_2 \) variability limit for Ohio is 25,603 tons.

* * * * *

§ 97.611 Timing requirements for TR \( \text{SO}_2 \) Group 1 allowance allocations.

(a) Existing units. (1) TR \( \text{SO}_2 \) Group 1 allowances are allocated, for the control periods in 2012 and each year thereafter, as provided in a notice of data availability issued by the Administrator. Providing an allocation to a unit in such notice does not constitute a determination that the unit is a TR \( \text{SO}_2 \) Group 1 unit, and not providing an allocation to a unit in such notice does not constitute a determination that the unit is not a TR \( \text{SO}_2 \) Group 1 unit.

(2) Notwithstanding paragraph (a)(1) of this section, if a unit provided an allocation in the notice of data availability issued under paragraph (a)(1) of this section does not operate, starting after 2011, during the control period in two consecutive years, such unit will not be allocated the TR \( \text{SO}_2 \) Group 1 allowances provided in such notice for the unit for the control periods in the fifth year after the first such year and in each year after that fifth year. All TR \( \text{SO}_2 \) Group 1 allowances that would otherwise have been allocated to such unit will be allocated to the new unit.
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set-aside for the State where such unit is located and for the respective years involved. If such unit resumes operation, the Administrator will allocate TR SO\(_2\) Group 1 allowances to the unit in accordance with paragraph (b) of this section.

(b) New units. (1) New unit set-asides. (i) By June 1, 2012 and June 1 of each year thereafter, the Administrator will calculate the TR SO\(_2\) Group 1 allowance allocation to each TR SO\(_2\) Group 1 unit in a State, in accordance with §97.612(a)(2) through (7) and (12), for the control period in the year of the applicable calculation deadline under this paragraph and will promulgate a notice of data availability of the results of the calculations.

(ii) For each notice of data availability required in paragraph (b)(1)(i) of this section, the Administrator will provide an opportunity for submission of objections to the calculations referenced in such notice.

(A) Objections shall be submitted by the deadline specified in each notice of data availability required in paragraph (b)(1)(i) of this section and shall be limited to addressing whether the calculations (including the identification of the TR SO\(_2\) Group 1 units) are in accordance with §97.612(a)(2) through (7) and (12) and §§97.606(b)(2) and 97.630 through 97.635.

(B) The Administrator will adjust the calculations to the extent necessary to ensure that they are in accordance with the provisions referenced in paragraph (b)(1)(ii)(A) of this section. By August 1 immediately after the promulgation of each notice of data availability required in paragraph (b)(1)(i) of this section, the Administrator will promulgate a notice of data availability of any adjustments that the Administrator determines to be necessary with regard to allocations under §97.612(a)(2) through (7) and (12) and the reasons for accepting or rejecting any objections submitted in accordance with paragraph (b)(1)(ii)(A) of this section.

(iii) If the new unit set-aside for such control period contains any TR SO\(_2\) Group 1 allowances that have not been allocated in the applicable notice of data availability required in paragraph (b)(1)(ii) of this section, the Administrator will promulgate, by December 15 immediately after such notice, a notice of data availability that identifies any TR SO\(_2\) Group 1 units that commenced commercial operation during the period starting January 1 of the year before the year of such control period and ending November 30 of year of such control period.

(iv) For each notice of data availability required in paragraph (b)(1)(iii) of this section, the Administrator will provide an opportunity for submission of objections to the identification of TR SO\(_2\) annual units in such notice.

(A) Objections shall be submitted by the deadline specified in each notice of data availability required in paragraph (b)(1)(iii) of this section and shall be limited to addressing whether the identification of TR SO\(_2\) annual units in such notice is in accordance with paragraph (b)(1)(iii) of this section.

(B) The Administrator will adjust the identification of TR SO\(_2\) Group 1 units in each notice of data availability required in paragraph (b)(1)(iii) of this section to the extent necessary to ensure that it is in accordance with paragraph (b)(1)(iii) of this section and will calculate the TR SO\(_2\) Group 1 allowance allocation to each TR SO\(_2\) Group 1 unit in accordance with §97.612(a)(9), (10), and (12) and §§97.606(b)(2) and 97.630 through 97.635. By February 15 immediately after the promulgation of each notice of data availability required in paragraph (b)(1)(iii) of this section, the Administrator will promulgate a notice of data availability of any adjustments of the identification of TR SO\(_2\) Group 1 units that the Administrator determines to be necessary, the reasons for accepting or rejecting any objections submitted in accordance with paragraph (b)(1)(iv)(A) of this section, and the results of such calculations.

(v) To the extent any TR SO\(_2\) Group 1 allowances are added to the new unit set-aside after promulgation of each notice of data availability required in paragraph (b)(1)(iv) of this section, the Administrator will promulgate additional notices of data availability, as deemed appropriate, of the allocation of such TR SO\(_2\) Group 1 allowances in accordance with §97.612(a)(10).

(2) Indian country new unit set-asides. (i) By June 1, 2012 and June 1 of
each year thereafter, the Administrator will calculate the TR SO₂ Group 1 allowance allocation to each TR SO₂ Group 1 unit in Indian country within the borders of a State, in accordance with § 97.612(b)(2) through (7) and (12), for the control period in the year of the applicable calculation deadline under this paragraph and will promulgate a notice of data availability of the results of the calculations.

(ii) For each notice of data availability required in paragraph (b)(2)(i) of this section, the Administrator will provide an opportunity for submission of objections to the identification of TR SO₂ annual units in such notice.

(A) Objections shall be submitted by the deadline specified in each notice of data availability required in paragraph (b)(2)(i) of this section and shall be limited to addressing whether the identification of the TR SO₂ Group 1 units is in accordance with § 97.606(b)(2) and 97.630 through 97.635.

(B) The Administrator will adjust the calculations to the extent necessary to ensure that they are in accordance with the provisions referenced in paragraph (b)(2)(i) of this section. By August 1 immediately after the promulgation of each notice of data availability required in paragraph (b)(2)(i) of this section, the Administrator will promulgate a notice of data availability of any adjustments of the identification of TR SO₂ Group 1 units that the Administrator determines to be necessary, the reasons for accepting or rejecting any objections submitted in accordance with paragraph (b)(2)(i)(A) of this section, and the results of such calculations.

(iii) If the Indian country new unit set-aside for such control period contains any TR SO₂ Group 1 allowances that have not been allocated in the applicable notice of data availability required in paragraph (b)(2)(i) of this section, the Administrator will promulgate, by December 15 immediately after such notice, a notice of data availability that identifies any TR SO₂ Group 1 units that commenced commercial operation during the period starting January 1 of the year before the year of such control period and ending November 30 of year of such control period.

(iv) For each notice of data availability required in paragraph (b)(2)(iii) of this section, the Administrator will provide an opportunity for submission of objections to the identification of TR SO₂ annual units in such notice.

(A) Objections shall be submitted by the deadline specified in each notice of data availability required in paragraph (b)(2)(iii) of this section and shall be limited to addressing whether the identification of TR SO₂ annual units in such notice is in accordance with paragraph (b)(2)(iii) of this section.

(B) The Administrator will adjust the identification of TR SO₂ Group 1 units in each notice of data availability required in paragraph (b)(2)(iii) of this section to the extent necessary to ensure that it is in accordance with paragraph (b)(2)(iii) of this section and will calculate the TR SO₂ Group 1 allowance allocation to each TR SO₂ Group 1 unit in accordance with § 97.612(b)(9), (10), and (12) and §§ 97.606(b)(2) and 97.630 through 97.635. By February 15 immediately after the promulgation of each notice of data availability required in paragraph (b)(2)(iii) of this section, the Administrator will promulgate additional notices of data availability, as deemed appropriate, of the allocation of such TR NOₓ Annual allowances in accordance with § 97.612(b)(10).

(c) Units incorrectly allocated TR SO₂ Group 1 allowances. (1) For each control period in 2012 and thereafter, if the Administrator determines that TR SO₂ Group 1 allowances were allocated under a provision of a SIP revision approved under § 52.39(d), (e), or (f) of this
chapter, where such control period and the recipient are covered by the provisions of paragraph (c)(1)(i) of this section or were allocated under §97.612(a)(2) through (7), (9), and (12) and (b)(2) through (7), (9), and (12), or under a provision of a SIP revision approved under §52.39(e) or (f) of this chapter, where such control period and the recipient are covered by the provisions of paragraph (c)(1)(ii) of this section, then the Administrator will notify the designated representative of the recipient and will act in accordance with the procedures set forth in paragraphs (c)(2) through (5) of this section:

(i)(A) The recipient is not actually a TR SO\textsubscript{2} Group 1 unit under §97.604 as of January 1, 2012 and is allocated TR SO\textsubscript{2} Group 1 allowances for such control period or, in the case of an allocation under a provision of a SIP revision approved under §52.39(d), (e), or (f) of this chapter, the recipient is not actually a TR SO\textsubscript{2} Group 1 unit as of January 1, 2012 and is allocated TR SO\textsubscript{2} Group 1 allowances for such control period that the SIP revision provides should be allocated only to recipients that are TR SO\textsubscript{2} Group 1 units as of January 1, 2012; or

(B) The recipient is not located as of January 1 of the control period in the State from whose SO\textsubscript{2} Group 1 trading budget the TR SO\textsubscript{2} Group 1 allowances allocated under paragraph (a) of this section, or under a provision of a SIP revision approved under §52.39(d), (e), or (f) of this chapter, were allocated for such control period.

(ii) The recipient is not actually a TR SO\textsubscript{2} Group 1 unit under §97.604 as of January 1 of such control period and is allocated TR SO\textsubscript{2} Group 1 allowances for such control period or, in the case of an allocation under a provision of a SIP revision approved under §52.39(d), (e), or (f) of this chapter, the recipient is not actually a TR SO\textsubscript{2} Group 1 unit as of January 1 of such control period and is allocated TR SO\textsubscript{2} Group 1 allowances for such control period that the SIP revision provides should be allocated only to recipients that are TR SO\textsubscript{2} Group 1 units as of January 1 of such control period.

(2) Except as provided in paragraph (c)(3) or (4) of this section, the Administrator will not record such TR SO\textsubscript{2} Group 1 allowances under §97.621.

(3) If the Administrator already recorded such TR SO\textsubscript{2} Group 1 allowances under §97.621 and if the Administrator makes the determination under paragraph (c)(1) of this section before making deductions for the source that includes such recipient under §97.624(b) for such control period, then the Administrator will deduct from the account in which such TR SO\textsubscript{2} Group 1 allowances were recorded an amount of TR SO\textsubscript{2} Group 1 allowances allocated for the same or a prior control period equal to the amount of such already recorded TR SO\textsubscript{2} Group 1 allowances. The authorized account representative shall ensure that there are sufficient TR SO\textsubscript{2} Group 1 allowances in such account for completion of the deduction.

(4) If the Administrator already recorded such TR SO\textsubscript{2} Group 1 allowances under §97.621 and if the Administrator makes the determination under paragraph (c)(1) of this section after making deductions for the source that includes such recipient under §97.624(b) for such control period, then the Administrator will not make any deduction to take account of such already recorded TR SO\textsubscript{2} Group 1 allowances.

(5)(i) With regard to the TR SO\textsubscript{2} Group 1 allowances that are not recorded, or that are deducted as an incorrect allocation, in accordance with paragraphs (c)(2) and (3) of this section for a recipient under paragraph (c)(1)(i) of this section, the Administrator will:

(A) Transfer such TR SO\textsubscript{2} Group 1 allowances to the new unit set-aside for such control period for the State from whose SO\textsubscript{2} Group 1 trading budget the TR SO\textsubscript{2} Group 1 allowances were allocated;

(B) If the State has a SIP revision approved under §52.39(e) or (f) covering such control period, include such TR SO\textsubscript{2} Group 1 allowances in the portion of the State SO\textsubscript{2} Group 1 trading budget that may be allocated for such control period in accordance with such SIP revision.

(ii) With regard to the TR SO\textsubscript{2} Group 1 allowances that were not allocated from the Indian country new unit set-aside for such control period and that are not recorded, or that are deducted
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as an incorrect allocation, in accordance with paragraphs (c)(2) and (3) of this section for a recipient under paragraph (c)(1)(ii) of this paragraph, the Administrator will:

(A) Transfer such TR SO\(_2\) Group 1 allowances to the new unit set-aside for such control period; or

(B) If the State has a SIP revision approved under §52.39(e) or (f) covering such control period, include such TR SO\(_2\) Group 1 allowances in the portion of the State SO\(_2\) Group 1 trading budget that may be allocated for such control period in accordance with such SIP revision.

(iii) With regard to the TR SO\(_2\) Group 1 allowances that were allocated from the Indian country new unit set-aside for such control period and that are not recorded, or that are deducted as an incorrect allocation, in accordance with paragraphs (c)(2) and (3) of this section for a recipient under paragraph (c)(1)(ii) of this paragraph, the Administrator will transfer such TR SO\(_2\) Group 1 allowances to the Indian country new unit set-aside for such control period.

§ 97.612 TR SO\(_2\) Group 1 allowance allocations to new units.

(a) For each control period in 2012 and thereafter and for the TR SO\(_2\) Group 1 units in each State, the Administrator will allocate TR SO\(_2\) Group 1 allowances to the TR SO\(_2\) Group 1 units as follows:

(1) The TR SO\(_2\) Group 1 allowances will be allocated to the following TR SO\(_2\) Group 1 units, except as provided in paragraph (a)(10) of this section:

(i) TR SO\(_2\) Group 1 units that are not allocated an amount of TR SO\(_2\) Group 1 allowances in the notice of data availability issued under §97.611(a)(1);

(ii) TR SO\(_2\) Group 1 units whose allocation of an amount of TR SO\(_2\) Group 1 allowances for such control period in the notice of data availability issued under §97.611(a)(1) is covered by §97.611(c)(2) or (3);

(iii) TR SO\(_2\) Group 1 units that are allocated an amount of TR SO\(_2\) Group 1 allowances for such control period in the notice of data availability issued under §97.611(a)(1), which allocation is terminated for such control period pursuant to §97.611(a)(2), and that operate during the control period immediately preceding such control period; or

(iv) For purposes of paragraph (a)(9) of this section, TR SO\(_2\) Group 1 units under §97.611(c)(1)(i) whose allocation of an amount of TR SO\(_2\) Group 1 allowances for such control period in the notice of data availability issued under §97.611(b)(1)(ii)(B) is covered by §97.611(c)(2) or (3).

(2) The Administrator will establish a separate new unit set-aside for the State for each such control period. Each such new unit set-aside will be allocated TR SO\(_2\) Group 1 allowances in an amount equal to the applicable amount of tons of SO\(_2\) emissions as set forth in §97.610(a) and will be allocated additional TR SO\(_2\) Group 1 allowances (if any) in accordance with §§97.611(a)(2) and (c)(5) and paragraph (b)(10) of this section.

(3) The Administrator will determine, for each TR SO\(_2\) Group 1 unit described in paragraph (a)(1) of this section, an allocation of TR SO\(_2\) Group 1 allowances for the later of the following control periods and for each subsequent control period:

(i) The control period in 2012;

(ii) The first control period after the control period in which the TR SO\(_2\) Group 1 unit commences commercial operation;

(iii) For a unit described in paragraph (a)(1)(ii) of this section, the first control period in which the TR SO\(_2\) Group 1 unit operates in the State after operating in another jurisdiction and for which the unit is not already allocated one or more TR SO\(_2\) Group 1 allowances; and

(iv) For a unit described in paragraph (a)(1)(iii) of this section, the first control period after the control period in which the unit resumes operation.

(4)(i) The allocation to each TR SO\(_2\) annual unit described in paragraph (a)(1)(i) through (iii) of this section and for each control period described in paragraph (a)(3) of this section will be an amount equal to the unit’s total tons of SO\(_2\) emissions during the immediately preceding control period.

(ii) The Administrator will adjust the allocation amount in paragraph (a)(4)(i) in accordance with paragraphs (a)(5) through (7) and (12) of this section.
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(5) The Administrator will calculate the sum of the TR SO2 Group 1 allowances determined for all such TR SO2 Group 1 units under paragraph (a)(4)(i) of this section in the State for such control period.

(6) If the amount of TR SO2 Group 1 allowances in the new unit set-aside for the State for such control period is greater than or equal to the sum under paragraph (a)(5) of this section, then the Administrator will allocate the amount of TR SO2 Group 1 allowances determined for each such TR SO2 Group 1 unit under paragraph (a)(4)(i) of this section.

(7) If the amount of TR SO2 Group 1 allowances in the new unit set-aside for the State for such control period is less than the sum under paragraph (a)(5) of this section, then the Administrator will allocate to each such TR SO2 Group 1 unit the amount of the TR SO2 Group 1 allowances determined under paragraph (a)(4)(i) of this section for the unit, multiplied by the amount of TR SO2 Group 1 allowances in the new unit set-aside for such control period, divided by the sum under paragraph (a)(5) of this section, and rounded to the nearest allowance.

(8) The Administrator will notify the public, through the promulgation of the notices of data availability described in §97.611(b)(1)(i) and (ii), of the amount of TR SO2 Group 1 allowances allocated under paragraphs (a)(2) through (7) and (12) of this section for such control period to each TR SO2 Group 1 unit eligible for such alloca-

(9) If, after completion of the procedures under paragraphs (a)(5) through (8) of this section for such control period, any unallocated TR SO2 Group 1 allowances remain in the new unit set-aside for the State for such control period, the Administrator will allocate such TR SO2 Group 1 allowances as follows-

(i) The Administrator will determine, for each unit described in paragraph (a)(1) of this section that commenced commercial operation during the period starting January 1 of the year before the year of such control period and ending November 30 of year of such control period, the positive difference (if any) between the unit’s emissions during such control period and the amount of TR SO2 Group 1 allowances referenced in the notice of data availability required under §97.611(b)(1)(ii) for the unit for such control period;

(ii) The Administrator will allocate the sum of the positive differences determined under paragraph (a)(9)(i) of this section;

(iii) If the amount of unallocated TR SO2 Group 1 allowances remaining in the new unit set-aside for the State for such control period is greater than or equal to the sum determined under paragraph (a)(9)(ii) of this section, then the Administrator will allocate the amount of TR SO2 Group 1 allowances determined for each such TR SO2 Group 1 unit under paragraph (a)(9)(i) of this section;

(iv) If the amount of unallocated TR SO2 Group 1 allowances remaining in the new unit set-aside for the State for such control period is less than the sum under paragraph (a)(9)(ii) of this section, then the Administrator will allocate to each such TR SO2 Group 1 unit the amount of the TR SO2 Group 1 allowances determined under paragraph (a)(9)(i) of this section for the unit, multiplied by the amount of unallocated TR SO2 Group 1 allowances remaining in the new unit set-aside for such control period, divided by the sum under paragraph (a)(9)(ii) of this section, and rounded to the nearest allowance.

(10) If, after completion of the procedures under paragraphs (a)(9) and (12) of this section for such control period, any unallocated TR SO2 Group 1 allowances remain in the new unit set-aside for the State for such control period, the Administrator will allocate to each TR SO2 Group 1 unit that is in the State, is allocated an amount of TR SO2 Group 1 allowances in the notice of data availability issued under §97.611(a)(1), and continues to be allocated TR SO2 Group 1 allowances for such control period in accordance with §97.611(a)(2), an amount of TR SO2 Group 1 allowances equal to the following: The total amount of such remaining unallocated TR SO2 Group 1 allowances in such new unit set-aside, multiplied by the unit’s allocation under §97.611(a) for such control period, divided by the remainder of the
amount of tons in the applicable State SO₂ Group 1 trading budget minus the sum of the amounts of tons in such new unit set-aside and the Indian country new unit set-aside for the State for such control period, and rounded to the nearest allowance.

(11) The Administrator will notify the public, through the promulgation of the notices of data availability described in §97.611(b)(1)(iii), (iv), and (v), of the amount of TR SO₂ Group 1 allowances allocated under paragraphs (a)(9), (10), and (12) of this section for such control period to each TR SO₂ Group 1 unit eligible for such allocation.

(12)(i) Notwithstanding the requirements of paragraphs (a)(2) through (11) of this section, if the calculations of allocations of a new unit set-aside for a control period in a given year under paragraph (a)(7) of this section, paragraphs (a)(6) and (9)(iv) of this section, or paragraphs (a)(6), (9)(iii), and (10) of this section would otherwise result in total allocations of such new unit set-aside exceeding the total amount of such new unit set-aside, then the Administrator will adjust the results of the calculations under paragraph (a)(7), (9)(iv), or (10) of this section, as applicable, as follows. The Administrator will list the TR SO₂ Group 1 units in descending order based on the amount of such units’ allocations under paragraph (a)(7), (9)(iv), or (10) of this section, as applicable, and, in cases of equal allocation amounts, in alphabetical order of the relevant source’s name and numerical order of the relevant unit’s identification number, and will reduce each unit’s allocation under paragraph (a)(10) of this section by one TR SO₂ Group 1 allowance in the order in which the units are listed and will repeat this reduction process as necessary, until the total allocations of such new unit set-aside equal the total amount of such new unit set-aside.

(b) For each control period in 2012 and thereafter and for the TR SO₂ Group 1 units located in Indian country within the borders of each State, the Administrator will allocate TR SO₂ Group 1 allowances to the TR SO₂ Group 1 units as follows:

(1) The TR SO₂ Group 1 allowances will be allocated to the following TR SO₂ Group 1 units, except as provided in paragraph (b)(10) of this section:

(i) TR SO₂ Group 1 units that are not allocated an amount of TR SO₂ Group 1 allowances in the notice of data availability issued under §97.611(a)(1); or

(ii) For purposes of paragraph (b)(9) of this section, TR SO₂ Group 1 units under §97.611(c)(1)(i) whose allocation of an amount of TR SO₂ Group 1 allowances for such control period in the notice of data availability issued under §97.611(b)(2)(ii)(B) is covered by §97.611(c)(2) or (3).

(2) The Administrator will establish a separate Indian country new unit set-aside for the State for each such control period. Each such Indian country new unit set-aside will be allocated TR SO₂ Group 1 allowances in an amount equal to the applicable amount of tons of SO₂ emissions as set forth in §97.610(a) and will be allocated additional TR SO₂ Group 1 allowances (if any) in accordance with §97.611(c)(5).

(3) The Administrator will determine, for each TR SO₂ Group 1 unit described in paragraph (b)(1) of this section, an
allocation of TR SO\textsubscript{2} Group 1 allowances for the later of the following control periods and for each subsequent control period:

(i) The control period in 2012; and

(ii) The first control period after the control period in which the TR SO\textsubscript{2} Group 1 unit commences commercial operation.

(4)(i) The allocation to each TR SO\textsubscript{2} annual unit described in paragraph (b)(1)(i) of this section and for each control period described in paragraph (b)(3) of this section will be an amount equal to the unit’s total tons of SO\textsubscript{2} emissions during the immediately preceding control period.

(ii) The Administrator will adjust the allocation amount in paragraph (b)(4)(i) in accordance with paragraphs (b)(5) through (7) and (12) of this section.

(5) The Administrator will calculate the sum of the TR SO\textsubscript{2} Group 1 allowances determined for all such TR SO\textsubscript{2} Group 1 units under paragraph (b)(4)(i) of this section in Indian country within the borders of the State for such control period.

(6) If the amount of TR SO\textsubscript{2} Group 1 allowances in the Indian country new unit set-aside for the State for such control period is greater than or equal to the sum under paragraph (b)(5) of this section, then the Administrator will allocate the amount of TR SO\textsubscript{2} Group 1 allowances determined for each such TR SO\textsubscript{2} Group 1 unit under paragraph (b)(4)(i) of this section.

(7) If the amount of TR SO\textsubscript{2} Group 1 allowances in the Indian country new unit set-aside for the State for such control period is less than the sum under paragraph (b)(5) of this section, then the Administrator will allocate to each such TR SO\textsubscript{2} Group 1 unit the amount of the TR SO\textsubscript{2} Group 1 allowances determined under paragraph (b)(4)(i) of this section for the unit, multiplied by the amount of TR SO\textsubscript{2} Group 1 allowances in the Indian country new unit set-aside for such control period, divided by the sum under paragraph (b)(5) of this section, and rounded to the nearest allowance.

The Administrator will notify the public, through the promulgation of the notices of data availability described in §97.611(b)(2)(i) and (ii), of the amount of TR SO\textsubscript{2} Group 1 allowances allocated under paragraphs (b)(2) through (7) and (12) of this section for such control period to each TR SO\textsubscript{2} Group 1 unit eligible for such allocation.

(9) If, after completion of the procedures under paragraphs (b)(5) through (8) of this section for such control period, any unallocated TR SO\textsubscript{2} Group 1 allowances remain in the Indian country new unit set-aside for the State for such control period, the Administrator will allocate such TR SO\textsubscript{2} Group 1 allowances as follows—

(i) The Administrator will determine, for each unit described in paragraph (b)(1) of this section that commenced commercial operation during the period starting January 1 of the year before the year of such control period and ending November 30 of year of such control period, the positive difference (if any) between the unit’s emissions during such control period and the amount of TR SO\textsubscript{2} Group 1 allowances determined under paragraph (b)(4)(i) of this section for the unit, multiplied by the amount of unallocated TR SO\textsubscript{2} Group 1 allowances remaining in the Indian country.

(ii) The Administrator will determine the sum of the positive differences determined under paragraph (b)(9)(i) of this section;

(iii) If the amount of unallocated TR SO\textsubscript{2} Group 1 allowances remaining in the Indian country new unit set-aside for the State for such control period is less than the sum under paragraph (b)(9)(ii) of this section, then the Administrator will allocate the amount of TR SO\textsubscript{2} Group 1 allowances determined for each such TR SO\textsubscript{2} Group 1 unit under paragraph (b)(9)(i) of this section, and rounded to the nearest allowance; and

(iv) If the amount of unallocated TR SO\textsubscript{2} Group 1 allowances remaining in the Indian country new unit set-aside for the State for such control period is less than the sum under paragraph (b)(9)(ii) of this section, then the Administrator will allocate to each such TR SO\textsubscript{2} Group 1 unit the amount of the TR SO\textsubscript{2} Group 1 allowances determined under paragraph (b)(9)(i) of this section for the unit.
new unit set-aside for such control period, divided by the sum under paragraph (b)(9)(ii) of this section, and rounded to the nearest allowance.

(10) If, after completion of the procedures under paragraphs (b)(9) and (12) of this section for such control period, any unallocated TR SO₂ Group 1 allowances remain in the Indian country new unit set-aside for the State for such control period, the Administrator will:

(i) Transfer such unallocated TR SO₂ Group 1 allowances to the new unit set-aside for the State for such control period; or

(ii) If the State has a SIP revision approved under §52.39(d), (e), or (f) of this chapter covering such control period, include such unallocated TR SO₂ Group 1 allowances in the portion of the State SO₂ Group 1 trading budget that may be allocated for such control period in accordance with such SIP revision.

(11) The Administrator will notify the public, through the promulgation of the notices of data availability described in §97.611(b)(2)(iii), (iv), and (v), of the amount of TR SO₂ Group 1 allowances allocated under paragraphs (b)(9), (10), and (12) for such control period to each TR SO₂ Group 1 unit eligible for such allocation.

(12)(i) Notwithstanding the requirements of paragraphs (b)(2) through (11) of this section, if the calculations of allocations of an Indian country new unit set-aside for a control period in a given year under paragraph (b)(7) of this section, paragraphs (b)(6), (9)(iv), or (10) of this section would otherwise result in a total allocations of such Indian country new unit set-aside less than the total amount of such Indian country new unit set-aside, then the Administrator will adjust the results of the calculations under paragraph (b)(10) of this section, as follows. The Administrator will list the TR SO₂ Group 1 units in descending order based on the amount of such units’ allocations under paragraph (b)(10) of this section and, in cases of equal allocation amounts, in alphabetical order of the relevant source’s name and numerical order of the relevant unit’s identification number, and will increase each unit’s allocation under paragraph (b)(10) of this section by one TR SO₂ Group 1 allowance in the order in which the units are listed and will repeat this increase process as necessary, until the total allocations of such Indian country new unit set-aside equal the total amount of such Indian country new unit set-aside.

(ii) Notwithstanding the requirements of paragraphs (b)(10) and (11) of this section, if the calculations of allocations of an Indian country new unit set-aside for a control period in a given year under paragraphs (b)(6), (9)(iii), and (10) of this section would otherwise result in total allocations of such Indian country new unit set-aside exceeding the total amount of such Indian country new unit set-aside, then the Administrator will adjust the results of the calculations under paragraph (b)(7), (9)(iv), or (10) of this section, as applicable, by one TR SO₂ Group 1 allowance (but not below zero) in the order in which the units are listed and will repeat this reduction process as necessary, until the total allocations of such Indian country new unit set-aside equal the total amount of such Indian country new unit set-aside.

§97.613 Authorization of designated representative and alternate designated representative.

(a) Except as provided under §97.615, each TR SO₂ Group 1 source, including all TR SO₂ Group 1 units at the source, shall have one and only one designated representative, with regard to all matters under the TR SO₂ Group 1 Trading Program.

(1) The designated representative shall be selected by an agreement binding on the owners and operators of the source and all TR SO₂ Group 1 units at the source and shall act in accordance
with the certification statement in §97.616(a)(4)(iii).

(2) Upon and after receipt by the Administrator of a complete certificate of representation under §97.616:

(i) The designated representative shall be authorized and shall represent and, by his or her representations, actions, inactions, or submissions, legally bind each owner and operator of the source and each TR SO\textsubscript{2} Group 1 unit at the source in all matters pertaining to the TR SO\textsubscript{2} Group 1 Trading Program, notwithstanding any agreement between the designated representative and such owners and operators; and

(ii) The owners and operators of the source and each TR SO\textsubscript{2} Group 1 unit at the source shall be bound by any decision or order issued to the designated representative by the Administrator regarding the source or any such unit.

(b) Except as provided under §97.615, each TR SO\textsubscript{2} Group 1 source may have one and only one alternate designated representative, who may act on behalf of the designated representative. The agreement by which the alternate designated representative is selected shall include a procedure for authorizing the alternate designated representative to act in lieu of the designated representative.

(1) The alternate designated representative shall be selected by an agreement binding on the owners and operators of the source and all TR SO\textsubscript{2} Group 1 units at the source and shall act in accordance with the certification statement in §97.616(a)(4)(iii).

(2) Upon and after receipt by the Administrator of a complete certificate of representation under §97.616:

(i) The alternate designated representative shall be authorized;

(ii) Any representation, action, inaction, or submission by the alternate designated representative shall be deemed to be a representation, action, inaction, or submission by the designated representative; and

(iii) The owners and operators of the source and each TR SO\textsubscript{2} Group 1 unit at the source shall be bound by any decision or order issued to the alternate designated representative by the Administrator regarding the source or any such unit.

(c) Except in this section, §97.602, and §§97.614 through 97.618, whenever the term “designated representative” (as distinguished from the term “common designated representative”) is used in this subpart, the term shall be construed to include the designated representative or any alternate designated representative.

§97.614 Responsibilities of designated representative and alternate designated representative.

(a) Except as provided under §97.618 concerning delegation of authority to make submissions, each submission under the TR SO\textsubscript{2} Group 1 Trading Program shall be made, signed, and certified by the designated representative or alternate designated representative for each TR SO\textsubscript{2} Group 1 source and TR SO\textsubscript{2} Group 1 unit for which the submission is made. Each such submission shall include the following certification statement by the designated representative or alternate designated representative: “I am authorized to make this submission on behalf of the owners and operators of the source or units for which the submission is made. I certify under penalty of law that I have personally examined, and am familiar with, the statements and information submitted in this document and all its attachments. Based on my inquiry of those individuals with primary responsibility for obtaining the information, I certify that the statements and information are to the best of my knowledge and belief true, accurate, and complete. I am aware that there are significant penalties for submitting false statements and information or omitting required statements and information, including the possibility of fine or imprisonment.”

(b) The Administrator will accept or act on a submission made for a TR SO\textsubscript{2} Group 1 source or a TR SO\textsubscript{2} Group 1 unit only if the submission has been made, signed, and certified in accordance with paragraph (a) of this section and §97.618.
§ 97.615 Changing designated representative and alternate designated representative; changes in owners and operators; changes in units at the source.

(a) Changing designated representative. The designated representative may be changed at any time upon receipt by the Administrator of a superseding complete certificate of representation under §97.616. Notwithstanding any such change, all representations, actions, inactions, and submissions by the previous designated representative before the time and date when the Administrator receives the superseding certificate of representation shall be binding on the new designated representative and the owners and operators of the TR SO\(_2\) Group 1 source and the TR SO\(_2\) Group 1 units at the source.

(b) Changing alternate designated representative. The alternate designated representative may be changed at any time upon receipt by the Administrator of a superseding complete certificate of representation under §97.616. Notwithstanding any such change, all representations, actions, inactions, and submissions by the previous alternate designated representative before the time and date when the Administrator receives the superseding certificate of representation shall be binding on the new alternate designated representative, the designated representative, and the owners and operators of the TR SO\(_2\) Group 1 source and the TR SO\(_2\) Group 1 units at the source.

(c) Changes in owners and operators. (1) In the event an owner or operator of a TR SO\(_2\) Group 1 source or a TR SO\(_2\) Group 1 unit at the source is not included in the list of owners and operators in the certificate of representation under §97.616, such owner or operator shall be deemed to be subject to and bound by the certificate of representation, the representations, actions, inactions, and submissions of the designated representative and any alternate designated representative of the source or unit, and the decisions and orders of the Administrator, as if the owner or operator were included in such list.

(2) Within 30 days after any change in the owners and operators of a TR SO\(_2\) Group 1 source or a TR SO\(_2\) Group 1 unit at the source, including the addition or removal of an owner or operator, the designated representative or any alternate designated representative shall submit a revision to the certificate of representation under §97.616 amending the list of owners and operators to reflect the change.

(d) Changes in units at the source. Within 30 days of any change in which units are located at a TR SO\(_2\) Group 1 source (including the addition or removal of a unit), the designated representative or any alternate designated representative shall submit a certificate of representation under §97.616 amending the list of units to reflect the change.

1. If the change is the addition of a unit that operated (other than for purposes of testing by the manufacturer before initial installation) before being located at the source, then the certificate of representation shall identify, in a format prescribed by the Administrator, the entity from whom the unit was purchased or otherwise obtained (including name, address, telephone number, and facsimile number (if any)), the date on which the unit was purchased or otherwise obtained, and the date on which the unit became located at the source.

2. If the change is the removal of a unit, then the certificate of representation shall identify, in a format prescribed by the Administrator, the entity to which the unit was sold or that otherwise obtained the unit (including name, address, telephone number, and facsimile number (if any)), the date on which the unit was sold or otherwise obtained, and the date on which the unit became no longer located at the source.

§ 97.616 Certificate of representation.

(a) A complete certificate of representation for a designated representative or an alternate designated representative shall include the following elements in a format prescribed by the Administrator:

1. Identification of the TR SO\(_2\) Group 1 source, and each TR SO\(_2\) Group 1 unit at the source, for which the certificate of representation is submitted, including source name, source category and NAICS code (or, in the absence of
§ 97.617 Objections concerning designated representative and alternate designated representative.

(a) Once a complete certificate of representation under §97.616 has been submitted and received, the Administrator will rely on the certificate of representation unless and until a superseding complete certificate of representation under §97.616 is received by the Administrator.

(b) Except as provided in paragraph (a) of this section, no objection or other communication submitted to the Administrator concerning the authorization, or any representation, action, inaction, or submission, of a designated representative or alternate designated representative shall affect any representation, action, inaction, or submission of the designated representative or alternate designated representative or the finality of any decision or order by the Administrator under the TR SO\textsubscript{2} Group 1 Trading Program.
(c) The Administrator will not adjudicate any private legal dispute concerning the authorization or any representation, action, inaction, or submission of any designated representative or alternate designated representative, including private legal disputes concerning the proceeds of TR SO\textsubscript{2} Group I allowance transfers.

§ 97.618 Delegation by designated representative and alternate designated representative.

(a) A designated representative may delegate, to one or more natural persons, his or her authority to make an electronic submission to the Administrator provided for or required under this subpart.

(b) An alternate designated representative may delegate, to one or more natural persons, his or her authority to make an electronic submission to the Administrator provided for or required under this subpart.

(c) In order to delegate authority to a natural person to make an electronic submission to the Administrator in accordance with paragraph (a) or (b) of this section, the designated representative or alternate designated representative, as appropriate, must submit to the Administrator a notice of delegation, in a format prescribed by the Administrator, that includes the following elements:

(1) The name, address, e-mail address, telephone number, and facsimile transmission number (if any) of such designated representative or alternate designated representative;

(2) The name, address, e-mail address, telephone number, and facsimile transmission number (if any) of each such natural person (referred to in this section as an “agent”);

(3) For each such natural person, a list of the type or types of electronic submissions under paragraph (a) or (b) of this section for which authority is delegated to him or her; and

(4) The following certification statements by such designated representative or alternate designated representative:

(i) ‘I agree that any electronic submission to the Administrator that is made by an agent identified in this notice of delegation and of a type listed for such agent in this notice of delegation and that is made when I am a designated representative or alternate designated representative, as appropriate, and before this notice of delegation is superseded by another notice of delegation under 40 CFR 97.618(d) shall be deemed to be an electronic submission by me.’

(ii) ‘Until this notice of delegation is superseded by another notice of delegation under 40 CFR 97.618(d), I agree to maintain an e-mail account and to notify the Administrator immediately of any change in my e-mail address unless all delegation of authority by me under 40 CFR 97.618 is terminated.’

(d) A notice of delegation submitted under paragraph (c) of this section shall be effective, with regard to the designated representative or alternate designated representative identified in such notice, upon receipt of such notice by the Administrator and until receipt by the Administrator of a superseding notice of delegation submitted by such designated representative or alternate designated representative, as appropriate. The superseding notice of delegation may replace any previously identified agent, add a new agent, or eliminate entirely any delegation of authority.

(e) Any electronic submission covered by the certification in paragraph (c)(4)(i) of this section and made in accordance with a notice of delegation effective under paragraph (d) of this section shall be deemed to be an electronic submission by the designated representative or alternate designated representative submitting such notice of delegation.

§ 97.619 [Reserved]

§ 97.620 Establishment of compliance accounts, assurance accounts, and general accounts.

(a) Compliance accounts. Upon receipt of a complete certificate of representation under §97.616, the Administrator will establish a compliance account for the TR SO\textsubscript{2} Group I source for which the certificate of representation was submitted, unless the source already has a compliance account. The designated representative and any alternate designated representative of the source shall be the authorized account.
representative and the alternate authorized account representative respectively of the compliance account.

(b) Assurance accounts. The Administrator will establish assurance accounts for certain owners and operators and States in accordance with §97.625(b)(3).

(c) General accounts. (1) Application for general account. (i) Any person may apply to open a general account, for the purpose of holding and transferring TR SO_2 Group 1 allowances, by submitting to the Administrator a complete application for a general account. Such application shall designate one and only one authorized account representative and may designate one and only one alternate authorized account representative who may act on behalf of the authorized account representative.

(A) The authorized account representative and alternate authorized account representative shall be selected by an agreement binding on the persons who have an ownership interest with respect to TR SO_2 Group 1 allowances held in the general account.

(B) The agreement by which the alternate authorized account representative is selected shall include a procedure for authorizing the alternate authorized account representative to act in lieu of the authorized account representative.

(ii) A complete application for a general account shall include the following elements in a format prescribed by the Administrator:

(A) Name, mailing address, e-mail address (if any), telephone number, and facsimile transmission number (if any) of the authorized account representative and any alternate authorized account representative;

(B) An identifying name for the general account;

(C) A list of all persons subject to a binding agreement for the authorized account representative and any alternate authorized account representative to represent their ownership interest with respect to the TR SO_2 Group 1 allowances held in the general account;

(D) The following certification statement by the authorized account representative and any alternate authorized account representative: "I certify that I was selected as the authorized account representative or the alternate authorized account representative, as applicable, by an agreement that is binding on all persons who have an ownership interest with respect to TR SO_2 Group 1 allowances held in the general account. I certify that I have all the necessary authority to carry out my duties and responsibilities under the TR SO_2 Group 1 Trading Program on behalf of such persons and that each such person shall be fully bound by my representations, actions, inactions, or submissions and by any decision or order issued to me by the Administrator regarding the general account."

(E) The signature of the authorized account representative and any alternate authorized account representative and the dates signed.

(iii) Unless otherwise required by the Administrator, documents of agreement referred to in the application for a general account shall not be submitted to the Administrator. The Administrator shall not be under any obligation to review or evaluate the sufficiency of such documents, if submitted.

(2) Authorization of authorized account representative and alternate authorized account representative. (i) Upon receipt by the Administrator of a complete application for a general account under paragraph (b)(1) of this section, the Administrator will establish a general account for the person or persons for whom the application is submitted, and upon and after such receipt by the Administrator:

(A) The authorized account representative of the general account shall be authorized and shall represent and, by his or her representations, actions, inactions, or submissions, legally bind each person who has an ownership interest with respect to TR SO_2 Group 1 allowances held in the general account in all matters pertaining to the TR SO_2 Group 1 Trading Program, notwithstanding any agreement between the authorized account representative and such person.

(B) Any alternate authorized account representative shall be authorized, and any representation, action, inaction, or submission by any alternate authorized account representative shall be deemed
to be a representation, action, inaction, or submission by the authorized account representative.

(C) Each person who has an ownership interest with respect to TR SO\textsubscript{2} Group 1 allowances held in the general account shall be bound by any decision or order issued to the authorized account representative or alternate authorized account representative by the Administrator regarding the general account.

(ii) Except as provided in paragraph (c)(5) of this section concerning delegation of authority to make submissions, each submission concerning the general account shall be made, signed, and certified by the authorized account representative or any alternate authorized account representative for the persons having an ownership interest with respect to TR SO\textsubscript{2} Group 1 allowances held in the general account. Each such submission shall include the following certification statement by the authorized account representative or any alternate authorized account representative: “I am authorized to make this submission on behalf of the persons having an ownership interest with respect to TR SO\textsubscript{2} Group 1 allowances held in the general account. I certify under penalty of law that I have personally examined, and am familiar with, the statements and information submitted in this document and all its attachments. Based on my inquiry of those individuals with primary responsibility for obtaining the information, I certify that the statements and information are to the best of my knowledge and belief true, accurate, and complete. I am aware that there are significant penalties for submitting false statements and information or omitting required statements and information, including the possibility of fine or imprisonment.”

(iii) Except in this section, whenever the term “authorized account representative” is used in this subpart, the term shall be construed to include the authorized account representative or any alternate authorized account representative.

(3) Changing authorized account representative and alternate authorized account representative; changes in persons with ownership interest. (i) The authorized account representative of a general account may be changed at any time upon receipt by the Administrator of a superseding complete application for a general account under paragraph (c)(1) of this section. Notwithstanding any such change, all representations, actions, inactions, and submissions by the previous authorized account representative before the time and date when the Administrator receives the superseding application for a general account shall be binding on the new authorized account representative and the persons with an ownership interest with respect to the TR SO\textsubscript{2} Group 1 allowances in the general account.

(ii) The alternate authorized account representative of a general account may be changed at any time upon receipt by the Administrator of a superseding complete application for a general account under paragraph (c)(1) of this section. Notwithstanding any such change, all representations, actions, inactions, and submissions by the previous alternate authorized account representative before the time and date when the Administrator receives the superseding application for a general account shall be binding on the new alternate authorized account representative, the authorized account representative, and the persons with an ownership interest with respect to the TR SO\textsubscript{2} Group 1 allowances in the general account.

(iii)(A) In the event a person having an ownership interest with respect to TR SO\textsubscript{2} Group 1 allowances in the general account is not included in the list of such persons in the application for a general account, such person shall be deemed to be subject to and bound by the application for a general account, the representation, actions, inactions, and submissions of the authorized account representative and any alternate authorized account representative of the account, and the decisions and orders of the Administrator, as if the person were included in such list.

(B) Within 30 days after any change in the persons having an ownership interest with respect to SO\textsubscript{2} Group 1 allowances in the general account, including the addition or removal of a
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person, the authorized account representative or any alternate authorized account representative shall submit a revision to the application for a general account amending the list of persons having an ownership interest with respect to the TR SO\textsubscript{2} Group 1 allowances in the general account to include the change.

(4) Objections concerning authorized account representative and alternate authorized account representative. (i) Once a complete application for a general account under paragraph (c)(1) of this section has been submitted and received, the Administrator will rely on the application unless and until a superseding complete application for a general account under paragraph (b)(1) of this section is received by the Administrator.

(ii) Except as provided in paragraph (c)(4)(i) of this section, no objection or other communication submitted to the Administrator concerning the authorization, or any representation, action, inaction, or submission of the authorized account representative or any alternate authorized account representative of a general account shall affect any representation, action, inaction, or submission of the authorized account representative or the finality of any decision or order by the Administrator under the TR SO\textsubscript{2} Group 1 Trading Program.

(iii) The Administrator will not adjudicate any private legal dispute concerning the authorization or any representation, action, inaction, or submission of the authorized account representative of a general account, including private legal disputes concerning the proceeds of TR SO\textsubscript{2} Group 1 allowance transfers.

(5) Delegation by authorized account representative and alternate authorized account representative. (i) An authorized account representative of a general account may delegate, to one or more natural persons, his or her authority to make an electronic submission to the Administrator provided for or required under this subpart.

(ii) An alternate authorized account representative of a general account may delegate, to one or more natural persons, his or her authority to make an electronic submission to the Administrator provided for or required under this subpart.

(iii) In order to delegate authority to a natural person to make an electronic submission to the Administrator in accordance with paragraph (c)(5)(i) or (ii) of this section, the authorized account representative or alternate authorized account representative, as appropriate, must submit to the Administrator a notice of delegation, in a format prescribed by the Administrator, that includes the following elements:

(A) The name, address, e-mail address, telephone number, and facsimile transmission number (if any) of each such natural person (referred to in this section as an “agent”);

(B) The name, address, e-mail address, telephone number, and facsimile transmission number (if any) of each such natural person (referred to in this section as an “agent”);

(C) For each such natural person, a list of the type or types of electronic submissions under paragraph (c)(5)(i) or (ii) of this section for which authority is delegated to him or her;

(D) The following certification statement by such authorized account representative or alternate authorized account representative: “I agree that any electronic submission to the Administrator that is made by an agent identified in this notice of delegation and of a type listed for such agent in this notice of delegation and that is made when I am an authorized account representative or alternate authorized account representative, as appropriate, and before this notice of delegation is superseded by another notice of delegation under 40 CFR 97.620(c)(5)(iv) shall be deemed to be an electronic submission by me.”;

(E) The following certification statement by such authorized account representative or alternate authorized account representative: “Until this notice of delegation is superseded by another notice of delegation under 40 CFR 97.620(c)(5)(iv), I agree to maintain an e-mail account and to notify the Administrator immediately of any change made to such account.”; and
§ 97.621 Recordation of TR SO\(_2\) Group 1 allowance allocations and auction results.

(a) By November 7, 2011, the Administrator will record in each TR SO\(_2\) Group 1 source’s compliance account the TR SO\(_2\) Group 1 allowances allocated to the TR SO\(_2\) Group 1 units at the source in accordance with §97.611(a) for the control period in 2012.

(b) By November 7, 2011, the Administrator will record in each TR SO\(_2\) Group 1 source’s compliance account the TR SO\(_2\) Group 1 allowances allocated to the TR SO\(_2\) Group 1 units at the source in accordance with §97.611(a) for the control period in 2013, unless the State in which the source is located notifies the Administrator in writing by October 17, 2011 of the State’s intent to submit to the Administrator a complete SIP revision by April 1, 2012 meeting the requirements of §52.39(d)(1) through (4) of this chapter.

(1) If, by April 1, 2012, the State does not submit to the Administrator such complete SIP revision, the Administrator will record by April 15, 2012 in each TR SO\(_2\) Group 1 source’s compliance account the TR SO\(_2\) Group 1 allowances allocated to the TR SO\(_2\)
§ 97.621 Group 1 units at the source in accordance with §97.611(a) for the control period in 2013.

(2) If the State submits to the Administrator by April 1, 2012, and the Administrator approves by October 1, 2012, such complete SIP revision, the Administrator will record by October 1, 2012 in each TR SO2 Group 1 source’s compliance account the TR SO2 Group 1 allowances allocated to the TR SO2 Group 1 units at the source as provided in such approved, complete SIP revision for the control period in 2013.

(3) If the State submits to the Administrator by April 1, 2012, and the Administrator does not approve by October 1, 2012, such complete SIP revision, the Administrator will record by October 1, 2012 in each TR SO2 Group 1 source’s compliance account the TR SO2 Group 1 allowances allocated to the TR SO2 Group 1 units at the source, or in each appropriate Allowance Management System account the TR SO2 Group 1 allowances auctioned to the TR SO2 Group 1 units at the source, or in each appropriate Allowance Management System account the TR SO2 Group 1 allowances auctioned to TR SO2 Group 1 units, in accordance with §97.611(a), or with a SIP revision approved under §52.39(e) and (f) of this chapter, for the control period in the fourth year after the year of the applicable recordation deadline under this paragraph.

(f) By July 1, 2016 and July 1 of each year thereafter, the Administrator will record in each TR SO2 Group 1 source’s compliance account the TR SO2 Group 1 allowances auctioned to TR SO2 Group 1 units at the source, or in each appropriate Allowance Management System account the TR SO2 Group 1 allowances auctioned to TR SO2 Group 1 units, in accordance with §97.611(a), or with a SIP revision approved under §52.39(e) and (f) of this chapter, for the control period in the fourth year after the year of the applicable recordation deadline under this paragraph.

(g) By August 1, 2012 and August 1 of each year thereafter, the Administrator will record in each TR SO2 Group 1 source’s compliance account the TR SO2 Group 1 allowances allocated to the TR SO2 Group 1 units at the source, or in each appropriate Allowance Management System account the TR SO2 Group 1 allowances auctioned to TR SO2 Group 1 units, in accordance with §97.611(a), or with a SIP revision approved under §52.39(e) and (f) of this chapter, for the control period in 2014 and 2015.

(h) By August 1, 2012 and August 1 of each year thereafter, the Administrator will record in each TR SO2 Group 1 source’s compliance account the TR SO2 Group 1 allowances allocated to the TR SO2 Group 1 units at the source, or in each appropriate Allowance Management System account the TR SO2 Group 1 allowances auctioned to TR SO2 Group 1 units, in accordance with §97.611(a), or with a SIP revision approved under §52.39(e) and (f) of this chapter, for the control period in the year of the applicable recordation deadline under this paragraph.

(i) By February 15, 2013 and February 16 of each year thereafter, the Administrator will record in each TR SO2 Group 1 source’s compliance account the TR SO2 Group 1 allowances allocated to the TR SO2 Group 1 units at the source in accordance with §97.612(a)(9) through (12), for the control period in the year before the year of the applicable recordation deadline under this paragraph.
§ 97.624  Compliance with TR SO\textsubscript{2} Group 1 emissions limitation.

(a) Availability for deduction for compliance. TR SO\textsubscript{2} Group 1 allowances are available to be deducted for compliance with a source’s TR SO\textsubscript{2} Group 1 emissions limitation for a control period in a given year only if the TR SO\textsubscript{2} Group 1 allowances:

(1) Were allocated for such control period or a control period in a prior year; and

(2) Are held in the source’s compliance account as of the allowance transfer deadline for such control period.

(b) Deductions for compliance. After the recordation, in accordance with
§ 97.625 Compliance with TR SO₂ Group 1 assurance provisions.

(a) Availability for deduction. TR SO₂ Group 1 allowances are available to be deducted for compliance with the TR SO₂ Group 1 assurance provisions for a control period in a given year by the owners and operators of a group of one or more TR SO₂ Group 1 sources and units in a State (and Indian country within the borders of such State) only if the TR SO₂ Group 1 allowances:

(1) Were allocated for a control period in a prior year or in the immediately following year; and

(2) Are held in the assurance account, established by the Administrator for such owners and operators of such group of TR SO₂ Group 1 sources and units in such State (and Indian country within the borders of such State) under paragraph (b)(3) of this section, as of the deadline established in paragraph (b)(4) of this section.

(b) Deductions for compliance. The Administrator will deduct TR SO₂ Group 1 allowances available under paragraph (a) of this section for compliance with the TR SO₂ Group 1 assurance provisions for a State for a control period in a given year in accordance with the following procedures:
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(1) By June 1, 2015 and June 1 of each year thereafter, the Administrator will:
   (i) Calculate, for each State (and Indian country within the borders of such State), the total SO₂ emissions from all TR SO₂ Group 1 units at TR SO₂ Group 1 sources in the State (and Indian country within the borders of such State) during the control period in the year before the year of this calculation deadline and the amount, if any, by which such total SO₂ emissions exceed the State assurance level as described in §97.606(c)(2)(iii); and
   (ii) Promulgate a notice of data availability of the results of the calculations required in paragraph (b)(1)(i) of this section, including separate calculations of the SO₂ emissions from each TR SO₂ Group 1 source.

(2) For each notice of data availability required in paragraph (b)(1)(ii) of this section and for any State (and Indian country within the borders of such State) identified in such notice as having TR SO₂ Group 1 units with total SO₂ emissions exceeding the State assurance level for a control period in a given year, as described in §97.606(c)(2)(iii):
   (i) By July 1 immediately after the promulgation of such notice, the designated representative of each TR SO₂ Group 1 source in each such State (and Indian country within the borders of such State) shall submit a statement, in a format prescribed by the Administrator, providing for each TR SO₂ Group 1 unit (if any) at the source that operates during, but is not allocated an amount of TR SO₂ Group 1 allowances for, such control period and, if such rate is expressed in lb per mmBtu, the unit’s heat rate.
   (ii) By August 1 immediately after the promulgation of such notice, the Administrator will calculate, for each such State (and Indian country within the borders of such State), the common designated representative’s share of the total SO₂ emissions from all TR SO₂ Group 1 units at TR SO₂ Group 1 sources in the State (and Indian country within the borders of such State), the common designated representative’s assurance level, and the amount (if any) of TR SO₂ Group 1 allowances that the owners and operators of such group of sources and units must hold in accordance with the calculation formula in §97.606(c)(2)(i) and will promulgate a notice of data availability of the results of these calculations.
   (iii) The Administrator will provide an opportunity for submission of objections to the calculations referenced by the notice of data availability required in paragraph (b)(2)(ii) of this section and the calculations referenced by the relevant notice of data availability required in paragraph (b)(1)(i) of this section.
      (A) Objections shall be submitted by the deadline specified in such notice and shall be limited to addressing whether the calculations referenced in the relevant notice required under paragraph (b)(1)(ii) of this section and referenced in the notice required under paragraph (b)(2)(ii) of this section are in accordance with §97.606(c)(2)(iii), §§97.606(b) and 97.630 through 97.635, the definitions of “common designated representative”, “common designated representative’s assurance level”, and “common designated representative’s share” in §97.602, and the calculation formula in §97.606(c)(2)(i).
      (B) The Administrator will adjust the calculations to the extent necessary to ensure that they are in accordance with the provisions referenced in paragraph (b)(2)(iii)(A) of this section. By October 1 immediately after the promulgation of such notice, the Administrator will promulgate a notice of data availability of any adjustments that the Administrator determines to be necessary and the reasons for accepting or rejecting any objections submitted in accordance with paragraph (b)(2)(iii)(A) of this section.

(3) For any State (and Indian country within the borders of such State) referenced in each notice of data availability required in paragraph (b)(2)(ii)(B) of this section as having TR SO₂ Group 1 units with total SO₂
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emissions exceeding the State assurance level for a control period in a given year, the Administrator will establish one assurance account for each set of owners and operators referenced, in the notice of data availability required under paragraph (b)(2)(iii)(B) of this section, as all of the owners and operators of a group of TR SO₂ Group 1 sources and units in the State (and Indian country within the borders of such State) having a common designated representative for such control period and as being required to hold TR SO₂ Group 1 allowances.

(4)(i) As of midnight of November 1 immediately after the promulgation of each notice of data availability required in paragraph (b)(2)(iii)(B) of this section, the owners and operators described in paragraph (b)(3) of this section shall hold in the assurance account established for them and for the appropriate TR SO₂ Group 1 sources, TR SO₂ Group 1 units, and State (and Indian country within the borders of such State) under paragraph (b)(3) of this section a total amount of TR SO₂ Group 1 allowances, available for deduction under paragraph (a) of this section, equal to the amount such owners and operators are required to hold with regard to such sources, units and State (and Indian country within the borders of such State) as calculated by the Administrator and referenced in such notice.

(ii) Notwithstanding the allowance-holding deadline specified in paragraph (b)(4)(i) of this section, if November 1 is not a business day, then such allowance-holding deadline shall be midnight of the first business day thereafter.

(5) After November 1 (or the date described in paragraph (b)(4)(ii) of this section) immediately after the promulgation of each notice of data availability required in paragraph (b)(2)(iii)(B) of this section and after the recordation, in accordance with §97.623, of TR SO₂ Group 1 allowance transfers submitted by midnight of such date, the Administrator will determine whether the owners and operators described in paragraph (b)(3) of this section hold, in the assurance account for the appropriate TR SO₂ Group 1 sources, TR SO₂ Group 1 units, and State (and Indian country within the borders of such State) established under paragraph (b)(3) of this section, the amount of TR SO₂ Group 1 allowances available under paragraph (a) of this section that the owners and operators are required to hold with regard to such sources, units, and State (and Indian country within the borders of such State) as calculated by the Administrator and referenced in the notice required in paragraph (b)(2)(iii)(B) of this section.

(6) Notwithstanding any other provision of this subpart and any revision, made by or submitted to the Administrator after the promulgation of the notice of data availability required in paragraph (b)(2)(iii)(B) of this section for a control period in a given year, of any data used in making the calculations referenced in such notice, the amounts of TR SO₂ Group 1 allowances that the owners and operators are required to hold in accordance with §97.606(c)(2)(i) for such control period shall continue to be such amounts as calculated by the Administrator and referenced in such notice required in paragraph (b)(2)(iii)(B) of this section, except as follows:

(i) If any such data are revised by the Administrator as a result of a decision in or settlement of litigation concerning such data on appeal under part 78 of this chapter of such notice, or on appeal under section 307 of the Clean Air Act of a decision rendered under part 78 of this chapter on appeal of such notice, then the Administrator will use the data as so revised to recalculate the amounts of TR SO₂ Group 1 allowances that owners and operators are required to hold in accordance with the calculation formula in §97.606(c)(2)(i) for such control period with regard to the TR SO₂ Group 1 sources, TR SO₂ Group 1 units, and State (and Indian country within the borders of such State) involved, provided that such litigation under part 78 of this chapter, or the proceeding under part 78 of this chapter that resulted in the decision appealed in such litigation under section 307 of the Clean Air Act, was initiated no later than 30 days after promulgation of such notice required in paragraph (b)(2)(iii)(B) of this section.
(ii) If any such data are revised by the owners and operators of a TR SO₂
Group 1 source and TR SO₂ Group 1 unit whose designated representative
submitted such data under paragraph (b)(2)(i) of this section, as a result of a
decision in or settlement of litigation concerning such submission, then the
Administrator will use the data as so revised to recalculate the amounts of
TR SO₂ Group 1 allowances that owners and operators are required to hold in
accordance with the calculation formula in §97.606(c)(2)(i) for such control
period with regard to the TR SO₂ Group 1 sources, TR SO₂ Group 1 units, and
State (and Indian country within the borders of such State) involved, pro-
vided that such litigation was initiated no later than 30 days after promulga-
tion of such notice required in paragraph (b)(2)(iii)(B) of this section.

(iii) If the revised data are used to re-
calculate, in accordance with para-
graphs (b)(6)(i) and (ii) of this section,
the amount of TR SO₂ Group 1 allow-
ances that the owners and operators
are required to hold for such control
period with regard to the TR SO₂ Group
1 sources, TR SO₂ Group 1 units, and
State (and Indian country within the
borders of such State) involved—

(A) Where the amount of TR SO₂
Group 1 allowances that the owners
and operators are required to hold in-
creases as a result of the use of all such
revised data, the Administrator will es-
tablish a new, reasonable deadline on
which the owners and operators shall
hold the additional amount of TR SO₂
Group 1 allowances in the assurance
account established by the Adminis-
trator for the appropriate TR SO₂
Group 1 sources, TR SO₂ Group 1 units,
and State (and Indian country within
the borders of such State) under para-
graph (b)(3) of this section. The owners' and operators' failure to hold such ad-
tional amount, as required, before
the new deadline shall not be a viola-
tion of the Clean Air Act. The owners'
and operators' failure to hold such ad-
tional amount, as required, as of the
new deadline shall be a violation of the
Clean Air Act. Each TR SO₂ Group 1
allowance that the owners and operators
fail to hold as required as of the new
deadline, and each day in such control
period, shall be a separate violation of
the Clean Air Act.

(B) For the owners and operators for
which the amount of TR SO₂ Group 1
allowances required to be held de-
creases as a result of the use of all such
revised data, the Administrator will
record, in all accounts from which TR
SO₂ Group 1 allowances were trans-
ferred by such owners and operators for
such control period to the assurance
account established by the Adminis-
trator for the appropriate TR SO₂
Group 1 sources, TR SO₂ Group 1 units,
and State (and Indian country within the
borders of such State) under para-
graph (b)(3) of this section, a total
amount of the TR SO₂ Group 1 allow-
ances held in such assurance account
equal to the amount of the decrease. If
TR SO₂ Group 1 allowances were trans-
ferred to such assurance account from
more than one account, the amount of
TR SO₂ Group 1 allowances recorded in
each such transferor account will be in
proportion to the percentage of the
total amount of TR SO₂ Group 1 allow-
ances transferred to such assurance ac-
count for such control period from such
transferor account.

(C) Each TR SO₂ Group 1 allowance
held under paragraph (b)(6)(iii)(A) of
this section as a result of recalculation
of requirements under the TR SO₂
Group 1 assurance provisions for such
control period must be a TR SO₂ Group
1 allowance allocated for a control pe-
riod in a year before or the year imme-
diately following, or in the same year
as, the year of such control period.

§97.626 Banking.

(a) A TR SO₂ Group 1 allowance may
be banked for future use or transfer in
a compliance account or a general ac-
count in accordance with paragraph (b)
of this section.

(b) Any TR SO₂ Group 1 allowance
that is held in a compliance account or
a general account will remain in such
account unless and until the TR SO₂
Group 1 allowance is deducted or trans-
ferred under §97.611(c), §97.623, §97.624,
§97.625, §97.627, or §97.628.
§ 97.627 Account error.

The Administrator may, at his or her sole discretion and on his or her own motion, correct any error in any Allowance Management System account. Within 10 business days of making such correction, the Administrator will notify the authorized account representative for the account.

§ 97.628 Administrator’s action on submissions.

(a) The Administrator may review and conduct independent audits concerning any submission under the TR SO₂ Group 1 Trading Program and make appropriate adjustments of the information in the submission.

(b) The Administrator may deduct TR SO₂ Group 1 allowances from or transfer TR SO₂ Group 1 allowances to a compliance account or an assurance account, based on the information in a submission, as adjusted under paragraph (a)(1) of this section, and record such deductions and transfers.

§ 97.629 [Reserved]

§ 97.630 General monitoring, recordkeeping, and reporting requirements.

The owners and operators, and to the extent applicable, the designated representative, of a TR SO₂ Group 1 unit, shall comply with the monitoring, recordkeeping, and reporting requirements as provided in this subpart and subparts F and G of part 75 of this chapter. For purposes of applying such requirements, the definitions in §97.602 and in §72.2 of this chapter shall apply, the terms “affected unit,” “designated representative,” and “continuous emission monitoring system” (or “CEMS”) in part 75 of this chapter shall be deemed to refer to the terms “TR SO₂ Group 1 unit,” “designated representative,” and “continuous emission monitoring system” (or “CEMS”) respectively as defined in §97.602, and the term “newly affected unit” shall be deemed to mean “newly affected TR SO₂ Group 1 unit.” The owner or operator of a unit that is not a TR SO₂ Group 1 unit but that is monitored under §75.16(b)(2) of this chapter shall comply with the same monitoring, recordkeeping, and reporting requirements as a TR SO₂ Group 1 unit.

(a) Requirements for installation, certification, and data accounting. The owner or operator of each TR SO₂ Group 1 unit shall:

(1) Install all monitoring systems required under this subpart for monitoring SO₂ mass emissions and individual unit heat input (including all systems required to monitor SO₂ concentration, stack gas moisture content, stack gas flow rate, CO₂ or O₂ concentration, and fuel flow rate, as applicable, in accordance with §§75.11 and 75.16 of this chapter);

(2) Successfully complete all certification tests required under §97.631 and meet all other requirements of this subpart and part 75 of this chapter applicable to the monitoring systems under paragraph (a)(1) of this section; and

(3) Record, report, and quality-assure the data from the monitoring systems under paragraph (a)(1) of this section.

(b) Compliance deadlines. Except as provided in paragraph (e) of this section, the owner or operator shall meet the monitoring system certification and other requirements of paragraphs (a)(1) and (2) of this section on or before the following dates and shall record, report, and quality-assure the data from the monitoring systems under paragraph (a)(1) of this section on and after the following dates.

(1) For the owner or operator of a TR SO₂ Group 1 unit that commences commercial operation before July 1, 2011, January 1, 2012.

(2) For the owner or operator of a TR SO₂ Group 1 unit that commences commercial operation on or after July 1, 2011, by the later of the following:

(i) January 1, 2012; or

(ii) 180 calendar days after the date on which the unit commences commercial operation.

(3) The owner or operator of a TR SO₂ Group 1 unit for which construction of a new stack or flue or installation of add-on SO₂ emission controls is completed after the applicable deadline under paragraph (b)(1) or (2) of this section shall meet the requirements of §§75.4(e)(1) through (e)(4) of this chapter, except that:
(i) Such requirements shall apply to the monitoring systems required under §97.630 through §97.635, rather than the monitoring systems required under part 75 of this chapter;

(ii) SO\textsubscript{2} concentration, stack gas moisture content, stack gas volumetric flow rate, and O\textsubscript{2} or CO\textsubscript{2} concentration data shall be determined and reported, rather than the data listed in §75.4(e)(2) of this chapter; and

(iii) Any petition for another procedure under §75.4(e)(2) of this chapter shall be submitted under §97.635, rather than §75.66.

(c) Reporting data. The owner or operator of a TR SO\textsubscript{2} Group 1 unit that does not meet the applicable compliance date set forth in paragraph (b) of this section for any monitoring system under paragraph (a)(1) of this section shall, for each such monitoring system, determine, record, and report maximum potential (or, as appropriate, minimum potential) values for SO\textsubscript{2} concentration, stack gas flow rate, stack gas moisture content, fuel flow rate, and any other parameters required to determine SO\textsubscript{2} mass emissions and heat input in accordance with §75.31(b)(2) or (c)(3) of this chapter or section 2.4 of appendix D to part 75 of this chapter, as applicable.

(d) Prohibitions. (1) No owner or operator of a TR SO\textsubscript{2} Group 1 unit shall use any alternative monitoring system, alternative reference method, or any other alternative to any requirement of this subpart without having obtained prior written approval in accordance with §97.635.

(2) No owner or operator of a TR SO\textsubscript{2} Group 1 unit shall operate the unit so as to discharge, or allow to be discharged, SO\textsubscript{2} to the atmosphere without accounting for all such SO\textsubscript{2} in accordance with the applicable provisions of this subpart and part 75 of this chapter.

(3) No owner or operator of a TR SO\textsubscript{2} Group 1 unit shall disrupt the continuous emission monitoring system, any portion thereof, or any other approved emission monitoring method, and thereby avoid monitoring and recording SO\textsubscript{2} mass discharged into the atmosphere or heat input, except for periods of recertification or periods when calibration, quality assurance testing, or maintenance is performed in accordance with the applicable provisions of this subpart and part 75 of this chapter.

(4) No owner or operator of a TR SO\textsubscript{2} Group 1 unit shall retire or permanently discontinue use of the continuous emission monitoring system, any component thereof, or any other approved monitoring system under this subpart, except under any one of the following circumstances:

(i) During the period that the unit is covered by an exemption under §97.605 that is in effect;

(ii) The owner or operator is monitoring emissions from the unit with another certified monitoring system approved, in accordance with the applicable provisions of this subpart and part 75 of this chapter, by the Administrator for use at that unit that provides emission data for the same pollutant or parameter as the retired or discontinued monitoring system; or

(iii) The designated representative submits notification of the date of certification testing of a replacement monitoring system for the retired or discontinued monitoring system in accordance with §97.631(d)(3)(i).

(e) Long-term cold storage. The owner or operator of a TR SO\textsubscript{2} Group 1 unit is subject to the applicable provisions of §75.4(d) of this chapter concerning units in long-term cold storage.

§97.631 Initial monitoring system certification and recertification procedures.

(a) The owner or operator of a TR SO\textsubscript{2} Group 1 unit shall be exempt from the initial certification requirements of this section for a monitoring system under §97.630(a)(1) if the following conditions are met:

(1) The monitoring system has been previously certified in accordance with part 75 of this chapter; and

(2) The applicable quality-assurance and quality-control requirements of §75.21 of this chapter and appendices B and D to part 75 of this chapter are fully met for the certified monitoring system described in paragraph (a)(1) of this section.

(b) The recertification provisions of this section shall apply to a monitoring system under §97.630(a)(1) that
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is exempt from initial certification requirements under paragraph (a) of this section.

(c) [Reserved]

(d) Except as provided in paragraph (a) of this section, the owner or operator of a TR SO\textsubscript{2} Group 1 unit shall comply with the following initial certification and recertification procedures, for a continuous monitoring system (i.e., a continuous emission monitoring system and an excepted monitoring system under appendix D to part 75 of this chapter) under § 97.630(a)(1). The owner or operator of a unit that qualifies to use the low mass emissions excepted monitoring methodology under § 75.19 of this chapter or that qualifies to use an alternative monitoring system under subpart E of part 75 of this chapter shall comply with the procedures in paragraph (e) or (f) of this section respectively.

(1) Requirements for initial certification. The owner or operator shall ensure that each continuous monitoring system under § 97.630(a)(1) (including the automated data acquisition and handling system) successfully completes all of the initial certification testing required under § 75.20 of this chapter by the applicable deadline in § 97.630(b). In addition, whenever the owner or operator installs a monitoring system to meet the requirements of this subpart in a location where no such monitoring system was previously installed, initial certification in accordance with § 75.20 of this chapter is required.

(2) Requirements for recertification. Whenever the owner or operator makes a replacement, modification, or change in any certified continuous emission monitoring system under § 97.630(a)(1) that may significantly affect the ability of the system to accurately measure or record SO\textsubscript{2} mass emissions or heat input rate or to meet the quality-assurance and quality-control requirements of § 75.21 of this chapter or appendix B to part 75 of this chapter, the owner or operator shall recertify the monitoring system in accordance with § 75.20(b) of this chapter. Furthermore, whenever the owner or operator makes a replacement, modification, or change to the flue gas handling system or the unit’s operation that may significantly change the stack flow or concentration profile, the owner or operator shall recertify each continuous emission monitoring system whose accuracy is potentially affected by the change, in accordance with § 75.20(b) of this chapter. Examples of changes to a continuous emission monitoring system that require recertification include: Replacement of the analyzer, complete replacement of an existing continuous emission monitoring system, or change in location or orientation of the sampling probe or site. Any fuel flowmeter system under § 97.630(a)(1) is subject to the recertification requirements in § 75.20(g)(6) of this chapter.

(3) Approval process for initial certification and recertification. For initial certification of a continuous monitoring system under § 97.630(a)(1), paragraphs (d)(3)(i) through (v) of this section apply. For recertifications of such monitoring systems, paragraphs (d)(3)(i) through (iv) of this section and the procedures in §§ 75.20(b)(5) and (g)(7) of this chapter apply, provided that in applying paragraphs (d)(3)(i) through (iv) of this section, the words “certification” and “initial certification” are replaced by the word “recertification” and the word “certified” is replaced by the word “recertified”.

(i) Notification of certification. The designated representative shall submit to the appropriate EPA Regional Office and the Administrator written notice of the dates of certification testing, in accordance with § 97.633.

(ii) Certification application. The designated representative shall submit to the Administrator a certification application for each monitoring system. A complete certification application shall include the information specified in § 75.63 of this chapter.

(iii) Provisional certification date. The provisional certification date for a monitoring system shall be determined in accordance with § 75.20(a)(3) of this chapter. A provisionally certified monitoring system may be used under the TR SO\textsubscript{2} Group 1 Trading Program for a period not to exceed 120 days after receipt by the Administrator of the complete certification application for the monitoring system under paragraph.
(d)(3)(ii) of this section. Data measured and recorded by the provisionally certified monitoring system, in accordance with the requirements of part 75 of this chapter, will be considered valid quality-assured data (retroactive to the date and time of provisional certification), provided that the Administrator does not invalidate the provisional certification by issuing a notice of disapproval within 120 days of the date of receipt of the complete certification application by the Administrator.

(iv) Certification application approval process. The Administrator will issue a written notice of approval or disapproval of the certification application to the owner or operator within 120 days of receipt of the complete certification application under paragraph (d)(3)(ii) of this section. In the event the Administrator does not issue such a notice within such 120-day period, each monitoring system that meets the applicable performance requirements of part 75 of this chapter and is included in the certification application will be deemed certified for use under the TR SO\textsubscript{2} Group 1 Trading Program.

(A) Approval notice. If the certification application is complete and shows that each monitoring system meets the applicable performance requirements of part 75 of this chapter, then the Administrator will issue a written notice of approval of the certification application within 120 days of receipt.

(B) Incomplete application notice. If the certification application is not complete, then the Administrator will issue a written notice of incompleteness that sets a reasonable date by which the designated representative must submit the additional information required to complete the certification application. If the designated representative does not comply with the notice of incompleteness by the specified date, then the Administrator may issue a notice of disapproval under paragraph (d)(3)(iv)(C) of this section.

(C) Disapproval notice. If the certification application shows that any monitoring system does not meet the performance requirements of part 75 of this chapter or if the certification application is incomplete and the requirement for disapproval under paragraph (d)(3)(iv)(B) of this section is met, then the Administrator will issue a written notice of disapproval of the certification application. Upon issuance of such notice of disapproval, the provisional certification is invalidated by the Administrator and the data measured and recorded by each uncertified monitoring system shall not be considered valid quality-assured data beginning with the date and hour of provisional certification (as defined under §75.20(a)(3) of this chapter).

(D) Audit decertification. The Administrator may issue a notice of disapproval of the certification status of a monitor in accordance with §97.632(b).

(v) Procedures for loss of certification. If the Administrator issues a notice of disapproval of a certification application under paragraph (d)(3)(iv)(C) of this section or a notice of disapproval of certification status under paragraph (d)(3)(iv)(D) of this section, then:

(A) The owner or operator shall substitute the following values, for each disapproved monitoring system, for each hour of unit operation during the period of invalid data specified under §75.20(a)(4)(iii), §75.20(g)(7), or §75.21(e) of this chapter and continuing until the applicable date and hour specified under §75.20(a)(5)(i) or (g)(7) of this chapter:

(1) For a disapproved SO\textsubscript{2} pollutant concentration monitor and disapproved flow monitor, respectively, the maximum potential concentration of SO\textsubscript{2} and the maximum potential flow rate, as defined in sections 2.1.1.1 and 2.1.4.1 of appendix A to part 75 of this chapter.

(2) For a disapproved moisture monitoring system and disapproved diluent gas monitoring system, respectively, the minimum potential moisture percentage and either the maximum potential CO\textsubscript{2} concentration or the minimum potential O\textsubscript{2} concentration (as applicable), as defined in sections 2.1.5, 2.1.3.1, and 2.1.3.2 of appendix A to part 75 of this chapter.

(3) For a disapproved fuel flowmeter system, the maximum potential fuel flow rate, as defined in section 2.4.2.1 of appendix D to part 75 of this chapter.

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(B) The designated representative shall submit a notification of certification retest dates and a new certification application in accordance with paragraphs (d)(3)(i) and (ii) of this section.

(C) The owner or operator shall repeat all certification tests or other requirements that were failed by the monitoring system, as indicated in the Administrator’s notice of disapproval, no later than 30 unit operating days after the date of issuance of the notice of disapproval.

(e) The owner or operator of a unit qualified to use the low mass emissions (LME) excepted methodology under §75.19 of this chapter shall meet the applicable certification and recertification requirements in §§75.19(a)(2) and 75.20(h) of this chapter. If the owner or operator of such a unit elects to certify a fuel flowmeter system for heat input determination, the owner or operator shall also meet the certification and recertification requirements in §75.20(g) of this chapter.

(f) The designated representative of each unit for which the owner or operator intends to use an alternative monitoring system approved by the Administrator under subpart E of part 75 of this chapter shall comply with the applicable notification and application procedures of §75.20(f) of this chapter.

§ 97.633 Notifications concerning monitoring.

The designated representative of a TR SO<sub>2</sub> Group 1 unit shall submit written notice to the Administrator in accordance with §75.61 of this chapter.

§ 97.634 Recordkeeping and reporting.

(a) General provisions. The designated representative shall comply with all recordkeeping and reporting requirements in paragraphs (b) through (e) of this section, the applicable recordkeeping and reporting requirements in subparts F and G of part 75 of this chapter, and the requirements of §97.614(a).

(b) Monitoring plans. The owner or operator of a TR SO<sub>2</sub> Group 1 unit shall comply with requirements of §75.62 of this chapter.

(c) Certification applications. The designated representative shall submit an application to the Administrator within 45 days after completing all initial certification or recertification tests required under §97.631, including the information required under §75.63 of this chapter.

(d) Quarterly reports. The designated representative shall submit quarterly reports, as follows:
(1) The designated representative shall report the SO₂ mass emissions data and heat input data for the TR SO₂ Group 1 unit in an electronic quarterly report in a format prescribed by the Administrator, for each calendar quarter beginning with:

(i) For a unit that commences commercial operation before July 1, 2011, the calendar quarter covering January 1, 2012 through March 31, 2012; or

(ii) For a unit that commences commercial operation on or after July 1, 2011, the calendar quarter corresponding to the earlier of the date of provisional certification or the applicable deadline for initial certification under §97.630(b), unless that quarter is the third or fourth quarter of 2011, in which case reporting shall commence in the quarter covering January 1, 2012 through March 31, 2012.

(2) The designated representative shall submit each quarterly report to the Administrator within 30 days after the end of the calendar quarter covered by the report. Quarterly reports shall be submitted in the manner specified in §75.64 of this chapter.

(3) For TR SO₂ Group 1 units that are also subject to the Acid Rain Program, TR NOₓ Annual Trading Program, or TR NOₓ Ozone Season Trading Program, quarterly reports shall include the applicable data and information required by subparts F through H of part 75 of this chapter as applicable, in addition to the SO₂ mass emission data, heat input data, and other information required by this subpart.

(4) The Administrator may review and conduct independent audits of any quarterly report in order to determine whether the quarterly report meets the requirements of this subpart and part 75 of this chapter, including the requirement to use substitute data.

(i) The Administrator will notify the designated representative of any determination that the quarterly report fails to meet any such requirements and specify in such notification any corrections that the Administrator believes are necessary to make through resubmission of the quarterly report and a reasonable time period within which the designated representative must respond. Upon request by the designated representative, the Administrator may specify reasonable extensions of such time period. Within the time period (including any such extensions) specified by the Administrator, the designated representative shall resubmit the quarterly report with the corrections specified by the Administrator, except to the extent the designated representative provides information demonstrating that a specified correction is not necessary because the quarterly report already meets the requirements of this subpart and part 75 of this chapter that are relevant to the specified correction.

(ii) Any resubmission of a quarterly report shall meet the requirements applicable to the submission of a quarterly report under this subpart and part 75 of this chapter, except for the deadline set forth in paragraph (d)(2) of this section.

(e) Compliance certification. The designated representative shall submit to the Administrator a compliance certification (in a format prescribed by the Administrator) in support of each quarterly report based on reasonable inquiry of those persons with primary responsibility for ensuring that all of the unit’s emissions are correctly and fully monitored. The certification shall state that:

(1) The monitoring data submitted were recorded in accordance with the applicable requirements of this subpart and part 75 of this chapter, including the quality assurance procedures and specifications; and

(2) For a unit with add-on SO₂ emission controls and for all hours where SO₂ data are substituted in accordance with §75.34(a)(1) of this chapter, the add-on emission controls were operating within the range of parameters listed in the quality assurance/quality control program under appendix B to part 75 of this chapter and the substitute data values do not systematically underestimate SO₂ emissions.

§97.635 Petitions for alternatives to monitoring, recordkeeping, or reporting requirements.

(a) The designated representative of a TR SO₂ Group 1 unit may submit a petition under §75.66 of this chapter to the Administrator, requesting approval
§ 97.701 Purpose.

This subpart sets forth the general, designated representative, allowance, and monitoring provisions for the Transport Rule (TR) SO$_2$ Group 2 Trading Program, under section 110 of the Clean Air Act and §52.39 of this chapter, as a means of mitigating interstate transport of fine particulates and sulfur dioxide.

§ 97.702 Definitions.

The terms used in this subpart shall have the meanings set forth in this section as follows:

**Acid Rain Program** means a multi-state SO$_2$ and NO$_X$ air pollution control and emission reduction program established by the Administrator under title IV of the Clean Air Act and parts 72 through 78 of this chapter.

**Allowance Management System** means the system by which the Administrator records allocations, deductions, and transfers of TR SO$_2$ Group 2 allowances under the TR SO$_2$ Group 2 Trading Program. Such allowances are allocated, recorded, held, deducted, or transferred only as whole allowances.

**Allowance Management System account** means an account in the Allowance Management System established by
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the Administrator for purposes of recording the allocation, holding, transfer, or deduction of TR SO₂ Group 2 allowances.

Allowance transfer deadline means, for a control period in a given year, midnight of March 1 (if it is a business day), or midnight of the first business day thereafter (if March 1 is not a business day), immediately after such control period and is the deadline by which a TR SO₂ Group 2 allowance transfer must be submitted for recordation in a TR SO₂ Group 2 source’s compliance account in order to be available for use in complying with the source’s TR SO₂ Group 2 emissions limitation for such control period in accordance with §§97.706 and 97.724.

Alternate designated representative means, for a TR SO₂ Group 2 source and each TR SO₂ Group 2 unit at the source, the natural person who is authorized by the owners and operators of the source and all such units at the source, in accordance with this subpart, to act on behalf of the designated representative in matters pertaining to the TR SO₂ Group 2 Trading Program. If the TR SO₂ Group 2 source is also subject to the Acid Rain Program, TR NOₓ Annual Trading Program, or TR NOₓ Ozone Season Trading Program, then this natural person shall be the same natural person as the alternate designated representative, as defined in the respective program.

Assurance account means an Allowance Management System account, established by the Administrator under §97.725(b)(3) for certain owners and operators of a group of one or more TR SO₂ Group 2 sources and units in a given State (and Indian country within the boundaries of such State), in which are held TR SO₂ Group 2 allowances available for use for a control period in a given year in complying with the TR SO₂ Group 2 assurance provisions in accordance with §§97.706 and 97.725.

Authorized account representative means, for a general account, the natural person who is authorized, in accordance with this subpart, to transfer and otherwise dispose of TR SO₂ Group 2 allowances held in the general account and, for a TR SO₂ Group 2 source’s compliance account, the designated representative of the source.

Automated data acquisition and handling system or DAHS means the component of the continuous emission monitoring system, or other emissions monitoring system approved for use under this subpart, designed to interpret and convert individual output signals from pollutant concentration monitors, flow monitors, diluent gas monitors, and other component parts of the monitoring system to produce a continuous record of the measured parameters in the measurement units required by this subpart.

Biomass means—

1. Any organic material grown for the purpose of being converted to energy;
2. Any organic byproduct of agriculture that can be converted into energy; or
3. Any material that can be converted into energy and is nonmerchantable for other purposes, that is segregated from other material that is nonmerchantable for other purposes, and that is;
   1. A forest-related organic resource, including mill residues, precommercial thinnings, slash, brush, or byproduct from conversion of trees to merchantable material; or
   2. A wood material, including pallets, crates, dunnage, manufacturing and construction materials (other than pressure-treated, chemically-treated, or painted wood products), and landscape or right-of-way tree trimmings.

Boiler means an enclosed fossil- or other-fuel-fired combustion device used to produce heat and to transfer heat to recirculating water, steam, or other medium.

Bottoming-cycle unit means a unit in which the energy input to the unit is first used to produce useful thermal energy, where at least some of the reject heat from the useful thermal energy application or process is then used for electricity production.

Business day means a day that does not fall on a weekend or a federal holiday.

Certifying official means a natural person who is:

1. For a corporation, a president, secretary, treasurer, or vice-president of the corporation in charge of a principal business function or any other
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person who performs similar policy- or decision-making functions for the corporation;

(2) For a partnership or sole proprietorship, a general partner or the proprietor respectively; or

(3) For a local government entity or State, federal, or other public agency, a principal executive officer or ranking elected official.

Clean Air Act means the Clean Air Act, 42 U.S.C. 7401, et seq.

Coal means “coal” as defined in §72.2 of this chapter.

Coal-derived fuel means any fuel (whether in a solid, liquid, or gaseous state) produced by the mechanical, thermal, or chemical processing of coal.

Cogeneration system means an integrated group, at a source, of equipment (including a boiler, or combustion turbine, and a steam turbine generator) designed to produce useful thermal energy for industrial, commercial, heating, or cooling purposes and electricity through the sequential use of energy.

Cogeneration unit means a stationary, fossil-fuel-fired boiler or stationary, fossil-fuel-fired combustion turbine that is a topping-cycle unit or a bottoming-cycle unit:

(1) Operating as part of a cogeneration system; and

(2) Producing on an annual average basis—

(i) For a topping-cycle unit,

(A) Useful thermal energy not less than 5 percent of total energy output; and

(B) Useful power that, when added to one-half of useful thermal energy produced, is not less than 42.5 percent of total energy input, if useful thermal energy produced is 15 percent or more of total energy output, or not less than 45 percent of total energy input, if useful thermal energy produced is less than 15 percent of total energy output.

(ii) For a bottoming-cycle unit, useful power not less than 45 percent of total energy input;

(3) Provided that the requirements in paragraph (2) of this definition shall not apply to a calendar year referenced in paragraph (2) of this definition during which the unit did not operate at all;

(4) Provided that the total energy input under paragraphs (2)(i)(B) and (2)(ii) of this definition shall equal the unit’s total energy input from all fuel, except biomass if the unit is a boiler; and

(5) Provided that, if, throughout its operation during the 12-month period or a calendar year referenced in paragraph (2) of this definition, a unit is operated as part of a cogeneration system and the cogeneration system meets on a system-wide basis the requirement in paragraph (2)(i)(B) or (2)(ii) of this definition, the unit shall be deemed to meet such requirement during that 12-month period or calendar year.

Combustion turbine means an enclosed device comprising:

(1) If the device is simple cycle, a compressor, a combustor, and a turbine and in which the flue gas resulting from the combustion of fuel in the combustor passes through the turbine, rotating the turbine; and

(2) If the device is combined cycle, the equipment described in paragraph (1) of this definition and any associated duct burner, heat recovery steam generator, and steam turbine.

Commence commercial operation means, with regard to a unit:

(1) To have begun to produce steam, gas, or other heated medium used to generate electricity for sale or use, including test generation, except as provided in §97.705.

(i) For a unit that is a TR SO2 Group 2 unit under §97.704 on the later of January 1, 2005 or the date the unit commences commercial operation as defined in the introductory text of paragraph (1) of this definition and that subsequently undergoes a physical change or is moved to a new location or source, such date shall remain the date of commencement of commercial operation of the unit, which shall continue to be treated as the same unit.

(ii) For a unit that is a TR SO2 Group 2 unit under §97.704 on the later of January 1, 2005 or the date the unit commences commercial operation as defined in the introductory text of paragraph (1) of this definition and that is subsequently replaced by a unit at the same or a different source, such date shall remain the replaced unit’s date of
commencement of commercial operation, and the replacement unit shall be treated as a separate unit with a separate date for commencement of commercial operation as defined in paragraph (1) or (2) of this definition as appropriate.

(2) Notwithstanding paragraph (1) of this definition and except as provided in §97.705, for a unit that is not a TR SO\(_2\) Group 2 unit under §97.704 on the later of January 1, 2005 or the date the unit commences commercial operation as defined in introductory text of paragraph (1) of this definition, the unit’s date for commencement of commercial operation shall be the date on which the unit becomes a TR SO\(_2\) Group 2 unit under §97.704.

(i) For a unit with a date for commencement of commercial operation as defined in the introductory text of paragraph (2) of this definition and that subsequently undergoes a physical change or is moved to a different location or source, such date shall remain the date of commencement of commercial operation of the unit, which shall continue to be treated as the same unit.

(ii) For a unit with a date for commencement of commercial operation as defined in the introductory text of paragraph (2) of this definition and that is subsequently replaced by a unit at the same or a different source, such date shall remain the replaced unit’s date of commencement of commercial operation, and the replacement unit shall be treated as a separate unit with a separate date for commencement of commercial operation as defined in paragraph (1) or (2) of this definition as appropriate.

Common designated representative means, with regard to a control period in a given year, a designated representative where, as of April 1 immediately after the allowance transfer deadline for such control period, the same natural person is authorized under §§97.713(a) and 97.715(a) as the designated representative for a group of one or more TR SO\(_2\) Group 2 sources and units located in a State (and Indian country within the borders of such State).

Common designated representative’s assurance level means, with regard to a specific common designated representative and a State (and Indian country within the borders of such State) and control period in a given year for which the State assurance level is exceeded as described in §97.706(c)(2)(i)(I), the common designated representative’s share of the State SO\(_2\) Group 2 trading budget with the variability limit for the State for such control period.

Common designated representative’s assurance level means, with regard to a specific common designated representative for a control period in a given year:

(1) With regard to a total amount of SO\(_2\) emissions from all TR SO\(_2\) Group 2 units in a State (and Indian country within the borders of such State) during such control period, the total tonnage of SO\(_2\) emissions during such control period from a group of one or more TR SO\(_2\) Group 2 units located in such State (and such Indian country) and having the common designated representative for such control period;

(2) With regard to a State SO\(_2\) Group 2 trading budget with the variability limit for such control period, the amount (rounded to the nearest allowance) equal to the sum of the total amount of TR SO\(_2\) Group 2 allowances allocated for such control period to a group of one or more TR SO\(_2\) Group 2 units located in the State (and Indian country within the borders of such State) and having the common designated representative for such control period and of the total amount of TR SO\(_2\) Group 2 allowances purchased by an owner or operator of such TR SO\(_2\) Group 2 units in an auction for such control period and submitted by the State or the permitting authority to the Administrator for recordation in the compliance accounts for such TR SO\(_2\) Group 2 units in accordance with the TR SO\(_2\) Group 2 allowance auction provisions in a SIP revision approved by the Administrator under §52.39(h) or (i) of this chapter, multiplied by the sum of the State SO\(_2\) Group 2 trading budget under §97.710(a) and the State’s variability limit under §97.710(b) for such control period and divided by such State SO\(_2\) Group 2 trading budget;

(3) Provided that, in the case of a unit that operates during, but has no amount of TR SO\(_2\) Group 2 allowances allocated under §§97.711 and 97.712 for,
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such control period, the unit shall be treated, solely for purposes of this definition, as being allocated an amount (rounded to the nearest allowance) of TR SO\textsubscript{2} Group 2 allowances for such control period equal to the unit’s allowable SO\textsubscript{2} emission rate applicable to such control period, multiplied by a capacity factor of 0.85 (if the unit is a boiler combusting any amount of coal or coal-derived fuel during such control period), 0.24 (if the unit is a simple combustion turbine during such control period), 0.67 (if the unit is a combined cycle turbine during such control period), 0.74 (if the unit is an integrated coal gasification combined cycle unit during such control period), or 0.36 (for any other unit), multiplied by the unit’s maximum hourly load as reported in accordance with this subpart and by 8,760 hours/control period, and divided by 2,000 lb/ton.

Common stack means a single flue through which emissions from 2 or more units are exhausted.

Compliance account means an Allowance Management System account established by the Administrator for a TR SO\textsubscript{2} Group 2 source under this subpart, in which any TR SO\textsubscript{2} Group 2 allowances to the TR SO\textsubscript{2} Group 2 units at the source are recorded and in which are held any TR SO\textsubscript{2} Group 2 allowances available for use for a control period in a given year in complying with the source’s TR SO\textsubscript{2} Group 2 emissions limitation in accordance with §§97.706 and 97.724.

Continuous emission monitoring system or CEMS means the equipment required under this subpart to sample, analyze, measure, and provide, by means of readings recorded at least once every 15 minutes and using an automated data acquisition and handling system (DAHS), a permanent record of SO\textsubscript{2} emissions, stack gas volumetric flow rate, stack gas moisture content, and \text{O}_2 or \text{CO}_2 concentration (as applicable), in a manner consistent with part 73 of this chapter and §§97.730 through 97.739. The following systems are the principal types of continuous emission monitoring systems:

(1) A flow monitoring system, consisting of a stack flow rate monitor and an automated data acquisition and handling system and providing a permanent, continuous record of stack gas volumetric flow rate, in standard cubic feet per hour (scfh);

(2) A SO\textsubscript{2} monitoring system, consisting of a SO\textsubscript{2} pollutant concentration monitor and an automated data acquisition and handling system and providing a permanent, continuous record of SO\textsubscript{2} emissions, in parts per million (ppm);

(3) A moisture monitoring system, as defined in §75.11(b)(2) of this chapter and providing a permanent, continuous record of the stack gas moisture content, in percent H\textsubscript{2}O;

(4) A \text{CO}_2 monitoring system, consisting of a \text{CO}_2 pollutant concentration monitor (or an \text{O}_2 monitor plus suitable mathematical equations from which the \text{CO}_2 concentration is derived) and an automated data acquisition and handling system and providing a permanent, continuous record of \text{CO}_2 emissions, in percent \text{CO}_2; and

(5) An \text{O}_2 monitoring system, consisting of an \text{O}_2 concentration monitor and an automated data acquisition and handling system and providing a permanent, continuous record of \text{O}_2, in percent \text{O}_2.

Control period means the period starting January 1 of a calendar year, except as provided in §97.706(c)(3), and ending on December 31 of the same year, inclusive.

Designated representative means, for a TR SO\textsubscript{2} Group 2 source and each TR SO\textsubscript{2} Group 2 unit at the source, the natural person who is authorized by the owners and operators of the source and all such units at the source, in accordance with this subpart, to represent and legally bind each owner and operator in matters pertaining to the TR SO\textsubscript{2} Group 2 Trading Program. If the TR SO\textsubscript{2} Group 2 source is also subject to the Acid Rain Program, TR \text{NO}_x Annual Trading Program, or TR \text{NO}_x Ozone Season Trading Program, then this natural person shall be the same natural person as the designated representative, as defined in the respective program.

Emissions means air pollutants exhausted from a unit or source into the atmosphere, as measured, recorded, and reported to the Administrator by the designated representative, and as modified by the Administrator:
(1) In accordance with this subpart; and

(2) With regard to a period before the unit or source is required to measure, record, and report such air pollutants in accordance with this subpart, in accordance with part 75 of this chapter.

Excess emissions means any ton of emissions from the TR SO\textsubscript{2} Group 2 units at a TR SO\textsubscript{2} Group 2 source during a control period in a given year that exceeds the TR SO\textsubscript{2} Group 2 emissions limitation for the source for such control period.

Fossil fuel means—

(1) Natural gas, petroleum, coal, or any form of solid, liquid, or gaseous fuel derived from such material; or

(2) For purposes of applying the limitation on “average annual fuel consumption of fossil fuel” in §§97.704(b)(1)(B) and (ii), natural gas, petroleum, coal, or any form of solid, liquid, or gaseous fuel derived from such material for the purpose of creating useful heat.

Fossil-fuel-fired means, with regard to a unit, combusting any amount of fossil fuel in 2005 or any calendar year thereafter.

General account means an Allowance Management System account, established under this subpart, that is not a compliance account or an assurance account.

Generator means a device that produces electricity.

Gross electrical output means, for a unit, electricity made available for use, including any such electricity used in the power production process (which process includes, but is not limited to, any on-site processing or treatment of fuel combusted at the unit and any on-site emission controls).

Heat input rate means, for a unit, the amount of heat input (in mmBtu) divided by unit operating time (in hr) or, for a unit and a specific fuel, the amount of heat input attributed to the fuel (in mmBtu) divided by the unit operating time (in hr) during which the unit combusted the fuel.

Heat rate means, for a unit, the unit’s maximum design heat input (in Btu/hr), divided by the product of 1,000,000 Btu/mmBtu and the unit’s maximum hourly load.

Indian country means “Indian country” as defined in 18 U.S.C. 1151.

Life-of-the-unit, firm power contractual arrangement means a unit participation power sales agreement under which a utility or industrial customer reserves, or is entitled to receive, a specified amount or percentage of nameplate capacity and associated energy generated by any specified unit and pays its proportional amount of such unit’s total costs, pursuant to a contract:

(1) For the life of the unit;

(2) For a cumulative term of no less than 30 years, including contracts that permit an election for early termination; or

(3) For a period no less than 25 years or 70 percent of the economic useful life of the unit determined as of the time the unit is built, with option rights to purchase or release some portion of the nameplate capacity and associated energy generated by the unit at the end of the period.

Maximum design heat input means, for a unit, the maximum amount of fuel per hour (in Btu/hr) that the unit is capable of combusting on a steady state basis as of the initial installation of the unit as specified by the manufacturer of the unit.

Monitoring system means any monitoring system that meets the requirements of this subpart, including a continuous emission monitoring system, an alternative monitoring system, or an excepted monitoring system under part 75 of this chapter.

Nameplate capacity means, starting from the initial installation of a generator, the maximum electrical generating output (in MWe, rounded to the nearest tenth) that the generator is capable of producing on a steady state basis and during continuous operation.
(when not restricted by seasonal or other deratings) as of such installation as specified by the manufacturer of the generator or, starting from the completion of any subsequent physical change in the generator resulting in an increase in the maximum electrical generating output that the generator is capable of producing on a steady state basis and during continuous operation (when not restricted by seasonal or other deratings), such increased maximum amount (in MWe, rounded to the nearest tenth) as of such completion as specified by the person conducting the physical change.

_Natural gas_ means “natural gas” as defined in §72.2 of this chapter.

_Newly affected TR SO₂ Group 2 unit_ means a unit that was not a TR SO₂ Group 2 unit when it began operating but that thereafter becomes a TR SO₂ Group 2 unit.

_Operate or operation_ means, with regard to a unit, to combust fuel.

_Operator_ means, for a TR SO₂ Group 2 source or a TR SO₂ Group 2 unit at a source respectively, any person who operates, controls, or supervises a TR SO₂ Group 2 unit at the source or the TR SO₂ Group 2 unit and shall include, but not be limited to, any holding company, utility system, or plant manager of such source or unit.

_Owner_ means, for a TR SO₂ Group 2 source or a TR SO₂ Group 2 unit at a source respectively, any of the following persons:

1. Any holder of any portion of the legal or equitable title in a TR SO₂ Group 2 unit at the source or the TR SO₂ Group 2 unit;

2. Any holder of a leasehold interest in a TR SO₂ Group 2 unit at the source or the TR SO₂ Group 2 unit, provided that, unless expressly provided for in a leasehold agreement, “owner” shall not include a passive lessor, or a person who has an equitable interest through such lessor, whose rental payments are not based (either directly or indirectly) on the revenues or income from such TR SO₂ Group 2 unit; and

3. Any purchaser of power from a TR SO₂ Group 2 unit at the source or the TR SO₂ Group 2 unit under a life-of-the-unit, firm power contractual arrangement.

_Permanently retired_ means, with regard to a unit, a unit that is unavailable for service and that the unit’s owners and operators do not expect to return to service in the future.

_Permitting authority_ means “permitting authority” as defined in §§70.2 and 71.2 of this chapter.

_Potential electrical output capacity_ means, for a unit, 33 percent of the unit’s maximum design heat input, divided by 3,413 Btu/kWh, divided by 1,000 kWh/MWh, and multiplied by 8,760 hr/yr.

_Receive or receipt of_ means, when referring to the Administrator, to come into possession of a document, information, or correspondence (whether sent in hard copy or by authorized electronic transmission), as indicated in an official log, or by a notation made on the document, information, or correspondence, by the Administrator in the regular course of business.

_Recordation, record, or recorded_ means, with regard to TR SO₂ Group 2 allowances, the moving of TR SO₂ Group 2 allowances by the Administrator into, out of, or between Allowance Management System accounts, for purposes of allocation, auction, transfer, or deduction.

_Reference method_ means any direct test method of sampling and analyzing for an air pollutant as specified in §75.22 of this chapter.

_Replacement, replace, or replaced_ means, with regard to a unit, the demolishing of a unit, or the permanent retirement and permanent disabling of a unit, and the construction of another unit (the replacement unit) to be used instead of the demolished or retired unit (the replaced unit).

_Sequential use of energy_ means:

1. The use of reject heat from electricity production in a useful thermal energy application or process; or

2. The use of reject heat from useful thermal energy application or process in electricity production.

_Serial number_ means, for a TR SO₂ Group 2 allowance, the unique identification number assigned to each TR SO₂ Group 2 allowance by the Administrator.

_Solid waste incineration unit_ means a stationary, fossil-fuel-fired boiler or stationary, fossil-fuel-fired combustion
turbine that is a “solid waste incineration unit” as defined in section 129(g)(1) of the Clean Air Act.

Source means all buildings, structures, or installations located in one or more contiguous or adjacent properties under common control of the same person or persons. This definition does not change or otherwise affect the definition of “major source”, “stationary source”, or “source” as set forth and implemented in a title V operating permit program or any other program under the Clean Air Act.

State means one of the States that is subject to the TR SO\textsubscript{2} Group 2 Trading Program pursuant to §52.39(a), (c), (g), (h), and (i) of this chapter.

Submit or serve means to send or transmit a document, information, or correspondence to the person specified in accordance with the applicable regulation:

(1) In person;
(2) By United States Postal Service; or
(3) By other means of dispatch or transmission and delivery;

(4) Provided that compliance with any “submission” or “service” deadline shall be determined by the date of dispatch, transmission, or mailing and not the date of receipt.

Topping-cycle unit means a unit in which the energy input to the unit is first used to produce useful power, including electricity, where at least some of the reject heat from the electricity production is then used to provide useful thermal energy.

Total energy input means, for a unit, total energy of all forms supplied to the unit, excluding energy produced by the unit. Each form of energy supplied shall be measured by the lower heating value of that form of energy calculated as follows:

\[
LHV = HHV - 10.55(W + 9H)
\]

where:

\( LHV \) = lower heating value of the form of energy in Btu/lb,
\( HHV \) = higher heating value of the form of energy in Btu/lb,
\( W \) = weight % of moisture in the form of energy, and
\( H \) = weight % of hydrogen in the form of energy.

Total energy output means, for a unit, the sum of useful power and useful thermal energy produced by the unit.

TR NO\textsubscript{X} Annual Trading Program means a multi-state NO\textsubscript{X} air pollution control and emission reduction program established in accordance with subpart AAAAA of this part and §52.38(a) of this chapter (including such a program that is revised in a SIP revision approved by the Administrator under §52.38(a)(3) or (4) of this chapter or that is established in a SIP revision approved by the Administrator under §52.38(a)(5) of this chapter), as a means of mitigating interstate transport of fine particulates and NO\textsubscript{X}.

TR NO\textsubscript{X} Ozone Season Trading Program means a multi-state NO\textsubscript{X} air pollution control and emission reduction program established in accordance with subpart BBBBB of this part and §52.38(b) of this chapter (including such a program that is revised in a SIP revision approved by the Administrator under §52.38(b)(3) or (4) of this chapter or that is established in a SIP revision approved by the Administrator under §52.38(b)(5) of this chapter), as a means of mitigating interstate transport of ozone and NO\textsubscript{X}.

TR SO\textsubscript{2} Group 2 allowance means a limited authorization issued and allocated or auctioned by the Administrator under this subpart, or by a State or permitting authority under a SIP revision approved by the Administrator under §52.39(g), (h), or (i) of this chapter, to emit one ton of SO\textsubscript{2} during a control period of the specified calendar year for which the authorization is allocated or auctioned or of any calendar year thereafter under the TR SO\textsubscript{2} Group 2 Trading Program.

TR SO\textsubscript{2} Group 2 allowance deduction or deduct TR SO\textsubscript{2} means the permanent withdrawal of TR SO\textsubscript{2} Group 2 allowances by the Administrator from a compliance account (e.g., in order to account for compliance with the TR SO\textsubscript{2} Group 2 emissions limitation) or from an assurance account (e.g., in order to account for compliance with the assurance provisions under §§97.706 and 97.725).

TR SO\textsubscript{2} Group 2 allowances held or hold TR SO\textsubscript{2} Group 2 allowances means the TR SO\textsubscript{2} Group 2 allowances treated
as included in an Allowance Management System account as of a specified point in time because at that time they:

1. Have been recorded by the Administrator in the account or transferred into the account by a correctly submitted, but not yet recorded, TR SO₂ Group 2 allowance transfer in accordance with this subpart; and

2. Have not been transferred out of the account by a correctly submitted, but not yet recorded, TR SO₂ Group 2 allowance transfer in accordance with this subpart.

TR SO₂ Group 2 emissions limitation means, for a TR SO₂ Group 2 source, the tonnage of SO₂ emissions authorized in a control period by the TR SO₂ Group 2 allowances available for deduction for the source under §97.724(a) for such control period.

TR SO₂ Group 2 source means a source that includes one or more TR SO₂ Group 2 units.

TR SO₂ Group 2 Trading Program means a multi-state SO₂ air pollution control and emission reduction program established in accordance with this subpart and §52.39(a), (c), and (g) through (k) of this chapter (including such a program that is revised in a SIP revision approved by the Administrator under §52.39(g) or (h) of this chapter or that is established in a SIP revision approved by the Administrator under §52.39(i) of this chapter), as a means of mitigating interstate transport of fine particulates and SO₂.

TR SO₂ Group 2 unit means a unit that is subject to the TR SO₂ Group 2 Trading Program under §97.704.

Unit means a stationary, fossil-fuel-fired boiler, stationary, fossil-fuel-fired combustion turbine, or other stationary, fossil-fuel-fired combustion device. A unit that undergoes a physical change or is moved to a different location or source shall continue to be treated as the same unit. A unit (the replaced unit) that is replaced by another unit (the replacement unit) at the same or a different source shall continue to be treated as the same unit, and the replacement unit shall be treated as a separate unit.

Unit operating day means, with regard to a unit, a calendar day in which the unit combusts any fuel.

Unit operating hour or hour of unit operation means, with regard to a unit, an hour in which the unit combusts any fuel.

Useful power means, with regard to a unit, electricity or mechanical energy that the unit makes available for use, excluding any such energy used in the power production process (which process includes, but is not limited to, any on-site processing or treatment of fuel combusted at the unit and any on-site emission controls).

Useful thermal energy means thermal energy that is:

1. Made available to an industrial or commercial process (not a power production process), excluding any heat contained in condensate return or makeup water;

2. Used in a heating application (e.g., space heating or domestic hot water heating); or

3. Used in a space cooling application (i.e., in an absorption chiller).

Utility power distribution system means the portion of an electricity grid owned or operated by a utility and dedicated to delivering electricity to customers.

§ 97.704 Applicability.

(a) Except as provided in paragraph (b) of this section:

1. The following units in a State (and Indian country within the borders of such State) shall be TR SO₂ Group 2 units, and any source that includes one or more such units shall be a TR SO₂
Group 2 source, subject to the requirements of this subpart: Any stationary, fossil-fuel-fired boiler or stationary, fossil-fuel-fired combustion turbine serving at any time, on or after January 1, 2005, a generator with nameplate capacity of more than 25 MWe producing electricity for sale.

(2) If a stationary boiler or stationary combustion turbine that, under paragraph (a)(1) of this section, is not a TR SO\textsubscript{2} Group 2 unit begins to combust fossil fuel or to serve a generator with nameplate capacity of more than 25 MWe producing electricity for sale, the unit shall become a TR SO\textsubscript{2} Group 2 unit as provided in paragraph (a)(1) of this section on the first date on which it both combusts fossil fuel and serves such generator.

(b) Any unit in a State (and Indian country within the borders of such State) that otherwise is a TR SO\textsubscript{2} Group 2 unit under paragraph (a) of this section and that meets the requirements set forth in paragraph (b)(1)(i) or (2)(i) of this section shall not be a TR SO\textsubscript{2} Group 2 unit:

(1)(i) Any unit:

(A) Qualifying as a cogeneration unit throughout the later of 2005 or the 12-month period starting on the date the unit first produces electricity and continuing to qualify as a cogeneration unit throughout each calendar year ending after the later of 2005 or such 12-month period; and

(B) Not supplying in 2005 or any calendar year thereafter more than one-third of the unit’s potential electric output capacity or 219,000 MWh, whichever is greater, to any utility power distribution system for sale.

(ii) If, after qualifying under paragraph (b)(1)(i) of this section as not being a TR SO\textsubscript{2} Group 2 unit, a unit subsequently no longer meets all the requirements of paragraph (b)(1)(i) of this section, the unit shall become a TR SO\textsubscript{2} Group 2 unit starting on the earlier of January 1 after the first calendar year during which the unit first no longer qualifies as a solid waste incineration unit or January 1 after the first 3 consecutive calendar years after 2005 for which the unit has an average annual fuel consumption of fossil fuel of 20 percent or more. The unit shall thereafter continue to be a TR SO\textsubscript{2} Group 2 unit.

(2)(i) Any unit:

(A) Qualifying as a solid waste incineration unit throughout the later of 2005 or the 12-month period starting on the date the unit first produces electricity and continuing to qualify as a solid waste incineration unit throughout each calendar year ending after the later of 2005 or such 12-month period; and

(B) With an average annual fuel consumption of fossil fuel for the first 3 consecutive calendar years of operation starting no earlier than 2005 of less than 20 percent (on a Btu basis) and an average annual fuel consumption of fossil fuel for any 3 consecutive calendar years thereafter of less than 20 percent (on a Btu basis).

(ii) If, after qualifying under paragraph (b)(2)(i) of this section as not being a TR SO\textsubscript{2} Group 2 unit, a unit subsequently no longer meets all the requirements of paragraph (b)(1)(i) of this section, the unit shall become a TR SO\textsubscript{2} Group 2 unit starting on the earlier of January 1 after the first calendar year during which the unit first no longer qualifies as a solid waste incineration unit or January 1 after the first 3 consecutive calendar years after 2005 for which the unit has an average annual fuel consumption of fossil fuel of 20 percent or more. The unit shall thereafter continue to be a TR SO\textsubscript{2} Group 2 unit.

(c) A certifying official of an owner or operator of any unit or other equipment may submit a petition (including any supporting documents) to the Administrator at any time for a determination concerning the applicability, under paragraphs (a) and (b) of this section or a SIP revision approved under §52.39(h) or (i) of this chapter, of the TR SO\textsubscript{2} Group 2 Trading Program to the unit or other equipment.

(1) Petition content. The petition shall be in writing and include the identification of the unit or other equipment and the relevant facts about the unit or other equipment. The petition and any other documents provided to the Administrator in connection with the petition shall include the following certification statement, signed by the certifying official: “I am authorized to make this submission on behalf of the owners and operators of
§ 97.705 Retired unit exemption.

(a)(1) Any TR SO₂ Group 2 unit that is permanently retired shall be exempt from §§ 97.706(b) and (c)(1), § 97.724, and §§ 97.730 through 97.735.

(2) The exemption under paragraph (a)(1) of this section shall become effective the day on which the TR SO₂ Group 2 unit is permanently retired. Within 30 days of the unit’s permanent retirement, the designated representative shall submit a statement to the Administrator. The statement shall state, in a format prescribed by the Administrator, that the unit was permanently retired on a specified date and will comply with the requirements of paragraph (b) of this section.

(b) Special provisions. (1) A unit exempt under paragraph (a) of this section shall not emit any SO₂, starting on the date that the exemption takes effect.

(2) For a period of 5 years from the date the records are created, the owners and operators of a unit exempt under paragraph (a) of this section shall retain, at the source that includes the unit, records demonstrating that the unit is permanently retired. The 5-year period for keeping records may be extended for cause, at any time before the end of the period, in writing by the Administrator. The owners and operators bear the burden of proof that the unit is permanently retired.

(3) The owners and operators and, to the extent applicable, the designated representative of a unit exempt under paragraph (a) of this section shall comply with the requirements of the TR SO₂ Group 2 Trading Program concerning all periods for which the exemption is not in effect, even if such requirements arise, or must be complied with, after the exemption takes effect.

(4) A unit exempt under paragraph (a) of this section shall lose its exemption on the first date on which the unit resumes operation. Such unit shall be treated, for purposes of applying allocation, monitoring, reporting, and recordkeeping requirements under this subpart, as a unit that commences commercial operation on the first date on which the unit resumes operation.

§ 97.706 Standard requirements.

(a) Designated representative requirements. The owners and operators shall comply with the requirement to have a designated representative, and may have an alternate designated representative, in accordance with §§ 97.713 through 97.718.

(b) Emissions monitoring, reporting, and recordkeeping requirements. (1) The owners and operators, and the designated representative, of each TR SO₂ Group 2 source and each TR SO₂ Group 2 unit at the source shall comply with the monitoring, reporting, and recordkeeping requirements of §§ 97.730 through 97.735.

(2) The emissions data determined in accordance with §§ 97.730 through 97.735 shall be used to calculate allocations of TR SO₂ Group 2 allowances under §§ 97.711(a)(2) and (b) and 97.712 and to determine compliance with the TR SO₂ Group 2 emissions limitation and assurance provisions under paragraph (c)
of this section, provided that, for each monitoring location from which mass emissions are reported, the mass emissions amount used in calculating such allocations and determining such compliance shall be the mass emissions amount for the monitoring location determined in accordance with §§97.730 through 97.735 and rounded to the nearest ton, with any fraction of a ton less than 0.50 being deemed to be zero.

(c) \(\text{SO}_2\) emissions limitation. (1) TR \(\text{SO}_2\) Group 2 emissions limitation. (i) As of the allowance transfer deadline for a control period in a given year, the owners and operators of each TR \(\text{SO}_2\) Group 2 source and each TR \(\text{SO}_2\) Group 2 unit at the source shall hold, in the source’s compliance account, TR \(\text{SO}_2\) Group 2 allowances available for deduction for such control period under §97.724(a) in an amount not less than the tons of total \(\text{SO}_2\) emissions for such control period from all TR \(\text{SO}_2\) Group 2 units at the source.

(ii) If total \(\text{SO}_2\) emissions during a control period in a given year from the TR \(\text{SO}_2\) Group 2 units at a TR \(\text{SO}_2\) Group 2 source are in excess of the TR \(\text{SO}_2\) Group 2 emissions limitation set forth in paragraph (c)(1)(i) of this section, then:

(A) The owners and operators of the source and each TR \(\text{SO}_2\) Group 2 unit at the source shall hold the TR \(\text{SO}_2\) Group 2 allowances required for deduction under §97.724(d); and

(B) The owners and operators of the source and each TR \(\text{SO}_2\) Group 2 unit at the source shall pay any fine, penalty, or assessment or comply with any other remedy imposed, for the same violations, under the Clean Air Act, and each ton of such excess emissions and each day of such control period shall constitute a separate violation of this subpart and the Clean Air Act.

(2) TR \(\text{SO}_2\) Group 2 assurance provisions. (i) If total \(\text{SO}_2\) emissions during a control period in a given year from all TR \(\text{SO}_2\) Group 2 units at TR \(\text{SO}_2\) Group 2 sources in a State (and Indian country within the borders of such State) exceed the State assurance level, then the owners and operators of such sources and units in each group of one or more sources and units having a common designated representative for such control period, where the common designated representative’s share of such \(\text{SO}_2\) emissions during such control period exceeds the common designated representative’s assurance level for the State and such control period, shall hold (in the assurance account established for the owners and operators of such group) TR \(\text{SO}_2\) Group 2 allowances available for deduction for such control period under §97.725(a) in an amount equal to two times the product (rounded to the nearest whole number), as determined by the Administrator in accordance with §97.725(b), of multiplying—

(A) The quotient of the amount by which the common designated representative’s share of such \(\text{SO}_2\) emissions exceeds the common designated representative’s assurance level divided by the sum of the amounts, determined for all common designated representatives for such sources and units in the State (and Indian country within the borders of such State) for such control period, by which each common designated representative’s share of such \(\text{SO}_2\) emissions exceeds the respective common designated representative’s assurance level; and

(B) The amount by which total \(\text{SO}_2\) emissions from all TR \(\text{SO}_2\) Group 2 units at TR \(\text{SO}_2\) Group 2 sources in the State (and Indian country within the borders of such State) for such control period exceed the State assurance level.

(ii) The owners and operators shall hold the TR \(\text{SO}_2\) Group 2 allowances required under paragraph (c)(2)(i) of this section, as of midnight of November 1 (if it is a business day), or midnight of the first business day thereafter (if November 1 is not a business day), immediately after such control period.

(iii) Total \(\text{SO}_2\) emissions from all TR \(\text{SO}_2\) Group 2 units at TR \(\text{SO}_2\) Group 2 sources in a State (and Indian country within the borders of such State) during a control period in a given year exceed the State assurance level if such total \(\text{SO}_2\) emissions exceed the sum, for such control period, of the State \(\text{SO}_2\) Group 2 trading budget under §97.719(a) and the State’s variability limit under §97.719(b).

(iv) It shall not be a violation of this subpart or of the Clean Air Act if total \(\text{SO}_2\) emissions from all TR \(\text{SO}_2\) Group 2
units at TR SO₂ Group 2 sources in a State (and Indian country within the borders of such State) during a control period exceed the State assurance level or if a common designated representative’s share of total SO₂ emissions from the TR SO₂ Group 2 units at TR SO₂ Group 2 sources in a State (and Indian country within the borders of such State) during a control period exceeds the common designated representative’s assurance level.

(v) To the extent the owners and operators fail to hold TR SO₂ Group 2 allowances for a control period in a given year in accordance with paragraphs (c)(2)(i) through (iii) of this section, (A) The owners and operators shall pay any fine, penalty, or assessment or comply with any other remedy imposed under the Clean Air Act; and

(B) Each TR SO₂ Group 2 allowance that the owners and operators fail to hold for such control period in accordance with paragraphs (c)(2)(i) through (iii) of this section and each day of such control period shall constitute a separate violation of this subpart and the Clean Air Act.

(3) Compliance periods. (i) A TR SO₂ Group 2 unit shall be subject to the requirements under paragraph (c)(1) of this section for the control period starting on the later of January 1, 2012 or the deadline for meeting the unit’s monitor certification requirements under §97.730(b) and for each control period thereafter.

(ii) A TR SO₂ Group 2 unit shall be subject to the requirements under paragraph (c)(2) of this section for the control period starting on the later of January 1, 2014 or the deadline for meeting the unit’s monitor certification requirements under §97.730(b) and for each control period thereafter.

(4) Vintage of allowances held for compliance. (i) A TR SO₂ Group 2 allowance held for compliance with the requirements under paragraph (c)(1)(i) of this section for a control period in a given year must be a TR SO₂ Group 2 allowance that was allocated for a control period in a prior year or the control period in the given year or in the immediately following year.

(5) Allowance Management System requirements. Each TR SO₂ Group 2 allowance shall be held in, deducted from, or transferred into, out of, or between Allowance Management System accounts in accordance with this subpart.

(6) Limited authorization. A TR SO₂ Group 2 allowance is a limited authorization to emit one ton of SO₂ during the control period in one year. Such authorization is limited in its use and duration as follows:

(i) Such authorization shall only be used in accordance with the TR SO₂ Group 2 Trading Program; and

(ii) Notwithstanding any other provision of this subpart, the Administrator has the authority to terminate or limit the use and duration of such authorization to the extent the Administrator determines is necessary or appropriate to implement any provision of the Clean Air Act.

(7) Property right. A TR SO₂ Group 2 allowance does not constitute a property right.

(d) Title V permit requirements. (1) No Title V permit revision shall be required for any allocation, holding, deduction, or transfer of TR SO₂ Group 2 allowances in accordance with this subpart.

(2) A description of whether a unit is required to monitor and report SO₂ emissions using a continuous emission monitoring system (under subpart H of part 75 of this chapter), an excepted monitoring system (under appendices D and E to part 75 of this chapter), a low mass emissions excepted monitoring methodology (under §75.19 of this chapter), or an alternative monitoring system (under subpart E of part 75 of this chapter) in accordance with §§97.730 through 97.735 may be added to, or changed in, a Title V permit using minor permit modification procedures in accordance with §§70.7(e)(2) and 71.7(e)(1) of this chapter, provided that the requirements applicable to the described monitoring and reporting (as
added or changed, respectively) are already incorporated in such permit. This paragraph explicitly provides that the addition of, or change to, a unit’s description as described in the prior sentence is eligible for minor permit modification procedures in accordance with §§70.7(e)(2)(i)(B) and 71.7(e)(1)(i)(B) of this chapter.

(e) Additional recordkeeping and reporting requirements. (1) Unless otherwise provided, the owners and operators of each TR SO\textsubscript{2} Group 2 source and each TR SO\textsubscript{2} Group 2 unit at the source shall keep on site at the source each of the following documents (in hardcopy or electronic format) for a period of 5 years from the date the document is created. This period may be extended for cause, at any time before the end of 5 years, in writing by the Administrator.

(i) The certificate of representation under §97.716 for the designated representative for the source and each TR SO\textsubscript{2} Group 2 unit at the source and all documents that demonstrate the truth of the statements in the certificate of representation; provided that the certificate and documents shall be retained on site at the source beyond such 5-year period until such certificate of representation and documents are superseded because of the submission of a new certificate of representation under §97.716 changing the designated representative.

(ii) All emissions monitoring information, in accordance with this subpart.

(iii) Copies of all reports, compliance certifications, and other submissions and all records made or required under, or to demonstrate compliance with the requirements of, the TR SO\textsubscript{2} Group 2 Trading Program.

(2) The designated representative of a TR SO\textsubscript{2} Group 2 source and each TR SO\textsubscript{2} Group 2 unit at the source shall make all submissions required under the TR SO\textsubscript{2} Group 2 Trading Program, except as provided in §97.718. This requirement does not change, create an exemption from, or otherwise affect the responsible official submission requirements under a title V operating permit program in parts 70 and 71 of this chapter.

(f) Liability. (1) Any provision of the TR SO\textsubscript{2} Group 2 Trading Program that applies to a TR SO\textsubscript{2} Group 2 source or the designated representative of a TR SO\textsubscript{2} Group 2 source shall also apply to the owners and operators of such source and of the TR SO\textsubscript{2} Group 2 units at the source.

(2) Any provision of the TR SO\textsubscript{2} Group 2 Trading Program that applies to a TR SO\textsubscript{2} Group 2 unit or the designated representative of a TR SO\textsubscript{2} Group 2 unit shall also apply to the owners and operators of such unit.

(g) Effect on other authorities. No provision of the TR SO\textsubscript{2} Group 2 Trading Program or exemption under §97.705 shall be construed as exempting or excluding the owners and operators, and the designated representative, of a TR SO\textsubscript{2} Group 2 source or TR SO\textsubscript{2} Group 2 unit from compliance with any other provision of the applicable, approved State implementation plan, a federally enforceable permit, or the Clean Air Act.

§ 97.707 Computation of time.

(a) Unless otherwise stated, any time period scheduled, under the TR SO\textsubscript{2} Group 2 Trading Program, to begin on the occurrence of an act or event shall begin on the day the act or event occurs.

(b) Unless otherwise stated, any time period scheduled, under the TR SO\textsubscript{2} Group 2 Trading Program, to begin before the occurrence of an act or event shall be computed so that the period ends the day before the act or event occurs.

(c) Unless otherwise stated, if the final day of any time period, under the TR SO\textsubscript{2} Group 2 Trading Program, is not a business day, the time period shall be extended to the next business day.

§ 97.708 Administrative appeal procedures.

The administrative appeal procedures for decisions of the Administrator under the TR SO\textsubscript{2} Group 2 Trading Program are set forth in part 78 of this chapter.
§ 97.710 State SO\textsubscript{2} Group 2 trading budgets, new unit set-asides, Indian country new unit set-aside, and variability limits.

(a) The State SO\textsubscript{2} trading budgets, new unit set-asides, and Indian country new unit set-asides for allocations of TR SO\textsubscript{2} Group 2 allowances for the control periods in 2012 and thereafter are as follows:

(1) Alabama. (i) The SO\textsubscript{2} trading budget for 2012 and 2013 is 216,033 tons.
(ii) The SO\textsubscript{2} new unit set-aside for 2012 and 2013 is 4,321 tons.
(iii) [Reserved]
(iv) The SO\textsubscript{2} trading budget for 2014 and thereafter is 213,258 tons.
(v) The SO\textsubscript{2} new unit set-aside for 2014 and thereafter is 4,265 tons.
(vi) [Reserved]

(2) Georgia. (i) The SO\textsubscript{2} trading budget for 2012 and 2013 is 158,527 tons.
(ii) The SO\textsubscript{2} new unit set-aside for 2012 and 2013 is 3,171 tons.
(iii) [Reserved]
(iv) The SO\textsubscript{2} trading budget for 2014 and thereafter is 1,905 tons.
(v) [Reserved]

(3) Kansas. (i) The SO\textsubscript{2} trading budget for 2012 and 2013 is 41,528 tons.
(ii) The SO\textsubscript{2} new unit set-aside for 2012 and 2013 is 789 tons.
(iii) The SO\textsubscript{2} Indian country new unit set-aside for 2012 and 2013 is 42 tons.
(iv) The SO\textsubscript{2} trading budget for 2014 and thereafter is 41,528 tons.
(v) The SO\textsubscript{2} new unit set-aside for 2014 and thereafter is 789 tons.
(vi) The SO\textsubscript{2} Indian country new unit set-aside for 2014 and thereafter is 42 tons.

(4) Minnesota. (i) The SO\textsubscript{2} trading budget for 2012 and 2013 is 41,981 tons.
(ii) The SO\textsubscript{2} new unit set-aside for 2012 and 2013 is 798 tons.
(iii) The SO\textsubscript{2} Indian country new unit set-aside for 2012 and 2013 is 42 tons.
(iv) The SO\textsubscript{2} trading budget for 2014 and thereafter is 41,981 tons.
(v) The SO\textsubscript{2} new unit set-aside for 2014 and thereafter is 798 tons.
(vi) The SO\textsubscript{2} Indian country new unit set-aside for 2014 and thereafter is 42 tons.

(5) Nebraska. (i) The SO\textsubscript{2} trading budget for 2012 and 2013 is 65,052 tons.
(ii) The SO\textsubscript{2} new unit set-aside for 2012 and 2013 is 2,537 tons.
(iii) The SO\textsubscript{2} Indian country new unit set-aside for 2012 and 2013 is 65 tons.
(iv) The SO\textsubscript{2} trading budget for 2014 and thereafter is 65,052 tons.
(v) The SO\textsubscript{2} new unit set-aside for 2014 and thereafter is 2,537 tons.
(vi) The SO\textsubscript{2} Indian country new unit set-aside for 2014 and thereafter is 65 tons.

(6) South Carolina. (i) The SO\textsubscript{2} trading budget for 2012 and 2013 is 88,620 tons.
(ii) The SO\textsubscript{2} new unit set-aside for 2012 and 2013 is 1,683 tons.
(iii) The SO\textsubscript{2} Indian country new unit set-aside for 2012 and 2013 is 89 tons.
(iv) The SO\textsubscript{2} trading budget for 2014 and thereafter is 88,620 tons.
(v) The SO\textsubscript{2} new unit set-aside for 2014 and thereafter is 1,683 tons.
(vi) The SO\textsubscript{2} Indian country new unit set-aside for 2014 and thereafter is 89 tons.

(7) Texas. (i) The SO\textsubscript{2} trading budget for 2012 and 2013 is 294,471 tons.
(ii) The SO\textsubscript{2} new unit set-aside for 2012 and 2013 is 14,430 tons.
(iii) The SO\textsubscript{2} Indian country new unit set-aside for 2012 and 2013 is 294 tons.
(iv) The SO\textsubscript{2} trading budget for 2014 and thereafter is 294,471 tons.
(v) The SO\textsubscript{2} new unit set-aside for 2014 and thereafter is 14,430 tons.
(vi) The SO\textsubscript{2} Indian country new unit set-aside for 2014 and thereafter is 294 tons.

(b) The States’ variability limits for the State SO\textsubscript{2} Group 2 trading budgets for the control periods in 2014 and thereafter are as follows:

(1) The SO\textsubscript{2} variability limit for Alabama is 38,386 tons.
(2) The SO\textsubscript{2} variability limit for Georgia is 17,142 tons.
(3) The SO\textsubscript{2} variability limit for Kansas is 7,475 tons.
(4) The SO\textsubscript{2} variability limit for Minnesota is 7,557 tons.
(5) The SO\textsubscript{2} variability limit for Nebraska is 11,709 tons.
(6) The SO\textsubscript{2} variability limit for South Carolina is 15,952 tons.
(7) The SO\textsubscript{2} variability limit for Texas is 53,005 tons.

(c) Each SO\textsubscript{2} Group 2 trading budget in this section includes any tons identified under a new unit set aside or Indian country new unit set aside, but
§ 97.710 State SO 2 Group 2 trading budgets, new unit set-asides, Indian country new unit set-aside, and variability limits.

(a) * * *

(2) * * *

(iv) The SO 2 trading budget for 2014 and thereafter is 2,711 tons.

* * * * *

(3) Kansas. (i) The SO 2 trading budget for 2012 and 2013 is 41,980 tons.

(ii) The SO 2 new unit set-aside for 2012 and 2013 is 798 tons.

(iii) The SO 2 Indian country new unit set-aside for 2012 and 2013 is 42 tons.

(iv) The SO 2 trading budget for 2014 and thereafter is 41,980 tons.

(v) The SO 2 new unit set-aside for 2014 and thereafter is 2,711 tons.

(vi) The SO 2 Indian country new unit set-aside for 2014 and thereafter is 42 tons.

* * * * *

(5) Nebraska. (i) The SO 2 trading budget for 2012 and 2013 is 68,162 tons.

(ii) The SO 2 new unit set-aside for 2012 and 2013 is 798 tons.

(iii) The SO 2 Indian country new unit set-aside for 2012 and 2013 is 42 tons.

(iv) The SO 2 trading budget for 2014 and thereafter is 68,162 tons.

(v) The SO 2 new unit set-aside for 2014 and thereafter is 2,658 tons.

(vi) The SO 2 Indian country new unit set-aside for 2014 and thereafter is 42 tons.

* * * * *

(6) South Carolina. (i) The SO 2 trading budget for 2012 and 2013 is 96,633 tons.

(ii) The SO 2 new unit set-aside for 2012 and 2013 is 1,836 tons.

(iii) The SO 2 Indian country new unit set-aside for 2012 and 2013 is 97 tons.

(iv) The SO 2 trading budget for 2014 and thereafter is 96,633 tons.

(v) The SO 2 new unit set-aside for 2014 and thereafter is 1,836 tons.

(vi) The SO 2 Indian country new unit set-aside for 2014 and thereafter is 97 tons.

* * * * *

§ 97.711 Timing requirements for TR SO 2 Group 2 allowance allocations.

(a) Existing units. (1) TR SO 2 Group 2 allowances are allocated, for the control periods in 2012 and each year thereafter, as provided in a notice of data availability issued by the Administrator. Providing an allocation to a unit in such notice does not constitute a determination that the unit is a TR SO 2 Group 2 unit, and not providing an allocation to a unit in such notice does not constitute a determination that the unit is not a TR SO 2 Group 2 unit.

(2) Notwithstanding paragraph (a)(1) of this section, if a unit provided an allocation in the notice of data availability issued under paragraph (a)(1) of this section does not operate, starting after 2011, during the control period in two consecutive years, such unit will not be allocated the TR SO 2 Group 2 allowances provided in such notice for the unit for the control periods in the fifth year after the first such year and in each year after that fifth year. All TR SO 2 Group 2 allowances that would otherwise have been allocated to such unit will be allocated to the new unit set-aside for the State where such unit is located and for the respective years involved. If such unit resumes operation, the Administrator will allocate TR SO 2 Group 2 allowances to the unit in accordance with paragraph (b) of this section.

(b) New units. (1) New unit set-asides. (i) By June 1, 2012 and June 1 of each year thereafter, the Administrator will calculate the TR SO 2 Group 2 allowance allocation to each TR SO 2 Group 2 unit in a State, in accordance with § 97.712(a)(2) through (7) and (12), for the control period in the year of the applicable calculation deadline under this
paragraph and will promulgate a notice of data availability of the results of the calculations.

(ii) For each notice of data availability required in paragraph (b)(1)(i) of this section, the Administrator will provide an opportunity for submission of objections to the calculations referenced in such notice.

(A) Objections shall be submitted by the deadline specified in each notice of data availability required in paragraph (b)(1)(i) of this section and shall be limited to addressing whether the calculations (including the identification of the TR SO₂ Group 2 units) are in accordance with §97.712(a)(2) through (7) and (12) and §§97.706(b)(2) and 97.730 through 97.735.

(B) The Administrator will adjust the calculations to the extent necessary to ensure that they are in accordance with the provisions referenced in paragraph (b)(1)(ii)(A) of this section. By August 1 immediately after the promulgation of each notice of data availability required in paragraph (b)(1)(i) of this section, the Administrator will promulgate a notice of data availability of any adjustments that the Administrator determines to be necessary, the reasons for accepting or rejecting any objections submitted in accordance with paragraph (b)(1)(ii)(A) of this section, and the results of such calculations.

(iii) If the new unit set-aside for such control period contains any TR SO₂ Group 2 allowances that have not been allocated in the applicable notice of data availability required in paragraph (b)(1)(ii) of this section, the Administrator will promulgate, by December 15 immediately after such notice, a notice of data availability that identifies any TR SO₂ Group 2 units that commenced commercial operation during the period starting January 1 of the year before the year of such control period and ending November 30 of year of such control period.

(iv) For each notice of data availability required in paragraph (b)(1)(iii) of this section, the Administrator will provide an opportunity for submission of objections to the identification of TR SO₂ Group 2 units in such notice.

(A) Objections shall be submitted by the deadline specified in each notice of data availability required in paragraph (b)(1)(iii) of this section and shall be limited to addressing whether the identification of TR SO₂ annual units in such notice is in accordance with paragraph (b)(1)(iii) of this section.

(B) The Administrator will adjust the identification of TR SO₂ Group 2 units in the each notice of data availability required in paragraph (b)(1)(iii) of this section to the extent necessary to ensure that it is in accordance with paragraph (b)(1)(iii) of this section and will calculate the TR SO₂ Group 2 allowance allocation to each TR SO₂ Group 2 unit in accordance with §97.712(a)(9), (10), and (12) and §§97.706(b)(2) and 97.730 through 97.735. By February 15 immediately after the promulgation of each notice of data availability required in paragraph (b)(1)(iii) of this section, the Administrator will promulgate a notice of data availability of any adjustments of the identification of TR SO₂ Group 2 units that the Administrator determines to be necessary, the reasons for accepting or rejecting any objections submitted in accordance with paragraph (b)(1)(iv)(A) of this section, and the results of such calculations.

(v) To the extent any TR SO₂ Group 2 allowances are added to the new unit set-aside after promulgation of each notice of data availability required in paragraph (b)(1)(iii) of this section, the Administrator will promulgate additional notices of data availability, as deemed appropriate, of the allocation of such TR SO₂ Group 2 allowances in accordance with §97.712(a)(10).

(2) Indian country new unit set-asides. (i) By June 1, 2012 and June 1 of each year thereafter, the Administrator will calculate the TR SO₂ Group 2 allowance allocation to each TR SO₂ Group 2 unit in Indian country within the borders of a State, in accordance with §97.712(b)(2) through (7) and (12), for the control period in the year of the applicable calculation deadline under this paragraph and will promulgate a notice of data availability of the results of the calculations.

(ii) For each notice of data availability required in paragraph (b)(2)(i) of this section, the Administrator will
provide an opportunity for submission of objections to the calculations referenced in such notice.

(A) Objections shall be submitted by the deadline specified in each notice of data availability required in paragraph (b)(2)(i) of this section and shall be limited to addressing whether the calculations (including the identification of the TR SO₂ Group 2 units) are in accordance with § 97.712(b)(2) through (7) and (12) and §§ 97.706(b)(2) and 97.730 through 97.735.

(B) The Administrator will adjust the calculations to the extent necessary to ensure that they are in accordance with the provisions referenced in paragraph (b)(2)(ii)(A) of this section. By August 1 immediately after the promulgation of each notice of data availability required in paragraph (b)(2)(i) of this section, the Administrator will promulgate a notice of data availability of any adjustments that the Administrator determines to be necessary with regard to allocations under § 97.712(b)(2) through (7) and (12) and the reasons for accepting or rejecting any objections submitted in accordance with paragraph (b)(2)(ii)(A) of this section.

(iii) If the Indian country new unit set-aside for such control period contains any TR SO₂ Group 2 allowances that have not been allocated in the applicable notice of data availability required in paragraph (b)(2)(ii)(A) of this section, the Administrator will promulgate, by December 15 immediately after such notice, a notice of data availability that identifies any TR SO₂ Group 2 units that commenced commercial operation during the period starting January 1 of the year before the year of such control period and ending November 30 of year of such control period.

(iv) For each notice of data availability required in paragraph (b)(2)(iii) of this section, the Administrator will provide an opportunity for submission of objections to the identification of TR SO₂ annual units in such notice is in accordance with paragraph (b)(2)(iii) of this section.

(B) The Administrator will adjust the identification of TR SO₂ Group 2 units in the each notice of data availability required in paragraph (b)(2)(iii) of this section to the extent necessary to ensure that it is in accordance with paragraph (b)(2)(iii) of this section and will calculate the TR SO₂ Group 2 allowance allocation to each TR SO₂ Group 2 unit in accordance with § 97.712(b)(9), (10), and (12) and §§ 97.706(b)(2) and 97.730 through 97.735. By February 15 immediately after the promulgation of each notice of data availability required in paragraph (b)(2)(iii) of this section, the Administrator will promulgate a notice of data availability of any adjustments of the identification of TR SO₂ Group 2 units that the Administrator determines to be necessary, the reasons for accepting or rejecting any objections submitted in accordance with paragraph (b)(2)(iv)(A) of this section, and the results of such calculations.

(v) To the extent any TR SO₂ Group 2 allowances are added to the Indian country new unit set-aside after promulgation of each notice of data availability required in paragraph (b)(2)(iv) of this section, the Administrator will promulgate additional notices of data availability, as deemed appropriate, of the allocation of such TR SO₂ Group 2 allowances in accordance with § 97.712(b)(10).

(c) Units incorrectly allocated TR SO₂ Group 2 allowances. (1) For each control period in 2012 and thereafter, if the Administrator determines that TR SO₂ Group 2 allowances were allocated under paragraph (a) of this section, or under a provision of a SIP revision approved § 52.39(g), (h), or (i) of this chapter, where such control period and the recipient are covered by the provisions of paragraphs (c)(1)(i) of this section or were allocated under § 97.712(a)(2) through (7), (9), and (12) or (b)(2) through (7), (9), and (12), or under a provision of a SIP revision approved § 52.39(h) or (i) of this chapter, where such control period and the recipient are covered by the provisions of paragraph (c)(1)(ii) of this section, then the Administrator will notify the designated representative of the recipient
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and will act in accordance with the procedures set forth in paragraphs (c)(2) through (5) of this section:

(i) (A) The recipient is not actually a TR SO2 Group 2 unit under §97.704 as of January 1, 2012 and is allocated TR SO2 Group 2 allowances for such control period or, in the case of an allocation under a provision of a SIP revision approved under §52.39(g), (h), or (i) of this chapter, the recipient is not actually a TR SO2 Group 2 unit as of January 1, 2012 and is allocated TR SO2 Group 2 allowances for such control period that the SIP revision provides should be allocated only to recipients that are TR SO2 Group 2 units as of January 1, 2012; or

(B) The recipient is not located as of January 1 of the control period in the State from whose SO2 Group 2 trading budget the TR SO2 Group 2 allowances allocated under paragraph (a) of this section, or under a provision of a SIP revision approved under §52.39(g), (h), or (i) of this chapter, were allocated for such control period.

(ii) The recipient is not actually a TR SO2 Group 2 unit under §97.704 as of January 1 of such control period and is allocated TR SO2 Group 2 allowances for such control period or, in the case of an allocation under a provision of a SIP revision approved under §52.39(g), (h), or (i) of this chapter, the recipient is not actually a TR SO2 Group 2 unit as of January 1 of such control period and is allocated TR SO2 Group 2 allowances for such control period that the SIP revision provides should be allocated only to recipients that are TR SO2 Group 2 units as of January 1 of such control period.

(2) Except as provided in paragraph (c)(3) or (4) of this section, the Administrator will not record such TR SO2 Group 2 allowances under §97.721.

(3) If the Administrator already recorded such TR SO2 Group 2 allowances under §97.721 and if the Administrator makes the determination under paragraph (c)(1) of this section after making deductions for the source that includes such recipient under §97.724(b) for such control period, then the Administrator will not make any deduction to take account of such already recorded TR SO2 Group 2 allowances.

(4) If the Administrator already recorded such TR SO2 Group 2 allowances under §97.721 and if the Administrator makes the determination under paragraph (c)(1) of this section after making deductions for the source that includes such recipient under §97.724(b) for such control period, then the Administrator will not make any deduction to take account of such already recorded TR SO2 Group 2 allowances.

(5)(i) With regard to the TR SO2 Group 2 allowances that are not recorded, or that are deducted as an incorrect allocation, in accordance with paragraphs (c)(2) and (3) of this section for a recipient under paragraph (c)(1)(i) of this section, the Administrator will:

(A) Transfer such TR SO2 Group 2 allowances to the new unit set-aside for such control period for the State from whose SO2 Group 2 trading budget the TR SO2 Group 2 allowances were allocated; or

(B) If the State has a SIP revision approved under §52.39(h) or (i) covering such control period, include such TR SO2 Group 2 allowances in the portion of the State SO2 Group 2 trading budget that may be allocated for such control period in accordance with such SIP revision.

(ii) With regard to the TR SO2 Group 2 allowances that were not allocated from the Indian country new unit set-aside for such control period and that are not recorded, or that are deducted as an incorrect allocation, in accordance with paragraphs (c)(2) and (3) of this section for a recipient under paragraph (c)(1)(ii) of this paragraph, the Administrator will:

(A) Transfer such TR SO2 Group 2 allowances to the new unit set-aside for such control period; or

(B) If the State has a SIP revision approved under §52.39(h) or (i) covering such control period, include such TR SO2 Group 2 allowances in the portion
of the State SO\textsubscript{2} Group 2 trading budget that may be allocated for such control period in accordance with such SIP revision.

(ii) With regard to the TR SO\textsubscript{2} Group 2 allowances that were allocated from the Indian country new unit set-aside for such control period and that are not recorded, or that are deducted as an incorrect allocation, in accordance with paragraphs (c)(2) and (3) of this section for a recipient under paragraph (c)(1)(ii) of this paragraph, the Administrator will transfer such TR SO\textsubscript{2} Group 2 allowances to the Indian country new unit set-aside for such control period.

§ 97.712 TR SO\textsubscript{2} Group 2 allowance allocations to new units.

(a) For each control period in 2012 and thereafter and for the TR SO\textsubscript{2} Group 2 units in each State, the Administrator will allocate TR SO\textsubscript{2} Group 2 allowances to the TR SO\textsubscript{2} Group 2 units as follows:

(1) The TR SO\textsubscript{2} Group 2 allowances will be allocated to the following TR SO\textsubscript{2} Group 2 units, except as provided in paragraph (a)(10) of this section:

(i) TR SO\textsubscript{2} Group 2 units that are not allocated an amount of TR SO\textsubscript{2} Group 2 allowances in the notice of data availability issued under §97.711(a)(1);

(ii) TR SO\textsubscript{2} Group 2 units whose allocation of an amount of TR SO\textsubscript{2} Group 2 allowances for such control period in the notice of data availability issued under §97.711(a)(1) is covered by §97.711(c)(2) or (3);

(iii) TR SO\textsubscript{2} Group 2 units that are allocated an amount of TR SO\textsubscript{2} Group 2 allowances for such control period in the notice of data availability issued under §97.711(a)(1), which allocation is terminated for such control period pursuant to §97.711(a)(2), and that operate during the control period immediately preceding such control period; or

(iv) For purposes of paragraph (a)(9) of this section, TR SO\textsubscript{2} Group 2 units under §97.711(c)(1)(ii) whose allocation of an amount of TR SO\textsubscript{2} Group 2 allowances for such control period in the notice of data availability issued under §97.711(b)(1)(ii)(B) is covered by §97.711(c)(2) or (3).

(2) The Administrator will establish a separate new unit set-aside for the State for each such control period. Each such new unit set-aside will be allocated TR SO\textsubscript{2} Group 2 allowances in an amount equal to the applicable amount of tons of SO\textsubscript{2} emissions as set forth in §97.710(a) and will be allocated additional TR SO\textsubscript{2} Group 2 allowances (if any) in accordance with §§97.711(a)(2) and (c)(5) and paragraph (b)(10) of this section.

(3) The Administrator will determine, for each TR SO\textsubscript{2} Group 2 unit described in paragraph (a)(1) of this section, an allocation of TR SO\textsubscript{2} Group 2 allowances for the later of the following control periods and for each subsequent control period:

(i) The control period in 2012;

(ii) The first control period after the control period in which the TR SO\textsubscript{2} Group 2 unit commences commercial operation;

(iii) For a unit described in paragraph (a)(1)(ii) of this section, the first control period in which the TR SO\textsubscript{2} Group 2 unit operates in the State after operating in another jurisdiction and for which the unit is not already allocated one or more TR SO\textsubscript{2} Group 2 allowances; and

(iv) For a unit described in paragraph (a)(1)(iii) of this section, the first control period after the control period in which the unit resumes operation.

(4)(i) The allocation to each TR SO\textsubscript{2} annual unit described in paragraph (a)(1)(i) through (iii) of this section, the first control period after the control period in which the unit resumes operation.

(ii) The Administrator will adjust the allocation amount in paragraph (a)(4)(i) in accordance with paragraphs (a)(5) through (7) and (12) of this section.

(5) The Administrator will calculate the sum of the TR SO\textsubscript{2} Group 2 allowances determined for all such TR SO\textsubscript{2} Group 2 units under paragraph (a)(4)(i) of this section in the State for such control period.

(6) If the amount of TR SO\textsubscript{2} Group 2 allowances in the new unit set-aside for the State for such control period is greater than or equal to the sum under paragraph (a)(5) of this section, then the Administrator will allocate the
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amount of TR SO\(_2\) Group 2 allowances determined for each such TR SO\(_2\) Group 2 unit under paragraph (a)(4)(i) of this section.

(7) If the amount of TR SO\(_2\) Group 2 allowances in the new unit set-aside for the State for such control period is less than the sum under paragraph (a)(5) of this section, then the Administrator will allocate to each such TR SO\(_2\) Group 2 unit the amount of the TR SO\(_2\) Group 2 allowances determined under paragraph (a)(4)(i) of this section for the unit, multiplied by the amount of TR SO\(_2\) Group 2 allowances in the new unit set-aside for such control period, divided by the sum under paragraph (a)(5) of this section, and rounded to the nearest allowance.

(8) The Administrator will notify the public, through the promulgation of the notices of data availability described in §97.711(b)(1)(i) and (ii), of the amount of TR SO\(_2\) Group 2 allowances allocated under paragraphs (a)(2) through (7) and (12) of this section for such control period to each TR SO\(_2\) Group 2 unit eligible for such allocation.

(9) If, after completion of the procedures under paragraphs (a)(5) through (8) of this section for such control period, any unallocated TR SO\(_2\) Group 2 allowances remain in the new unit set-aside for the State for such control period, the Administrator will allocate such TR SO\(_2\) Group 2 allowances as follows—

(i) The Administrator will determine, for each unit described in paragraph (a)(1) of this section that commenced commercial operation during the period starting January 1 of the year before the year of such control period and ending November 30 of year of such control period, the positive difference (if any) between the unit’s emissions during such control period and the amount of TR SO\(_2\) Group 2 allowances referenced in the notice of data availability required under §97.711(b)(1)(i) for the unit for such control period;

(ii) The Administrator will determine the sum of the positive differences determined under paragraph (a)(9)(i) of this section;

(iii) If the amount of unallocated TR SO\(_2\) Group 2 allowances remaining in the new unit set-aside for the State for such control period is greater than or equal to the sum determined under paragraph (a)(9)(ii) of this section, then the Administrator will allocate the amount of TR SO\(_2\) Group 2 allowances determined for each such TR SO\(_2\) Group 2 unit under paragraph (a)(9)(i) of this section; and

(iv) If the amount of unallocated TR SO\(_2\) Group 2 allowances remaining in the new unit set-aside for the State for such control period is less than the sum under paragraph (a)(9)(ii) of this section, then the Administrator will allocate to each such TR SO\(_2\) Group 2 unit the amount of the TR SO\(_2\) Group 2 allowances determined under paragraph (a)(9)(i) of this section for the unit, multiplied by the amount of unallocated TR SO\(_2\) Group 2 allowances remaining in the new unit set-aside for such control period, divided by the sum under paragraph (a)(5) of this section, and rounded to the nearest allowance.

(10) If, after completion of the procedures under paragraphs (a)(9) and (12) of this section for such control period, any unallocated TR SO\(_2\) Group 2 allowances remain in the new unit set-aside for the State for such control period, the Administrator will allocate such TR SO\(_2\) Group 2 allowances as follows:

(i) The Administrator will determine, for each unit described in paragraph (a)(1) of this section that commenced commercial operation during the period starting January 1 of the year before the year of such control period and ending November 30 of year of such control period, the positive difference (if any) between the unit’s emissions during such control period and the amount of TR SO\(_2\) Group 2 allowances referenced in the notice of data availability required under §97.711(b)(1)(i) for the unit for such control period;

(ii) The Administrator will determine the sum of the positive differences determined under paragraph (a)(9)(i) of this section;

(iii) If the amount of unallocated TR SO\(_2\) Group 2 allowances remaining in the new unit set-aside for the State for such control period is greater than or equal to the sum determined under paragraph (a)(9)(ii) of this section, then the Administrator will allocate the amount of TR SO\(_2\) Group 2 allowances determined for each such TR SO\(_2\) Group 2 unit under paragraph (a)(9)(i) of this section; and

(iv) If the amount of unallocated TR SO\(_2\) Group 2 allowances remaining in the new unit set-aside for the State for such control period is less than the sum under paragraph (a)(9)(ii) of this section, then the Administrator will allocate to each such TR SO\(_2\) Group 2 unit the amount of the TR SO\(_2\) Group 2 allowances determined under paragraph (a)(9)(i) of this section for the unit, multiplied by the amount of unallocated TR SO\(_2\) Group 2 allowances remaining in the new unit set-aside for such control period, divided by the sum under paragraph (a)(5) of this section, and rounded to the nearest allowance.

(11) The Administrator will notify the public, through the promulgation of the notices of data availability described in §97.711(b)(1)(iii), (iv), and (v),
of the amount of TR SO₂ Group 2 allowances allocated under paragraphs (a)(9), (10), and (12) of this section for such control period to each TR SO₂ Group 2 unit eligible for such allocation.

(12)(i) Notwithstanding the requirements of paragraphs (a)(2) through (11) of this section, if the calculations of allocations of a new unit set-aside for a control period in a given year under paragraph (a)(7) of this section, paragraphs (a)(6) and (9)(iv) of this section, or paragraphs (a)(6), (9)(iii), and (10) of this section would otherwise result in total allocations of such new unit set-aside exceeding the total amount of such new unit set-aside, then the Administrator will adjust the results of the calculations under paragraph (a)(7), (9)(iv), or (10) of this section, as applicable, and, in cases of equal allocation amounts, in alphabetical order of the relevant source’s name and numerical order of the relevant unit’s identification number, and will increase each unit’s allocation under paragraph (a)(10) of this section by one TR SO₂ Group 2 allowance in the order in which the units are listed and will repeat this increase process as necessary, until the total allocations of such new unit set-aside equal the total amount of such new unit set-aside.

(b) For each control period in 2012 and thereafter and for the TR SO₂ Group 2 units located in Indian country within the borders of each State, the Administrator will allocate TR SO₂ Group 2 allowances to the TR SO₂ Group 2 units as follows:

(1) The TR SO₂ Group 2 allowances will be allocated to the following TR SO₂ Group 2 units, except as provided in paragraph (b)(10) of this section:

(i) TR SO₂ Group 2 units that are not allocated an amount of TR SO₂ Group 2 allowances in the notice of data availability issued under §97.711(a)(1); or

(ii) For purposes of paragraph (b)(9) of this section, TR SO₂ Group 2 units under §97.711(c)(1)(ii) whose allocation of an amount of TR SO₂ Group 2 allowances for such control period in the notice of data availability issued under §97.711(b)(2)(ii)(B) is covered by §97.711(c)(2) or (3).

(2) The Administrator will establish a separate Indian country new unit set-aside for the State for each such control period. Each such Indian country new unit set-aside will be allocated TR SO₂ Group 2 allowances in an amount equal to the applicable amount of tons of SO₂ emissions as set forth in §97.710(a) and will be allocated additional TR SO₂ Group 2 allowances (if any) in accordance with §97.711(c)(6). (4)(3)

(3) The Administrator will determine, for each TR SO₂ Group 2 unit described in paragraph (b)(1) of this section, an allocation of TR SO₂ Group 2 allowances for the later of the following control periods and for each subsequent control period:

(i) The control period in 2012; and

(ii) The first control period after the control period in which the TR SO₂ Group 2 unit commences commercial operation.

(iii) The allocation to each TR SO₂ annual unit described in paragraph
(b)(1)(i) of this section and for each control period described in paragraph (b)(3) of this section will be an amount equal to the unit's total tons of SO\(_2\) emissions during the immediately preceding control period.

(ii) The Administrator will adjust the allocation amount in paragraph (b)(4)(i) in accordance with paragraphs (b)(5) through (7) and (12) of this section.

(5) The Administrator will calculate the sum of the TR SO\(_2\) Group 2 allowances determined for all such TR SO\(_2\) Group 2 units under paragraph (b)(4)(i) of this section in Indian country within the borders of the State for such control period.

(6) If the amount of TR SO\(_2\) Group 2 allowances in the Indian country new unit set-aside for the State for such control period is greater than or equal to the sum under paragraph (b)(5) of this section, then the Administrator will allocate the amount of TR SO\(_2\) Group 2 allowances determined for each such TR SO\(_2\) Group 2 unit under paragraph (b)(4)(i) of this section.

(7) If the amount of TR SO\(_2\) Group 2 allowances in the Indian country new unit set-aside for the State for such control period is less than the sum under paragraph (b)(5) of this section, then the Administrator will allocate to each such TR SO\(_2\) Group 2 unit the amount of the TR SO\(_2\) Group 2 allowances determined under paragraph (b)(4)(i) of this section for the unit, multiplied by the amount of TR SO\(_2\) Group 2 allowances in the Indian country new unit set-aside for such control period, divided by the sum under paragraph (b)(5) of this section, and rounded to the nearest allowance.

(8) The Administrator will notify the public, through the promulgation of the notices of data availability described in §97.711(b)(2)(i) and (ii), of the amount of TR SO\(_2\) Group 2 allowances allocated under paragraphs (b)(2) through (7) and (12) of this section for such control period to each TR SO\(_2\) Group 2 unit eligible for such allocation.

(9) If, after completion of the procedures under paragraphs (b)(5) through (8) of this section for such control period, any unallocated TR SO\(_2\) Group 2 allowances remain in the Indian country new unit set-aside for the State for such control period, the Administrator will allocate such TR SO\(_2\) Group 2 allowances as follows—

(i) The Administrator will determine, for each unit described in paragraph (b)(1) of this section that commenced commercial operation during the period starting January 1 of the year before the year of such control period and ending November 30 of year of such control period, the positive difference (if any) between the unit’s emissions during such control period and the amount of TR SO\(_2\) Group 2 allowances referenced in the notice of data availability required under §97.711(b)(2)(ii) for the unit for such control period;

(ii) The Administrator will determine the sum of the positive differences determined under paragraph (b)(9)(i) of this section;

(iii) If the amount of unallocated TR SO\(_2\) Group 2 allowances remaining in the Indian country new unit set-aside for the State for such control period is greater than or equal to the sum determined under paragraph (b)(9)(ii) of this section, then the Administrator will allocate the amount of TR SO\(_2\) Group 2 allowances determined for each such TR SO\(_2\) Group 2 unit under paragraph (b)(9)(i) of this section; and

(iv) If the amount of unallocated TR SO\(_2\) Group 2 allowances remaining in the Indian country new unit set-aside for the State for such control period is less than the sum under paragraph (b)(9)(ii) of this section, then the Administrator will allocate to each such TR SO\(_2\) Group 2 unit the amount of the TR SO\(_2\) Group 2 allowances determined under paragraph (b)(9)(i) of this section for the unit, multiplied by the amount of unallocated TR SO\(_2\) Group 2 allowances remaining in the Indian country new unit set-aside for such control period, divided by the sum under paragraph (b)(9)(ii) of this section, and rounded to the nearest allowance.

(10) If, after completion of the procedures under paragraphs (b)(9) and (12) of this section for such control period, any unallocated TR SO\(_2\) Group 2 allowances remain in the Indian country new unit set-aside for the State for such control period, the Administrator will:
(i) Transfer such unallocated TR SO\textsubscript{2} Group 2 allowances to the new unit set-aside for the State for such control period; or

(ii) If the State has a SIP revision approved under §52.39(g), (h), or (i) of this chapter covering such control period, include such unallocated TR SO\textsubscript{2} Group 2 allowances in the portion of the State SO\textsubscript{2} Group 2 trading budget that may be allocated for such control period in accordance with such SIP revision.

(11) The Administrator will notify the public, through the promulgation of the notices of data availability described in §97.711(b)(2)(iii), (iv), and (v), of the amount of TR SO\textsubscript{2} Group 2 allowances allocated under paragraphs (b)(9), (10), and (12) of this section for each TR SO\textsubscript{2} Group 2 unit eligible for such allocation.

(12)(i) Notwithstanding the requirements of paragraphs (b)(2) through (11) of this section, if the calculations of allocations of an Indian country new unit set-aside for a control period in a given year under paragraphs (b)(6), (9)(iv), or (10) of this section would otherwise result in total allocations of such Indian country new unit set-aside less than the total amount of such Indian country new unit set-aside, the Administrator will adjust the results of the calculations under paragraph (b)(10) of this section, as follows. The Administrator will list the TR SO\textsubscript{2} Group 2 units in descending order based on the amount of such units' allocations under paragraph (b)(10) of this section and, in cases of equal allocation amounts, in alphabetical order of the relevant source's name and numerical order of the relevant unit's identification number, and will increase each unit's allocation under paragraph (b)(10) of this section by one TR SO\textsubscript{2} Group 2 allowance in the order in which the units are listed and will repeat this increase process as necessary, until the total allocations of such Indian country new unit set-aside equal the total amount of such Indian country new unit set-aside.

§97.713 Authorization of designated representative and alternate designated representative.

(a) Except as provided under §97.715, each TR SO\textsubscript{2} Group 2 source, including all TR SO\textsubscript{2} Group 2 units at the source, shall have one and only one designated representative, with regard to all matters under the TR SO\textsubscript{2} Group 2 Trading Program.

(1) The designated representative shall be selected by an agreement binding on the owners and operators of the source and all TR SO\textsubscript{2} Group 2 units at the source, shall have one and only one designated representative, with regard to all matters under the TR SO\textsubscript{2} Group 2 Trading Program.

(2) Upon and after receipt by the Administrator of a complete certificate of representation under §97.716:

(i) The designated representative shall be authorized and shall represent and, by his or her representations, actions, inactions, or submissions, legally bind each owner and operator of the source and each TR SO\textsubscript{2} Group 2
§ 97.714 Responsibilities of designated representative and alternate designated representative.

(a) Except as provided under § 97.718 concerning delegation of authority to make submissions, each submission under the TR SO\textsubscript{2} Group 2 Trading Program shall be made, signed, and certified by the designated representative or alternate designated representative for each TR SO\textsubscript{2} Group 2 source and TR SO\textsubscript{2} Group 2 unit for which the submission is made. Each such submission shall include the following certification statement by the designated representative or alternate designated representative: "I am authorized to make this submission on behalf of the owners and operators of the source or units for which the submission is made. I certify under penalty of law that I have personally examined, and am familiar with, the statements and information submitted in this document and all its attachments. Based on my inquiry of those individuals with primary responsibility for obtaining the information, I certify that the statements and information are to the best of my knowledge and belief true, accurate, and complete. I am aware that there are significant penalties for submitting false statements and information or omitting required statements and information, including the possibility of fine or imprisonment."

(b) The Administrator will accept or act on a submission made for a TR SO\textsubscript{2} Group 2 source or a TR SO\textsubscript{2} Group 2 unit only if the submission has been made, signed, and certified in accordance with paragraph (a) of this section and § 97.718.

§ 97.715 Changing designated representative and alternate designated representative; changes in owners and operators; changes in units at the source.

(a) Changing designated representative. The designated representative may be changed at any time upon receipt by the Administrator of a superseding complete certificate of representation under § 97.716. Notwithstanding any such change, all representations, actions, inactions, and submissions by the previous designated representative...
before the time and date when the Administrator receives the superseding certificate of representation shall be binding on the new designated representative and the owners and operators of the TR SO\textsubscript{2} Group 2 source and the TR SO\textsubscript{2} Group 2 units at the source.

(b) Changing alternate designated representative. The alternate designated representative may be changed at any time upon receipt by the Administrator of a superseding complete certificate of representation under §97.716. Notwithstanding any such change, all representations, actions, inactions, and submissions by the previous alternate designated representative before the time and date when the Administrator receives the superseding certificate of representation shall be binding on the new alternate designated representative, the designated representative, and the owners and operators of the TR SO\textsubscript{2} Group 2 source and the TR SO\textsubscript{2} Group 2 units at the source.

(c) Changes in owners and operators.

(1) In the event an owner or operator of a TR SO\textsubscript{2} Group 2 source or a TR SO\textsubscript{2} Group 2 unit at the source is not included in the list of owners and operators in the certificate of representation under §97.716, such owner or operator shall be deemed to be subject to and bound by the certificate of representation, the designated representative, and the owners and operators of the TR SO\textsubscript{2} Group 2 source and the TR SO\textsubscript{2} Group 2 units at the source.

(2) Within 30 days after any change in the owners and operators of a TR SO\textsubscript{2} Group 2 source or a TR SO\textsubscript{2} Group 2 unit at the source, including the addition or removal of an owner or operator, the designated representative or any alternate designated representative shall submit a revision to the certificate of representation under §97.716 amending the list of owners and operators to reflect the change.

(d) Changes in units at the source. Within 30 days of any change in which units are located at a TR SO\textsubscript{2} Group 2 source (including the addition or removal of a unit), the designated representative or any alternate designated representative shall submit a certificate of representation under §97.716 amending the list of units to reflect the change.

(1) If the change is the addition of a unit that operated (other than for purposes of testing by the manufacturer before initial installation) before being located at the source, then the certificate of representation shall identify, in a format prescribed by the Administrator, the entity from whom the unit was purchased or otherwise obtained (including name, address, telephone number, and facsimile number (if any)), the date on which the unit was purchased or otherwise obtained, and the date on which the unit became located at the source.

(2) If the change is the removal of a unit, then the certificate of representation shall identify, in a format prescribed by the Administrator, the entity to which the unit was sold or that otherwise obtained the unit (including name, address, telephone number, and facsimile number (if any)), the date on which the unit was sold or otherwise obtained, and the date on which the unit became no longer located at the source.

§97.716 Certificate of representation.

(a) A complete certificate of representation for a designated representative or an alternate designated representative shall include the following elements in a format prescribed by the Administrator:

(1) Identification of the TR SO\textsubscript{2} Group 2 source, and each TR SO\textsubscript{2} Group 2 unit at the source, including source name, source category and NAICS code (or, in the absence of a NAICS code, an equivalent code), State, plant code, county, latitude and longitude, unit identification number and type, identification number and nameplate capacity (in MWe, rounded to the nearest tenth) of each generator served by each such unit, actual or projected date of commencement of commercial operation, and a statement of whether such source is located in Indian Country. If a projected date of commencement of commercial operation is provided, the actual date of

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commencement of commercial operation shall be provided when such information becomes available.

(2) The name, address, e-mail address (if any), telephone number, and facsimile transmission number (if any) of the designated representative and any alternate designated representative.

(3) A list of the owners and operators of the TR SO\textsubscript{2} Group 2 source and of each TR SO\textsubscript{2} Group 2 unit at the source.

(4) The following certification statements by the designated representative and any alternate designated representative—

(i) "I certify that I was selected as the designated representative or alternate designated representative, as applicable, by an agreement binding on the owners and operators of the source and each TR SO\textsubscript{2} Group 2 unit at the source."

(ii) "I certify that I have all the necessary authority to carry out my duties and responsibilities under the TR SO\textsubscript{2} Group 2 Trading Program on behalf of the owners and operators of the source and of each TR SO\textsubscript{2} Group 2 unit at the source and that each such owner and operator shall be fully bound by my representations, actions, inactions, or submissions and by any decision or order issued to me by the Administrator regarding the source or unit."

(iii) "Where there are multiple holders of a legal or equitable title to, or a leasehold interest in, a TR SO\textsubscript{2} Group 2 unit, or where a utility or industrial customer purchases power from a TR SO\textsubscript{2} Group 2 unit under a life-of-the-unit, firm power contractual arrangement, I certify that: I have given a written notice of my selection as the 'designated representative' or 'alternate designated representative', as applicable, and of the agreement by which I was selected to each owner and operator of the source and of each TR SO\textsubscript{2} Group 2 unit at the source; and TR SO\textsubscript{2} Group 2 allowances and proceeds of transactions involving TR SO\textsubscript{2} Group 2 allowances will be deemed to be held or distributed in accordance with the contract."

(5) The signature of the designated representative and any alternate designated representative and the dates signed.

§97.717 Objections concerning designated representative and alternate designated representative.

(a) Once a complete certificate of representation under §97.716 has been submitted and received, the Administrator will rely on the certificate of representation unless and until a superseding complete certificate of representation under §97.716 is received by the Administrator.

(b) Except as provided in paragraph (a) of this section, no objection or other communication submitted to the Administrator concerning the authorization, or any representation, action, inaction, or submission, of a designated representative or alternate designated representative shall affect any representation, action, inaction, or submission of the designated representative or alternate designated representative or the finality of any decision or order by the Administrator under the TR SO\textsubscript{2} Group 2 Trading Program.

(c) The Administrator will not adjudicate any private legal dispute concerning the authorization or any representation, action, inaction, or submission of any designated representative or alternate designated representative, including private legal disputes concerning the proceeds of TR SO\textsubscript{2} Group 2 allowance transfers.

§97.718 Delegation by designated representative and alternate designated representative.

(a) A designated representative may delegate, to one or more natural persons, his or her authority to make an
§ 97.720 Establishment of compliance accounts, assurance accounts, and general accounts.

(a) Compliance accounts. Upon receipt of a complete certificate of representation under § 97.716, the Administrator will establish a compliance account for the TR SO$_2$ Group 2 source for which the certificate of representation was submitted, unless the source already has a compliance account. The designated representative and any alternate designated representative of the source shall be the authorized account representative and the alternate authorized account representative respectively of the compliance account.

(b) Assurance accounts. The Administrator will establish assurance accounts for certain owners and operators and States in accordance with § 97.725(b)(3).

(c) General accounts. (1) Application for general account. (i) Any person may apply to open a general account, for the purpose of holding and transferring TR SO$_2$ Group 2 allowances, by submitting to the Administrator a
complete application for a general account. Such application shall designate one and only one authorized account representative and may designate one and only one alternate authorized account representative who may act on behalf of the authorized account representative.

(A) The authorized account representative and alternate authorized account representative shall be selected by an agreement binding on the persons who have an ownership interest with respect to TR SO\textsubscript{2} Group 2 allowances held in the general account.

(B) The agreement by which the alternate authorized account representative is selected shall include a procedure for authorizing the alternate authorized account representative to act in lieu of the authorized account representative.

(ii) A complete application for a general account shall include the following elements in a format prescribed by the Administrator:

(A) Name, mailing address, e-mail address (if any), telephone number, and facsimile transmission number (if any) of the authorized account representative and any alternate authorized account representative;

(B) An identifying name for the general account;

(C) A list of all persons subject to a binding agreement for the authorized account representative and any alternate authorized account representative to represent their ownership interest with respect to the TR SO\textsubscript{2} Group 2 allowances held in the general account;

(D) The following certification statement by the authorized account representative and any alternate authorized account representative: “I certify that I was selected as the authorized account representative or the alternate authorized account representative, as applicable, by an agreement that is binding on all persons who have an ownership interest with respect to TR SO\textsubscript{2} Group 2 allowances held in the general account. I certify that I have all the necessary authority to carry out my duties and responsibilities under the TR SO\textsubscript{2} Group 2 Trading Program on behalf of such persons and that each such person shall be fully bound by my representations, actions, inactions, or submissions and by any decision or order issued to me by the Administrator regarding the general account.”

(E) The signature of the authorized account representative and any alternate authorized account representative and the dates signed.

(iii) Unless otherwise required by the Administrator, documents of agreement referred to in the application for a general account shall not be submitted to the Administrator. The Administrator shall not be under any obligation to review or evaluate the sufficiency of such documents, if submitted.

(2) Authorization of authorized account representative and alternate authorized account representative. (i) Upon receipt by the Administrator of a complete application for a general account under paragraph (b)(1) of this section, the Administrator will establish a general account for the person or persons for whom the application is submitted, and upon and after such receipt by the Administrator:

(A) The authorized account representative of the general account shall be authorized and shall represent and, by his or her representations, actions, inactions, or submissions, legally bind each person who has an ownership interest with respect to TR SO\textsubscript{2} Group 2 allowances held in the general account in all matters pertaining to the TR SO\textsubscript{2} Group 2 Trading Program, notwithstanding any agreement between the authorized account representative and such person.

(B) Any alternate authorized account representative shall be authorized, and any representation, action, inaction, or submission by any alternate authorized account representative shall be deemed to be a representation, action, inaction, or submission by the authorized account representative.

(C) Each person who has an ownership interest with respect to TR SO\textsubscript{2} Group 2 allowances held in the general account shall be bound by any decision or order issued to the authorized account representative or alternate authorized account representative by the Administrator regarding the general account.

(ii) Except as provided in paragraph (c)(5) of this section concerning delegation of authority to make submissions,
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each submission concerning the general account shall be made, signed, and certified by the authorized account representative or any alternate authorized account representative for the persons having an ownership interest with respect to the TR SO$_2$ Group 2 allowances held in the general account. Each such submission shall include the following certification statement by the authorized account representative or any alternate authorized account representative: ‘‘I am authorized to make this submission on behalf of the persons having an ownership interest with respect to the TR SO$_2$ Group 2 allowances held in the general account. I certify under penalty of law that I have personally examined, and am familiar with, the statements and information submitted in this document and all its attachments. Based on my inquiry of those individuals with primary responsibility for obtaining the information, I certify that the statements and information are to the best of my knowledge and belief true, accurate, and complete. I am aware that there are significant penalties for submitting false statements and information or omitting required statements and information, including the possibility of fine or imprisonment.’’

(iii) Except in this section, whenever the term ‘‘authorized account representative’’ is used in this subpart, the term shall be construed to include the authorized account representative or any alternate authorized account representative.

(3) Changing authorized account representative and alternate authorized account representative; changes in persons with ownership interest. (i) The authorized account representative of a general account may be changed at any time upon receipt by the Administrator of a superseding complete application for a general account under paragraph (c)(1) of this section. Notwithstanding any such change, all representations, actions, inactions, and submissions by the previous authorized account representative shall be binding on the new alternate authorized account representative, the authorized account representative, and the persons with an ownership interest with respect to the TR SO$_2$ Group 2 allowances in the general account.

(ii) The alternate authorized account representative of a general account may be changed at any time upon receipt by the Administrator of a superseding complete application for a general account under paragraph (c)(1) of this section. Notwithstanding any such change, all representations, actions, inactions, and submissions by the previous alternate authorized account representative before the time and date when the Administrator receives the superseding application for a general account shall be binding on the new alternate authorized account representative.

(iii)(A) In the event a person having an ownership interest with respect to the TR SO$_2$ Group 2 allowances in the general account is not included in the list of such persons in the application for a general account, such person shall be deemed to be subject to and bound by the application for a general account, the representation, actions, inactions, and submissions of the authorized account representative and any alternate authorized account representative of the account, and the decisions and orders of the Administrator, as if the person were included in such list.

(B) Within 30 days after any change in the persons having an ownership interest with respect to the TR SO$_2$ Group 2 allowances in the general account, including the addition or removal of a person, the authorized account representative or any alternate authorized account representative shall submit a revision to the application for a general account amending the list of persons having an ownership interest with respect to the TR SO$_2$ Group 2 allowances in the general account to include the change.

(4) Objections concerning authorized account representative and alternate authorized account representative. (i) Once a complete application for a general account under paragraph (c)(1) of this section has been submitted and received, the Administrator will rely on
the application unless and until a superseding complete application for a general account under paragraph (b)(1) of this section is received by the Administrator.

(ii) Except as provided in paragraph (c)(4)(i) of this section, no objection or other communication submitted to the Administrator concerning the authorization, or any representation, action, inaction, or submission of the authorized account representative or any alternate authorized account representative of a general account shall affect any representation, action, inaction, or submission of the authorized account representative or any alternate authorized account representative or the finality of any decision or order by the Administrator under the TR SO\textsubscript{2} Group 2 Trading Program.

(iii) The Administrator will not adjudicate any private legal dispute concerning the authorization or any representation, action, inaction, or submission of the authorized account representative or any alternate authorized account representative of a general account, including private legal disputes concerning the proceeds of TR SO\textsubscript{2} Group 2 allowance transfers.

(5) Delegation by authorized account representative and alternate authorized account representative. (i) An authorized account representative of a general account may delegate, to one or more natural persons, his or her authority to make an electronic submission to the Administrator provided for or required under this subpart.

(ii) An alternate authorized account representative of a general account may delegate, to one or more natural persons, his or her authority to make an electronic submission to the Administrator provided for or required under this subpart.

(iii) In order to delegate authority to a natural person to make an electronic submission to the Administrator in accordance with paragraph (c)(5)(i) or (ii) of this section, the authorized account representative or alternate authorized account representative, as appropriate, must submit to the Administrator a notice of delegation, in a format prescribed by the Administrator, that includes the following elements:

(A) The name, address, e-mail address, telephone number, and facsimile transmission number (if any) of such authorized account representative or alternate authorized account representative;

(B) The name, address, e-mail address, telephone number, and facsimile transmission number (if any) of each such natural person (referred to in this section as an “agent”);

(C) For each such natural person, a list of the type or types of electronic submissions under paragraph (c)(5)(i) or (ii) of this section for which authority is delegated to him or her;

(D) The following certification statement by such authorized account representative or alternate authorized account representative: “I agree that any electronic submission to the Administrator that is made by an agent identified in this notice of delegation and of a type listed for such agent in this notice of delegation and that is made when I am an authorized account representative or alternate authorized representative, as appropriate, and before this notice of delegation is superseded by another notice of delegation under 40 CFR 97.720(c)(5)(iv) shall be deemed to be an electronic submission by me.”; and

(E) The following certification statement by such authorized account representative or alternate authorized account representative: “Until this notice of delegation is superseded by another notice of delegation under 40 CFR 97.720(c)(5)(iv), I agree to maintain an e-mail account and to notify the Administrator immediately of any change in my e-mail address unless all delegation of authority by me under 40 CFR 97.720(c)(5) is terminated.”;

(iv) A notice of delegation submitted under paragraph (c)(5)(iii) of this section shall be effective, with regard to the authorized account representative or alternate authorized account representative identified in such notice, upon receipt of such notice by the Administrator and until receipt by the Administrator of a superseding notice of delegation submitted by such authorized account representative or alternate authorized account representative, as appropriate. The superseding notice of delegation may replace any
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previously identified agent, add a new agent, or eliminate entirely any delegation of authority.

(v) Any electronic submission covered by the certification in paragraph (c)(5)(iii)(D) of this section and made in accordance with a notice of delegation effective under paragraph (c)(5)(iv) of this section shall be deemed to be an electronic submission by the designated representative or alternate designated representative submitting such notice of delegation.

(b) Closing a general account. (i) The authorized account representative or alternate authorized account representative of a general account may submit to the Administrator a request to close the account. Such request shall include a correctly submitted TR SO\textsubscript{2} Group 2 allowance transfer under §97.722 for any TR SO\textsubscript{2} Group 2 allowances in the account to one or more other Allowance Management System accounts.

(ii) If a general account has no TR SO\textsubscript{2} Group 2 allowance transfers to or from the account for a 12-month period or longer and does not contain any TR SO\textsubscript{2} Group 2 allowances, the Administrator may notify the authorized account representative for the account that the account will be closed after 30 days after the notice is sent. The account will be closed after the 30-day period unless, before the end of the 30-day period, the Administrator receives a statement submitted by the authorized account representative or alternate authorized account representative demonstrating to the satisfaction of the Administrator good cause as to why the account should not be closed.

(d) Account identification. The Administrator will assign a unique identifying number to each account established under paragraph (a), (b), or (c) of this section.

(e) Responsibilities of authorized account representative and alternate authorized account representative. After the establishment of a compliance account or general account, the Administrator will accept or act on a submission pertaining to the account, including, but not limited to, submissions concerning the deduction or transfer of TR SO\textsubscript{2} Group 2 allowances in the account, only if the submission has been made, signed, and certified in accordance with §§97.714(a) and 97.718 or paragraphs (c)(2)(i) and (c)(5) of this section.

§97.721 Recordation of TR SO\textsubscript{2} Group 2 allowance allocations and auction results.

(a) By November 7, 2011, the Administrator will record in each TR SO\textsubscript{2} Group 2 source’s compliance account the TR SO\textsubscript{2} Group 2 allowances allocated to the TR SO\textsubscript{2} Group 2 units at the source in accordance with §97.711(a) for the control period in 2012.

(b) By November 7, 2011, the Administrator will record in each TR SO\textsubscript{2} Group 2 source’s compliance account the TR SO\textsubscript{2} Group 2 allowances allocated to the TR SO\textsubscript{2} Group 2 units at the source in accordance with §97.711(a) for the control period in 2013, unless the State in which the source is located notifies the Administrator in writing by October 17, 2011 of the State’s intent to submit to the Administrator a complete SIP revision by April 1, 2012 meeting the requirements of §52.39(g)(1) through (4) of this chapter.

(1) If, by April 1, 2012, the State does not submit to the Administrator such complete SIP revision, the Administrator will record by April 15, 2012 in each TR SO\textsubscript{2} Group 2 source’s compliance account the TR SO\textsubscript{2} Group 2 allowances allocated to the TR SO\textsubscript{2} Group 2 units at the source in accordance with §97.711(a) for the control period in 2013.

(2) If the State submits to the Administrator by April 1, 2012, and the Administrator approves by October 1, 2012, such complete SIP revision, the Administrator will record by October 1, 2012 in each TR SO\textsubscript{2} Group 2 source’s compliance account the TR SO\textsubscript{2} Group 2 allowances allocated to the TR SO\textsubscript{2} Group 2 units at the source as provided in such approved, complete SIP revision for the control period in 2013.

(3) If the State submits to the Administrator by April 1, 2012, and the Administrator does not approve by October 1, 2012, such complete SIP revision, the Administrator will record by
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October 1, 2012 in each TR SO₂ Group 2 source’s compliance account the TR SO₂ Group 2 allowances allocated to the TR SO₂ Group 2 units at the source in accordance with §97.711(a) for the control period in 2013.

(c) By July 1, 2013, the Administrator will record in each TR SO₂ Group 2 source’s compliance account the TR SO₂ Group 2 allowances allocated to the TR SO₂ Group 2 units at the source, or in each appropriate Allowance Management System account the TR SO₂ Group 2 allowances auctioned to TR SO₂ Group 2 units, in accordance with §97.711(a), or with a SIP revision approved under §52.39(h) or (i) of this chapter, for the control period in 2014 and 2015.

(d) By July 1, 2014, the Administrator will record in each TR SO₂ Group 2 source’s compliance account the TR SO₂ Group 2 allowances allocated to the TR SO₂ Group 2 units at the source, or in each appropriate Allowance Management System account the TR SO₂ Group 2 allowances auctioned to TR SO₂ Group 2 units, in accordance with §97.711(a), or with a SIP revision approved under §52.39(h) or (i) of this chapter, for the control period in 2016 and 2017.

(e) By July 1, 2015, the Administrator will record in each TR SO₂ Group 2 source’s compliance account the TR SO₂ Group 2 allowances allocated to the TR SO₂ Group 2 units at the source, or in each appropriate Allowance Management System account the TR SO₂ Group 2 allowances auctioned to TR SO₂ Group 2 units, in accordance with §97.711(a), or with a SIP revision approved under §52.39(h) or (i) of this chapter, for the control period in 2018 and 2019.

(f) By July 1, 2016 and July 1 of each year thereafter, the Administrator will record in each TR SO₂ Group 2 source’s compliance account the TR SO₂ Group 2 allowances allocated to the TR SO₂ Group 2 units at the source, or in each appropriate Allowance Management System account the TR SO₂ Group 2 allowances auctioned to TR SO₂ Group 2 units, in accordance with §97.711(a), or with a SIP revision approved under §52.39(h) and (i) of this chapter, for the control period in the fourth year after the year of the applicable recordation deadline under this paragraph.

(g) By August 1, 2012 and August 1 of each year thereafter, the Administrator will record in each TR SO₂ Group 2 source’s compliance account the TR SO₂ Group 2 allowances allocated to the TR SO₂ Group 2 units at the source, or in each appropriate Allowance Management System account the TR SO₂ Group 2 allowances auctioned to TR SO₂ Group 2 units, in accordance with §97.712(a)(2) through (8) and (12), or with a SIP revision approved under §52.39(h) and (i) of this chapter, for the control period in the year of the applicable recordation deadline under this paragraph.

(h) By August 1, 2012 and August 1 of each year thereafter, the Administrator will record in each TR SO₂ Group 2 source’s compliance account the TR SO₂ Group 2 allowances allocated to the TR SO₂ Group 2 units at the source in accordance with §97.712(b)(2) through (8) and (12) for the control period in the year of the applicable recordation deadline under this paragraph.

(i) By February 15, 2013 and February 15 of each year thereafter, the Administrator will record in each TR SO₂ Group 2 source’s compliance account the TR SO₂ Group 2 allowances allocated to the TR SO₂ Group 2 units at the source in accordance with §97.712(a)(9) through (12), or with a SIP revision approved under §52.39(h) and (i) of this chapter, for the control period in the year before the year of the applicable recordation deadline under this paragraph.

(j) By the date on which any allocation or auction results, other than an allocation or auction results, described in paragraphs (a) through (i) of this section, of TR SO₂ Group 2 allowances to a recipient is made by or are submitted to the Administrator in accordance with §97.711 or §97.712 or with a SIP revision approved under §52.39(h) or (i) of this chapter, the Administrator will record such allocation or auction results in the appropriate Allowance Management System account.

(k) When recording the allocation or auction of TR SO₂ Group 2 allowances to a TR SO₂ Group 2 unit or other entity in an Allowance Management System account, the Administrator will assign each TR SO₂ Group 2 allowance
a unique identification number that will include digits identifying the year of the control period for which the TR SO\(_2\) Group 2 allowance is allocated or auctioned.

§ 97.722 Submission of TR SO\(_2\) Group 2 allowance transfers.

(a) An authorized account representative seeking recordation of a TR SO\(_2\) Group 2 allowance transfer shall submit the transfer to the Administrator.

(b) A TR SO\(_2\) Group 2 allowance transfer shall be correctly submitted if:

(1) The transfer includes the following elements, in a format prescribed by the Administrator:

(i) The account numbers established by the Administrator for both the transferor and transferee accounts;

(ii) The serial number of each TR SO\(_2\) Group 2 allowance that is in the transferor account and is to be transferred; and

(iii) The name and signature of the authorized account representative of the transferor account and the date signed.

(2) When the Administrator attempts to record the transfer, the transferor account includes each TR SO\(_2\) Group 2 allowance identified by serial number in the transfer.

§ 97.723 Recordation of TR SO\(_2\) Group 2 allowance transfers.

(a) Within 5 business days (except as provided in paragraph (b) of this section) of receiving a TR SO\(_2\) Group 2 allowance transfer that is correctly submitted under §97.722, the Administrator will record a TR SO\(_2\) Group 2 allowance transfer by moving each TR SO\(_2\) Group 2 allowance from the transferor account to the transferee account as specified in the transfer.

(b) A TR SO\(_2\) Group 2 allowance transfer to or from a compliance account that is submitted for recordation after the allowance transfer deadline for a control period and that includes any TR SO\(_2\) Group 2 allowances allocated for any control period before such allowance transfer deadline will not be recorded until after the Administrator completes the deductions from such compliance account under §97.724 for the control period immediately before such allowance transfer deadline.

(c) Where a TR SO\(_2\) Group 2 allowance transfer is not correctly submitted under §97.722, the Administrator will not record such transfer.

(d) Within 5 business days of recordation of a TR SO\(_2\) Group 2 allowance transfer under paragraphs (a) and (b) of the section, the Administrator will notify the authorized account representatives of both the transferor and transferee accounts.

(e) Within 10 business days of receipt of a TR SO\(_2\) Group 2 allowance transfer that is not correctly submitted under §97.722, the Administrator will notify the authorized account representatives of both accounts subject to the transfer of:

(1) A decision not to record the transfer, and

(2) The reasons for such non-recordation.

§ 97.724 Compliance with TR SO\(_2\) Group 2 emissions limitation.

(a) Availability for deduction for compliance. TR SO\(_2\) Group 2 allowances are available to be deducted for compliance with a source’s TR SO\(_2\) Group 2 emissions limitation for a control period in a given year only if the TR SO\(_2\) Group 2 allowances:

(1) Were allocated for such control period or a control period in a prior year; and

(2) Are held in the source’s compliance account as of the allowance transfer deadline for such control period.

(b) Deductions for compliance. After the recordation, in accordance with §97.723, of TR SO\(_2\) Group 2 allowance transfers submitted by the allowance transfer deadline for a control period in a given year, the Administrator will deduct from each source’s compliance account TR SO\(_2\) Group 2 allowances available under paragraph (a) of this section in order to determine whether the source meets the TR SO\(_2\) Group 2 emissions limitation for such control period, as follows:

(1) Until the amount of TR SO\(_2\) Group 2 allowances deducted equals the number of tons of total SO\(_2\) emissions from all TR SO\(_2\) Group 2 units at the source for such control period; or
(2) If there are insufficient TR SO\textsubscript{2} Group 2 allowances to complete the deductions in paragraph (b)(1) of this section, until no more TR SO\textsubscript{2} Group 2 allowances available under paragraph (a) of this section remain in the compliance account.

(c)(1) Identification of TR SO\textsubscript{2} Group 2 allowances by serial number. The authorized account representative for a source’s compliance account may request that specific TR SO\textsubscript{2} Group 2 allowances, identified by serial number, in the compliance account be deducted for emissions or excess emissions for a control period in a given year in accordance with paragraph (b) or (d) of this section. In order to be complete, such request shall be submitted to the Administrator by the allowance transfer deadline for such control period and include, in a format prescribed by the Administrator, the identification of the TR SO\textsubscript{2} Group 2 source and the appropriate serial numbers.

(2) First-in, first-out. The Administrator will deduct TR SO\textsubscript{2} Group 2 allowances under paragraph (b) or (d) of this section from the source’s compliance account in accordance with a complete request under paragraph (c)(1) of this section or, in the absence of such request or in the case of identification of an insufficient amount of TR SO\textsubscript{2} Group 2 allowances in such request, on a first-in, first-out accounting basis in the following order:

(i) Any TR SO\textsubscript{2} Group 2 allowances that were allocated to the units at the source and not transferred out of the compliance account, in the order of recordation; and then

(ii) Any TR SO\textsubscript{2} Group 2 allowances that were allocated to any unit and transferred to and recorded in the compliance account pursuant to this subpart, in the order of recordation.

(d) Deductions for excess emissions. After making the deductions for compliance under paragraph (b) of this section for a control period in a year in which the TR SO\textsubscript{2} Group 2 source has excess emissions, the Administrator will deduct from the source’s compliance account an amount of TR SO\textsubscript{2} Group 2 allowances, allocated for a control period in a prior year or the control period in the year of the excess emissions or in the immediately following year, equal to two times the number of tons of the source’s excess emissions.

(e) Recordation of deductions. The Administrator will record in the appropriate compliance account all deductions from such an account under paragraphs (b) and (d) of this section.

§ 97.725 Compliance with TR SO\textsubscript{2} Group 2 assurance provisions.

(a) Availability for deduction. TR SO\textsubscript{2} Group 2 allowances are available to be deducted for compliance with the TR SO\textsubscript{2} Group 2 assurance provisions for a control period in a given year by the owners and operators of a group of one or more TR SO\textsubscript{2} Group 2 sources and units in a State (and Indian country within the borders of such State) only if the TR SO\textsubscript{2} Group 2 allowances:

(1) Were allocated for a control period in a prior year or the control period in the given year or in the immediately following year; and

(2) Are held in the assurance account, established by the Administrator for such owners and operators of such group of TR SO\textsubscript{2} Group 2 sources and units in such State (and Indian country within the borders of such State) under paragraph (b)(3) of this section, as of the deadline established in paragraph (b)(4) of this section.

(b) Deductions for compliance. The Administrator will deduct TR SO\textsubscript{2} Group 2 allowances available under paragraph (a) of this section for compliance with the TR SO\textsubscript{2} Group 2 assurance provisions for a State for a control period in a given year in accordance with the following procedures:

(1) By June 1, 2015 and June 1 of each year thereafter, the Administrator will:

(i) Calculate, for each State (and Indian country within the borders of such State), the total SO\textsubscript{2} emissions from all TR SO\textsubscript{2} Group 2 units at TR SO\textsubscript{2} Group 2 sources in the State (and Indian country within the borders of such State) during the control period in the year before the year of this calculation deadline and the amount, if any, by which such total SO\textsubscript{2} emissions exceed the State assurance level as described in §97.706(c)(2)(iii); and
(ii) Promulgate a notice of data availability of the results of the calculations required in paragraph (b)(1)(i) of this section, including separate calculations of the SO\textsubscript{2} emissions from each TR SO\textsubscript{2} Group 2 source.

(2) For each notice of data availability required in paragraph (b)(1)(i) of this section and for any State (and Indian country within the borders of such State) identified in such notice as having TR SO\textsubscript{2} Group 2 units with total SO\textsubscript{2} emissions exceeding the State assurance level for a control period in a given year, as described in §97.706(c)(2)(iii):

(i) By July 1 immediately after the promulgation of such notice, the designated representative of each TR SO\textsubscript{2} Group 2 source in each such State (and Indian country within the borders of such State) shall submit a statement, in a format prescribed by the Administrator, providing for each TR SO\textsubscript{2} Group 2 unit (if any) at the source that operates during, but is not allocated an amount of TR SO\textsubscript{2} Group 2 allowances for, such control period, the unit’s allowable SO\textsubscript{2} emission rate for such control period and, if such rate is expressed in lb per mmBtu, the unit’s heat rate.

(ii) By August 1 immediately after the promulgation of such notice, the Administrator will calculate, for each such State (and Indian country within the borders of such State) and each common designated representative for such control period, the common designated representative’s share of the total SO\textsubscript{2} emissions from all TR SO\textsubscript{2} Group 2 units at TR SO\textsubscript{2} Group 2 sources in the State (and Indian country within the borders of such State), the common designated representative’s assurance level, and the amount (if any) of TR SO\textsubscript{2} Group 2 allowances that the owners and operators of such group of sources and units in the State (and Indian country within the borders of such State) must hold in accordance with the calculation formula in §97.706(c)(2)(i) and will promulgate a notice of data availability of the results of these calculations.

(iii) The Administrator will provide an opportunity for submission of objections to the calculations referenced by the notice of data availability required in paragraph (b)(2)(ii) of this section and the calculations referenced by the relevant notice of data availability required in paragraph (b)(1)(i) of this section.

(A) Objections shall be submitted by the deadline specified in such notice and shall be limited to addressing whether the calculations referenced in the relevant notice required under paragraph (b)(1)(i) of this section and referenced in the notice required under paragraph (b)(2)(i) of this section are in accordance with §§97.706(b) and 97.730 through 97.735, the definitions of “common designated representative”, “common designated representative’s assurance level”, and “common designated representative’s share” in §97.702, and the calculation formula in §97.706(c)(2)(i).

(B) The Administrator will adjust the calculations to the extent necessary to ensure that they are in accordance with the provisions referenced in paragraph (b)(2)(ii)(A) of this section. By October 1 immediately after the promulgation of such notice, the Administrator will promulgate a notice of data availability of any adjustments that the Administrator determines to be necessary and the reasons for accepting or rejecting any objections submitted in accordance with paragraph (b)(2)(ii)(A) of this section.

(3) For any State (and Indian country within the borders of such State) referenced in each notice of data availability required in paragraph (b)(2)(iii)(B) of this section as having TR SO\textsubscript{2} Group 2 units with total SO\textsubscript{2} emissions exceeding the State assurance level for a control period in a given year, the Administrator will establish one assurance account for each set of owners and operators referenced, in the notice of data availability required under paragraph (b)(2)(iii)(B) of this section, as all of the owners and operators of a group of TR SO\textsubscript{2} Group 2 sources and units in the State (and Indian country within the borders of such State) having a common designated representative for such control period and as being required to hold TR SO\textsubscript{2} Group 2 allowances.
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(4)(i) As of midnight of November 1 immediately after the promulgation of each notice of data availability required in paragraph (b)(2)(iii)(B) of this section, the owners and operators described in paragraph (b)(3) of this section shall hold in the assurance account established for them and for the appropriate TR SO₂ Group 2 sources, TR SO₂ Group 2 units, and State (and Indian country within the borders of such State) under paragraph (b)(3) of this section a total amount of TR SO₂ allowances, available for deduction under paragraph (a) of this section, equal to the amount such owners and operators are required to hold with regard to such sources, units and State (and Indian country within the borders of such State) as calculated by the Administrator and referenced in such notice.

(ii) Notwithstanding the allowance-holding deadline specified in paragraph (b)(4)(i) of this section, if November 1 is not a business day, then such allowance-holding deadline shall be midnight of the first business day thereafter.

(5) After November 1 (or the date described in paragraph (b)(4)(ii) of this section) immediately after the promulgation of each notice of data availability required in paragraph (b)(2)(iii)(B) of this section and after the recordation, in accordance with §97.723, of TR SO₂ Group 2 allowance transfers submitted by midnight of such date, the Administrator will determine whether the owners and operators described in paragraph (b)(3) of this section hold, in the assurance account for the appropriate TR SO₂ Group 2 sources, TR SO₂ Group 2 units, and State (and Indian country within the borders of such State) established under paragraph (b)(3) of this section, the amount of TR SO₂ allowances available under paragraph (a) of this section that the owners and operators are required to hold with regard to such sources, units, and State (and Indian country within the borders of such State) as calculated by the Administrator and referenced in the notice required in paragraph (b)(2)(iii)(B) of this section.

(6) Notwithstanding any other provision of this subpart and any revision, made by or submitted to the Administrator after the promulgation of the notice of data availability required in paragraph (b)(2)(iii)(B) of this section for a control period in a given year, of any data used in making the calculations referenced in such notice, the amounts of TR SO₂ Group 2 allowances that the owners and operators are required to hold in accordance with §97.706(c)(2)(i) for such control period shall continue to be such amounts as calculated by the Administrator and referenced in such notice required in paragraph (b)(2)(iii)(B) of this section, except as follows:

(i) If any such data are revised by the Administrator as a result of a decision in or settlement of litigation concerning such data on appeal under part 78 of this chapter of such notice, or on appeal under section 307 of the Clean Air Act of a decision rendered under part 78 of this chapter on appeal of such notice, then the Administrator will use the data as so revised to recalculate the amounts of TR SO₂ Group 2 allowances that owners and operators are required to hold in accordance with the calculation formula in §97.706(c)(2)(i) for such control period with regard to the TR SO₂ Group 2 sources, TR SO₂ Group 2 units, and State (and Indian country within the borders of such State) involved, provided that such litigation under part 78 of this chapter, or the proceeding under part 78 of this chapter that resulted in the decision appealed in such litigation under section 307 of the Clean Air Act, was initiated no later than 30 days after promulgation of such notice required in paragraph (b)(2)(iii)(B) of this section.

(ii) If any such data are revised by the owners and operators of a TR SO₂ Group 2 source and TR SO₂ Group 2 unit whose designated representative submitted such data under paragraph (b)(2)(i) of this section, as a result of a decision in or settlement of litigation concerning such submission, then the Administrator will use the data as so revised to recalculate the amounts of TR SO₂ Group 2 allowances that owners and operators are required to hold in accordance with the calculation formula in §97.706(c)(2)(i) for such control period with regard to the TR SO₂ Group 2 sources, TR SO₂ Group 2 units, and State (and Indian country within the borders of such State) involved, provided that such litigation under part 78 of this chapter, or the proceeding under part 78 of this chapter that resulted in the decision appealed in such litigation under section 307 of the Clean Air Act, was initiated no later than 30 days after promulgation of such notice required in paragraph (b)(2)(iii)(B) of this section.
§ 97.728 Administrator’s action on submissions.

(a) The Administrator may review and conduct independent audits concerning any submission under the TR SO\textsubscript{2} Group 2 Trading Program and make appropriate adjustments of the information in the submission.
§ 97.729 [Reserved]

§ 97.730 General monitoring, record-keeping, and reporting requirements.

The owners and operators, and to the extent applicable, the designated representative, of a TR SO₂ Group 2 unit, shall comply with the monitoring, recordkeeping, and reporting requirements as provided in this subpart and subparts F and G of part 75 of this chapter. For purposes of applying such requirements, the definitions in §97.702 and in §72.2 of this chapter shall apply, the terms “affected unit,” “designated representative,” and “continuous emission monitoring system” (or “CEMS”) in part 75 of this chapter shall be deemed to refer to the terms “TR SO₂ Group 2 unit,” “designated representative,” and “continuous emission monitoring system” (or “CEMS”) respectively as defined in §97.702, and the term “newly affected unit” shall be deemed to mean “newly affected TR SO₂ Group 2 unit.” The owner or operator of a unit that is not a TR SO₂ Group 2 unit but that is monitored under §75.16(b)(2) of this chapter shall comply with the same monitoring, recordkeeping, and reporting requirements as a TR SO₂ Group 2 unit.

(a) Requirements for installation, certification, and data accounting. The owner or operator of each TR SO₂ Group 2 unit shall:

(1) Install all monitoring systems required under this subpart for monitoring SO₂ mass emissions and individual unit heat input (including all systems required to monitor SO₂ concentration, stack gas moisture content, stack gas flow rate, CO₂ or O₂ concentration, and fuel flow rate, as applicable, in accordance with §§75.11 and 75.16 of this chapter);

(2) Successfully complete all certification tests required under §97.731 and meet all other requirements of this subpart and part 75 of this chapter applicable to the monitoring systems under paragraph (a)(1) of this section; and

(3) Record, report, and quality-assure the data from the monitoring systems under paragraph (a)(1) of this section.

(b) Compliance deadlines. Except as provided in paragraph (e) of this section, the owner or operator shall meet the monitoring system certification and other requirements of paragraphs (a)(1) and (2) of this section on or before the following dates and shall record, report, and quality-assure the data from the monitoring systems under paragraph (a)(1) of this section on and after the following dates.

(1) For the owner or operator of a TR SO₂ Group 2 unit that commences commercial operation before July 1, 2011, January 1, 2012.

(2) For the owner or operator of a TR SO₂ Group 2 unit that commences commercial operation on or after July 1, 2011, by the later of the following:

(i) January 1, 2012; or

(ii) 180 calendar days after the date on which the unit commences commercial operation.

(3) The owner or operator of a TR SO₂ Group 2 unit for which construction of a new stack or flue or installation of add-on SO₂ emission controls is completed after the applicable deadline under paragraph (b)(1) or (2) of this section shall meet the requirements of §§75.4(e)(1) through (e)(4) of this chapter, except that:

(i) Such requirements shall apply to the monitoring systems required under §97.730 through §97.735, rather than the monitoring systems required under part 75 of this chapter;

(ii) SO₂ concentration, stack gas moisture content, stack gas volumetric flow rate, and O₂ or CO₂ concentration data shall be determined and reported, rather than the data listed in §75.4(e)(2) of this chapter; and

(iii) Any petition for another procedure under §75.4(e)(2) of this chapter shall be submitted under §97.735, rather than §75.66.

(c) Reporting data. The owner or operator of a TR SO₂ Group 2 unit that does not meet the applicable compliance date set forth in paragraph (b) of this section for any monitoring system under paragraph (a)(1) of this section
shall, for each such monitoring system, determine, record, and report maximum potential (or, as appropriate, minimum potential) values for SO₂ concentration, stack gas flow rate, stack gas moisture content, fuel flow rate, and any other parameters required to determine SO₂ mass emissions and heat input in accordance with §75.31(b)(2) or (c)(3) of this chapter or section 2.4 of appendix D to part 75 of this chapter, as applicable.

(d) Prohibitions. (1) No owner or operator of a TR SO₂ Group 2 unit shall use any alternative monitoring system, alternative reference method, or any other alternative to any requirement of this subpart without having obtained prior written approval in accordance with §97.735.

(2) No owner or operator of a TR SO₂ Group 2 unit shall operate the unit so as to discharge, or allow to be discharged, SO₂ to the atmosphere without accounting for all such SO₂ in accordance with the applicable provisions of this subpart and part 75 of this chapter.

(3) No owner or operator of a TR SO₂ Group 2 unit shall disrupt the continuous emission monitoring system, any portion thereof, or any other approved emission monitoring method, and thereby avoid monitoring and recording SO₂ mass discharged into the atmosphere or heat input, except for periods of recertification or periods when calibration, quality assurance testing, or maintenance is performed in accordance with the applicable provisions of this subpart and part 75 of this chapter.

(4) No owner or operator of a TR SO₂ Group 2 unit shall retire or permanently discontinue use of the continuous emission monitoring system, any component thereof, or any other approved monitoring system under this subpart, except under any one of the following circumstances:

(i) During the period that the unit is covered by an exemption under §97.706 that is in effect;

(ii) The owner or operator is monitoring emissions from the unit with another certified monitoring system approved, in accordance with the applicable provisions of this subpart and part 75 of this chapter, by the Administrator for use at that unit that provides emission data for the same pollutant or parameter as the retired or discontinued monitoring system; or

(iii) The designated representative submits notification of the date of certification testing of a replacement monitoring system for the retired or discontinued monitoring system in accordance with §97.731(d)(3)(1).

(e) Long-term cold storage. The owner or operator of a TR SO₂ Group 2 unit is subject to the applicable provisions of §75.3(d) of this chapter concerning units in long-term cold storage.

§97.731 Initial monitoring system certification and recertification procedures.

(a) The owner or operator of a TR SO₂ Group 2 unit shall be exempt from the initial certification requirements of this section for a monitoring system under §97.730(a)(1) if the following conditions are met:

(1) The monitoring system has been previously certified in accordance with part 75 of this chapter; and

(2) The applicable quality-assurance and quality-control requirements of §75.21 of this chapter and appendices B and D to part 75 of this chapter are fully met for the certified monitoring system described in paragraph (a)(1) of this section.

(b) The recertification provisions of this section shall apply to a monitoring system under §97.730(a)(1) that is exempt from initial certification requirements under paragraph (a) of this section.

(c) [Reserved]

(d) Except as provided in paragraph (a) of this section, the owner or operator of a TR SO₂ Group 2 unit shall comply with the following initial certification and recertification procedures, for a continuous monitoring system (i.e., a continuous emission monitoring system and an excepted monitoring system under appendix D to part 75 of this chapter) under §97.730(a)(1). The owner or operator of a unit that qualifies to use the low mass emissions excepted monitoring methodology under §75.19 of this chapter or that qualifies to use an alternative monitoring system under subpart E of part 75 of this chapter shall comply with the
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procedures in paragraph (e) or (f) of this section respectively.

(1) Requirements for initial certification. The owner or operator shall ensure that each continuous monitoring system under §97.730(a)(1) (including the automated data acquisition and handling system) successfully completes all of the initial certification testing required under §75.20 of this chapter by the applicable deadline in §97.730(b). In addition, whenever the owner or operator installs a monitoring system to meet the requirements of this subpart in a location where no such monitoring system was previously installed, initial certification in accordance with §75.20 of this chapter is required.

(2) Requirements for recertification. Whenever the owner or operator makes a replacement, modification, or change in any certified continuous emission monitoring system under §97.730(a)(1) that may significantly affect the ability of the system to accurately measure or record SO₂ mass emissions or heat input rate or to meet the quality-assurance and quality-control requirements of §75.21 of this chapter or appendix B to part 75 of this chapter, the owner or operator shall recertify the monitoring system in accordance with §75.20 of this chapter. Furthermore, whenever the owner or operator makes a replacement, modification, or change to the flue gas handling system or the unit’s operation that may significantly change the stack flow or concentration profile, the owner or operator shall recertify each continuous emission monitoring system whose accuracy is potentially affected by the change, in accordance with §75.20(b) of this chapter. Examples of changes to a continuous emission monitoring system that require recertification include: Replacement of the analyzer, complete replacement of an existing continuous emission monitoring system, or change in location or orientation of the sampling probe or site. Any fuel flowmeter system under §97.730(a)(1) is subject to the recertification requirements in §75.20(g)(6) of this chapter.

(3) Approval process for initial certification and recertification. For initial certification of a continuous monitoring system under §97.730(a)(1), paragraphs (d)(3)(i) through (v) of this section apply. For recertifications of such monitoring systems, paragraphs (d)(3)(i) through (iv) of this section and the procedures in §§75.20(b)(5) and (g)(7) of this chapter (in lieu of the procedures in paragraph (d)(3)(v) of this section) apply, provided that in applying paragraphs (d)(3)(i) through (iv) of this section, the words “certification” and “initial certification” are replaced by the word “recertification” and the word “certified” is replaced by with the word “recertified”.

(i) Notification of certification. The designated representative shall submit to the appropriate EPA Regional Office and the Administrator written notice of the dates of certification testing, in accordance with §75.20 of this chapter.

(ii) Certification application. The designated representative shall submit to the Administrator a certification application for each monitoring system. A complete certification application shall include the information specified in §75.68 of this chapter.

(iii) Provisional certification date. The provisional certification date for a monitoring system shall be determined in accordance with §75.20(a)(3) of this chapter. A provisionally certified monitoring system may be used under the TR SO₂ Group 2 Trading Program for a period not to exceed 120 days after receipt by the Administrator of the complete certification application for the monitoring system under paragraph (d)(3)(ii) of this section. Data measured and recorded by the provisionally certified monitoring system, in accordance with the requirements of part 75 of this chapter, will be considered valid quality-assured data (retroactive to the date and time of provisional certification), provided that the Administrator does not invalidate the provisional certification by issuing a notice of disapproval within 120 days of the date of receipt of the complete certification application by the Administrator.

(iv) Certification application approval process. The Administrator will issue a written notice of approval or disapproval of the certification application to the owner or operator within 120 days of receipt of the complete certification application under paragraph
(d)(3)(ii) of this section. In the event the Administrator does not issue such a notice within such 120-day period, each monitoring system that meets the applicable performance requirements of part 75 of this chapter and is included in the certification application will be deemed certified for use under the TR \(SO_2\) Group 2 Trading Program.

(A) Approval notice. If the certification application is complete and shows that each monitoring system meets the applicable performance requirements of part 75 of this chapter, then the Administrator will issue a written notice of approval of the certification application within 120 days of receipt.

(B) Incomplete application notice. If the certification application is not complete, then the Administrator will issue a written notice of incompleteness that sets a reasonable date by which the designated representative must submit the additional information required to complete the certification application. If the designated representative does not comply with the notice of incompleteness by the specified date, then the Administrator may issue a notice of disapproval under paragraph (d)(3)(iv)(C) of this section.

(C) Disapproval notice. If the certification application shows that any monitoring system does not meet the performance requirements of part 75 of this chapter or if the certification application is incomplete and the requirement for disapproval under paragraph (d)(3)(iv)(B) of this section is met, then the Administrator will issue a written notice of disapproval of the certification application. Upon issuance of such notice of disapproval, the provisional certification is invalidated by the Administrator and the data measured and recorded by each uncertified monitoring system shall not be considered valid quality-assured data beginning with the date and hour of provisional certification (as defined under §75.20(a)(3) of this chapter).

(D) Audit decertification. The Administrator may issue a notice of disapproval of the certification status of a monitor in accordance with §97.732(b).

(v) Procedures for loss of certification. If the Administrator issues a notice of disapproval of a certification application under paragraph (d)(3)(iv)(C) of this section or a notice of disapproval of certification status under paragraph (d)(3)(iv)(D) of this section, then:

(A) The owner or operator shall substitute the following values, for each disapproved monitoring system, for each hour of unit operation during the period of invalid data specified under §75.20(a)(4)(iii), §75.20(g)(7), or §75.21(e) of this chapter and continuing until the applicable date and hour specified under §75.20(a)(5)(i) or (g)(7) of this chapter:

(1) For a disapproved \(SO_2\) pollutant concentration monitor and disapproved flow monitor, respectively, the maximum potential concentration of \(SO_2\) and the maximum potential flow rate, as defined in sections 2.1.1.1 and 2.1.4.1 of appendix A to part 75 of this chapter.

(2) For a disapproved moisture monitoring system and disapproved diluent gas monitoring system, respectively, the minimum potential moisture percentage and either the maximum potential \(CO_2\) concentration or the minimum potential \(O_2\) concentration (as applicable), as defined in sections 2.1.5, 2.1.3.1, and 2.1.3.2 of appendix A to part 75 of this chapter.

(3) For a disapproved fuel flowmeter system, the maximum potential fuel flow rate, as defined in section 2.4.2.1 of appendix D to part 75 of this chapter.

(B) The designated representative shall submit a notification of certification retest dates and a new certification application in accordance with paragraphs (d)(3)(i) and (ii) of this section.

(C) The owner or operator shall repeat all certification tests or other requirements that were failed by the monitoring system, as indicated in the Administrator’s notice of disapproval, no later than 30 unit operating days after the date of issuance of the notice of disapproval.

(e) The owner or operator of a unit qualified to use the low mass emissions (LME) excepted methodology under §75.19 of this chapter shall meet the applicable certification and recertification requirements in §§75.19(a)(2) and 75.20(h) of this chapter. If the owner or operator of such a unit elects to certify a fuel flowmeter system for heat input.
§ 97.732 Monitoring system out-of-control periods.

(a) General provisions. Whenever any monitoring system fails to meet the quality-assurance and quality-control requirements or data validation requirements of part 75 of this chapter, data shall be substituted using the applicable missing data procedures in subpart D or appendix D to part 75 of this chapter.

(b) Audit decertification. Whenever both an audit of a monitoring system and a review of the initial certification or recertification application reveal that any monitoring system should not have been certified or recertified because it did not meet a particular performance specification or other requirement under §97.731 or the applicable provisions of part 75 of this chapter, both at the time of the initial certification or recertification application submission and at the time of the audit, the Administrator will issue a notice of disapproval of the certification status of such monitoring system. For the purposes of this paragraph, an audit shall be either a field audit or an audit of any information submitted to the Administrator or any State or permitting authority. By issuing the notice of disapproval, the Administrator revokes prospectively the certification status of the monitoring system. The data measured and recorded by the monitoring system shall not be considered valid quality-assured data from the date of issuance of the notification of the revoked certification status until the date and time that the owner or operator completes subsequently approved initial certification or recertification tests for the monitoring system. The owner or operator shall follow the applicable initial certification or recertification procedures in §97.731 for each disapproved monitoring system.

§ 97.733 Notifications concerning monitoring.

The designated representative of a TR SO\textsubscript{2} Group 2 unit shall submit written notice to the Administrator in accordance with §75.61 of this chapter.

§ 97.734 Recordkeeping and reporting.

(a) General provisions. The designated representative shall comply with all recordkeeping and reporting requirements in paragraphs (b) through (e) of this section, the applicable recordkeeping and reporting requirements in subparts F and G of part 75 of this chapter, and the requirements of §97.74(a).

(b) Monitoring plans. The owner or operator of a TR SO\textsubscript{2} Group 2 unit shall comply with requirements of §75.62 of this chapter.

(c) Certification applications. The designated representative shall submit an application to the Administrator within 45 days after completing all initial certification or recertification tests required under §97.731, including the information required under §75.63 of this chapter.

(d) Quarterly reports. The designated representative shall submit quarterly reports, as follows:

(i) For a unit that commences commercial operation before July 1, 2011, the calendar quarter covering January 1, 2012 through March 31, 2012; or

(ii) For a unit that commences commercial operation on or after July 1, 2011, the calendar quarter corresponding to the earlier of the date of provisional certification or the applicable deadline for initial certification under §97.730(b), unless that quarter is the third or fourth quarter of 2011, in which case reporting shall commence in the quarter covering January 1, 2012 through March 31, 2012.
(2) The designated representative shall submit each quarterly report to the Administrator within 30 days after the end of the calendar quarter covered by the report. Quarterly reports shall be submitted in the manner specified in §75.64 of this chapter.

(3) For TR SO\textsubscript{2} Group 2 units that are also subject to the Acid Rain Program, TR NO\textsubscript{x} Annual Trading Program, or TR NO\textsubscript{X} Ozone Season Trading Program, quarterly reports shall include the applicable data and information required by subparts F through H of part 75 of this chapter as applicable, in addition to the SO\textsubscript{2} mass emission data, heat input data, and other information required by this subpart.

(4) The Administrator may review and conduct independent audits of any quarterly report in order to determine whether the quarterly report meets the requirements of this subpart and part 75 of this chapter, including the requirement to use substitute data.

(i) The Administrator will notify the designated representative of any determination that the quarterly report fails to meet any such requirements and specify in such notification any corrections that the Administrator believes are necessary to make through resubmission of the quarterly report and a reasonable time period within which the designated representative must respond. Upon request by the designated representative, the Administrator may specify reasonable extensions of such time period. Within the time period (including any such extensions) specified by the Administrator, the designated representative shall resubmit the quarterly report with the corrections specified by the Administrator, except to the extent the designated representative provides information demonstrating that a specified correction is not necessary because the quarterly report already meets the requirements of this subpart and part 75 of this chapter that are relevant to the specified correction.

(ii) Any resubmission of a quarterly report shall meet the requirements applicable to the submission of a quarterly report under this subpart and part 75 of this chapter, except for the deadline set forth in paragraph (d)(2) of this section.

(e) Compliance certification. The designated representative shall submit to the Administrator a compliance certification (in a format prescribed by the Administrator) in support of each quarterly report based on reasonable inquiry of those persons with primary responsibility for ensuring that all of the unit’s emissions are correctly and fully monitored. The certification shall state that:

(1) The monitoring data submitted were recorded in accordance with the applicable requirements of this subpart and part 75 of this chapter, including the quality assurance procedures and specifications; and

(2) For a unit with add-on SO\textsubscript{2} emission controls and for all hours where SO\textsubscript{2} data are substituted in accordance with §75.34(a)(1) of this chapter, the add-on emission controls were operating within the range of parameters listed in the quality assurance/quality control program under appendix B to part 75 of this chapter and the substitute data values do not systematically underestimate SO\textsubscript{2} emissions.

§ 97.735 Petitions for alternatives to monitoring, recordkeeping, or reporting requirements.

(a) The designated representative of a TR SO\textsubscript{2} Group 2 unit may submit a petition under §75.66 of this chapter to the Administrator, requesting approval to apply an alternative to any requirement of §§97.730 through 97.734.

(b) A petition submitted under paragraph (a) of this section shall include sufficient information for the evaluation of the petition, including, at a minimum, the following information:

(i) Identification of each unit and source covered by the petition;

(ii) A detailed explanation of why the proposed alternative is being suggested in lieu of the requirement;

(iii) A description and diagram of any equipment and procedures used in the proposed alternative;

(iv) A demonstration that the proposed alternative is consistent with the purposes of the requirement for which the alternative is proposed and with the purposes of this subpart and part 75 of this chapter and that any adverse effect of approving the alternative will be de minimis; and
APPENDIX A TO PART 97—FINAL SECTION 126 RULE: EGU ALLOCATIONS, 2004–2007

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Environmental Protection Agency

**APPENDIX B TO PART 97—FINAL SECTION 126 RULE: NON-EGU ALLOCATIONS, 2004–2007**

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[55 FR 2727, Jan. 18, 2000, as amended at 66 FR 48576, Sept. 21, 2001]
Environmental Protection Agency

APPENDIX C TO PART 97—FINAL SECTION 126 RULE: TRADING BUDGET

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APPENDIX D TO PART 97—FINAL SECTION 126 RULE: STATE COMPLIANCE SUPPLEMENT POOLS FOR THE SECTION 126 FINAL RULE (TONS)

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98.2 Who must report?
98.3 What are the general monitoring, reporting, recordkeeping and verification requirements of this part?
98.4 Authorization and responsibilities of the designated representative.
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APPENDIX B TO PART 98—SOURCE CATEGORY LIST FOR §98.2(a)(1)

APPENDIX C TO PART 98—SOURCE CATEGORY LIST FOR §98.2(a)(2)

APPENDIX D TO PART 98—SUPPLIER CATEGORY LIST FOR §98.2(a)(4)

APPENDIX E TO PART 98—DATA ELEMENTS THAT ARE INPUTS TO EMISSION EQUATIONS AND FOR WHICH THE REPORTING DEADLINE IS CHANGED TO SEPTEMBER 30, 2011

APPENDIX F TO PART 98—DATA ELEMENTS THAT ARE INPUTS TO EMISSION EQUATIONS AND FOR WHICH THE REPORTING DEADLINE IS MARCH 31, 2015

APPENDIX G TO PART 98—DATA ELEMENTS THAT ARE INPUTS TO EMISSION EQUATIONS AND FOR WHICH THE REPORTING DEADLINE IS JUNE 30, 2015

APPENDIX H TO PART 98—DATA ELEMENTS THAT ARE INPUTS TO EMISSION EQUATIONS AND FOR WHICH THE REPORTING DEADLINE IS SEPTEMBER 30, 2015

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98.56 Data reporting requirements.
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98.66 Data reporting requirements.
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98.86 Data reporting requirements.
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98.96 Data reporting requirements.
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98.123 Calculating GHG emissions.
98.124 Monitoring and QA/QC requirements.
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98.126 Data reporting requirements.
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98.147 Records that must be retained.
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98.151 Reporting threshold.
98.152 GHGs to report.
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98.155 Procedures for estimating missing data.
98.156 Data reporting requirements.
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98.158 Definitions.

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98.161 Reporting threshold.
98.162 GHGs to report.
98.163 Calculating GHG emissions.
98.164 Monitoring and QA/QC requirements.
98.165 Procedures for estimating missing data.
98.166 Data reporting requirements.
98.167 Records that must be retained.
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98.171 Reporting threshold.
98.172 GHGs to report.
98.173 Calculating GHG emissions.
98.174 Monitoring and QA/QC requirements.
98.175 Procedures for estimating missing data.
98.176 Data reporting requirements.
98.177 Records that must be retained.
98.178 Definitions.

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98.180 Definition of the source category.
98.181 Reporting threshold.
98.182 GHGs to report.
98.183 Calculating GHG emissions.
98.184 Monitoring and QA/QC requirements.
98.185 Procedures for estimating missing data.
98.186 Data reporting procedures.
98.187 Records that must be retained.
98.188 Definitions.

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98.191 Reporting threshold.
98.192 GHGs to report.
98.193 Calculating GHG emissions.
98.194 Monitoring and QA/QC requirements.
98.195 Procedures for estimating missing data.
98.196 Data reporting requirements.
98.197 Records that must be retained.
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98.201 Reporting threshold.
98.202 GHGs to report.
98.203 Calculating GHG emissions.
98.204 Monitoring and QA/QC requirements.
98.205 Procedures for estimating missing data.
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KRAFT PULPING LIQUOR EMISSIONS FACTORS FOR BIOMASS-BASED CO₂, CH₄, AND N₂O

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98.283 Calculating GHG emissions.
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98.285 Procedures for estimating missing data.
98.286 Data reporting requirements.
98.287 Records that must be retained.
98.288 Definitions.

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98.291 Reporting threshold.
98.292 GHGs to report.
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98.294 Monitoring and QA/QC requirements.
98.295 Procedures for estimating missing data.
98.296 Data reporting requirements.
98.297 Records that must be retained.
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98.302 GHGs to report.
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98.304 Monitoring and QA/QC requirements.
98.305 Procedures for estimating missing data.
98.306 Data reporting requirements.
98.307 Records that must be retained.
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98.311 Reporting threshold.
98.312 GHGs to report.
98.313 Calculating GHG emissions.
98.314 Monitoring and QA/QC requirements.
98.315 Procedures for estimating missing data.
98.316 Data reporting requirements.
98.317 Records that must be retained.
98.318 Definitions.

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98.324 Monitoring and QA/QC requirements.
98.325 Procedures for estimating missing data.
98.326 Data reporting requirements.
98.327 Records that must be retained.
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98.331 Reporting threshold.
98.332 GHGs to report.
98.333 Calculating GHG emissions.
98.334 Monitoring and QA/QC requirements.
98.335 Procedures for estimating missing data.
98.336 Data reporting requirements.
98.337 Records that must be retained.
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98.341 Reporting threshold.
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98.343 Calculating GHG emissions.
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98.346 Data reporting requirements.
98.347 Records that must be retained.
98.348 Definitions.

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98.354 Monitoring and QA/QC requirements.
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98.356 Data reporting requirements.
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98.386 Data reporting requirements.
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98.391 Reporting threshold.
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98.394 Monitoring and QA/QC requirements.
98.395 Procedures for estimating missing data.
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98.405 Procedures for estimating missing data.
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98.443 Calculating CO₂ geologic sequestration.
§ 98.2 Purpose and scope.

(a) This part establishes mandatory greenhouse gas (GHG) reporting requirements for owners and operators of certain facilities that directly emit GHG as well as for certain suppliers. For suppliers, the GHGs reported are the quantity that would be emitted from combustion or use of the products supplied.

(b) Owners and operators of facilities and suppliers that are subject to this part must follow the requirements of this subpart and all applicable subparts of this part. If a conflict exists between a provision in subpart A and any other applicable subpart, the requirements of the applicable subpart shall take precedence.

(c) For facilities required to report under onshore petroleum and natural gas production under subpart W of this part, the terms Owner and Operator used in subpart A have the same definition as Onshore petroleum and natural gas production owner or operator, as defined in §98.238 of this part.

§ 98.2 Who must report?

(a) The GHG reporting requirements and related monitoring, recordkeeping, and reporting requirements of this part apply to the owners and operators of any facility that is located in the United States or under or attached to the Outer Continental Shelf (as defined in 43 U.S.C. 1331) and that meets the requirements of either paragraph (a)(1), (a)(2), or (a)(3) of this section; and any supplier that meets the requirements of paragraph (a)(4) of this section:

(1) A facility that contains any source category that is listed in Table A–3 of this subpart in any calendar year starting in 2010. For these facilities, the annual GHG report must cover stationary fuel combustion sources (subpart C of this part), miscellaneous use of carbonates (subpart U of this part), and all applicable source categories listed in Table A–3 and Table A–4 of this subpart.

(2) A facility that contains any source category that is listed in Table A–4 of this subpart and that emits 25,000 metric tons CO₂e or more per year in combined emissions from stationary fuel combustion units, miscellaneous uses of carbonate, and all applicable source categories that are listed in Table A–3 and Table A–4 of this subpart. For these facilities, the annual GHG report must cover stationary fuel combustion sources (subpart C of this part), miscellaneous use of carbonates (subpart U of this part),
and all applicable source categories listed in Table A–3 and Table A–4 of this subpart.

(3) A facility that in any calendar year starting in 2010 meets all three of the conditions listed in this paragraph (a)(3). For these facilities, the annual GHG report must cover emissions from stationary fuel combustion sources only.
   (i) The facility does not meet the requirements of either paragraph (a)(1) or (a)(2) of this section.
   (ii) The aggregate maximum rated heat input capacity of the stationary fuel combustion units at the facility is 30 mmBtu/hr or greater.
   (iii) The facility emits 25,000 metric tons CO$_2$e or more per year in combined emissions from all stationary fuel combustion sources.

(4) A supplier that is listed in Table A–5 of this subpart. For these suppliers, the annual GHG report must cover all applicable products for which calculation methodologies are provided in the subparts listed in Table A–5 of this subpart.

(5) Research and development activities are not considered to be part of any source category defined in this part.

(b) To calculate GHG emissions for comparison to the 25,000 metric ton CO$_2$e per year emission threshold in paragraph (a)(2) of this section, the owner or operator shall calculate annual CO$_2$e emissions, as described in paragraphs (b)(1) through (b)(4) of this section.

(1) Calculate the annual emissions of CO$_2$, CH$_4$, N$_2$O, and each fluorinated GHG in metric tons from all applicable source categories listed in paragraph (a)(2) of this section. The GHG emissions shall be calculated using the calculation methodologies specified in each applicable subpart and available company records. Include emissions from only those gases listed in Table A–1 of this subpart.

(2) For each general stationary fuel combustion unit, calculate the annual CO$_2$ emissions in metric tons using any of the four calculation methodologies specified in §98.33(a). Calculate the annual CH$_4$ and N$_2$O emissions from the stationary fuel combustion sources in metric tons using the appropriate equation in §98.33(c). Exclude carbon dioxide emissions from the combustion of biomass, but include emissions of CH$_4$ and N$_2$O from biomass combustion.

(3) For miscellaneous uses of carbonate, calculate the annual CO$_2$ emissions in metric tons using the procedures specified in subpart U of this part.

(4) Sum the emissions estimates from paragraphs (b)(1), (b)(2), and (b)(3) of this section for each GHG and calculate metric tons of CO$_2$e using Equation A–1 of this section.

\[
\text{CO}_2\text{e} = \sum_{i=1}^{n} \text{GHG}_i \times \text{GWP}_i \quad \text{(Eq. A-1)}
\]

Where:
- CO$_2$e = Carbon dioxide equivalent, metric tons/year.
- GHG$_i$ = Mass emissions of each greenhouse gas listed in Table A–1 of this subpart, metric tons/year.
- GWP$_i$ = Global warming potential for each greenhouse gas from Table A–1 of this subpart.
- n = The number of greenhouse gases emitted.

(5) For purposes of determining if an emission threshold has been exceeded, include in the emissions calculation any CO$_2$ that is captured for transfer off site.

(c) To calculate GHG emissions for comparison to the 25,000 metric ton CO$_2$e/year emission threshold for stationary fuel combustion under paragraph (a)(3) of this section, calculate CO$_2$, CH$_4$, and N$_2$O emissions from each stationary fuel combustion unit by following the methods specified in paragraph (b)(2) of this section. Then, convert the emissions of each GHG to metric tons CO$_2$e per year using Equation A–1 of this section, and sum the emissions for all units at the facility.

(d) To calculate GHG quantities for comparison to the 25,000 metric ton CO$_2$ per year threshold for importers and exporters of coal-to-liquid products under paragraph (a)(4) of this section, calculate the mass in metric tons per year of CO$_2$ that would result from the complete combustion or oxidation of the quantity of coal-to-liquid products that are imported during the reporting year and, that are exported during the reporting year. Compare the imported quantities and the exported quantities separately to the 25,000 metric ton CO$_2$
per year threshold. Calculate the quantities using the methodology specified in subpart LL of this part.

(e) To calculate GHG quantities for comparison to the 25,000 metric ton CO\textsubscript{2}e per year threshold for importers and exporters of petroleum products under paragraph (a)(4) of this section, calculate the mass in metric tons per year of CO\textsubscript{2} that would result from the complete combustion or oxidation of the combined volume of petroleum products and natural gas liquids that are imported during the reporting year and that are exported during the reporting year. Compare the imported quantities and the exported quantities separately to the 25,000 metric ton CO\textsubscript{2} per year threshold. Calculate the quantities using the methodology specified in subpart MM of this part.

(f) To calculate GHG quantities for comparison to the 25,000 metric ton CO\textsubscript{2}e per year threshold under paragraph (a)(4) of this section for importers and exporters of industrial greenhouse gases and for importers and exporters of CO\textsubscript{2}, the owner or operator shall calculate the mass in metric tons per year of CO\textsubscript{2}e imports and exports as described in paragraphs (f)(1) through (f)(3) of this section. Compare the imported quantities and the exported quantities separately to the 25,000 metric ton CO\textsubscript{2} per year threshold.

(1) Calculate the mass in metric tons per year of CO\textsubscript{2}, N\textsubscript{2}O, and each fluorinated GHG that is imported and the mass in metric tons per year of CO\textsubscript{2}, N\textsubscript{2}O, and each fluorinated GHG that is exported during the year. Include only those gases listed in Table A–1 of this subpart.

(2) Convert the mass of each imported and each GHG exported from paragraph (f)(1) of this section to metric tons of CO\textsubscript{2}e using Equation A–1 of this section.

(3) Sum the total annual metric tons of CO\textsubscript{2}e in paragraph (f)(2) of this section for all imported GHGs. Sum the total annual metric tons of CO\textsubscript{2}e in paragraph (f)(2) of this section for all exported GHGs.

(g) If a capacity or generation reporting threshold in paragraph (a)(1) of this section applies, the owner or operator shall review the appropriate records and perform any necessary calculations to determine whether the threshold has been exceeded.

(h) An owner or operator of a facility or supplier that does not meet the applicability requirements of paragraph (a) of this section is not subject to this rule. Such owner or operator would become subject to the rule and reporting requirements, if a facility or supplier exceeds the applicability requirements of paragraph (a) of this section at a later time pursuant to §98.3(b)(3). Thus, the owner or operator should reevaluate the applicability to this part (including the revising of any relevant emissions calculations or other calculations) whenever there is any change that could cause a facility or supplier to meet the applicability requirements of paragraph (a) of this section. Such changes include but are not limited to process modifications, increases in operating hours, increases in production, changes in fuel or raw material use, addition of equipment, and facility expansion.

(i) Except as provided in this paragraph, once a facility or supplier is subject to the requirements of this part, the owner or operator must continue for each year thereafter to comply with all requirements of this part, including the requirement to submit annual GHG reports, even if the facility or supplier does not meet the applicability requirements in paragraph (a) of this section in a future year.

(1) If reported emissions are less than 25,000 metric tons CO\textsubscript{2}e per year for five consecutive years, then the owner or operator may discontinue complying with this part provided that the owner or operator submits a notification to the Administrator that announces the cessation of reporting and explains the reasons for the reduction in emissions. The notification shall be submitted no later than March 31 of the year immediately following the fifth consecutive year of emissions less than 25,000 tons CO\textsubscript{2}e per year. The owner or operator must maintain the corresponding records required under §98.3(g) for each of the five consecutive years and retain such records for three years following the year that reporting was discontinued. The owner or operator must resume reporting if annual emissions in any future calendar year increase to
§ 98.3 What are the general monitoring, reporting, recordkeeping and verification requirements of this part?

The owner or operator of a facility or supplier that is subject to the requirements of this part must submit GHG reports to the Administrator, as specified in this section.

(a) General. Except as provided in paragraph (d) of this section, follow the procedures for emission calculation, monitoring, quality assurance, missing data, recordkeeping, and reporting that are specified in each relevant subpart of this part.

(b) Schedule. The annual GHG report for reporting year 2010 must be submitted no later than September 30, 2011. The annual report for reporting years 2011 and beyond must be submitted no later than March 31 of each calendar year for GHG emissions in the previous calendar year, except as provided in paragraph (b)(1) of this section.

(1) For reporting year 2011, facilities with one or more of the subparts listed in paragraphs (b)(1)(i) through (b)(1)(xi) of this section and suppliers listed in paragraph (b)(1)(xii) of this section are required to submit their annual GHG report no later than September 28, 2012. Facilities and suppliers that are submitting their second annual GHG report in 2012 and that are reporting on one or more subparts listed in paragraphs (b)(1)(i) through (b)(1)(xii) of this section must notify EPA by March 31, 2012 that they are not required to submit their annual GHG report until September 28, 2012.

(i) Electronics Manufacturing (subpart I).

(ii) Fluorinated Gas Production (subpart L).

(iii) Magnesium Production (subpart T).

(iv) Petroleum and Natural Gas Systems (subpart W).

(j) Table A–2 of this subpart provides a conversion table for some of the common units of measure used in part 98.
(v) Use of Electric Transmission and Distribution Equipment (subpart DD).
(vi) Underground Coal Mines (subpart FF).
(vii) Industrial Wastewater Treatment (subpart II).
(viii) Geologic Sequestration of Carbon Dioxide (subpart RR).
(x) Industrial Waste Landfills (subpart TT).
(xi) Injection of Carbon Dioxide (subpart UU).
(xii) Imports and Exports of Equipment Pre-charged with Fluorinated GHGs or Containing Fluorinated GHGs in Closed-cell Foams (subpart QQ).

(2) For a new facility or supplier that begins operation on or after January 1, 2010 and becomes subject to the rule in the year that it becomes operational, report emissions beginning with the first operating month and ending on December 31 of that year. Each subsequent annual report must cover emissions for the calendar year, beginning on January 1 and ending on December 31.

(3) For any facility or supplier that becomes subject to this rule because of a physical or operational change that is made after January 1, 2010, report emissions for the first calendar year in which the change occurs, beginning with the first month of the change and ending on December 31 of that year. For a facility or supplier that becomes subject to this rule solely because of an increase in hours of operation or level of production, if maintained for the remainder of the year, would cause the facility or supplier to exceed the applicable threshold. Each subsequent annual report must cover emissions for the calendar year, beginning on January 1 and ending on December 31.

(4) Unless otherwise stated, if the final day of any time period falls on a weekend or a federal holiday, the time period shall be extended to the next business day.

(c) Content of the annual report. Except as provided in paragraph (d) of this section, each annual GHG report shall contain the following information:

(1) Facility name or supplier name (as appropriate), and physical street address of the facility or supplier, including the city, State, and zip code.

(2) Year and months covered by the report.

(3) Date of submittal.

(4) For facilities, except as otherwise provided in paragraph (c)(12) of this section, report annual emissions of CO₂, CH₄, N₂O, and each fluorinated GHG (as defined in §98.6) as follows.

(i) Annual emissions (excluding biogenic CO₂) aggregated for all GHGs from all applicable source categories, expressed in metric tons of CO₂e calculated using Equation A–1 of this subpart.

(ii) Annual emissions of biogenic CO₂ aggregated for all applicable source categories, expressed in metric tons.

(iii) Annual emissions from each applicable source category, expressed in metric tons of each applicable GHG listed in paragraphs (c)(4)(iii)(A) through (c)(4)(iii)(E) of this section.

(A) Biogenic CO₂.

(B) CO₂ (excluding biogenic CO₂).

(C) CH₄.

(D) N₂O.

(E) Each fluorinated GHG (including those not listed in Table A–1 of this subpart).

(iv) Except as provided in paragraph (c)(4)(vii) of this section, emissions and other data for individual units, processes, activities, and operations as specified in the “Data reporting requirements” section of each applicable subpart of this part.

(v) Indicate (yes or no) whether reported emissions include emissions from a cogeneration unit located at the facility.

(vi) When applying paragraph (c)(4)(i) of this section to fluorinated GHGs, calculate and report CO₂e for only those fluorinated GHGs listed in Table A–1 of this subpart.

(vii) The owner or operator of a facility is not required to report the data elements specified in Table A–6 to this subpart for calendar years 2010 through 2011 until March 31, 2013. The owner or operator of a facility is not required to report the data elements specified in Table A–7 to this subpart for calendar years 2010 through 2011 until March 31, 2013.
years 2010 through 2013 until March 31, 2015.

(viii) Applicable source categories means stationary fuel combustion sources (subpart C of this part), miscellaneous use of carbonates (subpart U of this part), and all of the source categories listed in Table A–3 and Table A–4 of this subpart present at the facility.

(5) For suppliers, report annual quantities of CO$_2$, CH$_4$, N$_2$O, and each fluorinated GHG (as defined in §98.6) that would be emitted from combustion or use of the products supplied, imported, and exported during the year. Calculate and report quantities at the following levels:

(i) Total quantity of GHG aggregated for all GHG from all applicable supply categories in Table A–5 of this subpart and expressed in metric tons of CO$_2$e calculated using Equation A–1 of this subpart. For fluorinated GHGs, calculate and report CO$_2$e for only those fluorinated GHGs listed in Table A–1 of this subpart.

(ii) Quantity of each GHG from each applicable supply category in Table A–5 to this subpart, expressed in metric tons of each GHG. For fluorinated GHGs, report quantities of all fluorinated GHG, including those not listed in Table A–1 to this subpart.

(iii) Any other data specified in the “Data reporting requirements” section of each applicable subpart of this part.

(6) A written explanation, as required under §98.3(e), if you change emission calculation methodologies during the reporting period.

(7) A brief description of each “best available monitoring method” used, the parameter measured using the method, and the time period during which the “best available monitoring method” was used, if applicable.

(8) Each data element for which a missing data procedure was used according to the procedures of an applicable subpart and the total number of hours in the year that a missing data procedure was used for each data element.

(9) A signed and dated certification statement provided by the designated representative of the owner or operator, according to the requirements of §98.4(e)(1).

(10) NAICS code(s) that apply to the facility or supplier.

(i) Primary NAICS code. Report the NAICS code that most accurately describes the facility or supplier’s primary product/activity/service. The primary product/activity/service is the principal source of revenue for the facility or supplier. A facility or supplier that has two distinct products/activities/services providing comparable revenue may report a second primary NAICS code.

(ii) Additional NAICS code(s). Report all additional NAICS codes that describe all product(s/activity(s)/service(s) at the facility or supplier that are not related to the principal source of revenue.

(11) Legal name(s) and physical address(es) of the highest-level United States parent company(s) of the owners (or operators) of the facility or supplier and the percentage of ownership interest for each listed parent company as of December 31 of the year for which data are being reported according to the following instructions:

(i) If the facility or supplier is entirely owned by a single United States company that is not owned by another company, provide that company’s legal name and physical address as the United States parent company and report 100 percent ownership.

(ii) If the facility or supplier is entirely owned by a single United States company that is, itself, owned by another company (e.g., it is a division or subsidiary of a higher-level company), provide the legal name and physical address of the highest-level company in the ownership hierarchy as the United States parent company and report 100 percent ownership.

(iii) If the facility or supplier is owned by more than one United States company (e.g., company A owns 40 percent, company B owns 35 percent, and company C owns 25 percent), provide the legal names and physical addresses of all the highest-level companies with an ownership interest as the United States parent companies, and report the percent ownership of each company.

(iv) If the facility or supplier is owned by a joint venture or a cooperative, the joint venture or cooperative is
its own United States parent company. Provide the legal name and physical address of the joint venture or cooperative as the United States parent company, and report 100 percent ownership by the joint venture or cooperative.

(v) If the facility or supplier is entirely owned by a foreign company, provide the legal name and physical address of the foreign company’s highest-level company based in the United States as the United States parent company, and report 100 percent ownership.

(vi) If the facility or supplier is partially owned by a foreign company and partially owned by one or more U.S. companies, provide the legal name and physical address of the foreign company’s highest-level company based in the United States, along with the legal names and physical addresses of the other U.S. parent companies, and report the percent ownership of each of these companies.

(vii) If the facility or supplier is a federally owned facility, report “U.S. Government” and do not report physical address or percent ownership.

(12) For the 2010 reporting year only, facilities that have “part 75 units” (i.e. units that are subject to subpart D of this part or units that use the methods in part 75 of this chapter to quantify CO₂ mass emissions in accordance with §98.33(a)(5)) must report annual GHG emissions either in full accordance with paragraphs (c)(4)(i) through (c)(4)(iii) of this section or in full accordance with paragraphs (c)(12)(i) through (c)(12)(iii) of this section. If the latter reporting option is chosen, you must report:

(i) Annual emissions aggregated for all GHG from all applicable source categories, expressed in metric tons of CO₂e calculated using Equation A–1 of this subpart. You must include biogenic CO₂ emissions from part 75 units in these annual emissions, but exclude biogenic CO₂ emissions from any non-part 75 units and other source categories.

(ii) Annual emissions of biogenic CO₂, expressed in metric tons (excluding biogenic CO₂ emissions from part 75 units), aggregated for all applicable source categories.

(iii) Annual emissions from each applicable source category, expressed in metric tons of each applicable GHG listed in paragraphs (c)(12)(i)(A) through (c)(12)(i)(E) of this section.

(A) Biogenic CO₂ (excluding biogenic CO₂ emissions from part 75 units).

(B) CO₂. You must include biogenic CO₂ emissions from part 75 units in these totals and exclude biogenic CO₂ emissions from other non-part 75 units and other source categories.

(C) CH₄.

(D) N₂O.

(E) Each fluorinated GHG (including those not listed in Table A–1 of this subpart).

(d) Special provisions for reporting year 2010.

(1) Best available monitoring methods. During January 1, 2010 through March 31, 2010, owners or operators may use best available monitoring methods for any parameter (e.g., fuel use, daily carbon content of feedstock by process line) that cannot reasonably be measured according to the monitoring and QA/QC requirements of a relevant subpart. The owner or operator must use the calculation methodologies and equations in the “Calculating GHG Emissions” sections of each relevant subpart, but may use the best available monitoring method for any parameter for which it is not reasonably feasible to acquire, install, and operate a required piece of monitoring equipment by January 1, 2010. Starting no later than April 1, 2010, the owner or operator must discontinue using best available methods and begin following all applicable monitoring and QA/QC requirements of this part, except as provided in paragraphs (d)(2) and (d)(3) of this section. Best available monitoring methods means any of the following methods specified in this paragraph:

(i) Monitoring methods currently used by the facility that do not meet the specifications of an relevant subpart.

(ii) Supplier data.

(iii) Engineering calculations.

(iv) Other company records.

(2) Requests for extension of the use of best available monitoring methods. The owner or operator may submit a request to the Administrator to use one
or more best available monitoring methods beyond March 31, 2010.

(i) **Timing of request.** The extension request must be submitted to EPA no later than 30 days after the effective date of the GHG reporting rule.

(ii) **Content of request.** Requests must contain the following information:

(A) A list of specific item of monitoring instrumentation for which the request is being made and the locations where each piece of monitoring instrumentation will be installed.

(B) Identification of the specific rule requirements (by rule subpart, section, and paragraph numbers) for which the instrumentation is needed.

(C) A description of the reasons why the needed equipment could not be obtained and installed before April 1, 2010.

(D) If the reason for the extension is that the equipment cannot be purchased and delivered by April 1, 2010, include supporting documentation such as the date the monitoring equipment was ordered, investigation of alternative suppliers and the dates by which alternative vendors promised delivery, backorder notices or unexpected delays, descriptions of actions taken to expedite delivery, and the current expected date of delivery.

(E) If the reason for the extension is that the equipment cannot be installed without a process unit shutdown, include supporting documentation demonstrating that it is not practicable to isolate the equipment and install the monitoring instrument without a full process unit shutdown. Include the date of the most recent process unit shutdown, the frequency of shutdowns for this process unit, and the date of the next planned shutdown during which the monitoring equipment can be installed. If there has been a shutdown or if there is a planned process unit shutdown between promulgation of this part and April 1, 2010, include a justification of why the equipment could not be obtained and installed during that shutdown.

(F) A description of the specific actions the facility will take to obtain and install the equipment as soon as reasonably feasible and the expected date by which the equipment will be installed and operating.

(iii) **Approval criteria.** To obtain approval, the owner or operator must demonstrate to the Administrator’s satisfaction that it is not reasonably feasible to acquire, install, and operate a required piece of monitoring equipment by April 1, 2010. The use of best available methods will not be approved beyond December 31, 2010.

(3) **Abbreviated emissions report for facilities containing only general stationary fuel combustion sources.** In lieu of the report required by paragraph (c) of this section, the owner or operator of an existing facility that is in operation on January 1, 2010 and that meets the conditions of §98.2(a)(3) may submit an abbreviated GHG report for the facility for GHGs emitted in 2010. The abbreviated report must be submitted by September 30, 2011. An owner or operator that submits an abbreviated report must submit a full GHG report according to the requirements of paragraph (c) of this section beginning in calendar year 2012. The abbreviated facility report must include the following information:

(i) Facility name and physical street address including the city, state and zip code.

(ii) The year and months covered by the report.

(iii) Date of submittal.

(iv) Total facility GHG emissions aggregated for all stationary fuel combustion units calculated according to any method specified in §98.33(a) and expressed in metric tons of CO₂, CH₄, N₂O, and CO₂e.

(v) Any facility operating data or process information used for the GHG emission calculations.

(vi) A signed and dated certification statement provided by the designated representative of the owner or operator, according to the requirements of paragraph (e)(1) of this section.

(e) **Emission calculations.** In preparing the GHG report, you must use the calculation methodologies specified in the relevant subparts, except as specified in paragraph (d) of this section. For each source category, you must use the same calculation methodology throughout a reporting period unless you provide a written explanation of why a change in methodology was required.
(f) Verification. To verify the completeness and accuracy of reported GHG emissions, the Administrator may review the certification statements described in paragraphs (c)(9) and (d)(3)(vi) of this section and any other credible evidence, in conjunction with a comprehensive review of the GHG reports and periodic audits of selected reporting facilities. Nothing in this section prohibits the Administrator from using additional information to verify the completeness and accuracy of the reports.

(g) Recordkeeping. An owner or operator that is required to report GHGs under this part must keep records as specified in this paragraph. Retain all required records for at least 3 years. Retain all required records for at least 3 years from the date of submission of the annual GHG report for the reporting year in which the record was generated. Upon request by the Administrator, the records required under this section must be made available to EPA. Records may be retained off site if the records are readily available for expeditious inspection and review. For records that are electronically generated or maintained, the equipment or software necessary to read the records shall be made available, or, if requested by EPA, electronic records shall be converted to paper documents. You must retain the following records, in addition to those records prescribed in each applicable subpart of this part:

1. A list of all units, operations, processes, and activities for which GHG emission were calculated.

2. The data used to calculate the GHG emissions for each unit, operation, process, and activity, categorized by fuel or material type. These data include but are not limited to the following information in this paragraph (g)(2):
   i. The GHG emissions calculations and methods used.
   ii. Analytical results for the development of site-specific emissions factors.
   iii. The results of all required analyses for high heat value, carbon content, and other required fuel or feedstock parameters.

3. The annual GHG reports.

4. Missing data computations. For each missing data event, also retain a record of the cause of the event and the corrective actions taken to restore malfunctioning monitoring equipment.

5. A written GHG Monitoring Plan.
   i. At a minimum, the GHG Monitoring Plan shall include the elements listed in this paragraph (g)(5)(i).
   A. Identification of positions of responsibility (i.e., job titles) for collection of the emissions data.
   B. Explanation of the processes and methods used to collect the necessary data for the GHG calculations.
   C. Description of the procedures and methods that are used for quality assurance, maintenance, and repair of all continuous monitoring systems, flow meters, and other instrumentation used to provide data for the GHGs reported under this part.

   ii. The GHG Monitoring Plan may rely on references to existing corporate documents (e.g., standard operating procedures, quality assurance programs under appendix F to 40 CFR part 60 or appendix B to 40 CFR part 75, and other documents) provided that the elements required by paragraph (g)(5)(i) of this section are easily recognizable.

   iii. The owner or operator shall revise the GHG Monitoring Plan as needed to reflect changes in production processes, monitoring instrumentation, and quality assurance procedures; or to improve procedures for the maintenance and repair of monitoring systems to reduce the frequency of monitoring equipment downtime.

   iv. Upon request by the Administrator, the owner or operator shall make all information that is collected in conformance with the GHG Monitoring Plan available for review during an audit. Electronic storage of the information in the plan is permissible, provided that the information can be made available in hard copy upon request during an audit.

6. The results of all required certification and quality assurance tests of continuous monitoring systems, fuel
flow meters, and other instrumentation used to provide data for the GHGs reported under this part.

(7) Maintenance records for all continuous monitoring systems, flow meters, and other instrumentation used to provide data for the GHGs reported under this part.

(h) Annual GHG report revisions. (1) The owner or operator shall submit a revised annual GHG report within 45 days of discovering that an annual GHG report that the owner or operator previously submitted contains one or more substantive errors. The revised report must correct all substantive errors.

(2) The Administrator may notify the owner or operator in writing that an annual GHG report previously submitted by the owner or operator contains one or more substantive errors. Such notification will identify each such substantive error. The owner or operator shall, within 45 days of receipt of the notification, either resubmit the report that, for each identified substantive error, corrects the identified substantive error (in accordance with the applicable requirements of this part) or provide information demonstrating that the previously submitted report does not contain the identified substantive error or that the identified error is not a substantive error.

(3) A substantive error is an error that impacts the quantity of GHG emissions reported or otherwise prevents the reported data from being validated or verified.

(4) Notwithstanding paragraphs (h)(1) and (h)(2) of this section, upon request by the owner or operator, the Administrator may provide reasonable extensions of the 45-day period for submission of the revised report or information under paragraphs (h)(1) and (h)(2) of this section. If the Administrator receives a request for extension of the 45-day period, by e-mail to an address prescribed by the Administrator, at least two business days prior to the expiration of the 45-day period, and the Administrator does not respond to the request by the end of such period, the extension request is deemed to be automatically granted for 30 more days. During the automatic 30-day extension, the Administrator will determine what extension, if any, beyond the automatic extension is reasonable and will provide any such additional extension.

(5) The owner or operator shall retain documentation for 3 years to support any revision made to an annual GHG report.

(i) Calibration accuracy requirements. The owner or operator of a facility or supplier that is subject to the requirements of this part must meet the applicable flow meter calibration and accuracy requirements of this paragraph (i). The accuracy specifications in this paragraph (i) do not apply where either the use of company records (as defined in §98.6) or the use of “best available information” is specified in an applicable subpart of this part to quantify fuel usage and/or other parameters. Further, the provisions of this paragraph (i) do not apply where either the use of company records (as defined in §98.6) or the use of “best available information” is specified in an applicable subpart of this part to quantify fuel combustion units that use the methodologies in part 75 of this chapter to calculate CO₂ mass emissions.

(1) Except as otherwise provided in paragraphs (i)(4) through (i)(6) of this section, flow meters that measure liquid and gaseous fuel feed rates, process stream flow rates, or feedstock flow rates and provide data for the GHG emissions calculations shall be calibrated prior to April 1, 2010 using the procedures specified in this paragraph (i) when such calibration is specified in a relevant subpart of this part. Each of these flow meters shall meet the applicable accuracy specification in paragraph (i)(2) or (i)(3) of this section. All other measurement devices (e.g., weighing devices) that are required by a relevant subpart of this part, and that are used to provide data for the GHG emissions calculations, shall also be calibrated prior to April 1, 2010; however, the accuracy specifications in paragraphs (i)(2) and (i)(3) of this section do not apply to these devices. Rather, each of these measurement devices shall be calibrated to meet the accuracy requirement specified for the device in the applicable subpart of this part, or, in the absence of such accuracy requirement, the device must be calibrated to an accuracy within the appropriate error range for the specific measurement technology, based on an
applicable operating standard, including but not limited to manufacturer’s specifications and industry standards. The procedures and methods used to quality-assure the data from each measurement device shall be documented in the written monitoring plan, pursuant to paragraph (g)(5)(i)(C) of this section.

(i) All flow meters and other measurement devices that are subject to the provisions of this paragraph (i) must be calibrated according to one of the following: You may use the manufacturer’s recommended procedures; an appropriate industry consensus standard method; or a method specified in a relevant subpart of this part. The calibration method(s) used shall be documented in the monitoring plan required under paragraph (g) of this section.

(ii) For facilities and suppliers that become subject to this part after April 1, 2010, all flow meters and other measurement devices (if any) that are required by the relevant subpart(s) of this part to provide data for the GHG emissions calculations shall be installed no later than the date on which data collection is required to begin using the measurement device, and the initial calibration(s) required by this paragraph (i) (if any) shall be performed no later than that date.

(iii) Except as otherwise provided in paragraphs (i)(4) through (i)(6) of this section, subsequent recalibrations of the flow meters and other measurement devices subject to the requirements of this paragraph (i) shall be performed at one of the following frequencies:

(A) You may use the frequency specified in each applicable subpart of this part.

(B) You may use the frequency recommended by the manufacturer or by an industry consensus standard practice, if no recalibration frequency is specified in an applicable subpart.

(2) Perform all flow meter calibration at measurement points that are representative of the normal operating range of the meter. Except for the orifice, nozzle, and venturi flow meters described in paragraph (i)(3) of this section, calculate the calibration error at each measurement point using Equation A–2 of this section. The terms “R” and “A” in Equation A–2 must be expressed in consistent units of measure (e.g., gallons/minute, ft³/min). The calibration error at each measurement point shall not exceed 5.0 percent of the reference value.

\[
CE = \left(\frac{|R - A|}{R}\right) \times 100
\]

where:

CE = Calibration error (%).
R = Reference value.
A = Flow meter response to the reference value.

(3) For orifice, nozzle, and venturi flow meters, the initial quality assurance consists of in-situ calibration of the differential pressure (delta-P), total pressure, and temperature transmitters.

(i) Calibrate each transmitter at a zero point and at least one upscale point. Fixed reference points, such as the freezing point of water, may be used for temperature transmitter calibrations. Calculate the calibration error of each transmitter at each measurement point, using Equation A–3 of this subpart. The terms “R,” “A,” and “FS” in Equation A–3 of this subpart must be in consistent units of measure (e.g., milliamperes, inches of water, psi, degrees). For each transmitter, the CE value at each measurement point shall not exceed 2.0 percent of full-scale. Alternatively, the results are acceptable if the sum of the calculated CE values for the three transmitters at each calibration level (i.e., at the zero level and at each upscale level) does not exceed 6.0 percent.
where:

\[ CE = \frac{|R - A|}{FS} \times 100 \]  

(Eq. A-3)

(C) You must document the methods used for the demonstration described in paragraph (i)(3)(ii)(A) of this section in the written GHG Monitoring Plan under paragraph (g)(5)(i)(C) of this section. You must also include the data from the demonstration, the mathematical correlation(s) between the remote readings and actual flow meter conditions derived from the data, and any supporting engineering calculations in the GHG Monitoring Plan. You must maintain all of this information in a format suitable for auditing and inspection.

(D) You must use the mathematical correlation(s) derived from the demonstration described in paragraph (i)(3)(ii)(A) of this section to convert the remote temperature or the total pressure readings, or both, to the actual temperature or total pressure at the flow meter, or both, on a daily basis. You shall then use the actual temperature and total pressure values to correct the measured flow rates to standard conditions.

(E) You shall periodically check the correlation(s) between the remote and actual readings (at least once a year), and make any necessary adjustments to the mathematical relationship(s).

(4) Fuel billing meters are exempted from the calibration requirements of this section and from the GHG Monitoring Plan and recordkeeping provisions of paragraphs (g)(5)(i)(C), (g)(6), and (g)(7) of this section, provided that the fuel supplier and any unit combusting the fuel do not have any common owners and are not owned by subsidiaries or affiliates of the same company. Meters used exclusively to measure the flow rates of fuels that are used for unit startup are also exempted from the calibration requirements of this section.

(5) For a flow meter that has been previously calibrated in accordance with paragraph (1)(1) of this section, an
additional calibration is not required by the date specified in paragraph (i)(1) of this section if, as of that date, the previous calibration is still active (i.e., the device is not yet due for recalibration because the time interval between successive calibrations has not elapsed). In this case, the deadline for the successive calibrations of the flow meter shall be set according to one of the following. You may use either the manufacturer’s recommended calibration schedule or you may use the industry consensus calibration schedule.

(6) For units and processes that operate continuously with infrequent outages, it may not be possible to meet the April 1, 2010 deadline for the initial calibration of a flow meter or other measurement device without disrupting normal process operation. In such cases, the owner or operator may postpone the initial calibration until the next scheduled maintenance outage. The best available information from company records may be used in the interim. The subsequent required recalibrations of the flow meters may be similarly postponed. Such postponements shall be documented in the monitoring plan that is required under paragraph (g)(5) of this section.

(7) If the results of an initial calibration or a recalibration fail to meet the required accuracy specification, data from the flow meter shall be considered invalid, beginning with the hour of the failed calibration and continuing until a successful calibration is completed. You shall follow the missing data provisions provided in the relevant missing data sections during the period of data invalidation.

(j) Measurement device installation—(1) General: If an owner or operator required to report under subpart P, subpart X or subpart Y of this part has process equipment or units that operate continuously and it is not possible to install a required flow meter or other measurement device by April 1, 2010, (or by any later date in 2010 approved by the Administrator as part of an extension of best available monitoring methods per paragraph (d) of this section) without process equipment or unit shutdown, or through a hot tap, the owner or operator may request an extension from the Administrator to delay installing the measurement device until the next scheduled process equipment or unit shutdown. If approval for such an extension is granted by the Administrator, the owner or operator must use best available monitoring methods during the extension period.

(2) Requests for extension of the use of best available monitoring methods for measurement device installation. The owner or operator must first provide the Administrator an initial notification of the intent to submit an extension request for use of best available monitoring methods beyond December 31, 2010 (or an earlier date approved by EPA) in cases where measurement device installation would require a process equipment or unit shutdown, or could only be done through a hot tap. The owner or operator must follow-up this initial notification with the complete extension request containing the information specified in paragraph (j)(4) of this section.

(3) Timing of request. (i) The initial notice of intent must be submitted no later than January 1, 2011, or by the end of the approved use of best available monitoring methods extension in 2010, whichever is earlier. The completed extension request must be submitted to the Administrator no later than February 15, 2011.

(ii) Any subsequent extensions to the original request must be submitted to the Administrator within 4 weeks of the owner or operator identifying the need to extend the request, but in any event no later than 4 weeks before the date for the planned process equipment or unit shutdown that was provided in the original request.

(4) Content of the request. Requests must contain the following information:

(i) Specific measurement device for which the request is being made and the location where each measurement device will be installed.

(ii) Identification of the specific rule requirements (by rule subpart, section, and paragraph numbers) requiring the measurement device.

(iii) A description of the reasons why the needed equipment could not be installed before April 1, 2010, or by the expiration date for the use of best
available monitoring methods, in cases where an extension has been granted under §98.3(d).

(iv) Supporting documentation showing that it is not practicable to isolate the process equipment or unit and install the measurement device without a full shutdown or a hot tap, and that there was no opportunity during 2010 to install the device. Include the date of the three most recent shutdowns for each relevant process equipment or unit, the frequency of shutdowns for each relevant process equipment or unit, and the date of the next planned process equipment or unit shutdown.

(v) Include a description of the proposed best available monitoring method for estimating GHG emissions during the time prior to installation of the meter.

(5) Approval criteria. The owner or operator must demonstrate to the Administrator’s satisfaction that it is not reasonably feasible to install the measurement device before April 1, 2010 (or by the expiration date for the use of best available monitoring methods, in cases where an extension has been granted under paragraph (d) of this section) without a process equipment or unit shutdown, or through a hot tap, and that the proposed method for estimating GHG emissions during the time before which the measurement device will be installed is appropriate. The Administrator will not initially approve the use of the proposed best available monitoring method past December 31, 2013.

(6) Measurement device installation deadline. Any owner or operator that submits both a timely initial notice of intent and a timely completed extension request under paragraph (j)(3) of this section to extend use of best available monitoring methods for measurement device installation must install all such devices by December 31, 2013, unless the extension request under this paragraph is approved by the Administrator.

(7) One time extension past December 31, 2013. If an owner or operator determines that a scheduled process equipment or unit shutdown will not occur by December 31, 2013, the owner or operator may re-apply to use best available monitoring methods for one additional time period, not to extend beyond December 31, 2015. To extend use of best available monitoring methods past December 31, 2013, the owner or operator must submit a new extension request by June 1, 2013 that contains the information required in paragraph (j)(4) of this section. The owner or operator must demonstrate to the Administrator’s satisfaction that it continues to not be reasonably feasible to install the measurement device before December 31, 2013 without a process equipment or unit shutdown, or that installation of the measurement device could only be done through a hot tap, and that the proposed method for estimating GHG emissions during the time before which the measurement device will be installed is appropriate. An owner or operator that submits a request under this paragraph to extend use of best available monitoring methods for measurement device installation must install all such devices by December 31, 2013, unless the extension request under this paragraph is approved by the Administrator.

§ 98.4 Authorization and responsibilities of the designated representative.

(a) General. Except as provided under paragraph (f) of this section, each facility, and each supplier, that is subject to this part, shall have one and only one designated representative, who shall be responsible for certifying, signing, and submitting GHG emissions reports and any other submissions for such facility and supplier respectively to the Administrator under this part. If the facility is required under any other part of title 40 of the Code of Federal Regulations to submit to the Administrator any other emission report that is subject to any requirement in 40 CFR part 75, the same individual shall be the designated representative responsible for certifying, signing, and submitting the GHG emissions reports and all such other emissions reports under this part.

(b) **Authorization of a designated representative.** The designated representative of the facility or supplier shall be an individual selected by an agreement binding on the owners and operators of such facility or supplier and shall act in accordance with the certification statement in paragraph (i)(4)(iv) of this section.

(c) **Responsibility of the designated representative.** Upon receipt by the Administrator of a complete certificate of representation under this section for a facility or supplier, the designated representative identified in such certificate of representation shall represent and, by his or her representations, actions, inactions, or submissions, legally bind each owner and operator of such facility or supplier in all matters pertaining to this part, notwithstanding any agreement between the designated representative and such owners and operators. The owners and operators shall be bound by any decision or order issued to the designated representative by the Administrator or a court.

(d) **Timing.** No GHG emissions report or other submissions under this part for a facility or supplier will be accepted until the Administrator has received a complete certificate of representation under this section for a designated representative of the facility or supplier. Such certificate of representation shall be submitted at least 60 days before the deadline for submission of the facility’s or supplier’s initial emission report under this part.

(e) **Certification of the GHG emissions report.** Each GHG emission report and any other submission under this part for a facility or supplier shall be certified, signed, and submitted by the designated representative or any alternate designated representative of the facility or supplier in accordance with this section and §3.10 of this chapter.

1. Each such submission shall include the following certification statement signed by the designated representative or any alternate designated representative: “I am authorized to make this submission on behalf of the owners and operators of the facility or supplier, as applicable, for which the submission is made. I certify under penalty of law that I have personally examined, and am familiar with, the statements and information submitted in this document and all its attachments. Based on my inquiry of those individuals with primary responsibility for obtaining the information, I certify that the statements and information are to the best of my knowledge and belief true, accurate, and complete. I am aware that there are significant penalties for submitting false statements and information or omitting required statements and information, including the possibility of fine or imprisonment.”

2. The Administrator will accept a GHG emission report or other submission for a facility or supplier under this part only if the submission is certified, signed, and submitted in accordance with this section.

(f) **Alternate designated representative.** A certificate of representation under this section for a facility or supplier may designate one alternate designated representative, who shall be an individual selected by an agreement binding on the owners and operators, and may act on behalf of the designated representative, of such facility or supplier. The agreement by which the alternate designated representative is selected shall include a procedure for authorizing the alternate designated representative to act in lieu of the designated representative.

1. Upon receipt by the Administrator of a complete certificate of representation under this section for a facility or supplier identifying an alternate designated representative, who shall be an individual selected by an agreement binding on the owners and operators, and may act on behalf of the designated representative, of such facility or supplier.

(i) The alternate designated representative may act on behalf of the designated representative for such facility or supplier.

(ii) Any representation, action, inaction, or submission by the alternate designated representative shall be deemed to be a representation, action, inaction, or submission by the designated representative.

2. Except in this section, whenever the term “designated representative” is used in this part, the term shall be construed to include the designated representative or any alternate designated representative.
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(g) Changing a designated representative or alternate designated representative. The designated representative or alternate designated representative identified in a complete certificate of representation under this section for a facility or supplier received by the Administrator may be changed at any time upon receipt by the Administrator of another later signed, complete certificate of representation under this section for the facility or supplier. Notwithstanding any such change, all representations, actions, inactions, and submissions by the previous designated representative or the previous alternate designated representative of the facility or supplier before the time and date when the Administrator receives such later signed certificate of representation shall be binding on the new designated representative and the owners and operators of the facility or supplier.

(h) Changes in owners and operators. In the event an owner or operator of the facility or supplier is not included in the list of owners and operators in the certificate of representation under this section for the facility or supplier, such owner or operator shall be deemed to be subject to and bound by the certificate of representation, the representations, actions, inactions, and submissions of the designated representative and any alternate designated representative as if the owner or operator were included in such list. Within 90 days after any change in the owners and operators of the facility or supplier (including the addition of a new owner or operator), the designated representative or any alternate designated representative shall submit a certificate of representation that is complete under this section except that such list shall be amended to include such owner or operator.

(i) Certificate of representation. A certificate of representation shall be complete if it includes the following elements in a format prescribed by the Administrator in accordance with this section:

1. Identification of the facility or supplier for which the certificate of representation is submitted.
2. The name, organization name (company affiliation-employer), address, e-mail address (if any), telephone number, and facsimile transmission number (if any) of the designated representative and any alternate designated representative.
3. A list of the owners and operators of the facility or supplier identified in paragraph (i)(1) of this section, provided that, if the list includes the operators of the facility or supplier and the owners with control of the facility or supplier, the failure to include any other owners shall not make the certificate of representation incomplete.
4. The following certification statements by the designated representative and any alternate designated representative:
   (i) “I certify that I was selected as the designated representative or alternate designated representative, as applicable, by an agreement binding on the owners and operators of the facility or supplier, as applicable.”
   (ii) “I certify that I have all the necessary authority to carry out my duties and responsibilities under 40 CFR part 98 on behalf of the owners and operators of the facility or supplier, as applicable, and that each such owner and operator shall be fully bound by my representations, actions, inactions, or submissions.”
   (iii) “I certify that the owners and operators of the facility or supplier, as applicable, shall be bound by any order issued to me by the Administrator or a court regarding the facility or supplier.”
   (iv) “If there are multiple owners and operators of the facility or supplier, as applicable, I certify that I have given a written notice of my selection as the
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"designated representative" or "alternate designated representative", as applicable, and of the agreement by which I was selected to each owner and operator of the facility or supplier.

(5) The signature of the designated representative and any alternate designated representative and the dates signed.

(j) Documents of agreement. Unless otherwise required by the Administrator, documents of agreement referred to in the certificate of representation shall not be submitted to the Administrator. The Administrator shall not be under any obligation to review or evaluate the sufficiency of such documents, if submitted.

(k) Binding nature of the certificate of representation. Once a complete certificate of representation under this section for a facility or supplier has been received, the Administrator will rely on the certificate of representation unless and until a later signed, complete certificate of representation under this section for the facility or supplier is received by the Administrator.

(l) Objections Concerning a Designated Representative

(1) Except as provided in paragraph (g) of this section, no objection or other communication submitted to the Administrator concerning the authorization, or any representation, action, inaction, or submission, of the designated representative or alternate designated representative shall affect any representation, action, inaction, or submission of the designated representative or alternate designated representative, or the finality of any decision or order by the Administrator under this part.

(2) The Administrator will not adjudicate any private legal dispute concerning the authorization or any representation, action, inaction, or submission of any designated representative or alternate designated representative.

(m) Delegation by designated representative and alternate designated representative.

(1) A designated representative or an alternate designated representative may delegate his or her own authority, to one or more individuals, to submit an electronic submission to the Administrator provided for or required under this part, except for a submission under this paragraph.

(2) In order to delegate his or her own authority, to one or more individuals, to submit an electronic submission to the Administrator in accordance with paragraph (m)(1) of this section, the designated representative or alternate designated representative must submit electronically to the Administrator a notice of delegation, in a format prescribed by the Administrator, that includes the following elements:

(i) The name, organization name (company affiliation-employer) address, e-mail address (if any), telephone number, and facsimile transmission number (if any) of each such individual (referred to as an "agent").

(ii) For each such individual, a list of the type or types of electronic submissions under paragraph (m)(1) of this section for which authority is delegated to him or her.

(iii) The name, address, e-mail address, telephone number, and facsimile transmission number (if any) of each such individual.

(iv) For each type of electronic submission listed in accordance with paragraph (m)(2)(iii) of this section, the facility or supplier for which the electronic submission may be made.

(v) The following certification statements by such designated representative or alternate designated representative:

(A) "I agree that any electronic submission to the Administrator that is by an agent identified in this notice of delegation and of a type listed, and for a facility or supplier designated, for such agent in this notice of delegation and that is made when I am a designated representative or alternate designated representative, as applicable, and before this notice of delegation is superseded by another notice of delegation under § 98.4(m)(3) shall be deemed to be an electronic submission certified, signed, and submitted by me."

(B) "Until this notice of delegation is superseded by a later signed notice of delegation under § 98.4(m)(3), I agree to
§ 98.5 How is the report submitted?

Each GHG report and certificate of representation for a facility or supplier must be submitted electronically in accordance with the requirements of § 98.4 and in a format specified by the Administrator.

§ 98.6 Definitions.

All terms used in this part shall have the same meaning given in the Clean Air Act and in this section.

Absorbent circulation pump means a pump commonly powered by natural gas pressure that circulates the absorbent liquid between the absorbent regenerator and natural gas contactor.

Accuracy of a measurement at a specified level (e.g., one percent of full scale or one percent of the value measured) means that the mean of repeat measurements made by a device or technique are within 95 percent of the range bounded by the true value plus or minus the specified level.

Acid Rain Program means the program established under title IV of the Clean Air Act, and implemented under parts 72 through 78 of this chapter for the reduction of sulfur dioxide and nitrogen oxides emissions.

Administrator means the Administrator of the United States Environmental Protection Agency or the Administrator’s authorized representative.

AGA means the American Gas Association

Agricultural by-products means those parts of arable crops that are not used for the primary purpose of producing food. Agricultural by-products include, but are not limited to, oat, corn and wheat straws, bagasse, peanut shells, rice and coconut husks, soybean hulls, palm kernel cake, cottonseed and sunflower seed cake, and pomace.

Air injected flare means a flare in which air is blown into the base of a flare stack to induce complete combustion of gas.

Alkali bypass means a duct between the feed end of the kiln and the preheater tower through which a portion of the kiln exit gas stream is withdrawn and quickly cooled by air or water to avoid excessive buildup of alkali, chloride and/or sulfur on the raw feed. This may also be referred to as the “kiln exhaust gas bypass.”

Anaerobic digester means the system where wastes are collected and anaerobically digested in large containment vessels or covered lagoons. Anaerobic digesters stabilize wastes by the microbial reduction of complex organic compounds to CO2 and CH4, which is captured and may be flared or used as fuel. Anaerobic digestion systems, include but are not limited to covered lagoon, complete mix, plug flow, and fixed film digesters. Anaerobic lagoon, with respect to subpart JJ of this part, means a type of liquid storage system component that is designed and operated to stabilize wastes using anaerobic microbial processes. Anaerobic lagoons may be designed for combined stabilization and
storage with varying lengths of retention time (up to a year or greater), depending on the climate region, volatile solids loading rate, and other operational factors.

Anode effect is a process upset condition of an aluminum electrolysis cell caused by too little alumina dissolved in the electrolyte. The anode effect begins when the voltage rises rapidly and exceeds a threshold voltage, typically 8 volts.

Anode Effect Minutes per Cell Day (24 hours) are the total minutes during which an electrolysis cell voltage is above the threshold voltage, typically 8 volts.

ANSI means the American National Standards Institute.

API means the American Petroleum Institute.

ASABE means the American Society of Agricultural and Biological Engineers.

ASME means the American Society of Mechanical Engineers.

ASTM means the American Society of Testing and Materials.

Asphalt means a dark brown-to-black cement-like material obtained by petroleum processing and containing bitumens as the predominant component. It includes crude asphalt as well as the following finished products: cements, fluxes, the asphalt content of emulsions (exclusive of water), and petroleum distillates blended with asphalt to make cutback asphalts.

Aviation Gasoline means a complex mixture of volatile hydrocarbons, with or without additives, suitably blended to be used in aviation reciprocating engines. Specifications can be found in ASTM Specification D910-07a, Standard Specification for Aviation Gasolines (incorporated by reference, see §98.7).

B₀ means the maximum CH₄ producing capacity of a waste stream, kg CH₄/kg COD.

Basic oxygen furnace means any refractory-lined vessel in which high-purity oxygen is blown under pressure through a bath of molten iron, scrap metal, and fluxes to produce steel.

bbl means barrel.

Biodiesel means a mono-alkyl ester derived from biomass and conforming to ASTM D6751-08, Standard Specification for Biodiesel Fuel Blend Stock (B100) for Middle Distillate Fuels.

Biogenic CO₂ means carbon dioxide emissions generated as the result of biomass combustion from combustion units for which emission calculations are required by an applicable part 98 subpart.

Biomass means non-fossilized and biodegradable organic material originating from plants, animals or microorganisms, including products, by-products, residues and waste from agriculture, forestry and related industries as well as the non-fossilized and biodegradable organic fractions of industrial and municipal wastes, including gases and liquids recovered from the decomposition of non-fossilized and biodegradable organic material.

Blast furnace means a furnace that is located at an integrated iron and steel plant and is used for the production of molten iron from iron ore pellets and other iron bearing materials.

Blendstocks are petroleum products used for blending or compounding into finished motor gasoline. These include RBOB (reformulated blendstock for oxygenate blending) and CBOB (conventional blendstock for oxygenate blending), but exclude oxygenates, butane, and pentanes plus.

Blendstocks—Others are products used for blending or compounding into finished motor gasoline that are not defined elsewhere. Excludes Gasoline Treated as Blendstock (GTAB), Diesel Treated as Blendstock (DTAB), conventional blendstock for oxygenate blending (CBOB), reformulated blendstock for oxygenate blending (RBOB), oxygenates (e.g. fuel ethanol and methyl tertiary butyl ether), butane, and pentanes plus.

Blowdown mean the act of emptying or depressuring a vessel. This may also refer to the discarded material such as blowdown water from a boiler or cooling tower.

Blowdown vent stack emissions mean natural gas and/or CO₂ released due to maintenance and/or blowdown operations including compressor blowdown and emergency shut-down (ESD) system testing.

British Thermal Unit or Btu means the quantity of heat required to raise the temperature of one pound of water by
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one degree Fahrenheit at about 39.2 degrees Fahrenheit.

Bulk, with respect to industrial GHG suppliers and CO2 suppliers, means the transfer of a product inside containers, including but not limited to tanks, cylinders, drums, and pressure vessels.

Bulk natural gas liquid or NGL refers to mixtures of hydrocarbons that have been separated from natural gas as liquids through the process of absorption, condensation, adsorption, or other methods. Generally, such liquids consist of ethane, propane, butanes, and pentanes plus. Bulk NGL is sold to fractionators or to refiners and petrochemical plants where the fractionation takes place.

Butane, or n-Butane, is a paraffinic straight-chain hydrocarbon with molecular formula C8H18.

Butylene, or n-Butylene, is an olefinic straight-chain hydrocarbon with molecular formula C8H16.

By-product coke oven battery means a group of ovens connected by common walls, where coal undergoes destructive distillation under positive pressure to produce coke and coke oven gas from which by-products are recovered.

Calcination means the process of thermally treating minerals to decompose carbonates from ore.

Calculation methodology means a methodology prescribed under the section “Calculating GHG Emissions” in any subpart of part 98.

Calibrated bag means a flexible, non-elastic, anti-static bag of a calibrated volume that can be affixed to an emitting source such that the emissions inflate the bag to its calibrated volume.

Carbon dioxide equivalent or CO2e means the number of metric tons of CO2 emissions with the same global warming potential as one metric ton of another greenhouse gas, and is calculated using Equation A–1 of this subpart.

Carbon dioxide production well means any hole drilled in the earth for the primary purpose of extracting carbon dioxide from a geologic formation or group of formations which contain deposits of carbon dioxide.

Carbon dioxide production well facility means one or more carbon dioxide production wells that are located on one or more contiguous or adjacent properties, which are under the control of the same entity. Carbon dioxide production wells located on different oil and gas leases, mineral fee tracts, lease tracts, subsurface or surface unit areas, surface fee tracts, surface lease tracts, or separate surface sites, whether or not connected by a road, waterway, power line, or pipeline, shall be considered part of the same CO2 production well facility if they otherwise meet the definition.

Carbon dioxide stream means carbon dioxide that has been captured from an emission source (e.g. a power plant or other industrial facility) or extracted from a carbon dioxide production well plus incidental associated substances either derived from the source materials and the capture process or extracted with the carbon dioxide.

Carbon share means the percent of total mass that carbon represents in any product.

Carbonate means compounds containing the radical CO3– 3. Upon calcination, the carbonate radical decomposes to evolve carbon dioxide (CO2). Common carbonates consumed in the mineral industry include calcium carbonate (CaCO3) or calcite; magnesium carbonate (MgCO3) or magnesite; and calcium-magnesium carbonate (CaMg(CO3)2) or dolomite.

Carbonate-based mineral means any of the following minerals used in the manufacture of glass: Calcium carbonate (CaCO3), calcium magnesium carbonate (CaMg(CO3)2), sodium carbonate (Na2CO3), barium carbonate (BaCO3), potassium carbonate (K2CO3), lithium carbonate (Li2CO3), and strontium carbonate (SrCO3).

Carbonate-based mineral mass fraction means the following: For limestone, the mass fraction of calcium carbonate (CaCO3) in the limestone; for dolomite, the mass fraction of calcium magnesium carbonate (CaMg(CO3)2) in the dolomite; for soda ash, the mass fraction of sodium carbonate (Na2CO3) in the soda ash; for barium carbonate, the mass fraction of barium carbonate (BaCO3) in the barium carbonate; for potassium carbonate, the mass fraction of potassium carbonate (K2CO3) in the potassium carbonate; for lithium carbonate, the mass fraction of lithium carbonate (Li2CO3); and for strontium...
carbonate, the mass fraction of strontium carbonate (SrCO$_3$).

**Carbonate-based raw material** means any of the following materials used in the manufacture of glass: Limestone, dolomite, soda ash, barium carbonate, potassium carbonate, lithium carbonate, and strontium carbonate.

**Catalytic cracking unit** means a refinery process unit in which petroleum derivatives are continuously charged and hydrocarbon molecules in the presence of a catalyst are fractured into smaller molecules, or react with a contact material suspended in a fluidized bed to improve feedstock quality for additional processing and the catalyst or contact material is continuously regenerated by burning off coke and other deposits. Catalytic cracking units include both fluidized bed systems, which are referred to as fluid catalytic cracking units (FCCU), and moving bed systems, which are also referred to as thermal catalytic cracking units. The unit includes the riser, regenerator, air blowers, spent catalyst or contact material stripper, catalyst or contact material recovery equipment, and regenerator equipment for controlling air pollutant emissions and for heat recovery.

**CBOB-Summer** (conventional blendstock for oxygenate blending) means a petroleum product which, when blended with a specified type and percentage of oxygenate, meets the definition of Conventional-Summer.

**CBOB-Winter** (conventional blendstock for oxygenate blending) means a petroleum product which, when blended with a specified type and percentage of oxygenate, meets the definition of Conventional-Winter.

**Cement kiln dust** means non-calcined to fully calcined dust produced in the kiln or pyroprocessing line. Cement kiln dust is a fine-grained, solid, highly alkaline material removed from the cement kiln exhaust gas by scrubbers (filtration baghouses and/or electrostatic precipitators).

**Centrifugal compressor** means any equipment that increases the pressure of a process natural gas or CO$_2$ by centrifugal action, employing rotating movement of the driven shaft.

**Centrifugal compressor dry seal emissions** mean natural gas or CO$_2$ released from a dry seal vent pipe and/or the seal face around the rotating shaft where it exits one or both ends of the compressor case.

**Centrifugal compressor dry seals** mean a series of rings around the compressor shaft where it exits the compressor case that operates mechanically under the opposing forces to prevent natural gas or CO$_2$ from escaping to the atmosphere.

**Centrifugal compressor wet seal degassing vent emissions** means emissions that occur when the high-pressure oil barriers for centrifugal compressors are depressurized to release absorbed natural gas or CO$_2$. High-pressure oil is used as a barrier against escaping gas in centrifugal compressor shafts. Very little gas escapes through the oil barrier, but under high pressure, considerably more gas is absorbed by the oil. The seal oil is purged of the absorbed gas (using heaters, flash tanks, and degassing techniques) and recirculated. The separated gas is commonly vented to the atmosphere.

**Certified standards** means calibration gases certified by the manufacturer of the calibration gases to be accurate to within 2 percent of the value on the label or calibration gases.

**CH$_4$** means methane.

**Chemical recovery combustion unit** means a combustion device, such as a recovery furnace or fluidized-bed reactor where spent pulping liquor from sulfite or semi-chemical pulping processes is burned to recover pulping chemicals.

**Chemical recovery furnace** means an enclosed combustion device where concentrated spent liquor produced by the kraft or soda pulping process is burned to recover pulping chemicals and produce steam. Includes any recovery furnace that burns spent pulping liquor produced from both the kraft and soda pulping processes.

**Chloride process** means a production process where titanium dioxide is produced using calcined petroleum coke and chlorine as raw materials.

**City gate** means a location at which natural gas ownership or control passes from one party to another, neither of which is the ultimate consumer. In this rule, in keeping with common practice, the term refers to a point or measuring point.
station at which a local gas distribution utility receives gas from a natural gas pipeline company or transmission system. Meters at the city gate station measure the flow of natural gas into the local distribution company system and typically are used to measure local distribution company system sendout to customers.

$CO_2$ means carbon dioxide.

Coal means all solid fuels classified as anthracite, bituminous, sub-bituminous, or lignite by the American Society for Testing and Materials Designation ASTM D388–05 Standard Classification of Coals by Rank (incorporated by reference, see §98.7).

COD means the chemical oxygen demand as determined using methods specified pursuant to 40 CFR part 136.

Cogeneration unit means a unit that produces electrical energy and useful thermal energy for industrial, commercial, or heating or cooling purposes, through the sequential or simultaneous use of the original fuel energy.

Coke burn-off means the coke removed from the surface of a catalyst by combustion during catalyst regeneration. Coke burn-off also means the coke combusted in fluid coking unit burner.

Cokemaking means the production of coke from coal in either a by-product coke oven battery or a non-recovery coke oven battery.

Commercial applications means executing a commercial transaction subject to a contract. A commercial application includes transferring custody of a product from one facility to another if it otherwise meets the definition.

Company records means, in reference to the amount of fuel consumed by a stationary combustion unit (or by a group of such units), a complete record of the methods used, the measurements made, and the calculations performed to quantify fuel usage. Company records may include, but are not limited to, direct measurements of fuel consumption by gravimetric or volumetric means, tank drop measurements, and calculated values of fuel usage obtained by measuring auxiliary parameters such as steam generation or unit operating hours. Fuel billing records obtained from the fuel supplier qualify as company records.

Connector means to flanged, screwed, or other joined fittings used to connect pipe line segments, tubing, pipe components (such as elbows, reducers, “T’s” or valves) or a pipe line and a piece of equipment or an instrument to a pipe, tube or piece of equipment. A common connector is a flange. Joined fittings welded completely around the circumference of the interface are not considered connectors for the purpose of this part.

Container glass means glass made of soda-lime recipe, clear or colored, which is pressed and/or blown into bottles, jars, ampoules, and other products listed in North American Industry Classification System 327213 (NAICS 327213).

Continuous bleed means a continuous flow of pneumatic supply natural gas to the process control device (e.g., level control, temperature control, pressure control) where the supply gas pressure is modulated by the process condition, and then flows to the valve controller where the signal is compared with the process set-point to adjust gas pressure in the valve actuator.

Continuous emission monitoring system or CEMS means the total equipment required to sample, analyze, measure, and provide, by means of readings recorded at least once every 15 minutes, a permanent record of gas concentrations, pollutant emission rates, or gas volumetric flow rates from stationary sources.

Continuous glass melting furnace means a glass melting furnace that operates continuously except during periods of maintenance, malfunction, control device installation, reconstruction, or rebuilding.

Conventional-Summer refers to finished gasoline formulated for use in motor vehicles, the composition and properties of which do not meet the requirements of the reformulated gasoline regulations promulgated by the U.S. Environmental Protection Agency under 40 CFR 80.40, but which meet summer RVP standards required under 40 CFR 80.27 or as specified by the state. NOTE: This category excludes conventional gasoline for oxygenate blending (CBOB) as well as other blendstock.
Conventional-Winter refers to finished gasoline formulated for use in motor vehicles, the composition and properties of which do not meet the requirements of the reformulated gasoline regulations promulgated by the U.S. Environmental Protection Agency under 40 CFR 80.40 or the summer RVP standards required under 40 CFR 80.27 or as specified by the state. NOTE: This category excludes conventional blendstock for oxygenate blending (CBOB) as well as other blendstock.

Crude oil means a mixture of hydrocarbons that exists in liquid phase in natural underground reservoirs and remains liquid at atmospheric pressure after passing through surface separating facilities. (1) Depending upon the characteristics of the crude stream, it may also include any of the following:

(i) Small amounts of hydrocarbons that exist in gaseous phase in natural underground reservoirs but are liquid at atmospheric conditions (temperature and pressure) after being recovered from oil well (casing-head) gas in lease separators and are subsequently commingled with the crude stream without being separately measured. Lease condensate recovered as a liquid from natural gas wells in lease or field separation facilities and later mixed into the crude stream is also included.

(ii) Small amounts of non-hydrocarbons, such as sulfur and various metals.

(iii) Drip gases, and liquid hydrocarbons produced from tar sands, oil sands, gilsonite, and oil shale.

(iv) Petroleum products that are received or produced at a refinery and subsequently injected into a crude supply or reservoir by the same refinery owner or operator.

(2) Liquids produced at natural gas processing plants are excluded. Crude oil is refined to produce a wide array of petroleum products, including heating oils; gasoline, diesel and jet fuels; lubricants; asphalt; ethane, propane, and butane; and many other products used for their energy or chemical content.

Daily spread means a manure management system component in which manure is routinely removed from a confinement facility and is applied to cropland or pasture within 24 hours of excretion.

Day means any consistently designated 24 hour period during which an emission unit is operated.

Decarburization vessel means any vessel used to further refine molten steel with the primary intent of reducing the carbon content of the steel, including but not limited to vessels used for argon-oxygen decarburization and vacuum oxygen decarburization.

Deep bedding systems for cattle swine means a manure management system in which, as manure accumulates, bedding is continually added to absorb moisture over a production cycle and possibly for as long as 6 to 12 months. This manure management system also is known as a bedded pack manure management system and may be combined with a dry lot or pasture.

Degasification system means the entirety of the equipment that is used to drain gas from underground and collect it at a common point, such as a vacuum pumping station. This includes all degasification wells and gob gas vent holes at the underground coal mine. Degasification systems include surface pre-mining, horizontal pre-mining, and post-mining systems.

Degradable organic carbon (DOC) means the fraction of the total mass of a waste material that can be biologically degraded.

Dehydrator means a device in which a liquid absorbent (including desiccant, ethylene glycol, diethylene glycol, or triethylene glycol) directly contacts a natural gas stream to absorb water vapor.

Dehydrator vent emissions means natural gas and CO2 released from a natural gas dehydrator system absorbent (typically glycol) reboiler or regenerator to the atmosphere or a flare, including stripping natural gas and motive natural gas used in absorbent circulation pumps.

Delayed coking unit means one or more refinery process units in which high molecular weight petroleum derivatives are thermally cracked and petroleum coke is produced in a series of closed, batch system reactors. A delayed coking unit consists of the coke drums and ancillary equipment associated with a single fractionator.
De-methanizer means the natural gas processing unit that separates methane rich residue gas from the heavier hydrocarbons (e.g., ethane, propane, butane, pentane-plus) in feed natural gas stream.

Density means the mass contained in a given unit volume (mass/volume).

Desiccant means a material used in solid-bed dehydrators to remove water from raw natural gas by adsorption or absorption. Desiccants include activated alumina, pelleted calcium chloride, lithium chloride and granular silica gel material. Wet natural gas is passed through a bed of the granular or pelleted solid adsorbent or absorbent in these dehydrators. As the wet gas contacts the surface of the particles of desiccant material, water is adsorbed on the surface or absorbed into the desiccant material, leaving the dry gas to exit the contactor.

Destruction means:
(1) With respect to landfills and manure management, the combustion of methane in any on-site or off-site combustion technology. Destroyed methane includes, but is not limited to, methane combusted by flaring, methane destroyed by thermal oxidation, methane combusted for use in on-site energy or heat production technologies, methane that is conveyed through pipelines (including natural gas pipelines) for off-site combustion, and methane that is collected for any other on-site or off-site use as a fuel.
(2) With respect to fluorinated GHGs, the expiration of a fluorinated GHG to the destruction efficiency actually achieved. Such destruction does not result in a commercially useful end product.

Destruction device, for the purposes of subparts II and TT of this part, means a flare, thermal oxidizer, boiler, turbine, internal combustion engine, or any other combustion unit used to destroy or oxidize methane contained in landfill gas or wastewater biogas.

Destruction efficiency means the efficiency with which a destruction device reduces the mass of a greenhouse gas fed into the device. Destruction efficiency, or flaring destruction efficiency, refers to the fraction of the gas that leaves the flare partially or fully oxidized. The destruction efficiency is expressed in Equation A-2 of this section:

\[
DE = 1 - \frac{tGHG_{OUT}}{tGHG_{IN}} \quad (\text{Eq. A-2}),
\]

where:
- \(DE\) = Destruction Efficiency
- \(tGHG_{IN}\) = The mass of GHG i fed into the destruction device
- \(tGHG_{OUT}\) = The mass of GHG i exhausted from the destruction device

Diesel—Other is any distillate fuel oil not defined elsewhere, including Diesel Treated as Blendstock (DTAB).

DIPE (diisopropyl ether, \((\text{CH}_3)_2\text{CHOCH(CH}_3)_2\)) is an ether as described in “Oxygenates.”

Direct liquefaction means the conversion of coal directly into liquids, rather than passing through an intermediate gaseous state.

Direct reduction furnace means a high temperature furnace typically fired with natural gas to produce solid iron from iron ore or iron ore pellets and coke, coal, or other carbonaceous materials.

Distillate fuel oil means a classification for one of the petroleum fractions produced in conventional distillation operations and from crackers and hydrotreating process units. The generic term distillate fuel oil includes kerosene, kerosene-type jet fuel, diesel fuels (Diesel Fuels No. 1, No. 2, and No. 4), and fuel oils (Fuel Oils No. 1, No. 2, and No. 4).

Distillate Fuel No. 1 has a maximum distillation temperature of 550 °F at the 90 percent recovery point and a
minimum flash point of 100 °F and includes fuels commonly known as Diesel Fuel No. 1 and Fuel Oil No. 1, but excludes kerosene. This fuel is further subdivided into categories of sulfur content: High Sulfur (greater than 500 ppm), Low Sulfur (less than or equal to 500 ppm and greater than 15 ppm), and Ultra Low Sulfur (less than or equal to 15 ppm).

Distillate Fuel No. 2 has a minimum and maximum distillation temperature of 540 °F and 640 °F at the 90 percent recovery point, respectively, and includes fuels commonly known as Diesel Fuel No. 2 and Fuel Oil No. 2. This fuel is further subdivided into categories of sulfur content: High Sulfur (greater than 500 ppm), Low Sulfur (less than or equal to 500 ppm and greater than 15 ppm), and Ultra Low Sulfur (less than or equal to 15 ppm).

Distillate Fuel No. 4 is a distillate fuel oil made by blending distillate fuel oil and residual fuel oil, with a minimum flash point of 131 °F.

DOC means the fraction of DOC that actually decomposes under the (presumably anaerobic) conditions within the landfill.

Dry lot means a manure management system component consisting of a paved or unpaved open confinement area without any significant vegetative cover where accumulating manure may be removed periodically.

Electric arc furnace (EAF) means a furnace that produces molten alloy metal and heats the charge materials with electric arcs from carbon electrodes.

Electric arc furnace steelmaking means the production of carbon, alloy, or specialty steels using an EAF. This definition excludes EAFs at steel foundries and EAFs used to produce nonferrous metals.

Electrothermic furnace means a furnace that heats the charged materials with electric arcs from carbon electrodes.

Emergency generator means a stationary combustion device, such as a reciprocating internal combustion engine or turbine that serves solely as a secondary source of mechanical or electrical power whenever the primary energy supply is disrupted or discontinued during power outages or natural disasters that are beyond the control of the owner or operator of a facility. An emergency generator operates only during emergency situations, for training of personnel under simulated emergency conditions, as part of emergency demand response procedures, or for standard performance testing procedures as required by law or by the generator manufacturer. A generator that serves as a back-up power source under conditions of load shedding, peak shaving, power interruptions pursuant to an interruptible power service agreement, or scheduled facility maintenance shall not be considered an emergency generator.

Emergency equipment means any auxiliary fossil fuel-powered equipment, such as a fire pump, that is used only in emergency situations.

ETBE (ethyl tertiary butyl ether, \((\text{CH}_3)_3\text{COC}_2\text{H})\) is an ether as described in “Oxygenates.”

Ethane is a paraffinic hydrocarbon with molecular formula \(\text{C}_2\text{H}_6\).

Ethanol is an anhydrous alcohol with molecular formula \(\text{C}_2\text{H}_5\text{OH}\).

Ethylene is an olefinic hydrocarbon with molecular formula \(\text{C}_2\text{H}_4\).

Ex refinery gate means the point at which a petroleum product leaves the refinery.

Experimental furnace means a glass melting furnace with the sole purpose of operating to evaluate glass melting processes, technologies, or glass products. An experimental furnace does not produce glass that is sold (except for further research and development purposes) or that is used as a raw material for non-experimental furnaces.

Export means to transport a product from inside the United States to persons outside the United States, excluding any such transport on behalf of the United States military including foreign military sales under the Arms Export Control Act.

Exporter means any person, company or organization of record that transfers for sale or for other benefit, domestic products from the United States to another country or to an affiliate in another country, excluding any such transfers on behalf of the United States military or military purposes including foreign military sales under the Arms Export Control Act. An exporter is not
the entity merely transporting the domestic products, rather an exporter is the entity deriving the principal benefit from the transaction.

**Facility** means any physical property, plant, building, structure, source, or stationary equipment located on one or more contiguous or adjacent properties in actual physical contact or separated solely by a public roadway or other public right-of-way and under common ownership or common control, that emits or may emit any greenhouse gas. Operators of military installations may classify such installations as more than a single facility based on distinct and independent functional groupings within contiguous military properties.

**Feed** means the prepared and mixed materials, which include but are not limited to materials such as limestone, clay, shale, sand, iron ore, mill scale, cement kiln dust and flyash, that are fed to the kiln. Feed does not include the fuels used in the kiln to produce heat to form the clinker product.

**Feedstock** means raw material inputs to a process that are transformed by reaction, oxidation, or other chemical or physical methods into products and by-products. Supplemental fuel burned to provide heat or thermal energy is not a feedstock.

**Fischer-Tropsch process** means a catalyzed chemical reaction in which synthesis gas, a mixture of carbon monoxide and hydrogen, is converted into liquid hydrocarbons of various forms.

**Flare** means a combustion device, whether at ground level or elevated, that uses an open flame to burn combustible gases with combustion air provided by uncontrolled ambient air around the flame.

**Flat glass** means glass made of soda-lime recipe and produced into continuous flat sheets and other products listed in NAICS 327211.

**Flowmeter** means a device that measures the mass or volumetric rate of flow of a gas, liquid, or solid moving through an open or closed conduit (e.g., flowmeters include, but are not limited to, rotameters, turbine meters, coriolis meters, orifice meters, ultra-sonic flowmeters, and vortex flowmeters).

**Fluid coking unit** means one or more refinery process units in which high molecular weight petroleum derivatives are thermally cracked and petroleum coke is continuously produced in a fluidized bed system. The fluid coking unit includes equipment for controlling air pollutant emissions and for heat recovery on the fluid coking burner exhaust vent. There are two basic types of fluid coking units: A traditional fluid coking unit in which only a small portion of the coke produced in the unit is burned to fuel the unit and the fluid coking burner exhaust vent is directed to the atmosphere (after processing in a CO boiler or other air pollutant control equipment) and a flexicoking unit in which an auxiliary burner is used to partially combust a significant portion of the produced petroleum coke to generate a low value fuel gas that is used as fuel in other combustion sources at the refinery.

**Fluorinated greenhouse gas** means sulfur hexafluoride ($\text{SF}_6$), nitrogen trifluoride ($\text{NF}_3$), and any fluorocarbon except for controlled substances as defined at 40 CFR part 82, subpart A, and substances with vapor pressures of less than 1 mm of Hg absolute at 25 degrees C. With these exceptions, “fluorinated GHG” includes but is not limited to any hydrofluorocarbon, any perfluorocarbon, any fully fluorinated linear, branched or cyclic alkane, ether, tertiary amine or aminoether, any perfluoropolyether, and any hydrofluoropolyether.

**Fossil fuel** means natural gas, petroleum, coal, or any form of solid, liquid, or gaseous fuel derived from such material, for purpose of creating useful heat.

**Fractionators** means plants that produce fractionated natural gas liquids (NGLs) extracted from produced natural gas and separate the NGLs individual component products: ethane, propane, butanes and pentane-plus (C5+). Plants that only process natural gas but do not fractionate NGLs further into component products are not considered fractionators. Some fractionators do not process production gas, but instead fractionate bulk NGLs received from natural gas processors. Some fractionators both process natural gas and fractionate bulk NGLs received from other plants.

**Fuel** means solid, liquid or gaseous combustible material.
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Fuel gas means gas generated at a petroleum refinery or petrochemical plant and that is combusted separately or in any combination with any type of gas.

Fuel gas system means a system of compressors, piping, knock-out pots, mix drums, and, if necessary, units used to remove sulfur contaminants from the fuel gas (e.g., amine scrubbers) that collects fuel gas from one or more sources for treatment, as necessary, and transport to a stationary combustion unit. A fuel gas system may have an overpressure vent to a flare but the primary purpose for a fuel gas system is to provide fuel to the various combustion units at the refinery or petrochemical plant.

Furnace slag means a by-product formed in metal melting furnaces when slagging agents, reducing agents, and/or fluxes (e.g., coke ash, limestone, silicates) are added to remove impurities from the molten metal.

Gas collection system or landfill gas collection system means a system of pipes used to collect landfill gas from different locations in the landfill by means of a fan or similar mechanical draft equipment to a single location for treatment (thermal destruction) or use. Landfill gas collection systems may also include knock-out or separator drums and/or a compressor. A single landfill may have multiple gas collection systems. Landfill gas collection systems do not include "passive" systems, whereby landfill gas flows naturally to the surface of the landfill where an opening or pipe (vent) is installed to allow for natural gas flow.

Gas conditions mean the actual temperature, volume, and pressure of a gas sample.

Gas-fired unit means a stationary combustion unit that derives more than 50 percent of its annual heat input from the combustion of gaseous fuels, and the remainder of its annual heat input from the combustion of fuel oil or other liquid fuels.

Gas monitor means an instrument that continuously measures the concentration of a particular gaseous species in the effluent of a stationary source.

Gas to oil ratio (GOR) means the ratio of the volume of gas at standard temperature and pressure that is produced from a volume of oil when depressurized to standard temperature and pressure.

Gaseous fuel means a material that is in the gaseous state at standard atmospheric temperature and pressure conditions and that is combusted to produce heat and/or energy.

Gasification means the conversion of a solid or liquid raw material into a gas.

Gasoline—Other is any gasoline that is not defined elsewhere, including GTAB (gasoline treated as blendstock).

Glass melting furnace means a unit comprising a refractory-lined vessel in which raw materials are charged and melted at high temperature to produce molten glass.

Glass produced means the weight of glass exiting a glass melting furnace.

Global warming potential or GWP means the ratio of the time-integrated radiative forcing from the instantaneous release of one kilogram of a trace substance relative to that of one kilogram of a reference gas, i.e., CO\(_2\).

GPA means the Gas Processors Association.

Greenhouse gas or GHG means carbon dioxide (CO\(_2\)), methane (CH\(_4\)), nitrous oxide (N\(_2\)O), sulfur hexafluoride (SF\(_6\)), hydrofluorocarbons (HFCs), perfluorocarbons (PFCs), and other fluorinated greenhouse gases as defined in this section.

GTBA (gasoline-grade tertiary butyl alcohol, (CH\(_3\)\(_3\)COH), or t-butanol, is an alcohol as described in "Oxygenates."

Heavy Gas Oils are petroleum distillates with an approximate boiling range from 651 °F to 1,000 °F.

Heel means the amount of gas that remains in a shipping container after it is discharged or off-loaded (that is no more than ten percent of the volume of the container).

High-bleed pneumatic devices are automated, continuous bleed flow control devices powered by pressurized natural gas and used for maintaining a process condition such as liquid level, pressure, delta-pressure and temperature. Part of the gas power stream that is regulated by the process condition flows to a valve actuator controller where it
vents continuously (bleeds) to the atmosphere at a rate in excess of 6 standard cubic feet per hour.  

*High heat value or HHV* means the high or gross heat content of the fuel with the heat of vaporization included. The water is assumed to be in a liquid state.  

*Hydrofluorocarbons or HFCs* means a class of GHGs consisting of hydrogen, fluorine, and carbon.  

*Import* means, to land on, bring into, or introduce into, any place subject to the jurisdiction of the United States whether or not such landing, bringing, or introduction constitutes an importation within the meaning of the customs laws of the United States, with the following exemptions:  

1. Off-loading used or excess fluorinated GHGs or nitrous oxide of U.S. origin from a ship during servicing.  

2. Bringing fluorinated GHGs or nitrous oxide into the U.S. from Mexico where the fluorinated GHGs or nitrous oxide had been admitted into Mexico in bond and were of U.S. origin.  

3. Bringing fluorinated GHGs or nitrous oxide into the U.S. when transported in a consignment of personal or household effects or in a similar non-commercial situation normally exempted from U.S. Customs attention.  

4. Bringing fluorinated GHGs or nitrous oxide into U.S. jurisdiction exclusively for U.S. military purposes.  

*Importer* means any person, company, or organization of record that for any reason brings a product into the United States from a foreign country, excluding introduction into U.S. jurisdiction exclusively for United States military purposes. An importer is the person, company, or organization primarily liable for the payment of any duties on the merchandise or an authorized agent acting on their behalf. The term includes, as appropriate:  

1. The consignee.  
2. The importer of record.  
3. The actual owner.  
4. The transferee, if the right to draw merchandise in a bonded warehouse has been transferred.  

*Indurating furnace* means a furnace where unfired taconite pellets, called green balls, are hardened at high temperatures to produce fired pellets for use in a blast furnace. Types of indurating furnaces include straight gate and grate kiln furnaces.  

*Industrial greenhouse gases* means nitrous oxide or any fluorinated greenhouse gas.  

*In-line kiln/raw mill* means a system in a portland cement production process where a dry kiln system is integrated with the raw mill so that all or a portion of the kiln exhaust gases are used to perform the drying operation of the raw mill, with no auxiliary heat source used. In this system the kiln is capable of operating without the raw mill operating, but the raw mill cannot operate without the kiln gases, and consequently, the raw mill does not generate a separate exhaust gas stream.  

*Intermittent bleed pneumatic devices* mean automated flow control devices powered by pressurized natural gas and used for automatically maintaining a process condition such as liquid level, pressure, delta-pressure, and temperature. These are snap-acting or throttling devices that discharge all or a portion of the full volume of the actuator intermittently when control action is necessary, but do not bleed continuously.  

*Isobutane* is a paraffinic branch chain hydrocarbon with molecular formula C₄H₁₀.  

*Isobutylene* is an olefinic branch chain hydrocarbon with molecular formula C₄H₈.  

*Kerosene* is a light petroleum distillate with a maximum distillation temperature of 400 °F at the 10-percent recovery point, a final maximum boiling point of 572 °F, a minimum flash point of −22 °F, and a maximum freezing point of −22 °F. Included are No. 1-K and No. 2-K, distinguished by maximum sulfur content (0.04 and 0.30 percent of total mass, respectively), as well as all other grades of kerosene called range or stove oil. Excluded is kerosene-type jet fuel (see definition herein).  

*Kerosene-type jet fuel* means a kerosene-based product used in commercial and military turbojet and turbo-prop aircraft. The product has a maximum distillation temperature of 400 °F at the 10 percent recovery point and a final maximum boiling point of 572
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Kiln means an oven, furnace, or heated enclosure used for thermally processing a mineral or mineral-based substance.

Landfill means an area of land or an excavation in which wastes are placed for permanent disposal and that is not a land application unit, surface impoundment, injection well, or waste pile as those terms are defined under 40 CFR 257.2.

Landfill gas means gas produced as a result of anaerobic decomposition of waste materials in the landfill. Landfill gas generally contains 40 to 60 percent methane on a dry basis, typically less than 1 percent non-methane organic chemicals, and the remainder being carbon dioxide.

Liberated means released from coal and surrounding rock strata during the mining process. This includes both methane emitted from the ventilation system and methane drained from degasification systems.

Lime is the generic term for a variety of chemical compounds that are produced by the calcination of limestone or dolomite. These products include but are not limited to calcium oxide, high-calcium quicklime, calcium hydroxide, hydrated lime, dolomitic quicklime, and dolomitic hydrate.

Liquid/Slurry means a manure management component in which manure is stored as excreted or with some minimal addition of water to facilitate handling and is stored in either tanks or earthen ponds, usually for periods less than one year.

Low-bleed pneumatic devices mean automated flow control devices powered by pressurized natural gas and used for maintaining a process condition such as liquid level, pressure, delta-pressure and temperature. Part of the gas power stream that is regulated by the process condition flows to a valve actuator controller where it vents continuously (bleeds) to the atmosphere at a rate equal to or less than six standard cubic feet per hour.

Lubricants include all grades of lubricating oils, from spindle oil to cylinder oil to those used in greases. Petroleum lubricants may be produced from distillates or residues.

Makeup chemicals means carbonate chemicals (e.g., sodium and calcium carbonates) that are added to the chemical recovery areas of chemical pulp mills to replace chemicals lost in the process.

Manure composting means the biological oxidation of a solid waste including manure usually with bedding or another organic carbon source typically at thermophilic temperatures produced by microbial heat production. There are four types of composting employed for manure management: Static, in vessel, intensive windrow and passive windrow. Static composting typically occurs in an enclosed channel, with forced aeration and continuous mixing. In vessel composting occurs in piles with forced aeration but no mixing. Intensive windrow composting occurs in windrows with regular turning for mixing and aeration. Passive windrow composting occurs in windrows with infrequent turning for mixing and aeration.

Maximum rated heat input capacity means the hourly heat input to a unit (in mmBtu/hr), when it combusted the maximum amount of fuel per hour that it is capable of combusting on a steady state basis, as of the initial installation of the unit, as specified by the manufacturer.

Maximum rated input capacity means the maximum charging rate of a municipal waste combustor unit expressed in tons per day of municipal solid waste combusted, calculated according to the procedures under 40 CFR 60.58b(j).

Mcf means thousand cubic feet.

Methane conversion factor means the extent to which the CH₄ producing capacity (Bₒ) is realized in each type of treatment and discharge pathway and system. Thus, it is an indication of the degree to which the system is anaerobic.

Methane correction factor means an adjustment factor applied to the methane generation rate to account for portions of the landfill that remain aerobic. The methane correction factor can be considered the fraction of the total landfill waste volume that is ultimately disposed of in an anaerobic state. Managed landfills that have soil
or other cover materials have a methane correction factor of 1.

Methanol (CH\textsubscript{3}OH) is an alcohol as described in “Oxygenates.”

Midgrade gasoline has an octane rating greater than or equal to 88 and less than or equal to 90. This definition applies to the midgrade categories of Conventional-Summer, Conventional-Winter, Reformulated-Summer, and Reformulated-Winter. For midgrade categories of RBOB-Summer, RBOB-Winter, CBOB-Summer, and CBOB-Winter, this definition refers to the expected octane rating of the finished gasoline after oxygenate has been added to the RBOB or CBOB.

Miscellaneous products include all refined petroleum products not defined elsewhere. It includes, but is not limited to, naphtha-type jet fuel (Jet B and JP-4), petroleum lube refining by-products (aromatic extracts and tars), absorption oils, ram-jet fuel, petroleum rocket fuels, synthetic natural gas feedstocks, waste feedstocks, and specialty oils. It excludes organic waste sludges, tank bottoms, spent catalysts, and sulfuric acid.

MMBtu means million British thermal units.

Motor gasoline (finished) means a complex mixture of volatile hydrocarbons, with or without additives, suitably blended to be used in spark ignition engines. Motor gasoline includes conventional gasoline, reformulated gasoline, and all types of oxygenated gasoline. Gasoline also has seasonal variations in an effort to control ozone levels. This is achieved by lowering the Reid Vapor Pressure (RVP) of gasoline during the summer driving season. Depending on the region of the country the RVP is lowered to below 9.0 psi or 7.8 psi. The RVP may be further lowered by state regulations.

Mscf means thousand standard cubic feet.

MTBE (methyl tertiary butyl ether, (CH\textsubscript{3})\textsubscript{3}COCH\textsubscript{3}) is an ether as described in “Oxygenates.”

Municipal solid waste landfill or MSW landfill means an entire disposal facility in a contiguous geographical space where household waste is placed in or on land. An MSW landfill may also receive other types of RCRA Subtitle D wastes (40 CFR 257.2) such as commercial solid waste, nonhazardous sludge, conditionally exempt small quantity generator waste, and industrial solid waste. Portions of an MSW landfill may be separated by access roads, public roadways, or other public right-of-ways. An MSW landfill may be publicly or privately owned.

Municipal solid waste or MSW means solid phase household, commercial/retail, and/or institutional waste. Household waste includes material discarded by single and multiple residential dwellings, hotels, motels, and other similar permanent or temporary housing establishments or facilities. Commercial/retail waste includes material discarded by stores, offices, restaurants, warehouses, non-manufacturing activities at industrial facilities, and other similar establishments or facilities. Institutional waste includes material discarded by schools, nonmedical waste discarded by hospitals, material discarded by non-manufacturing activities at prisons and government facilities, and material discarded by other similar establishments or facilities. Household, commercial/retail, and institutional wastes include yard waste, refuse-derived fuel, and motor vehicle maintenance materials. Insofar as there is separate collection, processing and disposal of industrial source waste streams consisting of used oil, wood pallets, construction, renovation, and demolition wastes (which includes, but is not limited to, railroad ties and telephone poles), paper, clean wood, plastics, industrial process or manufacturing wastes, medical waste, motor vehicle parts or vehicle fluff, or used tires that do not contain hazardous waste identified or listed under 42 U.S.C. §6921, such wastes are not municipal solid waste. However, such wastes qualify as municipal solid waste where they are collected with other municipal solid waste or are otherwise combined with other municipal solid waste for processing and/or disposal.

Municipal wastewater treatment plant means a series of treatment processes used to remove contaminants and pollutants from domestic, business, and industrial wastewater collected in city sewers and transported to a centralized wastewater treatment system such as a
publicly owned treatment works (POTW).

\( \text{N}_2\text{O} \) means nitrous oxide.

*Naphthas \(< 401^\circ\text{F}\)* is a generic term applied to a petroleum fraction with an approximate boiling range between 122 \(^\circ\text{F}\) and 400 \(^\circ\text{F}\). The naphtha fraction of crude oil is the raw material for gasoline and is composed largely of paraffinic hydrocarbons.

*Natural gas* means a naturally occurring mixture of hydrocarbon and non-hydrocarbon gases found in geologic formations beneath the earth’s surface, of which the principal constituent is methane. Natural gas may be field quality or pipeline quality.

*Natural gas driven pneumatic pump* means a pump that uses pressurized natural gas to move a piston or diaphragm, which pumps liquids on the opposite side of the piston or diaphragm.

*Natural gas liquids (NGLs)* means those hydrocarbons in natural gas that are separated from the gas as liquids through the process of absorption, condensation, adsorption, or other methods. Generally, such liquids consist of ethane, propane, butanes, and pentanes plus. Bulk NGLs refers to mixtures of NGLs that are sold or delivered as undifferentiated product from natural gas processing plants.

*Natural gasoline* means a mixture of liquid hydrocarbons (mostly pentanes and heavier hydrocarbons) extracted from natural gas. It includes isopentane.

*NIST* means the United States National Institute of Standards and Technology.

*Nitric acid production line* means a series of reactors and absorbers used to produce nitric acid.

*Nitrogen excreted* is the nitrogen that is excreted by livestock in manure and urine.

*Non-crude feedstocks* means any petroleum product or natural gas liquid that enters the refinery to be further refined or otherwise used on site.

*Non-recovery coke oven battery* means a group of ovens connected by common walls and operated as a unit, where coal undergoes destructive distillation under negative pressure to produce coke, and which is designed for the combustion of the coke oven gas from which by-products are not recovered.


*Oil-fired unit* means a stationary combustion unit that derives more than 50 percent of its annual heat input from the combustion of fuel oil, and the remainder of its annual heat input from the combustion of natural gas or other gaseous fuels.

*Open-ended valve or lines (OELs)* means any valve, except pressure relief valves, having one side of the valve seat in contact with process fluid and one side open to atmosphere, either directly or through open piping.

*Operating hours* means the duration of time in which a process or process unit is utilized; this excludes shutdown, maintenance, and standby.

*Operational change* means, for purposes of §98.3(b), a change in the type of feedstock or fuel used, a change in operating hours, or a change in process production rate.

*Operator* means any person who operates or supervises a facility or supplier.

*Other oils \(> 401^\circ\text{F}\)* are oils with a boiling range equal to or greater than 401 \(^\circ\text{F}\) that are generally intended for use as a petrochemical feedstock and are not defined elsewhere.

*Outer Continental Shelf* means all submerged lands lying seaward and outside of the area of lands beneath navigable waters as defined in 43 U.S.C. 1331, and of which the subsoil and seabed appertain to the United States and are subject to its jurisdiction and control.

*Owner* means any person who has legal or equitable title to, has a leasehold interest in, or control of a facility or supplier, except a person whose legal or equitable title to or leasehold interest in the facility or supplier arises solely because the person is a limited
partner in a partnership that has legal or equitable title to, has a leasehold interest in, or control of the facility or supplier shall not be considered an "owner" of the facility or supplier.

Oxygenates means substances which, when added to gasoline, increase the oxygen content of the gasoline. Common oxygenates are ethanol, methyl tertiary butyl ether (MTBE), ethyl tertiary butyl ether (ETBE), tertiary amyl methyl ether (TAME), diisopropyl ether (DICE), and methanol.

Pasture/Range/Paddock means the manure from pasture and range grazing animals is allowed to lie as deposited, and is not managed.

Pentanes plus, or C₅+, is a mixture of hydrocarbons that is a liquid at ambient temperature and pressure, and consists mostly of pentanes (five carbon chain) and higher carbon number hydrocarbons. Pentanes plus includes, but is not limited to, normal pentane, isopentane, hexanes-plus (natural gasoline), and plant condensate.

Perfluorocarbons or PFCs means a class of greenhouse gases consisting on the molecular level of carbon and fluorine.

Petrochemical means methanol, acrylonitrile, ethylene, ethylene oxide, ethylene dichloride, and any form of carbon black.

Petrochemical feedstocks means feedstocks derived from petroleum for the manufacture of chemicals, synthetic rubber, and a variety of plastics. This category is usually divided into naphthas less than 401 °F and other oils greater than 401 °F.

Petroleum means oil removed from the earth and the oil derived from tar sands and shale.

Petroleum coke means a black solid residue, obtained mainly by cracking and carbonizing of petroleum derived feedstocks, vacuum bottoms, tar and pitches in processes such as delayed coking or fluid coking. It consists mainly of carbon (90 to 95 percent), has low ash content, and may be used as a feedstock in coke ovens. This product is also known as marketable coke or catalyst coke.

Petroleum product means all refined and semi-refined products that are produced at a refinery by processing crude oil and other petroleum-based feedstocks, including petroleum products derived from co-processing biomass and petroleum feedstock together, but not including plastics or plastic products. Petroleum products may be combusted for energy use, or they may be used either for non-energy processes or as non-energy products. The definition of petroleum product for importers and exporters excludes waxes.

Physical address, with respect to a United States parent company as defined in this section, means the street address, city, state and zip code of that company’s physical location.

Pit storage below animal confinement (deep pits) means the collection and storage of manure typically below a slatted floor in an enclosed animal confinement facility. This usually occurs with little or no added water for periods less than one year.

Portable means designed and capable of being carried or moved from one location to another. Indications of portability include but are not limited to wheels, skids, carrying handles, dolly, trailer, or platform. Equipment is not portable if any one of the following conditions exists:

1. The equipment is attached to a foundation.
2. The equipment or a replacement resides at the same location for more than 12 consecutive months.
3. The equipment is located at a seasonal facility and operates during the full annual operating period of the seasonal facility, remains at the facility for at least two years, and operates at that facility for at least three months each year.
4. The equipment is moved from one location to another in an attempt to circumvent the portable residence time requirements of this definition.

Poultry manure with litter means a manure management system component that is similar to cattle and swine deep bedding except usually not combined with a dry lot or pasture. The system is typically used for poultry breeder flocks and for the production of meat type chickens (broiler) and other fowl.
Poultry manure without litter means a manure management system component that may manage manure in a liquid form, similar to open pits in enclosed animal confinement facilities. These systems may alternatively be designed and operated to dry manure as it accumulates. The latter is known as a high-rise manure management system and is a form of passive windrow manure composting when designed and operated properly.

Precision of a measurement at a specified level (e.g., one percent of full scale or one percent of the value measured) means that 95 percent of repeat measurements made by a device or technique are within the range bounded by the mean of the measurements plus or minus the specified level.

Premium grade gasoline is gasoline having an antiknock index, i.e., octane rating, greater than 90. This definition applies to the premium grade categories of Conventional-Summer, Conventional-Winter, Reformulated-Summer, and Reformulated-Winter. For premium grade categories of RBOB-Summer, RBOB-Winter, CBOB-Summer, and CBOB-Winter, this definition refers to the expected octane rating of the finished gasoline after oxygenate has been added to the RBOB or CBOB.

Pressed and blown glass means glass which is pressed, blown, or both, into products such as light bulbs, glass fiber, technical glass, and other products listed in NAICS 327212.

Process vent means a gas stream that is discharged through a conveyance to the atmosphere either directly or after passing through a control device; originates from a unit operation, including but not limited to reactors (including reformers, crackers, and furnaces, and separation equipment for products and recovered byproducts); and contains or has the potential to contain GHG that is generated in the process. Process vent does not include safety device discharges, equipment leaks, gas streams routed to a fuel gas system or to a flare, discharges from storage tanks.

Propane is a paraffinic hydrocarbon with molecular formula C_3H_8.

Propylene is an olefinic hydrocarbon with molecular formula C_3H_6.

Pulp mill lime kiln means the combustion units (e.g., rotary lime kiln or fluidized bed calciner) used at a kraft or soda pulp mill to calcine lime mud, which consists primarily of calcium carbonate, into quicklime, which is calcium oxide.

Pushing means the process of removing the coke from the coke oven at the end of the coking cycle. Pushing begins when coke first begins to fall from the oven into the quench car and ends when the quench car enters the quench tower.

Raw mill means a ball and tube mill, vertical roller mill or other size reduction equipment, that is not part of an in-line kiln/raw mill, used to grind feed to the appropriate size. Moisture may be added or removed from the feed during the grinding operation. If the raw...
mill is used to remove moisture from feed materials, it is also, by definition, a raw material dryer. The raw mill also includes the air separator associated with the raw mill.

RBOB-Summer (reformulated blendstock for oxygenate blending) means a petroleum product which, when blended with a specified type and percentage of oxygenate, meets the definition of Reformulated-Summer.

RBOB-Winter (reformulated blendstock for oxygenate blending) means a petroleum product which, when blended with a specified type and percentage of oxygenate, meets the definition of Reformulated-Winter.

Reciprocating compressor means a piece of equipment that increases the pressure of a process natural gas or CO$_2$ by positive displacement, employing linear movement of a shaft driving a piston in a cylinder.

Reciprocating compressor rod packing means a series of flexible rings in machined metal cups that fit around the reciprocating compressor piston rod to create a seal limiting the amount of compressed natural gas or CO$_2$ that escapes to the atmosphere.

Re-condenser means heat exchangers that cool compressed boil-off gas to a temperature that will condense natural gas to a liquid.

Reformulated-Summer refers to finished gasoline formulated for use in motor vehicles, the composition and properties of which meet the requirements of the reformulated gasoline regulations promulgated by the U.S. Environmental Protection Agency under 40 CFR 80.40 and 40 CFR 80.41, and summer RVP standards required under 40 CFR 80.27 or as specified by the state. Reformulated gasoline excludes Reformulated Blendstock for Oxygenate Blending (RBOB) as well as other blendstock.

Reformulated-Winter refers to finished gasoline formulated for use in motor vehicles, the composition and properties of which meet the requirements of the reformulated gasoline regulations promulgated by the U.S. Environmental Protection Agency under 40 CFR 80.40 and 40 CFR 80.41, but which do not meet summer RVP standards required under 40 CFR 80.27 or as specified by the state. NOTE: This category includes Oxygenated Fuels Program Reformulated Gasoline (OPFRG). Reformulated gasoline excludes Reformulated Blendstock for Oxygenate Blending (RBOB) as well as other blendstock.

Regular grade gasoline is gasoline having an anti-knock index, i.e., octane rating, greater than or equal to 85 and less than 88. This definition applies to the regular grade categories of Conventional-Summer, Conventional-Winter, Reformulated-Summer, and Reformulated-Winter. For regular grade categories of RBOB-Summer, RBOB-Winter, CBOB-Summer, and CBOB-Winter, this definition refers to the expected octane rating of the finished gasoline after oxygenate has been added to the RBOB or CBOB.

Rendered animal fat, or tallow, means fats extracted from animals which are generally extracted from animals which are generally used as a feedstock in making biodiesel.

Research and development means those activities conducted in process units or at laboratory bench-scale settings whose purpose is to conduct research and development for new processes, technologies, or products and whose purpose is not for the manufacture of products for commercial sale, except in a de minimis manner.

Residual Fuel Oil No. 5 (Navy Special) is a classification for the heavier fuel oil generally used in steam powered vessels in government service and inshore power plants. It has a minimum flash point of 131°F.

Residual Fuel Oil No. 6 (a.k.a. Bunker C) is a classification for the heavier fuel oil generally used for the production of electric power, space heating, vessel bunkering and various industrial purposes. It has a minimum flash point of 140°F.

Residuum is residue from crude oil after distilling off all but the heaviest components, with a boiling range greater than 1,000°F. Road oil is any heavy petroleum oil, including residual asphaltic oil used as a dust palliative and surface treatment on roads and highways. It is generally produced in six grades, from 0, the most liquid, to 5, the most viscous.

Rotary lime kiln means a unit with an inclined rotating drum that is used to produce a lime product from limestone by calcination.
Safety device means a closure device such as a pressure relief valve, frangible disc, fusible plug, or any other type of device which functions exclusively to prevent physical damage or permanent deformation to a unit or its air emission control equipment by venting gases or vapors directly to the atmosphere during unsafe conditions resulting from an unplanned, accidental, or emergency event. A safety device is not used for routine venting of gases or vapors from the vapor headspace underneath a cover such as during filling of the unit or to adjust the pressure in response to normal daily diurnal ambient temperature fluctuations. A safety device is designed to remain in a closed position during normal operations and open only when the internal pressure, or another relevant parameter, exceeds the device threshold setting applicable to the air emission control equipment as determined by the owner or operator based on manufacturer recommendations, applicable regulations, fire protection and prevention codes and practices, or other requirements for the safe handling of flammable, combustible, explosive, reactive, or hazardous materials.

Sales oil means produced crude oil or condensate measured at the production lease automatic custody transfer (LACT) meter or custody transfer tank gauge.

Semi-refined petroleum product means all oils requiring further processing. Included in this category are unfinished oils which are produced by the partial refining of crude oil and include the following: Naphthas and lighter oils; kerosene and light gas oils; heavy gas oils; and residuum, and all products that require further processing or the addition of blendstocks.

Sendout means, in the context of a local distribution company, the total deliveries of natural gas to customers over a specified time interval (typically hour, day, month, or year). Sendout is the sum of gas received through the city gate, gas withdrawn from on-system storage or peak shaving plants, and gas produced and delivered into the distribution system; and is net of any natural gas injected into on-system storage. It comprises gas sales, exchange, deliveries, gas used by company, and unaccounted for gas. Sendout is measured at the city gate station, and other on-system receipt points from storage, peak shaving, and production.

Sensor means a device that measures a physical quantity/quality or the change in a physical quantity/quality, such as temperature, pressure, flow rate, pH, or liquid level.

SF<sub>6</sub> means sulfur hexafluoride.

Shutdown means the cessation of operation of an emission source for any purpose.

Silicon carbide means an artificial abrasive produced from silica sand or quartz and petroleum coke.

Sinter process means a process that produces a fused aggregate of fine iron-bearing materials suited for use in a blast furnace. The sinter machine is composed of a continuous traveling grate that conveys a bed of ore fines and other finely divided iron-bearing material and fuel (typically coke breeze), a burner at the feed end of the grate for ignition, and a series of downdraft windboxes along the length of the strand to support downdraft combustion and heat sufficient to produce a fused sinter product.

Site means any combination of one or more graded pad sites, gravel pad sites, foundations, platforms, or the immediate physical location upon which equipment is physically located.

Smelting furnace means a furnace in which lead-bearing materials, carbon-containing reducing agents, and fluxes are melted together to form a molten mass of material containing lead and slag.

Solid by-products means plant matter such as vegetable waste, animal materials, and other solid biomass, except for wood, wood waste, and sulphite lyes (black liquor).

Solid storage is the storage of manure, typically for a period of several months, in unconfined piles or stacks. Manure is able to be stacked due to the presence of a sufficient amount of bedding material or loss of moisture by evaporation.

Sour gas means any gas that contains significant concentrations of hydrogen...
sulfide. Sour gas may include untreated fuel gas, amine stripper off-gas, or sour water stripper gas.

Sour natural gas means natural gas that contains significant concentrations of hydrogen sulfide (H$_2$S) and/or carbon dioxide (CO$_2$) that exceed the concentrations specified for commercially saleable natural gas delivered from transmission and distribution pipelines.

Special naphthas means all finished products with the naphtha boiling range (290 °F to 470 °F) that are generally used as paint thinners, cleaners or solvents. These products are refined to a specified flash point. Special naphthas include all commercial hexane and cleaning solvents conforming to ASTM Specification D1896-07, Standard Specification for Commercial Hexanes, and D235-02 (Reapproved 2007), Standard Specification for Mineral Spirits (Petroleum Spirits) (Hydrocarbon Dry Cleaning Solvent), respectively. Naphthas to be blended or marketed as motor gasoline or aviation gasoline, or that are to be used as petrochemical and synthetic natural gas (SNG) feedstocks are excluded.

Spent liquor solids means the dry weight of the solids in the spent pulping liquor that enters the chemical recovery furnace or chemical recovery combustion unit.

Spent pulping liquor means the residual liquid collected from on-site pulping operations at chemical pulp facilities that is subsequently fired in chemical recovery furnaces at kraft and soda pulp facilities or chemical recovery combustion units at sulfite or semi-chemical pulp facilities.

Standard conditions or standard temperature and pressure (STP), for the purposes of this part, means either 60 or 68 degrees Fahrenheit and 14.7 pounds per square inch absolute.

Steam reforming means a catalytic process that involves a reaction between natural gas or other light hydrocarbons and steam. The result is a mixture of hydrogen, carbon monoxide, carbon dioxide, and water.

Still gas means any form or mixture of gases produced in refineries by distillation, cracking, reforming, and other processes. The principal constituents are methane, ethane, ethylene, normal butane, butylene, propane, and propylene.

Storage tank means a vessel (excluding sumps) that is designed to contain an accumulation of crude oil, condensate, intermediate hydrocarbon liquids, or produced water and that is constructed entirely of non-earthen materials (e.g., wood, concrete, steel, plastic) that provide structural support.

Sulfur recovery plant means all process units which recover sulfur or produce sulfuric acid from hydrogen sulfide (H$_2$S) and/or sulfur dioxide (SO$_2$) from a common source of sour gas at a petroleum refinery. The sulfur recovery plant also includes sulfur pits used to store the recovered sulfur product, but it does not include secondary sulfur storage vessels or loading facilities downstream of the sulfur pits. For example, a Claus sulfur recovery plant includes: Reactor furnace and waste heat boiler, catalytic reactors, sulfur pits, and, if present, oxidation or reduction control systems, or incinerator, thermal oxidizer, or similar combustion device. Multiple sulfur recovery units are a single sulfur recovery plant only when the units share the same source of sour gas. Sulfur recovery units that receive source gas from completely segregated sour gas treatment systems are separate sulfur recovery plants.

Supplemental fuel means a fuel burned within a petrochemical process that is not produced within the process itself.

Supplier means a producer, importer, or exporter in any supply category included in Table A–5 to this subpart, as defined by the corresponding subpart of this part.

Sweet gas is natural gas with low concentrations of hydrogen sulfide (H$_2$S) and/or carbon dioxide (CO$_2$) that does not require (or has already had) acid gas treatment to meet pipeline corrosion-prevention specifications for transmission and distribution.

Taconite iron ore processing means an industrial process that separates and concentrates iron ore from taconite, a low grade iron ore, and heats the taconite in an indurating furnace to produce taconite pellets that are used as the primary feed material for the production of iron in blast furnaces at integrated iron and steel plants.
TAME means tertiary amyl methyl ether, \((\text{CH}_3)_2\text{(C}_2\text{H}_5)\text{COCH}_3\).

Trace concentrations means concentrations of less than 0.1 percent by mass of the process stream.

Transform means to use and entirely consume (except for trace concentrations) nitrous oxide or fluorinated GHGs in the manufacturing of other chemicals for commercial purposes. Transformation does not include burning of nitrous oxide.

Transshipment means the continuous shipment of nitrous oxide or a fluorinated GHG from a foreign state of origin through the United States or its territories to a second foreign state of final destination, as long as the shipment does not enter into United States jurisdiction. A transshipment, as it moves through the United States or its territories, cannot be re-packaged, sorted or otherwise changed in condition.

Trona means the raw material (mineral) used to manufacture soda ash; hydrated sodium bicarbonate carbonate (e.g., \(\text{Na}_2\text{CO}_3\cdot\text{NaHCO}_3\cdot2\text{H}_2\text{O}\)).

Ultimate analysis means the determination of the percentages of carbon, hydrogen, nitrogen, sulfur, and chlorine and (by difference) oxygen in the gaseous products and ash after the complete combustion of a sample of an organic material.

Unfinished oils are all oils requiring further processing, except those requiring only mechanical blending.

United States means the 50 States, the District of Columbia, the Commonwealth of Puerto Rico, American Samoa, the Virgin Islands, Guam, and any other Commonwealth, territory or possession of the United States, as well as the territorial sea as defined by Presidential Proclamation No. 5928.

United States parent company(s) means the highest-level United States company(s) with an ownership interest in the facility or supplier as of December 31 of the year for which data are being reported.

Unstabilized crude oil means, for the purposes of this part, crude oil that is pumped from the well to a pipeline or pressurized storage vessel for transport to the refinery without intermediate storage in a storage tank at atmospheric pressures. Unstabilized crude oil is characterized by having a true vapor pressure of 5 pounds per square inch absolute (psia) or greater.

Used oil means a petroleum-derived or synthetically-derived oil whose physical properties have changed as a result of handling or use, such that the oil cannot be used for its original purpose. Used oil consists primarily of automotive oils (e.g., used motor oil, transmission oil, hydraulic fluids, brake fluid, etc.) and industrial oils (e.g., industrial engine oils, metalworking oils, process oils, industrial grease, etc).

Valve means any device for halting or regulating the flow of a liquid or gas through a passage, pipeline, inlet, outlet, or orifice; including, but not limited to, gate, globe, plug, ball, butterfly and needle valves.

Vapor recovery system means any equipment located at the source of potential gas emissions to the atmosphere or to a flare, that is composed of piping, connections, and, if necessary, flow-inducing devices, and that is used for routing the gas back into the process as a product and/or fuel.

Vaporization unit means a process unit that performs controlled heat input to vaporize LNG to supply transmission and distribution pipelines or consumers with natural gas.

Vegetable oil means oils extracted from vegetation that are generally used as a feedstock in making biodiesel.

Ventilation well or shaft means a well or shaft employed at an underground coal mine to serve as the outlet or conduit to move air from the ventilation system out of the mine.

Ventilation system means a system that is used to control the concentration of methane and other gases within mine working areas through mine ventilation, rather than a mine degasification system. A ventilation system consists of fans that move air through the mine workings to dilute methane concentrations. This includes all ventilation shafts and wells at the underground coal mine.

Volatile solids are the organic material in livestock manure and consist of both biodegradable and non-biodegradable fractions.
Waelz kiln means an inclined rotary kiln in which zinc-containing materials are charged together with a carbon reducing agent (e.g., petroleum coke, metallurgical coke, or anthracite coal).

Waxes means a solid or semi-solid material at 77 °F consisting of a mixture of hydrocarbons obtained or derived from petroleum fractions, or through a Fischer-Tropsch type process, in which the straight chained paraffin series predominates. This includes all marketable wax, whether crude or refined, with a congealing point between 80 (or 85) and 240 °F and a maximum oil content of 50 weight percent.

Well completions means the process that allows for the flow of petroleum or natural gas from newly drilled wells to expel drilling and reservoir fluids and test the reservoir flow characteristics, steps which may vent produced gas to the atmosphere via an open pit or tank. Well completion also involves connecting the wellbore to the reservoir, which may include treating the formation or installing tubing, packers, or lifting equipment, steps that do not significantly vent natural gas to the atmosphere. This process may also include high-rate flowback of injected gas, water, oil, and proppant used to fracture or re-fracture and prop open new fractures in existing lower permeability gas reservoirs, steps that may vent large quantities of produced gas to the atmosphere.

Well workover means the process(es) of performing one or more of a variety of remedial operations on producing petroleum and natural gas wells to try to increase production. This process also includes high-rate flowback of injected gas, water, oil, and proppant used to re-fracture and prop-open new fractures in existing low permeability gas reservoirs, steps that may vent large quantities of produced gas to the atmosphere.

Wellhead means the piping, casing, tubing and connected valves protruding above the earth’s surface for an oil and/or natural gas well. The wellhead ends where the flow line connects to a wellhead valve. Wellhead equipment includes all equipment, permanent and portable, located on the improved land area (i.e. well pad) surrounding one or multiple wellheads.

Wet natural gas means natural gas in which water vapor exceeds the concentration specified for commercially saleable natural gas delivered from transmission and distribution pipelines. This input stream to a natural gas dehydrator is referred to as “wet gas.”

Wood residuals means materials recovered from three principal sources: Municipal solid waste (MSW); construction and demolition debris; and primary timber processing. Wood residuals recovered from MSW include wooden furniture, cabinets, pallets and containers, scrap lumber (from sources other than construction and demolition activities), and urban tree and landscape residues. Wood residuals from construction and demolition debris originate from the construction, repair, remodeling and demolition of houses and non-residential structures. Wood residuals from primary timber processing include bark, sawmill slabs and edgings, sawdust, and peeler log cores. Other sources of wood residuals include, but are not limited to, railroad ties, telephone and utility poles, pier and dock timbers, wastewater process sludge from paper mills, trim, sander dust, and sawdust from wood products manufacturing (including resinated wood product residuals), and logging residues.

Wood fiberglass means fibrous glass of random texture, including fiberglass insulation, and other products listed in NAICS 327993.

Working capacity, for the purposes of subpart TT of this part, means the maximum volume or mass of waste that is actually placed in the landfill from an individual or representative type of container (such as a tank, truck, or roll-off bin) used to convey wastes to the landfill, taking into account that the container may not be able to be 100 percent filled and/or 100 percent emptied for each load.

You means an owner or operator subject to Part 98.

Zinc smelters means a facility engaged in the production of zinc metal, zinc oxide, or zinc alloy products from zinc sulfide ore concentrates, zinc calcine,
or zinc-bearing scrap and recycled materials through the use of pyrometallurgical techniques involving the reduction and volatization of zinc-bearing feed materials charged to a furnace.

§ 98.7 What standardized methods are incorporated by reference into this part?

The materials listed in this section are incorporated by reference in the corresponding sections noted. These incorporations by reference were approved by the Director 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 the materials will be published in the Federal Register. The materials are available for purchase at the corresponding address in this section. The materials are available for inspection at the EPA Docket Center, Public Reading Room, EPA West Building, Room 3334, 1301 Constitution Avenue, NW., Washington, DC, phone (202) 566–1744 and at the National Archives and Records Administration (NARA). For information on the availability of this material at NARA, call 202–741–6030, or go to: http://www.archives.gov/federal_register/code_of_federal_regulations/ibr_locations.html.

(a) [Reserved]

(b) [Reserved]

The following material is available for purchase from the ASM International, 9639 Kinsman Road, Materials Park, OH 44073, (440) 338–5151, http://www.asminternational.org.

(1) ASM CS–104 UNS No. G10460—Alloy Digest April 1985 (Carbon Steel of Medium Carbon Content), incorporation by reference (IBR) approved for §98.174(b).

(2) [Reserved]

(d) The following material is available for purchase from the American Society of Mechanical Engineers (ASME), Three Park Avenue, New York, NY 10016–5990, (800) 843–2763, http://www.asme.org.

(1) ASME MFC–3M–2004 Measurement of Fluid Flow in Pipes Using Orifice, Nozzle, and Venturi, incorporation by reference (IBR) approved for §98.124(m)(1), §98.324(e), §98.354(d), §98.354(h), §98.344(c) and §98.364(e).

(2) ASME MFC–4M–1996 (Reaffirmed 1997) Measurement of Gas Flow by Turbine Meters, IBR approved for §98.124(m)(2), §98.324(e), §98.344(c), §98.354(h), and §98.364(e).

(b) [Reserved]

(c) The following material is available for purchase from the American Society for Testing and Material (ASTM), 100 Barr Harbor Drive, P.O. Box CB700, West Conshohocken, Pennsylvania 19428–2399, (800) 262–1373, http://www.astm.org.


(4) ASME MFC–6M–1998 Measurement of Fluid Flow in Pipes Using Vortex Flowmeters, IBR approved for §98.124(m)(4), §98.324(e), §98.344(c), §98.354(h), and §98.364(e).


(7) ASME MFC–11M–2007 Measurement of Fluid Flow by Means of Coriolis Mass Flowmeters, IBR approved for §98.124(m)(7), §98.324(e), §98.344(c), and §98.354(h).

(8) ASME MFC–14M–2003 Measurement of Fluid Flow Using Small Bore Precision Orifice Meters, IBR approved for §98.124(m)(8), §98.324(e), §98.344(c), §98.354(h), and §98.364(e).


(10) ASME MFC–18M–2001 Measurement of Fluid Flow Using Variable Area Meters, IBR approved for §98.324(e), §98.344(c), §98.354(h), and §98.364(e).

(e) The following material is available for purchase from the American Society for Testing and Material (ASTM), 100 Barr Harbor Drive, P.O. Box CB700, West Conshohocken, Pennsylvania 19428–2399, (800) 262–1373, http://www.astm.org.
(1) ASTM C25–06 Standard Test Method for Chemical Analysis of Limestone, Quicklime, and Hydrated Lime, incorporation by reference (IBR) approved for §98.114(b), §98.174(b), §98.184(b), §98.194(c), and §98.334(b).

(2) ASTM C114–99 Standard Test Methods for Chemical Analysis of Hydraulic Cement, IBR approved for §98.84(a), §98.84(b), and §98.84(c).


(5) ASTM D388–05 Standard Classification of Coals by Rank, IBR approved for §98.6.


(7) [Reserved]


(10) ASTM D1945–03 Standard Test Method for Analysis of Natural Gas by Gas Chromatography, IBR approved for §98.74(c), §98.164(b), §98.244(b), §98.284(d), §98.324(d), §98.324(i), and §98.354(g).

(11) ASTM D1946–90 (Reapproved 2006) Standard Practice for Analysis of Reformed Gas by Gas Chromatography, IBR approved for §98.74(c), §98.164(b), §98.244(b), §98.254(d), §98.324(d), §98.324(i), and §98.354(g).

(12) ASTM D2013–07 Standard Practice for Preparing Coal Samples for Analysis, IBR approved for §98.164(b).


(14) ASTM D2245 Standard Test Method for Estimation of Mean Relative Molecular Mass of Petroleum Oils from Viscosity Measurements, IBR approved for §98.74(c).

(15) ASTM D2503–92 (Reapproved 2007) Standard Test Method for Relative Molecular Mass (Molecular Weight) of Hydrocarbons by Thermoelectric Measurement of Vapor Pressure, IBR approved for §98.74(c) and §98.254(d)(6).


(18) ASTM D3176–89 (Reapproved 2002) Standard Practice for Ultimate Analysis of Coal and Coke, IBR approved for §98.74(c), §98.164(b), §98.244(b), §98.284(d), §98.324(d), §98.314(c), §98.314(d), and §98.314(f).

(19) ASTM D3238–95 (Reapproved 2005) Standard Test Method for Calculation of Carbon Distribution and Structural Group Analysis of Petroleum Oils by the n-d-M Method, IBR approved for §98.74(c) and §98.164(b).


(26) ASTM D5291–02 (Reapproved 2007) Standard Test Methods for Instrumental Determination of Carbon, Hydrogen, and Nitrogen in Petroleum Products and Lubricants, IBR approved for § 98.74(c), § 98.164(b), § 98.244(b), and § 98.254(d).

(27) ASTM D5373–08 Standard Test Methods for Instrumental Determination of Carbon, Hydrogen, and Nitrogen in Laboratory Samples of Coal, IBR approved for § 98.74(c), § 98.164(b), § 98.244(b), § 98.254(d), § 98.274(b), § 98.284(c), § 98.284(d), § 98.314(c), § 98.314(d), § 98.314(f), and § 98.334(b).

(28) [Reserved]


(30) ASTM D6348–03 Standard Test Method for Determination of Gaseous Compounds by Extractive Direct Interface Fourier Transform Infrared (FTIR) Spectroscopy, IBR approved for § 98.54(b), § 98.124(e)(2), § 98.224(b), and § 98.414(n).

(31) ASTM D6609–08 Standard Guide for Part-Stream Sampling of Coal, IBR approved for § 98.164(b).

(32) ASTM D6751–08 Standard Specification for Biodiesel Fuel Blend Stock (B100) for Middle Distillate Fuels, IBR approved for § 98.6.

(33) ASTM D6866–08 Standard Test Methods for Determining the Biobased Content of Solid, Liquid, and Gaseous Samples Using Radiocarbon Analysis, IBR approved for § 98.34(d), § 98.34(e), and § 98.36(e).

(34) ASTM D6883–04 Standard Practice for Manual Sampling of Stationary Coal from Railroad Cars, Barges, Trucks, or Stockpiles, IBR approved for § 98.164(b).

(35) ASTM D7430–08a1 Standard Practice for Mechanical Sampling of Coal, IBR approved for § 98.164(b).

(36) ASTM D7599–08 Standard Practice for Collection of Integrated Samples for the Speciation of Biomass (Biogenic) and Fossil-Derived Carbon Dioxide Emitted from Stationary Emissions Sources, IBR approved for § 98.34(d), § 98.34(e), and § 98.36(e).

(37) ASTM D7359–00 (Reapproved 2005)e1 Standard Test Methods for Analysis of Soda Ash (Sodium Carbonate), IBR approved for § 98.294(a) and § 98.294(b).


(39) [Reserved]


(41) ASTM E1941–04 Standard Test Method for Determination of Carbon in Refractory and Reactive Metals and Their Alloys, IBR approved for § 98.114(b), § 98.184(b), § 98.334(b).

(42) ASTM UOP539–97 Refinery Gas Analysis by Gas Chromatography, IBR approved for § 98.164(b), § 98.244(b), § 98.254(d), § 98.324(d), § 98.344(b), and § 98.354(g).


(f) The following material is available for purchase from the Gas Processors Association (GPA), 6526 East 60th Street, Tulsa, Oklahoma 74143, (918) 493–3872, http://www.gasprocessors.com.

(G) GPA 2261–00 Analysis for Natural Gas and Similar Gaseous Mixtures by Gas Chromatography, IBR approved for § 98.164(b), § 98.254(d), § 98.344(b), and § 98.354(g).

(g) The following material is available for purchase from the International Standards Organization (ISO), 1, ch. de la Vole-Creuse, Case postale 56, CH–1211 Geneva 20, Switzerland, +41 22 749 01 11, http://www.iso.org/iso/home.htm.


(3) [Reserved]


(h) The following material is available for purchase from the National Lime Association (NLA), 200 North Glebe Road, Suite 800, Arlington, Virginia 22203, (703) 243–5463, http://www.lime.org.

(1) CO₂ Emissions Calculation Protocol for the Lime Industry—English Units Version, February 5, 2008 Revision—National Lime Association, incorporation by reference (IBR) approved for § 98.194(c) and § 98.194(e).

(2) [Reserved]


(1) T650 om-05 Solids Content of Black Liquor, TAPPI, incorporation by reference (IBR) approved for § 98.276(c) and § 98.277(d).

(2) T684 om-06 Gross Heating Value of Black Liquor, TAPPI, incorporation by reference (IBR) approved for § 98.274(b).

(k) The following material is available for purchase from Standard Methods, at http://www.standardmethods.org, (877) 574–1233; or, through a joint publication agreement from the American Public Health Association (APHA), P.O. Box 933019, Atlanta, GA 3139–3019, (888) 320–APHA (2742), http://www.apha.org/publications/pubscontact.

(1) Method 2540G Total, Fixed, and Volatile Solids in Solid and Semisolid Samples, IBR approved for § 98.464(b).

(2) [Reserved]


(2) [Reserved]
Environmental Protection Agency § 98.7

(m) The following material is available from the U.S. Environmental Protection Agency, 1200 Pennsylvania Avenue, NW., Washington, DC 20460, (202) 272-0167, http://www.epa.gov.


(14) AP 42, Section 7.1, Organic Liquid Storage Tanks, November 2006 (AP 42, Section 7.1), http://www.epa.gov/tnn/
§ 98.8 What are the compliance and enforcement provisions of this part?

Any violation of any requirement of this part shall be a violation of the Clean Air Act, including section 114 (42 U.S.C. 7414). A violation includes but is not limited to failure to report GHG emissions, failure to collect data needed to calculate GHG emissions, failure to continuously monitor and test as required, failure to retain records needed to verify the amount of GHG emissions, and failure to calculate GHG emissions following the methodologies specified in this part. Each day of a violation constitutes a separate violation.

§ 98.9 Addresses.

All requests, notifications, and communications to the Administrator pursuant to this part must be submitted electronically and in a format as specified by the Administrator. For example, any requests, notifications and communications that can be submitted through the electronic GHG reporting tool, must be submitted through that tool. If not specified, requests, notifications or communications shall be submitted to the following address:

(a) For U.S. mail, Director, Climate Change Division, 1200 Pennsylvania Ave., NW., Mail Code: 6207J, Washington, DC 20460.

(b) For package deliveries, Director, Climate Change Division, 1310 L St, NW., Washington, DC 20005.


TABLE A–1 TO SUBPART A OF PART 98—GLOBAL WARMING POTENTIALS
<table>
<thead>
<tr>
<th>Name</th>
<th>CAS No.</th>
<th>Chemical formula</th>
<th>Global warming potential (100 yr.)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Carbon dioxide</td>
<td>124–38–9</td>
<td>CO₂</td>
<td>1</td>
</tr>
<tr>
<td>Methane</td>
<td>74–82–8</td>
<td>CH₄</td>
<td>21</td>
</tr>
<tr>
<td>Nitrous oxide</td>
<td>10024–97–2</td>
<td>N₂O</td>
<td>310</td>
</tr>
<tr>
<td>HFC-23</td>
<td>75–46–7</td>
<td>CHF₃</td>
<td>11,700</td>
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<td>HFC-32</td>
<td>75–10–5</td>
<td>CHF₃</td>
<td>650</td>
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<tr>
<td>HFC-41</td>
<td>593–53–3</td>
<td>CHF₃</td>
<td>150</td>
</tr>
<tr>
<td>HFC-125</td>
<td>354–33–6</td>
<td>C₇H₁₈F₃</td>
<td>2,800</td>
</tr>
<tr>
<td>HFC-134</td>
<td>359–35–3</td>
<td>C₇H₁₈F₃</td>
<td>1,000</td>
</tr>
<tr>
<td>HFC-134a</td>
<td>811–97–2</td>
<td>CH₂F₆CHO</td>
<td>1,300</td>
</tr>
<tr>
<td>HFC-143</td>
<td>430–66–0</td>
<td>C₇H₁₈F₃</td>
<td>300</td>
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<td>3,300</td>
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<tr>
<td>HFC-152</td>
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<td>677–56–5</td>
<td>CH₂F₆CHO</td>
<td>1,340</td>
</tr>
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<td>431–43–0</td>
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<td>1,370</td>
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<td>HFC-236fa</td>
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<td>HFC-245ca</td>
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<td>C₂F₆CHO</td>
<td>560</td>
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<td>HFC-245fa</td>
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<td>HFC-43–10mee</td>
<td>138495–42–8</td>
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<td>Sulfur hexafluoride</td>
<td>2551–62–4</td>
<td>SF₆</td>
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<tr>
<td>Trifluoromethyl sulphur pentfluoride</td>
<td>373–80–8</td>
<td>SF₆</td>
<td>17,700</td>
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<tr>
<td>Nitrogen trifluoride</td>
<td>7783–54–2</td>
<td>NF₃</td>
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<td>PFC-14 (Perfluoromethane)</td>
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<td>PFC-116 (Perfluoroethane)</td>
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<td>PFC-218 (Perfluoropropane)</td>
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<td>C₂F₆CHO</td>
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<tr>
<td>Perfluorocyclopropane</td>
<td>931–91–9</td>
<td>C₃C₃F₆</td>
<td>17,340</td>
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<tr>
<td>PFC-3–1–10 (Perfluorobutane)</td>
<td>355–25–9</td>
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<td>7,000</td>
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<td>Perfluorobutane</td>
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<td>(Perfluorohexane)</td>
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<td>PFC-9–1–18</td>
<td>306–94–5</td>
<td>C₆F₁₃</td>
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<td>HCTE-235da2 (Sofluran)</td>
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<td>HFE-43–10ppcc (H-Galden 1040x)</td>
<td>E1730133</td>
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<td>HFE-134</td>
<td>1691–17–4</td>
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<td>HFE-143</td>
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<td>HFE-227ea</td>
<td>2356–62–9</td>
<td>CH₂F₆CHO</td>
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<td>HFE-236a12 (HG-10)</td>
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<td>HFE-236a2 (Desflurane)</td>
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<td>84011–15–4</td>
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<td>1885–49–9</td>
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<td>HFE-263m₂</td>
<td>67490–36–2</td>
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<td>E1730135</td>
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<td>HFE-347c₂</td>
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<td>HFE-347m₃</td>
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<td>HFE-356c₃</td>
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<td>CH₂F₆CHO</td>
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<td>HFE-365m₃f₃</td>
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<td>HFE-374p₂</td>
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</tr>
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<td>HFE-441 (HFE-7100)</td>
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<td>Chemical blend</td>
<td>163702–08–7</td>
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<td>297</td>
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<td>Chemical blend</td>
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<td>Chemical blend</td>
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<td>Savlorflurane</td>
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<td>Octafluorotetramethylenethylenehydroxymethyl group</td>
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<td>X(CH₂F₆CHOH)X</td>
<td>73</td>
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<td>HFE-347m₁y₁</td>
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<td>343</td>
</tr>
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</table>
### TABLE A–2 TO SUBPART A OF PART 98—UNITS OF MEASURE CONVERSIONS

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<thead>
<tr>
<th>To convert from</th>
<th>To</th>
<th>Multiply by</th>
</tr>
</thead>
<tbody>
<tr>
<td>Kilograms (kg)</td>
<td>Kilograms (kg)</td>
<td>1</td>
</tr>
<tr>
<td>Pounds (lbs)</td>
<td>Pounds (lbs)</td>
<td>45359.2</td>
</tr>
<tr>
<td>Metric tons</td>
<td>Metric tons</td>
<td>1</td>
</tr>
<tr>
<td>Short tons</td>
<td>Short tons</td>
<td>0.0001</td>
</tr>
<tr>
<td>Cubic meters (m³)</td>
<td>Cubic meters (m³)</td>
<td>1.000</td>
</tr>
<tr>
<td>Barrels of Liquid Fuel (bbl)</td>
<td>Barrels of Liquid Fuel (bbl)</td>
<td>0.42</td>
</tr>
<tr>
<td>Gallons (liquid, US)</td>
<td>Gallons (liquid, US)</td>
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</tr>
<tr>
<td>Liters (l)</td>
<td>Liters (l)</td>
<td>0.037854</td>
</tr>
<tr>
<td>Feet (ft)</td>
<td>Feet (ft)</td>
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</tr>
<tr>
<td>Meters (m)</td>
<td>Meters (m)</td>
<td>3.28084</td>
</tr>
<tr>
<td>Kilometers (km)</td>
<td>Kilometers (km)</td>
<td>0.62137</td>
</tr>
<tr>
<td>Square feet (ft²)</td>
<td>Acres</td>
<td>2.29568×10⁻⁴</td>
</tr>
<tr>
<td>Square meters (m²)</td>
<td>Acres</td>
<td>2.47105×10⁻⁴</td>
</tr>
<tr>
<td>Square miles (mi²)</td>
<td>Square kilometers (km²)</td>
<td>2.58999</td>
</tr>
<tr>
<td>Degrees Fahrenheit (°F)</td>
<td>Degrees Celsius (°C)</td>
<td>(°F) = (°C + 32) + 32</td>
</tr>
<tr>
<td>Degrees Celsius (°C)</td>
<td>Kelvin (K)</td>
<td>K = °C + 273.15</td>
</tr>
<tr>
<td>Degrees Rankine (°R)</td>
<td>Degrees Rankine (°R)</td>
<td>1.8</td>
</tr>
<tr>
<td>Joules</td>
<td>Btu</td>
<td>9.47817×10⁻⁴</td>
</tr>
<tr>
<td>Btu</td>
<td>MMBtu</td>
<td>1×10⁻⁶</td>
</tr>
<tr>
<td>Pascals (Pa)</td>
<td>Inches of Mercury (in Hg)</td>
<td>1.36934×10⁻⁴</td>
</tr>
<tr>
<td>Inches of Mercury (in Hg)</td>
<td>Pounds per square inch (psi)</td>
<td>0.49110</td>
</tr>
<tr>
<td>Pounds per square inch (psi)</td>
<td>Inches of Mercury (in Hg)</td>
<td>2.03825</td>
</tr>
</tbody>
</table>

### TABLE A–3 TO SUBPART A OF PART 98—SOURCE CATEGORY LIST FOR § 98.2(a)(1)

**TABLE A–3 TO SUBPART A—SOURCE CATEGORY LIST FOR § 98.2(a)(1)**

**Source Categories**
- Applicable in 2010 and Future Years
- Electricity generation units that report CO₂ mass emissions year round through 40 CFR part 75 (subpart D).
- Adipic acid production (subpart E).
- Aluminum production (subpart F).
- Ammonia manufacturing (subpart G).
- Cement production (subpart H).
- HCFC–22 production (subpart O).
- HFC–23 destruction processes that are not collocated with a HCFC–22 production facility and that destroy more than 2.14 metric tons of HFC–23 per year (subpart O).
- Lime manufacturing (subpart S).
- Nitric acid production (subpart V).
- Petrochemical production (subpart X).
- Petroleum refineries (subpart Y).
- Phosphoric acid production (subpart Z).
- Silicon carbide production (subpart BB).
- Soda ash production (subpart CC).
TABLE A–3 TO SUBPART A—SOURCE CATEGORY LIST FOR § 98.2(a)(1)—Continued

Titanium dioxide production (subpart EE).
Municipal solid waste landfills that generate CH\textsubscript{4} in amounts equivalent to 25,000 metric tons CO\textsubscript{2}e or more per year, as determined according to subpart HH of this part.
Manure management systems with combined CH\textsubscript{4} and N\textsubscript{2}O emissions in amounts equivalent to 25,000 metric tons CO\textsubscript{2}e or more per year, as determined according to subpart JJ of this part.

Additional Source Categories

- Electrical transmission and distribution equipment use at facilities where the total nameplate capacity of SF\textsubscript{6} and PFC containing equipment exceeds 17,820 pounds, as determined under § 98.301 (subpart DD).
- Underground coal mines liberating 36,500,000 actual cubic feet of CH\textsubscript{4} or more per year (subpart FF).
- Geologic sequestration of carbon dioxide (subpart RR).
- Electrical transmission and distribution equipment manufacture or refurbishment (subpart SS).
- Injection of carbon dioxide (subpart UU).

* Source categories are defined in each applicable subpart.


TABLE A–4 TO SUBPART A OF PART 98—SOURCE CATEGORY LIST FOR § 98.2(a)(2)

Source Categories

- Ferroalloy production (subpart K).
- Glass production (subpart N).
- Hydrogen production (subpart P).
- Iron and steel production (subpart Q).
- Lead production (subpart R).
- Pulp and paper manufacturing (subpart AA).
- Zinc production (subpart GG).
- Electronics manufacturing (subpart I)
- Magnesium production (subpart T).
- Petroleum and Natural Gas Systems (subpart W).
- Industrial wastewater treatment (subpart II).
- Industrial waste landfills (subpart TT).

* Source categories are defined in each applicable subpart.


TABLE A–5 TO SUBPART A OF PART 98—SUPPLIER CATEGORY LIST FOR § 98.2(a)(4)

Supplier Categories

- Coal-to-liquids suppliers (subpart LL):
  (A) All producers of coal-to-liquid products.
  (B) Importers of an annual quantity of coal-to-liquid products that is equivalent to 25,000 metric tons CO\textsubscript{2}e or more.
  (C) Exporters of an annual quantity of coal-to-liquid products that is equivalent to 25,000 metric tons CO\textsubscript{2}e or more.

Petroleum product suppliers (subpart MM):
(A) All petroleum refineries that distill crude oil.
TABLE A–5 TO SUBPART A—SUPPLIER CATEGORY LIST FOR § 98.2(a)(4)—Continued

(B) Importers of an annual quantity of petroleum products and natural gas liquids that is equivalent to 25,000 metric tons CO\(_2\)e or more.
(C) Exporters of an annual quantity of petroleum products and natural gas liquids that is equivalent to 25,000 metric tons CO\(_2\)e or more.

N atural gas and natural gas liquids suppliers (subpart NN): (A) All fractionators.
(B) Local natural gas distribution companies that deliver 460,000 thousand standard cubic feet or more of natural gas per year.

Industrial greenhouse gas suppliers (subpart OO): (A) All producers of industrial greenhouse gases.
(B) Importers of industrial greenhouse gases with annual bulk imports of N\(_2\)O, fluorinated GHG, and CO\(_2\) that in combination are equivalent to 25,000 metric tons CO\(_2\)e or more.
(C) Exporters of industrial greenhouse gases with annual bulk exports of N\(_2\)O, fluorinated GHG, and CO\(_2\) that in combination are equivalent to 25,000 metric tons CO\(_2\)e or more.

Carbon dioxide suppliers (subpart PP): (A) All producers of CO\(_2\).
(B) Importers of CO\(_2\) with annual bulk imports of N\(_2\)O, fluorinated GHG, and CO\(_2\) that in combination are equivalent to 25,000 metric tons CO\(_2\)e or more.
(C) Exporters of CO\(_2\) with annual bulk exports of N\(_2\)O, fluorinated GHG, and CO\(_2\) that in combination are equivalent to 25,000 metric tons CO\(_2\)e or more.

Additional Supplier Categories Applicable\(^a\) in 2011 and Future Years

Importers and exporters of fluorinated greenhouse gases contained in pre-charged equipment or closed-cell foams (subpart QQ): (A) Importers of an annual quantity of fluorinated greenhouse gases contained in pre-charged equipment or closed-cell foams that is equivalent to 25,000 metric tons CO\(_2\)e or more.
(B) Exporters of an annual quantity of fluorinated greenhouse gases contained in pre-charged equipment or closed-cell foams that is equivalent to 25,000 metric tons CO\(_2\)e or more.

\(^a\) Suppliers are defined in each applicable subpart.


TABLE A–6 TO SUBPART A OF PART 98—DATA ELEMENTS THAT ARE INPUTS TO EMISSION EQUATIONS AND FOR WHICH THE REPORTING DEADLINE IS MARCH 31, 2013

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<td>Only year in which landfill first accepted waste, last year the landfill accepted waste (if used as an input in Equation HH–3), capacity of the landfill (if used as an input in Equation HH–3), and waste disposal quantity for each year of landfilling.</td>
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<td>Only quantity of waste determined using the methods in § 98.343(a)(3)(i), quantity of waste determined using the methods in § 98.343(a)(3)(ii), population served by the landfill for each year, and the value of landfill capacity (LFC) used in the calculation.</td>
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**Table A–7 to Subpart A of Part 98—Data Elements That Are Inputs to Emission Equations and for Which the Reporting Deadline Is March 31, 2015**

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**[76 FR 53065, Aug. 25, 2011]**
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Only monthly volume values, monthly mass values, monthly carbon content values, molecular weights for gaseous feedstocks, molecular weights for gaseous products, and indication of whether the alternative method in §98.243(c)(4) was used.
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[76 FR 53065, Aug. 25, 2011]
Subpart C—General Stationary Fuel Combustion Sources

§ 98.30 Definition of the source category.

(a) Stationary fuel combustion sources are devices that combust solid, liquid, or gaseous fuel, generally for the purposes of producing electricity, generating steam, or providing useful heat or energy for industrial, commercial, or institutional use, or reducing the volume of waste by removing combustible matter. Stationary fuel combustion sources include, but are not limited to, boilers, simple and combined-cycle combustion turbines, engines, incinerators, and process heaters.

(b) This source category does not include:

(1) Portable equipment, as defined in §98.6.
(2) Emergency generators and emergency equipment, as defined in §98.6.
(3) Irrigation pumps at agricultural operations.
(4) Flares, unless otherwise required by provisions of another subpart of this part to use methodologies in this subpart.
(5) Electricity generating units that are subject to subpart D of this part.

(c) For a unit that combusts hazardous waste (as defined in §261.3 of this chapter), reporting of GHG emissions is not required unless either of the following conditions apply:

(1) Continuous emission monitors (CEMS) are used to quantify CO₂ mass emissions.

(2) Any fuel listed in Table C–1 of this subpart is also combusted in the unit. In this case, report GHG emissions from combustion of all fuels listed in Table C–1 of this subpart.

(d) You are not required to report GHG emissions from pilot lights. A pilot light is a small auxiliary flame that ignites the burner of a combustion device when the control valve opens.

§ 98.31 Reporting threshold.

You must report GHG emissions under this subpart if your facility contains one or more stationary fuel combustion sources and the facility meets the applicability requirements of either §§98.2(a)(1), 98.2(a)(2), or 98.2(a)(3).

§ 98.32 GHGs to report.

You must report CO₂, CH₄, and N₂O mass emissions from each stationary fuel combustion unit, except as otherwise indicated in this subpart.

§ 98.33 Calculating GHG emissions.

You must calculate CO₂ emissions according to paragraph (a) of this section, and calculate CH₄ and N₂O emissions according to paragraph (c) of this section.

(a) CO₂ emissions from fuel combustion. Calculate CO₂ mass emissions by using one of the four calculation methodologies in paragraphs (a)(1) through (a)(4) of this section, subject to the applicable conditions, requirements, and restrictions set forth in paragraph (b) of this section. Alternatively, for units that meet the conditions of paragraph (a)(5) of this section, you may use CO₂ mass emissions calculation methods from part 75 of this chapter, as described in paragraph (a)(5) of this section. For units that combust both biomass and fossil fuels, you must calculate and report CO₂ emissions from the combustion of biomass separately using the methods in paragraph (e) of this section, except as otherwise provided in paragraphs (a)(5)(iv) and (e) of this section and in §98.36(d).

(1) Tier 1 Calculation Methodology. Calculate the annual CO₂ mass emissions for each type of fuel by using Equation C–1, C–1a, or C–1b of this section (as applicable).

(i) Use Equation C–1 except when natural gas billing records are used to quantify fuel usage and gas consumption is expressed in units of therms or million Btu. In that case, use Equation C–1a or C–1b, as applicable.
§ 98.33 CO₂ = 1 × 10⁻³ * Fuel * HHV * EF (Eq. C-1)

where:
CO₂ = Annual CO₂ mass emissions for the specific fuel type (metric tons).
Fuel = Mass or volume of fuel combusted per year, from company records as defined in §98.6 (express mass in short tons for solid fuel, volume in standard cubic feet for gaseous fuel, and volume in gallons for liquid fuel).
HHV = Default high heat value of the fuel, from Table C-1 of this subpart (mmBtu per mass or mmBtu per volume, as applicable).
EF = Fuel-specific default CO₂ emission factor, from Table C-1 of this subpart (kg CO₂/mmBtu).
1 × 10⁻³ = Conversion factor from kilograms to metric tons.

(iii) If natural gas consumption is obtained from billing records and fuel usage is expressed in therms, use Equation C-1a.

CO₂ = 1 × 10⁻³ [0.1 * Gas * EF] (Eq. C-1a)

where:
CO₂ = Annual CO₂ mass emissions from natural gas combustion (metric tons).
Gas = Annual natural gas usage, from billing records (therms).
EF = Fuel-specific default CO₂ emission factor for natural gas, from Table C-1 of this subpart (kg CO₂/mmBtu).
0.1 = Conversion factor from therms to mmBtu.
1 × 10⁻³ = Conversion factor from kilograms to metric tons.

(iii) If natural gas consumption is obtained from billing records and fuel usage is expressed in mmBtu, use Equation C-1b.

CO₂ = 1 × 10⁻³ * Gas * EF (Eq. C-1b)

where:
CO₂ = Annual CO₂ mass emissions from natural gas combustion (metric tons).
Gas = Annual natural gas usage, from billing records (mmBtu).
EF = Fuel-specific default CO₂ emission factor for natural gas, from Table C-1 of this subpart (kg CO₂/mmBtu).
1 × 10⁻³ = Conversion factor from kilograms to metric tons.

(2) Tier 2 Calculation Methodology.
Calculate the annual CO₂ mass emissions for each type of fuel by using either Equation C2a or C2c of this section, as appropriate.
(i) Equation C-2a of this section applies to any type of fuel listed in Table C-1 of the subpart, except for municipal solid waste (MSW). For MSW combustion, use Equation C-2c of this section.

CO₂ = 1 × 10⁻³ * Fuel * HHV * EF (Eq. C-2a)

where:
CO₂ = Annual CO₂ mass emissions for a specific fuel type (metric tons).
Fuel = Mass or volume of the fuel combusted during the year, from company records as defined in §98.6 (express mass in short tons for solid fuel, volume in standard cubic feet for gaseous fuel, and volume in gallons for liquid fuel).
HHV = Annual average high heat value of the fuel (mmBtu per mass or volume). The average HHV shall be calculated according to the requirements of paragraph (a)(2)(i) of this section.
EF = Fuel-specific default CO\textsubscript{2} emission factor, from Table C–1 of this subpart (kg CO\textsubscript{2}/mmBtu).

\(1 \times 10^{-3}\) = Conversion factor from kilograms to metric tons.

(i) The minimum required sampling frequency for determining the annual average HHV (e.g., monthly, quarterly, semi-annually, or by lot) is specified in §98.34. The method for computing the annual average HHV is a function of unit size and how frequently you perform or receive from the fuel supplier the results of fuel sampling for HHV. The method is specified in paragraph (a)(2)(i)(A) or (a)(2)(i)(B) of this section, as applicable.

(A) If the results of fuel sampling are received monthly or more frequently, then for each unit with a maximum rated heat input capacity greater than or equal to 100 mmBtu/hr (or for a group of units that includes at least one unit of that size), the annual average HHV shall be calculated using Equation C–2b of this section. If multiple HHV determinations are made in any month, average the values for the month arithmetically.

\[
(HHV)_{\text{annual}} = \frac{\sum_{i=1}^{n}(HHV)_i \times (Fuel)_i}{\sum_{i=1}^{n}(Fuel)_i}
\]  
(Eq. C-2b)

Where:

\((HHV)_{\text{annual}}\) = Weighted annual average high heat value of the fuel (mmBtu per mass or volume).

\((HHV)_i\) = Measured high heat value of the fuel, for month “i” (which may be the arithmetic average of multiple determinations), or, if applicable, an appropriate substitute data value (mmBtu per mass or volume).

\((Fuel)_i\) = Mass or volume of the fuel combusted during month “i,” from company records (express mass in short tons for solid fuel, volume in standard cubic feet for gaseous fuel, and volume in gallons for liquid fuel).

\(n\) = Number of months in the year that the fuel is burned in the unit.

(B) If the results of fuel sampling are received less frequently than monthly, or, for a unit with a maximum rated heat input capacity less than 100 mmBtu/hr (or a group of such units) regardless of the HHV sampling frequency, the annual average HHV shall either be computed according to paragraph (a)(2)(i)(A) of this section or as the arithmetic average HHV for all values for the year (including valid samples and substitute data values under §98.35).

(iii) For units that combust municipal solid waste (MSW) and that produce steam, use Equation C–2c of this section. Equation C–2c of this section may also be used for any other solid fuel listed in Table C–1 of this subpart provided that steam is generated by the unit.

\[
CO_2 = 1 \times 10^{-3} \text{ Steam} \times B \times EF
\]  
(Eq. C-2c)

Where:

\(CO_2\) = Annual CO\textsubscript{2} mass emissions from MSW or solid fuel combustion (metric tons).

\(Steam\) = Total mass of steam generated by MSW or solid fuel combustion during the reporting year (lb steam).

\(B\) = Ratio of the boiler’s maximum rated heat input capacity to its design rated steam output capacity (mmBtu/lb steam).

\(EF\) = Fuel-specific default CO\textsubscript{2} emission factor, from Table C–1 of this subpart (kg CO\textsubscript{2}/mmBtu).

\(1 \times 10^{-3}\) = Conversion factor from kilograms to metric tons.
§ 98.33 Tier 3 Calculation Methodology.

Calculate the annual CO₂ mass emissions for each fuel by using either Equation C3, C4, or C5 of this section, as appropriate.

(i) For a solid fuel, use Equation C-3 of this section.

\[
\text{CO}_2 = \frac{44}{12} \times \text{Fuel} \times \text{CC} \times 0.91 \quad \text{(Eq. C-3)}
\]

Where:
- \( \text{CO}_2 \) = Annual CO₂ mass emissions from the combustion of the specific solid fuel (metric tons).
- \( \text{Fuel} \) = Annual mass of the solid fuel combusted, from company records as defined in §98.6 (short tons).
- \( \text{CC} \) = Annual average carbon content of the solid fuel (percent by weight, expressed as a decimal fraction, e.g., 95% = 0.95). The annual average carbon content shall be determined using the same procedures as specified for HHV in paragraph (a)(2)(ii) of this section.
- \( \frac{44}{12} \) = Ratio of molecular weights, CO₂ to carbon.
- 0.91 = Conversion factor from short tons to metric tons.

(ii) For a liquid fuel, use Equation C-4 of this section.

\[
\text{CO}_2 = \frac{44}{12} \times \text{Fuel} \times \text{CC} \times 0.001 \quad \text{(Eq. C-4)}
\]

Where:
- \( \text{CO}_2 \) = Annual CO₂ mass emissions from the combustion of the specific liquid fuel (metric tons).
- \( \text{Fuel} \) = Annual volume of the liquid fuel combusted (gallons). The volume of fuel combusted must be measured directly, using fuel flow meters calibrated according to §98.3(i). Fuel billing meters may be used for this purpose. Tank drop measurements may also be used.
- \( \text{CC} \) = Annual average carbon content of the liquid fuel (kg C per gallon of fuel). The annual average carbon content shall be determined using the same procedures as specified for HHV in paragraph (a)(2)(ii) of this section.
- \( \frac{44}{12} \) = Ratio of molecular weights, CO₂ to carbon.
- 0.001 = Conversion factor from kg to metric tons.

(iii) For a gaseous fuel, use Equation C-5 of this section.

\[
\text{CO}_2 = \frac{44}{12} \times \text{Fuel} \times \text{CC} \times \frac{\text{MW}}{\text{MVC}} \times 0.001 \quad \text{(Eq. C-5)}
\]

Where:
- \( \text{CO}_2 \) = Annual CO₂ mass emissions from combustion of the specific gaseous fuel (metric tons).
- \( \text{Fuel} \) = Annual volume of the gaseous fuel combusted (scf). The volume of fuel combusted must be measured directly, using fuel flow meters calibrated according to §98.3(i). Fuel billing meters may be used for this purpose.
- \( \text{CC} \) = Annual average carbon content of the gaseous fuel (kg C per kg of fuel). The annual average carbon content shall be determined using the same procedures as specified for HHV in paragraph (a)(2)(ii) of this section.
- \( \text{MW} \) = Annual average molecular weight of the gaseous fuel (kg/kg-mole). The annual average molecular weight shall be determined using the same procedures as specified for HHV in paragraph (a)(2)(ii) of this section.
- \( \text{MVC} \) = Molar volume conversion factor at standard conditions, as defined in §98.6. Use 849.5 scf per kg mole if you select 68 °F as standard temperature and 866.6 scf
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per kg mole if you select 60 °F as standard temperature.

\( \text{Ratio of molecular weights, } \text{CO}_2 \text{ to carbon.} \)

0.801 = Conversion factor from kg to metric tons.

(iv) Fuel flow meters that measure mass flow rates may be used for liquid or gaseous fuels, provided that the fuel density is used to convert the readings to volumetric flow rates. The density shall be measured at the same frequency as the carbon content. You must measure the density using one of the following appropriate methods.


(v) The following default density values may be used for fuel oil, in lieu of using the methods in paragraph (a)(3)(iv) of this section: 6.8 lb/gal for No. 1 oil; 7.2 lb/gal for No. 2 oil; 8.1 lb/gal for No. 6 oil.

(4) Tier 4 Calculation Methodology.

Calculate the annual CO₂ mass emissions from all fuels combusted in a unit, by using quality- assured data from continuous emission monitoring systems (CEMS).

(i) This methodology requires a CO₂ concentration monitor and a stack gas volumetric flow rate monitor, except as otherwise provided in paragraph (a)(4)(iv) of this section. Hourly measurements of CO₂ concentration and stack gas flow rate are converted to CO₂ mass emission rates in metric tons per hour.

(ii) When the CO₂ concentration is measured on a wet basis, Equation C–6 of this section is used to calculate the hourly CO₂ emission rates:

\[
\text{CO}_2 = 5.18 \times 10^{-7} \times \text{CO}_2 \times Q \]

(\text{Eq. C-6})

Where:

- \( \text{CO}_2 \) = CO₂ mass emission rate (metric tons/hr).
- \( \text{C}_{\text{CO2}} \) = Hourly average CO₂ concentration (% CO₂).
- \( Q \) = Hourly average stack gas volumetric flow rate (scfh).

5.18 \times 10^{-7} = Conversion factor (metric tons/scf/% CO₂).

(iii) If the CO₂ concentration is measured on a dry basis, a correction for the stack gas moisture content is required. You shall either continuously monitor the stack gas moisture content using a method described in §75.11(b)(2) of this chapter or use an appropriate default moisture percentage. For coal, wood, and natural gas combustion, you may use the default moisture values specified in §75.11(b)(1) of this chapter. Alternatively, for any type of fuel, you may determine an appropriate site-specific default moisture value (or values), using measurements made with EPA Method 4—Determination Of Moisture Content In Stack Gases, in appendix A–3 to part 60 of this chapter. Moisture data from the relative accuracy test audit (RATA) of a CEMS may be used for this purpose. If this option is selected, the site-specific moisture default value(s) must represent the fuel(s) or fuel blends that are combusted in the unit during normal, stable operation, and must account for any distinct difference(s) in the stack gas moisture content associated with different process operating conditions. For each site-specific default moisture percentage, at least nine Method 4 runs are required, except where the option to use moisture data from a RATA is selected, and the applicable regulation allows a single moisture determination.
to represent two or more RATA runs. In that case, you may base the site-specific moisture percentage on the number of moisture runs allowed by the RATA regulation. Calculate each site-specific default moisture value by taking the arithmetic average of the Method 4 runs. Each site-specific moisture default value shall be updated whenever the owner or operator believes the current value is non-representative, due to changes in unit or process operation, but in any event no less frequently than annually. Use the updated moisture value in the subsequent CO$_2$ emissions calculations. For each unit operating hour, a moisture correction must be applied to Equation C–6 of this section as follows:

$$\text{CO}_2^* = \text{CO}_2 \left( \frac{100 - \%H_2O}{100} \right)$$

(Eq. C–7)

where:

- CO$_2^*$ = Hourly CO$_2$ mass emission rate, corrected for moisture (metric tons/hr).
- CO$_2$ = Hourly CO$_2$ mass emission rate from Equation C–6 of this section, uncorrected (metric tons/hr).
- $\%H_2O$ = Hourly moisture percentage in the stack gas (measured or default value, as appropriate).

(iv) An oxygen (O$_2$) concentration monitor may be used in lieu of a CO$_2$ concentration monitor to determine the hourly CO$_2$ concentrations, in accordance with Equation F–14a or F–14b (as applicable) in appendix F to part 75 of this chapter, if the effluent gas stream monitored by the CEMS consists solely of combustion products (i.e., no process CO$_2$ emissions or CO$_2$ emissions from sorbent are mixed with the combustion products) and if only fuels that are listed in Table 1 in section 3.3.5 of appendix F to part 75 of this chapter are combusted in the unit. If the O$_2$ monitoring option is selected, the F-factors used in Equations F–14a and F–14b shall be determined according to section 3.3.5 or section 3.3.6 of appendix F to part 75 of this chapter, as applicable. If Equation F–14b is used, the hourly moisture percentage in the stack gas shall be determined in accordance with paragraph (a)(4)(iii) of this section.

(v) Each hourly CO$_2$ mass emission rate from Equation C–6 or C–7 of this section is multiplied by the operating time to convert it from metric tons per hour to metric tons. The operating time is the fraction of the hour during which fuel is combusted (e.g., the unit operating time is 1.0 if the unit operates for the whole hour and is 0.5 if the unit operates for 30 minutes in the hour). For common stack configurations, the operating time is the fraction of the hour during which effluent gases flow through the common stack.

(vi) The hourly CO$_2$ mass emissions are then summed over each calendar quarter and the quarterly totals are summed to determine the annual CO$_2$ mass emissions.

(vii) If both biomass and fossil fuel are combusted during the year, determine and report the biogenic CO$_2$ mass emissions separately, as described in paragraph (e) of this section.

(viii) If a portion of the flue gases generated by a unit subject to Tier 4 (e.g., a slip stream) is continuously diverted from the main flue gas exhaust system for the purpose of heat recovery or some other similar process, and then exhausts through a stack that is not equipped with the continuous emission monitors to measure CO$_2$ mass emissions, CO$_2$ emissions shall be determined as follows:

(A) At least once a year, use EPA Methods 2 and 3A, and (if necessary) Method 4 in appendices A–2 and A–3 to part 60 of this chapter to perform emissions testing at a set point that best represents normal, stable process operating conditions. A minimum of three one-hour Method 3A tests are required, to determine the CO$_2$ concentration. A Method 2 test shall be performed during each Method 3A run, to determine the stack gas volumetric flow rate. If moisture correction is necessary, a
Method 4 run shall also be performed during each Method 3A run. Important parametric information related to the stack gas flow rate (e.g., damper positions, fan settings, etc.) shall also be recorded during the test.

(B) Calculate a CO\textsubscript{2} mass emission rate (in metric tons/hr) from the stack test data, using a version of Equation C–6 in paragraph (a)(4)(ii) of this section, modified as follows. In the Equation C–6 nomenclature, replace the words “Hourly average” in the definitions of “\(C\)”, “\(C\textsubscript{CEMS}\)”, and “\(Q\)” with the words “3-run average”. Substitute the arithmetic average values of CO\textsubscript{2} concentration and stack gas flow rate from the emission testing into modified Equation C–6. If CO\textsubscript{2} is measured on a dry basis, a moisture correction of the calculated CO\textsubscript{2} mass emission rate is required. Use Equation C–7 in paragraph (a)(4)(ii) of this section to make this correction; replace the word “Hourly” with the words “3-run average” in the equation nomenclature.

(C) The results of each annual stack test shall be used in the GHG emissions calculations for the year of the test.

(D) If, for the majority of the operating hours during the year, the diverted stream is withdrawn at a steady rate at or near the tested set point (as evidenced by fan and damper settings and/or other parameters), you may use the calculated CO\textsubscript{2} mass emission rate from paragraph (a)(4)(viii)(B) of this section to estimate the CO\textsubscript{2} mass emissions for all operating hours in which flue gas is diverted from the main exhaust system. Otherwise, you must account for the variation in the flow rate of the diverted stream, as described in paragraph (c)(4)(viii)(E) of this section.

(E) If the flow rate of the diverted stream varies significantly throughout the year, except as provided below, repeat the stack test and emission rate calculation procedures described in paragraphs (c)(4)(viii)(A) and (c)(4)(viii)(B) of this section at a minimum of two more set points across the range of typical operating conditions to develop a correlation between CO\textsubscript{2} mass emission rate and the parametric data. If additional testing is not feasible, use the following approach to develop the necessary correlation. Assume that the average CO\textsubscript{2} concentration obtained in the annual stack test is the same at all operating set points. Then, beginning with the measured flow rate from the stack test and the associated parametric data, perform an engineering analysis to estimate the stack gas flow rate at two or more additional set points. Calculate the CO\textsubscript{2} mass emission rate at each set point.

(F) Calculate the annual CO\textsubscript{2} mass emissions for the diverted stream as follows. For a steady-state process, multiply the number of hours in which flue gas was diverted from the main exhaust system by the CO\textsubscript{2} mass emission rate from the stack test. Otherwise, using the best available information and engineering judgment, apply the most representative CO\textsubscript{2} mass emission rate from the correlation in paragraph (c)(4)(viii)(E) of this section to determine the CO\textsubscript{2} mass emissions for each hour in which flue gas was diverted, and sum the results. To simplify the calculations, you may count partial operating hours as full hours.

(G) Finally, add the CO\textsubscript{2} mass emissions from paragraph (c)(4)(viii)(F) of this section to the annual CO\textsubscript{2} mass emissions measured by the CEMS at the main stack. Report this sum as the total annual CO\textsubscript{2} mass emissions for the unit.

(H) The exact method and procedures used to estimate the CO\textsubscript{2} mass emissions for the diverted portion of the flue gas exhaust stream shall be documented in the Monitoring Plan required under §98.3(g)(5).

(5) Alternative methods for certain units subject to Part 75 of this chapter. Certain units that are not subject to subpart D of this part and that report data to EPA according to part 75 of this chapter may qualify to use the alternative methods in this paragraph (a)(5), in lieu of using any of the four calculation methodology tiers.

(i) For a unit that combusts only natural gas and/or fuel oil, is not subject to subpart D of this part, monitors and reports heat input data year-round according to appendix D to part 75 of this chapter, but is not required by the applicable part 75 program to report CO\textsubscript{2} mass emissions data, calculate the annual CO\textsubscript{2} mass emissions for the purposes of this part as follows:
(A) Use the hourly heat input data from appendix D to part 75 of this chapter, together with Equation G–4 in appendix G to part 75 of this chapter to determine the hourly CO\textsubscript{2} mass emission rates, in units of tons/hr;

(B) Use Equations F–12 and F–13 in appendix F to part 75 of this chapter to calculate the quarterly and cumulative annual CO\textsubscript{2} mass emissions, respectively, in units of short tons; and

(C) Divide the cumulative annual CO\textsubscript{2} mass emissions value by 1.1 to convert it to metric tons.

(ii) For a unit that combusts only natural gas and/or fuel oil, is not subject to subpart D of this part, monitors and reports heat input data year-round according to §75.19 of this chapter but is not required by the applicable part 75 program to report CO\textsubscript{2} mass emissions data, calculate the annual CO\textsubscript{2} mass emissions for the purposes of this part as follows:

(A) Calculate the hourly CO\textsubscript{2} mass emissions, in units of short tons, using Equation LM–11 in §75.19(c)(4)(iii) of this chapter.

(B) Sum the hourly CO\textsubscript{2} mass emissions values over the entire reporting year to obtain the cumulative annual CO\textsubscript{2} mass emissions, in units of short tons.

(C) Divide the cumulative annual CO\textsubscript{2} mass emissions value by 1.1 to convert it to metric tons.

(iii) For a unit that is not subject to subpart D of this part, uses flow rate and CO\textsubscript{2} (or O\textsubscript{2}) CEMS to report heat input data year-round according to §75.19 of this chapter but is not required by the applicable part 75 program to report CO\textsubscript{2} mass emissions data, calculate the annual CO\textsubscript{2} mass emissions as follows:

(A) Use Equation F–11 or F–2 (as applicable) in appendix F to part 75 of this chapter to calculate the hourly CO\textsubscript{2} mass emission rates from the CEMS data. If an O\textsubscript{2} monitor is used, convert the hourly average O\textsubscript{2} readings to CO\textsubscript{2} using Equation F–14a or F–14b in appendix F to part 75 of this chapter (as applicable), before applying Equation F–11 or F–2.

(B) Use Equations F–12 and F–13 in appendix F to part 75 of this chapter to calculate the quarterly and cumulative annual CO\textsubscript{2} mass emissions, respectively, in units of short tons.

(C) Divide the cumulative annual CO\textsubscript{2} mass emissions value by 1.1 to convert it to metric tons.

(iv) For units that qualify to use the alternative CO\textsubscript{2} emissions calculation methods in paragraphs (a)(5)(i) through (a)(5)(iii) of this section, if both biomass and fossil fuel are combusted during the year, separate calculation and reporting of the biogenic CO\textsubscript{2} mass emissions (as described in paragraph (e) of this section) is optional, only for the 2010 reporting year, as provided in §98.3(c)(12).

(b) Use of the four tiers. Use of the four tiers of CO\textsubscript{2} emissions calculation methodologies described in paragraph (a) of this section is subject to the following conditions, requirements, and restrictions:

(1) The Tier 1 Calculation Methodology:

(i) May be used for any fuel listed in Table C–1 of this subpart that is combusted in a unit with a maximum rated heat input capacity of 250 mmBtu/hr or less.

(ii) May be used for MSW in a unit of any size that does not produce steam, if the use of Tier 4 is not required.

(iii) May be used for solid, gaseous, or liquid biomass fuels in a unit of any size provided that the fuel is listed in Table C–1 of this subpart.

(iv) May not be used if you routinely perform fuel sampling and analysis for the fuel high heat value (HHV) or routinely receive the results of HHV sampling and analysis from the fuel supplier at the minimum frequency specified in §98.34(a), or at a greater frequency. In such cases, Tier 2 shall be used. This restriction does not apply to paragraphs (b)(1)(vii), (b)(1)(v), (b)(1)(vi), and (b)(1)(vii) of this section.

(v) May be used for natural gas combustion in a unit of any size, in cases where the annual natural gas consumption is obtained from fuel billing records in units of therms or mmBtu.

(vi) May be used for MSW combustion in a small, batch incinerator that burns no more than 1,000 tons per year of MSW.

(vii) May be used for the combustion of MSW and/or tires in a unit, provided that no more than 10 percent of the
unit’s annual heat input is derived from those fuels, combined. Notwithstanding this requirement, if a unit combusts both MSW and tires and the reporter elects not to separately calculate and report biogenic CO₂ emissions from the combustion of tires, Tier 1 may be used for the MSW combustion, provided that no more than 10 percent of the unit’s annual heat input is derived from MSW.

(2) The Tier 2 Calculation Methodology:
   (i) May be used for the combustion of any type of fuel in a unit with a maximum rated heat input capacity of 250 mmBtu/hr or less provided that the fuel is listed in Table C–1 of this subpart.
   (ii) May be used in a unit with a maximum rated heat input capacity greater than 250 mmBtu/hr for the combustion of natural gas and/or distillate fuel oil.
   (iii) May be used for MSW in a unit of any size that produces steam, if the use of Tier 4 is not required.

(3) The Tier 3 Calculation Methodology:
   (i) May be used for a unit of any size that combusts any type of fuel listed in Table C–1 of this subpart (except for MSW), unless the use of Tier 4 is required.
   (ii) Shall be used for a unit with a maximum rated heat input capacity greater than 250 mmBtu/hr that combusts any type of fuel listed in Table C–1 of this subpart (except MSW), unless either of the following conditions apply:
      (A) The use of Tier 1 or 2 is permitted, as described in paragraphs (b)(1)(iii), (b)(1)(v), and (b)(2)(ii) of this section.
      (B) The fuel provides 10% or more of the annual heat input to the unit or, if §98.36(c)(3) applies, to the group of units served by a common supply pipe.
   (iv) Shall be used when specified in another applicable subpart of this part, regardless of unit size.

(4) The Tier 4 Calculation Methodology:
   (i) May be used for a unit of any size, combusting any type of fuel. Tier 4 may also be used for any group of stationary fuel combustion units, process units, or manufacturing units that share a common stack or duct.
   (ii) Shall be used if the unit meets all six of the conditions specified in paragraphs (b)(4)(ii)(A) through (b)(4)(ii)(F) of this section:
      (A) The unit has a maximum rated heat input capacity greater than 250 mmBtu/hr, or if the unit combusts municipal solid waste and has a maximum rated input capacity greater than 600 tons per day of MSW.
      (B) The unit combusts solid fossil fuel or MSW as the primary fuel.
      (C) The unit has operated for more than 1,000 hours in any calendar year since 2005.
      (D) The unit has installed CEMS that are required either by an applicable Federal or State regulation or the unit’s operating permit.
      (E) The installed CEMS include a gas monitor of any kind or a stack gas volumetric flow rate monitor, or both and the monitors have been certified, either in accordance with the requirements of part 75 of this chapter, appendix F to part 60 of this chapter, or an applicable State continuous monitoring program.
      (F) The installed gas or stack gas volumetric flow rate monitors are required, either by an applicable Federal or State regulation or by the unit’s operating permit, to undergo periodic quality assurance testing in accordance with either appendix B to part 75 of this chapter, appendix F to part 60 of this chapter, or an applicable State continuous monitoring program.
   (iii) Shall be used for a unit with a maximum rated heat input capacity of 250 mmBtu/hr or less and for a unit that combusts municipal solid waste with a maximum rated input capacity of 600 tons of MSW per day or less.
the unit meets all of the following three conditions:

(A) The unit has both a stack gas volumetric flow rate monitor and a CO₂ concentration monitor.

(B) The unit meets the conditions specified in paragraphs (b)(4)(ii)(B) through (b)(4)(ii)(D) of this section.

(C) The CO₂ and stack gas volumetric flow rate monitors meet the conditions specified in paragraphs (b)(4)(ii)(E) and (b)(4)(ii)(F) of this section.

(iv) May apply to common stack or duct configurations where:

(A) The combined effluent gas streams from two or more stationary fuel combustion units are vented through a monitored common stack or duct. In this case, Tier 4 shall be used if all of the conditions in paragraph (b)(4)(iv)(A)(1) of this section or if the conditions in paragraph (b)(4)(iv)(A)(2) of this section are met.

(B) The combined effluent gas streams from a process or manufacturing unit and a stationary fuel combustion unit are vented through a monitored common stack or duct. In this case, Tier 4 shall be used if the combustion unit and the monitors installed at the common stack or duct meet the requirements of paragraphs (b)(4)(iv)(A) through (b)(4)(iv)(C) of this section, and the CEMS installed at the common stack (or duct) meet the requirements of paragraphs (b)(4)(iv)(D) through (b)(4)(iv)(F) of this section.

(2) At least one of the units and the monitors installed at the common stack or duct meet the requirements of paragraph (b)(4)(iii) of this section.

(B) The combined effluent gas streams from two or more manufacturing or process units are vented through a monitored common stack or duct. In this case, Tier 4 shall be used if the combustion unit and the monitors installed at the common stack or duct meet the applicability criteria specified in paragraph (b)(4)(iv)(A)(1), or (b)(4)(iv)(A)(2) of this section.

(C) The combined effluent gas streams from two or more manufacturing or process units are vented through a common stack or duct. In this case, if any of the units is required by an applicable subpart of this part to use Tier 4, the CO₂ mass emissions may be monitored at each individual unit, or the combined CO₂ mass emissions may be monitored at the common stack or duct. However, if it is not feasible to monitor the individual units, the combined CO₂ mass emissions shall be monitored at the common stack or duct.

(5) The Tier 4 Calculation Methodology shall be used:

(i) Starting on January 1, 2010, for a unit that is required to report CO₂ mass emissions beginning on that date, if all of the monitors needed to measure CO₂ mass emissions have been installed and certified by that date.

(ii) No later than January 1, 2011, for a unit that is required to report CO₂ mass emissions beginning on January 1, 2010, if all of the monitors needed to measure CO₂ mass emissions have not been installed and certified by January 1, 2010. In this case, you may use Tier 2 or Tier 3 to report GHG emissions for 2010. However, if the required CEMS are certified some time in 2010, you need not wait until January 1, 2011 to begin using Tier 4. Rather, you may switch from Tier 2 or Tier 3 to Tier 4 as soon as CEMS certification testing is successfully completed. If this reporting option is chosen, you must document the change in CO₂ calculation methodology in the Monitoring Plan required under §98.3(g)(5) and in the GHG emissions report under §98.3(c). Data recorded by the CEMS during a certification test period in 2010 may be used for reporting under this part, provided that the following two conditions are met:

(A) The certification tests are passed in sequence, with no test failures.

(B) No unscheduled maintenance or repair of the CEMS is performed during the certification test period.

(iii) No later than 180 days following the date on which a change is made that triggers Tier 4 applicability under paragraph (b)(4)(ii) or (b)(4)(iii) of this section (e.g., a change in the primary fuel, manner of unit operation, or installed continuous monitoring equipment).

(6) You may elect to use any applicable higher tier for one or more of the fuels combusted in a unit. For example, if a 100 mmBtu/hr unit combusts natural gas and distillate fuel oil, you may elect to use Tier 1 for natural gas and Tier 3 for the fuel oil, even though Tier 1 could have been used for both fuels. However, for units that use either the Tier 4 or the alternative calculation methodology specified in paragraph
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(a)(5)(iii) of this section, CO₂ emissions from the combustion of all fuels shall be based solely on CEMS measurements.

(c) Calculation of CH₄ and N₂O emissions from stationary combustion sources. You must calculate annual CH₄ and N₂O mass emissions only for units that are required to report CO₂ emissions using the calculation methodologies of this subpart and for only those fuels that are listed in Table C–2 of this subpart.

(1) Use Equation C–8 of this section to estimate CH₄ and N₂O emissions for any fuels for which you use the Tier 1 or Tier 3 calculation methodologies for CO₂, except when natural gas usage in units of therms or mmBtu is obtained from gas billing records. In that case, use Equation C–8a in paragraph (c)(1)(i) of this section or Equation C–8b in paragraph (c)(1)(ii) of this section (as applicable). For Equation C–8, use the same values for fuel consumption that you use for the Tier 1 or Tier 3 calculation.

\[ CH_4 \text{ or } N_2O = 1 \times 10^{-3} \times Fuel \times HHV \times EF \]  
(Eq. C–8)

Where:

\( CH_4 \) or \( N_2O = \) Annual CH₄ or N₂O emissions from the combustion of a particular type of fuel (metric tons).

Fuel = Mass or volume of the fuel combusted, either from company records or directly measured by a fuel flow meter, as applicable (mass or volume per year).

HHV = Default high heat value of the fuel from Table C–1 of this subpart; alternatively, for Tier 3, if actual HHV data are available for the reporting year, you may average these data using the procedures specified in paragraph (a)(2)(ii) of this section, and use the average value in Equation C–8 (mmBtu per mass or volume).

EF = Fuel-specific default emission factor for CH₄ or N₂O, from Table C–2 of this subpart (kg CH₄ or N₂O per mmBtu).

1 \times 10^{-3} = Conversion factor from kilograms to metric tons.

(i) Use Equation C–8a to calculate CH₄ and N₂O emissions when natural gas usage is obtained from gas billing records in units of therms.

\[ CH_4 \text{ or } N_2O = 1 \times 10^{-3} \times Fuel \times 0.1 \times EF \]  
(Eq. C–8a)

where:

\( CH_4 \) or \( N_2O = \) Annual CH₄ or N₂O emissions from the combustion of natural gas (metric tons).

Fuel = Annual natural gas usage, from gas billing records (therms).

EF = Fuel-specific default emission factor for CH₄ or N₂O, from Table C–2 of this subpart (kg CH₄ or N₂O per mmBtu).

0.1 = Conversion factor from therms to mmBtu

1 \times 10^{-3} = Conversion factor from kilograms to metric tons.

(ii) Use Equation C–8b to calculate CH₄ and N₂O emissions when natural gas usage is obtained from gas billing records in units of mmBtu.

\[ CH_4 \text{ or } N_2O = 1 \times 10^{-3} \times Fuel \times EF \]  
(Eq. C–8b)

where:

\( CH_4 \) or \( N_2O = \) Annual CH₄ or N₂O emissions from the combustion of natural gas (metric tons).

Fuel = Annual natural gas usage, from gas billing records (mmBtu).

EF = Fuel-specific default emission factor for CH₄ or N₂O, from Table C–2 of this subpart (kg CH₄ or N₂O per mmBtu).

1 \times 10^{-3} = Conversion factor from kilograms to metric tons.

(2) Use Equation C–9a of this section to estimate CH₄ and N₂O emissions for any fuels for which you use the Tier 2 Equation C–2a of this section to estimate CO₂ emissions. Use the same values for fuel consumption and HHV that you use for the Tier 2 calculation.

\[ CH_4 \text{ or } N_2O = 1 \times 10^{-3} \times Fuel \times EF \]  
(Eq. C–9a)

where:

\( CH_4 \) or \( N_2O = \) Annual CH₄ or N₂O emissions from the combustion of natural gas (metric tons).

Fuel = Annual natural gas usage, from gas billing records (mmBtu).

EF = Fuel-specific default emission factor for CH₄ or N₂O, from Table C–2 of this subpart (kg CH₄ or N₂O per mmBtu).

1 \times 10^{-3} = Conversion factor from kilograms to metric tons.
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CH₄ or N₂O = 1 × 10⁻³ * HHV * EF * Fuel

(Eq. C-9a)

Where:

CH₄ or N₂O = Annual CH₄ or N₂O emissions from the combustion of a particular type of fuel (metric tons).

Fuel = Mass or volume of the fuel combusted during the reporting year.

HHV = High heat value of the fuel, averaged for all valid measurements for the reporting year (mmBtu per mass or volume).

EF = Fuel-specific default emission factor for CH₄ or N₂O, from Table C-2 of this subpart (kg CH₄ or N₂O per mmBtu).

1 × 10⁻³ = Conversion factor from kilograms to metric tons.

(3) Use Equation C-9b of this section to estimate CH₄ and N₂O emissions for any fuels for which you use Equation C-2c of this section to calculate the CO₂ emissions. Use the same values for steam generation and the ratio “B” that you use for Equation C-2c.

CH₄ or N₂O = 1 × 10⁻³ * Steam * B * EF

(Eq. C-9b)

Where:

CH₄ or N₂O = Annual CH₄ or N₂O emissions from the combustion of a solid fuel (metric tons).

Steam = Total mass of steam generated by solid fuel combustion during the reporting year (lb steam).

B = Ratio of the boiler’s maximum rated heat input capacity to its design rated steam output (mmBtu/lb steam).

EF = Fuel-specific emission factor for CH₄ or N₂O, from Table C-2 of this subpart (kg CH₄ or N₂O per mmBtu).

1 × 10⁻³ = Conversion factor from kilograms to metric tons.

(4) Use Equation C-10 of this section for: units subject to subpart D of this part; units that qualify for and elect to use the alternative CO₂ mass emissions calculation methodologies described in paragraph (a)(5) of this section; and units that use the Tier 4 Calculation Methodology.

CH₄ or N₂O = 0.001 * (HI)ₐ * EF

(Eq. C-10)

Where:

CH₄ or N₂O = Annual CH₄ or N₂O emissions from the combustion of a particular type of fuel (metric tons).

(HI)ₐ = Cumulative annual heat input from combustion of the fuel (mmBtu).

EF = Fuel-specific emission factor for CH₄ or N₂O, from Table C-2 of this section (kg CH₄ or N₂O per mmBtu).

0.001 = Conversion factor from kg to metric tons.

(i) If only one type of fuel listed in Table C-2 of this subpart is combusted during the reporting year, substitute the cumulative annual heat input from combustion of the fuel into Equation C-10 of this section to calculate the annual CH₄ or N₂O emissions. For units in the Acid Rain Program and units that report heat input data to EPA year-round according to part 75 of this chapter, obtain the cumulative annual heat input directly from the electronic data reports required under §75.64 of this chapter. For Tier 4 units, use the best available information, as described in paragraph (c)(4)(ii)(C) of this section, to estimate the cumulative annual heat input (HI)ₐ.

(ii) If more than one type of fuel listed in Table C-2 of this subpart is combusted during the reporting year, use Equation C-10 of this section separately for each type of fuel, except as provided in paragraph (c)(4)(ii)(B) of this section. Determine the appropriate values of (HI)ₐ as follows:
(A) For units in the Acid Rain Program and other units that report heat input data to EPA year-round according to part 75 of this chapter, obtain $(HI)_A$ for each type of fuel from the electronic data reports required under §75.64 of this chapter, except as otherwise provided in paragraphs (c)(4)(ii)(B) and (c)(4)(ii)(D) of this section.

(B) For a unit that uses CEMS to monitor hourly heat input according to part 75 of this chapter, the value of $(HI)_A$ obtained from the electronic data reports under §75.64 of this chapter may be attributed exclusively to the fuel with the highest $F$-factor, when the reporting option in 3.3.6.5 of appendix F to part 75 of this chapter is selected and implemented.

(C) For Tier 4 units, use the best available information (e.g., fuel feed rate measurements, fuel heating values, engineering analysis) to estimate the value of $(HI)_A$ for each type of fuel. Instrumentation used to make these estimates is not subject to the calibration requirements of §98.3(i) or to the QA requirements of §98.34.

(D) Units in the Acid Rain Program and other units that report heat input data to EPA year-round according to part 75 of this chapter may use the best available information described in paragraph (c)(4)(ii)(C) of this section, to estimate $(HI)_A$ for each fuel type, whenever fuel-specific heat input values cannot be directly obtained from the electronic data reports under §75.64 of this chapter.

(5) When multiple fuels are combusted during the reporting year, sum the fuel-specific results from Equations C–8, C–8a, C–8b, C–9a, C–9b, or C–10 of this section (as applicable) to obtain the total annual CH$_4$ and N$_2$O emissions, in metric tons.

(6) Calculate the annual CH$_4$ and N$_2$O mass emissions from the combustion of blended fuels as follows:

(i) If the mass or volume of each component fuel in the blend is measured before the fuels are mixed and combusted, calculate and report CH$_4$ and N$_2$O emissions separately for each component fuel, using the applicable procedures in this paragraph (c).

(ii) If the mass or volume of each component fuel in the blend is not measured before the fuels are mixed and combusted, a reasonable estimate of the percentage composition of the blend, based on best available information, is required. Perform the following calculations for each component fuel "i" that is listed in Table C–2:

(A) Multiply (% Fuel)$_i$, the estimated mass or volume percentage (decimal fraction) of component fuel "i", by the total annual mass or volume of the blended fuel combusted during the reporting year, to obtain an estimate of the annual consumption of component "i";

(B) Multiply the result from paragraph (c)(6)(ii)(A) of this section by the HHV of the fuel (default value or, if available, the measured annual average value), to obtain an estimate of the annual heat input from component "i";

(C) Calculate the annual CH$_4$ and N$_2$O emissions from component "i", using Equation C–8, C–8a, C–8b, C–9a, or C–10 of this section, as applicable;

(D) Sum the annual CH$_4$ emissions across all component fuels to obtain the annual CH$_4$ emissions for the blend. Similarly sum the annual N$_2$O emissions across all component fuels to obtain the annual N$_2$O emissions for the blend. Report these annual emissions totals.

(d) Calculation of CO$_2$ from sorbent.

(1) When a unit is a fluidized bed boiler, is equipped with a wet flue gas desulfurization system, or uses other acid gas emission controls with sorbent injection to remove acid gases, if the chemical reaction between the acid gas and the sorbent produces CO$_2$ emissions, use Equation C–11 of this section to calculate the CO$_2$ emissions from the sorbent, except when those CO$_2$ emissions are monitored by CEMS. When a sorbent other than CaCO$_3$ is used, determine site-specific values of $R$ and MWs.
$CO_2 = 0.91 * S * R * \left( \frac{MW_{CO2}}{MW_S} \right)$  
(Eq. C-11)

Where:
- $CO_2$ = $CO_2$ emitted from sorbent for the reporting year (metric tons).
- $S$ = Limestone or other sorbent used in the reporting year, from company records (short tons).
- $R$ = The number of moles of $CO_2$ released upon capture of one mole of the acid gas species being removed ($R = 1.00$ when the sorbent is CaCO$_3$ and the targeted acid gas species is SO$_2$).
- $MW_{CO2}$ = Molecular weight of carbon dioxide (44).
- $MW_S$ = Molecular weight of sorbent (100 if calcium carbonate).
- 0.91 = Conversion factor from short tons to metric tons.

(2) The total annual $CO_2$ mass emissions reported for the unit shall include the $CO_2$ emissions from the combustion process and the $CO_2$ emissions from the sorbent.

(e) Biogenic $CO_2$ emissions from combustion of biomass with other fuels. Use the applicable procedures of this paragraph (e) to estimate biogenic $CO_2$ emissions from units that combust a combination of biomass and fossil fuels (i.e., either co-fired or blended fuels). Separate reporting of biogenic $CO_2$ emissions from the combined combustion of biomass and fossil fuels is required for those biomass fuels listed in Table C–1 of this subpart (except MSW and tires), in a unit of any size, including units equipped with a $CO_2$ CEMS, except when the use of Tier 2 is required as specified in paragraph (b)(1)(iv) of this section. Determine the quantity of biomass combusted using one of the following procedures in this paragraph (e)(1), as appropriate, and document the selected procedures in the Monitoring Plan under §98.3(g):

(i) Company records.

(ii) The procedures in paragraph (e)(5) of this section.

(iii) The best available information for premixed fuels that contain biomass and fossil fuels (e.g., liquid fuel mixtures containing biodiesel).

(2) You may use the procedures of this paragraph if the following three conditions are met: First, a $CO_2$ CEMS (or a surrogate O$_2$ monitor) and a stack gas flow rate monitor are used to determine the annual $CO_2$ mass emissions (either according to part 75 of this chapter, pursuant to paragraph (a)(5) of this section. However, if the owner or operator opts to report biogenic $CO_2$ emissions separately for these units, the appropriate method(s) in this paragraph (e) shall be used. Separate reporting of biogenic $CO_2$ emissions from the combustion of tires is also optional, but may be reported by following the provisions of paragraph (e)(3) of this section.

(1) You may use Equation C–1 of this subpart to calculate the annual $CO_2$ mass emissions from the combustion of the biomass fuels listed in Table C–1 of this subpart (except MSW and tires), in a unit of any size, including units equipped with a $CO_2$ CEMS, except when the use of Tier 2 is required as specified in paragraph (b)(1)(iv) of this section. Determine the quantity of biomass combusted using one of the following procedures in this paragraph (e)(1), as appropriate, and document the selected procedures in the Monitoring Plan under §98.3(g):

(i) Company records.

(ii) The procedures in paragraph (e)(5) of this section.

(iii) The best available information for premixed fuels that contain biomass and fossil fuels (e.g., liquid fuel mixtures containing biodiesel).

(2) You may use the procedures of this paragraph if the following three conditions are met: First, a $CO_2$ CEMS (or a surrogate O$_2$ monitor) and a stack gas flow rate monitor are used to determine the annual $CO_2$ mass emissions (either according to part 75 of this chapter, the Tier 4 Calculation Methodology, or the alternative calculation methodology specified in paragraph (a)(6)(iii) of this section); second, neither MSW nor tires is combusted in the unit during the reporting year; and third, the $CO_2$ emissions consist solely of combustion products (i.e., no process or sorbent emissions included).

(i) For each operating hour, use Equation C–12 of this section to determine the volume of $CO_2$ emitted.
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\[
V_{CO2h} = \frac{(\%CO_2)_h \times Q_h \times t_h}{100} \quad \text{(Eq. C-12)}
\]

Where:
- \(V_{CO2h}\) = Hourly volume of \(CO_2\) emitted (scf).
- \((\%CO_2)_h\) = Hourly average \(CO_2\) concentration, measured by the \(CO_2\) concentration monitor, or, if applicable, calculated from the hourly average \(O_2\) concentration (%\(CO_2\)).
- \(Q_h\) = Hourly average stack gas volumetric flow rate, measured by the stack gas volumetric flow rate monitor (scfh).
- \(t_h\) = Source operating time (decimal fraction of the hour during which the source combusts fuel, i.e., 1.0 for a full operating hour, 0.5 for 30 minutes of operation, etc.).
- 100 = Conversion factor from percent to a decimal fraction.

(ii) Sum all of the hourly \(V_{CO2h}\) values for the reporting year, to obtain \(V_{total}\), the total annual volume of \(CO_2\) emitted.

(iii) Calculate the annual volume of \(CO_2\) emitted from fossil fuel combustion using Equation C–13 of this section. If two or more types of fossil fuel are combusted during the year, perform a separate calculation with Equation C–13 of this section for each fuel and sum the results.

\[
V_{ff} = \frac{\text{Fuel} \times F_c \times \text{HHV}}{10^6} \quad \text{(Eq. C-13)}
\]

Where:
- \(V_{ff}\) = Annual volume of \(CO_2\) emitted from combustion of a particular fossil fuel (scf).
- \(\text{Fuel}\) = Total quantity of the fossil fuel combusted in the reporting year, from company records, as defined in §98.6 (lb for solid fuel, gallons for liquid fuel, and scf for gaseous fuel).
- \(F_c\) = Fuel-specific carbon based F-factor, either a default value from Table 1 in section 3.3.5 of appendix F to part 75 of this chapter, or a site-specific value determined under section 3.3.6 of appendix F to part 75 (scf \(CO_2\)/mmBtu).
- \(\text{HHV}\) = High heat value of the fossil fuel, from fuel sampling and analysis (annual average value in Btu/lb for solid fuel, Btu/gal for liquid fuel and Btu/scf for gaseous fuel, sampled as specified (e.g., monthly, quarterly, semi-annually, or by lot) in §98.34(a)(2)). The average HHV shall be calculated according to the requirements of paragraph (a)(2)(ii) of this section.
- 10^6 = Conversion factor, Btu per mmBtu.

(iv) Subtract \(V_{ff}\) from \(V_{total}\) to obtain \(V_{bio}\), the annual volume of \(CO_2\) from the combustion of biomass.

(v) Calculate the biogenic percentage of the annual \(CO_2\) emissions, expressed as a decimal fraction, using Equation C–14 of this section:

\[
\% \text{Biogenic} = \frac{V_{bio}}{V_{total}} \quad \text{(Eq. C-14)}
\]

(vi) Calculate the annual biogenic \(CO_2\) mass emissions, in metric tons, by multiplying the results obtained from Equation C–14 of this section by the annual \(CO_2\) mass emissions in metric tons, as determined:

(A) Under paragraph (a)(4)(vi) of this section, for units using the Tier 4 Calculation Methodology.

(B) Under paragraph (a)(5)(iii)(B) of this section, for units using the alternative calculation methodology specified in paragraph (a)(5)(iii).

(C) From the electronic data report required under §75.64 of this chapter, for units in the Acid Rain Program and other units using CEMS to monitor and report \(CO_2\) mass emissions according to part 75 of this chapter. However, before calculating the annual biogenic \(CO_2\) mass emissions, multiply the cumulative annual \(CO_2\) mass emissions by 0.91 to convert from short tons to metric tons.

(3) You must use the procedures in paragraphs (e)(3)(i) through (e)(3)(iii) of this section to determine the annual biogenic \(CO_2\) emissions from the combustion of MSW, except as otherwise provided in paragraph (e)(3)(iv) of this section. These procedures also may be used for any unit that co-fires biomass and fossil fuels, including units equipped with a \(CO_2\) CEMS, and units for which optional separate reporting of biogenic \(CO_2\) emissions from the combustion of tires is selected.

(i) Use an applicable \(CO_2\) emissions calculation method in this section to quantify the total annual \(CO_2\) mass emissions from the unit.
(ii) Determine the relative proportions of biogenic and non-biogenic CO\textsubscript{2} emissions in the flue gas on a quarterly basis using the method specified in §98.34(d) (for units that combust MSW as the primary fuel or as the only fuel with a biogenic component) or in §98.34(e) (for other units, including units that combust tires).

(iii) Determine the annual biogenic CO\textsubscript{2} mass emissions from the unit by multiplying the total annual CO\textsubscript{2} mass emissions by the annual average biogenic decimal fraction obtained from §98.34(d) or §98.34(e), as applicable.

(iv) If the combustion of MSW and/or tires provides no more than 10 percent of the annual heat input to a unit, or if a small, batch incinerator combusts no more than 1,000 tons per year of MSW, you may estimate the annual biogenic CO\textsubscript{2} emissions as follows, in lieu of following the procedures in paragraphs (e)(3)(i) through (e)(3)(iii) of this section:

(A) Calculate the total annual CO\textsubscript{2} emissions from combustion of MSW and/or tires in the unit, using the Tier 1 calculation methodology in paragraph (a)(1) of this section.

\[
(Fuel)_p = \frac{[H \times S] - (HI)_{nb}}{2000 \times (HHV)_{bio} \times (Eff)_{bio}} \quad \text{(Eq. C-15)}
\]

Where:

\((Fuel)_p\) = Quantity of biomass consumed during the measurement period “p” (tons/year or tons/month, as applicable).

\(H\) = Average enthalpy of the boiler steam for the measurement period (Btu/lb).

\(S\) = Total boiler steam production for the measurement period (lb/month or lb/year, as applicable).

\((HI)_{nb}\) = Heat input from co-fired fossil fuels and non-biomass-derived fuels for the measurement period, based on company records of fuel usage and default or measured HHV values (Btu/month or Btu/year, as applicable).

\((HHV)_{bio}\) = Default or measured high heat value of the biomass fuel (Btu/lb).

\((Eff)_{bio}\) = Percent efficiency of biomass-to-energy conversion, expressed as a decimal fraction.

2000 = Conversion factor (lb/ton).

(B) Multiply the result from paragraph (e)(3)(iv)(A) of this section by the appropriate default factor to determine the annual biogenic CO\textsubscript{2} emissions, in metric tons. For MSW, use a default factor of 0.60 and for tires, use a default factor of 0.20.

(4) If Equation C–1 or Equation C–2a of this section is selected to calculate the annual biogenic mass emissions for wood, wood waste, or other solid biomass-derived fuel, Equation C–15 of this section may be used to quantify biogenic fuel consumption, provided that all of the required input parameters are accurately quantified. Similar equations and calculation methodologies based on steam generation and boiler efficiency may be used, provided that they are documented in the GHG Monitoring Plan required by §98.3(g)(5).

(5) For units subject to subpart D of this part and for units that use the methods in part 75 of this chapter to quantify CO\textsubscript{2} mass emissions in accordance with paragraph (a)(5) of this section, you may calculate biogenic CO\textsubscript{2} emissions from the combustion of biomass fuels listed in Table C–1 of this subpart using Equation C–15a. This equation may not be used to calculate biogenic CO\textsubscript{2} emissions from the combustion of tires or MSW; the methods described in paragraph (e)(3) of this section must be used for those fuels. Whenever \((HI)_A\), the annual heat input from combustion of biomass fuel in Equation C–15a, cannot be determined solely from the information in the electronic emissions reports under §75.84 of this chapter (e.g., in cases where a unit uses CEMS in combination with multiple F-factors, a worst-case F-factor, or a prorated F-factor to report heat input rather than reporting heat input based on fuel type), use the best available information (as described in §§98.33(c)(4)(i)(A)\textsuperscript{c} and (c)(4)(i)(D)) to determine \((HI)_A\).

\[
CO_2 = 0.001 \times (HI)_A \times EF \quad \text{(Eq. C–15a)}
\]
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where:

CO₂ = Annual CO₂ mass emissions from the combustion of a particular type of biomass fuel listed in Table C–1 (metric tons)

(HI)_A = Annual heat input from the biomass fuel, obtained, where feasible, from the electronic emissions reports required under §75.64 of this chapter. Where this is not feasible use best available information, as described in §§98.33(c)(4)(i)(C) and (c)(4)(ii)(D) (mmBtu)

EF = CO₂ emission factor for the biomass fuel, from Table C–1 (kg CO₂/mmBtu)

0.001 = Conversion factor from kg to metric tons


§ 98.34 Monitoring and QA/QC requirements.

The CO₂ mass emissions data for stationary fuel combustion sources shall be monitored as follows:

(a) For the Tier 2 Calculation Methodology:

(1) All fuel samples shall be taken at a location in the fuel handling system that provides a sample representative of the fuel combusted. The fuel sampling and analysis may be performed by either the owner or operator or the supplier of the fuel.

(2) The minimum required frequency of the HHV sampling and analysis for each type of fuel or fuel mixture (blend) is specified in this paragraph. When the specified frequency for a particular fuel or blend is based on a specified time period (e.g., week, month, quarter, or half-year), fuel sampling and analysis is required only for those time periods in which the fuel or blend is combusted. The owner or operator may perform fuel sampling and analysis more often than the minimum required frequency, in order to obtain a more representative annual average HHV.

(i) For natural gas, semiannual sampling and analysis is required (i.e., twice in a calendar year, with consecutive samples taken at least four months apart).

(ii) For coal, the “type” of fuel means the rank of the coal (i.e., anthracite, bituminous, sub-bituminous, or lignite). For fuel oil, the “type” of fuel means the grade number classification of the oil (e.g., No. 1 oil, No. 2 oil, kerosene, Jet A fuel, etc.).

(A) For coal, the “type” of fuel means the rank of the coal (i.e., anthracite, bituminous, sub-bituminous, or lignite). For fuel oil, the “type” of fuel means the grade number classification of the oil (e.g., No. 1 oil, No. 2 oil, kerosene, Jet A fuel, etc.).

(B) The owner or operator shall document in the monitoring plan under §98.3(g)(5) how the monthly sampling of each type of fuel is performed.

(iii) For liquid fuels other than fuel oil, and for gaseous fuels other than natural gas (including biogas), sampling and analysis is required at least once per calendar quarter. To the extent practicable, consecutive quarterly samples shall be taken at least 30 days apart.
(iv) For other solid fuels (except MSW), weekly sampling is required to obtain composite samples, which are then analyzed monthly.

(v) For fuel blends that are received already mixed, or that are mixed on-site without measuring the exact amount of each component, as described in paragraph (a)(3)(ii) of this section, determine the HHV of the blend as follows. For blends of solid fuels (except MSW), weekly sampling is required to obtain composite samples, which are analyzed monthly. For blends of liquid or gaseous fuels, sampling and analysis is required at least once per calendar quarter. More frequent sampling is recommended if the composition of the blend varies significantly during the year.

(3) Special considerations for blending of fuels. In situations where different types of fuel listed in Table C-1 of this subpart (for example, different ranks of coal or different grades of fuel oil) are in the same state of matter (i.e., solid, liquid, or gas), and are blended prior to combustion, use the following procedures to determine the appropriate CO₂ emission factor and HHV for the blend.

(i) If the fuels to be blended are received separately, and if the quantity (mass or volume) of each fuel is measured before the fuels are mixed and combusted, then, for each component of the blend, calculate the CO₂ mass emissions separately. Substitute into Equation C-2a of this subpart the annual average HHV value for the blend according to §98.33(a)(2)(ii).

(ii) If the fuel is received as a blend (i.e., already mixed) or if the components are mixed on site without precisely measuring the mass or volume of each one individually, a reasonable estimate of the relative proportions of the components of the blend must be made, using the best available information (e.g., the approximate annual average mass or volume percentage of each fuel, based on the typical or expected range of values). Determine the appropriate CO₂ emission factor and HHV for use in Equation C-2a of this subpart, as follows:

(A) Consider the blend to be the “fuel type,” measure its HHV at the frequency prescribed in paragraph (a)(2)(v) of this section, and determine the annual average HHV value for the blend according to §98.33(a)(2)(ii).

(B) Calculate a heat-weighted CO₂ emission factor, (EF)_B, for the blend, using Equation C-16 of this section. The heat-weighting in Equation C-16 is provided by the default HHVs (from Table C-1) and the estimated mass or volume percentages of the components of the blend.

(C) Substitute into Equation C-2a of this subpart, the annual average HHV for the blend (from paragraph (a)(3)(i)(A) of this section) and the calculated value of (EF)_B, along with the total mass or volume of the blend combusted during the reporting year, to determine the annual CO₂ mass emissions from combustion of the blend.

\[
(\text{EF})_B = \frac{\sum_{i=1}^{n} ((\text{HHV})_i \times (%\text{Fuel})_i \times (EF)_i)}{\text{(HHV)}_B}
\]

(Eq. C-16)

where:

(\text{(EF)}_B = \text{Heat-weighted CO₂ emission factor for the blend (kg CO₂/mmBtu})

(\text{(HHV)}_B = \text{Default high heat value for fuel “i” in the blend, from Table C-1 (mmBtu per mass or volume})

(%\text{Fuel})_i = \text{Estimated mass or volume percentage of fuel “i” (mass % or volume %, as applicable, expressed as a decimal fraction; e.g., 25% = 0.25})

(\text{(EF)}_i = \text{Default CO₂ emission factor for fuel “i” from Table C-1 (mmBtu per mass or volume})
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(HHV)<sub>B</sub> = Annual average high heat value for the blend, calculated according to §98.33(a)(2)(ii) (mmBtu per mass or volume)

(iii) Note that for the case described in paragraph (a)(3)(ii) of this section, if measured HHV values for the individual fuels in the blend or for the blend itself are not routinely received at the minimum frequency prescribed in paragraph (a)(2) of this section (or at a greater frequency), and if the unit qualifies to use Tier 1, calculate (HHV)<sub>B</sub><sup>*</sup>, the heat-weighted default HHV for the blend, using Equation C–17 of this section. Then, use Equation C–16 of this section, replacing the term (HHV)<sub>B</sub> with (HHV)<sub>B</sub><sup>*</sup> in the denominator, to determine the heat-weighted CO<sub>2</sub> emission factor for the blend. Finally, substitute into Equation C–1 of this subpart, the calculated values of (HHV)<sub>B</sub><sup>*</sup> and (EF)<sub>B</sub>, along with the total mass or volume of the blend combusted during the reporting year, to determine the annual CO<sub>2</sub> mass emissions from combustion of the blend.

\[
HHV_B^* = \sum_{i=1}^{n} [(HHV)_i \times (%Fuel)_i]
\]

(Eq. C–17')

where:

(HHV)<sub>B</sub><sup>*</sup> = Heat-weighted default high heat value for the blend (mmBtu per mass or volume)

(HHV)<sub>i</sub> = Default high heat value for fuel “i” in the blend, from Table C–1 (mmBtu per mass or volume)

(%Fuel)<sub>i</sub> = Estimated mass or volume percentage of fuel “i” in the blend (mass % or volume %, as applicable, expressed as a decimal fraction)

(iv) If the fuel blend described in paragraph (a)(3)(i) of this section consists of a mixture of fuel(s) listed in Table C–1 of this subpart and one or more fuels not listed in Table C–1, calculate CO<sub>2</sub> and other GHG emissions only for the Table C–1 fuel(s), using the best available estimate of the mass or volume percentage(s) of the Table C–1 fuels in the blend. In this case, Tier 1 shall be used, with the following modifications to Equations C–17 and C–1, to account for the fact that not all of the fuels in the blend are listed in Table C–1:

(A) In Equation C–17, apply the term (Fuel), only to the Table C–1 fuels. For each Table C–1 fuel, (Fuel), will be the estimated mass or volume percentage of the fuel in the blend, divided by the sum of the mass or volume percentages of the Table C–1 fuels. For example, suppose that a blend consists of two Table C–1 fuels (“A” and “B”) and one fuel type (“C”) not listed in the Table, and that the volume percentages of fuels A, B, and C in the blend, expressed as decimal fractions, are, respectively, 0.50, 0.30, and 0.20. The term (Fuel), in Equation C–17 for fuel A will be 0.50/(0.50 + 0.30) = 0.625, and for fuel B, (Fuel), will be 0.30/(0.50 + 0.30) = 0.375.

(B) In Equation C–1, the term “Fuel” will be equal to the total mass or volume of the blended fuel combusted during the year multiplied by the sum of the mass or volume percentages of the Table C–1 fuels in the blend. For the example in paragraph (a)(3)(i)(A) of this section, “Fuel” = (Annual volume of the blend combusted)(0.80).

(4) If, for a particular type of fuel, HHV sampling and analysis is performed more often than the required frequency specified in paragraph (a)(2) of this section, the results of all valid fuel analyses shall be used in the GHG emission calculations.

(5) If, for a particular type of fuel, valid HHV values are obtained at less than the minimum frequency specified in paragraph (a)(2) of this section, appropriate substitute data values shall be used in the emissions calculations, in accordance with the procedures of §98.35.

(6) You must use one of the following appropriate fuel sampling and analysis methods. The HHV may be calculated using chromatographic analysis together with standard heating values of the fuel constituents, provided that the gas chromatograph is operated, maintained, and calibrated according to the
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(C) You may use an industry-accepted practice.

(ii) In addition to the initial calibration required by §98.3(i), recalibrate each fuel flow meter (except as otherwise provided in paragraph (b)(1)(iii) of this section) according to one of the following. You may recalibrate annually, at the minimum frequency specified by the manufacturer, or at the interval specified by industry standard practice.

(iii) Fuel billing meters are exempted from the initial and ongoing calibration requirements of this paragraph and from the Monitoring Plan and recordkeeping requirements of §§98.3(g)(5)(i)(C), (g)(6), and (g)(7), provided that the fuel supplier and the unit combusting the fuel do not have any common owners and are not owned by subsidiaries or affiliates of the same company. Meters used exclusively to measure the flow rates of fuels that are only used for unit startup are also exempted from the initial and ongoing calibration requirements of this paragraph.

(iv) For the initial calibration of an orifice, nozzle, or venturi meter; in-situ calibration of the transmitters is sufficient. A primary element inspection (PEI) shall be performed at least once every three years.

(v) For the continuously-operating units and processes described in §98.3(i)(6), the required flow meter recalibrations and, if necessary, the PEIs may be postponed until the next scheduled maintenance outage.

(vi) If a mixture of liquid or gaseous fuels is transported by a common pipe, you may either separately meter each
of the fuels prior to mixing, using flow meters calibrated according to §98.3(i), or consider the fuel mixture to be the "fuel type" and meter the mixed fuel, using a flow meter calibrated according to §98.3(i).

(2) Oil tank drop measurements (if used to determine liquid fuel use volume) shall be performed according to any an appropriate method published by a consensus-based standards organization (e.g., the American Petroleum Institute).

(3) The carbon content and, if applicable, molecular weight of the fuels shall be determined according to the procedures in this paragraph (b)(3).

(i) All fuel samples shall be taken at a location in the fuel handling system that provides a sample representative of the fuel combusted. The fuel sampling and analysis may be performed by either the owner or operator or by the supplier of the fuel.

(ii) For each type of fuel, the minimum required frequency for collecting and analyzing samples for carbon content and (if applicable) molecular weight is specified in this paragraph.

(A) For natural gas, semiannual sampling and analysis is required (i.e., twice in a calendar year, with consecutive samples taken at least four months apart).

(B) For coal and fuel oil and for any other solid or liquid fuel that is delivered in lots, analysis of at least one representative sample from each fuel lot is required. For fuel oil, as an alternative to sampling each fuel lot, a sample may be taken upon each addition of oil to the storage tank. Flow proportional sampling, continuous drip sampling, or daily manual oil sampling may be used, in lieu of sampling each fuel lot. If the daily manual oil sampling option is selected, sampling from a particular tank is required only on days when oil from the tank is combusted by the unit (or units) served by the tank. If you elect to sample from the storage tank upon each addition of oil to the tank, you must take at least one sample from each tank that is currently in service and whenever oil is added to the tank, for as long as the tank remains in service. You need not take any samples from a storage tank while it is out of service. Rather, take a sample when the tank is brought into service and whenever oil is added to the tank, for as long as the tank remains in service. If multiple additions of oil are made to a particular in service tank on a given day (e.g., from multiple deliveries), one sample taken after the final addition of oil is sufficient. For the purposes of this section, a fuel lot is defined as a shipment or delivery of a single type of fuel (e.g., ship load, barge load, group of trucks, group of railroad cars, oil delivery via pipeline from a tank farm, etc.). However, if multiple deliveries of a particular type of fuel are received from the same supply source in a given calendar month, the deliveries for that month may be considered, collectively, to comprise a fuel lot, requiring only one representative sample, subject to the following conditions:

(1) For coal, the "type" of fuel means the rank of the coal (i.e., anthracite, bituminous, sub-bituminous, or lignite). For fuel oil, the "type" of fuel means the grade number or classification of the oil (e.g., No. 1 oil, No. 2 oil, kerosene, Jet A fuel, etc.).

(2) The owner or operator shall document in the monitoring plan under §98.3(g)(5) how the monthly sampling of each type of fuel is performed.

(C) For liquid fuels other than fuel oil and for biogas, sampling and analysis is required at least once per calendar quarter. To the extent practicable, consecutive quarterly samples shall be taken at least 30 days apart.

(D) For other solid fuels (except MSW), weekly sampling is required to obtain composite samples, which are then analyzed monthly.

(E) For gaseous fuels other than natural gas and biogas (e.g., process gas), daily sampling and analysis to determine the carbon content and molecular weight of the fuel is required if continuous, on-line equipment, such as a gas chromatograph, is in place to make these measurements. Otherwise, weekly sampling and analysis shall be performed.
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(F) For mixtures (blends) of solid fuels, weekly sampling is required to obtain composite samples, which are analyzed monthly. For blends of liquid fuels, and for gas mixtures consisting only of natural gas and biogas, sampling and analysis is required at least once per calendar quarter. For gas mixtures that contain gases other than natural gas (including biogas), daily sampling and analysis to determine the carbon content and molecular weight of the fuel is required if continuous, on-line equipment is in place to make these measurements. Otherwise, weekly sampling and analysis shall be performed.

(iii) If, for a particular type of fuel, sampling and analysis for carbon content and molecular weight is performed more often than the minimum frequency specified in paragraph (b)(3) of this section, the results of all valid fuel analyses shall be used in the GHG emission calculations.

(iv) If, for a particular type of fuel, sampling and analysis for carbon content and molecular weight is performed at less than the minimum frequency specified in paragraph (b)(3) of this section, appropriate substitute data values shall be used in the emissions calculations, in accordance with the missing data procedures of §98.33.

(v) To calculate the CO₂ mass emissions from combustion of a blend of fuels in the same state of matter (solid, liquid, or gas), you may either:

(A) Apply Equation C–3, C–4 or C–5 of this subpart (as applicable) to each component of the blend, if the mass or volume, the carbon content, and (if applicable), the molecular weight of each component are accurately measured prior to blending; or

(B) Consider the blend to be the “fuel type.” Then, at the frequency specified in paragraph (b)(3)(ii)(F) of this section, measure the carbon content and, if applicable, the molecular weight of the blend and calculate the annual average value of each parameter in the manner described in §98.33(a)(2)(ii). Also measure the mass or volume of the blended fuel combusted during the reporting year. Substitute these measured values into Equation C–3, C–4, or C–5 of this subpart (as applicable).

(4) You must use one of the following appropriate fuel sampling and analysis methods. The results of chromatographic analysis of the fuel may be used, provided that the gas chromatograph is operated, maintained, and calibrated according to the manufacturer’s instructions. Alternatively, you may use a method published by a consensus-based standards organization if such a method exists, or you may use industry standard practice to determine the carbon content and molecular weight (for gaseous fuel) of the fuel. Consensus-based standards organizations include, but are not limited to, the following: ASTM International (100 Barr Harbor Drive, P.O. Box CB700, West Conshohocken, Pennsylvania 19428–B295, (800) 242-1373, http://www.astm.org), the American National Standards Institute (ANSI, 1819 L Street, NW., 6th floor, Washington, DC 20036, (202) 293–8020, http://wwwansi.org), the American Gas Association (AGA, 400 North Capitol Street, NW., 4th Floor, Washington, DC 20001, (202) 824–7000, http://www.agag.org), the American Society of Mechanical Engineers (ASME, Three Park Avenue, New York, NY 10016–5990, (800) 843–2763, http://www.asme.org), the American Petroleum Institute (API, 1220 L Street, NW., Washington, DC 20005–4070, (202) 682–8000, http://www.api.org), and the North American Energy Standards Board (NAESB, 801 Travis Street, Suite 1675, Houston, TX 77002, (713) 356–0060, http://www.api.org). The method(s) used shall be documented in the Monitoring Plan required under §98.3(g)(5).

(c) For the Tier 4 Calculation Methodology, the CO₂, flow rate, and (if applicable) moisture monitors must be certified prior to the applicable deadline specified in §98.33(b)(5).

(1) For initial certification, you may use any one of the following three procedures in this paragraph.

(i) §§ 75.20(c)(2), (c)(4), and (c)(5) through (c)(7) of this chapter and appendix A to part 75 of this chapter.

(ii) The calibration drift test and relative accuracy test audit (RATA) procedures of Performance Specification 3 in appendix B to part 60 of this chapter (for the CO₂ concentration monitor) and Performance Specification 6 in appendix B to part 60 of this chapter (for
the continuous emission rate monitoring system (CERMS)).

(iii) The provisions of an applicable State continuous monitoring program.

(2) If an $O_2$ concentration monitor is used to determine $CO_2$ concentrations, the applicable provisions of part 75 of this chapter, part 60 of this chapter, or an applicable State continuous monitoring program shall be followed for initial certification and on-going quality assurance, and all required RATAs of the monitor shall be done on a percent $CO_2$ basis.

(3) For ongoing quality assurance, follow the applicable procedures in either appendix B to part 75 of this chapter, appendix F to part 60 of this chapter, or an applicable State continuous monitoring program. If appendix F to part 60 of this chapter is selected for on-going quality assurance, perform daily calibration drift assessments for both the $CO_2$ monitor (or surrogate $O_2$ monitor) and the flow rate monitor, conduct cylinder gas audits of the $CO_2$ concentration monitor in three of the four quarters of each year (except for non-operating quarters), and perform annual RATAs of the $CO_2$ concentration monitor and the CERMS.

(4) For the purposes of this part, the stack gas volumetric flow rate monitor RATAs required by appendix B to part 75 of this chapter and the annual RATAs of the CERMS required by appendix F to part 60 of this chapter need only be done at one operating level, representing normal load or normal process operating conditions, both for initial certification and for ongoing quality assurance.

(5) If, for any source operating hour, quality assured data are not obtained with a $CO_2$ monitor (or surrogate $O_2$ monitor), flow rate monitor, or (if applicable) moisture monitor, use appropriate substitute data values in accordance with the missing data provisions of §98.35.

(6) For certain applications where combined process emissions and combustion emissions are measured, the $CO_2$ concentrations in the flue gas may be considerably higher than for combustion emissions alone. In such cases, the span of the $CO_2$ monitor may, if necessary, be set higher than the specified levels in the applicable regulations. If the $CO_2$ span value is set higher than 20 percent $CO_2$, the cylinder gas audits of the $CO_2$ monitor under appendix F to part 60 of this chapter may be performed at 40 to 60 percent and 80 to 100 percent of span, in lieu of the prescribed calibration levels of 5 to 8 percent $CO_2$ and 10 to 14 percent $CO_2$.

(7) Hourly average data from the CEMS shall be validated in a manner consistent with one of the following: §§60.13(h)(2)(i) through (h)(2)(vi) of this chapter; §75.10(d)(1) of this chapter; or the hourly data validation requirements of an applicable State CEM regulation.

(d) Except as otherwise provided in §98.33 (b)(1)(vi) and (b)(1)(vii), when municipal solid waste (MSW) is either the primary fuel combusted in a unit or the only fuel with a biogenic component combusted in the unit, determine the biogenic portion of the $CO_2$ emissions using ASTM D6866–08 Standard Test Methods for Determining the Biobased Content of Solid, Liquid, and Gaseous Samples Using Radiocarbon Analysis (incorporated by reference, see §98.7) and ASTM D7459–08 Standard Practice for Collection of Integrated Samples for the Speciation of Biomass (Biogenic) and Fossil-Derived Carbon Dioxide Emitted from Stationary Emissions Sources (incorporated by reference, see §98.7). Perform the ASTM D7459–08 sampling and the ASTM D6866–08 analysis at least once in every calendar quarter in which MSW is combusted in the unit. Collect each gas sample during normal unit operating conditions for at least 24 total (not necessarily consecutive) hours, or longer if the facility deems it necessary to obtain a representative sample. Notwithstanding this requirement, if the types of fuels combusted and their relative proportions are consistent throughout the year, the minimum required sampling time may be reduced to 8 hours if at least two 8-hour samples and one 24-hour sample are collected under normal operating conditions, and arithmetic average of the biogenic fraction of the flue gas from the 8-hour samples (expressed as a decimal) is within ±5 percent of the biogenic fraction from the 24-hour test. There must be no overlapping of the 8-
hour and 24-hour test periods. Document the results of the demonstration in the unit’s monitoring plan. If the types of fuels and their relative proportions are not consistent throughout the year, an optional sampling approach that facilities may wish to consider to obtain a more representative sample is to collect an integrated sample by extracting a small amount of flue gas (e.g., 1 to 5 cc) in each unit operating hour during the quarter. Separate the total annual CO\textsubscript{2} emissions into the biogenic and non-biogenic fractions using the average proportion of biogenic emissions of all samples analyzed during the reporting year. Express the results as a decimal fraction (e.g., 0.30, if 30 percent of the CO\textsubscript{2} is biogenic).

(e) For other units that combust combinations of biomass fuel(s) (or heterogeneous fuels that have a biomass component, e.g., tires) and fossil (or other non-biogenic) fuel(s), in any proportions, ASTM D6866–08 (incorporated by reference, see §98.7) and ASTM D7459–08 (incorporated by reference, see §98.7) may be used to determine the biogenic portion of the CO\textsubscript{2} emissions in every calendar quarter in which biomass and non-biogenic fuels are co-fired in the unit. Follow the procedures in paragraph (d) of this section. If the primary fuel for multiple units at the facility consists of tires, and the units are fed from a common fuel source, testing at only one of the units is sufficient.

(f) The records required under §98.3(g)(2)(i) shall include an explanation of how the following parameters are determined from company records (or, if applicable, from the best available information):

1. Fuel consumption, when the Tier 1 and Tier 2 Calculation Methodologies are used, including cases where §98.36(c)(4) applies.

2. Fuel consumption, when solid fuel is combusted and the Tier 3 Calculation Methodology is used.

3. Fossil fuel consumption when §98.33(e)(2) applies to a unit that uses CEMS to quantify CO\textsubscript{2} emissions and that combests both fossil and biomass fuels.

4. Sorbent usage, when §98.33(d) applies.

5. Quantity of steam generated by a unit when §98.33(a)(2)(iii) applies.

6. Biogenic fuel consumption and high heating value, as applicable, under §§98.33(e)(5) and (e)(6).

7. Fuel usage for CH\textsubscript{4} and N\textsubscript{2}O emissions calculations under §98.33(c)(4)(ii).

8. Mass of biomass combusted, for premixed fuels that contain biomass and fossil fuels under §98.33(e)(1)(iii).

§98.35 Procedures for estimating missing data.

Whenever a quality-assured value of a required parameter is unavailable (e.g., if a CEMS malfunctions during unit operation or if a required fuel sample is not taken), a substitute data value for the missing parameter shall be used in the calculations.

(a) For all units subject to the requirements of the Acid Rain Program, and all other stationary combustion units subject to the requirements of this part that monitor and report emissions and heat input data year-round in accordance with part 75 of this chapter, the missing data substitution procedures in part 75 of this chapter shall be followed for CO\textsubscript{2} concentration, stack gas flow rate, fuel flow rate, high heating value, and fuel carbon content.

(b) For units that use the Tier 1, Tier 2, Tier 3, and Tier 4 Calculation Methodologies, perform missing data substitution as follows for each parameter:

1. For each missing value of the high heating value, carbon content, or molecular weight of the fuel, substitute the arithmetic average of the quality-assured values of that parameter immediately preceding and immediately following the missing data incident. If the “after” value has not been obtained by the time that the GHG emissions report is due, you may use the “before” value for missing data substitution or the best available estimate of the parameter, based on all available process data (e.g., electrical load, steam production, operating hours). If, for a particular parameter, no quality-assured data are available prior to the
missing data incident, the substitute data value shall be the first quality-assured value obtained after the missing data period.

(2) For missing records of CO\textsubscript{2} concentration, stack gas flow rate, percent moisture, fuel usage, and sorbent usage, the substitute data value shall be the best available estimate of the parameter, based on all available process data (e.g., electrical load, steam production, operating hours, etc.). You must document and retain records of the procedures used for all such estimates.


§ 98.36 Data reporting requirements.

(a) In addition to the facility-level information required under § 98.3, the annual GHG emissions report shall contain the unit-level or process-level emissions data in paragraphs (b) through (d) of this section (as applicable) and the emissions verification data in paragraph (e) of this section.

(b) Units that use the four tiers. You shall report the following information for stationary combustion units that use the Tier 1, Tier 2, Tier 3, or Tier 4 methodology in § 98.33(a) to calculate CO\textsubscript{2} emissions, except as otherwise provided in paragraphs (c) and (d) of this section:

(1) The unit ID number.

(2) A code representing the type of unit.

(3) Maximum rated heat input capacity of the unit, in mmBtu/hr for boilers and process heaters only and relevant units of measure for other combustion sources.

(4) Each type of fuel combusted in the unit during the report year.

(5) The methodology (i.e., tier) used to calculate the CO\textsubscript{2} emissions for each type of fuel combusted (i.e., Tier 1, 2, 3, or 4).

(6) The methodology start date, for each fuel type.

(7) The methodology end date, for each fuel type.

(8) For a unit that uses Tiers 1, 2, or 3:

(i) The annual CO\textsubscript{2} mass emissions (including biogenic CO\textsubscript{2}), and the annual CH\textsubscript{4} and N\textsubscript{2}O mass emissions for each type of fuel combusted during the reporting year, expressed in metric tons of each gas and in metric tons of CO\textsubscript{2}e; and

(ii) Metric tons of biogenic CO\textsubscript{2} emissions (if applicable).

(9) For a unit that uses Tier 4:

(i) If the total annual CO\textsubscript{2} mass emissions measured by the CEMS consists entirely of non-biogenic CO\textsubscript{2} (i.e., CO\textsubscript{2} from fossil fuel combustion plus, if applicable, CO\textsubscript{2} from sorbent and/or process CO\textsubscript{2}), report the total annual CO\textsubscript{2} mass emissions, expressed in metric tons. You are not required to report the combustion CO\textsubscript{2} emissions by fuel type.

(ii) Report the total annual CO\textsubscript{2} mass emissions measured by the CEMS. If this total includes both biogenic and non-biogenic CO\textsubscript{2}, separately report the annual non-biogenic CO\textsubscript{2} mass emissions and the annual CO\textsubscript{2} mass emissions from biomass combustion, each expressed in metric tons. You are not required to report the combustion CO\textsubscript{2} emissions by fuel type.

(iii) An estimate of the heat input from each type of fuel listed in Table C–2 of this subpart that was combusted in the unit during the report year, and the annual CH\textsubscript{4} and N\textsubscript{2}O emissions for each of these fuels, expressed in metric tons of each gas and in metric tons of CO\textsubscript{2}e.

(10) Annual CO\textsubscript{2} emissions from sorbent (if calculated using Equation C–11 of this subpart), expressed in metric tons.

(c) Reporting alternatives for units using the four Tiers. You may use any of the applicable reporting alternatives of this paragraph to simplify the unit-level reporting required under paragraph (b) of this section:

(1) Aggregation of units. If a facility contains two or more units (e.g., boilers or combustion turbines), each of which has a maximum rated heat input capacity of 250 mmBtu/hr or less, you may report the combined GHG emissions for the group of units in lieu of reporting GHG emissions from the individual units, provided that the use of Tier 4 is not required or elected for any of the units and the units use the same tier for any common fuels combusted.

If this option is selected, the following information shall be reported instead
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of the information in paragraph (b) of this section:

(i) Group ID number, beginning with the prefix “GP”.

(ii) [Reserved]

(iii) [Reserved]

(iv) The highest maximum rated heat input capacity of any unit in the group (mmBtu/hr).

(v) Each type of fuel combusted in the group of units during the reporting year.

(vi) Annual CO\textsubscript{2} mass emissions and annual CH\textsubscript{4} and N\textsubscript{2}O mass emissions, aggregated for each type of fuel combusted in the group of units during the report year, expressed in metric tons of each gas and in metric tons of CO\textsubscript{2}e. If any of the units burn both fossil fuels and biomass, report also the annual CO\textsubscript{2} emissions from combustion of all fossil fuels combined and annual CO\textsubscript{2} emissions from combustion of all biomass fuels combined, expressed in metric tons.

(vii) The methodology (i.e., tier) used to calculate the CO\textsubscript{2} mass emissions for each type of fuel combusted in the units (i.e., Tier 1, Tier 2, or Tier 3).

(viii) The methodology start date, for each fuel type.

(ix) The methodology end date, for each fuel type.

(x) The calculated CO\textsubscript{2} mass emissions (if any) from sorbent expressed in metric tons.

(2) Monitored common stack or duct configurations. When the flue gases from two or more stationary fuel combustion units at a facility are combined together in a common stack or duct before exiting to the atmosphere and if CEMS are used to continuously monitor CO\textsubscript{2} mass emissions at the common stack or duct according to the Tier 4 Calculation Methodology, you may report the combined emissions from the units sharing the common stack or duct, in lieu of separately reporting the GHG emissions from the individual units. This monitoring and reporting alternative may also be used when process off-gases or a mixture of combustion products and process gases are combined together in a common stack or duct before exiting to the atmosphere. Whenever the common stack or duct monitoring option is applied, the following information shall be reported instead of the information in paragraph (b) of this section:

(i) Common stack or duct identification number, beginning with the prefix “CS”.

(ii) Number of units sharing the common stack or duct. Report “1” when the flue gas flowing through the common stack or duct includes combustion products and/or process off-gases, and all of the effluent comes from a single unit (e.g., a furnace, kiln, petrochemical production unit, or smelter).

(iii) Combined maximum rated heat input capacity of the units sharing the common stack or duct (mmBtu/hr). This data element is required only when all of the units sharing the common stack are stationary fuel combustion units.

(iv) Each type of fuel combusted in the units during the year.

(v) The methodology (tier) used to calculate the CO\textsubscript{2} mass emissions, i.e., Tier 4.

(vi) The methodology start date.

(vii) The methodology end date.

(viii) Total annual CO\textsubscript{2} mass emissions measured by the CEMS, expressed in metric tons. If any of the units burn both fossil fuels and biomass, separately report the annual non-biogenic CO\textsubscript{2} mass emissions (i.e., CO\textsubscript{2} from fossil fuel combustion plus, if applicable, CO\textsubscript{2} from sorbent and/or process CO\textsubscript{2}) and the annual CO\textsubscript{2} mass emissions from biomass combustion, each expressed in metric tons.

(ix) An estimate of the heat input from each type of fuel listed in Table C–2 of this subpart that was combusted during the report year in the units sharing the common stack or duct during the report year, and, for each of these fuels, the annual CH\textsubscript{4} and N\textsubscript{2}O mass emissions from the units sharing the common stack or duct, expressed in metric tons of each gas and in metric tons of CO\textsubscript{2}e.

(3) Common pipe configurations. When two or more stationary combustion units at a facility combust the same type of liquid or gaseous fuel and the fuel is fed to the individual units through a common supply line or pipe, you may report the combined emissions from the units served by the common supply line, in lieu of separately reporting the GHG emissions from the
individual units, provided that the total amount of fuel combusted by the units is accurately measured at the common pipe or supply line using a fuel flow meter, or, for natural gas, the amount of fuel combusted may be obtained from gas billing records. For Tier 3 applications, the flow meter shall be calibrated in accordance with §98.34(b). If a portion of the fuel measured (or obtained from gas billing records) at the main supply line is diverted to either: A flare; or another stationary fuel combustion unit (or units), including units that use a CO₂ mass emissions calculation method in part 75 of this chapter; or a chemical or industrial process (where it is used as a raw material but not combusted), and the remainder of the fuel is distributed to a group of combustion units for which you elect to use the common pipe reporting option, you may use company records to subtract out the diverted portion of the fuel from the fuel measured (or obtained from gas billing records) at the main supply line prior to performing the GHG emissions calculations for the group of units using the common pipe option. If the diverted portion of the fuel is combusted, the GHG emissions from the diverted portion shall be accounted for in accordance with the applicable provisions of this part. When the common pipe option is selected, the applicable tier shall be used based on the maximum rated heat input capacity of the largest unit served by the common pipe configuration, except where the applicable tier is based on criteria other than unit size. For example, if the maximum rated heat input capacity of the largest unit is greater than 230 mmBtu/hr, Tier 3 will apply, unless the fuel transported through the common pipe is natural gas or distillate oil, in which case Tier 2 may be used, in accordance with §98.33(b)(1)(ii). As a second example, in accordance with §98.33(b)(1)(v), Tier 1 may be used regardless of unit size when natural gas is transported through the common pipe. If the annual fuel consumption is obtained from gas billing records in units of therms. When the common pipe option is selected, the following information shall be reported instead of the information in paragraph (b) of this section:

(i) Common pipe identification number, beginning with the prefix "CP".
(ii) [Reserved]
(iii) The highest maximum rated heat input capacity of any unit served by the common pipe (mmBtu/hr).
(iv) The fuels combusted in the units during the reporting year.
(v) The methodology used to calculate the CO₂ mass emissions (i.e., Tier 1, Tier 2, or Tier 3).
(vi) If any of the units burns both fossil fuels and biomass, the annual CO₂ mass emissions from combustion of all fossil fuels and annual CO₂ emissions from combustion of all biomass fuels from the units served by the common pipe, expressed in metric tons.
(vii) Annual CO₂ mass emissions and annual CH₄ and N₂O emissions from each fuel type for the units served by the common pipe, expressed in metric tons of each gas and in metric tons of CO₂e.
(viii) Methodology start date.
(ix) Methodology end date.

(4) The following alternative reporting option applies to facilities at which a common liquid or gaseous fuel supply is shared between one or more large combustion units, such as boilers or combustion turbines (including units subject to subpart D of this part and other units subject to part 75 of this chapter) and small combustion sources, including, but not limited to, space heaters, hot water heaters, and lab burners. In this case, you may simplify reporting by attributing all of the GHG emissions from combustion of the shared fuel to the large combustion unit(s), provided that:

(i) The total quantity of the fuel combusted during the report year in the units sharing the fuel supply is measured, either at the "gate" to the facility or at a point inside the facility, using a fuel flow meter, billing meter, or tank drop measurements (as applicable);
(ii) On an annual basis, at least 95 percent (by mass or volume) of the shared fuel is combusted in the large combustion unit(s), provided that:

(i) The total quantity of the fuel combusted during the report year in the units sharing the fuel supply is measured, either at the "gate" to the facility or at a point inside the facility, using a fuel flow meter, billing meter, or tank drop measurements (as applicable);
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to determine the percentage distribution of the shared fuel to the large and small units; and
(iii) The use of this reporting option is documented in the Monitoring Plan required under §98.3(g)(5). Indicate in the Monitoring Plan which units share the common fuel supply and the method used to demonstrate that this alternative reporting option applies. For the small combustion sources, a description of the types of units and the approximate number of units is sufficient.

(d) Units subject to part 75 of this chapter.

(1) For stationary combustion units that are subject to subpart D of this part, you shall report the following unit-level information:
(i) Unit or stack identification numbers. Use exact same unit, common stack, common pipe, or multiple stack identification numbers that represent the monitored locations (e.g., 1, 2, CS001, MS1A, CP001, etc.) that are reported under §75.64 of this chapter.
(ii) Annual CO\textsubscript{2} emissions at each monitored location, expressed in both short tons and metric tons. Separate reporting of biogenic CO\textsubscript{2} emissions under §98.3(c)(4)(ii) and §98.3(c)(4)(iii)(A) is optional only for the 2010 reporting year, as provided in §98.3(c)(12).
(iii) Annual CH\textsubscript{4} and N\textsubscript{2}O emissions at each monitored location, for each fuel type listed in Table C–2 that was combusted during the year (except as otherwise provided in §98.33(c)(4)(ii)(B)), expressed in metric tons of CO\textsubscript{2}e.
(iv) The total heat input from each fuel listed in Table C–2 that was combusted during the year (except as otherwise provided in §98.33(c)(4)(ii)(B)), expressed in mmBtu.
(v) Identification of the Part 75 methodology used to determine the CO\textsubscript{2} mass emissions.
(vi) Methodology start date.
(vii) Methodology end date.
(viii) Acid Rain Program indicator.
(ix) Annual CO\textsubscript{2} mass emissions from the combustion of biomass, expressed in metric tons of CO\textsubscript{2}e, except where the reporting provisions of §§98.3(c)(12)(i) through (c)(12)(iii) are implemented for the 2010 reporting year.

(2) For units that use the alternative CO\textsubscript{2} mass emissions calculation methods provided in §98.33(a)(5), you shall report the following unit-level information:
(i) Unit, stack, or pipe ID numbers. Use exact same unit, common stack, common pipe, or multiple stack identification numbers that represent the monitored locations (e.g., 1, 2, CS001, MS1A, CP001, etc.) that are reported under §75.64 of this chapter.
(ii) For units that use the alternative methods specified in §98.33(a)(5)(i) and (ii) to monitor and report heat input data year-round according to appendix D to part 75 of this chapter or §75.19 of this chapter:
(A) Each type of fuel combusted in the unit during the reporting year.
(B) The methodology used to calculate the CO\textsubscript{2} mass emissions for each fuel type.
(C) Methodology start date.
(D) Methodology end date.
(E) A code or flag to indicate whether heat input is calculated according to appendix D to part 75 of this chapter or §75.19 of this chapter.
(F) Annual CO\textsubscript{2} emissions at each monitored location, across all fuel types, expressed in metric tons of CO\textsubscript{2}e.
(G) Annual heat input from each type of fuel listed in Table C–2 of this subpart that was combusted during the reporting year, expressed in mmBtu.
(H) Annual CH\textsubscript{4} and N\textsubscript{2}O emissions at each monitored location, from each fuel type listed in Table C–2 of this subpart that was combusted during the reporting year (except as otherwise provided in §98.33(c)(4)(ii)(D)), expressed in metric tons CO\textsubscript{2}e.
(I) Annual CO\textsubscript{2} mass emissions from the combustion of biomass, expressed in metric tons CO\textsubscript{2}e, except where the reporting provisions of §§98.3(c)(12)(i) through (c)(12)(iii) are implemented for the 2010 reporting year.

(iii) For units with continuous monitoring systems that use the alternative method for units with continuous monitoring systems in §98.33(a)(5)(iii) to monitor heat input year-round according to part 75 of this chapter:
(A) Each type of fuel combusted during the reporting year.
(B) Methodology used to calculate the CO\textsubscript{2} mass emissions.
(C) Methodology start date.
(D) Methodology end date.
(E) A code or flag to indicate that the heat input data is derived from CEMS measurements.
(F) The total annual CO\textsubscript{2} emissions at each monitored location, expressed in metric tons of CO\textsubscript{2}e.
(G) Annual heat input from each type of fuel listed in Table C–2 of this subpart that was combusted during the reporting year, expressed in mmBtu.
(H) Annual CH\textsubscript{4} and N\textsubscript{2}O emissions at each monitored location, from each fuel type listed in Table C–2 of this subpart that was combusted during the reporting year (except as otherwise provided in §98.33(c)(4)(ii)(B)), expressed in metric tons CO\textsubscript{2}e.

(e) Verification data. You must keep on file, in a format suitable for inspection and auditing, sufficient data to verify the reported GHG emissions. This data and information must, where indicated in this paragraph (e), be included in the annual GHG emissions report.

(1) The applicable verification data specified in this paragraph (e) are not required to be kept on file or reported for units that meet any one of the three following conditions:
(i) Are subject to the Acid Rain Program.
(ii) Use the alternative methods for units with continuous monitoring systems provided in §98.33(a)(5).
(iii) Are not in the Acid Rain Program, but are required to monitor and report CO\textsubscript{2} mass emissions and heat input data year-round, in accordance with part 75 of this chapter.

(2) For stationary combustion sources using the Tier 1, Tier 2, Tier 3, and Tier 4 Calculation Methodologies in §98.33(a) to quantify CO\textsubscript{2} emissions, the following additional information shall be kept on file and included in the GHG emissions report, where indicated:
(i) For the Tier 1 Calculation Methodology, report the total quantity of each type of fuel combusted in the unit or group of aggregated units (as applicable) during the reporting year, in short tons for solid fuels, gallons for liquid fuels and standard cubic feet for gaseous fuels, or, if applicable, therms or mmBtu for natural gas.
(ii) For the Tier 2 Calculation Methodology, report:
(A) The total quantity of each type of fuel combusted in the unit or group of aggregated units (as applicable) during each month of the reporting year. Express the quantity of each fuel combusted during the measurement period in short tons for solid fuels, gallons for liquid fuels, and scf for gaseous fuels.
(B) The frequency of the HHV determinations (e.g., once a month, once per fuel lot).
(C) The high heat values used in the CO\textsubscript{2} emissions calculations for each type of fuel combusted during the reporting year, in mmBtu per short ton for solid fuels, mmBtu per gallon for liquid fuels, and mmBtu per scf for gaseous fuels. Report a HHV value for each calendar month in which HHV determination is required. If multiple values are obtained in a given month, report the arithmetic average value for the month. Indicate whether each reported HHV is a measured value or a substitute data value.
(D) If Equation C–2c of this subpart is used to calculate CO\textsubscript{2} mass emissions, report the total quantity (i.e., pounds) of steam produced from MSW or solid fuel combustion during each month of the reporting year, and the ratio of the maximum rate heat input capacity to the design rated steam output capacity of the unit, in mmBtu per lb of steam.

(iii) For the Tier 2 Calculation Methodology, keep records of the methods used to determine the HHV for each type of fuel combusted and the date on which each fuel sample was taken, except where fuel sampling data are received from the fuel supplier. In that case, keep records of the dates on which the results of the fuel analyses for HHV are received.

(iv) For the Tier 3 Calculation Methodology, report:
(A) The quantity of each type of fuel combusted in the unit or group of units (as applicable) during each month of the reporting year, in short tons for solid fuels, gallons for liquid fuels, and scf for gaseous fuels.
(B) The frequency of carbon content and, if applicable, molecular weight determinations for each type of fuel for the reporting year (e.g., daily, weekly, monthly, semiannually, once per fuel lot).

(C) The carbon content and, if applicable, gas molecular weight values used in the emission calculations (including both valid and substitute data values). For each calendar month of the reporting year in which carbon content and, if applicable, molecular weight determination is required, report a value of each parameter. If multiple values of a parameter are obtained in a given month, report the arithmetic average value for the month. Express carbon content as a decimal fraction for solid fuels, kg C per gallon for liquid fuels, and kg C per kg of fuel for gaseous fuels. Express the gas molecular weights in units of kg per kg-mole.

(D) The total number of valid carbon content determinations and, if applicable, molecular weight determinations made during the reporting year, for each fuel type.

(E) The number of substitute data values used for carbon content and, if applicable, molecular weight used in the annual GHG emissions calculations.

(F) The annual average HHV, when measured HHV data, rather than a default HHV from Table C-1 of this subpart, are used to calculate CH₄ and N₂O emissions for a Tier 3 unit, in accordance with §98.33(c)(1).

(G) The value of the molar volume constant (MVC) used in Equation C-5 (if applicable).

(v) For the Tier 3 Calculation Methodology, keep records of the following:

(A) For liquid and gaseous fuel combustion, the dates and results of the initial calibrations and periodic recalibrations of the required fuel flow meters.

(B) For fuel oil combustion, the method from §98.34(b) used to make tank drop measurements (if applicable).

(C) The methods used to determine the carbon content and (if applicable) the molecular weight of each type of fuel combusted.

(D) The methods used to calibrate the fuel flow meters.

(E) The date on which each fuel sample was taken, except where fuel sampling data are received from the fuel supplier. In that case, keep records of the dates on which the results of the fuel analyses for carbon content and (if applicable) molecular weight are received.

(vi) For the Tier 4 Calculation Methodology, report:

(A) The total number of source operating hours in the reporting year.

(B) The cumulative CO₂ mass emissions in each quarter of the reporting year, i.e., the sum of the hourly values calculated from Equation C-6 or C-7 of this subpart (as applicable), in metric tons.

(C) For CO₂ concentration, stack gas flow rate, and (if applicable) stack gas moisture content, the percentage of source operating hours in which a substitute data value of each parameter was used in the emissions calculations.

(vii) For the Tier 4 Calculation Methodology, keep records of:

(A) Whether the CEMS certification and quality assurance procedures of part 75 of this chapter, part 60 of this chapter, or an applicable State continuous monitoring program were used.

(B) The dates and results of the initial certification tests of the CEMS.

(C) The dates and results of the major quality assurance tests performed on the CEMS during the reporting year, i.e., linearity checks, cylinder gas audits, and relative accuracy test audits (RATAs).

(viii) If CO₂ emissions that are generated from acid gas scrubbing with sorbent injection are not captured using CEMS, report:

(A) The total amount of sorbent used during the report year, in short tons.

(B) The molecular weight of the sorbent.

(C) The ratio (‘‘R’’) in Equation C-11 of this subpart.

(ix) For units that combust both fossil fuel and biomass, when biogenic CO₂ is determined according to §98.33(e)(2), you shall report the following additional information, as applicable:

(A) The annual volume of CO₂ emitted from the combustion of all fuels, i.e., Vₜₐₚₑ, in scf.
(B) The annual volume of CO$_2$ emitted from the combustion of fossil fuels, i.e., $V_{ff}$, in scf. If more than one type of fossil fuel was combusted, report the combustion volume of CO$_2$ for each fuel separately as well as the total.

(C) The annual volume of CO$_2$ emitted from the combustion of biomass, i.e., $V_{bio}$, in scf.

(D) The carbon-based F-factor used in Equation C–13 of this subpart, for each type of fossil fuel combusted, in scf CO$_2$ per mmBtu.

(E) The annual average HHV value used in Equation C–13 of this subpart, for each type of fossil fuel combusted, in Btu/lb, Btu/gal, or Btu/scf, as appropriate.

(F) The total quantity of each type of fossil fuel combusted during the reporting year, in lb, gallons, or scf, as appropriate.

(G) Annual biogenic CO$_2$ mass emissions, in metric tons.

(x) When ASTM methods D7459–08 (incorporated by reference, see §98.7) and D6866–08 (incorporated by reference, see §98.7) are used to determine the biogenic portion of the annual CO$_2$ emissions from MSW combustion, as described in §98.34(d), report:

(A) The results of each quarterly sample analysis, expressed as a decimal fraction (e.g., if the biogenic fraction of the CO$_2$ emissions from MSW combustion is 30 percent, report 0.30).

(B) The annual biogenic CO$_2$ mass emissions from MSW combustion, in metric tons.

(xi) When ASTM methods D7459–08 (incorporated by reference, see §98.7) and D6866–08 (incorporated by reference, see §98.7) are used in accordance with §98.34(e) to determine the biogenic portion of the annual CO$_2$ emissions from a unit that co-fires biogenic fuels (or partly-biogenic fuels, including tires if you are electing to report biogenic CO$_2$ emissions from tire combustion) and non-biogenic fuels, you shall report the results of each quarterly sample analysis, expressed as a decimal fraction (e.g., if the biogenic fraction of the CO$_2$ emissions is 30 percent, report 0.30).

(3) Within 30 days of receipt of a written request from the Administrator, you shall submit explanations of the following:

(i) An explanation of how company records are used to quantify fuel consumption, if the Tier 1 or Tier 2 Calculation Methodology is used to calculate CO$_2$ emissions.

(ii) An explanation of how company records are used to quantify fuel consumption, if solid fuel is combusted and the Tier 3 Calculation Methodology is used to calculate CO$_2$ emissions.

(iii) An explanation of how sorbent usage is quantified.

(iv) An explanation of how company records are used to quantify fossil fuel consumption in units that uses CEMS to quantify CO$_2$ emissions and combusts both fossil fuel and biomass.

(v) An explanation of how company records are used to measure steam production, when it is used to calculate CO$_2$ mass emissions under §98.33(a)(2)(iii) or to quantify solid fuel usage under §98.33(c)(3).

(4) Within 30 days of receipt of a written request from the Administrator, you shall submit the verification data and information described in paragraphs (e)(2)(iii), (e)(2)(v), and (e)(2)(vii) of this section.


§98.37 Records that must be retained.

In addition to the requirements of §98.3(g), you must retain the applicable records specified in §§98.34(f) and (g), 98.35(b), and 98.36(e).

§98.38 Definitions.

All terms used in this subpart have the same meaning given in the Clean Air Act and subpart A of this part.

Table C–1 to Subpart C—Default CO$_2$ Emission Factors and High Heat Values for Various Types of Fuel
<table>
<thead>
<tr>
<th>Fuel type</th>
<th>Default high heat value</th>
<th>Default CO₂ emission factor</th>
</tr>
</thead>
<tbody>
<tr>
<td>Coal and coke</td>
<td>mmBtu/short ton</td>
<td>kg CO₂/mmBtu</td>
</tr>
<tr>
<td>Anthracite</td>
<td>25.09</td>
<td>103.54</td>
</tr>
<tr>
<td>Bituminous</td>
<td>24.93</td>
<td>93.40</td>
</tr>
<tr>
<td>Subbituminous</td>
<td>17.25</td>
<td>97.02</td>
</tr>
<tr>
<td>Lignite</td>
<td>14.21</td>
<td>96.36</td>
</tr>
<tr>
<td>Coke</td>
<td>24.80</td>
<td>102.04</td>
</tr>
<tr>
<td>Mixed (Commercial sector)</td>
<td>21.39</td>
<td>95.26</td>
</tr>
<tr>
<td>Mixed (Industrial coking)</td>
<td>26.28</td>
<td>93.65</td>
</tr>
<tr>
<td>Mixed (Industrial sector)</td>
<td>22.35</td>
<td>93.91</td>
</tr>
<tr>
<td>Mixed (Electric Power sector)</td>
<td>19.73</td>
<td>94.38</td>
</tr>
<tr>
<td>Natural gas</td>
<td>mmBtu/scf</td>
<td>kg CO₂/mmBtu</td>
</tr>
<tr>
<td>(Weighted U.S. Average)</td>
<td>$1.028 \times 10^{-3}$</td>
<td>53.02</td>
</tr>
<tr>
<td>Petroleum products</td>
<td>mmBtu/gallon</td>
<td>kg CO₂/mmBtu</td>
</tr>
<tr>
<td>Distillate Fuel Oil No. 1</td>
<td>0.139</td>
<td>73.25</td>
</tr>
<tr>
<td>Distillate Fuel Oil No. 2</td>
<td>0.138</td>
<td>73.96</td>
</tr>
<tr>
<td>Distillate Fuel Oil No. 4</td>
<td>0.146</td>
<td>75.04</td>
</tr>
<tr>
<td>Residual Fuel Oil No. 5</td>
<td>0.140</td>
<td>72.93</td>
</tr>
<tr>
<td>Residual Fuel Oil No. 6</td>
<td>0.150</td>
<td>75.10</td>
</tr>
<tr>
<td>Used Oil</td>
<td>0.135</td>
<td>76.00</td>
</tr>
<tr>
<td>Kerosene</td>
<td>0.135</td>
<td>75.20</td>
</tr>
<tr>
<td>Liquefied petroleum gases (LPG)</td>
<td>0.092</td>
<td>62.98</td>
</tr>
<tr>
<td>Propane</td>
<td>0.091</td>
<td>61.46</td>
</tr>
<tr>
<td>Propylene</td>
<td>0.091</td>
<td>65.95</td>
</tr>
<tr>
<td>Ethane</td>
<td>0.069</td>
<td>62.64</td>
</tr>
<tr>
<td>Ethanol</td>
<td>0.084</td>
<td>68.44</td>
</tr>
<tr>
<td>Ethylene</td>
<td>0.100</td>
<td>67.43</td>
</tr>
<tr>
<td>Isobutane</td>
<td>0.097</td>
<td>64.91</td>
</tr>
<tr>
<td>Isobutylene</td>
<td>0.103</td>
<td>67.74</td>
</tr>
<tr>
<td>Butane</td>
<td>0.101</td>
<td>65.15</td>
</tr>
<tr>
<td>Butylene</td>
<td>0.103</td>
<td>67.73</td>
</tr>
<tr>
<td>Naphtha (&lt;401 deg F)</td>
<td>0.125</td>
<td>68.02</td>
</tr>
<tr>
<td>Natural Gasoline</td>
<td>0.110</td>
<td>66.83</td>
</tr>
<tr>
<td>Other Oil (&gt;401 deg F)</td>
<td>0.139</td>
<td>76.22</td>
</tr>
<tr>
<td>Pentanes Plus</td>
<td>0.110</td>
<td>70.02</td>
</tr>
<tr>
<td>Petrochemical Feedstocks</td>
<td>0.129</td>
<td>70.97</td>
</tr>
<tr>
<td>Petroleum Coke</td>
<td>0.143</td>
<td>102.41</td>
</tr>
<tr>
<td>Special Naphtha</td>
<td>0.125</td>
<td>72.34</td>
</tr>
<tr>
<td>Unfinished Oils</td>
<td>0.139</td>
<td>74.49</td>
</tr>
<tr>
<td>Heavy Gas Oils</td>
<td>0.148</td>
<td>74.92</td>
</tr>
<tr>
<td>Lubricants</td>
<td>0.144</td>
<td>74.27</td>
</tr>
<tr>
<td>Motor Gasoline</td>
<td>0.125</td>
<td>70.22</td>
</tr>
<tr>
<td>Aviation Gasoline</td>
<td>0.120</td>
<td>69.25</td>
</tr>
<tr>
<td>Kerosene-Type Jet Fuel</td>
<td>0.135</td>
<td>72.22</td>
</tr>
<tr>
<td>Asphalt and Road Oil</td>
<td>0.158</td>
<td>75.36</td>
</tr>
<tr>
<td>Crude Oil</td>
<td>0.138</td>
<td>74.49</td>
</tr>
<tr>
<td>Other fuels—gaseous</td>
<td>mmBtu/scf</td>
<td>kg CO₂/mmBtu</td>
</tr>
<tr>
<td>Municipal Solid Waste</td>
<td>9.95</td>
<td>90.7</td>
</tr>
<tr>
<td>Tires</td>
<td>26.87</td>
<td>85.97</td>
</tr>
<tr>
<td>Plastics</td>
<td>38.00</td>
<td>75.00</td>
</tr>
<tr>
<td>Petroleum Coke</td>
<td>30.00</td>
<td>102.41</td>
</tr>
<tr>
<td>Other fuels—gaseous</td>
<td>mmBtu/scf</td>
<td>kg CO₂/mmBtu</td>
</tr>
<tr>
<td>Blast Furnace Gas</td>
<td>$0.092 \times 10^{-3}$</td>
<td>274.32</td>
</tr>
<tr>
<td>Coke Oven Gas</td>
<td>$0.599 \times 10^{-3}$</td>
<td>46.85</td>
</tr>
<tr>
<td>Propane Gas</td>
<td>$2.516 \times 10^{-3}$</td>
<td>61.48</td>
</tr>
<tr>
<td>Fuel Gas $^2$</td>
<td>$1.388 \times 10^{-3}$</td>
<td>59.00</td>
</tr>
<tr>
<td>Biomass fuels—solid</td>
<td>mmBtu/short ton</td>
<td>kg CO₂/mmBtu</td>
</tr>
<tr>
<td>Wood and Wood Residuals</td>
<td>15.38</td>
<td>93.80</td>
</tr>
<tr>
<td>Agricultural Byproducts</td>
<td>8.25</td>
<td>118.17</td>
</tr>
<tr>
<td>Peat</td>
<td>8.90</td>
<td>111.84</td>
</tr>
<tr>
<td>Solid Byproducts</td>
<td>25.83</td>
<td>105.51</td>
</tr>
<tr>
<td>Biomass fuels—gaseous</td>
<td>mmBtu/scf</td>
<td>kg CO₂/mmBtu</td>
</tr>
<tr>
<td>Biogas (Captured methane)</td>
<td>$0.841 \times 10^{-3}$</td>
<td>52.07</td>
</tr>
</tbody>
</table>
Subpart D—Electricity Generation

§ 98.40 Definition of the source category.

(a) The electricity generation source category comprises electricity generating units that are subject to the requirements of the Acid Rain Program and any other electricity generating units that are required to monitor and report to EPA CO₂ mass emissions year-round according to 40 CFR part 75.

(b) This source category does not include portable equipment, emergency equipment, or emergency generators, as defined in §98.6.


§ 98.41 Reporting threshold.

You must report GHG emissions under this subpart if your facility contains one or more electricity generating units and the facility meets the requirements of §98.2(a)(1).

§ 98.42 GHGs to report.

(a) For each electricity generating unit that is subject to the requirements of the Acid Rain Program or is otherwise required to monitor and report to EPA CO₂ emissions year-round according to 40 CFR part 75, you must report under this subpart the annual mass emissions of CO₂, N₂O, and CH₄ by following the requirements of this subpart.

(b) For each electricity generating unit that is not subject to the Acid Rain Program or otherwise required to monitor and report to EPA CO₂ emissions year-round according to 40 CFR part 75, you must report under subpart C of this part (General Stationary Fuel Combustion Sources) the emissions of CO₂, CH₄, and N₂O by following the requirements of subpart C.

(c) For each stationary fuel combustion unit that does not generate electricity, you must report under subpart C of this part (General Stationary Fuel Combustion Sources) the emissions of CO₂, CH₄, and N₂O by following the requirements of subpart C of this part.

§ 98.43 Calculating GHG emissions.

(a) Except as provided in paragraph (b) of this section, continue to monitor and report CO₂ mass emissions as required under §75.13 or section 2.3 of appendix G to 40 CFR part 75, and §75.64. Calculate CO₂, CH₄, and N₂O emissions as follows:

(1) Convert the cumulative annual CO₂ mass emissions reported in the fourth quarter electronic data report required under §75.64 from units of short tons to metric tons. To convert tons to metric tons, divide by 1.1023.

(2) Calculate and report annual CH₄ and N₂O mass emissions under this subpart by following the applicable method specified in §98.33(c).

(b) Calculate and report biogenic CO₂ emissions under this subpart by following the applicable methods specified in §98.33(e). The CO₂ emissions (excluding biogenic CO₂) for units subject to this subpart that are reported under §§98.3(c)(4)(i) and (c)(4)(iii)(B) shall be calculated by subtracting the biogenic CO₂ mass emissions calculated according to §98.33(e) from the cumulative annual CO₂ mass emissions from paragraph (a)(1) of this section. Separate calculation and reporting of biogenic CO₂ emissions is optional only for the 2010 reporting year pursuant to §98.3(c)(12) and required every year thereafter.

(75 FR 79155, Dec. 17, 2010)

§ 98.44 Monitoring and QA/QC requirements.

Follow the applicable quality assurance procedures for CO₂ emissions in appendices B, D, and G to 40 CFR part 75.

§ 98.45 Procedures for estimating missing data.

Follow the applicable missing data substitution procedures in 40 CFR part 75 for CO₂ concentration, stack gas flow rate, high heating value, and fuel carbon content.

§ 98.46 Data reporting requirements.

The annual report shall comply with the data reporting requirements specified in §98.36(d)(1).

(75 FR 79155, Dec. 17, 2010)

§ 98.47 Records that must be retained.

You shall comply with the recordkeeping requirements of §§98.3(g) and 98.37. Records retained under §75.57(h) of this chapter for missing data events satisfy the recordkeeping requirements of §98.3(g)(4) for those same events.

(75 FR 79155, Dec. 17, 2010)

§ 98.48 Definitions.

All terms used in this subpart have the same meaning given in the Clean Air Act and subpart A of this part.

Subpart E—Adipic Acid Production

§ 98.50 Definition of source category.

The adipic acid production source category consists of all adipic acid production facilities that use oxidation to produce adipic acid.

§ 98.51 Reporting threshold.

You must report GHG emissions under this subpart if your facility contains an adipic acid production process and the facility meets the requirements of either §98.2(a)(1) or (2).

§ 98.52 GHGs to report.

(a) You must report N₂O process emissions at the facility level.

(b) You must report under subpart C of this part (General Stationary Fuel Combustion Sources) the emissions of CO₂, CH₄, and N₂O from each stationary combustion unit following the requirements of subpart C.

§ 98.53 Calculating GHG emissions.

(a) You must determine annual N₂O emissions from adipic acid production according to paragraphs (a)(1) or (2) of this section.

(1) Use a site-specific emission factor and production data according to paragraphs (b) through (i) of this section.

(2) Request Administrator approval for an alternative method of determining N₂O emissions according to
Environmental Protection Agency § 98.53

paragraphs (a)(2)(i) and (ii) of this section.

(i) You must submit the request within 45 days following promulgation of this subpart or within the first 30 days of each subsequent reporting year.

(ii) If the Administrator does not approve your requested alternative method within 150 days of the end of the reporting year, you must determine the \( \text{N}_2\text{O} \) emissions for the current reporting period using the procedures specified in paragraphs (b) through (h) of this section.

(b) You must conduct an annual performance test according to paragraphs (b)(1) through (3) of this section.

(1) You must conduct the test on the vent stream from the nitric acid oxidation step of the process, referred to as the test point, according to the methods specified in §98.54(b) through (f). If multiple adipic acid production units exhaust to a common abatement technology and/or emission point, you must sample each process in the ducts before the emissions are combined, sample each process when only one process is operating, or sample the combined emissions when multiple processes are operating and base the site-specific emission factor on the combined production rate of the multiple adipic acid production units.

(2) You must conduct the performance test under normal process operating conditions.

(3) You must measure the adipic acid production rate during the test and calculate the production rate for the test period in metric tons per hour.

(c) Using the results of the performance test in paragraph (b) of this section, you must calculate an emission factor for each adipic acid unit according to Equation E–1 of this section:

\[
EF_{\text{N}_2\text{O}, z} = \frac{\sum_{n} C_{\text{N}_2\text{O}} \times 1.14 \times 10^{-7} \times Q}{n} \quad (\text{Eq. E-1})
\]

where:

\( EF_{\text{N}_2\text{O}, z} \) = Average facility-specific \( \text{N}_2\text{O} \) emission factor for each adipic acid production unit “\( z \)” (lb \( \text{N}_2\text{O} \)/ton adipic acid produced).

\( C_{\text{N}_2\text{O}} \) = \( \text{N}_2\text{O} \) concentration per test run during the performance test (ppm \( \text{N}_2\text{O} \)).

1.14 \times 10^{-7} = Conversion factor (lb/dscf-ppm \( \text{N}_2\text{O} \)).

\( Q \) = Volumetric flow rate of effluent gas per test run during the performance test (dscf/hr).

\( P \) = Production rate per test run during the performance test (tons adipic acid produced/hr).

\( n \) = Number of test runs.

(d) If any \( \text{N}_2\text{O} \) abatement technology “\( N \)” is located after your test point, you must determine the destruction efficiency according to paragraphs (d)(1), (2), or (3) of this section.

(1) Use the manufacturer’s specified destruction efficiency.

(2) Estimate the destruction efficiency through process knowledge. Examples of information that could constitute process knowledge include calculations based on material balances, process stoichiometry, or previous test results provided the results are still relevant to the current vent stream conditions. You must document how process knowledge was used to determine the destruction efficiency.

(3) Calculate the destruction efficiency by conducting an additional performance test on the vent stream following the \( \text{N}_2\text{O} \) abatement technology.

(e) If any \( \text{N}_2\text{O} \) abatement technology “\( N \)” is located after your test point, you must determine the annual amount of adipic acid produced while \( \text{N}_2\text{O} \) abatement technology “\( N \)” is operating according to §98.54(f). Then you must calculate the abatement factor for \( \text{N}_2\text{O} \) abatement technology “\( N \)” according to Equation E–2 of this section.

\[
AF_{N} = \frac{P_{a,N}}{P_{z}} \quad (\text{Eq. E-2})
\]

where:

\( P_{a,N} \) = Adipic acid production rate.

\( P_{z} \) = Total production rate.

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\( AF_N \) = Abatement utilization factor of N\(_2\)O abatement technology “N” (fraction of annual production that abatement technology is operating).

\( P_{a,n} \) = Annual adipic acid production during which N\(_2\)O abatement technology “N” was used on unit “z” (ton adipic acid produced).

\( P_z \) = Total annual adipic acid production from unit “z” (ton acid produced).

(f) You must determine the annual amount of adipic acid produced according to §98.54(f).

(g) You must calculate N\(_2\)O emissions according to paragraph (g)(1), (2), (3), or (4) of this section for each adipic acid production unit.

(1) If one N\(_2\)O abatement technology “N” is located after your test point, you must use the emissions factor (determined in Equation E–1 of this section), the destruction efficiency (determined in paragraph (d) of this section), the annual adipic acid production (determined in paragraph (f) of this section), and the abatement utilization factor (determined in paragraph (e) of this section), according to Equation E–3a of this section:

\[
E_{a,z} = \frac{EF_{N2O, z} \times P_z}{2205} \times \left(1 - \left(DF \times AF\right)\right)
\]

(Eq. E-3a)

where:

\( E_{a,z} \) = Annual N\(_2\)O mass emissions from adipic acid production unit “z” according to this Equation E–3a (metric tons).

\( EF_{N2O, z} \) = N\(_2\)O emissions factor for unit “z” (lb N\(_2\)O/ton adipic acid produced).

\( P_z \) = Annual adipic acid production from unit “z” (ton).

\( DF \) = Destruction efficiency of N\(_2\)O abatement technology “N” (percent of N\(_2\)O removed from vent stream).

\( AF \) = Abatement utilization factor of N\(_2\)O abatement technology “N” (percent of time that the abatement technology is operating).

2205 = Conversion factor (lb/metric ton).

(2) If multiple N\(_2\)O abatement technologies are located in series after your test point, you must use the emissions factor (determined in Equation E–1 of this section), the destruction efficiency (determined in paragraph (d) of this section), the annual adipic acid production (determined in paragraph (f) of this section), and the abatement utilization factor (determined in paragraph (e) of this section), according to Equation E–3b of this section:

\[
E_{b,z} = \frac{EF_{N2O, z} \times P_z}{2205} \times \left(1 - \left(DF_1 \times AF_1\right)\right) \times \left(1 - \left(DF_2 \times AF_2\right)\right) \times \ldots \times \left(1 - \left(DF_N \times AF_N\right)\right)
\]

(Eq. E-3b)

where:

\( E_{b,z} \) = Annual N\(_2\)O mass emissions from adipic acid production unit “z” according to this Equation E–3b (metric tons).

\( EF_{N2O, z} \) = N\(_2\)O emissions factor for unit “z” (lb N\(_2\)O/ton adipic acid produced).

\( P_z \) = Annual adipic acid production from unit “z” (ton).

\( DF_1 \) = Destruction efficiency of N\(_2\)O abatement technology 1 (percent of N\(_2\)O removed from vent stream).

\( AF_1 \) = Abatement utilization factor of N\(_2\)O abatement technology 1 (percent of time that abatement technology 1 is operating).

\( DF_2 \) = Destruction efficiency of N\(_2\)O abatement technology 2 (percent of N\(_2\)O removed from vent stream).

\( AF_2 \) = Abatement utilization factor of N\(_2\)O abatement technology 2 (percent of time that abatement technology 2 is operating).

\( DF_N \) = Destruction efficiency of N\(_2\)O abatement technology N (percent of N\(_2\)O removed from vent stream).

\( AF_N \) = Abatement utilization factor of N\(_2\)O abatement technology N (percent of time that abatement technology N is operating).

2205 = Conversion factor (lb/metric ton).

\( N \) = Number of different N\(_2\)O abatement technologies.

(3) If multiple N\(_2\)O abatement technologies are located in parallel after
your test point, you must use the emissions factor (determined in Equation E-1 of this section), the destruction efficiency (determined in paragraph (d) of this section), the annual adipic acid production (determined in paragraph (f) of this section), and the abatement utilization factor (determined in paragraph (e) of this section), according to Equation E-3c of this section:

\[ E_{c,z} = \frac{E_{F_{N2O,z}} \times P_z}{2205} \sum_{i=1}^{N} \left( (1-DF_N \times AF_N) \right) \times FC_N \]  

(Eq. E-3c)

where:

- \( E_{c,z} \) = Annual \( N_2O \) mass emissions from adipic acid production unit “\( z \)” according to this Equation E-3c (metric tons).
- \( E_{F_{N2O,z}} \) = \( N_2O \) emissions factor for unit “\( z \)” (lb \( N_2O \)/ton adipic acid produced).
- \( P_z \) = Annual adipic acid produced from unit “\( z \)” (tons).
- \( DF_N \) = Destruction efficiency of \( N_2O \) abatement technology “\( N \)” (percent of \( N_2O \) removed from vent stream).
- \( AF_N \) = Abatement utilization factor of \( N_2O \) abatement technology “\( N \)” (percent of \( N_2O \) sent to abatement technology “\( N \)”)
- \( FC_N \) = Fraction control factor of \( N_2O \) abatement technology “\( N \)” (percent of total \( N_2O \) emissions from unit “\( z \)” that are sent to abatement technology “\( N \)”)
- \( 2205 \) = Conversion factor (lb/metric ton).
- \( N \) = Number of different \( N_2O \) abatement technologies with a fraction control factor.

(4) If no \( N_2O \) abatement technologies are located after your test point, you must use the emissions factor (determined using Equation E-1 of this section) and the annual adipic acid production (determined in paragraph (f) of this section) according to Equation E-3d of this section for each adipic acid production unit.

\[ E_{d,z} = \frac{E_{F_{N2O}} \times P_z}{2205} \]  

(Eq. E-3d)

where:

- \( E_{d,z} \) = Annual \( N_2O \) mass emissions from adipic acid production for unit “\( z \)” according to this Equation E-3d (metric tons).
- \( E_{F_{N2O}} \) = \( N_2O \) emissions factor for unit “\( z \)” (lb \( N_2O \)/ton adipic acid produced).
- \( P_z \) = Annual adipic acid produced from unit “\( z \)” (tons).
- \( 2205 \) = Conversion factor (lb/metric ton).

(h) You must determine the emissions for the facility by summing the unit level emissions according to Equation E-4 of this section.

\[ N_2O = \sum_{z=1}^{M} E_{a,z} + E_{b,z} + E_{c,z} + E_{d,z} \]  

(Eq. E-4)

where:

- \( E_{a,z} \) = Annual \( N_2O \) mass emissions from adipic acid production unit “\( z \)” according to Equation E-3a of this section (metric tons).
- \( E_{b,z} \) = Annual \( N_2O \) mass emissions from adipic acid production unit “\( z \)” according to Equation E-3b of this section (metric tons).
- \( E_{c,z} \) = Annual \( N_2O \) mass emissions from adipic acid production unit “\( z \)” according to Equation E-3c of this section (metric tons).
- \( E_{d,z} \) = Annual \( N_2O \) mass emissions from adipic acid production unit “\( z \)” according to Equation E-3d of this section (metric tons).
- \( M \) = Total number of adipic acid production units.

(1) You must determine the amount of process \( N_2O \) emissions that is sold or transferred off site (if applicable). You can determine the amount using existing process flow meters and \( N_2O \) analyzers.

[75 FR 66458, Oct. 28, 2010]
§ 98.54 Monitoring and QA/QC requirements.

(a) You must conduct a new performance test and calculate a new emissions factor for each adipic acid production unit according to the frequency specified in paragraphs (a)(1) through (3) of this section.

(1) Conduct the performance test annually. The test must be conducted at a point during production that is representative of the average emissions rate from your process. You must document the methods used to determine the representative point.

(2) Conduct the performance test when your adipic acid production process is changed either by altering the ratio of cyclohexanone to cyclohexanol or by installing abatement equipment.

(3) If you requested Administrator approval for an alternative method of determining N\textsubscript{2}O emissions under § 98.53(a)(2), you must conduct the performance test if your request has not been approved by the Administrator within 150 days of the end of the reporting year in which it was submitted.

(b) You must measure the N\textsubscript{2}O concentration during the performance test using one of the methods in paragraphs (b)(1) through (b)(3) of this section.

(1) EPA Method 320, Measurement of Vapor Phase Organic and Inorganic Emissions by Extractive Fourier Transform Infrared (FTIR) Spectroscopy in 40 CFR part 63, Appendix A;

(2) ASTM D6348–03 Standard Test Method for Determination of Gaseous Compounds by Extractive Direct Interface Fourier Transform Infrared (FTIR) Spectroscopy (incorporated by reference, see §98.7); or

(3) An equivalent method, with Administrator approval.

(c) You must determine the adipic acid production rate during the performance test according to paragraph (c)(1) or (c)(2) of this section.

(1) Direct measurement (such as using flow meters or weigh scales).

(2) Existing plant procedures used for accounting purposes.

(d) You must determine the volumetric flow rate during the performance test in conjunction with the applicable EPA methods in 40 CFR part 60, appendices A–1 through A–4. Conduct three emissions test runs of 1 hour each. All QA/QC procedures specified in the reference test methods and any associated performance specifications apply. For each test, the facility must prepare an emissions factor determination report that must include the items in paragraphs (d)(1) through (d)(3) of this section:

(1) Analysis of samples, determination of emissions, and raw data.

(2) All information and data used to derive the emissions factor.

(3) The production rate(s) during the performance test and how each production rate was determined.

(e) You must determine the monthly amount of adipic acid produced. You must also determine the monthly amount of adipic acid produced during which N\textsubscript{2}O abatement technology, located after the test point, is operating. These monthly amounts are determined according to the methods in paragraphs (c)(1) or (2) of this section.

(f) You must determine the annual amount of adipic acid produced. You must also determine the annual amount of adipic acid produced during which N\textsubscript{2}O abatement technology located after the test point is operating. These are determined by summing the respective monthly adipic acid production quantities determined in paragraph (e) of this section.


§ 98.55 Procedures for estimating missing data.

A complete record of all measured parameters used in the GHG emissions calculations is required. Therefore, whenever a quality-assured value of a required parameter is unavailable, a substitute data value for the missing parameter shall be used in the calculations as specified in paragraphs (a) and (b) of this section.

(a) For each missing value of monthly adipic acid production, the substitute data shall be the best available estimate based on all available process data or data used for accounting purposes (such as sales records).

(b) For missing values related to the performance test, including emission factors, production rate, and N\textsubscript{2}O concentration, you must conduct a new
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performance test according to the procedures in §98.54 (a) through (d).

§ 98.56 Data reporting requirements.

In addition to the information required by §98.3(c), each annual report must contain the information specified in paragraphs (a) through (l) of this section at the facility level.

(a) Annual process N₂O emissions from adipic acid production (metric tons).
(b) Annual adipic acid production (tons).
(c) Annual adipic acid production during which N₂O abatement technology (located after the test point) is operating (tons).
(d) Annual process N₂O emissions from adipic acid production facility that is sold or transferred off site (metric tons).
(e) Number of abatement technologies (if applicable).
(f) Types of abatement technologies used (if applicable).
(g) Abatement technology destruction efficiency for each abatement technology (percent destruction).
(h) Abatement utilization factor for each abatement technology (fraction of annual production that abatement technology is operating).
(i) Number of times in the reporting year that missing data procedures were followed to measure adipic acid production (months).
(j) If you conducted a performance test and calculated a site-specific emissions factor according to §98.53(a)(1), each annual report must also contain the information specified in paragraphs (j)(1) through (7) of this section for each adipic acid production unit.

(1) Emission factor (lb N₂O/ton adipic acid).
(2) Test method used for performance test.
(3) Production rate per test run during performance test (tons/hr).
(4) N₂O concentration per test run during performance test (ppm N₂O).
(5) Volumetric flow rate per test run during performance test (dscf/hr).
(6) Number of test runs.
(7) Number of times in the reporting year that a performance test had to be repeated (number).
(k) If you requested Administrator approval for an alternative method of determining N₂O emissions under §98.53(a)(2), each annual report must also contain the information specified in paragraphs (k)(1) through (4) of this section for each adipic acid production facility.

(1) Name of alternative method.
(2) Description of alternative method.
(3) Request date.
(4) Approval date.

(l) Fraction control factor for each abatement technology (percent of total emissions from the production unit that are sent to the abatement technology) if equation E–3c is used.


§ 98.57 Records that must be retained.

In addition to the information required by §98.3(g), you must retain the records specified in paragraphs (a) through (h) of this section at the facility level:

(a) Annual adipic acid production capacity (tons).
(b) Records of significant changes to process.
(c) Number of facility and unit operating hours in calendar year.
(d) Documentation of how accounting procedures were used to estimate production rate.
(e) Documentation of how process knowledge was used to estimate abatement technology destruction efficiency.
(f) Performance test reports.
(g) Measurements, records and calculations used to determine reported parameters.
(h) Documentation of the procedures used to ensure the accuracy of the measurements of all reported parameters, including but not limited to, calibration of weighing equipment, flow meters, and other measurement devices. The estimated accuracy of measurements made with these devices must also be recorded, and the technical basis for these estimates must be provided.

§ 98.58 Definitions.

All terms used in this subpart have the same meaning given in the Clean Air Act and subpart A of this part.

Subpart F—Aluminum Production

§ 98.60 Definition of the source category.

(a) A primary aluminum production facility manufactures primary aluminum using the Hall-Héroult manufacturing process. The primary aluminum manufacturing process comprises the following operations:

(1) Electrolysis in prebake and Söderberg cells.

(2) Anode baking for prebake cells.

(b) This source category does not include experimental cells or research and development process units.

§ 98.61 Reporting threshold.

You must report GHG emissions under this subpart if your facility contains an aluminum production process and the facility meets the requirements of either § 98.2(a)(1) or (a)(2).

§ 98.62 GHGs to report.

You must report:

(a) Perfluoromethane (CF₄) and perfluoroethane (C₂F₆) emissions from anode effects in all prebake and Söderberg electrolysis cells.

(b) CO₂ emissions from anode consumption during electrolysis in all prebake and Söderberg electrolysis cells.

(c) CO₂ emissions from on-site anode baking.

(d) You must report under subpart C of this part (General Stationary Fuel Combustion Sources) the emissions of CO₂, N₂O, and CH₄ emissions from each stationary fuel combustion unit by following the requirements of subpart C.


§ 98.63 Calculating GHG emissions.

(a) The annual value of each PFC compound (CF₄, C₂F₆) shall be estimated from the sum of monthly values using Equation F–1 of this section:

\[ E_{\text{PFC}} = \sum_{m=1}^{12} E_m \]  (Eq. F-1)

Where:

- \( E_{\text{PFC}} \) = Annual emissions of each PFC compound from aluminum production (metric tons PFC).
- \( E_m \) = Emissions of the individual PFC compound from aluminum production for the month “m” (metric tons PFC).

(b) Use Equation F–2 of this section to estimate CF₄ emissions from anode effect duration or Equation F–3 of this section to estimate CF₄ emissions from overvoltage, and use Equation F–4 of this section to estimate C₂F₆ emissions from anode effects from each prebake and Söderberg electrolysis cell.

\[ E_{\text{CF}_4} = S_{\text{CF}_4} \times \text{AEM} \times \text{MP} \times 0.001 \]  (Eq. F-2)

Where:

- \( E_{\text{CF}_4} \) = Monthly CF₄ emissions from aluminum production (metric tons CF₄).
- \( S_{\text{CF}_4} \) = The slope coefficient ((kg CF₄/metric ton Al)/(AE-Mins/cell-day)).
- \( \text{AEM} \) = The anode effect minutes per cell-day (AE-Mins/cell-day).
- \( \text{MP} \) = Metal production (metric tons Al), where AEM and MP are calculated monthly.

\[ E_{\text{CF}_4} = \text{EF}_{\text{CF}_4} \times \text{MP} \times 0.001 \]  (Eq. F-3)

Where:

- \( E_{\text{CF}_4} \) = Monthly CF₄ emissions from aluminum production (metric tons CF₄).
- \( \text{EF}_{\text{CF}_4} \) = The overvoltage emission factor (kg CF₄/metric ton Al).
- \( \text{MP} \) = Metal production (metric tons Al), where MP is calculated monthly.
\[ E_{\text{C}_2\text{F}_6} = E_{\text{CF}_4} \times F_{\text{C}_2\text{F}_6/\text{CF}_4} \times 0.001 \quad \text{(Eq. F-4)} \]

Where:
- \( E_{\text{C}_2\text{F}_6} \) = Monthly \( \text{C}_2\text{F}_6 \) emissions from aluminum production (metric tons \( \text{C}_2\text{F}_6 \)).
- \( E_{\text{CF}_4} \) = \( \text{CF}_4 \) emissions from aluminum production (kg \( \text{CF}_4 \)).
- \( F_{\text{C}_2\text{F}_6/\text{CF}_4} \) = The weight fraction of \( \text{C}_2\text{F}_6/\text{CF}_4 \) (kg \( \text{C}_2\text{F}_6 \)/kg \( \text{CF}_4 \)).
- 0.001 = Conversion factor from kg to metric tons, where \( E_{\text{CF}_4} \) is calculated monthly.

(c) You must calculate and report the annual process \( \text{CO}_2 \) emissions from anode consumption during electrolysis and anode baking of prebake cells using either the procedures in paragraph (d) of this section, the procedures in paragraphs (e) and (f) of this section, or the procedures in paragraph (g) of this section.

(d) Calculate and report under this subpart the process \( \text{CO}_2 \) emissions by operating and maintaining CEMS according to the Tier 4 Calculation Methodology in §98.33(a)(4) and all associated requirements for Tier 4 in subpart C of this part (General Stationary Fuel Combustion Sources).

(e) Use the following procedures to calculate \( \text{CO}_2 \) emissions from anode consumption during electrolysis:

(1) For prebake cells you must calculate \( \text{CO}_2 \) emissions from anode consumption using Equation F-5 of this section:

\[ E_{\text{CO}_2} = NAC \times MP \times \left( \left[ 100 - S_a - \text{Ash}_a \right]/100 \right) \times (44/12) \quad \text{(Eq. F-5)} \]

Where:
- \( E_{\text{CO}_2} \) = Annual \( \text{CO}_2 \) emissions from prebaked anode consumption (metric tons \( \text{CO}_2 \)).
- \( NAC \) = Net annual prebaked anode consumption per metric ton Al (metric tons \( \text{C}/ \text{metric tons Al} \)).
- \( MP \) = Annual metal production (metric tons Al).
- \( S_a \) = Sulfur content in baked anode (percent weight).
- \( \text{Ash}_a \) = Ash content in baked anode (percent weight).
- 44/12 = Ratio of molecular weights, \( \text{CO}_2 \) to carbon.

(2) For Soderberg cells you must calculate \( \text{CO}_2 \) emissions using Equation F-6 of this section:

\[ E_{\text{CO}_2} = (PC \times MP - [CSM \times MP]/1000 - BC/100 \times PC \times MP \times \left[ S_p + \text{Ash}_p + H_p \right]/100 - [100 - BC]/100 \times PC \times MP \times \left[ S_c + \text{Ash}_c \right]/100 - MP \times CD) \times (44/12) \quad \text{(Eq. F-6)} \]

Where:
- \( E_{\text{CO}_2} \) = Annual \( \text{CO}_2 \) emissions from paste consumption (metric ton \( \text{CO}_2 \)).
- \( PC \) = Annual paste consumption (metric ton \( \text{C}/ \text{metric ton Al} \)).
- \( MP \) = Annual metal production (metric ton Al).
- \( CSM \) = Annual emissions of cyclohexane soluble matter (kg/metric ton Al).
- \( BC \) = Binder content of paste (percent weight).
- \( S_p \) = Sulfur content of pitch (percent weight).
- \( \text{Ash}_p \) = Ash content of pitch (percent weight).
- \( H_p \) = Hydrogen content of pitch (percent weight).
- \( S_c \) = Sulfur content in calcined coke (percent weight).
- \( \text{Ash}_c \) = Ash content in calcined coke (percent weight).
- \( CD \) = Carbon in skimmed dust from Soderberg cells (metric ton \( \text{C}/ \text{metric ton Al} \)).
- 44/12 = Ratio of molecular weights, \( \text{CO}_2 \) to carbon.
(f) Use the following procedures to calculate CO₂ emissions from anode baking of prebake cells:

\[ E_{\text{CO}_2\text{PV}} = (GA - H_w - BA - WT) \times (44/12) \]  
(Eq. F-7)

Where:
- \( E_{\text{CO}_2\text{PV}} \) = Annual CO₂ emissions from pitch volatiles combustion (metric tons CO₂).
- \( GA \) = Initial weight of green anodes (metric tons).
- \( H_w \) = Annual hydrogen content in green anodes (metric tons).
- \( BA \) = Annual baked anode production (metric tons).
- \( WT \) = Annual waste tar collected (metric tons).
- 44/12 = Ratio of molecular weights, CO₂ to carbon.

(1) Use Equation F-7 of this section to calculate emissions from pitch volatiles combustion.

(2) Use Equation F-8 of this section to calculate emissions from bake furnace packing material.

\[ E_{\text{CO}_2\text{PC}} = PCC \times BA \times \left( 100 - S_{pc} - \frac{\text{Ash}_{pc}}{100} \right) \times (44/12) \]  
(Eq. F-8)

Where:
- \( E_{\text{CO}_2\text{PC}} \) = Annual CO₂ emissions from bake furnace packing material (metric tons CO₂).
- \( PCC \) = Annual packing coke consumption (metric tons/metric ton baked anode).
- \( BA \) = Annual baked anode production (metric tons).
- \( S_{pc} \) = Sulfur content in packing coke (percent weight).
- \( \text{Ash}_{pc} \) = Ash content in packing coke (percent weight).
- 44/12 = Ratio of molecular weights, CO₂ to carbon.

(g) If process CO₂ emissions from anode consumption during electrolysis or anode baking of prebake cells are vented through the same stack as any combustion unit or process equipment that reports CO₂ emissions using a CEMS that complies with the Tier 4 Calculation Methodology in subpart C of this part (General Stationary Fuel Combustion Sources), then the calculation methodology in paragraphs (d) and (e) of this section shall not be used to calculate those process emissions. The owner or operation shall report under this subpart the combined stack emissions according to the Tier 4 Calculation Methodology in §98.33(a)(4) and all associated requirements for Tier 4 in subpart C of this part (General Stationary Fuel Combustion Sources).

the technology specific default values in Table F–1 of this subpart.

(b) The minimum frequency of the measurement and analysis is annually except as follows:

(1) Monthly for anode effect minutes per cell day (or anode effect over-voltage and current efficiency).

(2) Monthly for aluminum production.

(3) Smelter-specific slope coefficients, overvoltage emission factors, and weight fractions according to paragraph (a) of this section.

(c) Sources may use either smelter-specific values from annual measurements of parameters needed to complete the equations in §98.63 (e.g., sulfur, ash, and hydrogen contents) or the default values shown in Table F–2 of this subpart.


§ 98.65 Procedures for estimating missing data.

A complete record of all measured parameters used in the GHG emissions calculations is required. Therefore, whenever a quality-assured value of a required parameter is unavailable (e.g., if a meter malfunctions during unit operation or if a required sample measurement is not taken), a substitute data value for the missing parameter shall be used in the calculations, according to the following requirements:

(a) Where anode or paste consumption data are missing, CO₂ emissions can be estimated from aluminum production per Equation F–8 of this section.

\[
ECO_2 = EF_p \times MP_p + EF_s \times MP_s
\]  

Where:

- \( ECO_2 \) = CO₂ emissions from anode and/or paste consumption, metric tons CO₂.
- \( EF_p \) = Prebake technology specific emission factor (1.6 metric tons CO₂/metric ton aluminum produced).
- \( MP_p \) = Metal production from prebake process (metric tons Al).
- \( EF_s \) = Söderberg technology specific emission factor (1.7 metric tons CO₂/metric ton Al produced).
- \( MP_s \) = Metal production from Söderberg process (metric tons Al).

(b) For other parameters, use the average of the two most recent data points after the missing data.


§ 98.66 Data reporting requirements.

In addition to the information required by §98.3(c), you must report the following information at the facility level:

(a) Annual aluminum production in metric tons.

(b) Type of smelter technology used.

(c) The following PFC-specific information on an annual basis:

(1) Perfluoromethane emissions and perfluoroethane emissions from anode effects in all prebake and all Söderberg electrolysis cells combined.

(2) Anode effect minutes per cell-day (AE-mins/cell-day), anode effect frequency (AE/cell-day), anode effect duration (minutes), (Or anode effect over-voltage factor ((kg CF₄/metric ton Al)/ (mV/cell day)), potline overvoltage (mV/cell day), current efficiency (%)).

(3) Smelter-specific slope coefficients (or overvoltage emission factors) and the last date when the smelter-specific-slope coefficients (or overvoltage emission factors) were measured.

(d) Method used to measure the frequency and duration of anode effects (or overvoltage).

(e) The following CO₂-specific information for prebake cells:

(1) Annual anode consumption.

(2) Annual CO₂ emissions from the smelter.

(f) The following CO₂-specific information for Söderberg cells:

(1) Annual paste consumption.

(2) Annual CO₂ emissions from the smelter.
§ 98.67 Records that must be retained.

In addition to the information required by § 98.3(g), you must retain the following records:

(a) Monthly aluminum production in metric tons.

(b) Type of smelter technology used.

(c) The following PFC-specific information on a monthly basis:

(1) Perfluoromethane and perfluoroethane emissions from anode effects in prebake and Söderberg electrolysis cells.

(2) Anode effect minutes per cell-day (AE-mins/cell-day), anode effect frequency (AE/cell-day), anode effect duration (minutes). (Or anode effect overvoltage factor ((kg CF₄/metric ton Al)/(mV/cell day)), potline overvoltage (mV/cell day), current efficiency (%).)

(3) Smelter-specific slope coefficients and the last date when the smelter-specific-slope coefficients were measured.

(d) Method used to measure the frequency and duration of anode effects (or to measure anode effect overvoltage and current efficiency).

(e) The following CO₂-specific information for prebake cells:

(1) Annual anode consumption.

(2) Annual CO₂ emissions from the smelter.

(f) The following CO₂-specific information for Söderberg cells:

(1) Annual paste consumption.

(2) Annual CO₂ emissions from the smelter.

(g) Smelter-specific inputs to the CO₂ process equations (e.g., levels of sulfur and ash) that were used in the calculation, on an annual basis.

(h) Exact data elements required will vary depending on smelter technology (e.g., point-feed prebake or Söderberg) and process control technology (e.g., Pechiney or other).

§ 98.68 Definitions.

All terms used in this subpart have the same meaning given in the Clean Air Act and subpart A of this part.

### Table F–1 to Subpart F of Part 98—Slope and Overvoltage Coefficients for the Calculation of PFC Emissions from Aluminum Production

<table>
<thead>
<tr>
<th>Technology</th>
<th>CF₄ slope coefficient [(kg CF₄/metric ton Al)/(AE–Mins/cell-day)]</th>
<th>CF₄ overvoltage coefficient [(kg CF₄/metric ton Al)/(mV)]</th>
<th>Weight fraction C₂F₆/CF₄ [(kg C₂F₆/kg CF₄)]</th>
</tr>
</thead>
<tbody>
<tr>
<td>Center Worked Prebake (CWPB)</td>
<td>0.143</td>
<td>1.16</td>
<td>0.121</td>
</tr>
<tr>
<td>Side Worked Prebake (SWPB)</td>
<td>0.272</td>
<td>3.65</td>
<td>0.252</td>
</tr>
<tr>
<td>Vertical Stud Söderberg (VSS)</td>
<td>0.082</td>
<td>NA</td>
<td>0.053</td>
</tr>
<tr>
<td>Horizontal Stud Söderberg (HSS)</td>
<td>0.099</td>
<td>NA</td>
<td>0.085</td>
</tr>
</tbody>
</table>

[75 FR 79156, Dec. 17, 2010]

### Table F–2 to Subpart F of Part 98—Default Data Sources for Parameters Used for CO₂ Emissions

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Data source</th>
</tr>
</thead>
<tbody>
<tr>
<td>CO₂ Emissions from Prebake Cells (CWPB and SWPB)</td>
<td>Individual facility records.</td>
</tr>
<tr>
<td>NAC: net annual prebaked anode consumption per metric ton Al (metric tons C/metric tons Al)</td>
<td>Individual facility records.</td>
</tr>
<tr>
<td>Sₓ: sulfur content in baked anode (percent weight)</td>
<td>2.0.</td>
</tr>
<tr>
<td>Ashₜ: ash content in baked anode (percent weight)</td>
<td>0.4.</td>
</tr>
</tbody>
</table>
§ 98.72 GHGs to report.

You must report:

(a) CO₂ process emissions from steam reforming of a hydrocarbon or the gasification of solid and liquid raw material, reported for each ammonia manufacturing process unit following the requirements of this subpart (CO₂ process emissions reported under this subpart may include CO₂ that is later consumed on site for urea production, and therefore is not released to the ambient air from the ammonia manufacturing process unit).

(b) CO₂, CH₄, and N₂O emissions from each stationary fuel combustion unit. You must report these emissions under subpart C of this part (General Stationary Fuel Combustion Sources), by following the requirements of subpart C, except that for ammonia manufacturing processes subpart C does not apply to any CO₂ resulting from combustion of the waste recycle stream (commonly referred to as the purge gas stream).

(c) CO₂ emissions collected and transferred off site under subpart PP of this part (Suppliers of CO₂), following the requirements of subpart PP.

§ 98.73 Calculating GHG emissions.

You must calculate and report the annual process CO₂ emissions from each ammonia manufacturing process unit using the procedures in either paragraph (a) or (b) of this section.

(a) Calculate and report under this subpart the process CO₂ emissions by operating and maintaining CEMS according to the Tier 4 Calculation Methodology specified in §98.33(a)(4) and all associated requirements for Tier 4 in subpart C of this part (General Stationary Fuel Combustion Sources).

(b) Calculate and report under this subpart process CO₂ emissions using the procedures in paragraphs (b)(1) through (b)(5) of this section for gaseous feedstock, liquid feedstock, or solid feedstock, as applicable.

(1) **Gaseous feedstock.** You must calculate, from each ammonia manufacturing unit, the CO₂ process emissions from gaseous feedstock according to Equation G-1 of this section:

\[
\text{CO}_2,G,k = \frac{\sum_{n=1}^{12} \frac{44}{12} \times \text{Fdstk}_{n,k} \times \text{CC}_n \times \frac{\text{MW}}{\text{MVC}}} {0.001} \quad \text{(Eq. G-1)}
\]

Where:
- \(\text{CO}_2,G,k\) = Annual CO₂ emissions arising from gaseous feedstock consumption (metric tons).
- \(\text{Fdstk}_{n,k}\) = Volume of the gaseous feedstock used in month \(n\) (scf of feedstock).
- \(\text{CC}_n\) = Carbon content of the gaseous feedstock, for month \(n\) (kg C per kg of feedstock), determined according to §98.74(c).
- \(\text{MW}\) = Molecular weight of the gaseous feedstock (kg/kg-mole).
- \(\text{MVC}\) = Molar volume conversion factor (849.5 scf per kg-mole at standard conditions).
- \(44/12\) = Ratio of molecular weights, CO₂ to carbon.
- 0.001 = Conversion factor from kg to metric tons.
- \(k\) = Processing unit.
- \(n\) = Number of month.

(2) **Liquid feedstock.** You must calculate, from each ammonia manufacturing unit, the CO₂ process emissions from liquid feedstock according to Equation G-2 of this section:

\[
\text{CO}_2,L,k = \left( \sum_{n=1}^{12} \frac{44}{12} \times \text{Fdstk}_{n,k} \times \text{CC}_n \right) \times 0.001 \quad \text{(Eq. G-2)}
\]

Where:
- \(\text{CO}_2,L,k\) = Annual CO₂ emissions arising from liquid feedstock consumption (metric tons).
- \(\text{Fdstk}_{n,k}\) = Volume of the liquid feedstock used in month \(n\) (gallons of feedstock).
- \(\text{CC}_n\) = Carbon content of the liquid feedstock, for month \(n\) (kg C per gallon of feedstock) determined according to §98.74(c).
- \(44/12\) = Ratio of molecular weights, CO₂ to carbon.
- 0.001 = Conversion factor from kg to metric tons.
- \(k\) = Processing unit.
- \(n\) = Number of month.

(3) **Solid feedstock.** You must calculate, from each ammonia manufacturing unit, the CO₂ process emissions from solid feedstock according to Equation G-3 of this section:
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\[ \text{CO}_2,\text{S},k = \left( \sum_{n=1}^{12} \frac{44}{12} \text{Fdstk}_{n,k} \times \text{CC}_n \right) \times 0.001 \]  
(Eq. G-3)

Where:
- \( \text{CO}_2,\text{S},k \) = Annual \( \text{CO}_2 \) emissions arising from solid feedstock consumption (metric tons).
- \( \text{Fdstk}_{n,k} \) = Mass of the solid feedstock used in month \( n \) (kg of feedstock).
- \( \text{CC}_n \) = Carbon content of the solid feedstock, for month \( n \) (kg C per kg of feedstock), determined according to 98.74(c).
- \( 44/12 \) = Ratio of molecular weights, \( \text{CO}_2 \) to carbon.
- 0.001 = Conversion factor from kg to metric tons.
- \( k \) = Processing unit.
- \( n \) = Number of month.

(4) You must calculate the annual process \( \text{CO}_2 \) emissions from each ammonia processing unit \( k \) at your facility summing emissions, as applicable from Equation G–1, G–2, and G–3 of this section using Equation G–4.

\[ \text{E}_{\text{CO}_2 k} = \text{CO}_2,\text{G} + \text{CO}_2,\text{S} + \text{CO}_2,\text{L} \]  
(Eq. G-4)

Where:
- \( \text{E}_{\text{CO}_2 k} \) = Annual \( \text{CO}_2 \) emissions from each ammonia processing unit \( k \) (metric tons).
- \( \text{CO}_2,\text{G} \) = Annual \( \text{CO}_2 \) process emissions from each ammonia processing unit \( k \) (metric tons).
- \( \text{CO}_2,\text{S} \) = Annual \( \text{CO}_2 \) emissions arising from solid feedstock consumption (metric tons) (\( \text{CO}_2 \) process emissions reported under this subpart may include \( \text{CO}_2 \) that is later consumed on site for urea production, and therefore is not released to the ambient air from the ammonia manufacturing process unit(s)).
- \( \text{CO}_2,\text{L} \) = Annual \( \text{CO}_2 \) emissions from each ammonia processing unit (metric tons).
- \( k \) = Processing unit.
- \( n \) = Total number of ammonia processing units.

(5) You must determine the combined \( \text{CO}_2 \) emissions from all ammonia processing units at your facility using Equation G–5 of this section.

\[ \text{CO}_2 = \sum_{k=1}^{n} \text{E}_{\text{CO}_2 k} \]  
(Eq. G-5)

Where:
- \( \text{CO}_2 \) = Annual combined \( \text{CO}_2 \) emissions from all ammonia processing units (metric tons) (\( \text{CO}_2 \) process emissions reported under this subpart may include \( \text{CO}_2 \) that is later consumed on site for urea production, and therefore is not released to the ambient air from the ammonia manufacturing process unit(s)).
- \( \text{E}_{\text{CO}_2 k} \) = Annual \( \text{CO}_2 \) emissions from each ammonia processing unit (metric tons).
- \( k \) = Processing unit.
- \( n \) = Total number of ammonia processing units.

(c) If GHG emissions from an ammonia manufacturing unit are vented through the same stack as any combustion unit or process equipment that reports \( \text{CO}_2 \) emissions using a CEMS that complies with the Tier 4 Calculation Methodology in subpart C of this part (General Stationary Fuel Combustion Sources), then the calculation methodology in paragraph (b) of this section shall not be used to calculate process emissions. The owner or operator shall report under this subpart the combined stack emissions according to the Tier 4 Calculation Methodology in §98.33(a)(4) and all associated requirements for Tier 4 in subpart C of this part.


§ 98.74 Monitoring and QA/QC requirements.

(a) You must continuously measure the quantity of gaseous or liquid feedstock consumed using a flow meter. The quantity of solid feedstock consumed can be obtained from company records and aggregated on a monthly basis.

(b) You must document the procedures used to ensure the accuracy of the estimates of feedstock consumption.

(c) You must determine monthly carbon contents and the average molecular weight of each feedstock consumed from reports from your supplier. As an alternative to using supplier information on carbon contents, you can also collect a sample of each feedstock on a monthly basis and analyze the carbon content and molecular weight of the fuel using any of the following methods listed in paragraphs (c)(1) through (c)(8) of this section, as applicable.
§ 98.75 Procedures for estimating missing data.

A complete record of all measured parameters used in the GHG emissions calculations is required. Therefore, whenever the monitoring and quality assurance procedures in §98.74 cannot be followed (e.g., if a meter malfunctions during unit operation), a substitute data value for the missing parameter shall be used in the calculations following paragraphs (a) and (b) of this section. You must document and keep records of the procedures used for all such estimates.

(a) For missing data on monthly carbon contents of feedstock, the substitute data value shall be the arithmetic average of the quality-assured values of that carbon content in the month preceding and the month immediately following the missing data incident. If no quality-assured data are available prior to the missing data incident, the substitute data value shall be the first quality-assured value for carbon content obtained in the month after the missing data period.

(b) For missing feedstock supply rates or waste recycle stream used to determine monthly feedstock consumption or monthly waste recycle stream quantity, you must determine the best available estimate(s) of the parameter(s), based on all available process data.


§ 98.76 Data reporting requirements.

In addition to the information required by §98.3(c), each annual report must contain the information specified
in paragraphs (a) and (b) of this section, as applicable for each ammonia manufacturing process unit.

(a) If a CEMS is used to measure CO₂ emissions, then you must report the relevant information required under §98.36 for the Tier 4 Calculation Methodology and the following information in this paragraph (a):

(1) Annual quantity of each type of feedstock consumed for ammonia manufacturing (scf of feedstock or gallons of feedstock or kg of feedstock).

(2) Method used for determining quantity of feedstock used.

(b) If a CEMS is not used to measure emissions, then you must report the following information:

(1) Annual CO₂ process emissions (metric tons) for each ammonia manufacturing process unit.

(2) Monthly quantity of each type of feedstock consumed for ammonia manufacturing for each ammonia processing unit (scf of feedstock or gallons of feedstock or kg of feedstock).

(3) Method used for determining quantity of monthly feedstock used.

(4) Whether carbon content for each feedstock for month n is based on reports from the supplier or analysis of carbon content.

(5) If carbon content of feedstock for month n is based on analysis, the test method used.

(6) Sampling analysis results of carbon content of feedstock as determined for QA/QC of supplier data under §98.74(e).

(7) If a facility uses gaseous feedstock, the carbon content of the gaseous feedstock, for month n, (kg C per kg of feedstock).

(8) If a facility uses gaseous feedstock, the molecular weight of the gaseous feedstock (kg/kg-mole).

(9) If a facility uses gaseous feedstock, the molar volume conversion factor of the gaseous feedstock (scf per kg-mole).

(10) If a facility uses liquid feedstock, the carbon content of the liquid feedstock, for month n, (kg C per gallon of feedstock).

(11) If a facility uses solid feedstock, the carbon content of the solid feedstock, for month n, (kg C per kg of feedstock).

(12) Annual urea production (metric tons) and method used to determine urea production.

(13) CO₂ from the steam reforming of a hydrocarbon or the gasification of solid and liquid raw material at the ammonia manufacturing process unit used to produce urea and the method used to determine the CO₂ consumed in urea production.


§98.77 Records that must be retained.

In addition to the records required by §98.3(g), you must retain the following records specified in paragraphs (a) and (b) of this section for each ammonia manufacturing unit.

(a) If a CEMS is used to measure emissions, retain records of all feedstock purchases in addition to the requirements in §98.37 for the Tier 4 Calculation Methodology.

(b) If a CEMS is not used to measure process CO₂ emissions, you must also retain the records specified in paragraphs (b)(1) through (b)(2) of this section:

(1) Records of all analyses and calculations conducted for reported data as listed in §98.76(b).

(2) Monthly records of carbon content of feedstock from supplier and/or all analyses conducted of carbon content.

§98.78 Definitions.

All terms used in this subpart have the same meaning given in the Clean Air Act and subpart A of this part.

Subpart H—Cement Production

§98.80 Definition of the source category.

The cement production source category consists of each kiln and each in-line kiln/raw mill at any portland cement manufacturing facility including alkali bypasses, and includes kilns and in-line kiln/raw mills that burn hazardous waste.

§98.81 Reporting threshold.

You must report GHG emissions under this subpart if your facility contains a cement production process and
§ 98.82 GHGs to report.

You must report:

(a) CO₂ process emissions from calcination in each kiln.
(b) CO₂ combustion emissions from each kiln.
(c) CH₄ and N₂O combustion emissions from each kiln. You must calculate and report these emissions under subpart C of this part (General Stationary Fuel Combustion Sources) by following the requirements of subpart C.
(d) CO₂, CH₄, and N₂O emissions from each stationary combustion unit other than kilns. You must report these emissions under subpart C of this part (General Stationary Fuel Combustion Sources) by following the requirements of subpart C.

§ 98.83 Calculating GHG emissions.

You must calculate and report the annual process CO₂ emissions from each kiln using the procedure in paragraphs (a) and (b) of this section.

(a) For each cement kiln that meets the conditions specified in §98.33(b)(4)(ii) or (b)(4)(iii), you must calculate and report under this subpart the combined process and combustion CO₂ emissions by operating and maintaining a CEMS to measure CO₂ emissions according to the Tier 4 Calculation Methodology specified in §98.33(a)(4) and all associated requirements for Tier 4 in subpart C of this part (General Stationary Fuel Combustion Sources).

(b) For each kiln that is not subject to the requirements in paragraph (a) of this section, calculate and report the process and combustion CO₂ emissions from the kiln by using the procedure in either paragraph (c) or (d) of this section.

(c) Calculate and report under this subpart the combined process and combustion CO₂ emissions by operating and maintaining a CEMS to measure CO₂ emissions according to the Tier 4 Calculation Methodology specified in §98.33(a)(4) and all associated requirements for Tier 4 in subpart C of this part (General Stationary Fuel Combustion Sources).

(d) Calculate and report process and combustion CO₂ emissions separately using the procedures specified in paragraphs (d)(1) through (d)(4) of this section.

(1) Calculate CO₂ process emissions from all kilns at the facility using Equation H–1 of this section:

\[
CO_{2,CMP} = \sum_{m=1}^{k} CO_{2,Cl,m} + CO_{2,r,m} \quad \text{(Eq. H-1)}
\]

Where:

- \( CO_{2,CMP} \) = Annual process emissions of CO₂ from cement manufacturing, metric tons.
- \( CO_{2,Cl,m} \) = Total annual emissions of CO₂ from clinker production from kiln m, metric tons.
- \( CO_{2,r,m} \) = Total annual emissions of CO₂ from raw materials, metric tons.
- \( k \) = Total number of kilns at a cement manufacturing facility.

(2) CO₂ emissions from clinker production. Calculate CO₂ emissions from each kiln using Equations H–2 through H–5 of this section.

\[
CO_{2,Cl,m} = \sum_{j=1}^{p} \left( Cl_{i,j} \right) \times \left( EF_{Cl,j} \right) \times \frac{2000}{2205} + \sum_{j=1}^{p} \left( CKD_{i,j} \right) \times \left( EF_{CKD,i,j} \right) \times \frac{2000}{2205} \quad \text{(Eq. H-2)}
\]

Where:

- \( Cl_{i,j} \) = Quantity of clinker produced in month \( j \) from kiln m, tons.
EF_{CLi} = \frac{C_{Li}CaO}{MR_{CaO}} \times MR_{CaO} + \frac{C_{Li}MgO}{MR_{MgO}} \times MR_{MgO} \quad \text{(Eq. H-3)}

Where:
- $C_{Li}CaO$ = Monthly total CaO content of Clinker, wt-fraction.
- $C_{Li}ncCaO$ = Monthly non-calcined CaO content of Clinker, wt-fraction.
- MR_{CaO} = Molecular-weight Ratio of CO$_2$/CaO = 0.785.
- $C_{Li}MgO$ = Monthly total MgO content of Clinker, wt-fraction.
- $C_{Li}ncMgO$ = Monthly non-calcined MgO content of Clinker, wt-fraction.
- MR_{MgO} = Molecular-weight Ratio of CO$_2$/MgO = 1.092.

(B) Non-calcined CaO is CaO that remains in the clinker in the form of CaCO$_3$ and CaO in the clinker that entered the kiln as a non-carbonate species. Non-calcined MgO is MgO that remains in the clinker in the form of MgCO$_3$ and MgO in the clinker that entered the kiln as a non-carbonate species.

(ii) Kiln-Specific CKD Emission Factor.
(A) Calculate the kiln-specific CKD emission factor for CKD not recycled to the kiln using Equation H-4 of this section.

\[ EF_{CKD} = \left( C_{KD_{CaO}} - C_{KD_{ncCaO}} \right) \times MR_{CaO} + \left( C_{KD_{MgO}} - C_{KD_{ncMgO}} \right) \times MR_{MgO} \quad \text{(Eq. H-4)} \]

Where:
- $C_{KD_{CaO}}$ = Quarterly total CaO content of CKD not recycled to the kiln, wt-fraction.
- $C_{KD_{ncCaO}}$ = Quarterly non-calcined CaO content of CKD not recycled to the kiln, wt-fraction.
- MR_{CaO} = Molecular-weight Ratio of CO$_2$/CaO = 0.785.
- $C_{KD_{MgO}}$ = Quarterly total MgO content of CKD not recycled to the kiln, wt-fraction.
- $C_{KD_{ncMgO}}$ = Quarterly non-calcined MgO content of CKD not recycled to the kiln, wt-fraction.
- MR_{MgO} = Molecular-weight Ratio of CO$_2$/MgO = 1.092.

(B) Non-calcined CaO is CaO that remains in the CKD in the form of CaCO$_3$ and CaO in the CKD that entered the kiln as a non-carbonate species. Non-calcined MgO is MgO that remains in the CKD in the form of MgCO$_3$ and MgO in the CKD that entered the kiln as a non-carbonate species.

(3) CO$_2$ emissions from raw materials. Calculate CO$_2$ emissions from raw materials using Equation H-5 of this section:

\[ CO_{2,rm} = \sum_{i=1}^{m} r_m \times TOC_{rm} \times \frac{44}{12} \times \frac{2000}{2205} \quad \text{(Eq. H-5)} \]
§ 98.84 Monitoring and QA/QC requirements.

(a) You must determine the weight fraction of total CaO and total MgO in CKD not recycled to the kiln from each kiln using ASTM C114–09, Standard Test Methods for Chemical Analysis of Hydraulic Cement (incorporated by reference, see §98.7). The monitoring must be conducted quarterly for each kiln from a CKD sample drawn either as CKD is exiting the kiln or from bulk CKD storage.

(b) You must determine the weight fraction of total CaO and total MgO in clinker from each kiln using ASTM C114–09, Standard Test Methods for Chemical Analysis of Hydraulic Cement (incorporated by reference, see §98.7). The monitoring must be conducted monthly for each kiln from a CKD sample drawn either as CKD is exiting the kiln or from bulk CKD storage.

§ 98.84 Where:

\( rm \) = The amount of raw material \( i \) consumed annually, tons/yr (dry basis) or the amount of raw kiln feed consumed annually, tons/yr (dry basis).

\( \text{CO}_{2}\text{rm} \) = Annual \( \text{CO}_2 \) emissions from raw materials.

\( \text{TOC}_{\text{rm}} \) = Organic carbon content of raw material \( i \) or organic carbon content of combined raw kiln feed (dry basis), as determined in §98.84(c) or using a default factor of 0.2 percent of total raw material weight.

\( M \) = Number of raw materials or 1 if calculating emissions based on combined raw kiln feed.

\( \frac{44}{12} \) = Ratio of molecular weights, \( \text{CO}_2 \) to carbon.

\( \frac{2000}{2205} \) = Conversion factor to convert tons to metric tons.

(4) Calculate and report under subpart C of this part (General Stationary Fuel Combustion Sources) the combustion \( \text{CO}_2 \) emissions from the kiln according to the applicable requirements in subpart C.

calculational methods or the appropriate industry standard practice.

(h) The quarterly non-calcined CaO and MgO that remains in the CKD in the form of CaCO$_3$ or that enters the kiln as a non-carbonate species may be assumed to be a default value of 0.0 or may be determined quarterly by careful chemical analysis of feed material and CKD material from each kiln using well documented analytical and calculational methods or the appropriate industry standard practice.


§ 98.86 Data reporting requirements.

In addition to the information required by §98.3(c), each annual report must contain the information specified in paragraphs (a) and (b) of this section, as appropriate.

(a) If a CEMS is used to measure CO$_2$ emissions, then you must report under this subpart the relevant information required by §98.36(e)(2)(vi) and the information listed in this paragraph(a):

(1) Monthly clinker production from each kiln at the facility.

(2) Monthly cement production from each kiln at the facility.

(3) Number of kilns and number of operating kilns.

(b) If a CEMS is not used to measure CO$_2$ emissions, then you must report the information listed in this paragraph (b) for each kiln:

(1) Kiln identification number.

(2) Monthly clinker production from each kiln.

(3) Annual cement production at the facility.

(4) Number of kilns and number of operating kilns.

(5) Quarterly quantity of CKD not recycled to the kiln for each kiln.

(6) Monthly fraction of total CaO, total MgO, non-calcined CaO and non-calcined MgO in clinker for each kiln (as wt-fractions).

(7) Method used to determine non-calcined CaO and non-calcined MgO in clinker.

(8) Quarterly fraction of total CaO, total MgO, non-calcined CaO and non-calcined MgO in CKD not recycled to the kiln for each kiln (as wt-fractions).

(9) Method used to determine non-calcined CaO and non-calcined MgO in CKD.

(10) Monthly kiln-specific clinker CO$_2$ emission factors for each kiln (metric tons CO$_2$/metric ton clinker produced).

(11) Quarterly kiln-specific CKD CO$_2$ emission factors for each kiln (metric tons CO$_2$/metric ton CKD produced).

(12) Annual organic carbon content of raw kiln feed or annual organic carbon content of each raw material (wt-fraction, dry basis).
§ 98.87 Records that must be retained.

(a) If a CEMS is used to measure CO\(_2\) emissions, then in addition to the records required by §98.3(g), you must retain under this subpart the records required for the Tier 4 Calculation Methodology in §98.37.

(b) If a CEMS is not used to measure CO\(_2\) emissions, then in addition to the records required by §98.3(g), you must retain the records specified in this paragraph (b) for each portland cement manufacturing facility.

(1) Documentation of monthly calculated kiln-specific clinker CO\(_2\) emission factor.

(2) Documentation of quarterly calculated kiln-specific CKD CO\(_2\) emission factor.

(3) Measurements, records and calculations used to determine reported parameters.

§ 98.88 Definitions.

All terms used in this subpart have the same meaning given in the Clean Air Act and subpart A of this part.
§ 98.91 Reporting threshold.

(a) You must report GHG emissions under this subpart if electronics manufacturing production processes, as defined in §98.90, are performed at your facility and your facility meets the requirements of either §98.2(a)(1) or (a)(2). To calculate total annual GHG emissions for comparison to the 25,000 metric ton CO$_2$e per year emission threshold in §98.2(a)(2), follow the requirements of §98.2(b), with one exception. Rather than using the calculation methodologies in §98.93 to calculate emissions from electronics manufacturing processes, calculate emissions of each fluorinated GHG from electronics manufacturing production processes by using paragraphs (a)(1), (a)(2), or (a)(3) of this section, as appropriate, and then sum the emissions of each fluorinated GHG by using paragraph (a)(4) of this section.

(1) If you manufacture semiconductors or MEMS you must calculate annual production process emissions of each input gas $i$ for threshold applicability purposes using the default emission factors shown in Table I–1 to this subpart and Equation I–1 of this subpart.

$$E_i = S * EF_i * GWP_i * 0.001 \quad (\text{Eq. I-1})$$

where:
- $E_i =$ Annual production process emissions of input gas $i$ for threshold applicability purposes (metric tons CO$_2$e).
- $S =$ 100 percent of annual manufacturing capacity of a facility as calculated using Equation I-5 of this subpart (m$^2$).
- $EF_i =$ Emission factor for input gas $i$ (kg/m$^2$).
- $GWP_i =$ Gas-appropriate GWP as provided in Table A–1 to subpart A of this part.

0.001 = Conversion factor from kg to metric tons.

$i =$ Input gas.

(2) If you manufacture LCDs, you must calculate annual production process emissions of each input gas $i$ for threshold applicability purposes using the default emission factors shown in Table I–1 to this subpart and Equation I–2 of this subpart.

$$E_i = S * EF_i * GWP_i * 0.000001 \quad (\text{Eq. I-2})$$

where:
- $E_i =$ Annual production process emissions of input gas $i$ for threshold applicability purposes (metric tons CO$_2$e).
- $S =$ 100 percent of annual manufacturing capacity of a facility as calculated using Equation I-5 of this subpart (m$^2$).
- $EF_i =$ Emission factor for input gas $i$ (g/m$^2$).
- $GWP_i =$ Gas-appropriate GWP as provided in Table A–1 to subpart A of this part.

0.000001 = Conversion factor from g to metric tons.

$i =$ Input gas.

(3) If you manufacture PVs, you must calculate annual production process emissions of each input gas $i$ for threshold applicability purposes using gas-appropriate GWP values shown in Table A–1 to subpart A of this part and Equation I–3 of this subpart.

$$E_i = C_i * GWP_i * 0.001 \quad (\text{Eq. I-3})$$

where:
- $E_i =$ Annual production process emissions of input gas $i$ for threshold applicability purposes (metric tons CO$_2$e).
- $C_i =$ Annual fluorinated GHG (input gas $i$) purchases or consumption (kg). Only gases used in PV manufacturing that have listed GWP values in Table A–1 to
§ 98.92 GHGs to report.

(a) You must report emissions of fluorinated GHGs (as defined in §98.6), N₂O, and fluorinated heat transfer fluids (as defined in §98.98). The fluorinated GHGs and fluorinated heat transfer fluids that are emitted from electronics manufacturing production processes include, but are not limited to, those listed in Table I–2 to this subpart. You must individually report, as appropriate:

(1) Fluorinated GHGs emitted from plasma etching.
(2) Fluorinated GHGs emitted from chamber cleaning.
(3) Fluorinated GHGs emitted from wafer cleaning.
(4) N₂O emitted from chemical vapor deposition and other electronics manufacturing processes.
(5) Emissions of fluorinated heat transfer fluids.
(6) All fluorinated GHGs and N₂O consumed, including gases used in manufacturing processes other than those listed in paragraphs (a)(1) through (a)(5) of this section.

(b) CO₂, CH₄, and N₂O combustion emissions from each stationary combustion unit. You must calculate and report these emissions under subpart C of this part (General Stationary Fuel Combustion Sources) by following the requirements of subpart C of this part.

§ 98.93 Calculating GHG emissions.

(a) You must calculate total annual facility-level emissions of each fluorinated GHG used in electronics manufacturing production processes at your facility, for each process type,
using Equations I-6 and I-7 of this subpart according to the procedures in paragraphs (a)(1), (a)(2), (a)(3), (a)(4), (a)(5), or (a)(6) of this section, as appropriate. Facilities to which the procedures in paragraphs (a)(1) of this section or (a)(2) of this section apply may elect to use the procedures in paragraph (a)(3) as an alternative. If your facility uses less than 50 kg of a fluorinated GHG in one reporting year, you may calculate emissions as equal to your facility’s annual consumption for that specific gas as calculated in Equation I-11 of this subpart. Where your facility is required to perform calculations using default emission factors for gas utilization and by-product formation rates according to the procedures in paragraphs (a)(1) or (a)(2) of this section, and default values are not available for a particular input gas and process type or sub-type combination in Tables I-3, I-4, I-5, I-6, or I-7, you must follow the procedures in paragraph (a)(6) of this section.

\[ \text{ProcessType} E_i = \sum_{j=1}^{N} E_{ij} \quad \text{(Eq. I-6)} \]

where:
- ProcessType\( E_i \) = Annual emissions of input gas \( i \) from the processes type (metric tons).
- \( E_{ij} \) = Annual emissions of input gas \( i \) from recipe, process sub-type, or process type \( j \) as calculated in Equation I-8 of this subpart (metric tons).
- \( N \) = The total number of recipes or process sub-types \( j \) that depends on the electronics manufacturing facility and emission calculation methodology. If \( E_{ij} \) is calculated for a process type \( j \) in Equation I-8 of this subpart, \( N = 1 \).
- \( i \) = Input gas,
- \( j \) = Recipe, process sub-type, or process type.

\[ \text{ProcessType} BE_k = \sum_{j=1}^{N} \sum_{i} BE_{ijk} \quad \text{(Eq. I-7)} \]

where:
- ProcessType\( BE_k \) = Annual emissions of by-product gas \( k \) from the processes type (metric tons).
- \( BE_{ijk} \) = Annual emissions of by-product gas \( k \) formed from input gas \( i \) used for recipe, process sub-type, or process type \( j \) as calculated in Equation I-9 of this subpart (metric tons).
- \( N \) = The total number of recipes or process sub-types \( j \) that depends on the electronics manufacturing facility and emission calculation methodology. If \( BE_{ijk} \) is calculated for a process type \( j \) in Equation I-9 of this subpart, \( N = 1 \).
- \( i \) = Input gas,
- \( j \) = Recipe, process sub-type, or process type,
- \( k \) = By-product gas.

(1) If you manufacture MEMS, LCDs, or PVs, you must, except as provided in §98.93(a)(3), calculate annual facility-level emissions of each fluorinated GHG used for the plasma etching and chamber cleaning process types using default utilization and by-product formation rates as shown in Table I-5, I-6, or I-7 of this subpart, as appropriate, and by using Equations I-8 and I-9 of this subpart.

(2) If you manufacture semiconductors on wafers measuring 300 mm or less in diameter, except as provided in §98.93(a)(3), you must adhere to the procedures in paragraphs (a)(2)(i) or (a)(2)(ii) of this section.

(i) If your facility has an annual manufacturing capacity, as calculated using Equation I-5 of this subpart, of less than or equal to 10,500 m² of substrate, you must adhere to the procedures in paragraphs (a)(2)(i)(A) through (a)(2)(i)(C) of this section.

(A) You must calculate annual facility-level emissions of each fluorinated GHG used for the plasma etching process type using default utilization and by-product formation rates as shown in
(B) You must calculate annual facility-level emissions of each fluorinated GHG used for each of the process subtypes associated with the chamber cleaning process type, including in-situ plasma chamber clean, remote plasma chamber clean, and in-situ thermal chamber clean, using default utilization and by-product formation rates as shown in Table I-3 or I-4 of this subpart, and by using Equations I-8 and I-9 of this subpart.

(C) You must calculate annual facility-level emissions of each fluorinated GHG used for each of the process subtypes associated with the chamber cleaning process type, including in-situ plasma chamber clean, remote plasma chamber clean, and in-situ thermal chamber clean, using default utilization and by-product formation rates as shown in Table I-3 or I-4 of this subpart, and by using Equations I-8 and I-9 of this subpart.

(C) You must calculate annual facility-level emissions of each fluorinated GHG used for the wafer cleaning process type using default utilization and by-product formation rates as shown in Table I-3 or I-4 to this subpart, and by using Equations I-8 and I-9 to this subpart.

(ii) If your facility has an annual manufacturing capacity of greater than 10,500 m² of substrate, as calculated using Equation I-5 of this subpart, you must adhere to the procedures in paragraphs (a)(2)(ii)(A) through (a)(2)(ii)(C) of this section, except that you may use the procedures specified in paragraph (a)(2)(i) of this section for the 2011, 2012, and 2013 reporting years.

(A) You must calculate annual facility-level emissions of each fluorinated GHG used for the plasma etching process type using recipe-specific utilization and by-product formation rates determined as specified in §98.94(d), and by using Equations I-8 and I-9 of this subpart. You must develop recipe-specific utilization and by-product formation rates for each individual recipe or set of similar recipes as defined in §98.98. Recipe-specific utilization and by-product formation rates must be developed each reporting year only for recipes which are not similar to any recipe used in a previous reporting year, as defined in §98.98.

(B) You must calculate annual facility-level emissions of each fluorinated GHG used for each of the process subtypes associated with the chamber cleaning process type, including in-situ plasma chamber clean, remote plasma chamber clean, and in-situ thermal chamber clean, using default utilization and by-product formation rates as shown in Table I-3 or I-4 to this subpart, and by using Equations I-8 and I-9 of this subpart.

(C) You must calculate annual facility-level emissions of each fluorinated GHG used for the wafer cleaning process type using default utilization and by-product formation rates as shown in Table I-3 or I-4 to this subpart, and by using Equations I-8 and I-9 of this subpart.

(ii) If your facility has an annual manufacturing capacity of greater than 10,500 m² of substrate, as calculated using Equation I-5 of this subpart, you must adhere to the procedures in paragraphs (a)(2)(ii)(A) through (a)(2)(ii)(C) of this section, except that you may use the procedures specified in paragraph (a)(2)(i) of this section for the 2011, 2012, and 2013 reporting years.

(A) You must calculate annual facility-level emissions of each fluorinated GHG used for the plasma etching process type using recipe-specific utilization and by-product formation rates determined as specified in §98.94(d), and by using Equations I-8 and I-9 of this subpart. You must develop recipe-specific utilization and by-product formation rates for each individual recipe or set of similar recipes as defined in §98.98. Recipe-specific utilization and by-product formation rates must be developed each reporting year only for recipes which are not similar to any recipe used in a previous reporting year, as defined in §98.98.

(B) You must calculate annual facility-level emissions of each fluorinated GHG used for each of the process subtypes associated with the chamber cleaning process type, including in-situ plasma chamber clean, remote plasma chamber clean, and in-situ thermal chamber clean, using default utilization and by-product formation rates as shown in Table I-3 or I-4 to this subpart, and by using Equations I-8 and I-9 of this subpart.

(C) You must calculate annual facility-level emissions of each fluorinated GHG used for the wafer cleaning process type using default utilization and by-product formation rates as shown in Table I-3 or I-4 to this subpart, and by using Equations I-8 and I-9 of this subpart.

To be included in a set of similar recipes for the purposes of this subpart, a recipe must be similar to the recipe in the set for which recipe-specific utilization and by-product formation rates have been measured.
(6) Where your facility is required to perform calculations using default emission factors for gas utilization and by-product formation rates according to the procedures in paragraphs (a)(1) or (a)(2) of this section, and default values are not available for a particular input gas and process type or sub-type combination in Tables I–3, I–4, I–5, I–6, or I–7, you must follow the procedures in either paragraph (a)(6)(i) or (a)(6)(ii) of this section and use Equations I–8 and I–9 of this subpart.

(i) You must use utilization and by-product formation rates of 0.

(ii) You must develop recipe-specific utilization and by-product formation rates determined as specified in §98.94(d) for each individual recipe or set of similar recipes as defined in §98.98. Recipe-specific utilization and by-product formation rates must be developed each reporting year only for recipes that are not similar to any recipe used in a previous reporting year, as defined in §98.98.

\[ E_{ij} = C_{ij} \times (1 - U_{ij}) \times (1 - a_{ij} \times d_{ij}) \times 0.001 \]  \hspace{1cm} \text{Equation I–8}

where:
- \( E_{ij} \) = Annual emissions of input gas \( i \) from recipe, process sub-type, or process type \( j \) (metric tons).
- \( C_{ij} \) = Amount of input gas \( i \) consumed for recipe, process sub-type, or process type \( j \), as calculated in Equation I–13 of this subpart (kg).
- \( U_{ij} \) = Process utilization rate for input gas \( i \) for recipe, process sub-type, or process type \( j \) (expressed as a decimal fraction).
- \( a_{ij} \) = Fraction of input gas \( i \) used in recipe, process sub-type, or process type \( j \) with abatement systems (expressed as a decimal fraction).
- \( d_{ij} \) = Fraction of input gas \( i \) destroyed or removed in abatement systems connected to process tools where recipe, process sub-type, or process type \( j \) is used, as calculated in Equation I–14 of this subpart (expressed as a decimal fraction).
- 0.001 = Conversion factor from kg to metric tons.
- \( i \) = Input gas.
- \( j \) = Recipe, process sub-type, or process type.

\[ BE_{ijk} = B_{ijk} \times C_{ijk} \times (1 - a_{ijk} \times d_{jk}) \times 0.001 \]  \hspace{1cm} \text{Equation I–9}

where:
- \( BE_{ijk} \) = Annual emissions of by-product gas \( k \) formed from input gas \( i \) from recipe, process sub-type, or process type \( j \) (metric tons).
- \( B_{ijk} \) = By-product formation rate of gas \( k \) created as a by-product per amount of input gas \( i \) (kg) consumed by recipe, process sub-type, or process type \( j \) (kg).
- \( C_{ijk} \) = Amount of input gas \( i \) consumed for recipe, process sub-type, or process type \( j \), as calculated in Equation I–13 of this subpart (kg).
- \( a_{ijk} \) = Fraction of input gas \( i \) used for recipe, process sub-type, or process type \( j \) with abatement systems (expressed as a decimal fraction).
- \( d_{jk} \) = Fraction of by-product gas \( k \) destroyed or removed in abatement systems connected to process tools where recipe, process sub-type, or process type \( j \) is used, as calculated in Equation I–14 of this subpart (expressed as a decimal fraction).
- 0.001 = Conversion factor from kg to metric tons.
- \( i \) = Input gas.
- \( j \) = Recipe, process sub-type, or process type.
- \( k \) = By-product gas.

(b) You must calculate annual facility-level \( N_2O \) emissions from each chemical vapor deposition process and other electronics manufacturing production processes using Equation I–10 of this subpart and the methods in paragraphs (b)(1) and (b)(2) of this section. If your facility uses less than 50 kg of \( N_2O \) in one reporting year, you may calculate emissions as equal to your facility’s annual consumption for \( N_2O \) as calculated in Equation I–11 of this subpart.

(1) You must use a factor for \( N_2O \) utilization for chemical vapor deposition processes pursuant to either paragraph (b)(1)(i) or (b)(1)(ii) of this section.
(i) You must develop a facility-specific N\textsubscript{2}O utilization factor averaged over all N\textsubscript{2}O-using chemical vapor deposition processes determined as specified in §98.94(e).

(ii) If you do not use a facility-specific N\textsubscript{2}O utilization factor for chemical vapor deposition processes, you must use the default utilization factor as shown in Table I–8 to this subpart for N\textsubscript{2}O from chemical vapor deposition processes.

(2) You must use a factor for N\textsubscript{2}O utilization for other manufacturing processes pursuant to either paragraph (b)(2)(i) or (b)(2)(ii) of this section.

(i) You must develop a facility-specific N\textsubscript{2}O utilization factor averaged over all N\textsubscript{2}O-using electronics manufacturing production processes other than chemical vapor deposition processes determined as specified in §98.94(e).

(ii) If you do not use a facility-specific N\textsubscript{2}O utilization factor for manufacturing production processes other than chemical vapor deposition, you must use the default utilization factor as shown in Table I–8 to this subpart for N\textsubscript{2}O from manufacturing processes other than chemical vapor deposition.

\[
E(N_2O)_j = C_{N_2O,j} \times (1 - U_{N_2O,j}) \times (1 - a_{N_2O,j} \times d_{N_2O,j}) \times 0.001 \quad \text{(Eq. I-10')}
\]

where:
- \(E(N_2O)_j\) = Annual emissions of N\textsubscript{2}O for N\textsubscript{2}O-using process \(j\) (metric tons).
- \(C_{N_2O,j}\) = Amount of N\textsubscript{2}O consumed for N\textsubscript{2}O-using process \(j\), as calculated in Equation I-13 of this subpart and apportioned to N\textsubscript{2}O process \(j\) (kg).
- \(U_{N_2O,j}\) = Process utilization factor for N\textsubscript{2}O-using process \(j\) (expressed as a decimal fraction).
- \(a_{N_2O,j}\) = Fraction of N\textsubscript{2}O used in N\textsubscript{2}O-using process \(j\) with abatement systems (expressed as a decimal fraction).
- \(d_{N_2O,j}\) = Fraction of N\textsubscript{2}O for N\textsubscript{2}O-using process \(j\) destroyed or removed in abatement systems connected to process tools where process \(j\) is used, as calculated in Equation I-14 of this subpart (expressed as a decimal fraction).

\[
0.001 = \text{Conversion factor from kg to metric tons.}
\]

\(j\) = Type of N\textsubscript{2}O-using process, either chemical vapor deposition or other N\textsubscript{2}O-using manufacturing processes.

(c) You must calculate total annual input gas \(i\) consumption for each fluorinated GHG and N\textsubscript{2}O using Equation I-11 of this subpart. Pursuant to §98.92(a)(6), for all fluorinated GHGs and N\textsubscript{2}O used at your facility for which you do not calculate emissions using Equations I-6, I-7, I-8, I-9, and I-10 of this subpart, calculate consumption of these fluorinated GHGs and N\textsubscript{2}O using Equation I-11 of this subpart.

\[
C_i = (I_{Bi} - I_{Ei} + A_i - D_i) \quad \text{(Eq. I-11)}
\]

where:
- \(C_i\) = Annual consumption of input gas \(i\) (kg per year).
- \(I_{Bi}\) = Inventory of input gas \(i\) stored in containers at the beginning of the reporting year, including heels (kg). For containers in service at the beginning of a reporting year, account for the quantity in these containers as if they were full.
- \(I_{Ei}\) = Inventory of input gas \(i\) stored in containers at the end of the reporting year, including heels (kg). For containers in service at the end of a reporting year, account for the quantity in these containers as if they were full.
- \(A_i\) = Acquisitions of input gas \(i\) during the year through purchases or other transactions, including heels in containers returned to the electronics manufacturing facility (kg).
- \(D_i\) = Disbursements of input gas \(i\) through sales or other transactions during the year, including heels in containers returned by the electronics manufacturing facility to the chemical supplier, as calculated using Equation I-12 of this subpart (kg).

\(i\) = Input gas.

(d) You must calculate disbursements of input gas \(i\) using facility-wide gas-
specific heel factors, as determined in §98.94(b), and by using Equation I–12 of this subpart.

\[
D_i = \sum_{l=1}^{M} (h_{il} \ast N_{il} \ast F_{il}) + X_i \quad \text{(Eq. I–12)}
\]

where:

\(D_i\) = Disbursements of input gas \(i\) through sales or other transactions during the reporting year, including heels in containers returned by the electronics manufacturing facility to the gas distributor (kg).

\(h_{il}\) = Facility-wide gas-specific heel factor for input gas \(i\) and container size and type \(l\) (expressed as a decimal fraction), as determined in §98.94(b). If your facility uses less than 50 kg of a fluorinated GHG or N\(_2\)O in one reporting year, you may assume that any \(h_{il}\) for that fluorinated GHG or N\(_2\)O is equal to zero.

\(N_{il}\) = Number of containers of size and type \(l\) returned to the gas distributor containing the standard heel of input gas \(i\).

\(F_{il}\) = Full capacity of containers of size and type \(l\) containing input gas \(i\) (kg).

\(X_i\) = Disbursements under exceptional circumstances of input gas \(i\) through sales or other transactions during the year (kg). These include returns of containers whose contents have been weighed due to an exceptional circumstance as specified in §98.94(b)(4).

\(i\) = Input gas.

\(l\) = Size and type of gas container.

\(M\) = The total number of different sized container types. If only one size and container type is used for an input gas \(i\), \(M=1\).

(e) You must calculate the amount of input gas \(i\) consumed for each individual recipe (including those in a set of similar recipes) process sub-type, or process type \(j\), using Equation I–13 of this subpart.

\[
C_{ij} = f_{ij} \ast C_i \quad \text{(Eq. I–13)}
\]

where:

\(C_{ij}\) = The annual amount of input gas \(i\) consumed for recipe, process sub-type, or process type \(j\) (kg).

\(f_{ij}\) = Recipe-specific, process sub-type-specific, or process type-specific input gas \(i\) apportioning factor (expressed as a decimal fraction), as determined in accordance with §98.94(c).

\(C_i\) = Annual consumption of input gas \(i\) as calculated using Equation I–11 of this subpart (kg).

(f) If you report controlled emissions pursuant to §98.94(f), you must calculate the fraction of input gas \(i\) destroyed in abatement systems for each individual recipe (including those in a set of similar recipes) process sub-type, or process type \(j\) by using Equation I–14 of this subpart.

\[
d_{ij} = \frac{\sum p C_{ijp} \ast d_{ijp} \ast u_p}{\sum p C_{ijp}} \quad \text{(Eq. I–14)}
\]

where:

\(d_{ij}\) = Fraction of input gas \(i\) destroyed or removed in abatement systems connected to process tools where recipe, process sub-type, or process type \(j\) is used (expressed as a decimal fraction).
\[ C_{ijp} = \text{The amount of input gas } i \text{ consumed for recipe, process sub-type, or process type } j \text{ fed into abatement system } p \text{ (kg)}. \]

\[ d_{ijp} = \text{Destruction or removal efficiency for input gas } i \text{ in abatement system } p \text{ connected to process tools where recipe, process sub-type, or process type } j \text{ is used (expressed as a decimal fraction). This is zero unless the facility adheres to requirements in §98.94(f)}. \]

\[ u_p = \text{The uptime of abatement system } p \text{ as calculated in Equation I–15 of this subpart (expressed as a decimal fraction).} \]

\[ i = \text{Input gas}. \]

\[ j = \text{Recipe, process sub-type, or process type}. \]

\[ p = \text{Abatement system}. \]

\[ (g) \text{ If you report controlled emissions pursuant to §98.94(f), you must calculate the uptime by using Equation I–15 of this subpart.} \]

\[ u_p = \frac{t_p}{T_p} \quad \text{(Eq. I–15)} \]

where:

\[ u_p = \text{The uptime of abatement system } p \text{ (expressed as a decimal fraction)}. \]

\[ t_p = \text{The total time in which abatement system } p \text{ is in an operational mode when fluorinated GHGs or } \text{N}_2\text{O} \text{ are flowing through production process tool(s) connected to abatement system } p \text{ (hours)}. \]

\[ T_p = \text{Total time in which fluorinated GHGs or } \text{N}_2\text{O} \text{ are flowing through production process tool(s) connected to abatement system } p \text{ (hours)}. \]

\[ p = \text{Abatement system}. \]

\[ (h) \text{ If you use fluorinated heat transfer fluids, you must report the annual emissions of fluorinated heat transfer fluids using the mass balance approach described in Equation I–16 of this subpart.} \]

\[ E_{H_i} = \text{Emissions of fluorinated heat transfer fluid } i \text{, (metric tons/year)}. \]

\[ \text{Density} = \text{Density of fluorinated heat transfer fluid } i \text{ (kg/l)}. \]

\[ I_{iB}^m = \text{Inventory of fluorinated heat transfer fluid } i \text{ in containers other than equipment at the beginning of the reporting year (in stock or storage) (l). The inventory at the beginning of the reporting year must be the same as the inventory at the end of the previous reporting year}. \]

\[ P_i = \text{Acquisitions of fluorinated heat transfer fluid } i \text{ during the reporting year (l), including amounts purchased from chemical suppliers, amounts purchased from equipment suppliers with or inside of equipment, and amounts returned to the facility after off-site recycling}. \]

\[ N_i = \text{Total nameplate capacity (full and proper charge) of equipment that uses fluorinated heat transfer fluid } i \text{ and that is newly installed during the reporting year (l)}. \]

\[ R_i = \text{Total nameplate capacity (full and proper charge) of equipment that uses fluorinated heat transfer fluid } i \text{ and that is removed from service during the reporting year (l)}. \]

\[ I_{iE} = \text{Inventory of fluorinated heat transfer fluid } i \text{ in containers other than equipment at the end of the reporting year (in stock or storage) (l)}. \]

\[ D_i = \text{Disbursements of fluorinated heat transfer fluid } i \text{ during the reporting year, including amounts returned to chemical suppliers, sold with or inside of equipment, and sent off-site for verifiable recycling or destruction (l). Disbursements should include only amounts that are properly stored and transported so as to prevent emissions in transit}. \]

\[ 0.001 = \text{Conversion factor from kg to metric tons}. \]

\[ i = \text{Fluorinated heat transfer fluid}. \]

\[ (1) \text{ If you use a fluorinated chemical both as a fluorinated heat transfer fluid and in other applications, you may calculate and report either emissions from all applications or from only those specified in the definition of fluorinated heat transfer fluids in §98.98}. \]

\[ (2) \text{ For the 2012 reporting year, you may calculate and report emissions of fluorinated heat transfer fluids whose} \]
vapor pressure falls below 1 mm Hg absolute at 25 °C either for the time period January 1, 2012 through December 31, 2012 or for the time period March 23, 2012 through December 31, 2012. The term “reporting year” in Equation I–16 shall be interpreted to be consistent with the time period selected. In addition, for the 2012 reporting year \( I_a \) is not required to be the same as the inventory at the end of 2011 if the inventory at the end of 2011 excluded fluorinated heat transfer fluids whose vapor pressure falls below 1 mm Hg absolute at 25 °C. Starting in the reporting year 2013, you must calculate and report emissions of all fluorinated heat transfer fluids for the entirety of the reporting year.


§ 98.94 Monitoring and QA/QC requirements.

(a) For calendar year 2011 monitoring, you may follow the provisions in paragraphs (a)(1) through (a)(3) of this section for best available monitoring methods.

(1) Best available monitoring methods. From January 1, 2011 through December 31, 2011, owners or operators may use best available monitoring methods for any parameter that cannot reasonably be measured according to the monitoring and QA/QC requirements of this subpart. The owner or operator must use the calculation methodologies and equations in §98.93, but may use the best available monitoring method for any parameter for which it is not reasonably feasible to acquire, install, or operate a required piece of monitoring equipment in a facility, or to procure necessary measurement services by January 1, 2011. Starting no later than January 1, 2012, the owner or operator must discontinue using best available monitoring methods and begin following all applicable monitoring and QA/QC requirements of this part, except as provided in paragraphs (a)(2), (a)(3), or (a)(4) of this section. Best available monitoring methods means any of the following methods specified in this paragraph:

(i) Monitoring methods currently used by the facility that do not meet the specifications of this subpart.
(ii) Supplier data.
(iii) Engineering calculations.
(iv) Other company records.

(2) Requests for extension of the use of best available monitoring methods in 2011 for parameters other than recipe-specific utilization and by-product formation rates for the plasma etching process type. With respect to any provision of this subpart except §98.93(a)(2)(i)(A), the owner or operator may submit a request to the Administrator under this paragraph (a)(2) to use one or more best available monitoring methods to estimate emissions that occur between July 1, 2011 and December 31, 2011.

(i) Timing of request. The extension request must be submitted to EPA no later than February 28, 2011.

(ii) Content of request. Requests must contain the following information:

(A) A list of specific items of monitoring instrumentation and measuring services for which the request is being made and the locations where each piece of monitoring instrumentation will be installed and where each measurement service will be provided.

(B) Identification of the specific rule requirements for which the instrumentation or measurement service is needed.

(C) A description of the reasons why the needed equipment could not be obtained, installed, or operable or why the needed measurement service could not be provided before July 1, 2011.

(D) If the reason for the extension is that the equipment cannot be purchased, delivered, or installed before July 1, 2011, include supporting documentation such as the date the monitoring equipment was ordered, investigation of alternative suppliers, and the dates by which alternative vendors promised delivery or installation, backorder notices or unexpected delays, descriptions of actions taken to expedite delivery or installation, and the current expected date of delivery or installation.

(E) If the reason for the extension is that service providers were unable to provide necessary measurement services, include supporting documentation demonstrating that these services...
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could not be acquired before July 1, 2011. This documentation must include written correspondence to and from at least three service providers stating that they will not be available to provide the necessary services before July 1, 2011.

(F) A detailed description of the specific best available monitoring methods that the facility will use in place of the required methods.

(G) A description of the specific actions the owner or operator will take to comply with monitoring requirements by January 1, 2012.

(iii) Approval criteria. To obtain approval, the owner or operator must demonstrate to the Administrator’s satisfaction that by July 1, 2011, it is not reasonably feasible to acquire, install, or operate the required piece of monitoring equipment, or procure necessary measurement services to comply with the requirements of this subpart. As a condition for allowing the use of best available monitoring methods through December 31, 2011, facilities must recalculate and resubmit their 2011 estimated emissions using the requirements of this subpart. Where a facility is allowed to use best available monitoring methods for apportioning gas consumption under §98.94(c), it is not required to verify its 2011 engineering model with its recalculated report. The facility’s recalculated emissions must be reported with its report for the 2012 reporting year (to be submitted in 2013) unless the facility receives an additional extension under paragraph (a)(4) of this section.

(4) Requests for extension of the use of best available monitoring methods beyond 2011.

(i) Timing of request. The extension request must be submitted to EPA no later than October 17, 2011.

(ii) Content of request. Requests must contain the following information:

(A) A list of parameters for which the owner or operator is seeking use of best available monitoring methods beyond 2011.

(B) A description of the specific rule requirements that the owner or operator cannot meet, including a detailed explanation as to why the requirements cannot be met.
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(C) Detailed description of the unique circumstances necessitating an extension, including specific data collection issues that do not meet safety regulations, technical infeasibility, or specific laws or regulations that conflict with data collection.

(D) A detailed explanation and supporting documentation of how and when the owner or operator will receive the required data and/or services to comply with the reporting requirements of this subpart in the future.

(E) A detailed description of the specific best available monitoring methods that the facility will use in place of the required methods.

(F) The Administrator reserves the right to require that the owner or operator provide additional documentation.

(iii) Approval criteria. To obtain approval, the owner or operator must demonstrate to the Administrator's satisfaction that by December 31, 2011 (or in the case of facilities that are required to calculate and report emissions in accordance with § 98.93(a)(2)(ii)(A), December 31, 2012), it is not reasonably feasible to acquire, install, or operate the required piece of monitoring equipment according to the requirements of this subpart. As a condition for allowing the use of best available monitoring methods through December 31, 2012, facilities must recalculate and resubmit their 2012 estimated emissions using the requirements of this subpart. Where a facility is allowed to use best available monitoring methods for apportioning gas consumption under § 98.94(c), it is not required to verify its 2012 engineering model with its recalculated report. The facility's recalculated emissions must be reported with its report for the 2013 reporting year (to be submitted in 2014).

(b) For purposes of Equation I–12 of this subpart, you must estimate facility-wide gas-specific heel factors for each container type for each gas used, except for fluorinated GHGs or N₂O which your facility uses in quantities less than 50 kg in one reporting year, according to the procedures in paragraphs (b)(1) through (b)(5) of this section.

(1) Base your facility-wide gas-specific heel factors on the trigger point for change out of a container for each container size and type for each gas used. Facility-wide gas-specific heel factors must be expressed as the ratio of the trigger point for change out, in terms of mass, to the initial mass in the container, as determined by paragraphs (b)(2) and (b)(3) of this section.

(2) The trigger points for change out you use to calculate facility-wide gas-specific heel factors in § 98.94(b)(1) must be determined by monitoring the mass or the pressure of your containers. If you monitor the pressure, convert the pressure to mass using the ideal gas law, as displayed in Equation I–17 of this subpart, with the appropriate Z value selected based upon the properties of the gas.

\[ pV = ZnRT \]  

where:

- \( p \) = Absolute pressure of the gas (Pa).
- \( V \) = Volume of the gas (m³).
- \( Z \) = Compressibility factor.
- \( n \) = Amount of substance of the gas (moles).
- \( R \) = Gas constant (8.314 Joule/Kelvin mole).
- \( T \) = Absolute temperature (K).

(3) The initial mass you use to calculate a facility-wide gas-specific heel factor in § 98.94(b)(1) may be based on the weight of the gas provided to you in gas supplier documents; however, you remain responsible for the accuracy of these masses and weights under this subpart.

(4) If a container is changed in an exceptional circumstance, you must weigh that container or measure the pressure of that container with a pressure gauge, in place of using a heel factor to determine the residual weight of gas. An exceptional circumstance is a change out point that differs by more than 20 percent from the trigger point for change out used to calculate your facility-wide gas-specific heel factor for that gas and container type. When
using mass-based trigger points for change out, you must determine if an exceptional circumstance has occurred based on the net weight of gas in the container, excluding the tare weight of the container.

(5) You must re-calculate a facility-wide gas-specific heel factor if you use a trigger point for change out for a gas and container type that differs by more than 5 percent from the previously used trigger point for change out for that gas and container type.

(c) You must develop apportioning factors for fluorinated GHG and N$_2$O consumption to use in Equation I–13 of this subpart for each input gas i, as appropriate, using a facility-specific engineering model that is documented in your site GHG Monitoring Plan as required under §98.3(g)(5). This model must be based on a quantifiable metric, such as wafer passes or wafer starts. To verify your model, you must demonstrate its precision and accuracy by adhering to the requirements in paragraphs (c)(1) and (c)(2) of this section.

(1) You must demonstrate that the fluorinated GHG and N$_2$O apportioning factors are developed using calculations that are repeatable, as defined in §98.98.

(2) You must demonstrate the accuracy of your facility-specific model by comparing the actual amount of input gas consumed and the modeled amount of input gas consumed for the plasma etching and chamber cleaning process types, as follows:

(i) You must analyze at least a 30-day period of operation during which the capacity utilization equals or exceeds 60 percent of its design capacity during the reporting year. You must use the period during which the facility experiences its highest 30-day average utilization for model verification.

(ii) You must compare the actual gas consumed of input gas i to the modeled amount of input gas i consumed for the plasma etching and chamber cleaning process types. You must certify that the fluorinated GHGs selected for comparison correspond to the largest quantities, on a mass basis, of fluorinated GHGs used at your facility during the reporting year for the plasma etching process type and the chamber cleaning process type.

(iii) You must demonstrate that the comparison performed for the largest quantity of gas, on a mass basis, consumed under the plasma etching process type in paragraph (c)(2)(ii) of this section, does not result in a difference between the actual and modeled gas consumption that exceeds five percent relative to actual gas consumption, reported to one significant figure using standard rounding conventions.

(d) If you use factors for fluorinated GHG process utilization and by-product formation rates other than the defaults provided in Tables I–3, I–4, I–5, I–6, and I–7 to this subpart, you must use utilization and by-product formation rates that are developed with measurements made using the International SEMATECH #06124825A–ENG (incorporated by reference, see §98.7). You may use recipe-specific utilization and by-product formation rates that were measured using the International SEMATECH #01104197A–XFR (incorporated by reference, see §98.7) provided the measurements were made prior to January 1, 2007. You may use recipe-specific utilization and by-product formation rates measured by a third party, such as a manufacturing equipment supplier, if the conditions in paragraphs (d)(1) and (d)(2) of this section are met.

(1) The third party has measured recipe-specific utilization and by-product formation rates using the International SEMATECH #06124825A–ENG (incorporated by reference, see §98.7) or the International SEMATECH #01104197A–XFR (incorporated by reference, see §98.7) provided the measurements were made prior to January 1, 2007.

(2) Measurements made by a third party to develop recipe-specific utilization and by-product formation rates must have been made for recipes that are similar recipes to those used at your facility, as defined in §98.98.

(e) If you use N$_2$O utilization factors other than the defaults provided in Table I–8 to this subpart, you must use factors developed with measurements made using the International SEMATECH #01104197A–XFR (incorporated by reference, see §98.7) provided the measurements were made prior to January 1, 2007.
SEMATECH #06124825A–ENG (incorporated by reference, see §98.7). You may use measurements made using the International SEMATECH #01104197A–XFR (incorporated by reference, see §98.7) provided the measurements were made prior to January 1, 2007. You may use N$_2$O utilization factors measured by a third party, such as a manufacturing equipment supplier, if the conditions in paragraphs (e)(1) and (e)(2) of this section are met.

(1) The third party has measured N$_2$O utilization factors using the International SEMATECH #06124825A–ENG (incorporated by reference, see §98.7,) or the International SEMATECH #01104197A–XFR (incorporated by reference, see §98.7) provided the measurements were made prior to January 1, 2007.

(2) The conditions under which the measurements were made are representative of your facility’s N$_2$O emitting production processes.

(f) If your facility employs abatement systems and you wish to reflect emission reductions due to these systems in calculations in §98.93, you must adhere to the procedures in paragraphs (f)(1) and (f)(2) of this section. If you use the default destruction or removal efficiency of 60 percent, you must adhere to procedures in paragraph (f)(3) of this section.

(1) You must certify and document that the abatement systems are properly installed, operated, and maintained according to manufacturers’ specifications by adhering to the procedures in paragraphs (1)(i) and (1)(ii) of this section.

(i) You must certify and document proper installation by verifying your systems were installed in accordance with the manufacturers’ specifications.

(ii) You must certify and document your systems are operated and maintained in accordance with the manufacturers’ specifications.

(2) You must calculate and report the uptime of abatement systems using Equation I–15 of this subpart.

(3) To report emissions using the default destruction or removal efficiency of 60 percent, you must certify and document that the abatement systems at your facility are specifically designed for fluorinated GHG and N$_2$O abatement.

(4) If you do not use the default destruction or removal efficiency value to calculate and report controlled emissions, you must use either a properly measured destruction or removal efficiency, or a class average of properly measured destruction or removal efficiencies, determined in accordance with procedures in paragraphs (f)(4)(i) through (f)(4)(v) of this section.

(i) A properly measured destruction or removal efficiency value must be determined in accordance with EPA 430-R-10-003 (incorporated by reference, see §98.7).

(ii) You must annually select and properly measure the destruction or removal efficiency for a random sample of abatement systems to include in a random sampling abatement system testing program (RSASTP) in accordance with procedures in paragraphs (f)(4)(ii)(A) and (f)(4)(ii)(B) of this section.

(A) Each reporting year for each abatement system class a random sample of three or 20 percent of installed abatement systems, whichever is greater, must be tested. If 20 percent of the total number of abatement systems in each class does not equate to a whole number, the number of systems to be tested must be determined by rounding up to the nearest integer.

(B) You must select the random sample each reporting year for the RSASTP without repetition of previously-measured systems in the sample, until all systems in each class are properly measured in a 5-year period.

(iii) If you have measured the destruction or removal efficiency of a particular abatement system during the previous 2-year period, you must calculate emissions from that system using the most recently measured destruction or removal efficiency for that particular system.
(iv) If the destruction or removal efficiency of an individual abatement system has not been properly measured during the previous 2-year period, you may use a simple average of the properly measured destruction or removal efficiencies for systems of that class, in accordance with the RSASTP. Your facility must maintain or exceed the RSASTP schedule if you wish to apply class average destruction or removal efficiency factors to abatement systems that have not yet been properly measured.

(v) If your facility uses redundant abatement systems, you may account for the total abatement system uptime calculated for a specific exhaust stream during the reporting year.

(g) You must adhere to the QA/QC procedures of this paragraph when calculating fluorinated GHG and N\textsubscript{2}O emissions from electronics manufacturing production processes:

1. Follow the QA/QC procedures in the International SEMATECH #06124825A–ENG (incorporated by reference, see §98.7) when measuring and calculating facility-specific, recipe-specific fluorinated GHG and N\textsubscript{2}O utilization and by-product formation rates.

2. Where you use facility-specific, recipe-specific fluorinated GHG and N\textsubscript{2}O utilization and by-product formation rates measured prior to January 1, 2007, verify that the QA/QC procedures in the International SEMATECH #01104197A–XFR (incorporated by reference, see §98.7) were followed during measurement and calculation of the factors.

3. Follow the QA/QC procedures in accordance with those in EPA 430–R–10–003 (incorporated by reference, see §98.7) when calculating abatement systems destruction or removal efficiencies.

4. Demonstrate that as part of normal facility operations the inventory of gas stored in containers at the beginning of the reporting year is the same as the inventory of gas stored in containers at the end of the previous reporting year.

(h) You must adhere to the QA/QC procedures of this paragraph (h) when calculating annual gas consumption for each fluorinated heat transfer fluid used at your facility and emissions from the use of each fluorinated heat transfer fluid.

1. Review all inputs to Equations I–11 and I–16 of this subpart to ensure that all inputs and outputs are accounted for.

2. Do not enter negative inputs into the mass balance Equations I–11 and I–16 of this subpart and ensure that no negative emissions are calculated.

3. Ensure that the inventory at the beginning of one reporting year is identical to the inventory reported at the end of the previous reporting year. This requirement does not apply to the end-of-the-year inventory of fluorinated heat transfer fluids in 2011 and the beginning-of-the-year inventory of the same in 2012.

4. Ensure that the total quantity of gas i in containers in service at the end of a reporting year is accounted for as if the in-service containers were full for Equation I–11 of this subpart. Ensure also that the same quantity is accounted for in the inventory of input gas i stored in containers at the beginning of the subsequent reporting year.

(i) All flowmeters, weigh scales, pressure gauges, and thermometers used to measure quantities that are monitored under this section or used in calculations under §98.93 must have an accuracy and precision of one percent of full scale or better.

§ 98.96 Data reporting requirements.

In addition to the information required by §98.3(c), you must include in each annual report the following information for each electronics manufacturing facility:

(a) Annual manufacturing capacity of your facility as determined in Equation I–5 of this subpart.

(b) For facilities that manufacture semiconductors, the diameter of wafers manufactured at your facility (mm).

(c) Annual emissions of:
   (1) Each fluorinated GHG emitted from each process type for which your facility is required to calculate emissions as calculated in Equations I–6 and I–7 of this subpart.
   (2) Each fluorinated GHG emitted from each individual recipe (including those in a set of similar recipes), or process sub-type as calculated in Equations I–8 and I–9 of this subpart, as applicable.
   (3) N$_2$O emitted from each chemical vapor deposition process and from other N$_2$O-using manufacturing processes as calculated in Equation I–10 of this subpart.
   (4) Each fluorinated heat transfer fluid emitted as calculated in Equation 1–16 of this subpart.
   (d) The method of emissions calculation used in §98.93.
   (e) Annual production in terms of substrate surface area (e.g., silicon, PV-cell, glass).
   (f) When you use factors for fluorinated GHG process utilization and by-product formation rates other than the defaults provided in Tables I–3, I–4, I–5, I–6, and I–7 to this subpart and/or N$_2$O utilization factors other than the defaults provided in Table I–8 to this subpart, you must report the following, as applicable:
      (1) The recipe-specific utilization and by-product formation rates for each individual recipe (or set of similar recipes) and/or facility-specific N$_2$O utilization factors.
      (2) For recipe-specific utilization and by-product formation rates, the film or substrate that was etched/cleaned and the feature type that was etched, as applicable.
      (3) Certification that the recipes included in a set of similar recipes are similar, as defined in §98.96.
   (4) Certification that the measurements for all reported recipe-specific utilization and by-product formation rates and/or facility-specific N$_2$O utilization factors were made using the International SEMATECH #06120625A–ENG (incorporated by reference, see §98.7), or the International SEMATECH #01104197A–XFR (incorporated by reference, see §98.7) if measurements were made prior to January 1, 2007.
   (5) Source of the recipe-specific utilization and by-product formation rates and/or facility-specific N$_2$O utilization factors.
   (6) Certification that the conditions under which the measurements were made for facility-specific N$_2$O utilization factors are representative of your facility’s N$_2$O emitting production processes.
   (g) Annual gas consumption for each fluorinated GHG and N$_2$O as calculated in Equation I–11 of this subpart, including where your facility used less than 50 kg of a particular fluorinated GHG or N$_2$O during the reporting year. For all fluorinated GHGs and N$_2$O used at your facility for which you have not calculated emissions using Equations I–6, I–7, I–8, I–9, and I–10 of this subpart, the chemical name of the GHG used, the annual consumption of the gas, and a brief description of its use.
   (h) All inputs used to calculate gas consumption in Equation I–11 of this subpart, for each fluorinated GHG and N$_2$O used.
   (i) Disbursements for each fluorinated GHG and N$_2$O during the reporting year, as calculated using Equation I–12 of this subpart.
   (j) All inputs used to calculate disbursements for each fluorinated GHG and N$_2$O in Equation I–12 of this subpart, including all facility-wide gas-specific heel factors used for each fluorinated GHG and N$_2$O. If your facility used less than 50 kg of a particular fluorinated GHG during the reporting
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year, facility-wide gas-specific heel factors do not need to be reported for those gases.

(k) Annual amount of each fluorinated GHG consumed for each recipe, process sub-type, or process type, as appropriate, and the annual amount of N₂O consumed for each chemical vapor deposition and other electronics manufacturing production processes, as calculated using Equation I–13 of this subpart.

(l) All apportioning factors used to apportion fluorinated GHG and N₂O consumption.

(m) For the facility-specific apportioning model used to apportion fluorinated GHG and N₂O consumption under §98.94(c), the following information to determine it is verified in accordance with procedures in §98.94(c)(1) and (2):

(i) Identification of the quantifiable metric used in your facility-specific engineering model to apportion gas consumption.

(ii) The start and end dates selected under §98.94(c)(2)(i).

(iii) Certification that the gases you selected under §98.94(c)(2)(ii) correspond to the largest quantities consumed on a mass basis, at your facility in the reporting year for the plasma etching process type and the chamber cleaning process type.

(iv) The result of the calculation comparing the actual and modeled gas consumption under §98.94(c)(2)(ii).

(n) Fraction of each fluorinated GHG or N₂O fed into a recipe, process sub-type, or process type that is fed into tools connected to abatement systems.

(o) Fraction of each fluorinated GHG or N₂O destroyed or removed in abatement systems connected to process tools where recipe, process sub-type, or process type j is used, as well as all inputs and calculations used to determine the inputs for Equation I–14 of this subpart.

(p) Inventory and description of all abatement systems through which fluorinated GHGs or N₂O flow at your facility, including the number of devices of each manufacturer, model numbers, manufacturer claimed fluorinated GHG and N₂O destruction or removal efficiencies, if any, and records of destruction or removal efficiency measurements over their in-use lives. The inventory of abatement systems must describe the tools with model numbers and the recipe(s), process sub-type, or process type for which these systems treat exhaust.

(q) For each abatement system through which fluorinated GHGs or N₂O flow at your facility, for which you are reporting controlled emissions, the following:

(1) Certification that each abatement system has been installed, maintained, and operated in accordance with manufacturers’ specifications.

(2) All inputs and results of calculations made accounting for the uptime of abatement systems used during the reporting year, in accordance with Equations I–14 and I–15 of this subpart.

(3) The default destruction or removal efficiency value or properly measured destruction or removal efficiencies for each abatement system used in the reporting year.

(4) Where the default destruction or removal efficiency value is used to report controlled emissions, certification that the abatement systems for which emissions are being reported were specifically designed for fluorinated GHG and N₂O abatement. You must support this certification by providing abatement system supplier documentation stating that the system was designed for fluorinated GHG and N₂O abatement.

(5) Where properly measured destruction or removal efficiencies or class averages of destruction or removal efficiencies are used, the following must also be reported:

(i) A description of the class, including the abatement system manufacturer and model number and the fluorinated GHG(s) and N₂O in the effluent stream.

(ii) The total number of systems in that class for the reporting year.

(iii) The total number of systems for which destruction or removal efficiency was properly measured in that class for the reporting year.

(iv) A description of the calculation used to determine the class average, including all inputs to the calculation.

(v) A description of the method used for randomly selecting class members for testing.
Environmental Protection Agency § 98.97

For fluorinated heat transfer fluid emissions, inputs to the fluorinated heat transfer fluid mass balance equation, Equation I–16 of this subpart, for each fluorinated heat transfer fluid used.

Where missing data procedures were used to estimate inputs into the fluorinated heat transfer fluid mass balance equation under §98.95(b), the number of times missing data procedures were followed in the reporting year, the method used to estimate the missing data, and the estimates of those data.

A brief description of each “best available monitoring method” used according to §98.94(a), the parameter measured or estimated using the method, and the time period during which the “best available monitoring method” was used.

For each fluorinated heat transfer fluid used, whether the emission estimate includes emissions from all applications or from only the applications specified in the definition of fluorinated heat transfer fluids in §98.98.

For reporting year 2012 only, the date on which you began monitoring emissions of fluorinated heat transfer fluids whose vapor pressure falls below 1 mm Hg absolute at 25 °C. This is either January 1, 2012 or March 23, 2012.

§98.97 Records that must be retained.

In addition to the information required by §98.3(g), you must retain the following records:

(a) All data used and copies of calculations made as part of estimating gas consumption and emissions, including all spreadsheets.

(b) Documentation for the values used for fluorinated GHG and N₂O utilization and by-product formation rates. If you use facility-specific and recipe-specific utilization and by-product formation rates, the following records must also be retained, as applicable:

(1) Complete documentation and final report for measurements for recipe-specific utilization and by-product formation rates demonstrating that the values were measured using International SEMATECH #06124825A–ENG (incorporated by reference, see §98.7) or, if the measurements were made prior to January 1, 2007, International SEMATECH #01104197A–XFR (incorporated by reference, see §98.7).

(2) Documentation that recipe-specific utilization and by-product formation rates developed for your facility are measured for recipes that are similar to those used at your facility, as defined in §98.98. The documentation must include, at a minimum, recorded to the appropriate number of significant figures, reactor pressure, flow rates, chemical composition, applied RF power, direct current (DC) bias, temperature, flow stabilization time, and duration.

(3) Documentation that your facility’s N₂O measurements are representative of the N₂O emitting processes at your facility.

(4) The date and results of the initial and any subsequent tests to determine utilization and by-product formation rates.

(c) Documentation for the facility-specific engineering model used to apportion fluorinated GHG and N₂O consumption. This documentation must be part of your site GHG Monitoring Plan as required under §98.3(g)(5). At a minimum, you must retain the following:

(1) A clear, detailed description of the facility-specific model, including how it was developed; the quantifiable metric used in the model; all sources of information, equations, and formulas, each with clear definitions of terms and variables; and a clear record of any changes made to the model while it was used to apportion fluorinated GHG and N₂O consumption across individual recipes (including those in a set of similar recipes), process sub-types, and/or process types.

(2) Sample calculations used for developing a recipe-specific, process sub-type-specific, or process type-specific gas apportioning factors (fᵢⱼ) for the two fluorinated GHGs used at your facility in the largest quantities, on a mass basis, during the reporting year.

(d) For each abatement system through which fluorinated GHGs or N₂O flow at your facility, for which you are reporting controlled emissions, the following:
(1) Documentation to certify the abatement system is installed, maintained, and operated in accordance with manufacturers’ specifications.

(2) Abatement system calibration and maintenance records.

(3) Where the default destruction or removal efficiency value is used, documentation from the abatement system supplier describing the equipment’s designed purpose and emission control capabilities for fluorinated GHG and N₂O.

(4) Where properly measured DRE is used to report emissions, dated certification by the technician who made the measurement that the destruction or removal efficiency is calculated in accordance with methods in EPA 430–R–10–003 (incorporated by reference, see § 98.7), complete documentation of the results of any initial and subsequent tests, and the final report as specified in EPA 430–R–10–003 (incorporated by reference, see § 98.7).

(c) Purchase records for gas purchased.

(f) Invoices for gas purchases and sales.

(g) Documents and records used to monitor and calculate abatement system uptime.

(h) GHG Monitoring Plans, as described in §98.3(g)(5), must be completed by April 1, 2011. You must update your GHG Monitoring Plan to comply with §98.9(c) consistent with the requirements in §98.3(g)(5)(iii).

§ 98.98 Definitions.

Except as provided in this section, all of the terms used in this subpart have the same meaning given in the Clean Air Act and subpart A of this part. If a conflict exists between a definition provided in this subpart and a definition provided in subpart A, the definition in this subpart takes precedence for the reporting requirements in this subpart.

Abatement system means a device or equipment that destroys or removes fluorinated GHGs and N₂O in waste streams from one or more electronics manufacturing production processes.

Actual gas consumption means the quantity of gas used during wafer/substrate processing over some period based on a measured change in gas container pressure or on a measured volume of gas.

By-product formation means the creation of fluorinated GHGs during electronics manufacturing production processes or the creation of fluorinated GHGs by an abatement system. By-product formation is the ratio of the mass of the by-product formed to the mass flow of the input gas, where, for multi-fluorinated-GHG recipes, the denominator corresponds to the fluorinated GHG with the largest mass flow.

Chamber cleaning is a process type that consists of the process sub-types defined in paragraphs (1) through (3) of this definition.

(1) In situ plasma process sub-type consists of the cleaning of thin-film production chambers, after processing substrates, with a fluorinated GHG cleaning reagent that is dissociated into its cleaning constituents by a plasma generated inside the chamber where the film is produced.

(2) Remote plasma process sub-type consists of the cleaning of thin-film production chambers, after processing substrates, with a fluorinated GHG cleaning reagent dissociated by a remotely located plasma source.

(3) In situ thermal process sub-type consists of the cleaning of thin-film production chambers, after processing substrates, with a fluorinated GHG cleaning reagent that is thermally dissociated into its cleaning constituents inside the chamber where thin films are produced.

Class means a category of abatement systems grouped by manufacturer model number(s) and by the gas that the system abates, including N₂O and carbon tetrafluoride (CF₄) direct emissions and by-product formation, and all other fluorinated GHG direct emissions and by-product formation. Classes may also include any other abatement systems for which the reporting facility wishes to report controlled emissions provided that class is identified.

Controlled emissions means the quantity of emissions that are released to the atmosphere after application of an emission control device (e.g., abatement system).

Destruction or removal efficiency (DRE) means the efficiency of an abatement
system to destroy or remove fluorinated GHGs, N\textsubscript{2}O, or both. The destruction or removal efficiency is equal to one minus the ratio of the mass of all relevant GHGs exiting the abatement system to the mass of GHG entering the abatement system. When GHGs are formed in an abatement system, destruction or removal efficiency is expressed as one minus the ratio of amounts of exiting GHGs to the amounts entering the system in units of CO\textsubscript{2}-equivalents (CO\textsubscript{2}e).

Fluorinated heat transfer fluids means fluorinated GHGs used for temperature control, device testing, cleaning substrate surfaces and other parts, and soldering in certain types of electronics manufacturing production processes. Fluorinated heat transfer fluids do not include fluorinated GHGs used as lubricants or surfactants. For fluorinated heat transfer fluids under this subpart I, the lower vapor pressure limit of 1 mm Hg in absolute at 25 °C in the definition of Fluorinated greenhouse gas in §98.6 shall not apply.

Gas utilization means the fraction of input N\textsubscript{2}O or fluorinated GHG converted to other substances during the etching, deposition, and/or wafer and chamber cleaning processes. Gas utilization is expressed as a rate or factor for specific electronics manufacturing recipes, process sub-types, or process types.

Heel means the amount of gas that remains in a gas container after it is discharged or off-loaded; heel may vary by container type.

Individual recipe means a specific combination of gases, under specific conditions of reactor temperature, pressure, flow, radio frequency (RF) power and duration, used repeatedly to fabricate a specific feature on a specific film or substrate.

Maximum designed substrate starts means the maximum quantity of substrates, expressed as surface area, that could be started each month during a reporting year if the facility were fully equipped as defined in the facility design specifications and if the equipment were fully utilized. It denotes 100 percent of annual manufacturing capacity of a facility.

Modeled gas consumed means the quantity of gas used during wafer/substrate processing over some period based on a verified facility-specific engineering model used to apportion gas consumption.

Nameplate capacity means the full and proper charge of chemical specified by the equipment manufacturer to achieve the equipment’s specified performance. The nameplate capacity is typically indicated on the equipment’s nameplate; it is not necessarily the actual charge, which may be influenced by leakage and other emissions.

Operational mode means the time in which an abatement system is being operated within the range of parameters as specified in the operations manual provided by the system manufacturer.

Plasma etching is a process type that consists of any production process using fluorinated GHG reagents to selectively remove materials from a substrate during electronics manufacturing. The materials removed may include SiO\textsubscript{2}, SiO\textsubscript{x}-based or fully organic-based thin-film material, SiN, SiON, Si:N, SiC, SiCO, SiCN, etc. (represented by the general chemical formula, Si\textsubscript{w}O\textsubscript{x}N\textsubscript{y}X\textsubscript{z} where w, x, y and z are zero or integers and X may be some other element such as carbon), substrate, or metal films (such as aluminum or tungsten).

Process sub-type is a set of similar manufacturing steps, more closely related within a broad process type. For example, the chamber cleaning process type includes in-situ plasma chamber cleaning, remote plasma chamber cleaning, and in-situ thermal chamber cleaning sub-types.

Process types are broad groups of manufacturing steps used at a facility associated with substrate (e.g., wafer) processing during device manufacture for which fluorinated GHG emissions and fluorinated GHG usages are calculated and reported. The process types are Plasma etching, Chamber cleaning, and Wafer cleaning.
Properly measured destruction or removal efficiency means destruction or removal efficiencies measured in accordance with EPA 430–R–10–003 (incorporated by reference, see §98.7).

The Random Sampling Abatement System Testing Program (RSASTP) means the required frequency for measuring the destruction or removal efficiencies of abatement systems in order to apply properly measured destruction or removal efficiencies to report controlled emissions.

Redundant abatement systems means a system that is specifically designed, installed and operated for the purpose of destroying fluorinated GHGs and N₂O gases. A redundant abatement system is used as a backup to the main fluorinated GHGs and N₂O abatement system during those times when the main system is not functioning or operating in accordance with design and operating specifications.

Repeatable means that the variables used in the formulas for the facility’s engineering model for gas apportioning factors are based on observable and measurable quantities that govern gas consumption rather than engineering judgment about those quantities or gas consumption.

Similar, with respect to recipes, means those recipes that are composed of the same set of chemicals and have the same flow stabilization times and where the documented differences, considered separately, in reactor pressure, individual gas flow rates, and applied radio frequency (RF) power are less than or equal to plus or minus 10 percent. For purposes of comparing and documenting recipes that are similar, facilities may use either the best known method provided by an equipment manufacturer or the process of record, for which emission factors for either have been measured.

Trigger point for change out means the residual weight or pressure of a gas container type that a facility uses to change out that gas container.

Uptime means the ratio of the total time during which the abatement system is in an operational mode with fluorinated GHGs or N₂O flowing through production process tool(s) connected to that abatement system, to the total time during which fluorinated GHGs or N₂O are flowing through production process tool(s) connected to that abatement system.

Wafer cleaning is a process type that consists of any production process using fluorinated GHG reagents to clean wafers at any step during production.

Wafer passes is a count of the number of times a wafer substrate is processed in a specific process recipe, sub-type, or type. The total number of wafer passes over a reporting year is the number of wafer passes per tool multiplied by the number of operational process tools in use during the reporting year.

Wafer starts means the number of fresh wafers that are introduced into the fabrication sequence each month. It includes test wafers, which means wafers that are exposed to all of the conditions of process characterization, including but not limited to actual etch conditions or actual film deposition conditions.


Table I–1 to Subpart I—Default Emission Factors for Threshold Applicability Determination

<table>
<thead>
<tr>
<th>Product type</th>
<th>Emission factors EF&lt;sub&gt;i&lt;/sub&gt;</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>CF&lt;sub&gt;i&lt;/sub&gt;</td>
</tr>
<tr>
<td>Semiconductors (kg/m²)</td>
<td>0.90</td>
</tr>
<tr>
<td>LCD (g/m²)</td>
<td>0.50</td>
</tr>
<tr>
<td>MEMS (kg/m²)</td>
<td>NA</td>
</tr>
</tbody>
</table>

Notes: NA denotes not applicable based on currently available information.
### Table I–2 to Subpart I—Examples of Fluorinated GHGs and Fluorinated Heat Transfer Fluids Used by the Electronics Industry

<table>
<thead>
<tr>
<th>Product type</th>
<th>Fluorinated GHGs and fluorinated heat transfer fluids used during manufacture</th>
</tr>
</thead>
<tbody>
<tr>
<td>Electronics</td>
<td>CF₄, C₂F₆, C₃F₈, C₄F₉, C₅F₁₄, CHF₃, CH₂F₂, NF₃, SF₆, and fluorinated HTFs (CF₄-(O-CF(CF₃)-CF₂)n-(O-CF₂)m-O-CF₃, C₄F₉, C₅F₁₄, (OCF₂)m-O-CF₃, C₄F₉, O, (C₄F₉)₃N).</td>
</tr>
</tbody>
</table>

[77 FR 10381, Feb. 22, 2012]

### Table I–3 to Subpart I of Part 98—Default Emission Factors (1–Uᵢⱼ) for Gas Utilization Rates (Uᵢⱼ) and By-Product Formation Rates (Bᵢⱼₖ) for Semiconductor Manufacturing for 150mm and 200 mm Wafer Sizes

<table>
<thead>
<tr>
<th>Process type/Sub-type</th>
<th>Process gas i</th>
<th>CF₄</th>
<th>C₂F₆</th>
<th>CHF₃</th>
<th>CH₂F₂</th>
<th>C₃F₈</th>
<th>c-C₄F₉</th>
<th>NF₃</th>
<th>SF₆</th>
<th>C₅F₁₄</th>
<th>C₄F₉O</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Plasma Etching</strong></td>
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<tr>
<td>1–Uᵢ</td>
<td></td>
<td>0.69</td>
<td>0.56</td>
<td>0.38</td>
<td>0.093</td>
<td>NA</td>
<td>0.25</td>
<td>0.038</td>
<td>0.20</td>
<td>0.14</td>
<td>NA</td>
</tr>
<tr>
<td>BCF₄</td>
<td></td>
<td>NA</td>
<td>0.23</td>
<td>0.026</td>
<td>0.021</td>
<td>NA</td>
<td>0.19</td>
<td>0.0040</td>
<td>NA</td>
<td>0.13</td>
<td>NA</td>
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<td>BCF₂F₆</td>
<td></td>
<td>NA</td>
<td>NA</td>
<td>NA</td>
<td>NA</td>
<td>NA</td>
<td>0.084</td>
<td>NA</td>
<td>NA</td>
<td>0.12</td>
<td>NA</td>
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<td>BCF₃F₈</td>
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<td>NA</td>
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<tr>
<td><strong>Chamber Cleaning</strong></td>
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<tr>
<td>In situ plasma cleaning:</td>
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<tr>
<td>1–Uᵢ</td>
<td></td>
<td>0.92</td>
<td>0.55</td>
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Notes: NA denotes not applicable based on currently available information.

### Table I–4 to Subpart I—Table I–4 to Subpart I of Part 98—Default Emission Factors (1–Uᵢⱼ) for Gas Utilization Rates (Uᵢⱼ) and By-Product Formation Rates (Bᵢⱼₖ) for Semiconductor Manufacturing for 300 mm Wafer Size

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**Notes:** NA denotes not applicable based on currently available information.

**Table I–5 to Subpart I—Table I–5 to Subpart I of Part 98—Table I–5 to Subpart I of Part 98—Default Emission Factors (1–Uij) for Gas Utilization Rates (Uij) and By-Product Formation Rates (Bijk) for MEMS Manufacturing**

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**Notes:** NA denotes not applicable based on currently available information.

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**Table I–6 to Subpart I—Table I–6 to Subpart I of Part 98—Table I–6 to Subpart I of Part 98—Default Emission Factors (1–Uij) for Gas Utilization Rates (Uij) and By-Product Formation Rates (Bijk) for LCD Manufacturing**

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**Notes:** NA denotes not applicable based on currently available information.
Environmental Protection Agency

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Table I–7 to Subpart I—Table I–7 to Subpart I of Part 98—Table I–7 to Subpart I of Part 98—Default Emission Factors (1–Uij) for Gas Utilization Rates (Uij) and By-Product Formation Rates (Bijk) for PV Manufacturing

<table>
<thead>
<tr>
<th>Process type factors</th>
<th>CFC4</th>
<th>CF3</th>
<th>CHF3</th>
<th>CH2F2</th>
<th>C3F8</th>
<th>c-C4F8</th>
<th>NSF3</th>
<th>Remote</th>
</tr>
</thead>
<tbody>
<tr>
<td>Etch 1–Uij</td>
<td>0.7</td>
<td>0.4</td>
<td>0.4</td>
<td>NA</td>
<td>NA</td>
<td>0.2</td>
<td>NA</td>
<td>0.4</td>
</tr>
<tr>
<td>Etch BC-F3</td>
<td>NA</td>
<td>0.2</td>
<td>NA</td>
<td>NA</td>
<td>NA</td>
<td>0.1</td>
<td>NA</td>
<td>NA</td>
</tr>
<tr>
<td>Etch BCF2F6</td>
<td>NA</td>
<td>NA</td>
<td>NA</td>
<td>NA</td>
<td>NA</td>
<td>0.1</td>
<td>NA</td>
<td>NA</td>
</tr>
<tr>
<td>CVD 1–Uij</td>
<td>0.6</td>
<td>NA</td>
<td>NA</td>
<td>NA</td>
<td>NA</td>
<td>0.3</td>
<td>NA</td>
<td>0.4</td>
</tr>
<tr>
<td>CVD BCF2F6</td>
<td>NA</td>
<td>0.2</td>
<td>NA</td>
<td>0.2</td>
<td>0.1</td>
<td>NA</td>
<td>NA</td>
<td>NA</td>
</tr>
</tbody>
</table>

Notes: NA denotes not applicable based on currently available information.

Table I–8 to Subpart I—Table I–8 to Subpart I of Part 98—Table I–8 to Subpart I of Part 98—Default Emission Factors (1–UN2Oj) for N2O Utilization (UN2Oj)

<table>
<thead>
<tr>
<th>Process type factors</th>
<th>N2O</th>
</tr>
</thead>
<tbody>
<tr>
<td>CVD 1–Uij</td>
<td>0.8</td>
</tr>
<tr>
<td>Other Manufacturing Process 1–Uij</td>
<td>1.0</td>
</tr>
</tbody>
</table>

Subpart J [Reserved]

Subpart K—Ferroalloy Production

§ 98.110 Definition of the source category.

The ferroalloy production source category consists of any facility that uses pyrometallurgical techniques to produce any of the following metals: ferrochromium, ferromanganese, ferromolybdenum, ferronickel, ferrosilicon, ferrotitanium, ferrotungsten, ferrovanadium, silicomanganese, or silicon metal.

§ 98.111 Reporting threshold.

You must report GHG emissions under this subpart if your facility contains a ferroalloy production process and the facility meets the requirements of either §98.2(a)(1) or (2).

§ 98.112 GHGs to report.

You must report:

(a) Process CO2 emissions from each electric arc furnace (EAF) used for the production of any ferroalloy listed in §98.110, and process CH4 emissions from each EAF that is used for the production of any ferroalloy listed in Table K–1 to subpart K.

(b) CO2, CH4, and N2O emissions from each stationary combustion unit following the requirements of subpart C of this part. You must report these emissions under subpart C of this part (General Stationary Fuel Combustion Sources). [74 FR 56374, Oct. 30, 2009, as amended at 75 FR 66461, Oct. 28, 2010]

§ 98.113 Calculating GHG emissions.

You must calculate and report the annual process CO2 emissions from each EAF not subject to paragraph (c) of this section using the procedures in either paragraph (a) or (b) of this section. For each EAF also subject to annual process CH4 emissions reporting, you must also calculate and report the annual process CH4 emissions from the EAF using the procedures in paragraph (d) of this section.

(a) Calculate and report under this subpart the process CO2 emissions by operating and maintaining CEMS according to the Tier 4 Calculation Methodology in §98.33(a)(4) and the applicable requirements for Tier 4 in subpart C of this part (General Stationary Fuel Combustion Sources).

(b) Calculate and report under this subpart the annual process CO2 emissions using the procedure in either paragraph (b)(1) or (b)(2) of this section.

(1) Calculate and report under this subpart the annual process CO2 emissions from EAFs by operating and maintaining a CEMS according to the Tier 4 Calculation Methodology specified in §98.33(a)(4) and the applicable requirements for Tier 4 in subpart C of
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this part (General Stationary Fuel Combustion Sources).

(2) Calculate and report under this subpart the annual process CO₂ emissions from the EAFs using the carbon mass balance procedure specified in paragraphs (b)(2)(i) and (b)(2)(ii) of this section.

(i) For each EAF, determine the annual mass of carbon in each carbon-containing input and output material for the EAF and estimate annual process CO₂ emissions from the EAF using Equation K–1 of this section. Carbon-containing input materials include carbon electrodes and carbonaceous reducing agents. If you document that a specific input or output material contributes less than 1 percent of the total carbon into or out of the process, you do not have to include the material in your calculation using Equation K–1 of this section.

\[
E_{CO2} = \frac{44}{12} \times \frac{2000}{2205} \sum_{i} \left( M_{\text{reducing agent}_i} \times C_{\text{reducing agent}_i} \right) 
+ \frac{44}{12} \times \frac{2000}{2205} \sum_{m} \left( M_{\text{electrode}_m} \times C_{\text{electrode}_m} \right) 
+ \frac{44}{12} \times \frac{2000}{2205} \sum_{b} \left( M_{\text{ore}_b} \times C_{\text{ore}_b} \right) 
+ \frac{44}{12} \times \frac{2000}{2205} \sum_{l} \left( M_{\text{flux}_l} \times C_{\text{flux}_l} \right) 
- \frac{44}{12} \times \frac{2000}{2205} \sum_{k} \left( M_{\text{product outgoing}_k} \times C_{\text{product outgoing}_k} \right) 
- \frac{44}{12} \times \frac{2000}{2205} \sum_{l} \left( M_{\text{non-product outgoing}_l} \times C_{\text{non-product outgoing}_l} \right)
\]

(Eq. K-1)

Where:
\( E_{CO2} \) = Annual process CO₂ emissions from an individual EAF (metric tons).
\( \frac{44}{12} \) = Ratio of molecular weights, CO₂ to carbon.
\( \frac{2000}{2205} \) = Conversion factor to convert tons to metric tons.
\( M_{\text{reducing agent}_i} \) = Annual mass of reducing agent \( i \) fed, charged, or otherwise introduced into the EAF (tons).
\( C_{\text{reducing agent}_i} \) = Carbon content in reducing agent \( i \) (percent by weight, expressed as a decimal fraction).
\( M_{\text{electrode}_m} \) = Annual mass of carbon electrode \( m \) consumed in the EAF (tons).
\( C_{\text{electrode}_m} \) = Carbon content of the carbon electrode \( m \) (percent by weight, expressed as a decimal fraction).
\( M_{\text{ore}_b} \) = Annual mass of ore \( b \) charged to the EAF (tons).
\( C_{\text{ore}_b} \) = Carbon content in ore \( b \) (percent by weight, expressed as a decimal fraction).
\( M_{\text{flux}_l} \) = Annual mass of flux material \( l \) fed, charged, or otherwise introduced into the EAF to facilitate slag formation (tons).
\( C_{\text{flux}_l} \) = Carbon content in flux material \( l \) (percent by weight, expressed as a decimal fraction).
\( M_{\text{product outgoing}_k} \) = Annual mass of alloy product \( k \) tapped from EAF (tons).
\( C_{\text{product outgoing}_k} \) = Carbon content in alloy product \( k \) (percent by weight, expressed as a decimal fraction).
\( M_{\text{non-product outgoing}_l} \) = Annual mass of non-product outgoing material \( l \) removed from EAF (tons).
\( C_{\text{non-product outgoing}_l} \) = Carbon content in non-product outgoing material \( l \) (percent by weight, expressed as a decimal fraction).
(ii) Determine the combined annual process CO\textsubscript{2} emissions from the EAFs at your facility using Equation K-2 of this section.

\[ \text{CO}_2 = \sum_{k=1}^{k} E_{\text{CO}_2 k} \quad (\text{Eq. K-2}) \]

Where:

- \( E_{\text{CO}_2} \) = Annual process \( \text{CO}_2 \) emissions from an individual EAF (metric tons).
- \( E_{\text{CO}_2 k} \) = Annual process \( \text{CO}_2 \) emissions calculated from EAF \( k \) calculated using Equation K-1 of this section (metric tons).
- \( k \) = Total number of EAFs at facility used for the production of any ferroalloy listed in §98.110.

(c) If GHG emissions from an EAF are vented through the same stack as any combustion unit or process equipment that reports \( \text{CO}_2 \) emissions using a CEMS that complies with the Tier 4 Calculation Methodology in subpart C of this part (General Stationary Fuel Combustion Sources), then the calculation methodology in paragraph (b) of this section shall not be used to calculate process emissions. The owner or operator shall report under this subpart the combined stack emissions according to the Tier 4 Calculation Methodology in §98.33(a)(4) and all associated requirements for Tier 4 in subpart C of this part.

(d) For the EAFs at your facility used for the production of any ferroalloy listed in Table K-1 of this subpart, you must calculate and report the annual \( \text{CH}_4 \) emissions using the procedure specified in paragraphs (d)(1) and (2) of this section.

(1) For each EAF, determine the annual \( \text{CH}_4 \) emissions using Equation K-3 of this section.

\[ E_{\text{CH}_4} = \sum_{i=1}^{j} \left( M_{\text{product } i} \times \frac{2000}{2205} \times EF_{\text{product } i} \right) \quad (\text{Eq. K-3}) \]

Where:

- \( E_{\text{CH}_4} \) = Annual process \( \text{CH}_4 \) emissions from an individual EAF (metric tons).
- \( M_{\text{product } i} \) = Annual mass of alloy product \( i \) produced in the EAF (tons).
- 2000/2205 = Conversion factor to convert tons to metric tons.
- \( EF_{\text{product } i} \) = \( \text{CH}_4 \) emission factor for alloy product \( i \) from Table K-1 in this subpart (kg of \( \text{CH}_4 \) emissions per metric ton of alloy product \( i \)).

(2) Determine the combined process \( \text{CH}_4 \) emissions from the EAFs at your facility using Equation K-4 of this section:

\[ \text{CH}_4 = \sum_{j=1}^{j} E_{\text{CH}_4 j} \quad (\text{Eq. K-4}) \]

Where:

- \( E_{\text{CH}_4} \) = Annual process \( \text{CH}_4 \) emissions from EAFs at facility used for the production of ferroalloys listed in Table K-1 of this subpart (metric tons).
- \( E_{\text{CH}_4 j} \) = Annual process \( \text{CH}_4 \) emissions from EAF \( j \) calculated using Equation K-3 of this section (metric tons).
- \( j \) = Total number of EAFs at facility used for the production of ferroalloys listed in Table K-1 of this subpart.

§ 98.115 Procedures for estimating missing data.

A complete record of all measured parameters used in the GHG emissions calculations in §98.113 is required. Therefore, whenever a quality-assured value of a required parameter is unavailable, a substitute data value for the missing parameter shall be used in the calculations as specified in the paragraphs (a) and (b) of this section. You must document and keep records of the procedures used for all such estimates.

(a) If you determine CO\(_2\) emissions for the EAFs at your facility using the carbon mass balance procedure in §98.113(b), 100 percent data availability is required for the carbon content of the input and output materials. You must repeat the test for average carbon contents of inputs according to the procedures in §98.114(b) if data are missing.

(b) For missing records of the monthly mass of carbon-containing inputs and outputs, the substitute data value must be based on the best available estimate of the mass of the inputs and outputs from on all available process data or data used for accounting purposes, such as purchase records.

(c) If you are required to calculate CH\(_4\) emissions for an EAF at your facility as specified in §98.113(d), the estimate is based an annual quantity of certain alloy products, so 100 percent data availability is required.

§ 98.116 Data reporting requirements.

In addition to the information required by §98.3(c), each annual report must contain the information specified in paragraphs (a) through (e) of this section, as applicable:

(a) Annual facility ferroalloy product production capacity (tons).

(b) Annual production for each ferroalloy product identified in §98.110, from each EAF (tons).

(c) Total number of EAFs at facility used for production of ferroalloy products.

(d) If a CEMS is used to measure CO\(_2\) emissions, then you must report under this subpart the relevant information required by §98.36 for the Tier 4 Calculation Methodology and the following information specified in paragraphs (d)(1) through (d)(3) of this section.

(1) Annual process CO\(_2\) emissions (in metric tons) from each EAF used for the production of any ferroalloy product identified in §98.110.

(2) Annual process CH\(_4\) emissions (in metric tons) from each EAF used for the production of any ferroalloy listed in Table K–1 of this subpart (metric tons).

(3) Identification number of each EAF.
(e) If a CEMS is not used to measure CO₂ process emissions, and the carbon mass balance procedure is used to determine CO₂ emissions according to the requirements in §98.113(b), then you must report the following information specified in paragraphs (e)(1) through (e)(7) of this section.

1. Annual process CO₂ emissions (in metric tons) from each EAF used for the production of any ferroalloy identified in §98.110 (metric tons).
2. Identification number for each material.
3. Annual material quantity for each material included for the calculation of annual process CO₂ emissions for each EAF.
4. Annual average of the carbon content determinations for each material included for the calculation of annual process CO₂ emissions for each EAF (percent by weight, expressed as a decimal fraction).
5. List the method used for the determination of carbon content for each material reported in paragraph (e)(5) of this section (e.g., supplier provided information, analyses of representative samples you collected).
6. If you use the missing data procedures in §98.115(b), you must report how monthly mass of carbon-containing inputs and outputs with missing data was determined and the number of months the missing data procedures were used.


§ 98.117 Records that must be retained.

In addition to the records required by §98.3(g), you must retain the records specified in paragraphs (a) through (d) of this section for each EAF, as applicable.

(a) If a CEMS is used to measure CO₂ emissions according to the requirements in §98.113(a), then you must retain under this subpart the records required for the Tier 4 Calculation Methodology in §98.37 and the information specified in paragraphs (a)(1) through (a)(3) of this section.

1. Monthly EAF production quantity for each ferroalloy product (tons).
2. Number of EAF operating hours each month.
3. Number of EAF operating hours in a calendar year.

(b) If the carbon mass balance procedure is used to determine CO₂ emissions according to the requirements in §98.113(b)(2), then you must retain records for the information specified in paragraphs (b)(1) through (b)(5) of this section.

1. Monthly EAF production quantity for each ferroalloy product (tons).
2. Number of EAF operating hours each month.
3. Number of EAF operating hours in a calendar year.
4. Monthly material quantity consumed, used, or produced for each material included for the calculations of annual process CO₂ emissions (tons).
5. Average carbon content determined and records of the supplier provided information or analyses used for the determination for each material included for the calculations of annual process CO₂ emissions.

(c) You must keep records that include a detailed explanation of how company records of measurements are used to estimate the carbon input and output to each EAF, including documentation of specific input or output materials excluded from Equation K-1 of this subpart that contribute less than 1 percent of the total carbon into or out of the process. You also must document the procedures used to ensure the accuracy of the measurements of materials fed, charged, or placed in an EAF including, but not limited to, calibration of weighing equipment and other measurement devices. The estimated accuracy of measurements made with these devices must also be recorded, and the technical basis for these estimates must be provided.

(d) If you are required to calculate CH₄ emissions for the EAF as specified in §98.113(d), you must maintain records of the total amount of each alloy product produced for the specified reporting period, and the appropriate alloy-product specific emission factor used to calculate the CH₄ emissions.

§ 98.118 Definitions.

All terms used of this subpart have the same meaning given in the Clean Air Act and subpart A of this part.
Subpart L—Fluorinated Gas Production

Source: 75 FR 74831, Dec. 1, 2010, unless otherwise noted.

§ 98.120 Definition of the source category.

(a) The fluorinated gas production source category consists of processes that produce a fluorinated gas from any raw material or feedstock chemical, except for processes that generate HFC–23 during the production of HCFC–22.

(b) To produce a fluorinated gas means to manufacture a fluorinated gas from any raw material or feedstock chemical. Producing a fluorinated gas includes producing a fluorinated GHG as defined at §98.410(b). Producing a fluorinated gas also includes the manufacture of a chlorofluorocarbon (CFC) or hydrochlorofluorocarbon (HCFC) from any raw material or feedstock chemical, including manufacture of a CFC or HCFC as an isolated intermediate for use in a process that will result in the transformation of the CFC or HCFC either at or outside of the production facility. Producing a fluorinated gas does not include the reuse or recycling of a fluorinated gas, the creation of HFC–23 during the production of HCFC–22, the creation of intermediates that are created and transformed in a single process with no storage of the intermediates, or the creation of fluorinated GHGs that are released or destroyed at the production facility before the production measurement in §98.414(a).

§ 98.121 Reporting threshold.

You must report GHG emissions under this subpart if your facility contains a fluorinated gas production process that generates or emits fluorinated GHG and the facility meets the requirements of either §98.2(a)(1) or (a)(2). To calculate GHG emissions for comparison to the 25,000 metric ton CO₂e per year emission threshold in §98.2(a)(2), calculate process emissions from fluorinated gas production using uncontrolled GHG emissions.

§ 98.122 GHGs to report.

(a) You must report CO₂, CH₄, and N₂O combustion emissions from each stationary combustion unit. You must calculate and report these emissions under subpart C of this part (General Stationary Fuel Combustion Sources) by following the requirements of subpart C.

(b) You must report under subpart O of this part (HCFC–22 Production and HFC–23 Destruction) the emissions of HFC–23 from HCFC–22 production processes and HFC–23 destruction processes. Do not report the generation and emissions of HFC–23 from HCFC–22 production under this subpart.

(c) You must report the total mass of each fluorinated GHG emitted from:

(1) Each fluorinated gas production process and all fluorinated gas production processes combined.

(2) Each fluorinated gas transformation process that is not part of a fluorinated gas production process and all such fluorinated gas transformation processes combined, except report separately fluorinated GHG emissions.

---

### Table K–1

<table>
<thead>
<tr>
<th>Alloy product produced in EAF</th>
<th>CH₄ emission factor (kg CH₄ per metric ton product)</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Batch-charging</td>
</tr>
<tr>
<td>Silicon metal</td>
<td>1.5</td>
</tr>
<tr>
<td>Ferrosilicon 90%</td>
<td>1.4</td>
</tr>
<tr>
<td>Ferrosilicon 75%</td>
<td>1.3</td>
</tr>
<tr>
<td>Ferrosilicon 65%</td>
<td>1.3</td>
</tr>
</tbody>
</table>

*a* Sprinkle-charging is charging intermittently every minute.

*b* Temperature measured in off-gas channel downstream of the furnace hood.
Environmental Protection Agency

§ 98.123 Calculating GHG emissions.

For fluorinated gas production and transformation processes, you must calculate the fluorinated GHG emissions from each process using either the mass balance method specified in paragraph (b) of this section or the emission factor or emission calculation factor method specified in paragraphs (c), (d), and (e) of this section, as appropriate. For destruction processes that destroy fluorinated GHGs that were previously “produced” as defined at §98.410(b), you must calculate emissions using the procedures in paragraph (f) of this section. For venting of residual fluorinated GHGs from containers returned from the field.

(a) Default GWP value. In paragraphs (b)(1) and (c)(1) of this section and in §98.124(b)(8) and (c)(2), use a GWP of 2,000 for fluorinated GHGs that do not have GWPs listed in Table A–1 to subpart A of this part, except as provided in paragraph §98.123(c)(1)(vi). Do not report CO₂e emissions under §98.3(c)(4) for fluorinated GHGs that do not have GWPs listed in Table A–1 to subpart A of this part.

(b) Mass balance method. Before using the mass balance approach to estimate your fluorinated GHG emissions from a process, you must ensure that the process and the equipment and methods used to process it meet either the error limits described in this paragraph or the requirements specified in paragraph §98.124(b)(8). If you choose to calculate the error limits, you must estimate the absolute and relative errors associated with using the mass balance approach on that process using Equations L-1 through L-4 of this section in conjunction with Equations L-5 through L-10 of this section. You may use the mass-balance approach to estimate emissions from the process if this calculation results in an absolute error of less than or equal to 3,000 metric tons CO₂e per year or a relative error of less than or equal to 30 percent of the estimated CO₂e fluorinated GHG emissions. If you do not meet either of the error limits or the requirements of paragraph §98.124(b)(8), you must use the emission factor approach detailed in paragraphs (c), (d), and (e) of this section to estimate emissions from the process.

(i) Error calculation. To perform the calculation, you must first calculate the absolute and relative errors associated with the quantities calculated using either Equations L-7 through L-10 of this section or Equation L-17 of this section. Alternatively, you may estimate these errors based on the variability of previous process measurements (e.g., the variability of measurements of stream concentrations), provided these measurements are representative of the current process and current measurement devices and techniques. Once errors have been calculated for the quantities in these equations, those errors must be used to calculate the errors in Equations L-6 and L-5 of this section. You may ignore the errors associated with Equations L-11, L-12, and L-13 of this section.

(ii) Where the measured quantity is a mass, the error in the mass must be equated to the accuracy or precision (whichever is larger) of the flowmeter, scale, or combination of volumetric and density measurements at the flow rate or mass measured.

(ii) Where the measured quantity is a concentration of a stream component, the error in the concentration must be equated to the accuracy or precision (whichever is larger) of the analytical technique used to measure the concentration at the concentration measured.
shall be assumed to account both for the variability of the process and the precision of the analytical technique. Use standard statistical techniques such as the student's t distribution to estimate the error of the mean of the concentration measurements as a function of process variability and frequency of measurement.

(iii) Equation L-1 of this section provides the general formula for calculating the absolute errors of sums and differences where the sum, $S$, is the summation of variables measured, $a$, $b$, $c$, etc. (e.g., $S = a + b + c$):

$$e_{SA} = [(a \cdot e_a)^2 + (b \cdot e_b)^2 + (c \cdot e_c)^2]^{1/2} \quad (\text{Eq. L-1})$$

where:
- $e_{SA}$ = Absolute error of the sum, expressed as one half of a 95 percent confidence interval.
- $e_a$ = Relative error of $a$, expressed as one half of a 95 percent confidence interval.
- $e_b$ = Relative error of $b$, expressed as one half of a 95 percent confidence interval.
- $e_c$ = Relative error of $c$, expressed as one half of a 95 percent confidence interval.

(iv) Equation L-2 of this section provides the general formula for calculating the relative errors of sums and differences:

$$e_{SR} = \frac{e_{SM}}{(a + b + c)} \quad (\text{Eq. L-2})$$

where:
- $e_{SM}$ = Relative error of the sum, expressed as one half of a 95 percent confidence interval.
- $e_{SR}$ = Relative error of the sum, expressed as one half of a 95 percent confidence interval.
- $a + b + c$ = Sum of the variables measured.

(v) Equation L-3 of this section provides the general formula for calculating the absolute errors of products (e.g., flow rates of GHGs calculated as the product of the flow rate of the stream and the concentration of the GHG in the stream), where the product, $P$, is the result of multiplying the variables measured, $a$, $b$, $c$, etc. (e.g., $P = a \times b \times c$):

$$e_{PA} = (a \times b \times c) \left( e_a^2 + e_b^2 + e_c^2 \right)^{1/2} \quad (\text{Eq. L-3})$$

where:
- $e_{PA}$ = Absolute error of the product, expressed as one half of a 95 percent confidence interval.
- $e_a$ = Relative error of $a$, expressed as one half of a 95 percent confidence interval.
- $e_b$ = Relative error of $b$, expressed as one half of a 95 percent confidence interval.
- $e_c$ = Relative error of $c$, expressed as one half of a 95 percent confidence interval.

(vi) Equation L-4 of this section provides the general formula for calculating the relative errors of products:

$$e_{PR} = \frac{e_{PA}}{(a \times b \times c)} \quad (\text{Eq. L-4})$$
where:

  \( e_{PR} \) = Relative error of the product, expressed as one half of a 95 percent confidence interval.

  \( e_{PA} \) = Absolute error of the product, expressed as one half of a 95 percent confidence interval.

  \( \alpha \times \beta \times \gamma \) = Product of the variables measured.

(vii) Calculate the absolute error of the emissions estimate in terms of \( \text{CO}_2 \) by performing a preliminary estimate of the annual \( \text{CO}_2 \) emissions of the process using the method in paragraph (b)(1)(viii) of this section. Multiply this result by the relative error calculated for the mass of fluorine emitted from the process in Equation L–6 of this section.

(viii) To estimate the annual \( \text{CO}_2 \) emissions of the process for use in the error estimate, apply the methods set forth in paragraphs (b)(2) through (b)(7) and (b)(9) through (b)(16) of this section to representative process measurements. If these process measurements represent less than one year of typical process activity, adjust the estimated emissions to account for one year of typical process activity. To estimate the terms \( \text{FER}_d \), \( \text{FEP} \), and \( \text{FEB}_k \) for use in the error estimate for Equations L–11, L–12, and L–13 of this section, you must either use emission testing, monitoring of emitted streams, and/or engineering calculations or assessments, or in the alternative assume that all fluorine is emitted in the form of the fluorinated GHG that has the highest GWP among the fluorinated GHGs that occur in more than trace concentrations in the process. To convert the fluorinated GHG emissions to \( \text{CO}_2 \), use Equation A–1 of §98.2. For fluorinated GHGs whose GWPs are not listed in Table A–1 to subpart A of this part, use a default GWP of 2,000.

(2) The total mass of each fluorinated GHG emitted annually from each fluorinated gas production and each fluorinated GHG transformation process must be estimated by using Equation L–5 of this section.

\[
E_{\text{FHHGF}_f} = \sum_{p=1}^{n} (E_{\text{R}_p-\text{FHHGF}_f} + E_{\text{P}_p-\text{FHHGF}_f} + E_{\text{B}_p-\text{FHHGF}_f}) \quad (\text{Eq. L–5})
\]

where:

  \( E_{\text{FHHGF}_f} \) = Total mass of each fluorinated GHG \( f \) emitted annually from production or transformation process \( i \) (metric tons).

  \( E_{\text{R}_p-\text{FHHGF}_f} \) = Total mass of fluorinated GHG reactant \( f \) emitted from production process \( i \) over the period \( p \) (metric tons, calculated in Equation L–11 of this section).

  \( E_{\text{P}_p-\text{FHHGF}_f} \) = Total mass of the fluorinated GHG product \( f \) emitted from production process \( i \) over the period \( p \) (metric tons, calculated in Equation L–12 of this section).

  \( E_{\text{B}_p-\text{FHHGF}_f} \) = Total mass of fluorinated GHG by-product \( f \) emitted from production process \( i \) over the period \( p \) (metric tons, calculated in Equation L–13 of this section).

  \( n \) = Number of concentration and flow measurement periods for the year.

(3) The total mass of fluorine emitted from process \( i \) over the period \( p \) must be estimated at least monthly by calculating the difference between the total mass of fluorine in the reactant(s) (or inputs, for processes that do not involve a chemical reaction) and the total mass of fluorine in the product (or outputs, for processes that do not involve a chemical reaction), accounting for the total mass of fluorine in any destroyed or recaptured streams that contain reactants, products, or by-products (or inputs or outputs). This calculation must be performed using Equation L–6 of this section. An element other than fluorine may be used in the mass-balance equation, provided the element occurs in all of the fluorinated GHGs fed into or generated by the process. In this case, the mass fractions of the element in the reactants, products, and by-products must be calculated as appropriate for that element.
(4) The mass of total fluorine in destroyed or recaptured streams containing fluorine-containing reactants, products, and by-products must be estimated at least monthly using Equation L-7 of this section unless you use the alternative approach provided in paragraph (b)(15) of this section.

\[ E_F = \sum_{i=1}^{v} \left( R_d * MFF_{Rd} \right) - P * MFF_P - F_D \]  

(Eq. L-6)

where:
- \( E_F \) = Total mass of fluorine emitted from process \( i \) over the period \( p \) (metric tons).
- \( R_d \) = Total mass of the fluorine-containing reactant \( d \) that is fed into process \( i \) over the period \( p \) (metric tons).
- \( P \) = Total mass of the fluorine-containing product produced by process \( i \) over the period \( p \) (metric tons).
- \( MFF_{Rd} \) = Mass fraction of fluorine in reactant \( d \), calculated in Equation L-14 of this section.
- \( MFF_P \) = Mass fraction of fluorine in the product, calculated in Equation L-15 of this section.
- \( F_D \) = Total mass of fluorine in destroyed or recaptured streams from process \( i \) containing fluorine-containing reactants, products, and by-products over the period \( p \) (metric tons).
- \( v \) = Number of fluorine-containing reactants fed into process \( i \).

(5) The mass of each fluorinated GHG removed from process \( i \) in stream \( j \) and destroyed over the period \( p \) (i.e., \( P_j \), \( B_{kj} \), or \( R_{dj} \), as applicable) must be estimated by applying the destruction efficiency of the device that has been demonstrated for the fluorinated GHG \( f \) using Equation L-8 of this section:

\[ F_{Df} = \sum_{j=1}^{q} P_j * MFF_P + \sum_{k=1}^{u} \left[ \sum_{j=1}^{q} B_{kj} + \sum_{l=1}^{x} B_{kl} \right] * MFF_{Bk} + \sum_{d=1}^{v} \sum_{j=1}^{q} R_{dj} * MFF_{Rd} \]  

(Eq. L-7)

where:
- \( F_{Df} \) = Total mass of fluorine in destroyed or recaptured streams from process \( i \) containing fluorine-containing reactants, products, and by-products over the period \( p \) (calculated in Equation L-8 or L-9 of this section).
- \( P_j \) = Mass of the fluorine-containing product removed from process \( i \) in stream \( j \) and destroyed over the period \( p \) (calculated in Equation L-8 or L-9 of this section).
- \( B_{kj} \) = Mass of fluorine-containing by-product \( k \) removed from process \( i \) in stream \( j \) and destroyed over the period \( p \) (calculated in Equation L-8 or L-9 of this section).
- \( B_{kl} \) = Mass of fluorine-containing by-product \( k \) removed from process \( i \) in stream \( l \) and recaptured over the period \( p \) (calculated in Equation L-8 or L-9 of this section).
- \( R_{dj} \) = Mass of fluorine-containing reactant \( d \) removed from process \( i \) in stream \( j \) and destroyed over the period \( p \) (calculated in Equation L-8 or L-9 of this section).
- \( MFF_P \) = Mass fraction of fluorine in the product, calculated in Equation L-15 of this section.
- \( MFF_{Bk} \) = Mass fraction of fluorine in by-product \( k \), calculated in Equation L-16 of this section.
- \( q \) = Number of streams destroyed in process \( i \).
- \( x \) = Number of streams recaptured in process \( i \).
- \( u \) = Number of fluorine-containing by-products generated in process \( i \).
- \( v \) = Number of fluorine-containing reactants fed into process \( i \).

\[ M_{FGHGfj} = DE_{FGHGfj} * c_{FGHGfj} * S_j \]  

(Eq. L-8)

where:
- \( M_{FGHGfj} \) = Mass of fluorinated GHG \( f \) removed from process \( i \) in stream \( j \) and destroyed
over the period \(p\). (This may be \(P\), \(B\), or \(R\), as applicable.)

\[
\text{DE}_{\text{FCGf}} = \text{Destruction efficiency of the device that has been demonstrated for fluorinated GHG \(f\) in stream \(j\) (fraction)).}
\]

\[
C_{\text{FCGfj}} = \text{Concentration (mass fraction) of fluorinated GHG \(f\) in stream \(j\) removed from process \(i\) and fed into the destruction device over the period \(p\). If this concentration is only a trace concentration, } C_{\text{FCGfj}} \text{ is equal to zero.}
\]

\[
M_{\text{FCGj}} = c_{\text{FCGj}} \times S_j \quad \text{(Eq. L-9)}
\]

where:

\[
M_{\text{FCGj}} = \text{Mass of non-GHG fluorine-containing compound \(g\) removed from process \(i\) in stream \(j\) and destroyed over the period \(p\). (This may be \(P\), \(B\), or \(R\), as applicable).}
\]

\[
C_{\text{FCGj}} = \text{Concentration (mass fraction) of non-GHG fluorine-containing compound \(g\) in stream \(j\) removed from process \(i\) and fed into the destruction device over the period \(p\). If this concentration is only a trace concentration, } C_{\text{FCGj}} \text{ is equal to zero.}
\]

\[
B_{jk} = c_{Bjk} \times S_j \quad \text{(Eq. L-10)}
\]

where:

\[
B_{jk} = \text{Mass of fluorine-containing by-product \(k\) removed from process \(i\) in stream \(j\) and recaptured over the period \(p\).}
\]

\[
c_{Bjk} = \text{Concentration (mass fraction) of fluorine-containing by-product \(k\) in stream \(j\) removed from process \(i\) and recaptured over the period \(p\). If this concentration is only a trace concentration, } c_{Bjk} \text{ is equal to zero.}
\]

\[
S_j = \text{Mass removed in stream }j\text{ from process }i\text{ and fed into the destruction device over the period }p\text{ (metric tons).}
\]

(6) The mass of each fluorine-containing compound that is not a fluorinated GHG and that is removed from process \(i\) in stream \(j\) and destroyed over the period \(p\) (i.e., \(P\), \(B\), or \(R\), as applicable) must be estimated using Equation L-9 of this section.

\[
M_{\text{FCGj}} = c_{\text{FCGj}} \times S_j
\]

(7) The mass of fluorine-containing by-product \(k\) removed from process \(i\) in stream \(l\) and recaptured over the period \(p\) must be estimated using Equation L-10 of this section:

\[
B_{kl} = c_{Bkl} \times S_l
\]

(8) To estimate the terms \(\text{FER}_d\), \(\text{FEP}\), and \(\text{FEB}_k\) for Equations L-11, L-12, and L-13 of this section, you must assume that the total mass of fluorine emitted, \(E_F\), estimated in Equation L-6 of this section, occurs in the form of the fluorinated GHG that has the highest GWP among the fluorinated GHGs that occur in more than trace concentrations in the process unless you possess emission characterization measurements showing otherwise. These emission characterization measurements must meet the requirements in paragraph (b)(1)(viii) of this section, as appropriate. The sum of the terms must equal 1. You must document the data and calculations that are used to speciate individual compounds and to estimate \(\text{FER}_d\), \(\text{FEP}\), and \(\text{FEB}_k\). Exclude from your calculations the fluorine included in \(F_D\). For example, exclude fluorine-containing compounds that are not fluorinated GHGs and that result from the destruction of fluorinated GHGs by any destruction devices (e.g., the mass of HF created by combustion of an HFC). However, include emissions of fluorinated GHGs that survive the destruction process.

(i) If the calculations under paragraph (b)(1)(viii) of this section, or any subsequent measurements and calculations under this subpart, indicate that the process emits 25,000 metric tons \(\text{CO}_2\text{e}\) or more, estimate the emissions from each process vent, considering controls, using the methods in §98.123(c)(1). You must characterize the emissions of any process vent that...
emits 25,000 metric tons CO$_2$e or more as specified in §98.124(b)(4).

(ii) For other vents, including vents from processes that emit less than 25,000 metric tons CO$_2$e, you must characterize emissions as specified in §98.124(b)(5).

(iii) For fluorine emissions that are not accounted for by vent estimates, you must characterize emissions as specified in §98.124(b)(6).

(9) The total mass of fluorine-containing reactant d emitted must be estimated at least monthly based on the total fluorine emitted and the fraction that consists of fluorine-containing reactants using Equation L–11 of this section. If the fluorine-containing reactant d is a non-GHG, you may assume that FER$_d$ is zero.

\[
E_{R-ip} = \frac{FER_d \cdot E_F}{\left( \sum_{d=1}^{v} FER_d \cdot MFF_{Rd} + FEP \cdot MFF_p + \sum_{k=1}^{u} FEB_k \cdot MFF_{Bk} \right)} \quad \text{(Eq. L–11)}
\]

where:

- $E_{R-ip}$ = Total mass of fluorine-containing reactant d that is emitted from process i over the period p (metric tons).
- $FER_d$ = The fraction of the mass emitted that consists of the fluorine-containing reactant d.
- $E_F$ = Total mass of fluorine emissions from process i over the period p (metric tons), calculated in Equation L–6 of this section.
- $FEP = \text{The fraction of the mass emitted that consists of the fluorine-containing product.}$
- $FEB_k = \text{The fraction of the mass emitted that consists of fluorine-containing by-product k.}$
- $MFF_{Rd} = \text{Mass fraction of fluorine in reactant d, calculated in Equation L–14 of this section.}$
- $MFF_p = \text{Mass fraction of fluorine in the product, calculated in Equation L–15 of this section.}$
- $MFF_{Bk} = \text{Mass fraction of fluorine in by-product k, calculation in Equation L–16 of this section.}$
- $u = \text{Number of fluorine-containing by-products generated in process i.}$
- $v = \text{Number of fluorine-containing reactants fed into process i.}$

(10) The total mass of fluorine-containing product emitted must be estimated at least monthly based on the total fluorine emitted and the fraction that consists of fluorine-containing products using Equation L–12 of this section. If the fluorine-containing product is a non-GHG, you may assume that FEP is zero.

\[
E_{P-ip} = \frac{FEP \cdot E_F}{\left( \sum_{d=1}^{v} FER_d \cdot MFF_{Rd} + FEP \cdot MFF_p + \sum_{k=1}^{u} FEB_k \cdot MFF_{Bk} \right)} \quad \text{(Eq. L–12)}
\]

where:

- $E_{P-ip}$ = Total mass of fluorine-containing product emitted from process i over the period p (metric tons).
- $FEP = \text{The fraction of the mass emitted that consists of fluorine-containing reactant d.}$
- $FEB_k = \text{The fraction of the mass emitted that consists of fluorine-containing by-product k.}$
- $MFF_{Rd} = \text{Mass fraction of fluorine in reactant d, calculated in Equation L–14 of this section.}$
- $MFP_p = \text{Mass fraction of fluorine in the product, calculated in Equation L–15 of this section.}$
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MFF<sub>Rd</sub> = Mass fraction of fluorine in reactant d, calculated in Equation L–14 of this section.
MFF<sub>P</sub> = Mass fraction of fluorine in the product, calculated in Equation L–15 of this section.
MFF<sub>Bk</sub> = Mass fraction of fluorine in by-product k, calculation in Equation L–16 of this section.
u = Number of fluorine-containing by-products generated in process i.
v = Number of fluorine-containing reactants fed into process i.

(11) The total mass of fluorine-containing by-product k emitted must be estimated at least monthly based on the total fluorine emitted and the fraction that consists of fluorine-containing by-products using Equation L–13 of this section. If fluorine-containing by-product k is a non-GHG, you may assume that FEB<sub>k</sub> is zero.

\[
E_{Bk-ip} = \frac{FEB_k \cdot E_F}{\sum_1^u FER_d \cdot MFF_{Rd} + FEP \cdot MFF_P + \sum_{k=1}^u FEB_k \cdot MFF_{Bk}}
\]  

(Eq. L–13)

where:
E<sub>Bk-ip</sub> = Total mass of fluorine-containing by-product k emitted from process i over the period p (metric tons).
FEB<sub>k</sub> = The fraction of the mass emitted that consists of fluorine-containing by-product k.
FER<sub>d</sub> = The fraction of the mass emitted that consists of fluorine-containing reactant d.
FEP = The fraction of the mass emitted that consists of the fluorine-containing product.
E<sub>F</sub> = Total mass of fluorine emissions from process i over the period p (metric tons), calculated in Equation L–6 of this section.

(12) The mass fraction of fluorine in reactant d must be estimated using Equation L–14 of this section:

\[
MFF_{Rd} = MF_{Rd} \cdot \frac{AW_F}{MW_{Rd}}
\]  

(Eq. L–14)

where:
MFF<sub>Rd</sub> = Mass fraction of fluorine in reactant d (fraction).
MFF<sub>Rd</sub> = Moles fluorine per mole of reactant d.
AW<sub>F</sub> = Atomic weight of fluorine.
MW<sub>Rd</sub> = Molecular weight of reactant d.

(13) The mass fraction of fluorine in the product must be estimated using Equation L–15 of this section:

\[
MFF_p = MF_p \cdot \frac{AW_F}{MW_p}
\]  

(Eq. L–15)

where:
MFF<sub>P</sub> = Mass fraction of fluorine in the product (fraction).
MFF<sub>P</sub> = Moles fluorine per mole of product.
AW<sub>F</sub> = Atomic weight of fluorine.
MW<sub>p</sub> = Molecular weight of the product produced.

(14) The mass fraction of fluorine in by-product k must be estimated using Equation L–16 of this section:
where:

\[ MFF_{Bk} = MF_{Bk} \times \frac{AW_{F}}{MW_{Bk}} \]  

(Eq. L-16)

where:

- \( MFF_{Bk} \) = Mass fraction of fluorine in the product (fraction).
- \( MF_{Bk} \) = Moles fluorine per mole of by-product \( k \).
- \( AW_{F} \) = Atomic weight of fluorine.
- \( MW_{Bk} \) = Molecular weight of by-product \( k \).

(15) Alternative for determining the mass of fluorine destroyed or recaptured. As an alternative to using Equation L-7 of this section as provided in paragraph (b)(4) of this section, you may estimate at least monthly the total mass of fluorine in destroyed or recaptured streams containing fluorine-containing compounds (including all fluorine-containing reactants, products, and by-products) using Equation L-17 of this section.

\[ F_D = \sum_{j=1}^{q} DE_{avgj} \times c_{TFj} \times S_j + \sum_{l=1}^{x} c_{TFl} \times S_l \]  

(Eq. L-17)

where:

- \( F_D \) = Total mass of fluorine in destroyed or recaptured streams from process \( i \) containing fluorine-containing reactants, products, and by-products over the period \( p \).
- \( DE_{avgj} \) = Weighted average destruction efficiency of the destruction device for the fluorine-containing compounds identified in destroyed stream \( j \) under §88.124(b)(4)(ii) and (5)(ii) (calculated in Equation L-18 of this section)(fraction).
- \( c_{TFj} \) = Concentration (mass fraction) of total fluorine in stream \( j \) removed from process \( i \) and fed into the destruction device over the period \( p \). If this concentration is only a trace concentration, \( c_{TFj} \) is equal to zero.
- \( S_j \) = Mass removed in stream \( j \) from process \( i \) and fed into the destruction device over the period \( p \) (metric tons).
- \( c_{TFl} \) = Concentration (mass fraction) of total fluorine in stream \( l \) removed from process \( i \) and recaptured over the period \( p \). If this concentration is only a trace concentration, \( c_{TFl} \) is equal to zero.
- \( S_l \) = Mass removed in stream \( l \) from process \( i \) and recaptured over the period \( p \).
- \( q = Number of streams destroyed in process \( i \). \)
- \( x = Number of streams recaptured in process \( i \). \)

(16) Weighted average destruction efficiency. For purposes of Equation L-17 of this section, calculate the weighted average destruction efficiency applicable to a destroyed stream using Equation L-18 of this section.

\[ DE_{avgj} = \frac{\sum_{f=1}^{w} DE_{FGHGfj} \times c_{FGHGfj} \times S_j \times MFF_{FGHGfj} + \sum_{g=1}^{v} c_{FGG} \times S_j \times MFF_{FGG} \times S_j \times MFF_{FGG}}{\sum_{f=1}^{w} c_{FGHGfj} \times S_j \times MFF_{FGHGfj} + \sum_{g=1}^{v} c_{FGG} \times S_j \times MFF_{FGG} \times S_j \times MFF_{FGG}} \]  

(Eq. L-18)

where:

- \( DE_{avgj} \) = Weighted average destruction efficiency of the destruction device for the fluorine-containing compounds identified in destroyed stream \( j \) under 98.124(b)(4)(ii) or (b)(5)(ii), as appropriate.
- \( DE_{FGHGfj} \) = Destruction efficiency of the device that has been demonstrated for fluorinated GHG \( f \) in stream \( j \) (fraction).
- \( c_{FGHGfj} \) = Concentration (mass fraction) of fluorinated GHG \( f \) in stream \( j \) removed...
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from process i and fed into the destruction device over the period of. If this concentration is only a trace concentration, $c_{F\text{-GHG}}$ is equal to zero.

$\text{MFF}_{i\rightarrow d} = \text{Mass fraction of fluorine in non-GHG fluorine-containing compound} \ g$ in stream j removed from process i and fed into the destruction device over the period p. If this concentration is only a trace concentration, $c_{F\text{-GHG}}$ is equal to zero.

$S_j =$ Mass removed in stream j from process i and fed into the destruction device over the period p (metric tons).

$\text{MFF}_{FCg} =$ Mass fraction of fluorine in non-GHG fluorine-containing compound g, calculated in Equation L–14, L–15, or L–16 of this section, as appropriate.

$\text{MFF}_{F\text{-GHG}} =$ Mass fraction of fluorine in non-GHG fluorine-containing compound g, calculated in Equation L–14, L–15, or L–16 of this section, as appropriate.

$c_j =$ Concentration (mass fraction) of non-GHG fluorine-containing compound g in stream j removed from process i and fed into the destruction device over the period p. If this concentration is only a trace concentration, $c_{F\text{-GHG}}$ is equal to zero.

$w =$ Number of fluorinated GHGs in destroyed stream j.

$y =$ Number of non-GHG fluorine-containing compounds in destroyed stream j.

(c) Emission factor and emission calculation factor methods. To use the method in this paragraph for batch processes, you must comply with either paragraph (c)(3) of this section (Emission Factor approach) or paragraph (c)(4) of this section (Emission Calculation Factor approach). To use the method in this paragraph for continuous processes, you must first make a preliminary estimate of the emissions from each individual continuous process vent under paragraph (c)(1) of this section. If your continuous process operates under different conditions as part of normal operations, you must also define the different operating scenarios and make a preliminary estimate of the emissions from the vent for each operating scenario. Then, compare the preliminary estimate for each continuous process vent (summed across operating scenarios) to the criteria in paragraph (c)(2) of this section to determine whether the process vent meets the criteria for using the emission factor method described in paragraph (c)(3) of this section or whether the process vent meets the criteria for using the emission calculation factor method described in paragraph (c)(4) of this section. For continuous process vents that meet the criteria for using the emission factor method described in paragraph (c)(3) of this section and that have more than one operating scenario, compare the preliminary estimate for each operating scenario to the criteria in (c)(3)(ii) to determine whether an emission factor must be developed for that operating scenario.

(1) Preliminary estimate of emissions by process vent. You must estimate the annual CO2 emissions of fluorinated GHGs for each process vent within each operating scenario of a continuous process using the approaches specified in paragraph (c)(1)(i) or (c)(1)(ii) of this section, accounting for any destruction as specified in paragraph (c)(1)(iii) of this section. You must determine emissions of fluorinated GHGs by process vent by using measurements, by using calculations based on chemical engineering principles and chemical property data, or by conducting an engineering assessment. You may use previous measurements, calculations, and assessments if they represent current process operating conditions or process operating conditions that would result in higher fluorinated GHG emissions than the current operating conditions and if they were performed in accordance with paragraphs (c)(1)(i), (c)(1)(ii), and (c)(1)(iii) of this section, as applicable. You must document all data, assumptions, and procedures used in the calculations or engineering assessment and keep a record of the emissions determination as required by §98.127(a).

(i) Engineering calculations. For process vent emission calculations, you may use any of paragraphs (c)(1)(i)(A), (c)(1)(i)(B), or (c)(1)(i)(C) of this section.

(A) U.S. Environmental Protection Agency, Emission Inventory Improvement Program, Volume II: Chapter 16, Methods for Estimating Air Emissions from Chemical Manufacturing Facilities, August 2007, Final (incorporated by reference, see §98.7).

(B) You may determine the fluorinated GHG emissions from any process vent within the process using the procedures specified in §63.1257(d)(2)(i) and (d)(2)(i)(B) of this chapter, except as specified in paragraphs (c)(1)(i)(B)(f) through (c)(1)(i)(B)(d) of this section. For the purposes of this subpart, use of the term “HAP” in §63.1257(d)(2)(i) and (d)(2)(i)(B) of this chapter means “fluorinated GHG.”
(1) To calculate emissions caused by the heating of a vessel without a process condenser to a temperature lower than the boiling point, you must use the procedures in §63.1257(d)(2)(i)(C)(3) of this chapter.

(2) To calculate emissions from depressurization of a vessel without a process condenser, you must use the procedures in §63.1257(d)(2)(i)(D)(10) of this chapter.

(3) To calculate emissions from vacuum systems, the terms used in Equation 33 to §63.1257(d)(2)(i)(E) of this chapter are defined as follows:

(i) \( P_{\text{system}} \) = Absolute pressure of the receiving vessel.

(ii) \( P_i \) = Partial pressure of the fluorinated GHG determined at the exit temperature and exit pressure conditions of the condenser or at the conditions of the dedicated receiver.

(iii) \( P_j \) = Partial pressure of condensables (including fluorinated GHG) determined at the exit temperature and exit pressure conditions of the condenser or at the conditions of the dedicated receiver.

(iv) \( \text{MW}_{\text{fluorinated GHG}} \) = Molecular weight of the fluorinated GHG determined at the exit temperature and exit pressure conditions of the condenser or at the conditions of the dedicated receiver.

(4) To calculate emissions when a vessel is equipped with a process condenser or a control condenser, you must use the procedures in §63.1257(d)(3)(i)(B) of this chapter, except as follows:

(i) You must determine the flowrate of gas (or volume of gas), partial pressures of condensables, temperature (T), and fluorinated GHG molecular weight (\( \text{MW}_{\text{fluorinated GHG}} \)) at the exit temperature and exit pressure conditions of the condenser or at the conditions of the dedicated receiver.

(ii) You must assume that all of the components contained in the condenser exit vent stream are in equilibrium with the same components in the exit condensate stream (except for noncondensables).

(iii) You must perform a material balance for each component, if the condensate receiver composition is not known.

(iv) For the emissions from gas evolution, the term for time, \( t \), must be used in Equation 12 to §63.1257(d)(2)(i)(B) of this chapter.

(v) Emissions from empty vessel purging must be calculated using Equation 36 to §63.1257(d)(2)(i)(H) of this chapter and the exit temperature and exit pressure conditions of the condenser or the conditions of the dedicated receiver.

(C) Commercial software products that follow chemical engineering principles (e.g., including the calculation methodologies in paragraphs (c)(1)(i)(A) and (c)(1)(i)(B) of this section).

(ii) Engineering assessments. For process vent emissions determinations, you may conduct an engineering assessment to calculate uncontrolled emissions. An engineering assessment includes, but is not limited to, the following:

(A) Previous test results, provided the tests are representative of current operating practices of the process.

(B) Bench-scale or pilot-scale test data representative of the process operating conditions.

(C) Maximum flow rate, fluorinated GHG emission rate, concentration, or other relevant parameters specified or implied within a permit limit applicable to the process vent.

(D) Design analysis based on chemical engineering principles, measurable process parameters, or physical or chemical laws or properties.

(iii) Impact of destruction for the preliminary estimate. If the process vent is vented to a destruction device, you may reflect the impact of the destruction device on emissions. In your emissions estimate, account for the following:

(A) The destruction efficiencies of the device that have been demonstrated for the fluorinated GHGs in the vent stream for periods when the process vent is vented to the destruction device.

(B) Any periods when the process vent is not vented to the destruction device.

(iv) Use of typical recent values. In the calculations in paragraphs (c)(1)(i), (c)(1)(ii), and (c)(1)(iii) of this section,
the values used for the expected process activity and for the expected fraction of that activity whose emissions will be vented to the properly functioning destruction device must be based on either typical recent values for the process or values that would overestimate emissions from the process, unless there is a compelling reason to adopt a different value (e.g., installation of a destruction device for a previously uncontrolled process). If there is such a reason, it must be documented in the GHG Monitoring Plan.

(v) GWPs. To convert the fluorinated GHG emissions to CO$_2$e, use Equation A–1 of §98.2. For fluorinated GHGs whose GWPs are not listed in Table A–1 to subpart A of this part, use a default GWP of 2,000 unless you submit a request to use other GWPs for those fluorinated GHGs in that process under paragraph (c)(1)(vi) of this section and we approve that request.

(vi) Request to use a GWP other than 2,000 for fluorinated GHGs whose GWPs are not listed in Table A–1 to subpart A of this part. If your process vent emits one or more fluorinated GHGs whose GWPs are not listed in Table A–1 to subpart A of this part, that are emitted in quantities that, with a default GWP of 2,000, result in total calculated annual emissions equal to or greater than 10,000 metric tons CO$_2$e for the vent, and that you believe have GWPs that would result in total calculated annual emissions less than 10,000 metric tons CO$_2$e for the vent, you may submit a request to use provisional GWPs for these fluorinated GHGs for purposes of the calculations in paragraph (c)(1) of this section. The request must be submitted by February 28, 2011 for a completeness determination and review by EPA.

(A) Contents of the request. You must include the following information in the request for each fluorinated GHG that does not have a GWP listed in Table A–1 to subpart A of this part and that constitutes more than one percent by mass of the stream emitted from the vent:

(1) The identity of the fluorinated GHG, including its chemical formula and, if available, CAS number.

(2) The estimated GWP of the fluorinated GHG.

(3) The data and analysis that supports your estimate of the GWP of the fluorinated GHG, including:

(i) Data and analysis related to the low-pressure gas phase infrared absorption spectrum of the fluorinated GHG.

(ii) Data and analysis related to the estimated atmospheric lifetime of the fluorinated GHG (reaction mechanisms and rates, including e.g., photolysis and reaction with atmospheric components such as OH, O$_3$, CO, and water).

(iii) The radiative transfer analysis that integrates the lifetime and infrared absorption spectrum data to calculate the GWP.

(iv) Any published or unpublished studies of the GWP of the gas.

(4) The engineering calculations or assessments and underlying data that demonstrate that the process vent is calculated to emit less than 10,000 metric tons CO$_2$e of this and other fluorinated GHGs only when the proposed provisional GWPs, not the default GWP of 2,000, are used for fluorinated GHGs whose GWPs are not listed in Table A–1 to subpart A of this part.

(B) Review and completeness determination by EPA. If EPA makes a preliminary determination that the request is complete, that it substantiates each of the provisional GWPs, and that it demonstrates that the process vent is calculated to emit less than 10,000 metric tons CO$_2$e of this and other fluorinated GHGs only when the proposed provisional GWPs, not the default GWP of 2,000, are used for fluorinated GHGs whose GWPs are not listed in Table A–1 to subpart A of this part, then EPA will publish a notice including the data and analysis submitted under paragraphs (c)(1)(vi)(A)(1) through (c)(1)(vi)(A)(3) of this section. If, after review of public comment on the notice, EPA finalizes its preliminary determination, then EPA will permit the facility to use the provisional GWPs for the calculations in paragraph (c)(1) of this section unless and until EPA determines that one or more of the provisional GWPs is in error and provides reasonable notice to the facility.

(2) Method selection for continuous process vents.

(i) If the calculations under paragraph (c)(1) of this section, as well as
any subsequent measurements and calculations under this subpart, indicate that the continuous process vent has fluorinated GHG emissions of less than 10,000 metric ton CO$_2$e per year, summed across all operating scenarios, then you may comply with either paragraph (c)(3) of this section (Emission Factor approach) or paragraph (c)(4) of this section (Emission Calculation Factor approach).

(ii) If the continuous process vent does not meet the criteria in paragraph (c)(2)(i) of this section, then you must comply with the emission factor method specified in paragraph (c)(3) (Emission Factor approach) of this section.

(A) You must conduct emission testing for process-vent-specific emission factor development before the destruction device unless the calculations you performed under paragraph (c)(1)(iii) of this section indicate that the uncontrolled fluorinated GHG emissions that occur during periods when the process vent is not vented to the properly functioning destruction device are less than 10,000 metric tons CO$_2$e per year. In this case, you may conduct emission testing after the destruction device to develop a process-vent-specific emission factor. If you do so, you must develop and apply an emission calculation factor under paragraph (c)(4) to estimate emissions during any periods when the process vent is not vented to the properly functioning destruction device.

(B) Regardless of the level of uncontrolled emissions, the emission testing for process-vent-specific emission factor development may be conducted on the outlet side of a wet scrubber in place for acid gas reduction, if one is in place, as long as there is no appreciable reduction in the fluorinated GHG.

(3) Process-vent-specific emission factor method. For each process vent, conduct an emission test and measure fluorinated GHG emissions from the process and measure the process activity, such as the feed rate, production rate, or other process activity rate, during the test as described in this paragraph (c)(3). Conduct the emission test according to the procedures in §98.124. All emissions test data and procedures used in developing emission factors must be documented according to §98.127. If more than one operating scenario applies to the process that contains the subject process vent, you must comply with either paragraph (3)(i) or paragraph (3)(ii) of this section.

(i) Conduct a separate emissions test for operation under each operating scenario.

(ii) Conduct an emissions test for the operating scenario that is expected to have the largest emissions in terms of CO$_2$e (considering both activity levels and emission calculation factors) on an annual basis. Also conduct an emissions test for each additional operating scenario that is estimated to emit 10,000 metric tons CO$_2$e or more annually from the vent and whose emission calculation factor differs by 15 percent or more from the emission calculation factor of the operating scenario that is expected to have the largest emissions (or of another operating scenario for which emission testing is performed), unless the difference between the operating scenarios is solely due to the application of a destruction device to emissions under one of the operating scenarios. For any other operating scenarios, adjust the process-vent specific emission factor developed for the operating scenario that is expected to have the largest emissions (or for another operating scenario for which emission testing is performed) using the approach in paragraph (c)(3)(viii) of this section.

(iii) You must measure the process activity, such as the process feed rate, process production rate, or other process activity rate, as applicable, during the emission test and calculate the rate for the test period, in kg (or another appropriate metric) per hour.

(iv) For continuous processes, you must calculate the hourly emission rate of each fluorinated GHG using Equation L–19 of this section and determine the hourly emission rate of each fluorinated GHG per process vent (and per operating scenario, as applicable) for the test run.
where:

\[ E_{\text{ContPV}} = \frac{C_{PV}}{10^6} \times MW \times Q_{PV} \times \frac{1}{SV} \times \frac{1}{10^3} \times \frac{60}{1} \]  

(Eq. L-19)

\[ EF_{PV} = \frac{\sum_{r=1}^{r} \left( \frac{E_{PV}}{\text{Activity}_{EmissionTest}} \right)}{r} \]  

(Eq. L-20)

where:

- \( E_{\text{ContPV}} \) = Mass of fluorinated GHG \( f \) emitted from process vent \( v \) from process \( i \), operating scenario \( j \), during the emission test during test run \( r \) (kg/hr).
- \( C_{PV} \) = Concentration of fluorinated GHG \( f \) during test run \( r \) of the emission test (ppmv).
- \( MW \) = Molecular weight of fluorinated GHG \( f \) (g/mole).
- \( Q_{PV} \) = Flow rate of the process vent stream during test run \( r \) of the emission test (m\(^3\)/min).
- \( SV \) = Standard molar volume of gas (0.0240 m\(^3\)/g-mole at 68 °F and 1 atm).
- \( 1/10^3 \) = Conversion factor (1 kilogram/1,000 grams).

\( 60/1 \) = Conversion factor (60 minutes/1 hour).

(v) You must calculate a site-specific, process-vent-specific emission factor for each fluorinated GHG for each process vent and each operating scenario, in kg of fluorinated GHG per process activity rate (e.g., kg of feed or production), as applicable, using Equation L-20 of this section. For continuous processes, divide the hourly fluorinated GHG emission rate during the test by the hourly process activity rate during the test runs.

\[ E_{PV} = EF_{PV-C} \times \text{Activity}_C + ECF_{PV-U} \times \text{Activity}_U \]  

(Eq. L-21)

where:

- \( E_{PV} \) = Mass of fluorinated GHG \( f \) emitted from process vent \( v \) from process \( i \), operating scenario \( j \), during the year (kg).
- \( EF_{PV-C} \) = Emission factor for fluorinated GHG \( f \) emitted from process vent \( v \) during process \( i \), operating scenario \( j \), based on testing after the destruction device (kg emitted/activity) (e.g., kg emitted/kg product).
- \( \text{Activity}_C \) = Total process feed, process production, or other process activity for process \( i \), operating scenario \( j \), for the year (kg).
- \( ECF_{PV-U} \) = Emission factor for fluorinated GHG \( f \) emitted from process vent \( v \) during process \( i \), operating scenario \( j \), for the year for which emissions are vented to the properly functioning destruction device (i.e., controlled).

\( r \) = Number of test runs performed during the emission test.

(vi) If you conducted emissions testing after the destruction device, you must calculate the emissions of each fluorinated GHG for the process vent (and operating scenario, as applicable) using Equation L-21 of this section. You must also develop a process-vent-specific emission calculation factor based on paragraph (c)(4) of this section for the periods when the process vent is not venting to the destruction device.
ECF

PV–U

= Emission calculation factor for fluorinated GHG f emitted from process vent v during process i, operating scenario j during periods when the process vent is not vented to the properly functioning destruction device (kg emitted/ activity) (e.g., kg emitted/kg product).

Activity

U

= Total process feed, process production, or other process activity during the year for which the process vent is not vented to the properly functioning destruction device (e.g., kg product).

(vii) If you conducted emissions testing before the destruction device, apply the destruction efficiencies of the device that have been demonstrated for the fluorinated GHGs in the vent stream to the fluorinated GHG emissions for the process vent (and operating scenario, as applicable), using Equation L–22 of this section. You may apply the destruction efficiency only to the portion of the process activity during which emissions are vented to the properly functioning destruction device (i.e., controlled).

\[
E_{PV} = EF_{PV–U} \times (Activity_U + Activity_C \times (1 - DE)) \quad (Eq. \ L–22)
\]

where:

\( E_{PV} \) = Mass of fluorinated GHG f emitted from process vent v from process i, operating scenario j, for the year, considering destruction efficiency (kg).

\( EF_{PV–U} \) = Emission factor (uncontrolled) for fluorinated GHG f emitted from process vent v during process i, operating scenario j (kg emitted/kg product).

\( Activity_U \) = Total process feed, process production, or other process activity for process i, operating scenario j, during the year for which the process vent is not vented to the properly functioning destruction device (e.g., kg product).

\( Activity_C \) = Total process feed, process production, or other process activity for process i, operating scenario j, during the year for which the process vent is vented to the properly functioning destruction device (e.g., kg product).

\( DE \) = Demonstrated destruction efficiency of the destruction device (weight fraction).

(viii) Adjusted process-vent-specific emission factors for other operating scenarios. For process vents from processes with multiple operating scenarios, use Equation L–23 of this section to develop an adjusted process-vent-specific emission factor for each operating scenario from which the vent is estimated to emit less than 10,000 metric tons CO\textsubscript{2}e annually or whose emission calculation factor differs by less than 15 percent from the emission calculation factor of the operating scenario that is expected to have the largest emissions (or of another operating scenario for which emission testing is performed).

\[
EF_{PVadj} = \frac{ECF_{UT}}{ECF_T} \times EF_{PV} \quad (Eq. \ L–23)
\]

where:

\( EF_{PVadj} \) = Adjusted process-vent-specific emission factor for an untested operating scenario.

\( ECF_{UT} \) = Emission calculation factor for the untested operating scenario developed under paragraph (c)(4) of this section.

\( ECF_T \) = Emission calculation for the tested operating scenario developed under paragraph (c)(4) of this section.

\( EF_{PV} \) = Process vent specific emission factor for the tested operating scenario.

(ix) Sum the emissions of each fluorinated GHG from all process vents in each operating scenario and all operating scenarios in the process for the year to estimate the total process vent emissions of each fluorinated GHG from the process, using Equation L–24 of this section.
where:

\[ E_{pfi} = \frac{\sum_{i}^{o} \sum_{j}^{v} E_{PV}}{v o} \quad (\text{Eq. L-24}) \]

\[ E_{PV} = \text{Mass of fluorinated GHG f emitted from process vent v from process i, operating scenario j, for the year, considering destruction efficiency (kg).} \]

\[ v = \text{Number of process vents in process i, operating scenario j.} \]

\[ o = \text{Number of operating scenarios for process i.} \]

(4) Process-vent-specific emission calculation factor method. For each process vent within an operating scenario, determine fluorinated GHG emissions by calculations and determine the process activity rate, such as the feed rate, production rate, or other process activity rate, associated with the emission rate.

(i) You must calculate uncontrolled emissions of fluorinated GHG by individual process vent, \( E_{PV} \), by using measurements, by using calculations based on chemical engineering principles and chemical property data, or by conducting an engineering assessment. Use the procedures in paragraphs (c)(1)(i) or (ii) of this section, except paragraph (c)(1)(i)(C) of this section. The procedures in paragraphs (c)(1)(i) and (ii) of this section may be applied either to batch process vents or to continuous process vents. The uncontrolled emissions must be based on a typical batch or production rate under a defined operating scenario. The process activity rate associated with the uncontrolled emissions must be determined. The methods, data, and assumptions used to estimate emissions for each operating scenario must be selected to yield a best estimate (expected value) of emissions rather than an over- or underestimate of emissions for that operating scenario. All data, assumptions, and procedures used in the calculations or engineering assessment must be documented according to §98.127.

(ii) You must calculate a site-specific, process-vent-specific emission calculation factor for each process vent, each operating scenario, and each fluorinated GHG, in kg of fluorinated GHG per activity rate (e.g., kg of feed or production) as applicable, using Equation L-25 of this section.

\[ ECF_{PV} = \frac{E_{PV}}{\text{Activity}_{representative}} \quad (\text{Eq. L-25}) \]

where:

\[ ECF_{PV} = \text{Emission calculation factor for fluorinated GHG f emitted from process vent v during process i, operating scenario j, (e.g., kg emitted/kg product).} \]

\[ E_{PV} = \text{Average mass of fluorinated GHG f emitted, based on calculations, from process vent v from process i, operating scenario j, during the period or batch for which emissions were calculated, for either continuous or batch (kg emitted/hr for continuous, kg emitted/batch for batch).} \]

\[ \text{Activity}_{representative} = \text{Process feed, process production, or other process activity rate corresponding to average mass of emissions based on calculations (e.g., kg product/hr for continuous, kg product/batch for batch).} \]

(iii) You must calculate emissions of each fluorinated GHG for the process vent (and operating scenario, as applicable) for the year by multiplying the process-vent-specific emission calculation factor by the total process activity, as applicable, for the year, using Equation L-26 of this section.
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where:

\[ E_{PV} = \text{Mass of fluorinated GHG f emitted from process vent } v \text{ from process } i \text{, operating scenario } j, \text{ for the year (kg).} \]

\[ ECF_{PV} = \text{Emission calculation factor for fluorinated GHG f emitted from process vent } v \text{ during process } i \text{, operating scenario } j, \text{ (kg emitted/activity) (e.g., kg emitted/kg product).} \]

\[ \text{Activity} = \text{Process feed, process production, or other process activity for process } i, \text{ operating scenario } j, \text{ during the year.} \]

(iv) If the process vent is vented to a destruction device, apply the demonstrated destruction efficiency of the device to the fluorinated GHG emissions for the process vent (and operating scenario, as applicable), using Equation L–27 of this section. Apply the destruction efficiency only to the portion of the process activity that is vented to the properly functioning destruction device (i.e., controlled).

\[ E_{PV} = ECF_{PV} \cdot \text{(Activity}_U + \text{Activity}_C \cdot (1 - DE)) \]

where:

\[ E_{PV} = \text{Mass of fluorinated GHG f emitted from process vent } v \text{ from process } i \text{, operating scenario } j, \text{ for the year considering destruction efficiency (kg).} \]

\[ ECF_{PV} = \text{Emission calculation factor for fluorinated GHG f emitted from process vent } v \text{ during process } i \text{, operating scenario } j, \text{ (e.g., kg emitted/kg product).} \]

\[ \text{Activity}_U = \text{Total process feed, process production, or other process activity for process } i, \text{ operating scenario } j, \text{ during the year for which the process vent is not vented to the properly functioning destruction device (e.g., kg product).} \]

\[ \text{Activity}_C = \text{Total process feed, process production, or other process activity for process } i, \text{ operating scenario } j, \text{ during the year for which the process vent is vented to the properly functioning destruction device (e.g., kg product).} \]

\[ DE = \text{Demonstrated destruction efficiency of the destruction device (weight fraction).} \]

(v) Sum the emissions of each fluorinated GHG from all process vents in each operating scenario and all operating scenarios in the process for the year to estimate the total process vent emissions of each fluorinated GHG from the process, using Equation L–28 of this section.

\[ E_{pfi} = \sum_{1}^{o} \sum_{1}^{v} E_{PV} \]

where:

\[ E_{pfi} = \text{Mass of fluorinated GHG f emitted from process vents for process } i \text{ for the year (kg).} \]

\[ E_{PV} = \text{Mass of fluorinated GHG f emitted from process vent } v \text{ from process } i \text{, operating scenario } j, \text{ for the year, considering destruction efficiency (kg).} \]

\[ v = \text{Number of process vents in process } i \text{, operating scenario } j. \]

\[ o = \text{Number of operating scenarios in process } i. \]

(d) Calculate fluorinated GHG emissions for equipment leaks (EL). If you comply with paragraph (c) of this section, you must calculate the fluorinated GHG emissions from pieces of equipment associated with processes covered under this subpart and in fluorinated GHG service. If you conduct monitoring of equipment in fluorinated GHG service, monitoring must be conducted for those in light liquid and in gas and vapor service. If you conduct monitoring of equipment in fluorinated GHG service, you may exclude from monitoring each piece of equipment that is difficult-to-monitor, that is unsafe-to-monitor, that is insulated, or that is in heavy liquid service; you may exclude from monitoring each
pump with dual mechanical seals, agitator with dual mechanical seals, pump with no external shaft, agitator with no external shaft; you may exclude from monitoring each pressure relief device in gas and vapor service with upstream rupture disk, each sampling connection system with closed-loop or closed-purge systems, and any pieces of equipment where leaks are routed through a closed vent system to a destruction device. You must estimate emissions using another approach for those pieces of equipment excluded from monitoring. Equipment that is in fluorinated GHG service for less than 300 hr/yr; equipment that is in vacuum service; pressure relief devices that are in light liquid service; and instrumentation systems are exempted from these requirements.

(1) The emissions from equipment leaks must be calculated using any of the procedures in paragraphs (d)(1)(i), (d)(1)(ii), (d)(1)(iii), or (d)(1)(iv) of this section.


(ii) Use of Other Approaches in EPA Protocol for Equipment Leak Emission Estimates in conjunction with EPA Method 21 at 40 CFR part 60, appendix A–7. The emissions from equipment leaks may be calculated using one of the following methods in EPA–453/R–95–017 (incorporated by reference, see §98.7): The Screening Ranges Approach; the EPA Correlation Approach; or the Unit-Specific Correlation Approach. If you determine that EPA Method 21 at 40 CFR part 60, appendix A–7 is appropriate for monitoring a fluorinated GHG or surrogate to use along with these three approaches. The site-specific leak monitoring method must meet the requirements in §98.124(f)(1).

(iii) Use of Other Approaches in EPA Protocol for Equipment Leak Emission Estimates in conjunction with site-specific leak monitoring methods. The emissions from equipment leaks may be calculated using one of the following methods in EPA–453/R–95–017 (incorporated by reference, see §98.7): The Screening Ranges Approach; the EPA Correlation Approach; or the Unit-Specific Correlation Approach. You may develop a site-specific leak monitoring method appropriate for monitoring fluorinated GHGs or surrogates to use along with these three approaches. The site-specific leak monitoring method must meet the requirements in §98.124(f)(1).

(iv) Use of site-specific leak monitoring methods. The emissions from equipment leaks may be calculated using a site-specific leak monitoring method. The site-specific leak monitoring method must meet the requirements in §98.124(f)(1).

(2) You must collect information on the number of each type of equipment; the service of each piece of equipment (gas, light liquid, heavy liquid); the concentration of each fluorinated GHG in the stream; and the time period each piece of equipment was in service. Depending on which approach you follow, you may be required to collect information for equipment on the associated screening data concentrations for greater than or equal to 10,000 ppmv and associated screening data concentrations for less than 10,000 ppmv; associated actual screening data concentrations; or associated screening data and leak rate data (i.e., bagging) used to develop a unit-specific correlation.

(3) Calculate and sum the emissions of each fluorinated GHG in metric tons per year for equipment pieces for each process, \( E_{\text{fl}} \), annually. You must include and estimate emissions for types of equipment that are excluded from monitoring, including difficult-to-monitor, unsafe-to-monitor and insulated pieces of equipment, pieces of equipment in heavy liquid service, pumps
with dual mechanical seals, agitators with dual mechanical seals, pumps with no external shaft, agitators with no external shaft, pressure relief devices in gas and vapor service with upstream rupture disk, sampling connection systems with closed-loop or closed purge systems, and pieces of equipment where leaks are routed through a closed vent system to a destruction device.

(e) Calculate total fluorinated GHG emissions for each process and for production or transformation processes at the facility.

(i) Estimate annually the total mass of each fluorinated GHG emitted from each process, including emissions from process vents in paragraphs (c)(3) and (c)(4) of this section, as appropriate, and from equipment leaks in paragraph (d), using Equation L-29 of this section.

\[ E_i = E_{P,i} + E_{E,i} \]  
\(\text{(Eq. L-29)}\)

where:

- \(E_i\) = Total mass of each fluorinated GHG \(f\) emitted from process \(i\), annual basis (kg/year).
- \(E_{P,i}\) = Mass of fluorinated GHG \(f\) emitted from all process vents and all operating scenarios in process \(i\), annually (kg/year, calculated in Equation L-24 or L-28 of this section, as appropriate).
- \(E_{E,i}\) = Mass of fluorinated GHG \(f\) emitted from equipment leaks for pieces of equipment for process \(i\), annually (kg/year, calculated in paragraph (d)(3) of this section).

(ii) Estimate annually the total mass of each fluorinated GHG emitted from each type of production or transformation process at the facility using Equation L-30 of this section. Develop separate totals for fluorinated gas production processes, transformation processes that transform fluorinated gases produced at the facility, and transformation processes that transform fluorinated gases produced at another facility.

\[ E = \sum_{i=1}^{z} E_i \times 0.001 \]  
\(\text{(Eq. L-30)}\)

where:

- \(E\) = Total mass of each fluorinated GHG \(f\) emitted from all fluorinated gas production processes, all transformation processes that transform fluorinated gases produced at the facility, or all transformation processes that transform fluorinated gases produced at another facility, as appropriate (metric tons).
- \(E_i\) = Total mass of each fluorinated GHG \(f\) emitted from each production or transformation process, annual basis (kg/year, calculated in Equation L-29 of this section).
- 0.001 = Conversion factor from kg to metric tons.
- \(z\) = Total number of fluorinated gas production processes, fluorinated gas transformation processes that transform fluorinated gases produced at the facility, or transformation processes that transform fluorinated gases produced at another facility, as appropriate.

(f) Calculate fluorinated GHG emissions from destruction of fluorinated GHGs that were previously “produced”. Estimate annually the total mass of fluorinated GHGs emitted from destruction of fluorinated GHGs that were previously “produced” as defined at §98.410(b) using Equation L-31 of this section:

\[ E_D = R E_D \times (1 - DE) \]  
\(\text{(Eq. L-31)}\)
where:

\( E_D \) = The mass of fluorinated GHGs emitted annually from destruction of fluorinated GHGs that were previously “produced” as defined at § 98.410(b) (metric tons).

\( R_{Ed} \) = The mass of fluorinated GHGs that were previously “produced” as defined at § 98.410(b) and that are fed annually into the destruction device (metric tons).

\( DE \) = Destruction efficiency of the destruction device (fraction).

(g) Emissions from venting of residual fluorinated GHGs in containers. If you vent residual fluorinated GHGs from containers, you must either measure the residual fluorinated GHGs vented from each container or develop a heel factor for each combination of fluorinated GHG, container size, and container type that you vent. You do not need to estimate de minimis emissions associated with good-faith attempts to recycle or recover residual fluorinated GHGs in or from containers.

(1) Measuring contents of each container. If you weigh or otherwise measure the contents of each container before venting the residual fluorinated GHGs, use Equation L–32 of this section to calculate annual emissions of each fluorinated GHG from venting of residual fluorinated GHG from containers. Convert pressures to masses as directed in paragraph (g)(2)(ii) of this section.

\[
E_{CF} = \sum_{f=1}^{n} H_{Bf} - \sum_{f=1}^{n} H_{Ef} \quad \text{(Eq. L–32)}
\]

where:

\( E_{CF} \) = Total mass of each fluorinated GHG \( f \) emitted from the facility through venting of residual fluorinated GHG from containers, annual basis (kg/year).

\( H_{Bf} \) = Mass of residual fluorinated GHG \( f \) in container \( j \) when received by facility.

\( H_{Ef} \) = Mass of residual fluorinated GHG \( f \) in container \( j \) after evacuation by facility. (Facility may equate to zero.)

\( n \) = Number of vented containers for each fluorinated GHG \( f \).

(2) Developing and applying heel factors. If you use heel factors to estimate emissions of residual fluorinated GHGs vented from containers, you must annually develop these factors based on representative samples of the containers received by your facility from fluorinated GHG users.

(i) Sample size. For each combination of fluorinated GHG, container size, and container type that you vent, select a representative sample of containers that reflects the full range of quantities of residual gas returned in that container size and type. This sample must reflect the full range of the industries and a broad range of the customers that use and return the fluorinated GHG, container size, and container type. The minimum sample size for each combination of fluorinated GHG, container size, and container type must be 30, unless this is greater than the number of containers returned within that combination annually, in which case the contents of every container returned must be measured.

(ii) Measurement of residual gas. The residual weight or pressure you use for paragraph (g)(1) of this section must be determined by monitoring the mass or the pressure of your cylinders/containers according to § 98.124(k). If you monitor the pressure, convert the pressure to mass using the ideal gas law, as displayed in Equation L–33 of this section, with an appropriately selected \( Z \) value.

\[
pV = ZnRT \quad \text{(Eq. L–33)}
\]

where:

\( p \) = Absolute pressure of the gas (Pa)

\( V \) = Volume of the gas (m³)

\( Z \) = Compressibility factor
(iii) Heel factor calculation. To determine the heel factor $h_{fj}$ for each combination of fluorinated GHG, container size, and container type, use paragraph (g)(1) of this section to calculate the total heel emissions for each sample selected under paragraph (g)(2)(i) of this section. Divide this total by the number of containers in the sample. Divide the result by the full capacity (the mass of the contents of a full container) of that combination of fluorinated GHG, container size, and container type. The heel factor is expressed as a fraction of the full capacity.

(iv) Calculate annual emissions of each fluorinated GHG from venting of residual fluorinated GHG from containers using Equation L–34 of this section.

$$E_{Cf} = \sum_{j=1}^{n} h_{fj} \cdot N_{fj} \cdot F_{fj} \quad \text{(Eq. L–34)}$$

where:
- $E_{Cf}$ = Total mass of each fluorinated GHG $f$ emitted from the facility through venting of residual fluorinated GHG from containers, annual basis (kg/year).
- $h_{fj}$ = Facility-wide gas-specific heel factor for fluorinated GHG $f$ (fraction) and container size and type $j$, as determined in paragraph (g)(2)(iii) of this section.
- $N_{fj}$ = Number of containers of size and type $j$ returned to the fluorinated gas production facility.
- $F_{fj}$ = Full capacity of containers of size and type $j$ containing fluorinated GHG $f$ (kg).
- $n$ = Number of combinations of container sizes and types for fluorinated GHG $f$.

§98.124 Monitoring and QA/QC requirements.

(a) Initial scoping speciation to identify fluorinated GHGs. You must conduct an initial scoping speciation to identify all fluorinated GHGs that may be generated from processes that are subject to this subpart and that have at least one process vent with uncontrolled emissions of 1.0 metric ton or more of fluorinated GHGs per year based on the preliminary estimate of emissions in §98.123(c)(1). You are not required to quantify emissions under this initial scoping speciation. Only fluorinated GHG products and by-products that occur in greater than trace concentrations in at least one stream must be identified under this paragraph.

(1) Procedure. To conduct the scoping speciation, select the stream(s) (including process streams or destroyed streams) or process vent(s) that would be expected to individually or collectively contain all of the fluorinated GHG by-products of the process at their maximum concentrations and sample and analyze the contents of these selected streams or process vents. For example, if fluorinated GHG by-products are separated into one low-boiling-point and one high-boiling-point stream, sample and analyze both of these streams. Alternatively, you may sample and analyze streams where fluorinated GHG by-products occur at less than their maximum concentrations, but you must ensure that the sensitivity of the analysis is sufficient to compensate for the expected difference in concentration. For example, if you sample and analyze streams where fluorinated GHG by-products are expected to occur at one half their maximum concentrations elsewhere in the process, you must ensure that the sensitivity of the analysis is sufficient to detect fluorinated GHG by-products that occur at concentrations of 0.05 percent or higher. You do not have to sample and analyze every stream or process vent, i.e., you do not have to sample and analyze a stream or process vent that contains only fluorinated GHGs that are contained in other streams or process vents that are being sampled and analyzed. Sampling and analysis must be conducted according to the procedures in paragraph (e) of this section.

(2) Previous measurements. If you have conducted testing of streams (including process streams or destroyed
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streams) or process vents less than 10 years before December 31, 2010, and the testing meets the requirements in paragraph (a)(1) of this section, you may use the previous testing to satisfy this requirement.

(b) Mass balance monitoring. If you determine fluorinated GHG emissions from any process using the mass balance method under §98.123(b), you must estimate the total mass of each fluorinated GHG emitted from that process at least monthly. Only streams that contain greater than trace concentrations of fluorine-containing reactants, products, or by-products must be monitored under this paragraph. If you use an element other than fluorine in the mass-balance equation pursuant to §98.123(b)(3), substitute that element for fluorine in the monitoring requirements of this paragraph.

(1) Mass measurements. Measure the following masses on a monthly or more frequent basis using flowmeters, weigh scales, or a combination of volumetric and density measurements with accuracies and precisions that allow the facility to meet the error criteria in §98.123(b)(1):

(i) Total mass of each fluorine-containing product produced. Account for any used fluorine-containing product added into the production process upstream of the output measurement as directed at §98.413(b) and §98.414(b). For each product, the mass produced used for the mass-balance calculation must be the same as the mass produced that is reported under subpart OO of this part, where applicable.

(ii) Total mass of each fluorine-containing reactant fed into the process.

(iii) The mass removed from the process in each stream fed into the destruction device.

(iv) The mass removed from the process in each recaptured stream.

(2) Concentration measurements for use with §98.123(b)(4). If you use §98.123(b)(4) to estimate the mass of fluorine in destroyed or recaptured streams, measure the following concentrations at least once each calendar month during which the process is operating, on a schedule to ensure that the measurements are representative of the full range of process conditions (e.g., catalyst age). Measure more frequently if this is necessary to meet the error criteria in §98.123(b)(1). Use equipment and methods (e.g., gas chromatography) that comply with paragraph (e) of this section and that have an accuracy and precision that allow the facility to meet the error criteria in §98.123(b)(1). Only fluorine-containing reactants, products, and by-products that occur in a stream in greater than trace concentrations must be monitored under this paragraph.

(i) The concentration (mass fraction) of each fluorine-containing by-product in each stream that is fed into the destruction device.

(ii) The concentration (mass fraction) of each fluorine-containing by-product in each stream that is recaptured (C_BK).

(3) Concentration measurements for use with §98.123(b)(15). If you use §98.123(b)(15) to estimate the mass of fluorine in destroyed or recaptured streams, measure the concentrations listed in paragraphs (3)(i) and (ii) of this section at least once each calendar month during which the process is operating, on a schedule to ensure that the measurements are representative of the full range of process conditions (e.g., catalyst age). Measure more frequently if this is necessary to meet the error criteria in §98.123(b)(1). Use equipment and methods (e.g., gas chromatography) that comply with paragraph (e) of this section and that have an accuracy and precision that allow the facility to meet the error criteria in §98.123(b)(1). Only fluorine-containing reactants, products, and by-products that occur in a stream in greater than trace concentrations must be monitored under this paragraph.

(i) The concentration (mass fraction) of total fluorine in each stream that is fed into the destruction device.

(ii) The concentration (mass fraction) of total fluorine in each stream that is recaptured.
(4) Emissions characterization: process vents emitting 25,000 metric tons CO₂e or more. To characterize emissions from any process vent emitting 25,000 metric tons CO₂e or more, comply with paragraphs (b)(4)(i) through (b)(4)(v) of this section, as appropriate. Only fluorine-containing reactants, products, and byproducts that occur in a stream in greater than trace concentrations must be monitored under this paragraph.

(i) Uncontrolled emissions. If emissions from the process vent are not routed through a destruction device, sample and analyze emissions at the process vent or stack or sample and analyze emitted streams before the process vent. If the process has more than one operating scenario, you must either perform the emission characterization for each operating scenario or perform the emission characterization for the operating scenario that is expected to have the largest emissions and adjust the emission characterization for other scenarios using engineering calculations and assessments as specified in §98.123(c)(4). To perform the characterization, take three samples under conditions that are representative for the operating scenario. Measure the concentration of each fluorine-containing compound in each sample. Use equipment and methods that comply with paragraph (e) of this section. Calculate the average concentration of each fluorine-containing compound across all three samples.

(ii) Controlled emissions using §98.123(b)(15). If you use §98.123(b)(15) to estimate the total mass of fluorine in destroyed or recaptured streams, and if the emissions from the process vent are routed through a destruction device, characterize emissions as specified in paragraph (b)(4)(i) of this section before the destruction device. Apply the destruction efficiency demonstrated for each fluorinated GHG in the destroyed stream to that fluorinated GHG. Exclude from the characterization fluorine-containing compounds that are not fluorinated GHGs.

(iii) Controlled emissions using §98.123(b)(4). If you use §98.123(b)(4) to estimate the mass of fluorine in destroyed or recaptured streams, and if the emissions from the process vent are routed through a destruction device, characterize the process vent’s emissions monthly (or more frequently) using the monthly (or more frequent) measurements under paragraphs (b)(1)(iii) and (b)(2)(i) through (b)(2)(iii) of this section. Apply the destruction efficiency demonstrated for each fluorinated GHG in the destroyed stream to that fluorinated GHG. Exclude from the characterization fluorine-containing compounds that are not fluorinated GHGs.

(iv) Emissions characterization frequency. You must repeat emission characterizations performed under paragraph (b)(4)(i) and (b)(4)(ii) of this section under paragraph (b)(4)(iv)(A) or (b)(4)(iv)(B) of this section, whichever occurs first:

(A) 10-year revision. Repeat the emission characterization every 10 years. In the calculations under §98.123, apply the revised emission characterization to the process activity that occurs after the revision.

(B) Operating scenario change that affects the emission characterization. For planned operating scenario changes, you must estimate and compare the emission calculation factors for the changed operating scenario and for the original operating scenario whose process vent specific emission factor was measured. Use the engineering calculations and assessments specified in §98.123(c)(4). If the share of total fluorine-containing compound emissions represented by any fluorinated GHG changes under the changed operating scenario by 15 percent or more of the total, relative to the previous operating scenario (this includes the cumulative change in the emission calculation factor since the last emissions test), you must repeat the emission characterization. Perform the emission characterization before February 28 of the year that immediately follows the change. In the calculations under §98.123, apply the revised emission characterization to the process activity that occurs after the operating scenario change.

(v) Subsequent measurements. If a process vent with fluorinated GHG emissions less than 25,000 metric tons CO₂e, per §98.123(c)(2), is later found to have fluorinated GHG emissions of 25,000 metric tons CO₂e or greater, you must
perform an emission characterization under this paragraph during the following year.

(5) Emissions characterization: process vents emitting less than 25,000 metric tons CO\textsubscript{2}e. To characterize emissions from any process vent emitting less than 25,000 metric tons CO\textsubscript{2}e, comply with paragraphs (b)(5)(i) through (b)(5)(iii) of this section, as appropriate. Only fluorine-containing reactants, products, and by-products that occur in a stream in greater than trace concentrations must be monitored under this paragraph.

(i) Uncontrolled emissions. If emissions from the process vent are not routed through a destruction device, emission measurements must consist of sampling and analysis of emissions at the process vent or stack, sampling and analysis of emitted streams before the process vent, previous test results, provided the tests are representative of current operating conditions of the process, or bench-scale or pilot-scale test data representative of the process operating conditions.

(ii) Controlled emissions using § 98.123(b)(15). If you use § 98.123(b)(15) to estimate the total mass of fluorine in destroyed or recaptured streams, and if the emissions from the process vent are routed through a destruction device, characterize emissions as specified in paragraph (b)(5)(i) of this section before the destruction device. Apply the destruction efficiency demonstrated for each fluorinated GHG in the destroyed stream to that fluorinated GHG. Exclude from the characterization fluorine-containing compounds that are not fluorinated GHGs.

(iii) Controlled emissions using § 98.123(b)(4). If you use § 98.123(b)(4) to estimate the mass of fluorine in destroyed or recaptured streams, and if the emissions from the process vent are routed through a destruction device, characterize the process vent’s emissions monthly (or more frequently) using the monthly (or more frequent) measurements under paragraphs (b)(1)(iii) and (b)(2)(i) through (b)(2)(iii) of this section. Apply the destruction efficiency demonstrated for each fluorinated GHG in the destroyed stream to that fluorinated GHG. Exclude from the characterization fluorine-containing compounds that are not fluorinated GHGs.

(6) Emissions characterization: emissions not accounted for by process vent estimates. Calculate the weighted average emission characterization across the process vents before any destruction devices. Apply the weighted average emission characterization for all the process vents to any fluorine emissions that are not accounted for by process vent estimates.

(7) Impurities in reactants. If any fluorine-containing impurity is fed into a process along with a reactant (or other input) in greater than trace concentrations, this impurity shall be monitored under this section and included in the calculations under § 98.123 in the same manner as reactants fed into the process, fed into the destruction device, recaptured, or emitted, except the concentration of the impurity in the mass fed into the process shall be measured, and the mass of the impurity fed into the process shall be calculated as the product of the concentration of the impurity and the mass fed into the process. The mass of the reactant fed into the process may be reduced to account for the mass of the impurity.

(8) Alternative to error calculation. As an alternative to calculating the relative and absolute errors associated with the estimate of emissions under § 98.123(b), you may comply with the precision, accuracy, measurement and calculation frequency, and fluorinated GHG throughput requirements of paragraph (b)(8)(i) through (b)(8)(iv) of this section.

(i) Mass measurements. Measure the masses specified in paragraph (b)(1) of this section using flowmeters, weigh scales, or a combination of volumetric and density measurements with accuracies and precisions of ±0.2 percent of full scale or better.

(ii) Concentration measurements. Measure the concentrations specified in paragraph (b)(2) or paragraph (b)(3) of this section, as applicable, using analytical methods with accuracies and precisions of ±10 percent or better.

(iii) Measurement and calculation frequency. Perform the mass measurements specified in paragraph (b)(1) of this section and the concentration measurements specified in paragraph
(b)(2) or paragraph (b)(3) of this section, as applicable, at least weekly, and calculate emissions at least weekly.

(iv) Fluorinated-GHG throughput limit. You may use the alternative to the error calculation specified in paragraph (b)(8) of this section only if the total annual CO_{2}-equivalent fluorinated GHG throughput of the process is 500,000 mtCO_{2}e or less. The total throughput is the sum of the masses of the fluorinated GHG reactants, products, and by-products fed into and generated by the process. To convert these masses to CO_{2}e, use Equation A–1 of §98.2. For fluorinated GHGs whose GWPs are not listed in Table A–1 to subpart A of this part, use a default GWP of 2,000.

(c) Emission factor testing. If you determine fluorinated GHG emissions using the site-specific process-vent-specific emission factor, you must meet the requirements in paragraphs (c)(1) through (c)(8) of this section.

(1) Process vent testing. Conduct an emissions test that is based on representative performance of the process or operating scenario(s) of the process, as applicable. Include in the emission test any fluorinated greenhouse gas that occurs in more than trace concentrations in the vent stream or, where a destruction device is used, in the inlet to the destruction device. You may include startup and shutdown events if the testing is sufficiently long or comprehensive to ensure that such events are not overrepresented in the emission factor. Malfunction events must not be included in the testing. If you conduct your emission testing after a destruction device, and if the outlet concentration of a fluorinated GHG that is fed into the device is below the detection limit of the method, you may use a concentration of one-half the detection limit to estimate the emission factor.

(2) Number of runs. For continuous processes, sample the process vent for a minimum of 3 runs of 1 hour each. If the RSD of the emission factor calculated based on the first 3 runs is greater than or equal to 0.15 for the emission factor, continue to sample the process vent for an additional 3 runs of 1 hour each. If more than one fluorinated GHG is measured, the RSD must be expressed in terms of total CO_{2} equivalents. For fluorinated GHGs whose GWPs are not listed in Table A–1 to subpart A of this part, use a default GWP of 2,000 in the RSD calculation.

(3) Process activity measurements. Determine the mass rate of process feed, process production, or other process activity as applicable during the test using flow meters, weigh scales, or other measurement devices or instruments with an accuracy and precision of ±1 percent of full scale or better. These devices may be the same plant instruments or procedures that are used for accounting purposes (such as weigh hoppers, belt weigh feeders, combination of volume measurements and bulk density, etc.) if these devices or procedures meet the requirement. For monitoring ongoing process activity, use flow meters, weigh scales, or other measurement devices or instruments with an accuracy and precision of ±1 percent of full scale or better.

(4) Sample each process. If process vents from separate processes are manifolded together to a common vent or to a common destruction device, you must follow paragraph (c)(4)(i), (c)(4)(ii), or (c)(4)(iii) of this section.

(i) You may sample emissions from each process in the ducts before the emissions are combined.

(ii) You may sample in the common duct or at the outlet of the destruction device when only one process is operating.

(iii) You may sample the combined emissions and use engineering calculations and assessments as specified in §98.123(c)(4) to allocate the emissions to each manifolded process vent, provided the sum of the calculated fluorinated GHG emissions across the individual process vents is within 20 percent of the total fluorinated GHG emissions measured during the manifolded testing.

(5) Emission test results. The results of an emission test must include the analysis of samples, number of test runs, the results of the RSD analysis, the analytical method used, determination of emissions, the process activity, and raw data and must identify the process, the operating scenario, the process vents tested, and the fluorinated GHGs.
that were included in the test (i.e., the fluorinated GHGs that occur in more than trace concentrations in the vent stream or, where a destruction device is used, in the inlet to the destruction device, and any other fluorinated GHGs included in the test). The emissions test report must contain all information and data used to derive the process-vent-specific emission factor, as well as key process conditions during the test. Key process conditions include those that are normally monitored for process control purposes and may include but are not limited to yields, pressures, temperatures, etc. (e.g., of reactor vessels, distillation columns).

(7) Emissions testing frequency. You must conduct emissions testing to develop the process-vent-specific emission factor under paragraph (c)(7)(i) or (c)(7)(ii) of this section, whichever occurs first:

(i) 10-year revision. Conduct an emissions test every 10 years. In the calculations under §98.123, apply the revised process-vent-specific emission factor to the process activity that occurs after the revision.

(ii) Operating scenario change that affects the emission factor. For planned operating scenario changes, you must estimate and compare the emission calculation factors for the changed operating scenario and for the original operating scenario whose process vent specific emission factor was measured. Use the calculation methods in §98.123(c)(4). If the emission calculation factor for the changed operating scenario is 15 percent or more different from the emission calculation factor for the previous operating scenario (this includes the cumulative change in the emission calculation factor since the last emissions test), you must conduct an emissions test to update the process-vent-specific emission factor, unless the difference between the operating scenarios is solely due to the application of a destruction device to emissions under the changed operating scenario. Conduct the test before February 28 of the year that immediately follows the change. In the calculations under §98.123, apply the revised process-vent-specific emission factor to the process activity that occurs after the operating scenario change.

(8) Subsequent measurements. If a continuous process vent with fluorinated GHG emissions less than 10,000 metric tons CO₂e, per §98.123(c)(2), is later found to have fluorinated GHG emissions of 10,000 metric tons CO₂e or greater, you must conduct the emissions testing for the process vent during the following year and develop the process-vent-specific emission factor from the emissions testing.

(9) Previous measurements. If you have conducted an emissions test less than 10 years before December 31, 2010, and the emissions testing meets the requirements in paragraphs (c)(1) through (c)(8) of this section, you may use the previous emissions testing to develop process-vent-specific emission factors. For purposes of paragraph (c)(7)(i) of this section, the date of the previous emissions test rather than December 31, 2010 shall constitute the beginning of the 10-year re-measurement cycle.

(d) Emission calculation factor monitoring. If you determine fluorinated GHG emissions using the site-specific process-vent-specific emission calculation factor, you must meet the requirements in paragraphs (d)(1) through (d)(4) of this section.

(1) Operating scenario. Perform the emissions calculation for the process vent based on representative performance of the operating scenario of the process. If more than one operating scenario applies to the process that contains the subject process vent, you must conduct a separate emissions calculation for operation under each operating scenario. For each continuous process vent that contains more than trace concentrations of any fluorinated GHG and for each batch process vent, develop the process-vent-specific emission calculation factor for each operating scenario. For continuous process vents, determine the emissions based on the process activity for the representative performance of the operating scenario. For batch process vents, determine emissions based on the process activity for each typical batch operating scenario.
(2) Process activity measurements. Use flow meters, weigh scales, or other measurement devices or instruments with an accuracy and precision of ±1 percent of full scale or better for monitoring ongoing process activity.

(3) Emission calculation results. The emission calculation must be documented by identifying the process, the operating scenario, and the process vents. The documentation must contain the information and data used to calculate the process-vent-specific emission calculation factor.

(4) Operating scenario change that affects the emission calculation factor. For planned operating scenario changes that are expected to change the process-vent-specific emission calculation factor, you must conduct an emissions calculation to update the process-vent-specific emission calculation factor. In the calculations under §98.123, apply the revised emission calculation factor to the process activity that occurs after the operating scenario change.

(5) Previous calculations. If you have performed an emissions calculation for the process vent and operating scenario less than 10 years before December 31, 2010, and the emissions calculation meets the requirements in paragraphs (d)(1) through (d)(4) of this section and in §98.123(c)(4)(i) and (c)(4)(ii), you may use the previous calculation to develop the site-specific process-vent-specific emission calculation factor.

(e) Emission and stream testing, including analytical methods. Select and document testing and analytical methods as follows:

(1) Sampling and mass measurement for emission testing. For emission testing in process vents or at the stack, use methods for sampling, measuring volumetric flow rates, non-fluorinated-GHG gas analysis, and measuring stack gas moisture that have been validated using a scientifically sound validation protocol.

(ii) Sample and velocity traverses. Acceptable methods include but are not limited to EPA Method 1 or 1A in Appendix A–1 of 40 CFR part 60.

(ii) Velocity and volumetric flow rates. Acceptable methods include but are not limited to EPA Method 2, 2A, 2B, 2C, 2D, 2F, or 2G in Appendix A–1 of 40 CFR part 60. Alternatives that may be used for determining flow rates include OTM-24 (incorporated by reference, see §98.7) and ALT-012 (incorporated by reference, see §98.7).

(iii) Non-fluorinated-GHG gas analysis. Acceptable methods include but are not limited to EPA Method 3, 3A, or 3B in Appendix A–1 of 40 CFR part 60.

(iv) Stack gas moisture. Acceptable methods include but are not limited to EPA Method 4 in Appendix A–1 of 40 CFR part 60.

(2) Analytical methods. Use a quality-assured analytical measurement technology capable of detecting the analyte of interest at the concentration of interest and use a sampling and analytical procedure validated with the analyte of interest at the concentration of interest. Where calibration standards for the analyte are not available, a chemically similar surrogate may be used. Acceptable analytical measurement technologies include but are not limited to gas chromatography (GC) with an appropriate detector, infrared (IR), fourier transform infrared (FTIR), and nuclear magnetic resonance (NMR). Acceptable methods for determining fluorinated GHGs include EPA Method 18 in appendix A–1 of 40 CFR part 60, EPA Method 320 in appendix A–1 of 40 CFR part 63, EPA Method 301 at 40 CFR part 63, appendix A or some other scientifically sound validation protocol. Acceptable methods for determining total fluorine concentrations for fluorine-containing compounds in streams under paragraph (b)(3) of this section include ASTM D7359–08 (incorporated by reference, see §98.7), ASTM D6846–03 (incorporated by reference, see §98.7), or other analytical methods validated using EPA Method 301 at 40 CFR part 63, appendix A or some other scientifically sound validation protocol. The validation protocol may include analytical technology manufacturer specifications or recommendations.

(3) Documentation in GHG Monitoring Plan. Describe the sampling, measurement, and analytical method(s) used under paragraphs (e)(1) and (e)(2) of this section in the GHG Monitoring
Plan as required under §98.3(g)(5). Identify the methods used to obtain the samples and measurements listed under paragraphs (e)(1)(i) through (e)(1)(iv) of this section. At a minimum, include in the description of the analytical method a description of the analytical measurement equipment and procedures, quantitative estimates of the method’s accuracy and precision for the analytes of interest at the concentrations of interest, as well as a description of the validation protocol used.

(f) Emission monitoring for pieces of equipment. If you conduct a site-specific leak detection method or monitoring approach for pieces of equipment, follow paragraph (f)(1) or (f)(2) of this section and follow paragraph (f)(3) of this section.

(1) Site-specific leak monitoring approach. You may develop a site-specific leak monitoring approach. You must validate the leak monitoring method and describe the method and the validation in the GHG Monitoring Plan. To validate the site-specific method, you may, for example, release a known rate of the fluorinated GHGs or surrogates of interest, or you may compare the results of the site-specific method to those of a method that has been validated for the fluorinated GHGs or surrogates of interest. In the description of the leak detection method and its validation, include a detailed description of the method, including the procedures and equipment used and any sampling strategies. Also include the rationale behind the method, including why the method is expected to result in an unbiased estimate of emissions from equipment leaks. If the method is based on methods that are used to detect or quantify leaks or other emissions in other regulations, standards, or guidelines, identify and describe the regulations, standards, or guidelines and why their methods are applicable to emissions of fluorinated GHGs or surrogates from leaks. Account for possible sources of error in the method, e.g., instrument detection limits, measurement biases, and sampling biases. Describe validation efforts, including but not limited to any comparisons against standard leaks or concentrations, any comparisons against other methods, and their results. If you use the Screening Ranges Approach, the EPA Correlation Approach, or the Unit-Specific Correlation Approach with a monitoring instrument that does not meet all of the specifications in EPA Method 21 at 40 CFR part 60, appendix A–7, then explain how and why the monitoring instrument, as used at your facility, would nevertheless be expected to accurately detect and quantify emissions of fluorinated GHGs or surrogates from process equipment, and describe how you verified its accuracy. For all methods, provide a quantitative estimate of the accuracy and precision of the method.

(2) EPA Method 21 monitoring. If you determine that EPA Method 21 at 40 CFR part 60, appendix A–7 is appropriate for monitoring a fluorinated GHG, conduct the screening value concentration measurements using EPA Method 21 at 40 CFR part 60, appendix A–7 to determine the screening range data or the actual screening value data for the Screening Ranges Approach, EPA Correlation Approach, or the Unit-Specific Correlation Approach. For the one-time testing to develop the Unit-Specific Correlation equations in EPA-453/R-95-017 (incorporated by reference, see §98.7), conduct the screening value concentration measurements using EPA Method 21 at 40 CFR part 60, appendix A–7 and the bagging procedures to measure mass emissions. Concentration measurements of bagged samples must be conducted using gas chromatography following EPA Method 18 analytical procedures or other method according to §98.124(e). Use methane or other appropriate compound as the calibration gas.

(3) Frequency of measurement and sampling. If you estimate emissions based on monitoring of equipment, conduct monitoring at least annually. Sample at least one-third of equipment annually (except for equipment that is unsafe-to-monitor, difficult-to-monitor, insulated, or in heavy liquid service, pumps with dual mechanical seals, agitators with dual mechanical seals, pumps with no external shaft, agitators with no external shaft, pressure relief devices in gas and vapor service.
with an upstream rupture disk, sampling connection systems with closed-loop or closed purge systems, and pieces of equipment whose leaks are routed through a closed vent system to a destruction device, changing the sample each year such that at the end of three years, all equipment in the process has been monitored. If you estimate emissions based on a sample of the equipment in the process, ensure that the sample is representative of the equipment in the process. If you have multiple processes that have similar types of equipment in similar service, and that produce or transform similar fluorinated GHGs (in terms of chemical composition, molecular weight, and vapor pressure) at similar pressures and concentrations, then you may annually sample all of the equipment in one third of these processes rather than one third of the equipment in each process.

(g) Destruction device performance testing. If you vent or otherwise feed fluorinated GHGs into a destruction device and apply the destruction efficiency of the device to one or more fluorinated GHGs in §98.123, you must conduct emissions testing to determine the destruction efficiency for each fluorinated GHG to which you apply the destruction efficiency. You must either determine the destruction efficiency for the most-difficult-to-destroy fluorinated GHG fed into the device (or a surrogate that is still more difficult to destroy) and apply that destruction efficiency to all the fluorinated GHGs fed into the device or alternatively determine different destruction efficiencies for different groups of fluorinated GHGs using the most-difficult-to-destroy fluorinated GHG of each group (or a surrogate that is still more difficult to destroy).

(1) Destruction efficiency testing. You must sample the inlet and outlet of the destruction device for a minimum of three runs of 1 hour each to determine the destruction efficiency. You must conduct the emissions testing using the methods in paragraph (e) of this section. To determine the destruction efficiency, emission testing must be conducted when operating at high loads reasonably expected to occur (i.e., representative of high total fluorinated GHG load that will be sent to the device) and when destroying the most-difficult-to-destroy fluorinated GHG (or a surrogate that is still more difficult to destroy) that is fed into the device from the processes subject to this subpart or that belongs to the group of fluorinated GHGs for which you wish to establish a DE. If the outlet concentration of a fluorinated GHG that is fed into the device is below the detection limit of the method, you may use a concentration of one-half the detection limit to estimate the destruction efficiency.

(i) If perfluoromethane (CF\(_4\)) is vented to the destruction device in any stream in more than trace concentrations, you must test and determine the destruction efficiency achieved specifically for CF\(_4\) to take credit for the CF\(_4\) emissions reduction.

(ii) If sulfur hexafluoride (SF\(_6\)) is vented to the destruction device in any stream in more than trace concentrations, you must test and determine the destruction efficiency achieved specifically for SF\(_6\), or alternatively for CF\(_4\) as a surrogate, to take credit for the SF\(_6\) emissions reduction.

(iii) If saturated perfluorocarbons other than CF\(_4\) are vented to the destruction device in any stream in more than trace concentrations, you must test and determine the destruction efficiency achieved for the lowest molecular weight saturated perfluorocarbon fed into the device, or alternatively for a lower molecular weight saturated PFC or SF\(_6\) as a surrogate, to take credit for the PFC emission reduction.

(iv) For all other fluorinated GHGs that are vented to the destruction device in any stream in more than trace concentrations, you must test and determine the destruction efficiency achieved for the most-difficult-to-destroy fluorinated GHG or surrogate vented to the destruction device. Examples of acceptable surrogates include the Class 1 compounds (ranked 1 through 34) in Appendix D, Table D-1 of “Guidance on Setting Permit Conditions and Reporting Trial Burn Results; Volume II of the Hazardous Waste Incineration Guidance Series,” January 1989, EPA Publication EPA 625/6-89/019. You can obtain a copy of

(2) Destruction efficiency testing frequency. You must conduct emissions testing to determine the destruction efficiency as provided in paragraphs (g)(2)(i) or (ii) of this section, whichever occurs first:

(i) Conduct an emissions test every 10 years. In the calculations under §98.123, apply the updated destruction efficiency to the destruction that occurs after the test.

(ii) Destruction device changes that affect the destruction efficiency. If you make a change to the destruction device that would be expected to affect the destruction efficiency, you must conduct an emissions test to update the destruction efficiency. Conduct the test before the February 28 of the year that immediately follows the change. In the calculations under §98.123, apply the updated destruction efficiency to the destruction that occurs after the change to the device.

(3) Previous testing. If you have conducted an emissions test within the 10 years prior to December 31, 2010, and the emissions testing meets the requirements in paragraph (g)(1) of this section, you may use the destruction efficiency determined during this previous emissions testing. For purposes of paragraph (g)(2)(i) of this section, the date of the previous emissions test rather than December 31, 2010 shall constitute the beginning of the 10-year re-measurement cycle.

(4) Hazardous Waste Combustor testing. If a destruction device used to destroy fluorinated GHG is subject to subpart EEE of part 63 of this chapter or any portion of parts 260–270 of this chapter, you may apply the destruction efficiency specifically determined for CF₃, SF₆, PFCs other than CF₃, and all other fluorinated GHGs under that test if the testing meets the criteria in paragraph (g)(1)(i) through (g)(1)(iv) of this section. If the testing of the destruction efficiency under subpart EEE of part 63 of this chapter was conducted more than 10 years ago, you may use the most recent destruction efficiency test provided that the design, operation, or maintenance of the destruction device has not changed since the last destruction efficiency test in a manner that could affect the ability to achieve the destruction efficiency, and the hazardous waste is fed into the normal flame zone.

(h) Mass of previously produced fluorinated GHGs fed into destruction device. You must measure the mass of each fluorinated GHG that is fed into the destruction device in more than trace concentrations and that was previously produced as defined at §98.410(b). Such fluorinated GHGs include but are not limited to quantities that are shipped to the facility by another facility for destruction and quantities that are returned to the facility for reclamation but are found to be irretrievably contaminated and are therefore destroyed. You must use flowmeters, weigh scales, or a combination of volumetric and density measurements with an accuracy and precision of ±1 percent of full scale or better. If the measured mass includes more than trace concentrations of materials other than the fluorinated GHG being destroyed, you must measure the concentration of the fluorinated GHG being destroyed. You must multiply this concentration (mass fraction) by the mass measurement to obtain the mass of the fluorinated GHG fed into the destruction device.

(i) Emissions due to malfunctions of destruction device. In their estimates of the mass of fluorinated GHG destroyed, fluorinated gas production facilities that destroy fluorinated GHGs must account for any temporary reductions in the destruction efficiency that result from any malfunctions of the destruction device, including periods of operation outside of the operating conditions defined in operating permit requirements and/or destruction device manufacturer specifications.

(j) Emissions due to process startup, shutdown, or malfunctions. Fluorinated GHG production facilities must account for fluorinated GHG emissions that occur as a result of startups, shutdowns, and malfunctions, either recording fluorinated GHG emissions during these events, or documenting that these events do not result in significant fluorinated GHG emissions.
Facilities may use the calculation methods in §98.123(c)(1) to estimate emissions during startups, shutdowns, and malfunctions.

(k) Monitoring for venting residual fluorinated GHG in containers. Measure the residual fluorinated GHG in containers received by the facility either using scales or using pressure and temperature measurements. You may use pressure and temperature measurements only in cases where no liquid fluorinated GHG is present in the container. Scales must have an accuracy and precision of ±1 percent or better of the filled weight (gas plus tare) of the containers of fluorinated GHGs that are typically weighed on the scale. For example, for scales that are generally used to weigh cylinders that contain 115 pounds of gas when full and that have a tare weight of 115 pounds, this equates to ±1 percent of 230 pounds, or ±2.3 pounds. Pressure gauges and thermometers used to measure quantities that are monitored under this paragraph must have an accuracy and precision of ±1 percent of full scale or better.

(l) Initial scoping speciations, emissions testing, emission factor development, emission calculation factor development, emission characterization development, and destruction efficiency determinations must be completed by February 29, 2012 for processes and operating scenarios that operate between December 31, 2010 and December 31, 2011. For other processes and operating scenarios, initial scoping speciations, emissions testing, emission factor development, emission calculation factor development, emission characterization development, and destruction efficiency determinations must be complete by February 28 of the year following the year in which the process or operating scenario commences or recommences.

(m) Calibrate all flow meters, weigh scales, and combinations of volumetric and density measures at the minimum frequency specified by the manufacturer. Use any of the following applicable flow meter test methods or the calibration procedures specified by the flow meter, weigh-scale, or other volumetric or density measure manufacturer.


(n) All analytical equipment used to determine the concentration of fluorinated GHGs, including but not limited to gas chromatographs and associated detectors, infrared (IR), fourier transform infrared (FTIR), and nuclear magnetic resonance (NMR) devices, must be calibrated at a frequency needed to support the type of analysis specified in the GHG Monitoring Plan as required under §98.124(e)(3) and §93.3(g)(5). Quality assurance samples at the concentrations of concern must be used for the calibration. Such quality assurance samples must consist of or be prepared from certified standards of the analytes of
concern where available; if not available, calibration must be performed by a method specified in the GHG Monitoring Plan.

(o) Special provisions for estimating 2011 and subsequent year emissions.

(1) Best available monitoring methods. To estimate emissions that occur from January 1, 2011 through June 30, 2011, owners or operators may use best available monitoring methods for any parameter that cannot reasonably be measured according to the monitoring and QA/QC requirements of this subpart. The owner or operator must use the best available monitoring method for any parameter for which it is not reasonably feasible to acquire, install, or operate a required piece of monitoring equipment, to procure measurement services from necessary providers, or to gain physical access to make required measurements in a facility by January 1, 2011. Starting no later than July 1, 2011, the owner or operator must discontinue using best available methods and begin following all applicable monitoring and QA/QC requirements of this part, except as provided in paragraphs (o)(2) through (o)(4) of this section. Best available monitoring methods means any of the following methods specified in this paragraph:

(i) Monitoring methods currently used by the facility that do not meet the specifications of this subpart.

(ii) Supplier data.

(iii) Engineering calculations or assessments.

(iv) Other company records.

(2) Requests for extension of the use of best available monitoring methods to estimate 2011 emissions: parameters other than scoping specifications, emission factors, and emission characterizations. The owner or operator may submit a request to the Administrator to use one or more best available monitoring methods for parameters other than scoping specifications, emission factors, or emission characterizations to estimate emissions that occur between July 1, 2011 and December 31, 2011.

(i) Timing of request. The extension request must be submitted to EPA no later than February 28, 2011.

(ii) Content of request. Requests must contain the following information:

(A) A list of specific items of monitoring equipment and measurement services for which the request is being made and the locations (e.g., processes and vents) where each piece of monitoring equipment will be installed and where each measurement service will be provided.

(B) Identification of the specific rule requirements for which the monitoring equipment or measurement service is needed.

(C) A description of the reasons why the needed equipment could not be obtained, installed, or operated or why the needed measurement service could not be provided before July 1, 2011. The owner or operator must consider all of the data collection and emission calculation options outlined in the rule for a specific emissions source before claiming that a specific safety, technical, logistical, or legal barrier exists.

(D) If the reason for the extension is that the equipment cannot be purchased, delivered, or installed before July 1, 2011, include supporting documentation such as the date the monitoring equipment was ordered, investigation of alternative suppliers, the dates by which alternative vendors promised delivery or installation, backorder notices or unexpected delays, descriptions of actions taken to expedite delivery or installation, and the current expected date of delivery or installation.

(E) If the reason for the extension is that service providers were unable to provide necessary measurement services, include supporting documentation demonstrating that these services could not be acquired before July 1, 2011. This documentation must include written correspondence to and from at least two service providers stating that they will not be able to provide the necessary services before July 1, 2011.

(F) If the reason for the extension is that the process is operating continuously without process shutdown, include supporting documentation showing that it is not practicable to isolate the process equipment or unit and install the measurement device without a full shutdown or a hot tap, and that there is no opportunity before July 1,
2011 to install the device. Include the date of the three most recent shutdowns for each relevant process equipment or unit, the frequency of shutdowns for each relevant process equipment or unit, and the date of the next planned process equipment or unit shutdown.

(G) If the reason for the extension is that access to process streams, emissions streams, or destroyed streams, as applicable, could not be gained before July 1, 2011 for reasons other than the continuous operation of the process without shutdown, include illustrative documentation such as photographs and engineering diagrams demonstrating that access could not be gained.

(H) A description of the best available monitoring methods that will be used and how their results will be applied (i.e., which calculation method will be used) to develop the emission estimate. Where the proposed best available monitoring method is the use of current monitoring data in the mass-balance approach, include the estimated relative and absolute errors of the mass-balance approach using the current monitoring data.

(I) A description of the specific actions the owner or operator will take to comply with monitoring requirements by January 1, 2012.

(3) Requests for extension of the use of best available monitoring methods to estimate 2011 emissions: scoping speciations, emission factors, and emission characterizations. The owner or operator may submit a request to the Administrator to use one or more best available monitoring methods for scoping speciations, emission factors, and emission characterizations to estimate emissions that occur between July 1, 2011 and December 31, 2011.

(i) Timing of request. The extension request must be submitted to EPA no later than June 30, 2011.

(ii) Content of request. Requests must contain the information outlined in paragraph (o)(2)(ii) of this section, substituting March 1, 2013 for July 1, 2011 and substituting March 1, 2014 for January 1, 2012.

(4) Requests for extension of the use of best available monitoring methods to estimate emissions that occur after 2011. EPA does not anticipate approving the use of best available monitoring methods to estimate emissions that occur beyond December 31, 2011; however, EPA reserves the right to review requests for unique and extreme circumstances which include safety, technical infeasibility, or inconsistency with other local, State or Federal regulations.

(i) Timing of request. The extension request must be submitted to EPA no later than June 30, 2011.

(ii) Content of request. Requests must contain the following information:


(B) A detailed outline of the unique circumstances necessitating an extension, including specific data collection issues that do not meet safety regulations, technical infeasibility or specific laws or regulations that conflict with data collection. The owner or operator must consider all the data collection
and emission calculation options outlined in the rule for a specific emissions source before claiming that a specific safety, technical or legal barrier exists.

(C) A detailed explanation and supporting documentation of how and when the owner or operator will receive the required data and/or services to comply with the reporting requirements of this subpart in the future.

(E) The Administrator reserves the right to require that the owner or operator provide additional documentation.

(iii) Reporting of 2011 and subsequent year emissions using scoping speciations, emission factors, and emission characterizations developed after approval to use best available monitoring methods expires. Facilities that are approved to use best available monitoring methods in 2011 and subsequent years for scoping speciations, emission factors, or emission characterizations for certain processes must submit, by March 31 of the year that begins one year after their approval to use best available monitoring method(s) expires, revised emission estimates for 2011 and subsequent years that reflect the scoping speciations, emission factors, and emission characterizations that are measured for those processes in 2013 or subsequent years. If the operating scenario for 2011 or subsequent years is different from all of the operating scenarios for which emission factors or emission characterizations are developed in 2013 or subsequent years, use Equation L–23 of §98.123(c)(3)(viii) to adjust the emission factor(s) or emission characterization(s) measured for the new operating scenario(s) to account for the differences.

(5) Approval criteria. To obtain approval, the owner or operator must demonstrate to the Administrator’s satisfaction that it is not reasonably feasible to acquire, install, or operate the required piece of monitoring equipment, to procure measurement services from necessary providers, or to gain physical access to make required measurements in a facility according to the requirements of this subpart by the dates specified in paragraphs (o)(2), (3), and (4) of this section for any of the reasons described in paragraph (o)(2)(i) of this section, or, for requests under paragraph (o)(4) of this section, any of the reasons described in paragraph (o)(4)(i)(B) of this section.

§98.125 Procedures for estimating missing data.

(a) A complete record of all measured parameters used in the GHG emissions calculations in §98.123 is required. Therefore, whenever a quality-assured value of a required parameter is unavailable, a substitute data value for the missing parameter must be used in the calculations as specified in the paragraphs (b) and (c) of this section. You must document and keep records of the procedures used for all such estimates.

(b) For each missing value of the fluorinated GHG concentration or fluorine-containing compound concentration, the substitute data value must be the arithmetic average of the quality-assured values of that parameter immediately preceding and immediately following the missing data incident.

(c) For each missing value of the mass produced, fed into the production process, fed into the transformation process, or fed into destruction devices, the substitute value of that parameter must be a secondary mass measurement where such a measurement is available. For example, if the mass produced is usually measured with a flowmeter at the inlet to the day tank and that flowmeter fails to meet an accuracy or precision test, malfunctions, or is rendered inoperable, then the mass produced may be estimated by calculating the change in volume in the day tank and multiplying it by the density of the product. Where a secondary mass measurement is not available, the substitute value of the parameter must be an estimate based on a related parameter. For example, if a flowmeter measuring the mass fed into a destruction device is rendered inoperable, then the mass fed into the destruction device may be estimated using the production rate and the previously observed relationship between the production rate and the mass flow rate into the destruction device.

§98.126 Data reporting requirements.

(a) All facilities. In addition to the information required by §98.3(c), you...
must report the information in paragraphs (a)(2) through (a)(6) of this section.

(1) Frequency of reporting under paragraph (a) of this section. The information in paragraphs (a)(2), (5), and (6) of this section must be reported annually. The information in paragraphs (a)(3) and (4) of this section must be reported once by March 31, 2012 for each process and operating scenarios that operates between December 31, 2010 and December 31, 2011. For other processes and operating scenarios, the information in paragraphs (a)(3) and (4) of this section must be reported once by March 31 of the year following the year in which the process or operating scenario commences or recommences.

(2) You must report the total mass in metric tons of each fluorinated GHG emitted from:

(i) Each fluorinated gas production process and all fluorinated gas production processes combined.

(ii) Each fluorinated gas transformation process that is not part of a fluorinated gas production process and all such fluorinated gas transformation processes combined, except report separately fluorinated GHG emissions from transformation processes where a fluorinated GHG reactant is produced at another facility.

(iii) Each fluorinated gas destruction process that is not part of a fluorinated gas production process or a fluorinated gas transformation process and all such fluorinated gas destruction processes combined.

(iv) Venting of residual fluorinated GHGs from containers returned from the field.

(3) The chemical identities of the contents of the stream(s) (including emissions and destroyed streams) analyzed under the initial scoping speciation of fluorinated GHG at §98.124(a), by process.

(4) The location and function of the stream(s) (including process streams, emissions streams, and destroyed streams) that were analyzed under the initial scoping speciation of fluorinated GHG at §98.124(a), by process.

(5) The method used to determine the mass emissions of each fluorinated GHG, i.e., mass balance, process-vent-specific emission factor, or process-vent-specific emission calculation factor, for each process and process vent at the facility. For processes for which the process-vent-specific emission factor or process-vent-specific emission calculation factor are used, report the method used to estimate emissions from equipment leaks.

(6) The chemical formula and total mass produced of the fluorinated gas product in metric tons, by chemical and process.

(b) Reporting for mass balance approach. For processes whose emissions are determined using the mass-balance approach under §98.123(b), you must report the information listed in paragraphs (b)(1) through (b)(13) of this section for each process on an annual basis. Identify and separately report fluorinated GHG emissions from transformation processes where the fluorinated GHG reactants are produced at another facility. If you use an element other than fluorine in the mass-balance equation pursuant to §98.123(b)(3), substitute that element for fluorine in the reporting requirements of this paragraph.

(1) If you calculate the relative and absolute errors under §98.123(b)(1), the absolute and relative errors calculated under paragraph §98.123(b)(1), as well as the data (including quantities and their accuracies and precisions) used in these calculations.

(2) The balanced chemical equation that describes the reaction used to manufacture the fluorinated GHG product and each fluorinated GHG transformation product.

(3) The mass and chemical formula of each fluorinated GHG reactant emitted from the process in metric tons.

(4) The mass and chemical formula of the fluorinated GHG product emitted from the process in metric tons.

(5) The mass and chemical formula of each fluorinated GHG by-product produced by the process (metric tons).

(6) The mass and chemical formula of each fluorine-containing reactant that is fed into the process (metric tons).

(7) If you use §98.123(b)(4) to estimate the total mass of fluorine in destroyed
or recaptured streams, report the following:

(i) The mass and chemical formula of each fluorine-containing product that is removed from the process and fed into the destruction device (metric tons).

(ii) The mass and chemical formula of each fluorine-containing by-product that is removed from the process and fed into the destruction device (metric tons).

(iii) The mass and chemical formula of each fluorine-containing reactant that is removed from the process and fed into the destruction device (metric tons).

(iv) The mass and chemical formula of each fluorine-containing by-product that is removed from the process and recaptured (metric tons).

(v) The demonstrated destruction efficiency of the destruction device for each fluorinated GHG fed into the device from the process in greater than trace concentrations (fraction).

(9) If you use § 98.123(b)(15) to estimate the total mass of fluorine in destroyed or recaptured streams, report the following.

(i) The mass of fluorine in each stream that is fed into the destruction device (metric tons).

(ii) The mass of fluorine that is recaptured (metric tons).

(iii) The weighted average destruction efficiency of the destruction device calculated for each stream under § 98.123(b)(16).

(10) The fraction of the mass emitted that consists of each fluorine-containing reactant.

(11) The fraction of the mass emitted that consists of the fluorine-containing product.

(12) The fraction of the mass emitted that consists of each fluorine-containing by-product.

(13) The method used to estimate the total mass of fluorine in destroyed or recaptured streams (specify § 98.123(b)(4) or (15)).

(c) Reporting for emission factor and emission calculation factor approach. For processes whose emissions are determined using the emission factor approach under § 98.123(c)(3) or the emission calculation factor approach under § 98.123(c)(4), you must report the following for each process. Fluorinated GHG emissions from transformation processes where the fluorinated GHG reactants are produced at another facility must be identified and reported separately from other fluorinated GHG emissions.

(1) The identity and quantity of the process activity used to estimate emissions (e.g., tons of product produced or tons of reactant consumed).

(2) The site-specific, process-vent-specific emission factor(s) or emission calculation factor for each process vent.

(3) The mass of each fluorinated GHG emitted from each process vent (metric tons).

(4) The mass of each fluorinated GHG emitted from equipment leaks (metric tons).

(d) Reporting for missing data. Where missing data have been estimated pursuant to §98.125, you must report the reason the data were missing, the length of time the data were missing, the method used to estimate the missing data, and the estimates of those data.

(e) Reporting of destruction device excess emissions data. Each fluorinated gas production facility that destroys fluorinated GHGs must report the excess emissions that result from malfunctions of the destruction device, and these excess emissions would be reflected in the fluorinated GHG estimates in §98.123(b) and (c). Such excess emissions would occur if the destruction efficiency was reduced due to the malfunction.

(f) Reporting of destruction device testing. By March 31, 2012 or by March 31 of the year immediately following the year in which it begins fluorinated GHG destruction, each fluorinated gas production facility that destroys fluorinated GHGs must submit a report containing the information in paragraphs (f)(1) through (f)(4) of this section. This report is one-time unless you make a change to the destruction device that would be expected to affect its destruction efficiencies.

(1) Destruction efficiency (DE) of each destruction device for each fluorinated GHG whose destruction the facility reflects in §98.123, in accordance with §98.124(g)(1)(i) through (iv).
(2) Chemical identity of the fluorinated GHG(s) used in the performance test conducted to determine destruction efficiency, including surrogates, and information on why the surrogate is sufficient to demonstrate the destruction efficiency for each fluorinated GHG, consistent with requirements in §98.124(g)(1), vented to the destruction device.

(3) Date of the most recent destruction device test.

(4) Name of all applicable Federal or State regulations that may apply to the destruction process.

(5) If you make a change to the destruction device that would be expected to affect its destruction efficiencies, submit a revised report that reflects the changes, including the revised destruction efficiencies measured for the device under §98.124(g)(2)(ii), by March 31 of the year that immediately follows the change.

(g) Reporting for destruction of previously produced fluorinated GHGs. Each fluorinated gas production facility that destroys fluorinated GHGs must report, separately from the fluorinated GHG emissions reported under paragraphs (b) or (c) of this section, the following for each previously produced fluorinated GHG destroyed:

(1) The mass of the fluorinated GHG fed into the destruction device.

(2) The mass of the fluorinated GHG emitted from the destruction device.

(h) Reporting of emissions from venting of residual fluorinated GHGs from containers. Each fluorinated gas production facility that vents residual fluorinated GHGs from containers must report the following for each fluorinated GHG vented:

(1) The mass of the residual fluorinated GHG vented from each container size and type annually (tons).

(2) If applicable, the heel factor calculated for each container size and type.

(i) Reporting of fluorinated GHG products of incomplete combustion (PICs) of fluorinated gases. Each fluorinated gas production facility that destroys fluorinated gases must submit a one-time report by June 30, 2011, that describes any measurements, research, or analysis that it has performed or obtained that relate to the formation of products of incomplete combustion that are fluorinated GHGs during the destruction of fluorinated gases. The report must include the methods and results of any measurement or modeling studies, including the products of incomplete combustion for which the exhaust stream was analyzed, as well as copies of relevant scientific papers, if available, or citations of the papers, if they are not. No new testing is required to fulfill this requirement.

§98.127 Records that must be retained.

In addition to the records required by §98.3(g), you must retain the dated records specified in paragraphs (a) through (j) of this section, as applicable.

(a) Process information records.

Identify all products and processes subject to this subpart. Include the unit identification as appropriate.

(2) Monthly and annual records, as applicable, of all analyses and calculations conducted as required under §98.123, including the data monitored under §98.124, and all information reported as required and §98.126.

(b) Scoping speciation. Retain records documenting the information reported under §98.126(a)(3) and (4).

(c) Mass-balance method. Retain the following records for each process for which the mass-balance method was used to estimate emissions. If you use an element other than fluorine in the mass-balance equation pursuant to §98.123(b)(3), substitute that element for fluorine in the recordkeeping requirements of this paragraph.

(1) The data and calculations used to estimate the absolute and relative errors associated with use of the mass-balance approach.

(2) The data and calculations used to estimate the mass of fluorine emitted from the process.

(3) The data and calculations used to determine the fractions of the mass emitted consisting of each reactant (FERd), product (FEP), and by-product (FEBk), including the preliminary calculations in §98.123(b)(8)(i).

(d) Emission factor and emission calculation factor method. Retain the following records for each process for which the emission factor or emission
calculation factor method was used to estimate emissions.

(1) Identify all continuous process vents with emissions of fluorinated GHGs that are less than 10,000 metric tons CO$_2$e per year and all continuous process vents with emissions of 10,000 metric tons CO$_2$e per year or more. Include the data and calculation used to develop the preliminary estimate of emissions for each process vent.

(2) Identify all batch process vents.

(3) For each vent, identify the method used to develop the factor (i.e., emission factor by emissions test or emission calculation factor).

(4) The emissions test data and reports (see §98.124(c)(5)) and the calculations used to determine the process-vent-specific emission factor, including the actual process-vent-specific emission factor, the average hourly emission rate of each fluorinated GHG from the process vent during the test and the process feed rate, process production rate, or other process activity rate during the test.

(5) The process-vent-specific emission calculation factor and the calculations used to determine the process-vent-specific emission calculation factor.

(6) The annual process production quantity or other process activity information in the appropriate units, along with the dates and time period during which the process was operating and dates and time periods the process vents are vented to the destruction device. As an alternative to date and time periods when process vents are vented to the destruction device, a facility may track dates and time periods that process vents by-pass the destruction device.

(7) Calculations used to determine annual emissions of each fluorinated GHG for each process and the total fluorinated GHG emissions for all processes, i.e., total for facility.

(e) Destruction efficiency testing. A fluorinated GHG production facility that destroys fluorinated GHGs and reflects this destruction in §98.123 must retain the emissions performance testing reports (including revised reports) for each destruction device. The emissions performance testing report must contain all information and data used to derive the destruction efficiency for each fluorinated GHG whose destruction the facility reflects in §98.123, as well as the key process and device conditions during the test. This information includes the following:

(1) Destruction efficiency (DE) determined for each fluorinated GHG whose destruction the facility reflects in §98.123, in accordance with §98.124(g)(1)(i) through (iv).

(2) Chemical identity of the fluorinated GHG(s) used in the performance test conducted to determine destruction efficiency, including surrogates, and information on why the surrogate is sufficient to demonstrate destruction efficiency for each fluorinated GHG, consistent with requirements in §98.124(g)(1)(i) through (iv), vented to the destruction device.

(3) Mass flow rate of the stream containing the fluorinated GHG(s) or surrogate into the device during the test.

(4) Concentration (mass fraction) of each fluorinated GHG or surrogate in the stream flowing into the device during the test.

(5) Concentration (mass fraction) of each fluorinated GHG or surrogate at the outlet of the destruction device during the test.

(6) Mass flow rate at the outlet of the destruction device during the test.

(7) Test methods and analytical methods used to determine the mass flow rates and fluorinated GHG (or surrogate) concentrations of the streams flowing into and out of the destruction device during the test.

(8) Destruction device conditions that are normally monitored for device control, such as temperature, total mass flow rates into the device, and CO or O$_2$ levels.

(9) Name of all applicable Federal or State regulations that may apply to the destruction process.

(f) Equipment leak records. If you are subject to §98.123(d) of this subpart, you must maintain information on the number of each type of equipment; the service of each piece of equipment (gas, light liquid, heavy liquid); the concentration of each fluorinated GHG in the stream; each piece of equipment excluded from monitoring requirement; the time period each piece of equipment was in service, and the emission calculations for each fluorinated GHG.
for all processes. Depending on which equipment leak monitoring approach you follow, you must maintain information for equipment on the associated screening data concentrations for greater than or equal to 10,000 ppmv and associated screening data concentrations for less than 10,000 ppmv; associated actual screening data concentrations; and associated screening data and leak rate data (i.e., bagging) used to develop a unit-specific correlation. If you developed and follow a site-specific leak detection approach, provide the records for monitoring events and the emissions estimation calculations, as appropriate, consistent with the approach for equipment leak emission estimation in your GHG Monitoring Plan.

(g) Container heel records. If you vent residual fluorinated GHGs from containers, maintain the following records of the measurements and calculations used to estimate emissions of residual fluorinated GHGs from containers.

(i) If you measure the contents of each container, maintain records of these measurements and the calculations used to estimate emissions of each fluorinated GHG from each container size and type.

(ii) If you develop and apply container heel factors to estimate emissions, maintain records of the measurements and calculations used to develop the heel factor for each fluorinated GHG and each container size and type and of the number of containers of each fluorinated GHG and of each container size and type returned to your facility.

(h) Missing data records. Where missing data have been estimated pursuant to §98.125, you must record the reason the data were missing, the length of time the data were missing, the method used to estimate the missing data, and the estimates of those data.

(i) All facilities. Dated records documenting the initial and periodic calibration of all analytical equipment used to determine the concentration of fluorinated GHGs, including but not limited to gas chromatographs, gas chromatography-mass spectrometry (GC/MS), gas chromatograph-electron capture detector (GC/ECD), fourier transform infrared (FTIR), and nuclear magnetic resonance (NMR) devices, and all mass measurement equipment such as weigh scales, flowmeters, and volumetric and density measures used to measure the quantities reported under this subpart, including the industry standards or manufacturer directions used for calibration pursuant to §98.124(e), (f), (g), (m), and (n).

(j) GHG Monitoring Plans, as described in §98.3(g)(5), must be completed by April 1, 2011.

§98.128 Definitions.

Except as provided in this section, all of the terms used in this subpart have the same meaning given in the Clean Air Act and subpart A of this part. If a conflict exists between a definition provided in this subpart and a definition provided in subpart A, the definition in this subpart shall take precedence for the reporting requirements in this subpart.

Batch process or batch operation means a noncontinuous operation involving intermittent or discontinuous feed into equipment, and, in general, involves the emptying of the equipment after the batch operation ceases and prior to beginning a new operation. Addition of raw material and withdrawal of product do not occur simultaneously in a batch operation.

Batch emission episode means a discrete venting episode associated with a vessel in a process; a vessel may have more than one batch emission episode. For example, a displacement of vapor resulting from the charging of a vessel with a feed material will result in a discrete emission episode that will last through the duration of the charge and will have an average flow rate equal to the rate of the charge. If the vessel is then heated, there will also be another discrete emission episode resulting from the expulsion of expanded vapor. Other emission episodes also may occur from the same vessel and other vessels in the process, depending on process operations.

By-product means a chemical that is produced coincidentally during the production of another chemical.

Completely destroyed means destroyed with a destruction efficiency of 99.99 percent or greater.
Completely recaptured means 99.99 percent or greater of each fluorinated GHG is removed from a stream.

Continuous process or operation means a process where the inputs and outputs flow continuously throughout the duration of the process. Continuous processes are typically steady state.

Destruction device means any device used to destroy fluorinated GHG.

Destruction process means a process used to destroy fluorinated GHG in a destruction device such as a thermal incinerator or catalytic oxidizer.

Difficult-to-monitor means the equipment piece may not be monitored without elevating the monitoring personnel more than 2 meters (7 feet) above a support surface or it is not accessible in a safe manner when it is in fluorinated GHG service.

Dual mechanical seal pump and dual mechanical seal agitator means a pump or agitator equipped with a dual mechanical seal system that includes a barrier fluid system where the barrier fluid is not in light liquid service; each barrier fluid system is equipped with a sensor that will detect failure of the seal system, the barrier fluid system, or both; and meets the following requirements:

1. Each dual mechanical seal system is operated with the barrier fluid at a pressure that is at all times (except periods of startup, shutdown, or malfunction) greater than the pump or agitator stuffing box pressure; or
2. Equipped with a barrier fluid degassing reservoir that is routed to a process or fuel gas system or connected by a closed-vent system to a control device; or
3. Equipped with a closed-loop system that purges the barrier fluid into a process stream.

Equipment (for the purposes of §98.123(d) and §98.124(f) only) means each pump, compressor, agitator, pressure relief device, sampling connection system, open-ended valve or line, valve, connector, and instrumentation system in fluorinated GHG service for a process subject to this subpart; and any destruction devices or closed-vent systems to which processes subject to this subpart are vented.

Fluorinated gas means any fluorinated GHG, CFC, or HCFC.

In fluorinated GHG service means that a piece of equipment either contains or contacts a feedstock, by-product, or product that is a liquid or gas and contains at least 5 percent by weight fluorinated GHG.

In gas and vapor service means that a piece of equipment in regulated material service contains a gas or vapor at operating conditions.

In heavy liquid service means that a piece of equipment in regulated material service is not in gas and vapor service or in light liquid service.

In light liquid service means that a piece of equipment in regulated material service contains a liquid that meets the following conditions:

1. The vapor pressure of one or more of the compounds is greater than 0.3 kilopascals at 20 °C.
2. The total concentration of the pure compounds constituents having a vapor pressure greater than 0.3 kilopascals at 20 °C is equal to or greater than 20 percent by weight of the total process stream.
3. The fluid is a liquid at operating conditions.

Note to definition of “in light liquid service”: Vapor pressures may be determined by standard reference texts or ASTM D–2879, (incorporated by reference, see §98.7).

In vacuum service means that equipment is operating at an internal pressure which is at least 5 kilopascals below ambient pressure.

Isolated intermediate means a product of a process that is stored before subsequent processing. An isolated intermediate is usually a product of chemical synthesis. Storage of an isolated intermediate marks the end of a process. Storage occurs at any time the intermediate is placed in equipment used solely for storage.

No external shaft pump and No external shaft agitator means any pump or agitator that is designed with no externally actuated shaft penetrating the pump or agitator housing.

Operating scenario means any specific operation of a process and includes the information specified in paragraphs (1) through (5) of this definition for each process. A change or series of changes to any of these elements, except for...
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(4) A description of the process, the specific process equipment used, and the range of operating conditions for the process.

(2) An identification of related process vents, their associated emissions episodes and durations, and calculations and engineering analyses to show the annual uncontrolled fluorinated GHG emissions from the process vent.

(3) The control or destruction devices used, as applicable, including a description of operating and/or testing conditions for any associated destruction device.

(4) The process vents (including those from other processes) that are simultaneously routed to the control or destruction device(s).

(5) The applicable monitoring requirements and any parametric level that assures destruction or removal for all emissions routed to the control or destruction device.

Process means all equipment that collectively functions to produce a fluorinated gas product, including an isolated intermediate (which is also a fluorinated gas product), or to transform a fluorinated gas product. A process may consist of one or more unit operations. For the purposes of this subpart, process includes any, all, or a combination of reaction, recovery, separation, purification, or other activity, operation, manufacture, or treatment which are used to produce a fluorinated gas product. For a continuous process, cleaning operations conducted may be considered part of the process, at the discretion of the facility. For a batch process, cleaning operations are part of the process. Ancillary activities are not considered a process or part of any process under this subpart. Ancillary activities include boilers and incinerators, chillers and refrigeration systems, and other equipment and activities that are not directly involved (i.e., they operate within a closed system and materials are not combined with process fluids) in the processing of raw materials or the manufacturing of a fluorinated gas product.

Process condenser means a condenser whose primary purpose is to recover material as an integral part of a process. All condensers recovering condensate from a process vent at or above the boiling point or all condensers in line prior to a vacuum source are considered process condensers. Typically, a primary condenser or condensers in series are considered to be integral to the process if they are capable of and normally used for the purpose of recovering chemicals for fuel value (i.e., net positive heating value), use, reuse or for sale for fuel value, use, or reuse.

Process vent (for the purposes of this subpart only) means a vent from a process vessel or vents from multiple process vessels within a process that are manifolded together into a common header, through which a fluorinated GHG-containing gas stream is, or has the potential to be, released to the atmosphere (or the point of entry into a control device, if any). Examples of process vents include, but are not limited to, vents on condensers used for product recovery, bottoms receivers, surge control vessels, reactors, filters, centrifuges, and process tanks. Process vents do not include vents on storage tanks, wastewater emission sources, or pieces of equipment.

Typical batch means a batch process operated within a range of operating conditions that are documented in an operating scenario. Emissions from a typical batch are based on the operating conditions that result in representative emissions. The typical batch defines the uncontrolled emissions for each emission episode defined under the operating scenario.

Uncontrolled fluorinated GHG emissions means a gas stream containing fluorinated GHG which has exited the process (or process condenser or control condenser, where applicable), but which has not yet been introduced into a destruction device to reduce the mass of fluorinated GHG in the stream. If the emissions from the process are not routed to a destruction device, uncontrolled emissions are those fluorinated GHG emissions released to the atmosphere.

Unsafe-to-monitor means that monitoring personnel would be exposed to an immediate danger as a consequence of monitoring the piece of equipment. Examples of unsafe-to-monitor equipment include, but are not limited to,
equipment under extreme pressure or heat.

Subpart M [Reserved]

Subpart N—Glass Production

§ 98.140 Definition of the source category.
(a) A glass manufacturing facility manufactures flat glass, container glass, pressed and blown glass, or wool fiberglass by melting a mixture of raw materials to produce molten glass and form the molten glass into sheets, containers, fibers, or other shapes. A glass manufacturing facility uses one or more continuous glass melting furnaces to produce glass.

(b) A glass melting furnace that is an experimental furnace or a research and development process unit is not subject to this subpart.

§ 98.141 Reporting threshold.
You must report GHG emissions under this subpart if your facility contains a glass production process and the facility meets the requirements of either § 98.2(a)(1) or (2).

§ 98.142 GHGs to report.
You must report:
(a) CO₂ process emissions from each continuous glass melting furnace.
(b) CO₂ combustion emissions from each continuous glass melting furnace.
(c) CH₄ and N₂O combustion emissions from each continuous glass melting furnace. You must calculate and report these emissions under subpart C of this part (General Stationary Fuel Combustion Sources) by following the requirements of subpart C.
(d) CO₂, CH₄, and N₂O emissions from each stationary fuel combustion unit other than continuous glass melting furnaces. You must report these emissions under subpart C of this part (General Stationary Fuel Combustion Sources) by following the requirements of subpart C.

§ 98.143 Calculating GHG emissions.
You must calculate and report the annual process CO₂ emissions from each continuous glass melting furnace using the procedure in paragraphs (a) and (b) of this section.

(a) For each continuous glass melting furnace that meets the conditions specified in § 98.33(b)(4)(ii) or (iii), you must calculate and report under this subpart the combined process and combustion CO₂ emissions by operating and maintaining a CEMS to measure CO₂ emissions according to the Tier 4 Calculation Methodology specified in § 98.33(a)(4) and all associated requirements for Tier 4 in subpart C of this part (General Stationary Fuel Combustion Sources).

(b) For each continuous glass melting furnace that is not subject to the requirements in paragraph (a) of this section, calculate and report the process and combustion CO₂ emissions from the glass melting furnace by using either the procedure in paragraph (b)(1) of this section or the procedure in paragraphs (b)(2) through (b)(7) of this section, except as specified in paragraph (c) of this section.

(1) Calculate and report under this subpart the combined process and combustion CO₂ emissions by operating and maintaining a CEMS to measure CO₂ emissions according to the Tier 4 Calculation Methodology specified in § 98.33(a)(4) and all associated requirements for Tier 4 in subpart C of this part (General Stationary Fuel Combustion Sources).

(2) Calculate and report the process and combustion CO₂ emissions separately using the procedures specified in paragraphs (b)(2)(i) through (b)(2)(vi) of this section.

(i) For each carbonate-based raw material charged to the furnace, obtain from the supplier of the raw material the carbonate-based mineral mass fraction.

(ii) Determine the quantity of each carbonate-based raw material charged to the furnace.

(iii) Apply the appropriate emission factor for each carbonate-based raw material charged to the furnace, as shown in Table N–1 to this subpart.

(iv) Use Equation N–1 of this section to calculate process mass emissions of CO₂ for each furnace:
§ 98.144 Monitoring and QA/QC requirements.

(a) You must measure annual amounts of carbonate-based raw materials charged to each continuous glass melting furnace from monthly measurements using plant instruments used for accounting purposes, such as calibrated scales or weigh hoppers. Total annual mass charged to glass melting furnaces at the facility shall be compared to records of raw material purchases for the year.

(b) You must measure carbonate-based mineral mass fractions at least annually to verify the mass fraction data provided by the supplier of the raw material; such measurements shall be based on sampling and chemical analysis using ASTM D3682–01 (Re-approved 2006) Standard Test Method for Major and Minor Elements in Combustion Residues from Coal Utilization Processes (incorporated by reference, see §98.7) or ASTM D6349–09 Standard Test Method for Determination of Major and Minor Elements in Coal, Coke, and Solid Residues from Combustion of Coal and Coke by Inductively Coupled Plasma—Atomic Emission Spectrometry (incorporated by reference, see §98.7).

(c) You must determine the annual average mass fraction for the carbonate-based mineral in each carbonate-based raw material by calculating an arithmetic average of the monthly data obtained from raw material suppliers or sampling and chemical analysis.

(d) You must determine on an annual basis the calcination fraction for each carbonate consumed based on sampling and chemical analysis using an industry consensus standard. This chemical analysis must be conducted using an x-ray fluorescence test or other enhanced testing method published by an industry consensus standards organization (e.g., ASTM, ASME, API, etc.).

§ 98.145 Procedures for estimating missing data.

A complete record of all measured parameters used in the GHG emissions calculations is required (e.g., carbonate
raw materials consumed, etc.). If the monitoring and quality assurance procedures in §98.144 cannot be followed and data is missing, you must use the most appropriate of the missing data procedures in paragraphs (a) and (b) of this section. You must document and keep records of the procedures used for all such missing value estimates.

(a) For missing data on the monthly amounts of carbonate-based raw materials charged to any continuous glass melting furnace use the best available estimate(s) of the parameter(s), based on all available process data or data used for accounting purposes, such as purchase records.

(b) For missing data on the mass fractions of carbonate-based minerals in the carbonate-based raw materials assume that the mass fraction of each carbonate based mineral is 1.0.

§ 98.146 Data reporting requirements.

In addition to the information required by §98.3(c), each annual report must contain the information specified in paragraphs (a) and (b) of this section, as applicable.

(a) If a CEMS is used to measure CO₂ emissions, then you must report under this subpart the relevant information required under §98.36 for the Tier 4 Calculation Methodology and the following information specified in paragraphs (a)(1) and (2) of this section:

(1) Annual quantity of each carbonate-based raw material charged to each continuous glass melting furnace and for all furnaces combined (tons).

(2) Annual quantity of glass produced by each glass melting furnace and for all furnaces combined (tons).

(b) If a CEMS is not used to determine CO₂ emissions from continuous glass melting furnaces, and process CO₂ emissions are calculated according to the procedures specified in §98.143(b), then you must report the following information as specified in paragraphs (b)(1) through (b)(9) of this section:

(1) Annual process emissions of CO₂ (metric tons) for each continuous glass melting furnace and for all furnaces combined.

(2) Annual quantity of each carbonate-based raw material charged (tons) to each continuous glass melting furnace and for all furnaces combined.

(3) Annual quantity of glass produced (tons) from each continuous glass melting furnace and from all furnaces combined.

(4) Carbonate-based mineral mass fraction (percentage, expressed as a decimal) for each carbonate-based raw material charged to a continuous glass melting furnace.

(5) Results of all tests used to verify the carbonate-based mineral mass fraction for each carbonate-based raw material charged to a continuous glass melting furnace, as specified in paragraphs (b)(5)(i) through (b)(5)(iii) of this section.

(i) Date of test.

(ii) Method(s) and any variations used in the analyses.

(iii) Mass fraction of each sample analyzed.

(6) The fraction of calcination achieved for each carbonate-based raw material, if a value other than 1.0 is used to calculate process mass emissions of CO₂.

(7) Method used to determine fraction of calcination.

(8) Total number of continuous glass melting furnaces.

(9) The number of times in the reporting year that missing data procedures were followed to measure monthly quantities of carbonate-based raw materials or mass fraction of the carbonate-based minerals for any continuous glass melting furnace (months).


§ 98.147 Records that must be retained.

In addition to the information required by §98.3(g), you must retain the records listed in paragraphs (a), (b), and (c) of this section.

(a) If a CEMS is used to measure emissions, then you must retain the records required under §98.37 for the Tier 4 Calculation Methodology and the following information specified in paragraphs (a)(1) and (a)(2) of this section:

(1) Monthly glass production rate for each continuous glass melting furnace (tons).

(2) Monthly amount of each carbonate-based raw material charged to
§ 98.148 Definitions.

All terms used in this subpart have the same meaning given in the Clean Air Act and subpart A of this part.

Table N–1 to Subpart N of Part 98—CO₂ Emission Factors for Carbonate-Based Raw Materials

<table>
<thead>
<tr>
<th>Carbonate-based raw material—mineral</th>
<th>CO₂ emission factor a</th>
</tr>
</thead>
<tbody>
<tr>
<td>Limestone—CaCO₃</td>
<td>0.440</td>
</tr>
<tr>
<td>Dolomite—CaMg(CO₃)₂</td>
<td>0.477</td>
</tr>
<tr>
<td>Sodium carbonate/soda ash—Na₂CO₃</td>
<td>0.415</td>
</tr>
<tr>
<td>Barium carbonate—BaCO₃</td>
<td>0.223</td>
</tr>
<tr>
<td>Potassium carbonate—K₂CO₃</td>
<td>0.318</td>
</tr>
<tr>
<td>Lithium carbonate (Li₂CO₃)</td>
<td>0.596</td>
</tr>
<tr>
<td>Strontium carbonate (SrCO₃)</td>
<td>0.298</td>
</tr>
</tbody>
</table>

a Emission factors in units of metric tons of CO₂ emitted per metric ton of carbonate-based raw material charged to the furnace.


Subpart O—HCFC–22 Production and HFC–23 Destruction

§ 98.150 Definition of the source category.


(a) An HCFC–22 production process produces HCFC–22 (chlorodifluoromethane, or CHClF₂) from chloroform (CHCl₃) and hydrogen fluoride (HF).

(b) An HFC–23 destruction process is any process in which HFC–23 undergoes destruction. An HFC–23 destruction process may or may not be co-located with an HCFC–22 production process at the same facility.

§ 98.151 Reporting threshold.

You must report GHG emissions under this subpart if your facility contains an HCFC–22 production or HFC–23 destruction process and the facility meets the requirements of either §98.2(a)(1) or (a)(2).

§ 98.152 GHGs to report.

(a) You must report under subpart C of this part (General Stationary Fuel Combustion Sources) the emissions of CO₂, CH₄, and N₂O from each stationary combustion unit following the requirements of subpart C.

(b) You must report HFC–23 emissions from HCFC–22 production processes and HFC–23 destruction processes.
§ 98.153 Calculating GHG emissions.

(a) The mass of HFC–23 generated from each HCFC–22 production process shall be estimated by using one of two methods, as applicable:

(1) Where the mass flow of the combined stream of HFC–23 and another reaction product (e.g., HCl) is measured, multiply the weekly (or more frequent) HFC–23 concentration measurement (which may be the average of more frequent concentration measurements) by the weekly (or more frequent) mass flow of the combined stream of HFC–23 and the other product. To estimate annual HFC–23 production, sum the weekly (or more frequent) estimates of the quantities of HFC–23 produced over the year. This calculation is summarized in Equation O–1 of this section:

\[ G_{23} = \sum_{p=1}^{n} c_{23} \times F_{p} \times 10^{-3} \]  \hspace{1cm} (Eq. O–1)

Where:
- \( G_{23} \) = Mass of HFC–23 generated annually (metric tons).
- \( c_{23} \) = Fraction HFC–23 by weight in HFC–23/other product stream.
- \( F_{p} \) = Mass flow of HFC–23/other product stream during the period \( p \) (kg).
- \( p \) = Period over which masses and concentrations are measured.
- \( n \) = Number of concentration and flow measurement periods for the year.
- \( 10^{-3} \) = Conversion factor from kilograms to metric tons.

(2) Where the mass of only a reaction product other than HFC–23 (either HCFC–22 or HCl) is measured, multiply the ratio of the weekly (or more frequent) measurement of the HFC–23 concentration and the weekly (or more frequent) measurement of the other product concentration by the weekly (or more frequent) mass produced of the other product. To estimate annual HFC–23 production, sum the weekly (or more frequent) estimates of the quantities of HFC–23 produced over the year. This calculation is summarized in Equation O–2 of this section, assuming that the other product is HCFC–22. If the other product is HCl, HCl may be substituted for HCFC–22 in Equations O–2 and O–3 of this section.

\[ G_{23} = \sum_{p=1}^{n} \left( \frac{c_{23}}{c_{22}} \right) \times P_{22} \times 10^{-3} \]  \hspace{1cm} (Eq. O–2)

Where:
- \( G_{23} \) = Mass of HFC–23 generated annually (metric tons).
- \( c_{23} \) = Fraction HFC–23 by weight in HFC–23/other product stream.
- \( c_{22} \) = Fraction HCFC–22 by weight in HCFC–22/HFC–23 stream.
- \( P_{22} \) = Mass of HCFC–22 produced over the period \( p \) (kg), calculated using Equation O–3 of this section.
- \( p \) = Period over which masses and concentrations are measured.
- \( n \) = Number of concentration and mass measurement periods for the year.
- \( 10^{-3} \) = Conversion factor from kilograms to metric tons.

(b) The mass of HCFC–22 produced over the period \( p \) shall be estimated by using Equation O–3 of this section:

\[ P_{22} = LF \times (O_{22} - U_{22}) \]  \hspace{1cm} (Eq. O–3)

Where:
- \( P_{22} \) = Mass of HCFC–22 produced over the period \( p \) (kg).
- \( O_{22} \) = Mass of HCFC–22 that is measured coming out of the Production process over the period \( p \) (kg).
- \( U_{22} \) = Mass of used HCFC–22 that is added to the production process upstream of the output measurement over the period \( p \) (kg).
- \( LF \) = Factor to account for the loss of HCFC–22 upstream of the measurement. The value for LF shall be determined pursuant to §98.154(e).

(c) For HCFC–22 production facilities that do not use a thermal oxidizer or that have a thermal oxidizer that is not directly connected to the HCFC–22 production equipment, HFC–23 emissions shall be estimated using Equation O–4 of this section:

\[ E_{23} = G_{23} - (S_{23} + OD_{23} + D_{23} + I_{23}) \]  \hspace{1cm} (Eq. O–4)
Where:
\( E_{23} \) = Mass of HFC–23 emitted annually (metric tons).
\( G_{23} \) = Mass of HFC–23 generated annually (metric tons).
\( S_{23} \) = Mass of HFC–23 sent off site for sale annually (metric tons).
\( OD_{23} \) = Mass of HFC–23 sent off site for destruction (metric tons).
\( D_{23} \) = Mass of HFC–23 destroyed on site (metric tons).
\( I_{23} \) = Increase in HFC–23 inventory = HFC–23 in storage at end of year—HFC–23 in storage at beginning of year (metric tons).

(d) For HCFC–22 production facilities that use a thermal oxidizer connected to the HCFC–22 production equipment, HFC–23 emissions shall be estimated using Equation O–5 of this section:

\[
E_{23} = E + E + E_{LP} V D \quad \text{(Eq. O-5)}
\]

Where:
\( E_{23} \) = Mass of HFC–23 emitted annually (metric tons).
\( E_{LP} \) = Mass of HFC–23 emitted annually from equipment leaks, calculated using Equation O–6 of this section (metric tons).
\( E_{PV} \) = Mass of HFC–23 emitted annually from process vents, calculated using Equation O–7 of this section (metric tons).
\( E_D \) = Mass of HFC–23 emitted annually from thermal oxidizer (metric tons), calculated using Equation O–8 of this section.

(1) The mass of HFC–23 emitted annually from equipment leaks (for use in Equation O–5 of this section) shall be estimated by using Equation O–6 of this section:

\[
E_L = \sum_{p=1}^{n} \sum_{t} c_{23} \left( F_{Gl} \ast N_{Gl} + F_{Lt} \ast N_{Lt} \right) \ast 10^{-3} \quad \text{(Eq. O-6)}
\]

Where:
\( E_L \) = Mass of HFC–23 emitted annually from equipment leaks (metric tons).
\( c_{23} \) = Fraction HFC–23 by weight in the stream(s) in the equipment.
\( F_{Gl} \) = The applicable leak rate specified in Table O–1 of this subpart for each source of equipment type and service t with a screening value of less than 10,000 ppmv (kg/hr/source).
\( N_{Gl} \) = The number of sources of equipment type and service t with screening values less than 10,000 ppmv as determined according to §98.154(i).
\( F_{Lt} \) = The applicable leak rate specified in Table O–1 of this subpart for each source of equipment type and service t with screening values greater than or equal to 10,000 ppmv.
\( N_{Lt} \) = The number of sources of equipment type and service t with screening values greater than or equal to 10,000 ppmv as determined according to §98.154(i).
\( p \) = One hour.
\( n \) = Number of hours during the year during which equipment contained HFC–23.
\( t \) = Equipment type and service as specified in Table O–1 of this subpart.
10\(^{-3}\) = Factor converting kg to metric tons.

(2) The mass of HFC–23 emitted annually from process vents (for use in Equation O–5 of this section) shall be estimated by using Equation O–7 of this section:

\[
E_{PV} = \sum_{p=1}^{n} ER_T \ast \left( \frac{PR_T}{PR_T} \right) \ast 10^{-3} \quad \text{(Eq. O-7)}
\]

Where:
\( E_{PV} \) = Mass of HFC–23 emitted annually from process vents (metric tons).
\( ER_T \) = The HFC–23 emission rate from the process vents during the period of the most recent test (kg/hr).
\( PR_T \) = The HCFC–22 production rate during the period p (kg/hr).
\( PR_T \) = The HCFC–22 production rate during the most recent test period (kg/hr).
\( l_p \) = The length of the period p (hours).
10\(^{-3}\) = Factor converting kg to metric tons.
\( n \) = The number of periods in a year.
(3) The total mass of HFC–23 emitted from destruction devices shall be estimated by using Equation O–8 of this section:

\[
E_D = F_D - D_{23} \quad (\text{Eq. O-8})
\]

Where:
- \(E_D\) = Mass of HFC–23 emitted annually from the destruction device (metric tons).
- \(F_D\) = Mass of HFC–23 fed into the destruction device annually (metric tons).
- \(D_{23}\) = Mass of HFC–23 destroyed annually (metric tons).

(4) For facilities that destroy HFC–23, the total mass of HFC–23 destroyed shall be estimated by using Equation O–9 of this section:

\[
D_{23} = F_D \times DE \quad (\text{Eq. O-9})
\]

Where:
- \(D_{23}\) = Mass of HFC–23 destroyed annually (metric tons).
- \(F_D\) = Mass of HFC–23 fed into the destruction device annually (metric tons).
- \(DE\) = Destruction Efficiency of the destruction device (fraction).

§ 98.154 Monitoring and QA/QC requirements.

These requirements apply to measurements that are reported under this subpart or that are used to estimate reported quantities pursuant to § 98.153.

(a) The concentrations (fractions by weight) of HFC–23 and HCFC–22 in the product stream shall be measured at least weekly using equipment and methods (e.g., gas chromatography) with an accuracy and precision of 5 percent or better at the concentrations of the process samples.

(b) The mass flow of the product stream containing the HFC–23 shall be measured at least weekly using flowmeters, weigh scales, or a combination of volumetric and density measurements with an accuracy and precision of 1.0 percent of full scale or better.

(c) The mass of HCFC–22 or HCl coming out of the production process shall be measured at least weekly using weigh scales, flowmeters, or a combination of volumetric and density measurements with an accuracy and precision of 1.0 percent of full scale or better.

(d) The mass of any used HCFC–22 added back into the production process upstream of the output measurement in paragraph (c) of this section shall be measured (when being added) using flowmeters, weigh scales, or a combination of volumetric and density measurements with an accuracy and precision of 1.0 percent of full scale or better. If the mass in paragraph (c) of this section is measured by weighing containers that include returned heels as well as newly produced fluorinated GHGs, the returned heels shall be considered used fluorinated HCFC–22 for purposes of this paragraph (d) of this section and § 98.153(b).

(e) The loss factor LF in Equation O–3 of this subpart for the mass of HCFC–22 produced shall have the value 1.015 or another value that can be demonstrated, to the satisfaction of the Administrator, to account for losses of HCFC–22 between the reactor and the point of measurement at the facility where production is being estimated.

(f) The mass of HFC–23 sent off site for sale shall be measured at least weekly (when being packaged) using flowmeters, weigh scales, or a combination of volumetric and density measurements with an accuracy and precision of 1.0 percent of full scale or better.

(g) The mass of HFC–23 sent off site for destruction shall be measured at least weekly (when being packaged) using equipment and methods (e.g., gas chromatography) with an accuracy and precision of 5 percent or better at the concentrations of the process samples. This concentration (mass fraction) shall be multiplied by the mass measurement to obtain the mass of the HFC–23 sent to another facility for destruction.

(h) The masses of HFC–23 in storage at the beginning and end of the year shall be measured using flowmeters, weigh scales, or a combination of volumetric and density measurements with an accuracy and precision of 1.0 percent of full scale or better.
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(i) The number of sources of equipment type t with screening values greater than or equal to 10,000 ppmv shall be determined using EPA Method 21 at 40 CFR part 60, appendix A–7, and defining a leak as follows:

(1) A leak source that could emit HFC–23;

(2) A leak source at whose surface a concentration of fluorocarbons equal to or greater than 10,000 ppm is measured.

(j) The number of sources of equipment type t with screening values less than 10,000 ppmv shall be the difference between the number of leak sources of equipment type t that could emit HFC–23 and the number of sources of equipment type t with screening values greater than or equal to 10,000 ppmv as determined under paragraph (h) of this section.

(k) The mass of HFC–23 emitted from process vents shall be estimated at least monthly by incorporating the results of the most recent emissions test into Equation O–7 of this subpart. HCFC–22 production facilities that use a destruction device connected to the HCFC–22 production equipment shall conduct emissions tests at process vents at least once every five years or after significant changes to the process. Emissions tests shall be conducted in accordance with EPA Method 18 at 40 CFR part 60, appendix A–6, under conditions that are typical for the production process at the facility. The sensitivity of the tests shall be sufficient to detect an emission rate that would result in annual emissions of 200 kg of HFC–23 if sustained over one year.

(l) For purposes of Equation O–9 of this subpart, the destruction efficiency must be equated to the destruction efficiency determined during a new or previous performance test of the destruction device. HFC–23 destruction facilities shall conduct annual measurements of HFC–23 concentrations at the outlet of the destruction device in accordance with EPA Method 18 at 40 CFR part 60, appendix A–6. Three samples shall be taken under conditions that are typical for the production process and destruction device at the facility, and the average concentration of HFC–23 shall be determined. The sensitivity of the concentration measurement shall be sufficient to detect an outlet concentration equal to or less than the outlet concentration determined in the destruction efficiency performance test. If the concentration measurement indicates that the HFC–23 concentration is less than or equal to that measured during the performance test that is the basis for the destruction efficiency, continue to use the previously determined destruction efficiency. If the concentration measurement indicates that the HFC–23 concentration is greater than that measured during the performance test that is the basis for the destruction efficiency, facilities shall either:

(1) Substitute the higher HFC–23 concentration for that measured during the destruction efficiency performance test and calculate a new destruction efficiency, or

(2) Estimate the mass emissions of HFC–23 from the destruction device based on the measured HFC–23 concentration and volumetric flow rate determined by measurement of volumetric flow rate using EPA Method 2, 2A, 2C,2D, or 2F at 40 CFR part 60, appendix A–1, or Method 26 at 40 CFR part 60, appendix A–2. Determine the mass rate of HFC–23 into the destruction device by measuring the HFC–23 concentration and volumetric flow rate at the inlet or by a metering device for HFC–23 sent to the device. Determine a new destruction efficiency based on the mass flow rate of HFC–23 into and out of the destruction device.

(m) HCFC–22 production facilities shall account for HFC–23 generation and emissions that occur as a result of startups, shutdowns, and malfunctions, either recording HFC–23 generation and emissions during these events, or documenting that these events do not result in significant HFC–23 generation and/or emissions.

(n) The mass of HFC–23 fed into the destruction device shall be measured at least weekly using flow meters, weigh scales, or a combination of volumetric and density measurements with an accuracy and precision of 1.0 percent of full scale or better. If the measured mass includes more than trace concentrations of materials other than HFC–23, the concentrations of the HFC–23 shall be measured at least
weekly using equipment and methods (e.g., gas chromatography) with an accuracy and precision of 5 percent or better at the concentrations of the process samples. This concentration (mass fraction) shall be multiplied by the mass measurement to obtain the mass of the HFC–23 destroyed.

(o) In their estimates of the mass of HFC–23 destroyed, HFC–23 destruction facilities shall account for any temporary reductions in the destruction efficiency that result from any startups, shutdowns, or malfunctions of the destruction device, including departures from the operating conditions defined in State or local permitting requirements and/or destruction device manufacturer specifications.

(p) Calibrate all flow meters, weigh scales, and combinations of volumetric and density measures using NIST-traceable standards and suitable methods published by a consensus standards organization (e.g., ASTM, ASME, ISO, or others). Recalibrate all flow meters, weigh scales, and combinations of volumetric and density measures at the minimum frequency specified by the manufacturer.

(q) All gas chromatographs used to determine the concentration of HFC–23 in process streams shall be calibrated at least monthly through analysis of certified standards (or of calibration gases prepared from a high-concentration certified standard using a gas dilution system that meets the requirements specified in Method 205 at 40 CFR part 51, appendix M) with known HFC–23 concentrations that are in the same range (fractions by mass) as the process samples.

§ 98.156 Data reporting requirements.

(a) In addition to the information required by §98.3(c), the HCFC–22 production facility shall report the following information at the facility level:

(1) Annual mass of HCFC–22 produced in metric tons.

(2) Loss Factor used to account for the loss of HCFC–22 upstream of the measurement.

(3) Annual mass of reactants fed into the process in metric tons of reactant.

(4) The mass (in metric tons) of materials other than HCFC–22 and HFC–23 (i.e., unreacted reactants, HCl and other by-products) that occur in more than trace concentrations and that are permanently removed from the process.

(5) The method for tracking startups, shutdowns, and malfunctions and HFC–
23 generation/emissions during these events.

(6) The names and addresses of facilities to which any HFC–23 was sent for destruction, and the quantities of HFC–23 (metric tons) sent to each.

(7) Annual mass of the HFC–23 generated in metric tons.

(8) Annual mass of any HFC–23 sent off site for sale in metric tons.

(9) Annual mass of any HFC–23 sent off site for destruction in metric tons.

(10) Mass of HFC–23 in storage at the beginning and end of the year, in metric tons.

(11) Annual mass of HFC–23 emitted in metric tons.

(12) Annual mass of HFC–23 emitted from equipment leaks in metric tons.

(13) Annual mass of HFC–23 emitted from process vents in metric tons.

(b) In addition to the information required by §98.3(c), facilities that destroy HFC–23 shall report the following for each HFC–23 destruction process:

(1) Annual mass of HFC–23 fed into the destruction device.

(2) Annual mass of HFC–23 destroyed.

(3) Annual mass of HFC–23 emitted from the destruction device.

(c) Each HFC–23 destruction facility shall report the concentration (mass fraction) of HFC–23 measured at the outlet of the destruction device during the facility’s annual HFC–23 concentration measurements at the outlet of the device.

(d) If the HFC–23 concentration measured pursuant to §98.154(1) is greater than that measured during the performance test that is the basis for the destruction efficiency (DE), the facility shall report the revised destruction efficiency calculated under §98.154(1) and the values used to calculate it, specifying whether §98.154(1)(1) or §98.154(1)(2) has been used for the calculation. Specifically, the facility shall report the following:

(1) Flow rate of HFC–23 being fed into the destruction device in kg/hr.

(2) Concentration (mass fraction) of HFC–23 at the outlet of the destruction device.

(3) Flow rate at the outlet of the destruction device in kg/hr.

(4) Emission rate (in kg/hr) calculated from paragraphs (d)(2) and (d)(3) of this section.

(5) Destruction efficiency (DE) calculated from paragraphs (d)(1) and (d)(4) of this section.

(e) By March 31, 2011 or within 60 days of commencing HFC–23 destruction, HFC–23 destruction facilities shall submit a one-time report including the following information for each destruction process:

(1) Destruction efficiency (DE).

(2) The methods used to determine destruction efficiency.

(3) The methods used to record the mass of HFC–23 destroyed.

(4) The name of other relevant federal or state regulations that may apply to the destruction process.

(5) If any changes are made that affect HFC–23 destruction efficiency or the methods used to record volume destroyed, then these changes must be reflected in a revision to this report. The revised report must be submitted to EPA within 60 days of the change.

§98.157 Records that must be retained.

(a) In addition to the data required by §98.3(g), HCFC–22 production facilities shall retain the following records:

(1) The data used to estimate HFC–23 emissions.

(2) Records documenting the initial and periodic calibration of the gas chromatographs, weigh scales, volumetric and density measurements, and flowmeters used to measure the quantities reported under this rule, including the industry standard or manufacturer directions used for calibration pursuant to §98.154(p) and (q).

(b) In addition to the data required by §98.3(g), the HFC–23 destruction facilities shall retain the following records:

(1) Records documenting their one-time and annual reports in §98.156(b) through (e).

(2) Records documenting the initial and periodic calibration of the gas chromatographs, weigh scales, volumetric and density measurements, and flowmeters used to measure the quantities reported under this subpart, including the industry standard practice or manufacturer directions used for
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Calibration pursuant to §98.154(p) and (q).


§ 98.158 Definitions.

All terms used in this subpart have the same meaning given in the Clean Air Act and subpart A of this part.

### Table O–1 to Subpart O of Part 98—Emission Factors for Equipment Leaks

<table>
<thead>
<tr>
<th>Equipment type</th>
<th>Service</th>
<th>Emission factor (kg/hr/source)</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td>≥10,000 ppmv</td>
</tr>
<tr>
<td>Valves</td>
<td>Gas</td>
<td>0.0782</td>
</tr>
<tr>
<td>Valves</td>
<td>Light liquid</td>
<td>0.243</td>
</tr>
<tr>
<td>Pump seals</td>
<td>Light liquid</td>
<td>1.608</td>
</tr>
<tr>
<td>Compressor seals</td>
<td>Gas</td>
<td>1.691</td>
</tr>
<tr>
<td>Pressure relief valves</td>
<td>Gas</td>
<td>0.113</td>
</tr>
<tr>
<td>Connectors</td>
<td>All</td>
<td>0.01195</td>
</tr>
<tr>
<td>Open-ended lines</td>
<td>All</td>
<td></td>
</tr>
</tbody>
</table>

Subpart P—Hydrogen Production

§ 98.160 Definition of the source category.

(a) A hydrogen production source category consists of facilities that produce hydrogen gas sold as a product to other entities.

(b) This source category comprises process units that produce hydrogen by reforming, gasification, oxidation, reaction, or other transformations of feedstocks.

(c) This source category includes merchant hydrogen production facilities located within another facility if they are not owned by, or under the direct control of, the other facility's owner and operator.


§ 98.161 Reporting threshold.

You must report GHG emissions under this subpart if your facility contains a hydrogen production process and the facility meets the requirements of either §98.2(a)(1) or (a)(2).

§ 98.162 GHGs to report.

You must report:

(a) CO₂ emissions from each hydrogen production process unit.

(b) [Reserved]

(c) CO₂, CH₄, and N₂O emissions from each stationary combustion unit other than hydrogen production process units. You must calculate and report these emissions under subpart C of this part (General Stationary Fuel Combustion Sources) by following the requirements of subpart C.

(d) For CO₂ collected and transferred off site, you must follow the requirements of subpart PP of this part.


§ 98.163 Calculating GHG emissions.

You must calculate and report the annual CO₂ emissions from each hydrogen production process unit using the procedures specified in either paragraph (a) or (b) of this section.

(a) Continuous Emissions Monitoring Systems (CEMS). Calculate and report under this subpart the CO₂ emissions by operating and maintaining CEMS according to the Tier 4 Calculation Methodology specified in §98.33(a)(4) and all associated requirements for Tier 4 in subpart C of this part (General Stationary Fuel Combustion Sources).

(b) Fuel and feedstock material balance approach. Calculate and report CO₂ emissions as the sum of the annual emissions associated with each fuel and feedstock used for hydrogen production by following paragraphs (b)(1) through (b)(3) of this section.

1. Gaseous fuel and feedstock. You must calculate the annual CO₂ emissions from each gaseous fuel and feedstock according to Equation P–1 of this section:
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\[
CO_2 = \left( \sum_{n=1}^{k} \frac{44}{12} \ast Fdstk_n \ast CC_n \ast \frac{MW}{MVC} \right) \ast 0.001 \quad \text{(Eq. P-1)}
\]

Where:
- \(CO_2\) = Annual CO\(_2\) process emissions arising from fuel and feedstock consumption (metric tons/yr).
- \(Fdstk_n\) = Volume of the gaseous fuel and feedstock used in month \(n\) (scf (at standard conditions of 68 °F and atmospheric pressure) of fuel and feedstock).
- \(CC_n\) = Average carbon content of the gaseous fuel and feedstock, from the results of one or more analyses for month \(n\) (kg carbon per kg of fuel and feedstock). If measurements are taken more frequently than monthly, use the arithmetic average of measurement values within the month to calculate a monthly average.
- \(MW_n\) = Average molecular weight of the gaseous fuel and feedstock from the results of one or more analyses for month \(n\) (kg/kg-mole).
- \(MVC\) = Molar volume conversion factor (849.5 scf per kg-mole at standard conditions).
- \(k\) = Months in the year.
- \(\frac{44}{12}\) = Ratio of molecular weights, CO\(_2\) to carbon.
- 0.001 = Conversion factor from kg to metric tons.

(2) Liquid fuel and feedstock. You must calculate the annual CO\(_2\) emissions from each liquid fuel and feedstock according to Equation P–2 of this section:

\[
CO_2 = \left( \sum_{n=1}^{k} \frac{44}{12} \ast Fdstk_n \ast CC_n \right) \ast 0.001 \quad \text{(Eq. P-2)}
\]

Where:
- \(CO_2\) = Annual CO\(_2\) emissions arising from fuel and feedstock consumption (metric tons/yr).
- \(Fdstk_n\) = Volume of the liquid fuel and feedstock used in month \(n\) (gallons of fuel and feedstock).
- \(CC_n\) = Average carbon content of the liquid fuel and feedstock, from the results of one or more analyses for month \(n\) (kg carbon per gallon of fuel and feedstock).
- \(k\) = Months in the year.
- \(\frac{44}{12}\) = Ratio of molecular weights, CO\(_2\) to carbon.
- 0.001 = Conversion factor from kg to metric tons.

(3) Solid fuel and feedstock. You must calculate the annual CO\(_2\) emissions from each solid fuel and feedstock according to Equation P–3 of this section:

\[
CO_2 = \left( \sum_{n=1}^{k} \frac{44}{12} \ast Fdstk_n \ast CC_n \right) \ast 0.001 \quad \text{(Eq. P-3)}
\]

Where:
- \(CO_2\) = Annual CO\(_2\) emissions from fuel and feedstock consumption in metric tons per month (metric tons/yr).
- \(Fdstk_n\) = Mass of solid fuel and feedstock used in month \(n\) (kg of fuel and feedstock).
- \(CC_n\) = Average carbon content of the solid fuel and feedstock, from the results of one or more analyses for month \(n\) (kg carbon per kg of fuel and feedstock).
- \(k\) = Months in the year.
- \(\frac{44}{12}\) = Ratio of molecular weights, CO\(_2\) to carbon.
- 0.001 = Conversion factor from kg to metric tons.

(c) If GHG emissions from a hydrogen production process unit are vented through the same stack as any combustion unit or process equipment that reports CO\(_2\) emissions using a CEMS that complies with the Tier 4 Calculation Methodology in subpart C of this part
(General Stationary Fuel Combustion Sources), then the calculation methodology in paragraph (b) of this section shall not be used to calculate process emissions. The owner or operator shall report under this subpart the combined stack emissions according to the Tier 4 Calculation Methodology in §98.33(a)(4) and all associated requirements for Tier 4 in subpart C of this part (General Stationary Fuel Combustion Sources).

§ 98.164 Monitoring and QA/QC requirements.

The GHG emissions data for hydrogen production process units must be quality-assured as specified in paragraphs (a) or (b) of this section, as appropriate for each process unit:

(a) If a CEMS is used to measure GHG emissions, then the facility must comply with the monitoring and QA/QC procedures specified in §98.34(c).

(b) If a CEMS is not used to measure GHG emissions, then you must:

(1) Calibrate all oil and gas flow meters that are used to measure liquid and gaseous feedstock volumes (except for gas billing meters) according to the monitoring and QA/QC requirements for the Tier 3 methodology in §98.34(b)(1). Perform oil tank drop measurements (if used to quantify liquid fuel or feedstock consumption) according to §98.34(b)(2). Calibrate all solids weighing equipment according to the procedures in §98.3(i).

(2) Determine the carbon content and the molecular weight annually of standard gaseous hydrocarbon fuels and feedstocks having consistent composition (e.g., natural gas). For other gaseous fuels and feedstocks (e.g., biogas, refinery gas, or process gas), sample and analyze no less frequently than weekly to determine the carbon content and molecular weight of the fuel and feedstock.

(3) Determine the carbon content of fuel oil, naphtha, and other liquid fuels and feedstocks at least monthly, except annually for standard liquid hydrocarbon fuels and feedstocks having consistent composition, or upon delivery for solid fuels delivered by bulk transport (e.g., by truck or rail).

(4) Determine the carbon content of coal, coke, and other solid fuels and feedstocks at least monthly, except annually for standard solid hydrocarbon fuels and feedstocks having consistent composition, or upon delivery for solid fuels delivered by bulk transport (e.g., by truck or rail).

(5) You must use the following applicable methods to determine the carbon content for all fuels and feedstocks, and molecular weight of gaseous fuels and feedstocks. Alternatively, you may use the results of continuous chromatographic analysis of the fuel and feedstock, provided that the gas chromatograph (GC) is operated, maintained, and calibrated according to the manufacturer's instructions; and the methods used for operation, maintenance, and calibration of the GC are documented in the written monitoring plan for the unit under §98.3(g)(5).

(i) ASTM D1945–03 Standard Test Method for Analysis of Natural Gas by Gas Chromatography (incorporated by reference, see §98.7).

(ii) ASTM D1946–90 (Reapproved 2006), Standard Practice for Analysis of Reformed Gas by Gas Chromatography (incorporated by reference, see §98.7).

(iii) ASTM D2013–07 Standard Practice of Preparing Coal Samples for Analysis (incorporated by reference, see §98.7).

(iv) ASTM D2234/D2234M–07 Standard Practice for Collection of a Gross Sample of Coal (incorporated by reference, see §98.7).


(vi) ASTM D3176–89 (Reapproved 2002), Standard Practice for Ultimate Analysis of Coal and Coke (incorporated by reference, see §98.7).

§ 98.165 Procedures for estimating missing data.

A complete record of all measured parameters used in the GHG emissions calculations is required. Therefore, whenever a quality-assured value of a required parameter is unavailable (e.g., if a meter malfunctions during unit operation), a substitute data value for the missing parameter must be used in the calculations as specified in paragraphs (a), (b), and (c) of this section:

(a) For each missing value of the monthly fuel and feedstock consumption, the substitute data value must be the best available estimate of the fuel and feedstock consumption, based on all available process data (e.g., hydrogen production, electrical load, and operating hours). You must document and keep records of the procedures used for all such estimates.

(b) For each missing value of the carbon content or molecular weight of the fuel and feedstock, the substitute data value must be the arithmetic average of the quality-assured values of carbon contents or molecular weight of the fuel and feedstock immediately preceding and immediately following the missing data incident. If no quality-assured data on carbon contents or molecular weight of the fuel and feedstock are available prior to the missing data incident, the substitute data value must be the first quality-assured value for carbon contents or molecular weight.

and Petroleum Products (incorporated by reference, see §98.7).


(xii) ASTM D5373–08 Standard Test Methods for Instrumental Determination of Carbon, Hydrogen, and Nitrogen in Laboratory Samples of Coal (incorporated by reference, see §98.7).

(xiii) ASTM D5373–08 Standard Test Methods for Instrumental Determination of Carbon, Hydrogen, and Nitrogen in Laboratory Samples of Coal (incorporated by reference, see §98.7).

(xiv) ASTM D6609–08 Standard Guide for Part-Stream Sampling of Coal (incorporated by reference, see §98.7).

(xv) ASTM D6883–04 Standard Practice for Manual Sampling of Stationary Coal from Railroad Cars, Barges, Trucks, or Stockpiles (incorporated by reference, see §98.7).

(xvi) ASTM D7430–08 Standard Practice for Mechanical Sampling of Coal (incorporated by reference, see §98.7).

(xvii) ASTM UOP539–97 Refinery Gas Analysis by Gas Chromatography (incorporated by reference, see §98.7).

(xviii) GPA 2261–00 Analysis for Natural Gas and Similar Gaseous Mixtures by Gas Chromatography (incorporated by reference, see §98.7).


(c) For units using the calculation methodologies described in this section, the records required under §98.3(g) must include both the company records and a detailed explanation of how company records are used to estimate the following:

(1) Fuel and feedstock consumption, when solid fuel and feedstock is combusted and a CEMS is not used to measure GHG emissions.

(2) Fossil fuel consumption, when, pursuant to §98.33(e), the owner or operator of a unit that uses CEMS to quantify CO₂ emissions and that combusting both fossil and biogenic fuels separately reports the biogenic portion of the total annual CO₂ emissions.

(3) Sorbent usage, if the methodology in §98.33(d) is used to calculate CO₂ emissions from sorbent.

(d) The owner or operator must document the procedures used to ensure the accuracy of the estimates of fuel and feedstock usage and sorbent usage (as applicable) in paragraph (b) of this section, including, but not limited to, calibration of weighing equipment, fuel and feedstock flow meters, and other measurement devices. The estimated accuracy of measurements made with these devices must also be recorded, and the technical basis for these estimates must be provided.
§ 98.166 Data reporting requirements.

In addition to the information required by §98.3(c), each annual report must contain the information specified in paragraphs (a) or (b) of this section, as appropriate, and paragraphs (c) and (d) of this section:

(a) If a CEMS is used to measure CO\(_2\) emissions, then you must report the relevant information required under §98.36 for the Tier 4 Calculation Methodology and the following information in this paragraph (a):
   (1) Unit identification number and annual CO\(_2\) emissions.
   (2) Annual quantity of hydrogen produced (metric tons) for each process unit and for all units combined.
   (3) Annual quantity of ammonia produced (metric tons), if applicable, for each process unit and for all units combined.

(b) If a CEMS is not used to measure CO\(_2\) emissions, then you must report the following information for each hydrogen production process unit:
   (1) Unit identification number and annual CO\(_2\) emissions.
   (2) Monthly consumption of each fuel and feedstock used for hydrogen production and its type (scf of gaseous fuels and feedstocks, gallons of liquid fuels and feedstocks, kg of solid fuels and feedstocks).
   (3) Annual quantity of hydrogen produced (metric tons).
   (4) Annual quantity of ammonia produced, if applicable (metric tons).
   (5) Monthly analyses of carbon content for each fuel and feedstock used in hydrogen production (kg carbon/kg of gaseous and solid fuels and feedstocks, kg carbon per gallon of liquid fuels and feedstocks).
   (6) Monthly analyses of the molecular weight of gaseous fuels and feedstocks (kg/kg-mole) used, if any.
   (c) Quantity of CO\(_2\) collected and transferred off site in either gas, liquid, or solid forms, following the requirements of subpart PP of this part.
   (d) Annual quantity of carbon other than CO\(_2\) collected and transferred off site in either gas, liquid, or solid forms (kg carbon).

§ 98.167 Records that must be retained.

In addition to the information required by §98.3(g), you must retain the records specified in paragraphs (a) through (b) of this section for each hydrogen production facility.

(a) If a CEMS is used to measure CO\(_2\) emissions, then you must retain under this subpart the records required for the Tier 4 Calculation Methodology in §98.37.
   (b) If a CEMS is not used to measure CO\(_2\) emissions, then you must retain records of all analyses and calculations conducted as listed in §§98.166(b), (c), and (d).

§ 98.168 Definitions.

All terms used in this subpart have the same meaning given in the Clean Air Act and subpart A of this part.

Subpart Q—Iron and Steel Production

§ 98.170 Definition of the source category.

The iron and steel production source category includes facilities with any of the following processes: taconite iron ore processing, integrated iron and steel manufacturing, cokemaking not colocated with an integrated iron and steel manufacturing process, and electric arc furnace (EAF) steelmaking not colocated with an integrated iron and steel manufacturing process. Integrated iron and steel manufacturing means the production of steel from iron ore or iron ore pellets. At a minimum, an integrated iron and steel manufacturing process has a basic oxygen furnace for refining molten iron into steel. Each cokemaking process and EAF process located at a facility...
§ 98.171 Reporting threshold.

You must report GHG emissions under this subpart if your facility contains an iron and steel production process and the facility meets the requirements of either §98.2(a)(1) or (2).

§ 98.172 GHGs to report.

(a) You must report under subpart C of this part (General Stationary Fuel Combustion Sources) the emissions of CO₂, CH₄, and N₂O from each stationary combustion unit following the requirements of subpart C except for flares. Stationary combustion units include, but are not limited to, by-product recovery coke oven battery combustion stacks, blast furnace stoves, boilers, process heaters, reheating furnaces, annealing furnaces, flame suppression, ladle reheaters, and other miscellaneous combustion sources.

(b) You must report CO₂ emissions from flares that burn blast furnace gas or coke oven gas according to the procedures in §98.253(b)(1) of subpart Y (Petroleum Refineries) of this part. When using the alternatives set forth in §98.253(b)(1)(i)(B) and §98.253(b)(1)(ii)(C), you must use the default CO₂ emission factors for coke oven gas and blast furnace gas from Table C–1 to subpart C in Equations Y–2 and Y–3 of subpart Y. You must report CH₄ and N₂O emissions from flares according to the requirements in §98.33(c)(2) using the emission factors for coke oven gas and blast furnace gas in Table C–2 to subpart C of this part.

(c) You must report process CO₂ emissions from each taconite indurating furnace; basic oxygen furnace; non-recovery coke oven battery combustion stack; coke pushing process; sinter process; EAF; decarburization vessel; and direct reduction furnace by following the procedures in this subpart.


§ 98.173 Calculating GHG emissions.

You must calculate and report the annual process CO₂ emissions from each taconite indurating furnace, basic oxygen furnace, non-recovery coke oven battery, sinter process, EAF, decarburization vessel, and direct reduction furnace using the procedures in either paragraph (a) or (b) of this section. Calculate and report the annual process CO₂ emissions from the coke pushing process according to paragraph (c) of this section.

(a) Calculate and report under this subpart the process CO₂ emissions by operating and maintaining CEMS according to the Tier 4 Calculation Methodology in §98.33(a)(4) and all associated requirements for Tier 4 in subpart C of this part (General Stationary Fuel Combustion Sources).

(b) Calculate and report under this subpart the process CO₂ emissions using the procedure in paragraph (b)(1) or (b)(2) of this section.

1 Carbon mass balance method. Calculate the annual mass emissions of CO₂ for the process as specified in paragraphs (b)(1)(i) through (b)(1)(vii) of this section. The calculations are based on the annual mass of inputs and outputs to the process and an annual analysis of the respective weight fraction of carbon as determined according to the procedures in §98.174(b). If you have a process input or output other than CO₂ in the exhaust gas that contains carbon that is not included in Equations Q–1 through Q–7 of this section, you must account for the carbon and mass rate of that process input or output in your calculations according to the procedures in §98.174(b)(3).

(i) For taconite indurating furnaces, estimate CO₂ emissions using Equation Q–1 of this section.

\[ CO_2 = \frac{24}{17} \left( (F_i)(C_o) + (F_i')(C_o') + MFR \times 0.001 + (O) \times (C_o) - (P) \times (C_o') - (R) \times (C_o') \right) \] (Eq. Q-1)
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Where:

\( \text{CO}_2 = \) Annual \( \text{CO}_2 \) mass emissions from the taconite indurating furnace (metric tons).

\( 44/12 = \) Ratio of molecular weights, \( \text{CO}_2 \) to carbon.

\( (F_s) = \) Annual mass of the solid fuel combusted (metric tons).

\( (C_{sf}) = \) Carbon content of the solid fuel, from the fuel analysis (percent by weight, expressed as a decimal fraction, e.g., 95\% = 0.95).

\( (F_g) = \) Annual volume of the gaseous fuel combusted (scf).

\( (C_{gf}) = \) Average carbon content of the gaseous fuel, from the fuel analysis results (kg C per kg of fuel).

\( \text{MW} = \) Molecular weight of the gaseous fuel (kg/kg-mole).

\( \text{MVC} = \) Molar volume conversion factor (849.5 scf per kg-mole at standard conditions).

\( 0.001 = \) Conversion factor from kg to metric tons.

\( (F_l) = \) Annual volume of the liquid fuel combusted (gallons).

\( (C_{lf}) = \) Carbon content of the liquid fuel, from the fuel analysis results (kg C per gallon of fuel).

\( (O) = \) Annual mass of greenball (taconite) pellets fed to the furnace (metric tons).

\( (C_{O}) = \) Carbon content of the greenball (taconite) pellets, from the carbon analysis results (percent by weight, expressed as a decimal fraction).

\( (P) = \) Annual mass of fired pellets produced by the furnace (metric tons).

\( (C_{P}) = \) Carbon content of the fired pellets, from the carbon analysis results (percent by weight, expressed as a decimal fraction).

\( (R) = \) Annual mass of air pollution control residue collected (metric tons).

\( (C_R) = \) Carbon content of the air pollution control residue, from the carbon analysis results (percent by weight, expressed as a decimal fraction).

(ii) For basic oxygen process furnaces, estimate \( \text{CO}_2 \) emissions using Equation Q-2 of this section.

\[
\text{CO}_2 = \frac{44}{12} \left[ (\text{Iron}) \times (C_{\text{Iron}}) + (\text{Scrap}) \times (C_{\text{Scrap}}) + (\text{Flux}) \times (C_{\text{Flux}}) \\
+ (\text{Carbon}) \times (C_{\text{Carbon}}) - (\text{Steel}) \times (C_{\text{Steel}}) - (\text{Slag}) \times (C_{\text{Slag}}) - (R) \times (C_R) \right] \tag{Eq-Q-2}
\]

Where:

\( \text{CO}_2 = \) Annual \( \text{CO}_2 \) mass emissions from the basic oxygen furnace (metric tons).

\( 44/12 = \) Ratio of molecular weights, \( \text{CO}_2 \) to carbon.

\( (\text{Iron}) = \) Annual mass of molten iron charged to the furnace (metric tons).

\( (C_{\text{Iron}}) = \) Carbon content of the molten iron, from the carbon analysis results (percent by weight, expressed as a decimal fraction).

\( (\text{Scrap}) = \) Annual mass of ferrous scrap charged to the furnace (metric tons).

\( (C_{\text{Scrap}}) = \) Carbon content of the ferrous scrap, from the carbon analysis results (percent by weight, expressed as a decimal fraction).

\( (\text{Flux}) = \) Annual mass of flux materials (e.g., limestone, dolomite) charged to the furnace (metric tons).

\( (C_{\text{Flux}}) = \) Carbon content of the flux materials, from the carbon analysis results (percent by weight, expressed as a decimal fraction).

\( (\text{Carbon}) = \) Annual mass of carbonsaceous materials (e.g., coal, coke) charged to the furnace (metric tons).

\( (C_{\text{Carbon}}) = \) Carbon content of the carbonsaceous materials, from the carbon analysis results (percent by weight, expressed as a decimal fraction).

\( (\text{Steel}) = \) Annual mass of molten raw steel produced by the furnace (metric tons).

\( (C_{\text{Steel}}) = \) Carbon content of the steel, from the carbon analysis results (percent by weight, expressed as a decimal fraction).

\( (\text{Slag}) = \) Annual mass of slag produced by the furnace (metric tons).

\( (C_{\text{Slag}}) = \) Carbon content of the slag, from the carbon analysis results (percent by weight, expressed as a decimal fraction).

\( (R) = \) Annual mass of air pollution control residue collected (metric tons).

\( (C_R) = \) Carbon content of the air pollution control residue, from the carbon analysis results (percent by weight, expressed as a decimal fraction).

(iii) For non-recovery coke oven batteries, estimate \( \text{CO}_2 \) emissions using Equation Q-3 of this section.
\[
CO_2 = \frac{44}{12} \left[ (Coal) \cdot (C_{Coal}) - (\text{Coke}) \cdot (C_{\text{Coke}}) - (R) \cdot (C_R) \right]
\] (Eq. Q-3)

Where:
- \(CO_2\) = Annual \(CO_2\) mass emissions from the non-recovery coke oven battery (metric tons).
- 44/12 = Ratio of molecular weights, \(CO_2\) to carbon.
- \((\text{Coal})\) = Annual mass of coal charged to the battery (metric tons).
- \((C_{\text{Coal}})\) = Carbon content of the coal, from the carbon analysis results (percent by weight, expressed as a decimal fraction).
- \((\text{Coke})\) = Annual mass of coke produced by the battery (metric tons).
- \((C_{\text{Coke}})\) = Carbon content of the coke, from the carbon analysis results (percent by weight, expressed as a decimal fraction).
- \((R)\) = Annual mass of air pollution control residue collected (metric tons).

(iv) For sinter processes, estimate \(CO_2\) emissions using Equation Q-4 of this section.

\[
CO_2 = \frac{44}{12} \left[ \left( F_g \right) \cdot \left( C_{\text{g}} \right) \cdot \frac{\text{MW}}{\text{MVC}} + 0.001 \cdot (\text{Feed}) \cdot (C_{\text{Feed}}) - (\text{Sinter}) \cdot (C_{\text{Sinter}}) - (R) \cdot (C_R) \right]
\] (Eq. Q-4)

Where:
- \(CO_2\) = Annual \(CO_2\) mass emissions from the sinter process (metric tons).
- 44/12 = Ratio of molecular weights, \(CO_2\) to carbon.
- \((F_g)\) = Annual volume of the gaseous fuel combusted (scf).
- \((C_{\text{g}})\) = Carbon content of the gaseous fuel, from the fuel analysis results (kg C per kg of fuel).
- \(\text{MW}\) = Molecular weight of the gaseous fuel (kg/kg-mole).
- \(\text{MVC}\) = Molar volume conversion factor (849.5 scf per kg-mole at standard conditions).
- 0.001 = Conversion factor from kg to metric tons.
- \((\text{Feed})\) = Annual mass of sinter feed material (metric tons).
- \((C_{\text{Feed}})\) = Carbon content of the mixed sinter feed materials that form the bed entering the sintering machine, from the carbon analysis results (percent by weight, expressed as a decimal fraction).
- \((\text{Sinter})\) = Annual mass of sinter produced (metric tons).
- \((C_{\text{Sinter}})\) = Carbon content of the sinter pellets, from the carbon analysis results (percent by weight, expressed as a decimal fraction).
- \((R)\) = Annual mass of air pollution control residue collected (metric tons).
- \((C_R)\) = Carbon content of the air pollution control residue, from the carbon analysis results (percent by weight, expressed as a decimal fraction).

(v) For EAFs, estimate \(CO_2\) emissions using Equation Q-5 of this section.

\[
CO_2 = \frac{44}{12} \left[ (\text{Iron}) \cdot (C_{\text{Iron}}) + (\text{Scrap}) \cdot (C_{\text{Scrap}}) + (\text{Flux}) \right]
\]

\[
\cdot \left( C_f \right) + (\text{Electrode}) \cdot \left( C_{\text{Electrode}} \right) + (\text{Carbon}) \cdot (C_C) - (\text{Steel})
\]

\[
\cdot \left( C_{\text{Steel}} \right) - (\text{Slag}) \cdot (C_{\text{Slag}}) - (R) \cdot (C_R)
\] (Eq. Q-5)

Where:
- \(CO_2\) = Annual \(CO_2\) mass emissions from the EAF (metric tons).
- 44/12 = Ratio of molecular weights, \(CO_2\) to carbon.
- \((\text{Iron})\) = Annual mass of direct reduced iron (if any) charged to the furnace (metric tons).
- \((C_{\text{Iron}})\) = Carbon content of the direct reduced iron (percent by weight, expressed as a decimal fraction).
- \((C_{\text{Scrap}})\) = Carbon content of the scrap charged to the furnace (percent by weight, expressed as a decimal fraction).
- \((\text{Flux})\) = Annual mass of reducing agents charged to the furnace (metric tons).
- \((C_f)\) = Carbon content of the flux, from the carbon analysis results (percent by weight, expressed as a decimal fraction).
- \((\text{Electrode})\) = Annual mass of electrode charged to the furnace (metric tons).
- \((C_{\text{Electrode}})\) = Carbon content of the electrode, from the carbon analysis results (percent by weight, expressed as a decimal fraction).
- \((\text{Carbon})\) = Annual mass of carbon charged to the furnace (metric tons).
- \((C_C)\) = Carbon content of the carbon, from the carbon analysis results (percent by weight, expressed as a decimal fraction).
- \((\text{Steel})\) = Annual mass of steel charged to the furnace (metric tons).
- \((C_{\text{Steel}})\) = Carbon content of the steel, from the carbon analysis results (percent by weight, expressed as a decimal fraction).
- \((\text{Slag})\) = Annual mass of slag (metric tons).
- \((C_{\text{Slag}})\) = Carbon content of the slag, from the carbon analysis results (percent by weight, expressed as a decimal fraction).
- \((R)\) = Annual mass of slag (metric tons).
(C<br>iron) = Carbon content of the direct reduced iron, from the carbon analysis results (percent by weight, expressed as a decimal fraction).

(Scrap) = Annual mass of ferrous scrap charged to the furnace (metric tons).

(C<br>scrap) = Carbon content of the ferrous scrap, from the carbon analysis results (percent by weight, expressed as a decimal fraction).

(Flux) = Annual mass of flux materials (e.g., limestone, dolomite) charged to the furnace (metric tons).

(C<br>flux) = Carbon content of the flux materials, from the carbon analysis results (percent by weight, expressed as a decimal fraction).

(Electrode) = Annual mass of carbon electrode consumed (metric tons).

(C<br>electrode) = Carbon content of the carbon electrode, from the carbon analysis results (percent by weight, expressed as a decimal fraction).

(Carbon) = Annual mass of carbonaceous materials (e.g., coal, coke) charged to the furnace (metric tons).

(C<br>carbon) = Carbon content of the carbonaceous materials, from the carbon analysis results (percent by weight, expressed as a decimal fraction).

(Steel) = Annual mass of molten raw steel produced by the furnace (metric tons).

(C<br>steel) = Carbon content of the steel, from the carbon analysis results (percent by weight, expressed as a decimal fraction).

(Slag) = Annual mass of slag produced by the furnace (metric tons).

(C<br>slag) = Carbon content of the slag, from the carbon analysis results (percent by weight, expressed as a decimal fraction).

(R) = Annual mass of air pollution control residue collected (metric tons).

(C<br>r) = Carbon content of the air pollution control residue, from the carbon analysis results (percent by weight, expressed as a decimal fraction).

(vi) For decarburization vessels, estimate CO<sub>2</sub> emissions using Equation Q–6 of this section.

\[
\begin{align*}
CO_2 &= \frac{44}{12} \times (\text{Steel}) \times \left[ (C_{\text{steel in}}) - (C_{\text{steel out}}) \right] - (R) \times (C_r) \quad (\text{Eq. Q-6})
\end{align*}
\]

Where:

CO<sub>2</sub> = Annual CO<sub>2</sub> mass emissions from the decarburization vessel (metric tons).

44/12 = Ratio of molecular weights, CO<sub>2</sub> to carbon.

(Steel) = Annual mass of molten steel charged to the vessel (metric tons).

(C<sub>steel in</sub>) = Carbon content of the molten steel before decarburization, from the carbon analysis results (percent by weight, expressed as a decimal fraction).

(C<sub>steel out</sub>) = Carbon content of the molten steel after decarburization, from the carbon analysis results (percent by weight, expressed as a decimal fraction).

(R) = Annual mass of air pollution control residue collected (metric tons).

(C<sub>r</sub>) = Carbon content of the air pollution control residue, from the carbon analysis results (percent by weight, expressed as a decimal fraction).

(vii) For direct reduction furnaces, estimate CO<sub>2</sub> emissions using Equation Q–7 of this section.

\[
\begin{align*}
CO_2 &= \frac{44}{12} \times \left[ (F_g) \times \left( C_{gf} \right) \times \frac{MW}{MVC} \times 0.001 + (Ore) \times (C_{ore}) + (\text{Carbon}) \times (C_{\text{carbon}}) + (\text{Other}) \times (C_{\text{other}}) \right. \\
&\quad \left. + (\text{Iron}) \times (C_{\text{iron}}) - (NM) \times (C_{\text{nm}}) - (R) \times (C_r) \right]
\end{align*}
\]

Where:

CO<sub>2</sub> = Annual CO<sub>2</sub> mass emissions from the direct reduction furnace (metric tons).

44/12 = Ratio of molecular weights, CO<sub>2</sub> to carbon.

(F<sub>g</sub>) = Annual volume of the gaseous fuel combusted (scf).
(Cgf) = Carbon content of the gaseous fuel, from the fuel analysis results (kg C per kg of fuel).

MW = Molecular weight of the gaseous fuel (kg/kg-mole).

MVC = Molar volume conversion factor (849.5 scf per kg-mole at standard conditions).

0.001 = Conversion factor from kg to metric tons.

(Ore) = Annual mass of iron ore or iron ore pellets fed to the furnace (metric tons).

(COre) = Carbon content of the iron ore or iron ore pellets, from the carbon analysis results (percent by weight, expressed as a decimal fraction).

(Carbon) = Annual mass of carbonaceous materials (e.g., coal, coke) charged to the furnace (metric tons).

(CCarbon) = Carbon content of the carbonaceous materials, from the carbon analysis results (percent by weight, expressed as a decimal fraction).

(Other) = Annual mass of other materials charged to the furnace (metric tons).

(COther) = Average carbon content of the other materials charged to the furnace, from the carbon analysis results (percent by weight, expressed as a decimal fraction).

(Iron) = Annual mass of iron produced (metric tons).

(CIron) = Carbon content of the iron, from the carbon analysis results (percent by weight, expressed as a decimal fraction).

(NM) = Annual mass of non-metallic materials produced by the furnace (metric tons).

(CNM) = Carbon content of the non-metallic materials, from the carbon analysis results (percent by weight, expressed as a decimal fraction).

(R) = Annual mass of air pollution control residue collected (metric tons).

(2) Site-specific emission factor method.

Conduct a performance test and measure CO₂ emissions from all exhaust stacks for the process and measure either the feed rate of materials into the process or the production rate during the test as described in paragraphs (b)(2)(i) through (b)(2)(iv) of this section.

(i) You must measure the process production rate or process feed rate, as applicable, during the performance test according to the procedures in §98.174(c)(5) and calculate the average rate for the test period in metric tons per hour.

(ii) You must calculate the hourly CO₂ emission rate using Equation Q-8 of this section and determine the average hourly CO₂ emission rate for the test.

\[
CO₂ = 5.18 \times 10^{-7} \times C_{CO₂} \times Q \times \left(\frac{100 - \%H₂O}{100}\right)
\]

(Eq. Q-8)

Where:

CO₂ = CO₂ mass emission rate, corrected for moisture (metric tons/hr).

5.18 × 10⁻⁷ = Conversion factor (metric tons/scf-% CO₂).

C_{CO₂} = Hourly CO₂ concentration, dry basis (% CO₂).

Q = Hourly stack gas volumetric flow rate (scfh).

%H₂O = Hourly moisture percentage in the stack gas.

(iii) You must calculate a site-specific emission factor for the process in metric tons of CO₂ per metric ton of feed or production, as applicable, by dividing the average hourly CO₂ emission rate during the test by the average hourly feed or production rate during the test.

(iv) You must calculate CO₂ emissions for the process by multiplying the emission factor by the total amount of feed or production, as applicable, for the reporting period.

(c) You must determine emissions of CO₂ from the coke pushing process in mtCO₂e by multiplying the metric tons of coal charged to the coke ovens during the reporting period by 0.008.

(d) If GHG emissions from a taconite indurating furnace, basic oxygen furnace, non-recovery coke oven battery, sinter process, EAF, decarburization vessel, or direct reduction furnace are vented through the same stack as any combustion unit or process equipment that reports CO₂ emissions using a CEMS that complies with the Tier 4...
Calculation Methodology in subpart C of this part (General Stationary Fuel Combustion Sources), then the calculation methodology in paragraph (b) of this section shall not be used to calculate process emissions. The owner or operator shall report under this subpart the combined stack emissions according to the Tier 4 Calculation Methodology in §98.33(a)(4) and all associated requirements for Tier 4 in subpart C of this part (General Stationary Fuel Combustion Sources).

§ 98.174 Monitoring and QA/QC requirements.

(a) If you operate and maintain a CEMS that measures CO\textsubscript{2} emissions consistent with subpart C of this part, you must meet the monitoring and QA/QC requirements of §98.34(c).

(b) If you determine CO\textsubscript{2} emissions using the carbon mass balance procedure in §98.173(b)(1), you must:

(1) Except as provided in paragraph (b)(4) of this section, determine the mass of each process input and output other than fuels using the same plant instruments or procedures that are used for accounting purposes (such as weigh hoppers, belt weigh feeders, weighed purchased quantities in shipments or containers, combination of bulk density and volume measurements, etc.), record the totals for each process input and output for each calendar month, and sum the monthly mass to determine the annual mass for each process input and output. Determine the mass rate of fuels using the procedures for combustion units in §98.34.

(2) Except as provided in paragraph (b)(4) of this section, determine the carbon content of each process input and output annually for use in the applicable equations in §98.173(b)(1) based on analyses provided by the supplier or by the average carbon content determined by collecting and analyzing at least three samples each year using the standard methods specified in paragraphs (b)(2)(i) through (b)(2)(vi) of this section as applicable.

(i) ASTM C25–06, Standard Test Methods for Chemical Analysis of Limestone, Quicklime, and Hydrated Lime (incorporated by reference, see §98.7) for limestone, dolomite, and slag.

(ii) ASTM D5373–08 Standard Test Methods for Instrumental Determination of Carbon, Hydrogen, and Nitrogen in Laboratory Samples of Coal (incorporated by reference, see §98.7) for coal, coke, and other carbonaceous materials.

(iii) ASTM E1915–07a, Standard Test Methods for Analysis of Metal Bearing Ores and Related Materials by Combustion Infrared-Absorption Spectrometry (incorporated by reference, see §98.7) for iron ore, taconite pellets, and other iron-bearing materials.


(vi) For each process input that is a fuel, determine the carbon content and molecular weight (if applicable) using the applicable methods listed in §98.34.

(3) For solid ferrous materials charged to basic oxygen process furnaces or EAFs that differ in carbon content, you may determine a weighted average carbon content based on the carbon content of each type of ferrous material and the average weight percent of each type that is used. Examples of these different ferrous materials include carbon steel, low carbon steel, stainless steel, high alloy steel, pig iron, iron scrap, and direct reduced iron.

(4) If you document that a specific process input or output contributes

§ 98.175  Procedures for estimating missing data.

A complete record of all measured parameters used in the GHG emissions calculations in §98.173 is required. Therefore, whenever a quality-assured value of a required parameter is unavailable, a substitute data value for the missing parameter shall be used in the calculations as specified in the paragraphs (a) and (b) of this section. You must follow the missing data procedures in §98.255(b) of subpart Y (Petroleum Refineries) of this part for flares burning coke oven gas or blast furnace gas. You must document and keep records of the procedures used for all such estimates.

(a) For each missing data for the carbon content of inputs and outputs for facilities that estimate emissions using
the carbon mass balance procedure in §98.173(b)(1) or for facilities that estimate emissions using the site-specific emission factor procedure in §98.173(b)(2); 100 percent data availability is required. You must repeat the test for average carbon contents of inputs and outputs according to the procedures in §98.174(b)(2). Similarly, you must repeat the test to determine the site-specific emission factor if data on the CO_2 emission rate, process production rate or process feed rate are missing.

(b) For missing records of the monthly mass or volume of carbon-containing inputs and outputs using the carbon mass balance procedure in §98.173(b)(1), the substitute data value must be based on the best available estimate of the mass of the input or output material from all available process data or data used for accounting purposes.

§98.176 Data reporting requirements.

In addition to the information required by §98.3(c), each annual report must contain the information required in paragraphs (a) through (h) of this section for each coke pushing operation; taconite indurating furnace; basic oxygen furnace; non-recovery coke oven battery; sinter process; EAF; decarburization vessel; direct reduction furnace; and flare burning coke oven gas or blast furnace gas. For reporting year 2010, the information required in paragraphs (a) through (h) of this section is not required for decarburization vessels that are not argon-oxygen decarburization vessels. For reporting year 2011 and each subsequent reporting year, the information in paragraphs (a) through (h) of this section must be reported for all decarburization vessels.

(a) Unit identification number and annual CO_2 emissions (in metric tons).

(b) Annual production quantity (in metric tons) for taconite pellets, coke, sinter, iron, and raw steel.

(c) If a CEMS is used to measure CO_2 emissions, then you must report the relevant information required under §98.36 for the Tier 4 Calculation Methodology.

(d) If a CEMS is not used to measure CO_2 emissions, then you must report for each process whether the emissions were determined using the carbon mass balance method in §98.173(b)(1) or the site-specific emission factor method in §98.173(b)(2).

(e) If you use the carbon mass balance method in §98.173(b)(1) to determine CO_2 emissions, you must report the following information for each process:

1. The carbon content of each process input and output used to determine CO_2 emissions.
2. Whether the carbon content was determined from information from the supplier or by laboratory analysis, and if by laboratory analysis, the method used.
3. The annual volume of each type of gaseous fuel (reported separately for each type in standard cubic feet), the annual volume of each type of liquid fuel (reported separately for each type in gallons), and the annual mass (in metric tons) of each other process inputs and outputs used to determine CO_2 emissions.
4. The molecular weight of gaseous fuels.
5. If you used the missing data procedures in §98.175(b), you must report how the monthly mass for each process input or output with missing data was determined and the number of months the missing data procedures were used.
6. If you used the site-specific emission factor method in §98.173(b)(2) to determine CO_2 emissions, you must report the following information for each process:

1. The measured average hourly CO_2 emission rate during the test (in metric tons per hour).
2. The average hourly feed or production rate (as applicable) during the test (in metric tons per hour).
3. The site-specific emission factor (in metric tons of CO_2 per metric ton of feed or production, as applicable).
4. The annual feed or production rate (as applicable) used to estimate annual CO_2 emissions (in metric tons).
5. The annual amount of coal charged to the coke ovens (in metric tons).
6. For flares burning coke oven gas or blast furnace gas, the information
§ 98.177 Records that must be retained.

In addition to the records required by §98.3(g), you must retain the records specified in paragraphs (a) through (e) of this section, as applicable. Facilities that use CEMS to measure emissions must also retain records of the verification data required for the Tier 4 Calculating Methodology in §98.36(e).

(a) Records of all analyses and calculations conducted, including all information reported as required under §98.176.

(b) When the carbon mass balance method is used to estimate emissions for a process, the monthly mass of each process input and output that are used to determine the annual mass.

(c) Production capacity (in metric tons per year) for the production of taconite pellets, coke, sinter, iron, and raw steel.

(d) Annual operating hours for each taconite indurating furnace, basic oxygen furnace, non-recovery coke oven battery, sinter process, electric arc furnace, decarburization vessel, and direct reduction furnace.

(e) Facilities must keep records that include a detailed explanation of how company records or measurements are used to determine all sources of carbon input and output and the metric tons of coal charged to the coke ovens (e.g., weigh belts, a combination of measuring volume and bulk density). You also must document the procedures used to ensure the accuracy of the measurements of fuel usage including, but not limited to, calibration of weighing equipment, fuel flow meters, coal usage including, but not limited to, calibration of weighing equipment and other measurement devices. The estimated accuracy of measurements made with these devices must also be recorded, and the technical basis for these estimates must be provided.


§ 98.178 Definitions.

All terms used in this subpart have the same meaning given in the Clean Air Act and subpart A of this part.

Subpart R—Lead Production

§ 98.180 Definition of the source category.

The lead production source category consists of primary lead smelters and secondary lead smelters. A primary lead smelter is a facility engaged in the production of lead metal from lead sulfide ore concentrates through the use of pyrometallurgical techniques. A secondary lead smelter is a facility at which lead-bearing scrap materials (including but not limited to, lead-acid batteries) are recycled by smelting into elemental lead or lead alloys.

§ 98.181 Reporting threshold.

You must report GHG emissions under this subpart if your facility contains a lead production process and the facility meets the requirements of either §98.2(a)(1) or (a)(2).

§ 98.182 GHGs to report.

You must report:

(a) Process CO\textsubscript{2} emissions from each smelting furnace used for lead production.

(b) CO\textsubscript{2} combustion emissions from each smelting furnace used for lead production.

(c) CH\textsubscript{4} and N\textsubscript{2}O combustion emissions from each smelting furnace used for lead production. You must calculate and report these emissions under subpart C of this part (General Stationary Fuel Combustion Sources) by following the requirements of subpart C.

(d) CO\textsubscript{2}, CH\textsubscript{4}, and N\textsubscript{2}O emissions from each stationary combustion unit other than smelting furnaces used for lead production. You must report these emissions under subpart C of this part (General Stationary Fuel Combustion Sources) by following the requirements of subpart C.

§ 98.183 Calculating GHG emissions.

You must calculate and report the annual process CO\textsubscript{2} emissions from
each smelting furnace using the procedure in paragraphs (a) and (b) of this section.

(a) For each smelting furnace that meets the conditions specified in §98.33(b)(4)(ii) or (b)(4)(iii), you must calculate and report combined process and combustion CO\textsubscript{2} emissions by operating and maintaining a CEMS to measure CO\textsubscript{2} emissions according to the Tier 4 Calculation Methodology specified in §98.33(a)(4) and all associated requirements for Tier 4 in subpart C of this part (General Stationary Fuel Combustion Sources).

(b) For each smelting furnace that is not subject to the requirements in paragraph (a) of this section, calculate and report the process and combustion CO\textsubscript{2} emissions from the smelting furnace by using the procedure in either paragraph (b)(1) or (b)(2) of this section.

(1) Calculate and report under this subpart the combined process and combustion CO\textsubscript{2} emissions by operating and maintaining a CEMS to measure CO\textsubscript{2} emissions according to the Tier 4 Calculation Methodology specified in §98.33(a)(4) and all associated requirements for Tier 4 in subpart C of this part (General Stationary Fuel Combustion Sources).

(2) Calculate and report process and combustion CO\textsubscript{2} emissions separately using the procedures specified in paragraphs (b)(2)(i) through (b)(2)(iii). This section.

(i) For each smelting furnace, determine the annual mass of carbon in each carbon-containing material, other than fuel, that is fed, charged, or otherwise introduced into the smelting furnace and estimate annual process CO\textsubscript{2} emissions using Equation R–1 of this section. Carbon-containing materials include carbonaceous reducing agents. If you document that a specific material contributes less than 1 percent of the total carbon into the process, you do not have to include the material in your calculation using Equation R–1 of this section.

\[
\begin{align*}
E_{CO2} & = \frac{44}{12} \cdot \frac{2000}{2205} \left[ (\text{Ore} \times C_{\text{Ore}}) + (\text{Scrap} \times C_{\text{Scrap}}) + (\text{Flux} \times C_{\text{Flux}}) + (\text{Carbon} \times C_{\text{Carbon}}) + (\text{Other} \times C_{\text{Other}}) \right] \\
\text{Where:} \\
E_{CO2} & = \text{Annual process CO}_2 \text{ emissions from an individual smelting furnace (metric tons).} \\
44/12 & = \text{Ratio of molecular weights, CO}_2 \text{ to carbon.} \\
2000/2205 & = \text{Conversion factor to convert tons to metric tons.} \\
\text{Ore} & = \text{Annual mass of lead ore charged to the smelting furnace (tons).} \\
C_{\text{Ore}} & = \text{Carbon content of the lead ore, from the carbon analysis results (percent by weight, expressed as a decimal fraction).} \\
\text{Scrap} & = \text{Annual mass of lead scrap charged to the smelting furnace (tons).} \\
C_{\text{Scrap}} & = \text{Carbon content of the lead scrap, from the carbon analysis (percent by weight, expressed as a decimal fraction).} \\
\text{Flux} & = \text{Annual mass of flux materials (e.g., limestone, dolomite) charged to the smelting furnace (tons).} \\
C_{\text{Flux}} & = \text{Carbon content of the flux materials, from the carbon analysis (percent by weight, expressed as a decimal fraction).} \\
\text{Carbon} & = \text{Annual mass of carbonaceous materials (e.g., coal, coke) charged to the smelting furnace (tons).} \\
C_{\text{Carbon}} & = \text{Carbon content of the carbonaceous materials, from the carbon analysis (percent by weight, expressed as a decimal fraction).} \\
\text{Other} & = \text{Annual mass of any other material containing carbon, other than fuel, fed, charged, or otherwise introduced into the smelting furnace (tons).} \\
C_{\text{Other}} & = \text{Carbon content of the other material from the carbon analysis results (percent by weight, expressed as a decimal fraction).} \\
\end{align*}
\]

(ii) Determine the combined annual process CO\textsubscript{2} emissions from the smelting furnaces at your facility using Equation R–2 of this section.

\[
\begin{align*}
CO_2 & = \sum_{k=1}^{k} E_{CO2k} \\
\text{Where:} \\
CO_2 & = \text{Annual process CO}_2 \text{ emissions from smelting furnaces at facility used for lead production (metric tons).} \\
E_{CO2k} & = \text{Annual process CO}_2 \text{ emissions from smelting furnace } k \text{ calculated using Equation R–1 of this section (metric ton/year).} \\
k & = \text{Total number of smelting furnaces at facility used for lead production.}
\end{align*}
\]
§ 98.184

(iii) Calculate and report under subpart C of this part (General Stationary Fuel Combustion Sources) the combustion CO$_2$ emissions from the smelting furnaces according to the applicable requirements in subpart C.

§ 98.184 Monitoring and QA/QC requirements.

If you determine process CO$_2$ emissions using the carbon mass balance procedure in §98.183(b)(2)(i) and (b)(2)(ii), you must meet the requirements specified in paragraphs (a) and (b) of this section.

(a) Determine the annual mass for each material used for the calculations of annual process CO$_2$ emissions using Equation R–1 of this subpart by summing the monthly mass for the material determined for each month of the calendar year. The monthly mass may be determined using plant instruments used for accounting purposes, including either direct measurement of the quantity of the material placed in the unit or by calculations using process operating information.

(b) For each material identified in paragraph (a) of this section, you must determine the average carbon content of the material consumed or used in the calendar year using the methods specified in either paragraph (b)(1) or (b)(2) of this section. If you document that a specific process input or output contributes less than one percent of the total mass of carbon into or out of the process, you do not have to determine the monthly mass or annual carbon content of that input or output.

(1) Information provided by your material supplier.

(2) Collecting and analyzing at least three representative samples of the material each year. The carbon content of the material must be analyzed at least annually using the methods (and their QA/QC procedures) specified in paragraphs (b)(2)(i) through (b)(2)(iii) of this section, as applicable.

(i) ASTM E1941–04, Standard Test Method for Determination of Carbon in Refractory and Reactive Metals and Their Alloys (incorporated by reference, see §98.7) for analysis of metal ore and alloy product.

(ii) ASTM D5373–08 Standard Test Methods for Instrumental Determina-

§ 98.185 Procedures for estimating missing data.

A complete record of all measured parameters used in the GHG emissions calculations in §98.183 is required. Therefore, whenever a quality-assured value of a required parameter is unavailable, a substitute data value for the missing parameter shall be used in the calculations as specified in the paragraphs (a) and (b) of this section. You must document and keep records of the procedures used for all such estimates.

(a) For each missing data for the carbon content for the smelting furnaces at your facility that estimate annual process CO$_2$ emissions using the carbon mass balance procedure in §98.183(b)(2)(i) and (ii), 100 percent data availability is required. You must repeat the test for average carbon contents of inputs according to the procedures in §98.184(b) if data are missing.

(b) For missing records of the monthly mass of carbon-containing materials, the substitute data value must be based the best available estimate of the mass of the material from all available process data or data used for accounting purposes (such as purchase records).

§ 98.186 Data reporting procedures.

In addition to the information required by §98.3(c), each annual report must contain the information specified in paragraphs (a) or (b) of this section, as applicable.

(a) If a CEMS is used to measure CO$_2$ emissions according to the requirements in §98.183(a) or (b)(1), then you must report under this subpart the relevant information required by §98.36 and the information specified in paragraphs (a)(1) through (a)(4) of this section.
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§ 98.187 Records that must be retained.

In addition to the records required by §98.3(g), each annual report must contain the information specified in paragraphs (a) through (c) of this section, as applicable to the smelting furnaces at your facility.

(a) If a CEMS is used to measure combined process and combustion CO₂ emissions according to the requirements in §98.183(a) or (b)(1), then you must retain the records required for the Tier 4 Calculation Methodology in §98.37 and the information specified in paragraphs (a)(1) through (a)(3) of this section.

(1) Monthly smelting furnace production quantity for each lead product (tons).

(2) Number of smelting furnace operating hours each month.

(3) Number of smelting furnace operating hours in calendar year.

(b) If the carbon mass balance procedure is used to determine process CO₂ emissions according to the requirements in §98.183(b)(2)(i) and (b)(2)(ii), then you must retain the records specified in paragraphs (b)(1) through (b)(5) of this section.

(1) Monthly smelting furnace production quantity for each lead product (tons).

(2) Number of smelting furnace operating hours each month.

(3) Number of smelting furnace operating hours in calendar year.

(4) Monthly material quantity consumed, used, or produced for each material included for the calculations of annual process CO₂ emissions using Equation R–1 of this subpart (tons).

(5) Average carbon content determined and records of the supplier provided information or analyses used for the determination for each material included for the calculations of annual process CO₂ emissions using Equation R–1 of this subpart (tons).

(c) You must keep records that include a detailed explanation of how company records of measurements are used to estimate the carbon input to each smelting furnace, including documentation of any materials excluded from Equation R–1 of this subpart that contribute less than 1 percent of the total carbon into or out of the process. You also must document the procedures used to ensure the accuracy of the measurements of materials fed,
charged, or placed in an smelting furnace including, but not limited to, calibration of weighing equipment and other measurement devices. The estimated accuracy of measurements made with these devices must also be recorded, and the technical basis for these estimates must be provided.

§ 98.188 Definitions.

All terms used in this subpart have the same meaning given in the Clean Air Act and subpart A of this part.

Subpart S—Lime Manufacturing

§ 98.190 Definition of the source category.

(a) Lime manufacturing plants (LMPs) engage in the manufacture of a lime product (e.g., calcium oxide, high-calcium quicklime, calcium hydroxide, hydrated lime, dolomitic quicklime, dolomitic hydrate, or other lime products) by calcination of limestone, dolomite, shells or other calcareous substances as defined in 40 CFR 63.7081(a)(1).

(b) This source category includes all LMPs unless the LMP is located at a kraft pulp mill, soda pulp mill, sulfite pulp mill, or only processes sludge containing calcium carbonate from water softening processes. The lime manufacturing source category consists of marketed and non-marketed lime manufacturing facilities.

(c) Lime kilns at pulp and paper manufacturing facilities must report emissions under subpart AA of this part (Pulp and Paper Manufacturing).

§ 98.191 Reporting threshold.

You must report GHG emissions under this subpart if your facility is a lime manufacturing plant as defined in §98.190 and the facility meets the requirements of either §98.2(a)(1) or (a)(2).

§ 98.192 GHGs to report.

You must report:

(a) CO₂ process emissions from lime kilns.

(b) CO₂ emissions from fuel combustion at lime kilns.

(c) N₂O and CH₄ emissions from fuel combustion at each lime kiln. You must report these emissions under 40 CFR part 98, subpart C (General Stationary Fuel Combustion Sources).

(d) CO₂, N₂O, and CH₄ emissions from each stationary fuel combustion unit other than lime kilns. You must report these emissions under 40 CFR part 98, subpart C (General Stationary Fuel Combustion Sources).

(e) CO₂ collected and transferred off site under 40 CFR part 98, following the requirements of subpart PP of this part (Suppliers of Carbon Dioxide (CO₂)).

§ 98.193 Calculating GHG emissions.

You must calculate and report the annual process CO₂ emissions from all lime kilns combined using the procedure in paragraphs (a) and (b) of this section.

(a) If all lime kilns meet the conditions specified in §98.33(b)(4)(ii) or (b)(4)(iii), you must calculate and report under this subpart the combined process and combustion CO₂ emissions by operating and maintaining a CEMS to measure CO₂ emissions according to the Tier 4 Calculation Methodology specified in §98.33(a)(4) and all associated requirements for Tier 4 in subpart C of this part (General Stationary Fuel Combustion Sources).

(b) If CEMS are not required to be used to determine CO₂ emissions from all lime kilns under paragraph (a) of this section, then you must calculate and report the process and combustion CO₂ emissions from the lime kilns by using the procedures in either paragraph (b)(1) or (b)(2) of this section.

(1) Calculate and report under this subpart the combined process and combustion CO₂ emissions by operating and maintaining a CEMS to measure CO₂ emissions from all lime kilns according to the Tier 4 Calculation Methodology specified in §98.33(a)(4) and all associated requirements for Tier 4 in subpart C of this part (General Stationary Fuel Combustion Sources).

(2) Calculate and report process and combustion CO₂ emissions separately using the procedures specified in paragraphs (b)(2)(i) through (b)(2)(v) of this section.

(i) You must calculate a monthly emission factor for each type of lime
produced using Equation S–1 of this section. Calcium oxide and magnesium oxide content must be analyzed monthly for each lime product type that is produced:

\[ EF_{LIME,i,n} = \left( SR_{CaO} \cdot CaO_{i,n} \right) + \left( SR_{MgO} \cdot MgO_{i,n} \right) \times \frac{2000}{2205} \]  
(Eq. S-1)

Where:
- \( EF_{LIME,i,n} \) = Emission factor for lime type \( i \), for month \( n \) (metric tons CO\(_2\)/ton lime).
- \( SR_{CaO} \) = Stoichiometric ratio of CO\(_2\) and CaO for calcium carbonate (see Table S–1 of this subpart) (metric tons CO\(_2\)/metric tons CaO).
- \( SR_{MgO} \) = Stoichiometric ratio of CO\(_2\) and MgO for magnesium carbonate (See Table S–1 of this subpart) (metric tons CO\(_2\)/metric tons MgO).
- \( CaO_{i,n} \) = Calcium oxide content for lime type \( i \), for month \( n \), determined according to §98.194(c) (metric tons CaO/metric ton lime).
- \( MgO_{i,n} \) = Magnesium oxide content for lime type \( i \), for month \( n \), determined according to §98.194(c) (metric tons MgO/metric ton lime).
- 2000/2205 = Conversion factor for tons to metric tons.

(ii) You must calculate a monthly emission factor for each type of calcined byproduct/waste sold (including lime kiln dust) using Equation S–2 of this section:

\[ EF_{LKD,i,n} = \left( SR_{CaO} \cdot CaO_{LKD,i,n} \right) + \left( SR_{MgO} \cdot MgO_{LKD,i,n} \right) \times \frac{2000}{2205} \]  
(Eq. S-2)

Where:
- \( EF_{LKD,i,n} \) = Emission factor for calcined lime byproduct/waste type \( i \) sold, for month \( n \) (metric tons CO\(_2\)/ton lime byproduct).
- \( SR_{CaO} \) = Stoichiometric ratio of CO\(_2\) and CaO for calcium carbonate (see Table S–1 of this subpart) (metric tons CO\(_2\)/metric tons CaO).
- \( SR_{MgO} \) = Stoichiometric ratio of CO\(_2\) and MgO for magnesium carbonate (See Table S–1 of this subpart) (metric tons CO\(_2\)/metric tons MgO).
- \( CaO_{LKD,i,n} \) = Calcium oxide content for calcined lime byproduct/waste type \( i \) sold, for month \( n \) (metric tons CaO/metric ton lime).
- \( MgO_{LKD,i,n} \) = Magnesium oxide content for calcined lime byproduct/waste type \( i \) sold, for month \( n \) (metric tons MgO/metric ton lime).
- 2000/2205 = Conversion factor for tons to metric tons.

(iii) You must calculate the annual CO\(_2\) emissions from each type of calcined byproduct/waste that is not sold (including lime kiln dust and scrubber sludge) using Equation S–3 of this section:

\[ E_{waste,i} = \left( SR_{CaO} \cdot CaO_{waste,i} \right) + \left( SR_{MgO} \cdot MgO_{waste,i} \right) \times M_{waste,i} \times \frac{2000}{2205} \]  
(Eq. S-3)

Where:
- \( E_{waste,i} \) = Annual CO\(_2\) emissions for calcined lime byproduct/waste type \( i \) that is not sold (metric tons CO\(_2\)).
- \( SR_{CaO} \) = Stoichiometric ratio of CO\(_2\) and CaO for calcium carbonate (see Table S–1 of this subpart) (metric tons CO\(_2\)/metric tons CaO).
- \( SR_{MgO} \) = Stoichiometric ratio of CO\(_2\) and MgO for magnesium carbonate (See Table S–1 of this subpart) (metric tons CO\(_2\)/metric tons MgO).
- \( CaO_{waste,i} \) = Calcium oxide content for calcined lime byproduct/waste type \( i \) that is not sold (metric tons CaO/metric ton lime).
- \( MgO_{waste,i} \) = Magnesium oxide content for calcined lime byproduct/waste type \( i \) that is not sold (metric tons MgO/metric ton lime).
§ 98.194 Monitoring and QA/QC requirements.

(a) You must determine the total quantity of each type of lime product that is produced and each calcined byproduct/waste (such as lime kiln dust) that is sold. The quantities of each should be directly measured monthly with the same plant instruments used for accounting purposes, including but not limited to, calibrated weigh feeders, rail or truck scales, and barge measurements. The direct measurements of each lime product shall be reconciled annually with the difference in the beginning of and end of year inventories for these products, when measurements represent lime sold.

(b) You must determine the annual quantity of each calcined byproduct/waste generated that is not sold by either direct measurement using the same instruments identified in paragraph (a) of this section or by using a calcined byproduct/waste generation rate.

(c) You must determine the chemical composition (percent total CaO and percent total MgO) of each type of lime product that is produced and each type of calcined byproduct/waste sold according to paragraph (c)(1) or (2) of this section. You must determine the chemical composition for each type of calcined byproduct/waste that is not sold on an annual basis.

(1) ASTM C25–06 Standard Test Methods for Chemical Analysis of Limestone, Quicklime, and Hydrated Lime (incorporated by reference—see §98.7).


(d) You must use the analysis of calcium oxide and magnesium oxide content of each lime product that is produced and that is collected during the
same month as the production data in monthly calculations.

(e) You must follow the quality assurance/quality control procedures (including documentation) in National Lime Association’s CO\textsubscript{2} Emissions Calculation Protocol for the Lime Industry English Units Version, February 5, 2008 Revision—National Lime Association (incorporated by reference—see §98.7).

§ 98.195 Procedures for estimating missing data.

For the procedure in §98.193(b)(1), a complete record of all measured parameters used in the GHG emissions calculations is required (e.g., oxide content, quantity of lime products, etc.). Therefore, whenever a quality-assured value of a required parameter is unavailable, a substitute data value for the missing parameter shall be used in the calculations as specified in paragraphs (a) or (b) of this section. You must document and keep records of the procedures used for all such estimates.

(a) For each missing value of the quantity of lime produced (by lime type), and quantity of calcined byproduct/waste produced and sold, the substitute data value shall be the best available estimate based on all available process data or data used for accounting purposes.

(b) For missing values related to the CaO and MgO content, you must conduct a new composition test according to the standard methods in §98.194 (c)(1) or (c)(2).

§98.196 Data reporting requirements.

In addition to the information required by §98.3(c), each annual report must contain the information specified in paragraphs (a) or (b) of this section, as applicable.

(a) If a CEMS is used to measure CO\textsubscript{2} emissions, then you must report under this subpart the relevant information required by §98.36 and the information listed in paragraphs (a)(1) through (8) of this section.

1. Method used to determine the quantity of lime that is produced and sold.
2. Method used to determine the quantity of calcined lime byproduct/waste sold.
3. Beginning and end of year inventories for each lime product that is produced, by type.
4. Beginning and end of year inventories for calcined lime byproducts/wastes sold, by type.
5. Annual amount of calcined lime byproduct/waste sold, by type (tons).
6. Annual amount of lime product sold, by type (tons).
7. Annual amount of calcined lime byproduct/waste that is not sold, by type (tons).
8. Annual amount of lime product not sold, by type (tons).
9. Monthly emission factors for each lime type produced.
10. Monthly emission factors for each calcined byproduct/waste by lime type that is sold.
11. Standard method used (ASTM or NLA testing method) to determine chemical compositions of each lime type produced and each calcined lime byproduct/waste type.
12. Monthly results of chemical composition analysis of each type of lime byproduct/waste sold.
13. Annual results of chemical composition analysis of each type of lime byproduct/waste that is not sold.
14. Method used to determine the quantity of lime produced and/or lime sold.
15. Monthly amount of lime product sold, by type (tons).
16. Method used to determine the quantity of calcined lime byproduct/waste sold.
17. Monthly amount of calcined lime byproduct/waste sold, by type (tons).
18. Annual amount of calcined lime byproduct/waste that is not sold, by type (tons).
19. Monthly weight or mass of each lime type produced (tons).
§ 98.197 Records that must be retained.

In addition to the records required by §98.3(g), you must retain the records specified in paragraphs (a) and (b) of this section.

(a) Annual operating hours in calendar year.

(b) Records of all analyses (e.g. chemical composition of lime products, by type) and calculations conducted.

§ 98.198 Definitions.

All terms used in this subpart have the same meaning given in the Clean Air Act and subpart A of this part.

TABLE S–1 TO SUBPART S OF PART 98—
BASE Parameters FOR THE CALCULATION OF EMISSION FACTORS FOR LIME PRODUCTION

<table>
<thead>
<tr>
<th>Variable</th>
<th>Stoichiometric ratio</th>
</tr>
</thead>
<tbody>
<tr>
<td>SR&lt;sub&gt;CO&lt;/sub&gt;</td>
<td>0.7848</td>
</tr>
<tr>
<td>SR&lt;sub&gt;MgO&lt;/sub&gt;</td>
<td>1.0918</td>
</tr>
</tbody>
</table>

Subpart T—Magnesium Production

SOURCE: 75 FR 39761, July 12, 2010, unless otherwise noted.

§ 98.200 Definition of source category.

The magnesium production and processing source category consists of the following processes:

(a) Any process in which magnesium metal is produced through smelting (including electrolytic smelting), refining, or remelting operations.

(b) Any process in which molten magnesium is used in alloying, casting, drawing, extruding, forming, or rolling operations.

§ 98.201 Reporting threshold.

You must report GHG emissions under this subpart if your facility contains a magnesium production process and the facility meets the requirements of either §98.2(a)(1) or (2).

§ 98.202 GHGs to report.

(a) You must report emissions of the following gases in metric tons per year resulting from their use as cover gases or carrier gases in magnesium production or processing:

1. Sulfur hexafluoride (SF<sub>6</sub>).
2. HFC–134a.
3. The fluorinated ketone, FK 5–1–12.
4. Carbon dioxide (CO<sub>2</sub>).
5. Any other GHGs (as defined in §98.6).

(b) You must report under subpart C of this part (General Stationary Fuel Combustion Sources) the CO<sub>2</sub>, N<sub>2</sub>O, and CH<sub>4</sub> emissions from each combustion unit by following the requirements of subpart C.

§ 98.203 Calculating GHG emissions.

(a) Calculate the mass of each GHG emitted from magnesium production or processing over the calendar year using either Equation T–1 or Equation T–2 of this section, as appropriate. Both of these equations equate emissions of cover gases or carrier gases to consumption of cover gases or carrier gases.

1. To estimate emissions of cover gases or carrier gases by monitoring changes in container masses and inventories, emissions of each cover gas or carrier gas shall be estimated using Equation T–1 of this section:
\[ E_x = (I_{B,x} - I_{E,x} + A_x - D_x) \times 0.001 \quad \text{(Eq. T-1)} \]

Where:
- \( E_x \) = Emissions of each cover gas or carrier gas, \( X \), in metric tons over the reporting year.
- \( I_{B,x} \) = Inventory of each cover gas or carrier gas stored in cylinders or other containers at the beginning of the year, including heels, in kg.
- \( I_{E,x} \) = Inventory of each cover gas or carrier gas stored in cylinders or other containers at the end of the year, including heels, in kg.
- \( A_x \) = Acquisitions of each cover gas or carrier gas during the year through purchases or other transactions, including heels in cylinders or other containers returned to the magnesium production or processing facility, in kg.
- \( D_x \) = Disbursements of each cover gas or carrier gas to sources and locations outside the facility through sales or other transactions during the year, including heels in cylinders or other containers returned by the magnesium production or processing facility to the gas supplier, in kg.
- 0.001 = Conversion factor from kg to metric tons.
- \( X \) = Each cover gas or carrier gas that is a GHG.

(2) To estimate emissions of cover gases or carrier gases by monitoring changes in the masses of individual containers as their contents are used, emissions of each cover gas or carrier gas shall be estimated using Equation T-2 of this section:

\[ E_{\text{GHG}} = \sum_{p=1}^{n} Q_p \times 0.001 \quad \text{(Eq. T-2)} \]

Where:
- \( E_{\text{GHG}} \) = Emissions of each cover gas or carrier gas, \( X \), over the reporting year (metric tons).
- \( Q_p \) = The mass of the cover or carrier gas consumed (kg) over the container-use period \( p \) (e.g., one month).
- \( M_B \) = The mass of the container’s contents (kg) at the beginning of period \( p \).
- \( M_E \) = The mass of the container’s contents (kg) at the end of period \( p \).
- 0.001 = Conversion factor from kg to metric tons.
- \( X \) = Each cover gas or carrier gas that is a GHG.

(b) For purposes of Equation T-2 of this section, the mass of the cover gas used over the period \( p \) for an individual container shall be estimated by using Equation T-3 of this section:

\[ Q_p = M_B - M_E \quad \text{(Eq. T-3)} \]

Where:
- \( Q_p \) = The mass of the cover or carrier gas consumed (kg) over the container-use period \( p \) (e.g., one month).
- \( M_B \) = The mass of the container’s contents (kg) at the beginning of period \( p \).
- \( M_E \) = The mass of the container’s contents (kg) at the end of period \( p \).
- \( X \) = Each cover gas or carrier gas that is a GHG.

(c) If a facility has mass flow controllers (MFC) and the capacity to track and record MFC measurements to estimate total gas usage, the mass of each cover or carrier gas monitored may be used as the mass of cover gas or carrier gas consumed (\( Q_p \)), in kg for period \( p \) in Equation T-2 of this section.

§ 98.204 Monitoring and QA/QC requirements.

(a) For calendar year 2011 monitoring, the facility may submit a request to the Administrator to use one or more best available monitoring methods as listed in §98.3(d)(1)(i) through (iv). The request must be submitted no later than October 12, 2010 and must contain the information in §98.3(d)(2)(ii). To obtain approval, the request must demonstrate to the Administrator’s satisfaction that it is not reasonably feasible to acquire, install, and operate a required piece of monitoring equipment by January 1, 2011. The use of best available monitoring methods will not be approved beyond December 31, 2011.

(b) Emissions (consumption) of cover gases and carrier gases may be estimated by monitoring the changes in container weights and inventories using Equation T-1 of this subpart, by monitoring the changes in individual container weights as the contents of each container are used using Equations T-2 and T-3 of this subpart, or by monitoring the mass flow of the pure cover gas or carrier gas into the gas distribution system. Emissions must be estimated at least annually.
§ 98.205 Procedures for estimating missing data.

(a) A complete record of all measured parameters used in the GHG emission calculations is required. Therefore, whenever a quality-assured value of a required parameter is unavailable, a substitute data value for the missing parameter will be used in the calculations as specified in paragraph (b) of this section.

(b) Replace missing data on the emissions of cover or carrier gases by multiplying magnesium production during the missing data period by the average cover or carrier gas usage rate from the most recent period when operating conditions were similar to those for the period for which the data are missing. Calculate the usage rate for each cover or carrier gas using Equation T-4 of this section:

\[ R_{\text{GHG}} = \frac{C_{\text{GHG}}}{Mg} \times 0.001 \]  

(Eq. T-4)

Where:

- \( R_{\text{GHG}} \) = The usage rate for a particular cover or carrier gas over the period of comparable operation (metric tons gas/metric ton Mg).
- \( C_{\text{GHG}} \) = The consumption of that cover or carrier gas over the period of comparable operation (kg).
- \( Mg \) = The magnesium produced or fed into the process over the period of comparable operation (metric tons).
- 0.001 = Conversion factor from kg to metric tons.

(c) If the precise before and after weights are not available, it should be assumed that the container was emptied in the process (i.e., quantity purchased should be used, less heel).

§ 98.206 Data reporting requirements.

In addition to the information required by §98.3(c), each annual report must include the following information at the facility level:

(a) Emissions of each cover or carrier gas in metric tons.

(b) Types of production processes at the facility (e.g., primary, secondary, die casting).
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(c) Amount of magnesium produced or processed in metric tons for each process type. This includes the output of primary and secondary magnesium production processes and the input to magnesium casting processes.

(d) Cover and carrier gas flow rate (e.g., standard cubic feet per minute) for each production unit and composition in percent by volume.

(e) For any missing data, you must report the length of time the data were missing for each cover gas or carrier gas, the method used to estimate emissions in their absence, and the quantity of emissions thereby estimated.

(f) The annual cover gas usage rate for the facility for each cover gas, excluding the carrier gas (kg gas/metric ton Mg).

(g) If applicable, an explanation of any change greater than 30 percent in the facility’s cover gas usage rate (e.g., installation of new melt protection technology or leak discovered in the cover gas delivery system that resulted in increased emissions).

(h) A description of any new melt protection technologies adopted to account for reduced or increased GHG emissions in any given year.

§ 98.207 Records that must be retained.

In addition to the records specified in §98.3(g), you must retain the following information at the facility level:

(a) Check-out and weigh-in sheets and procedures for gas cylinders.

(b) Accuracy certifications and calibration records for scales including the method or manufacturer’s specification used for calibration.

(c) Residual gas amounts (heel) in cylinders sent back to suppliers.

(d) Records, including invoices, for gas purchases, sales, and disbursements for all GHGs.

§ 98.208 Definitions.

All terms used in this subpart have the same meaning given in the Clean Air Act and subpart A of this part. Additionally, some sector-specific definitions are provided below:

Carrier gas means the gas with which cover gas is mixed to transport and dilute the cover gas thus maximizing its efficient use. Carrier gases typically include CO₂, N₂, and/or dry air.

Cover gas means SF₆, HFC-134a, fluorinated ketone (FK 5–1–12) or other gas used to protect the surface of molten magnesium from rapid oxidation and burning in the presence of air. The molten magnesium may be the surface of a casting or ingot production operation or the surface of a crucible of molten magnesium that feeds a casting operation.

Subpart U—Miscellaneous Uses of Carbonate

§ 98.210 Definition of the source category.

(a) This source category includes any equipment that uses carbonates listed in Table U–1 in manufacturing processes that emit carbon dioxide. Table U–1 includes the following carbonates: limestone, dolomite, ankerite, magnesite, siderite, rhodochrosite, or sodium carbonate. Facilities are considered to emit CO₂ if they consume at least 2,000 tons per year of carbonates heated to a temperature sufficient to allow the calcination reaction to occur.

(b) This source category does not include equipment that uses carbonates or carbonate containing minerals that are consumed in the production of cement, glass, ferroalloys, iron and steel, lead, lime, phosphoric acid, pulp and paper, soda ash, sodium bicarbonate, sodium hydroxide, or zinc.

(c) This source category does not include carbonates used in sorbent technology used to control emissions from stationary fuel combustion equipment. Emissions from carbonates used in sorbent technology are reported under 40 CFR 98, subpart C (Stationary Fuel Combustion Sources).

§ 98.211 Reporting threshold.

You must report GHG emissions from miscellaneous uses of carbonate if your facility uses carbonates as defined in §98.210 of this subpart and the facility meets the requirements of either §98.2(a)(1) or (a)(2).

§ 98.212 GHGs to report.

You must report CO₂ process emissions from all miscellaneous carbonate
§ 98.213 Calculating GHG emissions.

You must determine CO$_2$ process emissions from carbonate use in accordance with the procedures specified in either paragraphs (a) or (b) of this section.

(a) Calculate the process emissions of CO$_2$ using calcination fractions with Equation U–1 of this section.

$$E_{CO_2} = \sum_{i=1}^{n} M_i \times EF_i \times F_i \times \frac{2000}{2205}$$

(Eq. U-1)

Where:

- $E_{CO_2}$ = Annual CO$_2$ mass emissions from consumption of carbonates (metric tons).
- $M_i$ = Annual mass of carbonate type $i$ consumed (tons).
- $EF_i$ = Emission factor for the carbonate type $i$, as specified in Table U–1 to this subpart, metric tons CO$_2$/metric ton carbonate consumed.
- $F_i$ = Fraction calcination achieved for each particular carbonate type $i$ (decimal fraction). As an alternative to measuring the calcination fraction, a value of 1.0 can be used.
- $n$ = Number of carbonate types.
- 2000/2205 = Conversion factor to convert tons to metric tons.

(b) Calculate the process emissions of CO$_2$ using actual mass of output carbonates with Equation U–2 of this section.

$$E_{CO_2} = \left[ \sum_{k=1}^{m} (M_k \times EF_k) - \sum_{j=1}^{n} (M_j \times EF_j) \right] \times \frac{2000}{2205}$$

(Eq. U-2)

Where:

- $E_{CO_2}$ = Annual CO$_2$ mass emissions from consumption of carbonates (metric tons).
- $M_k$ = Annual mass of input carbonate type $k$ (tons).
- $EF_k$ = Emission factor for the carbonate type $k$, as specified in Table U–1 of this subpart (metric tons CO$_2$/metric ton carbonate input).
- $M_j$ = Annual mass of output carbonate type $j$ (tons).
- $EF_j$ = Emission factor for the output carbonate type $j$, as specified in Table U–1 of this subpart (metric tons CO$_2$/metric ton carbonate input).
- $m$ = Number of input carbonate types.
- $n$ = Number of output carbonate types.

§ 98.214 Monitoring and QA/QC requirements.

(a) The annual mass of carbonate consumed (for Equation U–1 of this subpart) or carbonate inputs (for Equation U–2 of this subpart) must be determined annually from monthly measurements using the same plant instruments used for accounting purposes including purchase records or direct measurement, such as weigh hoppers or weigh belt feeders.

(b) The annual mass of carbonate outputs (for Equation U–2 of this subpart) must be determined annually from monthly measurements using the same plant instruments used for accounting purposes including purchase records or direct measurement, such as weigh hoppers or belt weigh feeders.

(c) If you follow the procedures of §98.213(a), as an alternative to assuming a calcination fraction of 1.0, you can determine on an annual basis the calcination fraction for each carbonate consumed based on sampling and chemical analysis using a suitable method such as using an x-ray fluorescence standard method or other enhanced industry consensus standard method published by an industry consensus standard organization (e.g., ASTM, ASME, etc.).
§ 98.215 Procedures for estimating missing data.

(a) A complete record of all measured parameters used in the GHG emissions calculations is required. Therefore, whenever a quality-assured value of a required parameter is unavailable, a substitute data value for the missing parameter shall be used in the calculations as specified in paragraph (b) of this section. You must document and keep records of the procedures used for all such estimates.

(b) For each missing value of monthly carbonate consumed, monthly carbonate output, or monthly carbonate input, the substitute data value must be the best available estimate based on the all available process data or data used for accounting purposes.

§ 98.216 Data reporting requirements.

In addition to the information required by §98.3(c), each annual report must contain the information specified in paragraphs (a) through (g) of this section at the facility level, as applicable.

(a) Annual CO\(_2\) emissions from miscellaneous carbonate use (metric tons).

(b) Annual mass of each carbonate type consumed (tons).

(c) Measurement method used to determine the mass of carbonate.

(d) Method used to calculate emissions.

(e) If you followed the calculation method of §98.213(b)(1)(i), you must report the information in paragraphs (e)(1) through (e)(3) of this section.

1. Annual carbonate consumption by carbonate type (tons).

2. Annual calcination fractions used in calculations.

3. If you determined the calcination fraction, indicate which standard method was used.

(f) If you followed the calculation method of §98.213(b)(1)(ii), you must report the information in paragraphs (f)(1) and (f)(2) of this section.

1. Annual carbonate input by carbonate type (tons).

2. Annual carbonate output by carbonate type (tons).

(g) Number of times in the reporting year that missing data procedures were followed to measure carbonate consumption, carbonate input or carbonate output (months).

§ 98.217 Records that must be retained.

In addition to the records required by §98.3(g), you must retain the records specified in paragraphs (a) through (d) of this section:

(a) Monthly carbonate consumption (by carbonate type in tons).

(b) You must document the procedures used to ensure the accuracy of the monthly measurements of carbonate consumption, carbonate input or carbonate output including, but not limited to, calibration of weighing equipment and other measurement devices.

(c) Records of all analyses conducted to meet the requirements of this rule.

(d) Records of all calculations conducted.

§ 98.218 Definitions.

All terms used in this subpart have the same meaning given in the Clean Air Act and subpart A of this part.

### Table U–1 to Subpart U of Part 98—CO\(_2\) Emission Factors for Common Carbonates

<table>
<thead>
<tr>
<th>Mineral name—carbonate</th>
<th>CO(_2) emission factor (tons CO(_2)/ton carbonate)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Limestone—CaCO(_3)</td>
<td>0.43971</td>
</tr>
<tr>
<td>Magnesite—MgCO(_3)</td>
<td>0.52197</td>
</tr>
<tr>
<td>Dolomite—CaMg(CO(_3))</td>
<td>0.47732</td>
</tr>
<tr>
<td>Siderite—FeCO(_3)</td>
<td>0.37987</td>
</tr>
<tr>
<td>Ankerite—Ca(Fe, Mg, Mn)(CO(_3))</td>
<td>0.47572</td>
</tr>
<tr>
<td>Rhodochrosite—MnCO(_3)</td>
<td>0.38286</td>
</tr>
<tr>
<td>Sodium Carbonate/Soda Ash—Na(_2)CO(_3)</td>
<td>0.41492</td>
</tr>
</tbody>
</table>

Subpart V—Nitric Acid Production

§ 98.220 Definition of source category.

A nitric acid production facility uses one or more trains to produce weak nitric acid (30 to 70 percent in strength). A nitric acid train produces weak nitric acid through the catalytic oxidation of ammonia.
§ 98.221 Reporting threshold.
You must report GHG emissions under this subpart if your facility contains a nitric acid train and the facility meets the requirements of either § 98.2(a)(1) or (a)(2).

§ 98.222 GHGs to report.
(a) You must report N₂O process emissions from each nitric acid production train as required by this subpart.
(b) You must report under subpart C of this part (General Stationary Fuel Combustion Sources) the emissions of CO₂, CH₄, and N₂O from each stationary combustion unit by following the requirements of subpart C.

§ 98.223 Calculating GHG emissions.
(a) You must determine annual N₂O process emissions from each nitric acid train according to paragraphs (a)(1) or (a)(2) of this section.
(1) Use a site-specific emission factor and production data according to paragraphs (b) through (i) of this section.
(2) Request Administrator approval for an alternative method of determining N₂O emissions according to paragraphs (a)(2)(i) and (a)(2)(ii) of this section.
(i) You must submit the request within 45 days following promulgation of this subpart or within the first 30 days of each subsequent reporting year.
(ii) If the Administrator does not approve your requested alternative method within 150 days of the end of the reporting year, you must determine the N₂O emissions for the current reporting period using the procedures specified in paragraph (a)(1) of this section.
(b) You must conduct an annual performance test for each nitric acid train according to paragraphs (b)(1) through (3) of this section.
(1) You must conduct the performance test at the absorber tail gas vent, referred to as the test point, for each nitric acid train according to § 98.224(b) through (f). If multiple nitric acid production units exhaust to a common abatement technology and/or emission point, you must sample each process in the ducts before the emissions are combined, sample each process when only one process is operating, or sample the combined emissions when multiple processes are operating and base the site-specific emission factor on the combined production rate of the multiple nitric acid production units.
(2) You must conduct the performance test under normal process operating conditions.
(3) You must measure the production rate during the performance test and calculate the production rate for the test period in metric tons (100 percent acid basis) per hour.
(c) Using the results of the performance test in paragraph (b) of this section, you must calculate an average site-specific emission factor for each nitric acid train “t” according to Equation V–1 of this section:

\[
EF_{N2O_t} = \frac{\sum_{i=1}^{n} C_{N2O_i} \times 1.14 \times 10^{-7} \times P}{n}
\]

where:
- \(EF_{N2O_t}\) = Average site-specific N₂O emissions factor for nitric acid train “t” (lb N₂O/ton nitric acid produced, 100 percent acid basis).
- \(C_{N2O}\) = N₂O concentration for each test run during the performance test (ppm N₂O).
- 1.14 \(\times 10^{-7}\) = Conversion factor (lb/dscf-ppm N₂O).
- \(Q\) = Volumetric flow rate of effluent gas for each test run during the performance test (dscf/hr).
- \(P\) = Production rate for each test run during the performance test (tons nitric acid produced per hour, 100 percent acid basis).
- \(n\) = Number of test runs.
(d) If nitric acid train “t” exhausts to any N₂O abatement technology “N” after the test point, you must determine the destruction efficiency for each N₂O abatement technology “N” according to paragraphs (d)(1), (d)(2), or (d)(3) of this section.
(1) Use the manufacturer’s specified destruction efficiency.
(2) Estimate the destruction efficiency through process knowledge. Examples of information that could constitute process knowledge include calculations based on material balances, process stoichiometry, or previous test results provided the results are still relevant to the current vent stream conditions. You must document how process knowledge (if applicable) was used to determine the destruction efficiency.
(3) Calculate the destruction efficiency by conducting an additional performance test on the emissions stream following the \(\text{N}_2\text{O}\) abatement technology.

(e) If \(\text{N}_2\text{O}\) train “t” exhausts to any \(\text{N}_2\text{O}\) abatement technology “N” after the test point, you must determine the annual amount of nitric acid produced on train “t” while \(\text{N}_2\text{O}\) abatement technology “N” is operating according to §98.224(f). Then you must calculate the abatement utilization factor for each \(\text{N}_2\text{O}\) abatement technology “N” for each nitric acid train “t” according to Equation V–2 of this section.

\[
AF_{t,N} = \frac{P_{t,N}}{P_t} \quad \text{(Eq. V-2)}
\]

where:
- \(AF_{t,N}\) = Abatement utilization factor of \(\text{N}_2\text{O}\) abatement technology “N” at nitric acid train “t” (fraction of annual production that abatement technology is operating).
- \(P_t\) = Total annual nitric acid production from nitric acid train “t” (ton acid produced, 100 percent acid basis).
- \(P_{t,N}\) = Annual nitric acid production from nitric acid train “t” during which \(\text{N}_2\text{O}\) abatement technology “N” was operational (ton acid produced, 100 percent acid basis).

(f) [Reserved]

(g) You must calculate \(\text{N}_2\text{O}\) emissions for each nitric acid train “t” according to paragraph (g)(1), (g)(2), (g)(3), or (g)(4) of this section.

(1) If nitric acid train “t” exhausts to one \(\text{N}_2\text{O}\) abatement technology “N” after the test point, you must use the emissions factor (determined in Equation V–1 of this section), the destruction efficiency (determined in paragraph (d) of this section), the annual nitric acid production (determined in paragraph (i) of this section), and the abatement utilization factor (determined in paragraph (e) of this section) according to Equation V–3a of this section:

\[
E_{\text{N}_2\text{O},t} = \frac{EF_{\text{N}_2\text{O},t} \cdot P_t \cdot DF}{2205} \cdot (1 - DF \cdot AF) \quad \text{(Eq. V-3a)}
\]

where:
- \(E_{\text{N}_2\text{O},t}\) = Annual \(\text{N}_2\text{O}\) mass emissions from nitric acid production unit “t” according to this Equation V–3a (metric tons).
- \(EF_{\text{N}_2\text{O},t}\) = Average site-specific \(\text{N}_2\text{O}\) emissions factor for nitric acid train “t” (lb \(\text{N}_2\text{O}/\text{ton acid produced, 100 percent acid basis})).
- \(P_t\) = Annual nitric acid production from the train “t” (ton acid produced, 100 percent acid basis).
- \(DF\) = Destruction efficiency of \(\text{N}_2\text{O}\) abatement technology N that is used on nitric acid train “t” (percent of \(\text{N}_2\text{O}\) removed from vent stream).
- \(AF\) = Abatement utilization factor of \(\text{N}_2\text{O}\) abatement technology “N” for nitric acid train “t” (percent of time that the abatement technology is operating).
- 2205 = Conversion factor (lb/metric ton).

(2) If multiple \(\text{N}_2\text{O}\) abatement technologies are located in series after your test point, you must use the emissions factor (determined in Equation V–1 of this section), the destruction efficiency (determined in paragraph (d) of this section), the annual nitric acid production (determined in paragraph (f) of this section), and the abatement utilization factor (determined in paragraph (e) of this section) according to Equation V–3b of this section:
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\[
E_{NO_2t} = \frac{EF_{NO_2t} \cdot P_t}{2205} \cdot \left( 1 - (DF_1 \cdot AF_1) \right) \cdot \left( 1 - (DF_2 \cdot AF_2) \right) \ldots \cdot \left( 1 - (DF_N \cdot AF_N) \right) \quad \text{(Eq. V-3b)}
\]

where:

- \( E_{NO_2t} \) = Annual \( NO_2 \) mass emissions from nitric acid production unit “t” according to this Equation V-3b \( \text{(metric tons)} \).
- \( EF_{NO_2t} \) = \( NO_2 \) emissions factor for unit “t” \( \text{(lb \( NO_2 \)/ton nitric acid produced)} \).
- \( P_t \) = Annual nitric acid produced from unit “t” \( \text{(ton acid produced, 100 percent acid basis)} \).
- \( DF_1 \) = Destruction efficiency of \( NO_2 \) abatement technology 1 \( \text{(percent of \( NO_2 \) removed from vent stream)} \).
- \( AF_1 \) = Abatement utilization factor of \( NO_2 \) abatement technology 1 \( \text{(percent of time that abatement technology 1 is operating)} \).
- \( DF_N \) = Destruction efficiency of \( NO_2 \) abatement technology \( N \) \( \text{(percent of \( NO_2 \) removed from vent stream)} \).
- \( AF_N \) = Abatement utilization factor of \( NO_2 \) abatement technology \( N \) \( \text{(percent of time that abatement technology \( N \) is operating)} \).
- \( 2205 \) = Conversion factor \( \text{(lb/metric ton)} \).
- \( N \) = Number of different \( NO_2 \) abatement technologies.

(3) If multiple \( NO_2 \) abatement technologies are located in parallel after your test point, you must use the emissions factor \( \text{(determined in Equation V–1 of this section)} \), the destruction efficiency \( \text{(determined in paragraph (d) of this section)} \), the annual nitric acid production \( \text{(determined in paragraph (i) of this section)} \), and the abatement utilization factor \( \text{(determined in paragraph (e) of this section)} \) according to Equation V–3c of this section:

\[
E_{NO_2t} = \frac{EF_{NO_2t} \cdot P_t}{2205} \cdot \sum_{1}^{N} \left( 1 - (DF_N \cdot AF_N) \right) \cdot FC_N \quad \text{(Eq. V-3c)}
\]

where:

- \( E_{NO_2t} \) = Annual \( NO_2 \) mass emissions from nitric acid production unit “t” according to this Equation V–3c \( \text{(metric tons)} \).
- \( EF_{NO_2t} \) = Average site-specific \( NO_2 \) emissions factor for nitric acid train “t” \( \text{(lb \( NO_2 \)/ton nitric acid produced, 100 percent acid basis)} \).
- \( P_t \) = Annual nitric acid produced from nitric acid train “t” \( \text{(ton acid produced, 100 percent acid basis)} \).
- \( 2205 \) = Conversion factor \( \text{(lb/metric ton)} \).
- \( N \) = Number of different \( NO_2 \) abatement technologies with a fraction control factor.

(4) If nitric acid train “t” does not exhaust to any \( NO_2 \) abatement technology after the test point, you must use the emissions factor \( \text{(determined in Equation V–1 of this section)} \), and the annual nitric acid production \( \text{(determined in paragraph (i) of this section)} \) according to Equation V–3d of this section:

\[
E_{NO_2t} = \frac{EF_{NO_2t} \cdot P_t}{2205} \quad \text{(Eq. V-3d)}
\]

where:

- \( E_{NO_2t} \) = Annual \( NO_2 \) mass emissions from nitric acid production unit “t” according to this Equation V–3d \( \text{(metric tons)} \).
- \( EF_{NO_2t} \) = Average site-specific \( NO_2 \) emissions factor for nitric acid train “t” \( \text{(lb \( NO_2 \)/ton nitric acid produced, 100 percent acid basis)} \).
- \( P_t \) = Annual nitric acid production from nitric acid train “t” \( \text{(ton acid produced, 100 percent acid basis)} \).
- \( 2205 \) = Conversion factor \( \text{(lb/metric ton)} \).

(h) You must determine the annual nitric acid production emissions combined from all nitric acid trains at your facility using Equation V–4 of this section:
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\[ N_2O = \sum_{t=1}^{m} E_{N2Ot} \quad \text{(Eq. V-4)} \]

Where:

- \( N_2O = \) Annual process \( N_2O \) emissions from nitric acid production facility (metric tons).
- \( E_{N2Ot} = \) \( N_2O \) mass emissions per year for nitric acid train "\( t \)" (metric tons).
- \( m = \) Number of nitric acid trains.

(i) You must determine the total annual amount of nitric acid produced on nitric acid train "\( t \)" for each nitric acid train (tons acid produced, 100 percent acid basis), according to § 98.224(f).

\[ [74 \ FR \ 56374, \ Oct. \ 30, \ 2009, \ as \ amended \ at \ 75 \ FR \ 66466, \ Oct. \ 28, \ 2010] \]

§ 98.224 Monitoring and QA/QC requirements.

(a) You must conduct a new performance test according to a test plan as specified in paragraphs (a)(1) through (3) of this section.

(1) Conduct the performance test annually. The test should be conducted at a point during the campaign which is representative of the average emissions rate from the nitric acid campaigns. Facilities must document the methods used to determine the representative point of the campaign when the performance test is conducted.

(2) Conduct the performance test when your nitric acid production process is changed, specifically when abatement equipment is installed.

(3) If you requested Administrator approval for an alternative method of determining \( N_2O \) emissions under § 98.223(a)(2), you must conduct the performance test if your request has not been approved by the Administrator within 150 days of the end of the reporting year in which it was submitted.

(b) You must measure the \( N_2O \) concentration during the performance test using one of the methods in paragraphs (b)(1) through (b)(3) of this section.

(1) EPA Method 320 at 40 CFR part 60, appendices A–1 through A–4. Conduct three emissions test runs of 1 hour each. All QA/QC procedures specified in the reference test methods and any associated performance specifications apply. For each test, the facility must prepare an emission factor determination report that must include the items in paragraphs (d)(1) through (d)(3) of this section.

(1) Analysis of samples, determination of emissions, and raw data.

(2) All information and data used to derive the emissions factor(s).

(3) The production rate during each test and how it was determined.

(c) You must determine the production rate(s) (100 percent basis) from each nitric acid train during the performance test according to paragraphs (c)(1) or (c)(2) of this section.

(1) Direct measurement of production and concentration (such as using flow meters, weigh scales, for production and concentration measurements).

(2) Existing plant procedures used for accounting purposes (i.e., dedicated tank-level and acid concentration measurements).

(d) You must determine the volumetric flow rate during the performance test in conjunction with the applicable EPA methods in 40 CFR part 60, appendices A–1 through A–4. Conduct three emissions test runs of 1 hour each. All QA/QC procedures specified in the reference test methods and any associated performance specifications apply. For each test, the facility must prepare an emission factor determination report that must include the items in paragraphs (d)(1) through (d)(3) of this section.

(1) Analysis of samples, determination of emissions, and raw data.

(2) All information and data used to derive the emissions factor(s).

(3) The production rate during each test and how it was determined.

(e) You must determine the total monthly amount of nitric acid produced. You must also determine the monthly amount of nitric acid produced while \( N_2O \) abatement technology (located after the test point) is operating from each nitric acid train. These monthly amounts are determined according to the methods in paragraphs (c)(1) or (2) of this section.

(f) You must determine the annual amount of nitric acid produced. You must also determine the annual amount of nitric acid produced while \( N_2O \) abatement technology (located
§ 98.225 Procedures for estimating missing data.

A complete record of all measured parameters used in the GHG emissions calculations is required. Therefore, whenever a quality-assured value of a required parameter is unavailable, a substitute data value for the missing parameter shall be used in the calculations as specified in paragraphs (a) and (b) of this section.

(a) For each missing value of nitric acid production, the substitute data shall be the best available estimate based on all available process data or data used for accounting purposes (such as sales records).

(b) For missing values related to the performance test, including emission factors, production rate, and N\textsubscript{2}O concentration, you must conduct a new performance test according to the procedures in §98.224 (a) through (d).

§ 98.226 Data reporting requirements.

In addition to the information required by §98.3(c), each annual report must contain the information specified in paragraphs (a) through (p) of this section.

(a) Train identification number.

(b) Annual process N\textsubscript{2}O emissions from each nitric acid train (metric tons).

(c) [Reserved]

(d) Annual nitric acid production from each nitric acid train during which N\textsubscript{2}O abatement technology is operating (ton acid produced, 100 percent acid basis).

(e) Annual nitric acid production from the nitric acid facility (tons, 100 percent acid basis).

(f) Number of nitric acid trains.

(g) Number of different N\textsubscript{2}O abatement technologies per nitric acid train "t".

(h) Abatement technologies used (if applicable).

(i) Abatement technology destruction efficiency for each abatement technology (percent destruction).

(j) Abatement utilization factor for each abatement technology (fraction of annual production that abatement technology is operating).

(k) Type of nitric acid process used for each nitric acid train (low, medium, high, or dual pressure).

(l) Number of times in the reporting year that missing data procedures were followed to measure nitric acid production (months).

(m) If you conducted a performance test and calculated a site-specific emissions factor according to §98.223(a)(1), each annual report must also contain the information specified in paragraphs (m)(1) through (7) of this section.

(1) Emission factor calculated for each nitric acid train (lb N\textsubscript{2}O/ton nitric acid, 100 percent acid basis).

(2) Test method used for performance test.

(3) Production rate per test run during performance test (tons nitric acid produced/hr, 100 percent acid basis).

(4) N\textsubscript{2}O concentration per test run during performance test (ppm N\textsubscript{2}O).

(5) Volumetric flow rate per test run during performance test (dscf/hr).

(6) Number of test runs during performance test.

(7) Number of times in the reporting year that a performance test had to be repeated (number).

(n) If you requested Administrator approval for an alternative method of determining N\textsubscript{2}O emissions under §98.223(a)(2), each annual report must also contain the information specified in paragraphs (n)(1) through (4) of this section of this section of this section:

(1) Name of alternative method.

(2) Description of alternative method.

(3) Request date.

(4) Approval date.

(p) Fraction control factor for each abatement technology (percent of total emissions from the production unit that are sent to the abatement technology) if equation V–3c is used.

§ 98.227 Records that must be retained.

In addition to the information required by §98.3(g), you must retain the records specified in paragraphs (a) through (g) of this section for each nitric acid production facility:

(a) Records of significant changes to process.

(b) Documentation of how process knowledge was used to estimate abatement technology destruction efficiency (if applicable).

(c) Performance test reports.

(d) Number of operating hours in the calendar year for each nitric acid train (hours).

(e) Annual nitric acid permitted production capacity (tons).

(f) Measurements, records, and calculations used to determine reported parameters.

(g) Documentation of the procedures used to ensure the accuracy of the measurements of all reported parameters, including but not limited to, calibration of weighing equipment, flow meters, and other measurement devices. The estimated accuracy of measurements made with these devices must also be recorded, and the technical basis for these estimates must be provided.

§ 98.228 Definitions.

All terms used in this subpart have the same meaning given in the Clean Air Act and subpart A of this part.

Subpart W—Petroleum and Natural Gas Systems

Source: 75 FR 74488, Nov. 30, 2010, unless otherwise noted.

§ 98.230 Definition of the source category.

(a) This source category consists of the following industry segments:

(1) Offshore petroleum and natural gas production. Offshore petroleum and natural gas production is any platform structure, affixed temporarily or permanently to offshore submerged lands, that houses equipment to extract hydrocarbons from the ocean or lake floor and that processes and/or transfers such hydrocarbons to storage, transport vessels, or onshore. In addition, offshore production includes secondary platform structures connected to the platform structure via walkways, storage tanks associated with the platform structure and floating production and storage offloading equipment (FPSO). This source category does not include reporting of emissions from offshore drilling and exploration that is not conducted on production platforms.

(2) Onshore petroleum and natural gas production. Onshore petroleum and natural gas production means all equipment on a single well-pad or associated with a single well-pad (including but not limited to compressors, generators, dehydrators, storage vessels, and portable non-self-propelled equipment which includes well drilling and completion equipment, workover equipment, gravity separation equipment, auxiliary non-transportation-related equipment, and leased, rented or contracted equipment) used in the production, extraction, recovery, lifting, stabilization, separation or treating of petroleum and/or natural gas (including condensate). This equipment also includes associated storage or measurement vessels and all enhanced oil recovery (EOR) operations using CO₂ or natural gas injection, and all petroleum and natural gas production equipment located on islands, artificial islands, or structures connected by a causeway to land, an island, or an artificial island.

(3) Onshore natural gas processing. Natural gas processing means the separation of natural gas liquids (NGLs) or non-methane gases from produced natural gas, or the separation of NGLs into one or more component mixtures. Separation includes one or more of the following: forced extraction of natural gas liquids, sulfur and carbon dioxide removal, fractionation of NGLs, or the capture of CO₂ separated from natural gas streams. This segment also includes all residue gas compression equipment owned or operated by the natural gas processing plant. This industry segment includes processing plants that fractionate gas liquids, and processing plants that do not fractionate gas liquids but have an annual average throughput of 25 MMscf per day or greater.
(4) **Onshore natural gas transmission compression.** Onshore natural gas transmission compression means any stationary combination of compressors that move natural gas from production fields, natural gas processing plants, or other transmission compressors through transmission pipelines to natural gas distribution pipelines, LNG storage facilities, or into underground storage. In addition, a transmission compressor station includes equipment for liquids separation, and tanks for the storage of water and hydrocarbon liquids. Residue (sales) gas compression that is part of onshore natural gas processing plants are included in the onshore natural gas processing segment and are excluded from this segment.

(5) **Underground natural gas storage.** Underground natural gas storage means subsurface storage, including depleted gas or oil reservoirs and salt dome caverns that store natural gas that has been transferred from its original location for the primary purpose of load balancing (the process of equalizing the receipt and delivery of natural gas); natural gas underground storage processes and operations (including compression, dehydration and flow measurement, and excluding transmission pipelines); and all the wellheads connected to the compression units located at the facility that inject and recover natural gas into and from the underground reservoirs.

(6) **Liquefied natural gas (LNG) storage.** LNG storage means onshore LNG storage vessels located above ground, equipment for liquefying natural gas, compressors to capture and re-liquefy boil-off-gas, re-condensers, and vaporization units for re-gasification of the liquefied natural gas.

(7) **LNG import and export equipment.** LNG import equipment means all onshore or offshore equipment that receives imported LNG via ocean transport, stores LNG, re-gasifies LNG, and delivers re-gasified natural gas to a natural gas transmission or distribution system. LNG export equipment means all onshore or offshore equipment that receives natural gas, liquefies natural gas, stores LNG, and transfers the LNG via ocean transportation to any location, including locations in the United States.

(8) **Natural gas distribution.** Natural gas distribution means the distribution pipelines and metering and regulating equipment at metering-regulating stations that are operated by a Local Distribution Company (LDC) within a single state that is regulated as a separate operating company by a public utility commission or that is operated as an independent municipally-owned distribution system. This segment also excludes customer meters and regulators, infrastructure, and pipelines (both interstate and intrastate) delivering natural gas directly to major industrial users and farm taps upstream of the local distribution company inlet.

(b) [Reserved]

§ 98.231 Reporting threshold.

(a) You must report GHG emissions under this subpart if your facility contains petroleum and natural gas systems and the facility meets the requirements of §98.2(a)(2). Facilities must report emissions from the onshore petroleum and natural gas production industry segment only if emission sources specified in paragraph §98.232(c) emit 25,000 metric tons of CO₂ equivalent or more per year. Facilities must report emissions from the natural gas distribution industry segment only if emission sources specified in paragraph §98.232(i) emit 25,000 metric tons of CO₂ equivalent or more per year.

(b) For applying the threshold defined in §98.2(a)(2), natural gas processing facilities must also include owned or operated residue gas compression equipment.

§ 98.232 GHGs to report.

(a) You must report CO₂, CH₄, and N₂O emissions from each industry segment specified in paragraph (b) through (i) of this section. CO₂, CH₄, and N₂O emissions from each flare as specified in paragraph (b) through (i) of this section, and stationary and portable combustion emissions as applicable as specified in paragraph (k) of this section.

(b) For offshore petroleum and natural gas production, report CO₂, CH₄,
and N₂O emissions from equipment leaks, vented emission, and flare emission source types as identified in the data collection and emissions estimation study conducted by BOEMRE in compliance with 30 CFR 250.302 through 304. Offshore platforms do not need to report portable emissions.

(c) For an onshore petroleum and natural gas production facility, report CO₂, CH₄, and N₂O emissions from only the following source types on a single well-pad or associated with a single well-pad:
(1) Natural gas pneumatic device venting.
(2) [Reserved]
(3) Natural gas driven pneumatic pump venting.
(4) Well venting for liquids unloading.
(5) Gas well venting during well completions without hydraulic fracturing.
(6) Gas well venting during well completions with hydraulic fracturing.
(7) Gas well venting during well workovers without hydraulic fracturing.
(8) Gas well venting during well workovers with hydraulic fracturing.
(9) Flare stack emissions.
(10) Storage tanks vented emissions from produced hydrocarbons.
(11) Reciprocating compressor rod packing venting.
(12) Well testing venting and flaring.
(13) Associated gas venting and flaring from produced hydrocarbons.
(14) Dehydrator vents.
(15) [Reserved]
(16) EOR injection pump blowdown.
(17) Acid gas removal vents.
(18) EOR hydrocarbon liquids dissolved CO₂.
(19) Centrifugal compressor venting.
(20) [Reserved]
(21) Equipment leaks from valves, connectors, open ended lines, pressure relief valves, pumps, flanges, and other equipment leak sources (such as instruments, loading arms, stuffing boxes, compressor seals, dump lever arms, and breather caps).
(22) You must use the methods in §98.233(z) and report under this subpart the emissions of CO₂, CH₄, and N₂O from stationary or portable fuel combustion equipment that cannot move on roadways under its own power and

drive train, and that is located at an onshore petroleum and natural gas production facility as defined in §98.238. Stationary or portable equipment are the following equipment, which are integral to the extraction, processing, or movement of oil or natural gas: well drilling and completion equipment, workover equipment, natural gas dehydrators, natural gas compressors, electrical generators, steam boilers, and process heaters.

(d) For onshore natural gas processing, report CO₂, CH₄, and N₂O emissions from the following sources:
(1) Reciprocating compressor rod packing venting.
(2) Centrifugal compressor venting.
(3) Blowdown vent stacks.
(4) Dehydrator vents.
(5) Acid gas removal vents.
(6) Flare stack emissions.
(7) Equipment leaks from valves, connectors, open ended lines, pressure relief valves, and meters.

(e) For onshore natural gas transmission compression, report CO₂, CH₄, and N₂O emissions from the following sources:
(1) Reciprocating compressor rod packing venting.
(2) Centrifugal compressor venting.
(3) Transmission storage tanks.
(4) Blowdown vent stacks.
(5) Natural gas pneumatic device venting.
(6) [Reserved]
(7) Equipment leaks from valves, connectors, open ended lines, pressure relief valves, and meters.

(f) For underground natural gas storage, report CO₂, CH₄, and N₂O emissions from the following sources:
(1) Reciprocating compressor rod packing venting.
(2) Centrifugal compressor venting.
(3) Natural gas pneumatic device venting.
(4) [Reserved]
(5) Equipment leaks from valves, connectors, open ended lines, pressure relief valves, and meters.

(g) For LNG storage, report CO₂, CH₄, and N₂O emissions from the following sources:
(1) Reciprocating compressor rod packing venting.
(2) Centrifugal compressor venting.
(3) Equipment leaks from valves; pump seals; connectors; vapor recovery compressors, and other equipment leak sources.

(h) LNG import and export equipment, report CO₂, CH₄, and N₂O emissions from the following sources:
(1) Reciprocating compressor rod packing venting.
(2) Centrifugal compressor venting.
(3) Blowdown vent stacks.
(4) Equipment leaks from valves, pump seals, connectors, vapor recovery compressors, and other equipment leak sources.

(i) For natural gas distribution, report CO₂, CH₄, and N₂O emissions from the following sources:
(1) Meters, regulators, and associated equipment at above grade transmission-distribution transfer stations, including equipment leaks from connectors, block valves, control valves, pressure relief valves, orifice meters, regulators, and open ended lines.
(2) Equipment leaks from vaults at below grade transmission-distribution transfer stations.
(3) Meters, regulators, and associated equipment at above grade metering-regulating stations.
(4) Equipment leaks from vaults at below grade metering-regulating stations.
(5) Pipeline main equipment leaks.
(6) Service line equipment leaks.
(7) Report under subpart W of this part the emissions of CO₂, CH₄, and N₂O emissions from stationary fuel combustion sources following the methods in §98.233(z).

(k) Report under subpart C of this part (General Stationary Fuel Combustion Sources) the emissions of CO₂, CH₄, and N₂O from each stationary fuel combustion unit by following the requirements of subpart C except for facilities under onshore petroleum and natural gas production and natural gas distribution. Onshore petroleum and natural gas production facilities must report stationary and portable combustion emissions as specified in paragraph (c) of this section. Natural gas distribution facilities must report stationary combustion emissions as specified in paragraph (i) of this section.

(l) You must report under subpart PP of this part (Suppliers of Carbon Dioxide), CO₂ emissions captured and transferred off site by following the requirements of subpart PP.

§98.233 Calculating GHG emissions.

You must calculate and report the annual GHG emissions as prescribed in this section. For actual conditions, reporters must use average atmospheric conditions or typical operating conditions as applicable to the respective monitoring methods in this section.

(a) Natural gas pneumatic device venting. Calculate CH₄ and CO₂ emissions from continuous high bleed, continuous low bleed, and intermittent bleed natural gas pneumatic devices using Equation W–1 of this section.

\[
Mass_{t,i} = Count_{t} \times EF_{t} \times GHG_{i} \times Conv_{i} \times T_{i} \quad (\text{Eq. W–1})
\]

Where:

- \(Mass_{t,i}\) = Annual total mass GHG emissions in metric tons CO₂e per year from a natural gas pneumatic device vent of type \(t\) for GHG.
- \(Count_{t}\) = Total number of natural gas pneumatic devices of type \(t\) (continuous high bleed, continuous low bleed, intermittent bleed) as determined in paragraph (a)(1), (a)(2), and (a)(3) of this section.
- \(EF_{t}\) = Population emission factors for natural gas pneumatic device venting listed in Tables W–1A, W–3, and W–4 of this subpart for onshore petroleum and natural gas production, onshore natural gas transmission compression, and underground natural gas storage facilities, respectively.
- \(GHG_{i}\) = For onshore petroleum and natural gas production facilities, concentration of GHG, CH₄, or CO₂ in natural gas as defined in paragraph (u)(2)(i) of this section and for onshore natural gas transmission compression and underground natural gas storage, GHG, equals 0.975 for CH₄ and 1.1 \times 10^{-2} for CO₂.
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Conv. = Conversion from standard cubic feet to metric tons CO₂e; 0.000403 for CH₄, and 0.00005262 for CO₂.

Tᵢ = Average estimated number of hours in the operating year the devices, of each type t, were operational. Default is 8760 hours.

(1) For onshore petroleum and natural gas production, provide the total number of continuous high bleed, continuous low bleed, or intermittent bleed natural gas pneumatic devices of each type as follows:

(i) In the first calendar year, for the total number of each type, you may count the total of each type, or count any percentage number of each type plus an engineering estimate based on best available data of the number not counted.

(ii) In the second consecutive year, for the total number of each type, you may count the total of each type, or count any percentage number of each type plus an engineering estimate based on best available data of the number not counted.

(iii) In the third consecutive calendar year, complete the count of all pneumatic devices, including any changes to equipment counted in prior years.

(iv) For the calendar year immediately following the third consecutive calendar year, and for calendar years thereafter, facilities must update the total count of pneumatic devices and adjust accordingly to reflect any modifications due to changes in equipment.

(2) For onshore natural gas transmission compression and underground natural gas storage, all natural gas pneumatic devices must be counted in the first year and updated every calendar year.

(3) For all industry segments, determine the type of pneumatic device using engineering estimates based on best available information.

(b) [Reserved]

(c) Natural gas driven pneumatic pump venting. Calculate CH₄ and CO₂ emissions from natural gas driven pneumatic pump venting using Equation W–2 of this section. Natural gas driven pneumatic pumps covered in paragraph (e) of this section do not have to report emissions under paragraph (c) of this section.

\[
Mass_i = Count \times EF \times GHG_i \times Conv_i \times T \quad \text{(Eq. W–2)}
\]

Where:

Massᵢ = Annual total mass GHG emissions in metric tons CO₂e per year from all natural gas pneumatic pump venting, for GHGᵢ.

Count = Total number of natural gas pneumatic pumps.

EF = Population emissions factors for natural gas pneumatic pump venting listed in Tables W–1A of this subpart for onshore petroleum and natural gas production.

GHGᵢ = Concentration of GHGᵢ, CH₄, or CO₂ in produced natural gas as defined in paragraph (u)(2)(i) of this section.

Convᵢ = Conversion from standard cubic feet to metric tons CO₂e; 0.000403 for CH₄, and 0.00005262 for CO₂.

T = Average estimated number of hours in the operating year the pumps were operational. Default is 8760 hours.

(d) Acid gas removal (AGR) vents. For AGR vent (including processes such as amine, membrane, molecular sieve or other absorbents and adsorbents), calculate emissions for CO₂ only (not CH₄) vented directly to the atmosphere or through a flare, engine (e.g., permeate from a membrane or de-adsorbed gas from a pressure swing adsorber used as fuel supplement), or sulfur recovery plant using any of the calculation methodologies described in paragraph (d) of this section, as applicable.

(1) Calculation Methodology 1. If you operate and maintain a CEMS that has both a CO₂ concentration monitor and volumetric flow rate monitor, you must calculate CO₂ emissions under this subpart by following the Tier 4 Calculation Methodology and all associated calculation, quality assurance, reporting, and recordkeeping requirements for Tier 4 in subpart C of this part (General Stationary Fuel Combustion Sources). Alternatively, you may follow the manufacturer’s instructions or industry standard practice. If a CO₂ concentration monitor and volumetric flow rate monitor are not available,
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you may elect to install a CO₂ concentration monitor and a volumetric flow rate monitor that comply with all of the requirements specified for the Tier 4 Calculation Methodology in subpart C of this part (General Stationary Fuel Combustion). The calculation and reporting of CH₄ and N₂O emissions is not required as part of the Tier 4 requirements for AGRs.

(2) Calculation Methodology 2. If CEMS is not available but a vent meter is installed, use the CO₂ composition and annual volume of vent gas to calculate emissions using Equation W–3 of this section.

\[ E_{a,CO_2} = V_S \times \text{Vol}_{CO_2} \]  \hspace{1cm} (Eq. W–3)

where:
- \( E_{a,CO_2} \) = Annual volumetric CO₂ emissions at actual conditions, in cubic feet per year.
- \( V_S \) = Total annual volume of vent gas flowing out of the AGR unit in cubic feet per year at actual conditions as determined by flow meter using methods set forth in §98.234(b). Alternatively, you may follow the manufacturer’s instructions or industry standard practice for calibration of the vent meter.
- \( \text{Vol}_{CO_2} \) = Volume fraction of CO₂ content in vent gas out of the AGR unit as determined in (d)(6) of this section.

(3) Calculation Methodology 3. If CEMS or a vent meter is not installed, you may use the inlet or outlet gas flow rate of the acid gas removal unit to calculate emissions for CO₂ using Equations W–4A or W–4B of this section. If inlet gas flow rate is known, use Equation W–4A. If outlet gas flow rate is known, use Equation W–4B.

\[ E_{a,CO_2} = V_{in} \times \left[ \frac{\text{Vol}_I - \text{Vol}_O}{1 - \text{Vol}_O} \right] \]  \hspace{1cm} (Eq. W–4A)

\[ E_{a,CO_2} = V_{out} \times \left[ \frac{\text{Vol}_I - \text{Vol}_O}{1 - \text{Vol}_I} \right] \]  \hspace{1cm} (Eq. W–4B)

Where:
- \( E_{a,CO_2} \) = Annual volumetric CO₂ emissions at actual conditions, in cubic feet per year.
- \( V_{in} \) = Total annual volume of natural gas flow into the AGR unit in cubic feet per year at actual condition as determined using methods specified in paragraph (d)(5) of this section.
- \( V_{out} \) = Total annual volume of natural gas flow out of the AGR unit in cubic feet per year at actual condition as determined using methods specified in paragraph (d)(5) of this section.
- \( \text{Vol}_I \) = Volume fraction of CO₂ content in natural gas into the AGR unit as determined in paragraph (d)(7) of this section.
- \( \text{Vol}_O \) = Volume fraction of CO₂ content in natural gas out of the AGR unit as determined in paragraph (d)(8) of this section.

(4) Calculation Methodology 4. If CEMS or a vent meter is not installed, you may calculate emissions using any standard simulation software packages, such as AspenTech HYSYS® and API 4679 AMINECalc, that uses the Peng-Robinson equation of state, and speciates CO₂ emissions. A minimum of the following determined for typical operating conditions over the calendar year by engineering estimate and process knowledge based on best available data must be used to characterize emissions:

(i) Natural gas feed temperature, pressure, and flow rate.
(ii) Acid gas content of feed natural gas.

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(iii) Acid gas content of outlet natural gas.
(iv) Unit operating hours, excluding downtime for maintenance or standby.
(v) Exit temperature of natural gas.
(vi) Solvent pressure, temperature, circulation rate, and weight.
(5) Record the gas flow rate of the inlet and outlet natural gas stream of an AGR unit using a meter according to methods set forth in §98.234(b). If you do not have a continuous flow meter, either install a continuous flow meter or use an engineering calculation to determine the flow rate.
(6) If continuous gas analyzer is not available on the vent stack, either install a continuous gas analyzer or take quarterly gas samples from the vent gas stream to determine Vol$_{CO_2}$ according to methods set forth in §98.234(b).
(7) If a continuous gas analyzer is installed on the inlet gas stream, then the continuous gas analyzer results must be used. If continuous gas analyzer is not available, either install a continuous gas analyzer or take quarterly gas samples from the inlet gas stream to determine Vol$_{CO_2}$ according to methods set forth in §98.234(b).
(8) Determine volume fraction of CO$_2$ content in natural gas out of the AGR unit using one of the methods specified in paragraph (d)(8) of this section.
(i) If a continuous gas analyzer is installed on the outlet gas stream, then the continuous gas analyzer results must be used. If a continuous gas analyzer is not available, you may install a continuous gas analyzer.
(ii) If a continuous gas analyzer is not available or installed, quarterly gas samples may be taken from the outlet gas stream to determine Vol$_{CO_2}$ according to methods set forth in §98.234(b).
(iii) Use sales line quality specification for CO$_2$ in natural gas.
(9) Calculate CO$_2$ volumetric emissions at standard conditions using calculations in paragraph (t) of this section.
(10) Mass CO$_2$ emissions shall be calculated from volumetric CO$_2$ emissions using calculations in paragraph (v) of this section.
(11) Determine if emissions from the AGR unit are recovered and transferred outside the facility. Adjust the emission estimated in paragraphs (d)(1) through (d)(10) of this section downward by the magnitude of emission recovered and transferred outside the facility.
(e) Dehydrator vents. For dehydrator vents, calculate annual CH$_4$, CO$_2$ and N$_2$O emissions using any of the calculation methodologies described in paragraph (e) of this section.
(1) Calculation Methodology 1. Calculate annual mass emissions from dehydrator vents with annual average daily throughput greater than or equal to 0.4 million standard cubic feet per day using a software program, such as AspenTech HYSYS® or GRI–GLYCalc, that uses the Peng-Robinson equation of state to calculate the equilibrium coefficient, speciates CH$_4$ and CO$_2$ emissions from dehydrators, and has provisions to include regenerator control devices, a separator flash tank, stripping gas and a gas injection pump or gas assist pump. A minimum of the following parameters determined by engineering estimate based on best available data must be used to characterize emissions from dehydrators:
(i) Feed natural gas flow rate.
(ii) Feed natural gas water content.
(iii) Outlet natural gas water content.
(iv) Absorbent circulation pump type (natural gas pneumatic/air pneumatic/electric).
(v) Absorbent circulation rate.
(vi) Absorbent type: including triethylene glycol (TEG), diethylene glycol (DEG) or ethylene glycol (EG).
(vii) Use of stripping gas.
(viii) Use of flash tank separator (and disposition of recovered gas).
(ix) Hours operated.
(x) Wet natural gas temperature and pressure.
(xi) Wet natural gas composition. Determine this parameter by selecting one of the methods described under paragraph (e)(1)(xi) of this section.
(A) Use the wet natural gas composition as defined in paragraph (u)(2)(i) or (u)(2)(ii) of this section.
(B) If wet natural gas composition cannot be determined using paragraph (u)(2)(i) or (u)(2)(ii) of this section, select a representative analysis.
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(C) You may use an appropriate standard method published by a consensus-based standards organization if such a method exists or you may use an industry standard practice as specified in §98.234(b) to sample and analyze wet natural gas composition.

(D) If only composition data for dry natural gas is available, assume the wet natural gas is saturated.

(2) Calculation Methodology 2. Calculate annual CH₄ and CO₂ emissions from glycol dehydrators with annual average daily throughput less than 0.4 million standard cubic feet per day using Equation W–5 of this section:

\[ E_{s,i} = EF_i \times Count \times 1000 \]  
(Eq. W–5)

where:
- \( E_{s,i} \) = Annual total volumetric GHG emissions (either CO₂ or CH₄) at standard conditions in cubic feet.
- \( EF_i \) = Population emission factors for glycol dehydrators in thousand standard cubic feet per dehydrator per year. Use 73.4 for CH₄ and 3.21 for CO₂ at 60°F and 14.7 psia.
- Count = Total number of glycol dehydrators with throughput less than 0.4 million standard cubic feet per day.
- 1000 = Conversion of \( EF_i \) in thousand standard cubic feet to standard cubic feet.

(3) Determine if dehydrator unit has vapor recovery. Adjust the emissions estimated in paragraphs (e)(1) or (e)(2) of this section downward by the magnitude of emissions captured.

(4) Calculate annual emissions from dehydrator vents to flares or regenerator fire-box/fire tubes as follows:

\[ E_{s,n} = \frac{(H \times D^2 \times P \times P_2 \times %G \times 365 \text{days/yr})}{(4 \times P_1 \times T \times 1,000 \text{cf/Mcf} \times 100)} \]  
(Eq. W–6)

where:
- \( E_{s,n} \) = Annual natural gas emissions at standard conditions in cubic feet.
- \( H \) = Height of the dehydrator vessel (ft).
- \( D \) = Inside diameter of the vessel (ft).
- \( P_1 \) = Atmospheric pressure (psia).
- \( P_2 \) = Pressure of the gas (psia).
- \( %G \) = Percent of packed vessel volume that is gas.
- \( T \) = Time between refilling (days).
- 100 = Conversion of %G to fraction.

(5) Dehydrators that use desiccant shall calculate emissions from the amount of gas vented from the vessel when it is depressurized for the desiccant refilling process using Equation W–6 of this section. Desiccant dehydrators covered in (e)(5) of this section do not have to report emissions under (i) of this section.

(6) For glycol dehydrators, both CH₄ and CO₂ mass emissions shall be calculated from volumetric GHG emissions using calculations in paragraph (v) of this section. For dehydrators that use desiccant, both CH₄ and CO₂ volumetric and mass emissions shall be calculated from volumetric natural gas emissions using calculations in paragraphs (u) and (v) of this section.

(f) Well venting for liquids unloadings. Calculate CO₂ and CH₄ emissions from well venting for liquids unloading using one of the calculation methodologies described in paragraphs (f)(1), (f)(2) or (f)(3) of this section.

(1) Calculation Methodology 1. For one well of each unique well tubing diameter group and pressure group combination in each sub-basin category (see
§ 98.238 for the definitions of tubing diameter group, pressure group, and sub-basin category, where gas wells are vented to the atmosphere to expel liquids accumulated in the tubing, a recording flow meter shall be installed on the vent line used to vent gas from the well (e.g., on the vent line off the wellhead separator or atmospheric storage tank) according to methods set forth in §98.234(b). Calculate emissions from well venting for liquids unloading using Equation W–7 of this section.

\[ E_{a,n} = \sum_{p=1}^{h} T_p FR_p \quad (\text{Eq. W–7}) \]

Where:

- \( E_{a,n} \) = Annual natural gas emissions for all wells of the same tubing diameter group and pressure group combination in a sub-basin at actual conditions in cubic feet.
- \( h \) = Total number of wells of the same tubing diameter group and pressure group combination in a sub-basin.
- \( p \) = Wells 1 through \( h \) of the same tubing diameter group and pressure group combination in a sub-basin.
- \( T_p \) = Cumulative amount of time in hours of venting from the measured well, \( p \), of the same tubing diameter group and pressure group combination in a sub-basin during the year.
- \( FR_p \) = Average flow rate in cubic feet per hour of a measured well venting for the duration of the liquids unloading, under actual conditions as determined in paragraph (f)(1)(i) of this section.

(i) Determine the well vent average flow rate as specified under paragraph (f)(1)(i) of this section.

(A) The average flow rate per hour of venting is calculated for each unique tubing diameter group and pressure group combination in each sub-basin category by dividing the recorded total flow by the recorded time (in hours) for a single liquid unloading with venting to the atmosphere.

(B) This average flow rate per hour is applied to all wells in the same pressure group that have the same tubing diameter group, for the number of hours of venting these wells.

(C) A new average flow rate is calculated every other calendar year for each reporting sub-basin category starting the first calendar year of data collection. For a new producing sub-basin category, an average flow rate is calculated beginning in the first year of production.

(ii) Calculate natural gas volumetric emissions at standard conditions using calculations in paragraph (t) of this section.

(2) Calculation Methodology 2. Calculate the total emissions for well venting for liquids unloading using Equation W–8 of this section.

\[ E_{s,n} = \sum_{p=1}^{W} V_p \times \left\{ 0.37 \times 10^{-1} \times \frac{CD_p \times WD_p \times SP_p}{3.14 (\text{pi})/4} \right\} + \sum_{q=1}^{V_p} \left\{ SFR_p \times (HR_{p,q} - 1.0) \times Z_{p,q} \right\} \quad (\text{Eq. W–8}) \]

Where:

- \( E_{s,n} \) = Annual natural gas emissions at standard conditions, in cubic feet per year.
- \( W \) = Total number of wells with well venting for liquids unloading for each sub-basin.
- \( 0.37 \times 10^{-1} \times \frac{CD_p \times WD_p \times SP_p}{3.14 (\text{pi})/4} \) (pea converted to pounds per square feet).
- \( CD_p \) = Casing internal diameter for each well, \( p \), in inches.
- \( WD_p \) = Well depth from either the top of the well or the lowest packer to the bottom of the well, for each well, \( p \), in feet.
- \( SP_p \) = Shut-in pressure or surface pressure for wells with tubing production and no packers or casing pressure for each well, \( p \), in pounds per square inch absolute (pea) or casing-to-tubing pressure of one well from the same sub-basin multiplied by the tubing pressure of each well, \( p \), in pounds per square inch absolute (psia) or casing-to-tubing pressure of one well from the same sub-basin multiplied by the tubing pressure of each well, \( p \), in the sub-basin, in pounds per square inch absolute (psia).
- \( V_p \) = Number of vents per year per well, \( p \).
- \( SFR_p \) = Average flow-line rate of gas for well, \( p \), at standard conditions in cubic feet per hour. Use Equation W–33 to calculate the average flow-line rate at standard conditions.
- \( HR_{p,q} \) = Hours that each well, \( p \), was left open to the atmosphere during unloading, \( q \).
- \( 1.0 \) = Hours for average well to blowdown casing volume at shut-in pressure.
- \( Z_{p,q} \) = If \( HR_{p,q} \) is less than 1.0 then \( Z_{p,q} \) is equal to 0. If \( HR_{p,q} \) is greater than or equal to 1.0 then \( Z_{p,q} \) is equal to 1.
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(3) Calculation Methodology 3. Calculate emissions from each well venting to the atmosphere for liquids unloading with plunger lift assist using Equation W–9 of this section.

\[
E_{s,n} = \sum_{p=1}^{W} \left[ V_p \times (0.37 \times 10^{-3}) \times T D_p \times W D_p \times S P_p \times \sum_{q=1}^{W} (S F R_p \times (H R_{p,q} - 0.5) \times Z_{p,q}) \right] \quad \text{(Eq. W–9)}
\]

Where:

- \( E_{s,n} \) = Annual natural gas emissions at standard conditions, in cubic feet/year.
- \( W \) = Total number of wells with well venting for liquids unloading for each sub-basin.
- \( 0.37 \times 10^{-3} = (3.14 \times (\pi)/4) / (14.7 \times 144) \) (psia converted to pounds per square feet).
- \( T D_p \) = Tubing internal diameter for each well, \( p \), in inches.
- \( W D_p \) = Tubing depth to plunger bumper for each well, \( p \), in feet.
- \( S P_p \) = Flow-line pressure for each well, \( p \), in pounds per square inch absolute (psia), using engineering estimate based on best available data.
- \( V_p \) = Number of vents per year for each well, \( p \).
- \( S F R_p \) = Average flow-line rate of gas for well, \( p \), at standard conditions in cubic feet per hour. Use Equation W–33 to calculate the average flow-line rate at standard conditions.
- \( H R_{p,q} \) = Hours that each well, \( p \), was left open to the atmosphere during each unloading, \( q \).
- \( Z_{p,q} \) = If \( H R_{p,q} \) is less than 0.5 then \( Z_{p,q} \) is equal to 0. If \( H R_{p,q} \) is greater than or equal to 0.5 then \( Z_{p,q} \) is equal to 1.

(i)-(ii) [Reserved]

(4) Both \( CH_4 \) and \( CO_2 \) volumetric and mass emissions shall be calculated from volumetric natural gas emissions using calculations in paragraphs (u) and (v) of this section.

\[(g)\] Gas well venting during completions and workovers from hydraulic fracturing. Calculate \( CH_4 \), \( CO_2 \) and \( N_2O \) annual emissions from gas well venting during completions involving hydraulic fracturing in wells and well workovers using Equation W–10A or Equation W–10B of this section. Equation W–10A applies to well venting when the backflow rate is measured or calculated. Equation W–10B applies when the backflow vent or flare volume is measured. Use Equation W–10A if the flow rate for backflow during well completions and workovers from hydraulic fracturing is known for the specified number of wells per paragraph (g)(1) in a sub-basin and well type (horizontal or vertical) combination. Use Equation W–10B if the flow volume for backflow during completing well completions and workovers from hydraulic fracturing is known for all wells in a sub-basin and well type (horizontal or vertical) combination. Both \( CH_4 \) and \( CO_2 \) volumetric and mass emissions shall be calculated from volumetric total gas emissions using calculations in paragraphs (u) and (v) of this section.

\[
E_{s,n} = \sum_{p=1}^{W} \left[ T_p \times F R M \times P R_p \times E n F_p \times S G_p \right] \quad \text{(Eq. W–10A)}
\]

\[
E_{s,n} = \sum_{p=1}^{W} \left[ F V_p \times E n F_p \right] \quad \text{(Eq. W–10B)}
\]

Where:

- \( E_{s,n} \) = Annual volumetric total gas emissions in cubic feet at standard conditions from gas well venting during completions or workovers following hydraulic fracturing for each sub-basin and well type (horizontal or vertical) combination.
- \( W \) = Total number of wells completed or worked over using hydraulic fracturing.
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in a sub-basin and well type (horizontal vs. vertical) combination.

\[ T_p = \text{Cumulative amount of time of backflow for the completion or workover, in hours, for each well, } p, \text{ in a sub-basin and well type (horizontal vs. vertical) combination during the reporting year.} \]

\[ \text{FRM} = \text{Ratio of backflow during well completions and workovers from hydraulic fracturing to 30-day production rate from Equation W–12.} \]

\[ \text{PR}_p = \text{First 30-day average production flow rate in standard cubic feet per hour of each well, } p, \text{ under actual conditions, converted to standard conditions, as required in paragraph (g)(1) of this section.} \]

\[ \text{EnF}_p = \text{Volume of CO}_2 \text{ or N}_2 \text{ injected gas in cubic feet at standard conditions that was injected into the reservoir during an energized fracture job for each well, } p. \text{ If the fracture process did not inject gas into the reservoir, then EnF}_p = 0. \text{ If injected gas is CO}_2, \text{ then EnF}_p = 0. \]

\[ \text{SG}_p = \text{Volume of natural gas in cubic feet at standard conditions that was recovered into a flow-line for well, } p \text{ as per paragraph (g)(3) of this section. This parameter includes any natural gas that is injected into the well for clean-up. If no gas was recovered, } \text{SG}_p = 0. \]

\[ \text{FV}_p = \text{Flow volume of each well, } p \text{ in standard cubic feet per hour measured using a recording flow meter (digital or analog) on the vent line to measure backflow during the completion or workover according to methods set forth in § 98.234(b).} \]

(1) The average flow rate for backflow during well completions and workovers from hydraulic fracturing shall be determined using measurement(s) for calculation methodology 1 or calculation(s) for calculation methodology 2 described in this paragraph (g)(1) of this section. If Equation W–10A is used, the number of measurements or calculations shall be determined per sub-basin and well type (horizontal or vertical) as follows: one measurement or calculation for less than or equal to 25 completions or workovers; two measurements or calculations for 26 to 50 completions or workovers; three measurements or calculations for 51 to 100 completions or workovers; four measurements or calculations for 101 to 250 completions or workovers; and five measurements or calculations for greater than 250 completions or workovers.

(i) Calculation Methodology 1. When using Equation W–10A, for each measured well completion(s) in each gas producing sub-basin category and well type (horizontal or vertical) combination and for each measured well workover(s) in each gas producing sub-basin category and well type (horizontal or vertical) combination, a recording flow meter (digital or analog) shall be installed on the vent line, ahead of a flare or vent if used, to measure the backflow rate according to methods set forth in § 98.234(b).

(ii) Calculation Methodology 2. When using Equation W–10A, for each calculated horizontal well completion and each calculated vertical well completion in each gas producing sub-basin category and for each calculated well horizontal workover and for each calculated vertical well workover in each gas producing sub-basin category, record the well flowing pressure upstream (and downstream in subsonic flow) of a well choke according to methods set forth in § 98.234(b) to calculate the well backflow during well completions and workovers from hydraulic fracturing. Calculate emissions using Equation W–11A of this section for subsonic flow or Equation W–11B of this section for sonic flow. Use best engineering estimate based on best available data along with Equation W–11C of this section to determine whether the predominant flow is sonic or subsonic. If the value of R in Equation W–11C is greater than or equal to 2, then flow is sonic; otherwise, flow is subsonic:

\[ FR = 1.27 \times 10^5 \times A^* \sqrt{\frac{3430 \times T_u^*}{\left(\frac{P_2}{P_1}\right)^{1.515} - \left(\frac{P_2}{P_1}\right)^{1.738}}} \] (Eq. W–11A)

Where:

\[ FR = \text{Average flow rate in cubic feet per hour, under subsonic flow conditions.} \]
\[ FR = 1.27 \times 10^5 \times A \times \sqrt{187.08 \times T_u} \]  

(Eq. W-11B)

Where:
- \( FR \) = Average flow rate in cubic feet per hour, under sonic flow conditions.
- \( A \) = Cross sectional area of orifice (m\(^2\)).
- \( T_u \) = Upstream temperature (degrees Kelvin).
- \( 187.08 \) = Constant with units of m\(^2\)/(sec\(^2\) * K).
- \( 1.27 \times 10^5 \) = Conversion from m\(^3\)/second to ft\(^3\)/hour.

\[ R = \frac{P_1}{P_2} \]  

(Eq. W-11C)

Where:
- \( R \) = Pressure ratio
- \( P_1 \) = Pressure upstream of the restriction orifice in pounds per square inch absolute.
- \( P_2 \) = Pressure downstream of the restriction orifice in pounds per square inch absolute.

(iii) For Equation W-10A, the ratio of backflow rate during well completions and workovers from hydraulic fracturing to 30-day production rate is calculated using Equation W-12 of this section.

\[ FRM = \frac{\sum_{p=1}^{W} FR_p}{\sum_{p=1}^{W} PR_p} \]  

(Eq. W-12)

Where:
- \( FRM \) = Ratio of backflow rate during well completions and workovers from hydraulic fracturing to 30-day production rate.
- \( FR_p \) = Measured backflow rate from Calculation Methodology 1 or calculated flow rate from Calculation Methodology 2 in standard cubic feet per hour for well(s) \( p \) for each sub-basin and well type (horizontal or vertical) combination. You may not use flow volume as used in Equation W-10B converted to a flow rate for this parameter.
- \( PR_p \) = First 30-day production rate in standard cubic feet per hour for each well \( p \) that was measured in the sub-basin and well type combination.
- \( W \) = Number of wells completed or worked over using hydraulic fracturing in a sub-basin and well type formation.

(iv) For Equation W-10A, the ratio of backflow rate during well completions and workovers from hydraulic fracturing to 30-day production rate for horizontal and vertical wells are applied to all horizontal and vertical well completions in the gas producing sub-basin and well type combination and to all horizontal and vertical well workovers, respectively, in the gas producing sub-basin and well type combination for the total number of hours of backflow for each of these wells.

(v) For Equation W-10A, new flow rates for horizontal and vertical gas well completions and horizontal and vertical gas well workovers in each sub-basin category shall be calculated once every two years starting in the first calendar year of data collection.
(2) The volume of CO\textsubscript{2} or N\textsubscript{2} injected into the well reservoir during energized hydraulic fractures will be measured using an appropriate meter as described in 98.234(b) or using receipts of gas purchases that are used for the energized fracture job.

(i) Calculate gas volume at standard conditions using calculations in paragraph (t) of this section.

(ii) [Reserved]

(3) Determine if the backflow gas from the well completion or workover from hydraulic fracturing is recovered with purpose designed equipment that separates natural gas from the backflow, and sends this natural gas to a flow-line (e.g., reduced emissions completion or workovers).

(i) Use the factor SG\textsubscript{P} in Equation W–10A of this section, to adjust the emissions estimated in paragraphs (g)(1) through (g)(4) of this section by the magnitude of emissions captured using purpose designed equipment that separates saleable gas from the backflow as determined by engineering estimate based on best available data.

(ii) [Reserved]

(iii) Calculate gas volume at standard conditions using calculations in paragraph (t) of this section.

(4) Both CH\textsubscript{4} and CO\textsubscript{2} volumetric and mass emissions shall be calculated from volumetric total emissions using calculations in paragraphs (u) and (v) of this section.

(5) Calculate annual emissions from gas well venting during well completions and workovers from hydraulic fracturing to flares as follows:

(i) Use the total gas well venting volume during well completions and workovers as determined in paragraph (g) of this section.

(ii) Use the calculation methodology of flare stacks in paragraph (n) of this section to determine gas well venting during well completions and workovers using hydraulic fracturing emissions from the flare. This adjustment to emissions from completions using flaring versus completions without flaring accounts for the conversion of CH\textsubscript{4} to CO\textsubscript{2} in the flare.

(h) Gas well venting during completions and workovers without hydraulic fracturing. Calculate CH\textsubscript{4}, CO\textsubscript{2} and N\textsubscript{2}O emissions from each gas well venting during well completions and workovers not involving hydraulic fracturing using Equation W–13 of this section:

\[
E_{s,\alpha} = N_{wo} * EF_{wo} + \sum_{p=1}^{f} V_{p} * T_{p}
\]

Eq. W–13

Where:

\( E_{s,\alpha} \) = Annual natural gas emissions in standard cubic feet from a gas well venting during well completions and workovers without hydraulic fracturing.

\( N_{wo} \) = Number of workovers per sub-basin category that flare gas or vent gas to the atmosphere and do not involve hydraulic fracturing in the reporting year.

\( EF_{wo} \) = Emission Factor for non-hydraulic fracture well workover venting in standard cubic feet per well workover without hydraulic fracturing.

\( p \) = Well completions 1 through \( f \) in a sub-basin.

\( f \) = Total number of well completions without hydraulic fracturing in a sub-basin category.

\( V_{p} \) = Average daily gas production rate in standard cubic feet per hour for each well completion without hydraulic fracturing.

\( T_{p} \) = Time each well completion without hydraulic fracturing, \( p \), was venting in hours during the year.
(1) Volumetric emissions for both CH\(_4\) and CO\(_2\) shall be calculated from volumetric natural gas emissions using calculations in paragraph (u) of this section. Mass emissions for both CH\(_4\) and CO\(_2\) shall be calculated from volumetric natural gas emissions using calculations in paragraphs (v) of this section.

(2) Calculate annual emissions from gas well venting during well completions and workovers not involving hydraulic fracturing to flares as follows:

(i) Use the gas well venting volume during well completions and workovers as determined in paragraph (h) of this section.

(ii) Use the calculation methodology of flare stacks in paragraph (n) of this section to determine gas well venting during well completions and workovers emissions without hydraulic fracturing from the flare.

(1) **Blowdown vent stacks.** Calculate CO\(_2\) and CH\(_4\) blowdown vent stack emissions from depressurizing equipment to reduce system pressure for planned or emergency shutdowns resulting from human intervention or to take equipment out of service for maintenance (excluding depressurizing to a flare, over-pressure relief, operating pressure control venting and blowdown of non-GHG gases; desiccant dehydrator blowdown venting before reloading is covered in paragraph (e)(5) of this section) as follows:

(i) Calculate the unique physical volume (including pipelines, compressor case or cylinders, manifolds, suction bottles, discharge bottles, and vessels) between isolation valves determined by engineering estimates based on best available data.

(ii) If the unique physical volume between isolation valves is greater than or equal to 50 cubic feet, retain logs of the number of blowdowns for each unique physical volume (including but not limited to compressors, vessels, pipelines, headers, fractionators, and tanks). Unique physical volumes smaller than 50 cubic feet are exempt from reporting under paragraph (i) of this section.

(3) Calculate the total annual venting emissions for unique volumes using either Equation W–14A or W–14B of this section.

\[
E_{s,n} = N \left( V \left( \frac{459.67 + T_s}{459.67 + T_a} \right) P_s \right) V \left( \frac{459.67 + T_s}{459.67 + T_a} \right) P_s \]  
\text{ (Eq. W–14A)}

Where:
\( E_{s,n} \) = Annual natural gas venting emissions at standard conditions from blowdowns in cubic feet.
\( N \) = Number of occurrences of blowdowns for each unique physical volume in calendar year.
\( V \) = Unique physical volume (including pipelines, compressors and vessels) between isolation valves in cubic feet.
\( C \) = Purge factor that is 1 if the unique physical volume is not purged or zero if the unique physical volume is purged using non-GHG gases.
\( T_s \) = Temperature at standard conditions (60 °F).
\( T_a \) = Temperature at actual conditions in the unique physical volume (°F).
\( P_s \) = Absolute pressure at standard conditions (14.7 psia).
\( P_a \) = Absolute pressure at actual conditions in the unique physical volume (psia).

\[
E_{s,n} = \sum_{p=1}^{N} V \left( \frac{459.67 + T_s}{459.67 + T_a} \right) \left( P_{a,b,p} - P_{a,x,p} \right) \left( 459.67 + T_a \right) P_s \]  
\text{ (Eq. W–14B)}
Where:

- \( E_{sn} \) = Annual natural gas venting emissions at standard conditions from blowdowns in cubic feet.
- \( p \) = Individual occurrence of blowdown for the same unique physical volume.
- \( N \) = Number of occurrences of blowdowns for each unique physical volume in the calendar year.
- \( V \) = Total physical volume (including pipelines, compressors and vessels) between isolation valves in cubic feet for each blowdown “\( p \).”
- \( T_s \) = Temperature at standard conditions (60 °F).
- \( T_a \) = Temperature at actual conditions in the unique physical volume (°F) for each blowdown “\( p \).”
- \( P_s \) = Absolute pressure at standard conditions (14.7 psia).
- \( P_{a,b,p} \) = Absolute pressure at actual conditions in the unique physical volume (psia) at the beginning of the blowdown “\( p \).”
- \( P_{a,e,p} \) = Absolute pressure at actual conditions in the unique physical volume (psia) at the end of the blowdown “\( p \); 0 if blowdown volume is purged using non-GHG gases.

(4) Calculate both \( \text{CH}_4 \) and \( \text{CO}_2 \) volumetric and mass emissions using calculations in paragraph (u) and (v) of this section.

(j) Onshore production storage tanks. Calculate \( \text{CH}_4, \text{CO}_2 \) and \( \text{N}_2\text{O} \) (when flared) emissions from atmospheric pressure fixed roof storage tanks receiving hydrocarbon produced liquids from onshore petroleum and natural gas production facilities (including stationary liquid storage not owned or operated by the reporter), calculate annual \( \text{CH}_4 \) and \( \text{CO}_2 \) emissions using any of the calculation methodologies described in this paragraph (j).

(1) Calculation Methodology 1. For separators with annual average daily throughput of oil greater than or equal to 10 barrels per day. Calculate annual \( \text{CH}_4 \) and \( \text{CO}_2 \) emissions from onshore production storage tanks using operating conditions in the last wellhead gas-liquid separator before liquid transfer to storage tanks. Calculate flashing emissions with a software program, such as AspenTech HYSYS® or API 4697 E&P Tank, that uses the Peng–Robinson equation of state, models flashing emissions, and speciates \( \text{CH}_4 \) and \( \text{CO}_2 \) emissions that will result when the oil from the separator enters an atmospheric pressure storage tank.

A minimum of the following parameters determined for typical operating conditions over the year by engineering estimate and process knowledge based on best available data must be used to characterize emissions from liquid transferred to tanks.

(i) Separator temperature.

(ii) Separator pressure.

(iii) Sales oil or stabilized oil API gravity.

(iv) Sales oil or stabilized oil production rate.

(v) Ambient air temperature.

(vi) Ambient air pressure.

(vii) Separator oil composition and Reid vapor pressure. If this data is not available, determine these parameters by selecting one of the methods described under paragraph (j)(1) (vii) of this section.

(A) If separator oil composition and Reid vapor pressure default data are provided with the software program, select the default values that most closely match your separator pressure first, and API gravity secondarily.

(B) If separator oil composition and Reid vapor pressure data are available through your previous analysis, select the latest available analysis that is representative of produced crude oil or condensate from the sub-basin category.

(C) Analyze a representative sample of separator oil in each sub-basin category for oil composition and Reid vapor pressure using an appropriate standard method published by a consensus-based standards organization.

(2) Calculation Methodology 2. Calculate annual \( \text{CH}_4 \) and \( \text{CO}_2 \) emissions from onshore production storage tanks for wellhead gas-liquid separators with annual average daily throughput of oil greater than or equal to 10 barrels per day by assuming that all of the \( \text{CH}_4 \) and \( \text{CO}_2 \) in solution at separator temperature and pressure is emitted from oil sent to storage tanks. You may use an appropriate standard method published by a consensus-based standards organization if such a method exists or you may use an industry standard practice as described in §98.234(b) to sample and analyze separator oil composition at separator pressure and temperature.
Calculation Methodology 3. For wells with annual average daily oil production greater than or equal to 10 barrels per day that flow directly to atmospheric storage tanks without passing through a wellhead separator, calculate annual CH₄ and CO₂ emissions by either of the methods in paragraph (j)(3) of this section:

(i) If well production oil and gas compositions are available through your previous analysis, select the latest available analysis that is representative of produced oil and gas from the sub-basin category and assume all of the CH₄ and CO₂ in both oil and gas are emitted from the tank.

(ii) If well production oil and gas compositions are not available, use default oil and gas compositions in software programs, such as API 4697 E&P Tank, that most closely match your well production gas/oil ratio and API gravity and assume all of the CH₄ and CO₂ in both oil and gas are emitted from the tank.

Calculation Methodology 4. For wells with annual average daily oil production greater than or equal to 10 barrels per day that flow directly to a separator not at the well pad, calculate annual CH₄ and CO₂ emissions by either of the methods in paragraph (j)(4) of this section:

(i) If well production oil composition is not available, use default oil composition in software programs, such as API 4697 E&P Tank, that most closely match your well production API gravity and pressure in the off-well pad separator determined by best available data. Assume all of the CH₄ and CO₂ in the oil phase is emitted from the tank.

(ii) If well production oil composition is available through your previous analysis, select the latest available analysis that is representative of oil at separator pressure determined by best available data and assume all of the CH₄ and CO₂ in the oil is emitted from the tank.

Calculation Methodology 5. For wellpad gas-liquid separators and for wells flowing off a well pad without passing through a gas-liquid separator with throughput less than 10 barrels per day use Equation W–15 of this section:

\[ E_{s,i} = E_{F,i} \times \text{Count} \times 1000 \]  

(Eq. W–15)

where:

- \( E_{s,i} \) = Annual total volumetric GHG emissions (either CO₂ or CH₄) at standard conditions in cubic feet.
- \( E_{F,i} \) = Population emission factor for separators or wells in thousand standard cubic feet per separator or well per year, for crude oil use 4.2 for CH₄ and 2.8 for CO₂ at 60 °F and 14.7 psia, and for gas condensate use 17.6 for CH₄ and 2.8 for CO₂ at 60 °F and 14.7 psia.
- Count = Total number of separators or wells with throughput less than 10 barrels per day.
- 1,000 = Conversion to cubic feet.

(6) Determine if the storage tank receiving your separator oil has a vapor recovery system.

(i) Adjust the emissions estimated in paragraphs (j)(1) through (j)(5) of this section downward by the magnitude of emissions recovered using a vapor recovery system as determined by engineering estimate based on best available data.

(ii) Reserved

(7) Determine if the storage tank receiving your separator oil is sent to flare(s).

(i) Use your separator flash gas volume and gas composition as determined in this section.

(ii) Use the calculation methodology of flare stacks in paragraph (n) of this section to determine your contribution to storage tank emissions from the flare.

(8) Calculate emissions from occurrences of well pad gas-liquid separator liquid dump valves not closing during the calendar year by using Equation W–16 of this section.
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\[ E_s, i = \left( \frac{CF_n \cdot E_n}{8760} \cdot T_n \right) + \left( \frac{E_n}{8760} \cdot (8760 - T_n) \right) \]  

(Eq. W-16)

where:

\( E_s, i \) = Annual total volumetric GHG emissions at standard conditions from each storage tank in cubic feet.

\( E_n \) = Storage tank emissions as determined in Calculation Methodologies 1, 2, or 4 in paragraphs (j)(1), (j)(2) and (j)(4) of this section (with wellhead separators) in standard cubic feet per year.

\( T_n \) = Total time the dump valve is not closing properly in the calendar year in hours. \( T_n \) is estimated by maintenance or operations records (records) such that when a record shows the valve to be open improperly, it is assumed the valve was open for the entire time period preceding the record starting at either the beginning of the calendar year or the previous record showing it closed properly within the calendar year. If a subsequent record shows it is closing properly, then assume from that time forward the valve closed properly until either the next record of it not closing properly or, if there is no subsequent record, the end of the calendar year.

\( CF_n \) = Correction factor for tank emissions for time period \( T_n \) is 3.87 for crude oil production. Correction factor for tank emissions for time period \( T_n \) is 5.37 for gas condensate production. Correction factor for tank emissions for time period \( T_n \) is 1.0 for periods when the dump valve is closed.

8,760 = Conversion to hourly emissions.

(9) Calculate both \( \text{CH}_4 \) and \( \text{CO}_2 \) mass emissions from volumetric natural gas emissions using calculations in paragraph (v) of this section.

(k) Transmission storage tanks. For vent stacks connected to one or more transmission condensate storage tanks, either water or hydrocarbon, without vapor recovery, in onshore natural gas transmission compression, calculate \( \text{CH}_4 \), \( \text{CO}_2 \) and \( \text{N}_2\text{O} \) annual emissions from compressor scrubber dump valve leakage as follows:

(1) Monitor the tank vapor vent stack annually for emissions using an optical gas imaging instrument according to methods set forth in §98.234(a)(1) or by directly measuring the tank vent using a flow meter or high volume sampler according to methods in §98.234(b) through (d) for a duration of 5 minutes, or a calibrated bag according to methods in §98.234(b). Or you may annually monitor leakage through compressor scrubber dump valve(s) into the tank using an acoustic leak detection device according to methods set forth in §98.234(a)(5).

(2) If the tank vapors from the vent stack are continuous for 5 minutes, or the acoustic leak detection device detects a leak, then use one of the following two methods in paragraph (k)(2) of this section to quantify annual emissions:

(i) Use a meter, such as a turbine meter, calibrated bag, or high flow sampler to estimate tank vapor volumes from the vent stack according to methods set forth in §98.234(b) through (d). If you do not have a continuous flow measurement device, you may install a flow measuring device on the tank vapor vent stack. If the vent is directly measured for five minutes under paragraph §98.233(k)(1) of this section to detect continuous leakage, this serves as the measurement.

(ii) Use an acoustic leak detection device on each scrubber dump valve connected to the tank according to the method set forth in §98.234(a)(5).

(iii) Use the appropriate gas composition in paragraph (u)(2)(iii) of this section.

(iv) Calculate GHG volumetric and mass emissions at standard conditions using calculations in paragraphs (t), (u), and (v) of this section, as applicable to the monitoring equipment used.

(3) If the leaking dump valve(s) is fixed following leak detection, the annual emissions shall be calculated from the beginning of the calendar year to the time the valve(s) is repaired.

(4) Calculate annual emissions from storage tanks to flares as follows:

(i) Use the storage tank emissions volume and gas composition as determined in paragraphs (k)(1) through (k)(3) of this section.

(ii) Use the calculation methodology of flare stacks in paragraph (n) of this
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section to determine storage tank emissions sent to a flare.

(1) Well testing venting and flaring. Calculate \( \text{CH}_4 \), \( \text{CO}_2 \), and \( \text{N}_2\text{O} \) (when flared) well testing venting and flaring emissions as follows:

(1) Determine the gas to oil ratio (GOR) of the hydrocarbon production from oil well(s) tested. Determine the production rate from gas well(s) tested.

(2) If GOR cannot be determined from your available data, then you must measure quantities reported in this section according to one of the two procedures in paragraph (l)(2) of this section to determine GOR:

(i) You may use an appropriate standard method published by a consensus-based standards organization if such a method exists.

(ii) Or you may use an industry standard practice as described in §98.234(b).

(3) Estimate venting emissions using Equation W–17A or Equation W–17B of this section.

\[
E_{a,n} = GOR \times FR \times D
\]  
(Eq. W–17A)

\[
E_{a,n} = PR \times D
\]  
(Eq. W–17B)

Where:

- \( E_{a,n} = \) Annual volumetric natural gas emissions from well(s) testing in cubic feet under actual conditions.
- \( GOR = \) Gas to oil ratio in cubic feet of gas per barrel of oil; oil here refers to hydrocarbon liquids produced of all API gravities.
- \( FR = \) Flow rate in barrels of oil per day for the oil well(s) being tested.
- \( PR = \) Average annual production rate in cubic feet per day for the gas well(s) being tested.
- \( D = \) Number of days during the year, the well(s) is tested.

(4) Calculate natural gas volumetric emissions at standard conditions using calculations in paragraph (t) of this section.

(5) Calculate both \( \text{CH}_4 \) and \( \text{CO}_2 \) volumetric and mass emissions from volumetric natural gas emissions using calculations in paragraphs (u) and (v) of this section.

(6) Calculate emissions from well testing to flares as follows:

(i) Use the well testing emissions volume and gas composition as determined in paragraphs (l)(1) through (3) of this section.

(ii) Use the calculation methodology of flare stacks in paragraph (n) of this section.
Where:

\[ E_{a,n} = \sum_{q=1}^{y} \sum_{p=1}^{x} GOR_{p,q} \times V_{p,q} \]  

(Eq. W-18)

(4) Calculate natural gas volumetric emissions at standard conditions using calculations in paragraph (t) of this section.

(5) Calculate both CH\textsubscript{4} and CO\textsubscript{2} volumetric and mass emissions from volumetric natural gas emissions using calculations in paragraphs (u) and (v) of this section.

(6) Calculate emissions from associated natural gas to flares as follows:

(i) Use the associated natural gas volume and gas composition as determined in paragraph (m)(1) through (4) of this section.

(ii) Use the calculation methodology of flare stacks in paragraph (n) of this section to determine associated gas emissions from the flare.

(n) Flare stack emissions. Calculate CO\textsubscript{2}, CH\textsubscript{4}, and N\textsubscript{2}O emissions from a flare stack as follows:

(1) If you have a continuous flow measurement device on the flare, you must use the measured flow volumes to calculate the flare gas emissions. If all of the flare gas is not measured can be estimated using engineering calculations based on best available data or company records. If you do not have a continuous flow measurement device on the flare, you can install a flow measuring device on the flare or use engineering calculations based on process knowledge, company records, and best available data.

(2) If you have a continuous gas composition analyzer on gas to the flare, you must use these compositions in calculating emissions. If you do not have a continuous gas composition analyzer on gas to the flare, you must use the appropriate gas compositions for each stream of hydrocarbons going to the flare as follows:

(i) For onshore natural gas production, determine natural gas composition using (u)(2)(i) of this section.

(ii) For onshore natural gas processing, when the stream going to flare is natural gas, use the GHG mole percent in feed natural gas for all streams upstream of the de-methanizer or dew point control, and GHG mole percent in facility specific residue gas to transmission pipeline systems for all emissions sources downstream of the de-methanizer overhead or dew point control for onshore natural gas processing facilities. For onshore natural gas processing plants that solely fractionate a liquid stream, use the GHG mole percent in feed natural gas liquid for all streams.

(iii) For any applicable industry segment, when the stream going to the flare is a hydrocarbon product stream, such as methane, ethane, propane, butane, pentane-plus and mixed light hydrocarbons, then you may use a representative composition from the source for the stream determined by engineering calculation based on process knowledge and best available data.

(3) Determine flare combustion efficiency from manufacturer. If not available, assume that flare combustion efficiency is 98 percent.

(4) Calculate GHG volumetric emissions at actual conditions using Equations W-19, W-20, and W-21 of this section.
$E_{a,CH_4}(\text{un-combusted}) = V_a * (1 - \eta) * X_{CH_4}$  
\hspace{1cm} (Eq. W-19)

$E_{a,CO_2}(\text{un-combusted}) = V_a * X_{CO_2}$  
\hspace{1cm} (Eq. W-20)

$E_{a,CO_2}(\text{combusted}) = \sum_{j=1}^{5} (\eta * V_a * Y_j * R_j)$  
\hspace{1cm} (Eq. W-21)

where:

$E_{a,CH_4}(\text{un-combusted})$ = Contribution of annual un-combusted CH$_4$ emissions from flare stack in cubic feet, under actual conditions.

$E_{a,CO_2}(\text{un-combusted})$ = Contribution of annual un-combusted CO$_2$ emissions from flare stack in cubic feet, under actual conditions.

$E_{a,CO_2}(\text{combusted})$ = Contribution of annual combusted CO$_2$ emissions from flare stack in cubic feet, under actual conditions.

$V_a$ = Volume of gas sent to flare in cubic feet, during the year.

$\eta$ = Fraction of gas combusted by a burning flare (default is 0.98). For gas sent to an unlit flare, $\eta$ is zero.

$X_{CH_4}$ = Mole fraction of CH$_4$ in gas to the flare.

$X_{CO_2}$ = Mole fraction of CO$_2$ in gas to the flare.

$Y_j$ = Mole fraction of gas hydrocarbon constituents $j$ (such as methane, ethane, propane, butane, and pentanes-plus).

$R_j$ = Number of carbon atoms in the gas hydrocarbon constituent $j$: 1 for methane, 2 for ethane, 3 for propane, 4 for butane, and 5 for pentanes-plus.

(5) Calculate GHG volumetric emissions at standard conditions using calculations in paragraph (t) of this section.

(6) Calculate both CH$_4$ and CO$_2$ mass emissions from volumetric CH$_4$ and CO$_2$ emissions using calculation in paragraph (v) of this section.

(7) Calculate total annual emission from flare stacks by summing Equation W-40, Equation W-19, Equation W-20 and Equation W-21 of this section.

(8) Calculate N$_2$O emissions from flare stacks using Equation W-40 in paragraph (t) of this section.

(9) If you operate and maintain a CEMS that has both a CO$_2$ concentration monitor and volumetric flow rate monitor, you must calculate only CO$_2$ emissions for the flare. You must follow the Tier 4 Calculation Methodology and all associated calculation, quality assurance, reporting, and record-keeping requirements for Tier 4 in subpart C of this part (General Stationary Fuel Combustion Sources). If a CEMS is used to calculate flare stack emissions, the requirements specified in paragraphs (n)(1) through (n)(7) are not required. If a CO$_2$ concentration monitor and volumetric flow rate monitor are not available, you may elect to install a CO$_2$ concentration monitor and a volumetric flow rate monitor that comply with all of the requirements specified for the Tier 4 Calculation Methodology in subpart C of this part (General Stationary Fuel Combustion).

(10) The flare emissions determined under paragraph (n) of this section must be corrected for flare emissions calculated and reported under other paragraphs of this section to avoid double counting of these emissions.

(11) If source types in §98.233 use Equations W-19 through W-21 of this section, use estimate of emissions under actual conditions for the parameter, $V_a$, in these equations.

(o) Centrifugal compressor venting. Calculate CH$_4$, CO$_2$ and N$_2$O (when flared) emissions from both wet seal and dry seal centrifugal compressor vents as follows:

(1) For each centrifugal compressor covered by §98.232 (d)(2), (e)(2), (f)(2), (g)(2), and (h)(2) you must conduct an annual measurement in the operating mode in which it is found. Measure emissions from all vents (including emissions manifolded to common vents) including wet seal oil degassing vents, unit isolation valve vents, and
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blowdown valve vents. Record emissions from the following vent types in the specified compressor modes during the annual measurement.

(i) Operating mode, blowdown valve leakage through the blowdown vent, wet seal and dry seal compressors.

(ii) Operating mode, wet seal oil degassing vents.

(iii) Not operating, depressurized mode, unit isolation valve leakage through open blowdown vent, without blind flanges, wet seal and dry seal compressors.

(A) For the not operating, depressurized mode, each compressor must be measured at least once in any three consecutive calendar years. If a compressor is not operated and has blind flanges in place throughout the 3 year period, measurement is not required in this mode. If the compressor is in standby depressurized mode without blind flanges in place and is not operated throughout the 3 year period, it must be measured in the standby depressurized mode.

(2) For wet seal oil degassing vents, determine vapor volumes sent to an atmospheric vent or flare, using a temporary meter such as a vane anemometer or permanent flow meter according to 98.234(b) of this section. If you do not have a permanent flow meter, you may install a permanent flow meter on the wet seal oil degassing tank vent.

(3) For blowdown valve leakage and unit isolation valve leakage to open ended vents, you can use one of the following methods: Calibrated bagging or high volume sampler according to methods set forth in § 98.234(c) and § 98.234(d), respectively. For through valve leakage, such as isolation valves, you may use an acoustic leak detection device according to methods set forth in § 98.234(a). If you do not have a flow meter, you may install a port for insertion of a temporary meter, or a permanent flow meter, on the vents.

(4) Estimate annual emissions using the flow measurement and Equation W–22 of this section.

\[ E_{s,j,m} = MT_m \cdot T_m \cdot M_{i,m} \cdot (1 - B_m) \quad \text{(Eq. W–22)} \]

where:

- \( E_{s,j,m} \) = Annual GHG, (either CH\(_4\) or CO\(_2\)) volumetric emissions at standard conditions, in cubic feet.
- \( MT_m \) = Measured gas emissions in standard cubic feet per hour.
- \( T_m \) = Total time the compressor is in the mode for which \( E_{s,j} \) is being calculated, in the calendar year in hours.
- \( M_{i,m} \) = Mole fraction of GHG, in the vent gas; use the appropriate gas compositions in paragraph (u)(2) of this section.
- \( B_m \) = Fraction of operating time that the vent gas is sent to vapor recovery or fuel gas as determined by keeping logs of the number of operating hours for the vapor recovery system and the time that vent gas is directed to the fuel gas system or sales.

(5) Calculate annual emissions from each centrifugal compressor using Equation W–23 of this section.

\[ E_{s,j} = \sum_m EF_m \cdot T_m \cdot \text{GHG}_i \quad \text{(Eq. W–23)} \]

where:

- \( E_{s,j} \) = Annual total volumetric GHG emissions at standard conditions from each centrifugal compressor in cubic feet.
- \( EF_m \) = Reporter emission factor for each mode \( m \), in cubic feet per hour, from Equation W–24 of this section as calculated in paragraph 6.
- \( T_m \) = Total time in hours per year the compressor was in each mode, as listed in paragraph (o)(1)(i) through (o)(1)(iii).
- \( \text{GHG}_i \) = For onshore natural gas processing facilities, concentration of GHG, CH\(_4\) or CO\(_2\), in produced natural gas or feed natural gas; for other facilities listed in § 98.230(a)(4) through (a)(8), GHG, equals 1.
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(6) You shall use the flow measurements of operating mode wet seal oil degassing vent, operating mode blowdown valve vent and not operating depressurized mode isolation valve vent for all the reporter’s compressor modes not measured in the calendar year to develop the following emission factors using Equation W–24 of this section for each emission source and mode as listed in paragraph (o)(1)(i) through (o)(1)(iii).

\[ EF_m = \sum \frac{MT_m}{Count_m} \]  
\[ \text{(Eq. W–24)} \]

where:
- \( EF_m \) = Reporter emission factors for compressor in the three modes \( m \) (as listed in paragraph (o)(1)(i) through (o)(1)(iii)) in cubic feet per hour.
- \( MT_m \) = Flow Measurements from all centrifugal compressor vents in each mode in (o)(1)(i) through (o)(1)(iii) of this section in standard cubic feet per hour.
- \( Count_m \) = Total number of compressors measured.
- \( m \) = Compressor mode as listed in paragraph (o)(1)(i) through (o)(1)(iii).

(i) The emission factors must be calculated annually. You must use all measurements from the current calendar year and the preceding two calendar years, totaling three consecutive calendar years of measurements in paragraph (o)(6) of this section.

(ii) [Reserved]

(7) Onshore petroleum and natural gas production shall calculate emissions from centrifugal compressor wet seal oil degassing vents as follows:

\[ E_s,i = \text{Count} \times EF_i \]  
\[ \text{(Eq. W–25)} \]

where:
- \( E_{s,i} \) = Annual total volumetric GHG emissions at standard conditions from centrifugal compressor wet seals in cubic feet.
- \( \text{Count} \) = Total number of centrifugal compressors for the reporter.
- \( EF_i \) = Emission factor for GHG \( i \). Use 1.2 \( \times 10^6 \) standard cubic feet per year per compressor for \( \text{CH}_4 \) and 5.30 \( \times 10^5 \) thousand standard cubic feet per year per compressor for \( \text{CO}_2 \) at 60 \( ^\circ \)F and 14.7 psia.

(8) Calculate both \( \text{CH}_4 \) and \( \text{CO}_2 \) mass emissions from volumetric emissions using calculations in paragraph (v) of this section.

(9) Calculate emissions from seal oil degassing vent vapors to flares as follows:

(i) Use the seal oil degassing vent vapor volume and gas composition as determined in paragraphs (o)(5) of this section to determine degassing vent vapor emissions from the flare.

(ii) Use the calculation methodology of flare stacks in paragraph (n) of this section to determine degassing vent vapor emissions from the flare.

(p) Reciprocating compressor venting. Calculate \( \text{CH}_4 \) and \( \text{CO}_2 \) emissions from all reciprocating compressor vents as follows. For each reciprocating compressor covered in §98.232(d)(1), (e)(1), (f)(1), (g)(1), and (h)(1) you must conduct an annual measurement for each compressor in the mode in which it is found during the annual measurement, except as specified in paragraph (p)(9) of this section. Measure emissions from (including emissions manifolded to common vents) reciprocating rod packing vents, unit isolation valve vents, and blowdown valve vents. Record emissions from the following vent types in the specified compressor modes during the annual measurement as follows:

(1) Operating or standby pressurized mode, blowdown vent leakage through the blowdown vent stack.

(2) Operating mode, reciprocating rod packing emissions.

(3) Not operating, depressurized mode, unit isolation valve leakage.
through the blowdown vent stack, without blind flanges.

(i) For the not operating, depressurized mode, each compressor must be measured at least once in any three consecutive calendar years if this mode is not found in the annual measurement. If a compressor is not operated and has blind flanges in place throughout the 3 year period, measurement is not required in this mode. If the compressor is in standby depressurized mode without blind flanges in place and is not operated throughout the 3 year period, it must be measured in the standby depressurized mode.

(ii) [Reserved]

(4) If reciprocating rod packing and blowdown vent are connected to an open-ended vent line use one of the following two methods to calculate emissions:

(i) Measure emissions from all vents (including emissions manifolded to common vents) including rod packing, unit isolation valves, and blowdown vents using either calibrated bagging or high volume sampler according to methods set forth in §98.234(c) and §98.234(d), respectively.

(ii) Use a temporary meter such as a vane anemometer or a permanent meter such as an orifice meter to measure emissions from all vents (including emissions manifolded to a common vent) including rod packing vents and unit isolation valve leakage through blowdown vents according to methods set forth in §98.234(b). If you do not have a permanent flow meter, you may install a port for insertion of a temporary meter or a permanent flow meter on the vents. For through-valve leakage to open ended vents, such as unit isolation valves on not operating, depressurized compressors and blowdown valves on pressurized compressors, you may use an acoustic detection device according to methods set forth in §98.234(a).

(5) If reciprocating rod packing is not equipped with a vent line use the following method to calculate emissions:

(i) You must use the methods described in §98.234(a) to conduct annual leak detection of equipment leaks from the packing case into an open distance piece, or from the compressor crank case breather cap or other vent with a closed distance piece.

(ii) Measure emissions found in paragraph (p)(5)(i) of this section using an appropriate meter, or calibrated bag, or high volume sampler according to methods set forth in §98.234(b), (c), and (d), respectively.

(6) Estimate annual emissions using the flow measurement and Equation W–26 of this section.

\[ E_{s,i,m} = M T_{m} * T_{m} * M_{i,m} \]  \hfill (Eq. W–26)

where:

- \( E_{s,i,m} \) = Annual GHG \( i \) (either \( \text{CH}_4 \) or \( \text{CO}_2 \)) volumetric emissions at standard conditions, in cubic feet.
- \( M T_{m} \) = Measured gas emissions in standard cubic feet per hour.
- \( T_{m} \) = Total time the compressor is in the mode for which \( E_{s,i,m} \) is being calculated, in the calendar year in hours.
- \( M_{i,m} \) = Mole fraction of GHG \( i \) in gas; use the appropriate gas compositions in paragraph (u)(2) of this section.

(7) Calculate annual emissions from each reciprocating compressor using Equation W–27 of this section.

\[ E_{s,j} = \sum_{m} E F_{m} * T_{m} * G H G_{j} \]  \hfill (Eq. W–27)

where:

- \( E_{s,j} \) = Annual total volumetric GHG emissions at standard conditions from each reciprocating compressor in cubic feet.
\( EF_m = \sum \frac{MT_m}{\text{Count}_m} \) (Eq. W-28)

where:
- \( EF_m \) = Reporter emission factors for compressor in the three modes, \( m \), in cubic feet per hour.
- \( MT_m \) = Meter readings from all reciprocating compressor vents in each and mode, \( m \), in standard cubic feet per hour.
- \( \text{Count}_m \) = Total number of compressors measured in each mode, \( m \).
- \( m \) = Compressor mode as listed in paragraph (p)(1) through (p)(3).

(A) You must combine emissions for blowdown vents, measured in the operating and standby pressurized modes.
(B) The emission factors must be calculated annually. You must use all measurements from the current calendar year and the preceding two calendar years, totaling three consecutive calendar years of measurements.

(10) Estimate \( \text{CH}_4 \) and \( \text{CO}_2 \) volumetric and mass emissions from volumetric natural gas emissions using the calculations in paragraphs (u) and (v) of this section.

(q) Leak detection and leaker emission factors. You must use the methods described in §98.234(a) to conduct leak detection(s) of equipment leaks from all component types listed in §98.233(d)(7), (e)(5), (g)(3), (h)(4), and (i)(1). This paragraph (q) applies to component types in streams with gas content greater than 10 percent \( \text{CH}_4 \) plus \( \text{CO}_2 \) by weight. Component types in streams with gas content less than 10 percent \( \text{CH}_4 \) plus \( \text{CO}_2 \) by weight do not need to be reported. Tubing systems equal to
Environmental Protection Agency § 98.233

or less than one half inch diameter are exempt from the requirements of this paragraph (q) and do not need to be reported. If equipment leaks are detected for sources listed in this paragraph (q), calculate equipment leak emissions per component type per reporting facility using Equations W–30A or W–30B of this section for each component type. Use Equation W–30A for industry segments listed in 98.230(a)(3)–(a)(7). Use Equation W–30B for industry segments listed in 98.230(a)(8).

\[ E_{s,i} = \frac{\sum_{p=1}^{x} (EF \cdot T_p)}{GHG_i} \]  

(Eq. W–30A)

\[ E_{s,i} = \frac{\sum_{q=1}^{n} \sum_{p=1}^{T_{p,q}} (EF \cdot T_{p,q})}{GHG_i} \]  

(Eq. W–30B)

Where:

\( E_{s,i} \) = Annual total volumetric GHG emissions at standard conditions from each component type in cubic feet, as specified in (q)(1) through (q)(8) of this section.

\( x \) = Total number of each component type.

\( EF \) = Leaker emission factor for specific component types listed in Table W–2 through Table W–7 of this subpart.

\( GHG_i \) = For onshore natural gas processing facilities, concentration of GHG, \( \text{CH}_4 \) or \( \text{CO}_2 \), in the total hydrocarbon of the feed natural gas; for onshore natural gas transmission compression and underground natural gas storage, \( GHG_i \) equals 0.975 for \( \text{CH}_4 \) and \( 1.1 \times 10^{-2} \) for \( \text{CO}_2 \); for LNG storage and LNG import and export equipment, \( GHG_i \) equals 1 for \( \text{CH}_4 \) and 0 for \( \text{CO}_2 \); and for natural gas distribution, \( GHG_i \) equals 1 for \( \text{CH}_4 \) and \( 1.1 \times 10^{-2} \) for \( \text{CO}_2 \).

\( T_p \) = The total time the component, \( p \), was found leaking and operational, in hours.

\( t \) = Calendar year of reporting.

\( n \) = The number of years over which one complete cycle of leak detection is conducted over all the T-D transfer stations in a natural gas distribution facility; \( 0 < n \leq 5 \). For the first \( (n-1) \) calendar years of reporting the summation in Equation W–30B should be for years that the data is available.

\( T_{p,q} \) = The total time the component, \( p \), was found leaking and operational, in hours, in year \( q \). If one leak detection survey is conducted, assume the component was leaking for the entire calendar year. If multiple leak detection surveys are conducted, assume that the component found to be leaking has been leaking since the previous survey (if not found to be leaking in the previous survey) or the beginning of the calendar year (if it was found to be leaking in the previous survey). For the last leak detection survey in the calendar year, assume that all leaking components continue to leak until the end of the calendar year.

(1) You must select to conduct either one leak detection survey in a calendar year or multiple complete leak detection surveys in a calendar year. The number of leak detection surveys selected must be conducted during the calendar year.

(2) Calculate GHG mass emissions in carbon dioxide equivalent at standard conditions using calculations in paragraph (v) of this section.

(3) Onshore natural gas processing facilities shall use the appropriate default leaker emission factors listed in Table W–2 of this subpart for equipment leaks detected from valves, connectors, open ended lines, pressure relief valves, and meters.

(4) Onshore natural gas transmission compression facilities shall use the appropriate default leaker emission factors listed in Table W–3 of this subpart.
for equipment leaks detected from valves, connectors, open ended lines, pressure relief valves, and meters.

(5) Underground natural gas storage facilities for storage stations shall use the appropriate default leaker emission factors listed in Table W–4 of this subpart for equipment leaks detected from valves, connectors, open ended lines, pressure relief valves, and meters.

(6) LNG storage facilities shall use the appropriate default leaker emission factors listed in Table W–5 of this subpart for equipment leaks detected from valves, pump seals, connectors, and other.

(7) LNG import and export facilities shall use the appropriate default leaker emission factors listed in Table W–6 of this subpart for equipment leaks detected from valves, pump seals, connectors, and other.

(8) Natural gas distribution facilities for above grade transmission-distribution transfer stations, shall use the appropriate default leaker emission factors listed in Table W–7 of this subpart for equipment leaks detected from connectors, block valves, control valves, pressure relief valves, orifice meters, regulators, and open ended lines. Leak detection at natural gas distribution facilities is only required at above grade stations that qualify as transmission-distribution transfer stations. Below grade transmission-distribution transfer stations and all metering-regulating stations that do meet the definition of transmission-distribution transfer stations are not required to perform component leak detection under this section.

(i) Natural gas distribution facilities may choose to conduct leak detection at the T-D transfer stations over multiple years, not exceeding a five year period to cover all T-D transfer stations. If the facility chooses to use the multiple year option then the number of T-D transfer stations that are monitored in each year should be approximately equal across all years in the cycle without monitoring the same station twice during the multiple year survey.

(ii) [Reserved]

(r) Population count and emission factors. This paragraph applies to emissions sources listed in §98.232 (c)(21), (f)(5), (g)(3), (h)(4), (i)(2), (i)(3), (i)(4), (i)(5), and (i)(6) on streams with gas content greater than 10 percent CH4 plus CO2 by weight. Emissions sources in streams with gas content less than 10 percent CH4 plus CO2 by weight do not need to be reported. Tubing systems equal to or less than one half inch diameter are exempt from the requirements of paragraph (r) of this section and do not need to be reported. Calculate emissions from all sources listed in this paragraph using Equation W–31 of this section.

\[
E_{sj} = \text{Count}_s \cdot EF_s \cdot GHG_i \cdot T_s \quad \text{(Eq. W–31)}
\]

Where:
- \(E_{sj}\) = Annual volumetric GHG emissions at standard conditions from each component type in cubic feet.
- \(\text{Count}_s\) = Total number of this type of emission source at the facility. For onshore petroleum and natural gas production, average component counts are provided by major equipment piece in Tables W–1B and Table W–1C of this subpart. Use average component counts as appropriate for operations in Eastern and Western U.S., according to Table W–1D of this subpart. Underground natural gas storage shall count the components listed for population emission factors in Table W–4. LNG Storage shall count the number of vapor recovery compressors. LNG import and export shall count the number of vapor recovery compressors. Natural gas distribution shall count the meter-regulator runs as described in paragraph (r)(6) of this section.
- \(EF_s\) = Population emission factor for the specific component type, as listed in Table W–1A and Tables W–3 through Table W–7 of this subpart. Use appropriate population emission factor for operations in Eastern and Western U.S., according to Table W–1D of this subpart. EF for meter-regulator runs at above grade metering-regulating stations is determined in Equation W–32 of this section.
- \(GHG_i\) = For onshore petroleum and natural gas production facilities, concentration of GHGs, CH4 or CO2, in produced natural gas.
gas as defined in paragraph (u)(2) of this section; for onshore natural gas transmission compression and underground natural gas storage, GHG equals 0.975 for CH\textsubscript{4} and 1.1 \times 10^{-2} for CO\textsubscript{2}; for LNG storage and LNG import and export equipment, GHG equals 1 for CH\textsubscript{4} and 0 for CO\textsubscript{2}; and for natural gas distribution, GHG equals 1 for CH\textsubscript{4} and 1.1 \times 10^{-2} CO\textsubscript{2}.

\( T_i = \text{Average estimated time that each component type associated with the equipment leak emission was operational in the calendar year, in hours, using engineering estimate based on best available data.} \)

(1) Calculate both CH\textsubscript{4} and CO\textsubscript{2} mass emissions from volumetric emissions using calculations in paragraph (v) of this section.

(2) Onshore petroleum and natural gas production facilities shall use the appropriate default population emission factors listed in Table W–1A of this subpart for equipment leaks from valves, connectors, open ended lines, pressure relief valves, pump, flanges, and other. Major equipment and components associated with gas wells are considered gas service components in reference to Table 1–A of this subpart and major natural gas equipment in reference to Table W–1B of this subpart. Major equipment and components associated with crude oil wells are considered crude service components in reference to Table 1–A of this subpart and major crude oil equipment in reference to Table W–1C of this subpart. Where facilities conduct EOR operations the emissions factor listed in Table W–1A of this subpart shall be used to estimate all streams of gases, including recycle CO\textsubscript{2} stream. The component count can be determined using either of the methodologies described in this paragraph (v)(2). The same methodology must be used for the entire calendar year.

(i) Component Count Methodology 1. For all onshore petroleum and natural gas production operations in the facility perform the following activities:

(A) Count all major equipment listed in Table W–1B and Table W–1C of this subpart. For meters/piping, use one meters/piping per well-pad.

(B) Multiply major equipment counts by the average component counts listed in Table W–1B and W–1C of this subpart for onshore natural gas production and onshore oil production, respectively. Use the appropriate factor in Table W–1A of this subpart for operations in Eastern and Western U.S. according to the mapping in Table W–1D of this subpart.

(ii) Component Count Methodology 2. Count each component individually for the facility. Use the appropriate factor in Table W–1A of this subpart for operations in Eastern and Western U.S. according to the mapping in Table W–1D of this subpart.

(3) Underground natural gas storage facilities for storage wellheads shall use the appropriate default population emission factors listed in Table W–4 of this subpart for equipment leak from connectors, valves, pressure relief valves, and open ended lines.

(4) LNG storage facilities shall use the appropriate default population emission factors listed in Table W–5 of this subpart for equipment leak from vapor recovery compressors.

(5) LNG import and export facilities shall use the appropriate default population emission factor listed in Table W–6 of this subpart for equipment leak from vapor recovery compressors.

(6) Natural gas distribution facilities shall use the appropriate emission factors as described in paragraph (r)(6) of this section.

(i) Below grade metering-regulating stations; distribution mains; and distribution services, shall use the appropriate default population emission factors listed in Table W–7 of this subpart. Below grade T–D transfer stations shall use the emission factor for below grade metering-regulating stations.

(ii) Emissions from all above grade metering-regulating stations (including above grade TD transfer stations) shall be calculated by applying the emission factor calculated in Equation W–32 and the total count of meter/regulator runs at all above grade metering-regulating stations (inclusive of TD transfer stations) to Equation W–31. The facility wide emission factor in Equation W–32 will be calculated by using the total volumetric GHG emissions at standard conditions for all equipment leak sources calculated in Equation W–30B in paragraph (q)(6) of this section and the count of meter/regulator runs located at above grade
transmission-distribution transfer stations that were monitored over the years that constitute one complete cycle as per (q)(8)(i) of this section. A meter on a regulator run is considered one meter or regulator run. Reporters that do not have above grade T–D transfer stations shall report a count of above grade metering-regulating stations only and do not have to comply with §98.236(c)(16)(xix).

\[
EF = \frac{E_{s,i} + 8760}{\text{Count}}
\]  
(Eq. W–32)

Where:
- \( EF \) = Facility emission factor for a meter/regulator run per component type at above grade metering-regulating for GHG, in cubic feet per meter/regulator run per hour.
- \( E_{s,i} \) = Annual volumetric GHG \( i \) emissions, \( CO_2 \) or \( CH_4 \) at standard condition from each component type at all above grade TD transfer stations, from Equation W–33B.
- \( \text{Count} \) = Total number of meter/regulator runs at all TD transfer stations that were monitored over the years that constitute one complete cycle as per (q)(8)(i) of this section.
- 8760 = Conversion to hourly emissions.

(s) **Offshore petroleum and natural gas production facilities.** Report \( CO_2 \), \( CH_4 \), and \( N_2O \) emissions for offshore petroleum and natural gas production from all equipment leaks, vented emission, and flare emission source types as identified in the data collection and emissions estimation study conducted by BOEMRE in compliance with 30 CFR 250.302 through 304.

(1) Offshore production facilities under BOEMRE jurisdiction shall report the same annual emissions as calculated and reported by BOEMRE in data collection and emissions estimation study published by BOEMRE referenced in 30 CFR 250.302 through 304 (GOADS).

(i) For any calendar year that does not overlap with the most recent BOEMRE emissions study publication, report the most recent reported emissions data with emissions adjusted based on the operating time for the facility relative to operating time in the previous reporting period.

(ii) [Reserved]

(2) Offshore production facilities that are not under BOEMRE jurisdiction shall use monitoring methods and calculation methodologies published by BOEMRE referenced in 30 CFR 250.302 through 304 to calculate and report emissions (GOADS).

(i) For any calendar year that does not overlap with the most recent BOEMRE emissions study publication, report the most recent reported emissions data with emissions adjusted based on the operating time for the facility relative to operating time in the previous reporting period.

(ii) [Reserved]

(3) If BOEMRE discontinues or delays their data collection effort by more than 4 years, then offshore reporters shall once in every 4 years use the most recent BOEMRE data collection and emissions estimation methods to report emission from the facility sources.

(4) For either first or subsequent year reporting, offshore facilities either within or outside of BOEMRE jurisdiction that were not covered in the previous BOEMRE data collection cycle shall use the most recent BOEMRE data collection and emissions estimation methods published by BOEMRE referenced in 30 CFR 250.302 through 304 to calculate and report emissions (GOADS) to report emissions.

(t) **Volumetric emissions.** Calculate volumetric emissions at standard conditions as specified in paragraphs (t)(1) or (2) of this section, with actual pressure and temperature determined by engineering estimates based on best available data unless otherwise specified.

(1) Calculate natural gas volumetric emissions at standard conditions using
actual natural gas emission temperature and pressure, and Equation W–33 of this section.

\[ E_{s,n} = \frac{E_{a,n} \cdot (459.67 + T_s) \cdot P_a}{(459.67 + T_a) \cdot P_s} \]  

(Eq. W–33)

where:
- \( E_{s,n} \) = Natural gas volumetric emissions at standard conditions in cubic feet.
- \( E_{a,n} \) = Natural gas volumetric emissions at actual conditions in cubic feet.
- \( T_s \) = Temperature at standard conditions (60 °F).
- \( T_a \) = Temperature at actual emission conditions (°F).
- \( P_s \) = Absolute pressure at standard conditions (14.7 psia).
- \( P_a \) = Absolute pressure at actual conditions (psia).

(2) Calculate GHG volumetric emissions at standard conditions using actual GHG emissions temperature and pressure, and Equation W–34 of this section.

\[ E_{s,i} = \frac{E_{a,i} \cdot (459.67 + T_s) \cdot P_a}{(459.67 + T_a) \cdot P_s} \]  

(Eq. W–34)

where:
- \( E_{s,i} \) = GHG \( i \) volumetric emissions at standard conditions in cubic feet.
- \( E_{a,i} \) = GHG \( i \) volumetric emissions at actual conditions in cubic feet.
- \( T_s \) = Temperature at standard conditions (60 °F).
- \( T_a \) = Temperature at actual emission conditions (°F).
- \( P_s \) = Absolute pressure at standard conditions (14.7 psia).
- \( P_a \) = Absolute pressure at actual conditions (psia).

(3) Reporters using 68 °F for standard temperature may use the ratio 519.67/527.67 to convert volumetric emissions from 68 °F to 60 °F.

(u) GHG volumetric emissions. Calculate GHG volumetric emissions at standard conditions as specified in paragraphs (u)(1) and (2) of this section, with mole fraction of GHGs in the natural gas determined by engineering estimate based on best available data unless otherwise specified.

(1) Estimate \( \text{CH}_4 \) and \( \text{CO}_2 \) emissions from natural gas emissions using Equation W–35 of this section.

\[ E_{s,i} = E_{s,n} \cdot M_i \]  

(Eq. W–35)

where:
- \( E_{s,n} \) = GHG 1 (either \( \text{CH}_4 \) or \( \text{CO}_2 \)) volumetric emissions at standard conditions in cubic feet.
- \( E_{s,n} \) = Natural gas volumetric emissions at standard conditions in cubic feet.
- \( M_i \) = Mole fraction of GHG 1 in the natural gas.

(2) For Equation W–35 of this section, the mole fraction, \( M_i \), shall be the annual average mole fraction for each sub-basin category or facility, as specified in paragraphs (u)(2)(i) through (vii) of this section.

(i) GHG mole fraction in produced natural gas for onshore petroleum and natural gas production facilities. If you have a continuous gas composition analyzer for produced natural gas, you must use an annual average of these values for determining the mole fraction. If you do not have a continuous
gas composition analyzer, then you must use an annual average gas composition based on your most recent available analysis of the sub-basin category or facility, as applicable to the emission source.

(ii) GHG mole fraction in feed natural gas for all emissions sources upstream of the de-methanizer or dew point control and GHG mole fraction in facility specific residue gas to transmission pipeline systems for all emissions sources downstream of the de-methanizer overhead or dew point control for onshore natural gas processing facilities. For onshore natural gas processing plants that solely fractionate a liquid stream, use the GHG mole percent in feed natural gas liquid for all streams. If you have a continuous gas composition analyzer on feed natural gas, you must use these values for determining the mole fraction. If you do not have a continuous gas composition analyzer, then annual samples must be taken according to methods set forth in §98.234(b).

(iii) GHG mole fraction in transmission pipeline natural gas that passes through the facility for the onshore natural gas transmission compression industry segment. You may use a default 95 percent methane and 1 percent carbon dioxide fraction for GHG mole fraction in natural gas.

(iv) GHG mole fraction in natural gas stored in the underground natural gas storage industry segment. You may use a default 95 percent methane and 1 percent carbon dioxide fraction for GHG mole fraction in natural gas.

(v) GHG mole fraction in natural gas stored in the LNG storage industry segment. You may use a default 95 percent methane and 1 percent carbon dioxide fraction for GHG mole fraction in natural gas.

(vi) GHG mole fraction in natural gas stored in the LNG import and export industry segment. For export facilities that receive gas from transmission pipelines, you may use a default 95 percent methane and 1 percent carbon dioxide fraction for GHG mole fraction in natural gas.

(vii) GHG mole fraction in local distribution pipeline natural gas that passes through the facility for natural gas distribution facilities. You may use a default 95 percent methane and 1 percent carbon dioxide fraction for GHG mole fraction in natural gas.

(v) GHG mass emissions. Calculate GHG mass emissions in carbon dioxide equivalent by converting the GHG volumetric emissions at standard conditions into mass emissions using Equation W–36 of this section.

\[ \text{Mass}_i = E_{v,i} \cdot \rho_i \cdot \text{GWP} \cdot 10^{-3} \quad \text{(Eq. W–36)} \]

Where:
- \( \text{Mass}_i \) = GHG, (either CH\(_4\), CO\(_2\), or N\(_2\)O) mass emissions in metric tons CO\(_2\)e.
- \( E_{v,i} \) = GHG, (either CH\(_4\), CO\(_2\), or N\(_2\)O) volumetric emissions at standard conditions, in cubic feet.
- \( \rho_i \) = Density of GHG\(_i\). Use 0.0526 kg/ft\(^3\) for CO\(_2\) and N\(_2\)O, and 0.0422 kg/ft\(^3\) for CH\(_4\) at 60 °F and 14.7 psia.
- \( \text{GWP} \) = Global warming potential, 1 for CO\(_2\), 21 for CH\(_4\), and 310 for N\(_2\)O.

(w) EOR injection pump blowdown. Calculate CO\(_2\) pump blowdown emissions as follows:

1. Calculate the total volume in cubic feet (including pipelines, manifolds and vessels) between isolation valves.
2. Retain logs of the number of blowdowns per calendar year.
3. Calculate the total annual venting emissions using Equation W–37 of this section:

\[ \text{Mass}_{\text{CO}_2} = N \cdot V_v \cdot R_c \cdot \text{GHG}_{\text{CO}_2} \cdot 10^{-3} \quad \text{(Eq. W–37)} \]
Where:

\[
\text{Mass}_{CO2} = \text{Annual EOR injection gas venting emissions in metric tons from blowdowns.}
\]

\[
N = \text{Number of blowdowns for the equipment in the calendar year.}
\]

\[
V_v = \text{Total volume in cubic feet of blowdown equipment chambers (including pipelines, manifolds and vessels) between isolation valves.}
\]

\[
R_c = \text{Density of critical phase EOR injection gas in kg/ft}^3. \text{You may use an appropriate standard method published by a consensus-based standards organization if such a method exists or you may use an industry standard practice to determine density of super critical EOR injection gas.}
\]

\[
\text{GHG}_{CO2} = \text{Mass fraction of CO}_2\text{ in critical phase injection gas.}
\]

\[
1 \times 10^{-3} = \text{Conversion factor from kilograms to metric tons.}
\]

\[\text{(x) EOR hydrocarbon liquids dissolved CO}_2. \text{Calculate dissolved CO}_2\text{ in hydrocarbon liquids produced through EOR operations as follows:}\]

(1) Determine the amount of CO\(_2\) retained in hydrocarbon liquids after flashing in tankage at STP conditions. Annual samples must be taken according to methods set forth in \$98.234(b) to determine retention of CO\(_2\) in hydrocarbon liquids immediately downstream of the storage tank. Use the annual analysis for the calendar year.

(2) Estimate emissions using Equation W–38 of this section.

\[
\text{Mass}_{CO2} = S_{h1} \times V_{h1} \quad (\text{Eq. W–38})
\]

Where:

\[
\text{Mass}_{CO2} = \text{Annual CO}_2\text{ emissions from CO}_2\text{ retained in hydrocarbon liquids produced through EOR operations beyond tankage, in metric tons.}
\]

\[
S_{h1} = \text{Amount of CO}_2\text{ retained in hydrocarbon liquids in metric tons per barrel, under standard conditions.}
\]

\[
V_{h1} = \text{Total volume of hydrocarbon liquids produced at the EOR operations in barrels in the calendar year.}
\]

(y) [Reserved]

(2) Onshore petroleum and natural gas production and natural gas distribution combustion emissions. Calculate CO\(_2\), CH\(_4\), and N\(_2\)O combustion-related emissions from stationary or portable equipment, except as specified in paragraph (y)(3) and (y)(4) of this section, as follows:

(1) If a fuel combusted in the stationary or portable equipment is listed in Table C–1 of subpart C of this part, or is a blend containing one or more fuels listed in Table C–1, calculate emissions according to (2)(1). If the fuel is field gas, process vent gas, or a blend containing field gas or process vent gas, calculate emissions according to (2)(2).

(i) For fuels listed in Table C–1 or a blend containing one or more fuels listed in Table C–1, calculate CO\(_2\), CH\(_4\), and N\(_2\)O emissions according to any Tier listed in subpart C of this part. You must follow all applicable calculation requirements for that tier listed in 98.33, any monitoring or QA/QC requirements listed for that tier in 98.34, any missing data procedures specified in 98.35, and any recordkeeping requirements specified in 98.37.

(ii) Emissions from fuel combusted in stationary or portable equipment at onshore natural gas and petroleum production facilities and at natural gas distribution facilities will be reported according to the requirements specified in 98.236(c)(19) and not according to the reporting requirements specified in subpart C of this part.

(2) For fuel combustion units that combust field gas, process vent gas, a blend containing field gas or process vent gas, or natural gas that is not of pipeline quality or that has a high heat value of less than 950 Btu per standard cubic foot, calculate combustion emissions as follows:
(i) You may use company records to determine the volume of fuel combusted in the unit during the reporting year.

(ii) If you have a continuous gas composition analyzer on fuel to the combustion unit, you must use these compositions for determining the concentration of gas hydrocarbon constituent in the flow of gas to the unit. If you do not have a continuous gas composition analyzer on gas to the combustion unit, you must use the appropriate gas compositions for each stream of hydrocarbons going to the combustion unit as specified in the applicable paragraph in (u)(2) of this section.

(iii) Calculate GHG volumetric emissions at actual conditions using Equations W–39A and W–39B of this section:

\[ E_{a, CO_2} = (V_a \times Y_{CO_2}) + \eta \sum_{j=1}^{5} V_a \times Y_j \times R_j \]  
\[ E_{a, CH_4} = V_a \times (1-\eta) \times Y_{CH_4} \]  

Where:
- \( E_{CO_2} \) = Contribution of annual CO2 emissions from portable or stationary fuel combustion sources in cubic feet, under actual conditions.
- \( V_a \) = Volume of gas sent to combustion unit in cubic feet, during the year.
- \( Y_{CO_2} \) = Concentration of CO2 constituent in gas sent to combustion unit.
- \( E_{a, CH_4} \) = Contribution of annual CH4 emissions from portable or stationary fuel combustion sources in cubic feet, under actual conditions.
- \( \eta \) = Fraction of gas combusted for portable and stationary equipment determined using engineering estimation. For internal combustion devices, a default of 0.995 can be used.
- \( Y_j \) = Concentration of gas hydrocarbon constituents \( j \) (such as methane, ethane, propane, butane, and pentanes plus) in gas sent to combustion unit.
- \( R_j \) = Number of carbon atoms in the gas hydrocarbon constituent \( j \): 1 for methane, 2 for ethane, 3 for propane, 4 for butane, and 5 for pentanes plus, in gas sent to combustion unit.
- \( Y_{CH_4} \) = Concentration of methane constituent in gas sent to combustion unit.

(iv) Calculate GHG volumetric emissions at standard conditions using calculations in paragraph (t) of this section.

(v) Calculate both combustion-related CH4 and CO2 mass emissions from volumetric CH4 and CO2 emissions using calculation in paragraph (v) of this section.

(vi) Calculate \( N_2O \) mass emissions using Equation W–40 of this section:

\[ Mass_{N_2O} = (1 \times 10^{-3}) \times Fuel \times HHV \times EF \times GWP \]  

Where:
- \( Mass_{N_2O} \) = Annual \( N_2O \) emissions from the combustion of a particular type of fuel (metric tons CO2e).
- \( Fuel \) = Mass or volume of the fuel combusted (mass or volume per year, choose appropriately to be consistent with the units of HHV).
- HHV = For the high heat value for field gas or process vent gas, use \( 1.235 \times 10^{-3} \) mmBtu/scf for HHV.
- \( EF \) = Use \( 1.0 \times 10^{-4} \) kg \( N_2O \)/mmBtu.

1 \( \times 10^{-3} \) = Conversion factor from kilograms to metric tons.
GWP = Global warming potential, as listed in Table A–1 of subpart A of this part.

(3) External fuel combustion sources with a rated heat capacity equal to or less than 5 mmBtu/hr do not need to report combustion emissions or include these emissions for threshold determination in § 98.231(a). You must report...
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the type and number of each external fuel combustion unit.
(4) Internal fuel combustion sources, not compressor-drivers, with a rated heat capacity equal to or less than 1 mmBtu/hr (or the equivalent of 130 horsepower), do not need to report combustion emissions or include these emissions for threshold determination in §98.231(a). You must report the type and number of each internal fuel combustion unit.


§98.234 Monitoring and QA/QC requirements.

The GHG emissions data for petroleum and natural gas emissions sources must be quality assured as applicable as specified in this section. Offshore petroleum and natural gas production facilities shall adhere to the monitoring and QA/QC requirements as set forth in 30 CFR 250.

(a) You must use any of the methods described as follows in this paragraph to conduct leak detection(s) of equipment leaks and through-valve leakage from all source types listed in §98.233(k), (o), (p) and (q) that occur during a calendar year, except as provided in paragraph (a)(4) of this section.

(1) Optical gas imaging instrument. Use an optical gas imaging instrument for equipment leak detection in accordance with 40 CFR part 60, subpart A, §60.18 of the Alternative work practice for monitoring equipment leaks, §60.18(1)(1)(i); §60.18(1)(2)(i) except that the monitoring frequency shall be annual using the detection sensitivity level of 60 grams per hour as stated in 40 CFR Part 60, subpart A, Table 1: Detection Sensitivity Levels; §60.18(1)(2)(ii) and (iii) except the gas chosen shall be methane, and §60.18(1)(2)(iv) and (v); §60.18(1)(3); §60.18(1)(4)(i) and (v); including the requirements for daily instrument checks and distances, and excluding requirements for video records. Any emissions detected by the optical gas imaging instrument is a leak unless screened with Method 21 monitoring, in which case 10,000 ppm or greater is designated a leak. In addition, you must operate the optical gas imaging instrument to image the source types required by this subpart in accordance with the instrument manufacturer’s operating parameters. Unless using methods in paragraph (a)(2) of this section, an optical gas imaging instrument must be used for all source types that are inaccessible and cannot be monitored without elevating the monitoring personnel more than 2 meters above a support surface.

(2) Method 21. Use the equipment leak detection methods in 40 CFR part 60, appendix A–7, Method 21. If using Method 21 monitoring, if an instrument reading of 10,000 ppm or greater is measured, a leak is detected. Inaccessible emissions sources, as defined in 40 CFR part 60, are not exempt from this subpart. Owners or operators must use alternative leak detection devices as described in paragraph (a)(1) or (a)(2) of this section to monitor inaccessible equipment leaks or vented emissions.

(3) Infrared laser beam illuminated instrument. Use an infrared laser beam illuminated instrument for equipment leak detection. Any emissions detected by the infrared laser beam illuminated instrument is a leak unless screened with Method 21 monitoring, in which case 10,000 ppm or greater is designated a leak. In addition, you must operate the infrared laser beam illuminated instrument to detect the source types required by this subpart in accordance with the instrument manufacturer’s operating parameters.

(4) [Reserved]

(5) Acoustic leak detection device. Use the acoustic leak detection device to detect through-valve leakage. When using the acoustic leak detection device to quantify the through-valve leakage, you must use the instrument manufacturer’s calculation methods to quantify the through-valve leak. When using the acoustic leak detection device, if a leak of 3.1 scf per hour or greater is calculated, a leak is detected. In addition, you must operate the acoustic leak detection device to monitor the source valves required by this subpart in accordance with the instrument manufacturer’s operating parameters. Acoustic stethoscope type devices designed to detect through valve leakage when put in contact with
the valve body and that provide an audible leak signal but do not calculate a leak rate can be used to identify non-leakers with subsequent measurement required to calculate the rate if through-valve leakage is identified. Leaks are reported if a leak rate of 3.1 scf per hour or greater is measured.

(b) You must operate and calibrate all flow meters, composition analyzers and pressure gauges used to measure quantities reported in §98.233 according to the procedures in §98.3(i) and the procedures in paragraph (b) of this section. You may use an appropriate standard method published by a consensus-based standards organization if such a method exists or you may use an industry standard practice. Consensus-based standards organizations include, but are not limited to, the following: ASTM International, the American National Standards Institute (ANSI), the American Gas Association (AGA), the American Society of Mechanical Engineers (ASME), the American Petroleum Institute (API), and the North American Energy Standards Board (NAESB).

(c) Use calibrated bags (also known as vent bags) only where the emissions are at near-atmospheric pressures and below the maximum temperature specified by the vent bag manufacturer such that the bag is safe to handle. The bag opening must be of sufficient size that the entire emission can be tightly encompassed for measurement till the bag is completely filled.

(1) Hold the bag in place enclosing the emissions source to capture the entire emissions and record the time required for completely filling the bag. If the bag inflates in less than one second, assume one second inflation time.

(2) Perform three measurements of the time required to fill the bag, report the emissions as the average of the three readings.

(3) Estimate natural gas volumetric emissions at standard conditions using calculations in §98.233(t).

(4) Estimate CH₄ and CO₂ volumetric and mass emissions from volumetric natural gas emissions using the calculations in §98.233(u) and (v).

(d) Use a high volume sampler to measure emissions within the capacity of the instrument.

(1) A technician following manufacturer instructions shall conduct measurements, including equipment manufacturer operating procedures and measurement methodologies relevant to using a high volume sampler, including positioning the instrument for complete capture of the equipment leak without creating backpressure on the source.

(2) If the high volume sampler, along with all attachments available from the manufacturer, is not able to capture all the emissions from the source then use anti-static wraps or other aids to capture all emissions without violating operating requirements as provided in the instrument manufacturer’s manual.

(3) Estimate natural gas volumetric emissions at standard conditions using calculations in §98.233(t). Estimate CH₄ and CO₂ volumetric and mass emissions from volumetric natural gas emissions using the calculations in §98.233(u) and (v).

(4) Calibrate the instrument at 2.5 percent methane with 97.5 percent air and 100 percent CH₄ by using calibrated gas samples and by following manufacturer’s instructions for calibration.

(e) Peng Robinson Equation of State means the equation of state defined by Equation W–41 of this section:

\[
p = \frac{RT}{V_m - b} - \frac{a\alpha}{V_m^2 + 2bV_m - b^2} \quad \text{(Eq. W–41)}
\]

Where:
\[ p = \text{Absolute pressure.} \]
\[ R = \text{Universal gas constant.} \]
\[ T = \text{Absolute temperature.} \]
\[ V_m = \text{Molar volume.} \]
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\[ a = \frac{0.45724R^2T_c^2}{P_c} \]
\[ b = \frac{0.7780RT_c}{P_c} \]
\[ \alpha = \left( 1 + \left( 0.37464 + 1.54226 \omega - 0.26992 \omega^2 \right) \left( 1 - \frac{T}{T_c} \right) \right)^2 \]

Where:
\( \omega \) = Acentric factor of the species.
\( T_c \) = Critical temperature.
\( P_c \) = Critical pressure.

(f) Special reporting provisions
(1) Best available monitoring methods. EPA will allow owners or operators to use best available monitoring methods for parameters in §98.233 Calculating GHG Emissions as specified in paragraphs (f)(2), (f)(3), and (f)(4) of this section. If the reporter anticipates the potential need for best available monitoring for sources for which they need to petition EPA and the situation is unresolved at the time of the deadline, reporters should submit written notice of this potential situation to EPA by the specified deadline for requests to be considered. EPA reserves the right to review best available monitoring method requests submitted after the deadlines specified in this section, and will consider requests which demonstrate unique or unusual circumstances unforeseen at the time of the applicable best available monitoring method deadline. The Administrator reserves the right to request further information in regard to all petition requests.

(ii) Supplier data.
(iii) Engineering calculations.
(iv) Other company records.

(2) Best available monitoring methods for well-related emissions. During January 1, 2011 through December 31, 2011, owners and operators may use best available monitoring methods for any well-related data that cannot reasonably be measured according to the monitoring and QA/QC requirements of this subpart. These well-related sources are:

(i) Gas well venting during well completions and workovers with hydraulic fracturing as specified in §98.233(g).

(ii) Well testing venting and flaring as specified in §98.233(l).

(3) Best available monitoring methods for specified activity data. During January 1, 2011 through December 31, 2011, owners or operators may use best available monitoring methods for activity data as listed below that cannot reasonably be obtained according to the monitoring and QA/QC requirements of this subpart. These sources are:

(i) Cumulative hours of venting, days, or times of operation in §98.233(e), (f), (g), (h), (l), (o), (p), (q), and (r).

(ii) Number of blowdowns, completions, workovers, or other events in §98.233(f), (g), (h), (l), and (w).

(iii) Cumulative volume produced, volume input or output, or volume of fuel used in paragraphs §98.233(d), (e), (j), (k), (l), (m), (n), (x), (y), and (z).
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(4) Best available monitoring methods for leak detection and measurement. During January 1, 2011 through December 31, 2011, owners or operators may use best available monitoring methods for sources requiring leak detection and/or measurement that cannot reasonably be obtained according to the monitoring and QA/QC requirements of this part. These sources include:

(i) Reciprocating compressor rod packing venting in onshore natural gas processing, onshore natural gas transmission compression, underground natural gas storage, LNG storage, and LNG import and export equipment as specified in §98.232(d)(1), (e)(1), (f)(1), (g)(1), and (h)(1).

(ii) Centrifugal compressor wet seal oil degassing venting in onshore natural gas processing, onshore natural gas transmission compression, underground natural gas storage, LNG storage, and LNG import and export equipment as specified in §98.232(d)(2), (e)(2), (f)(2), (g)(2), and (h)(2).

(iii) Acid gas removal vent stacks in onshore petroleum and natural gas production and onshore natural gas processing as specified in §98.232(c)(17) and (d)(6).

(iv) Equipment leak emissions from valves, connectors, open ended lines, pressure relief valves, block valves, control valves, compressor blowdown valves, orifice meters, other meters, regulators, vapor recovery compressors, centrifugal compressor dry seals, and/or other equipment leaks in onshore natural gas processing, onshore natural gas transmission compression, underground natural gas storage, LNG storage, LNG import and export equipment, and natural gas distribution as specified in §98.232(d)(7), (e)(7), (f)(5), (g)(3), (h)(4), and (i)(1).

(v) Condensate (oil and/or water) storage tanks in onshore natural gas transmission compression as specified in §98.232(e)(3).

(5) Requests for the use of best available monitoring methods.

(i) No request or approval by the Administrator is necessary to use best available monitoring methods for data that cannot reasonably be obtained between January 1, 2011 and December 31, 2011 for sources not listed in paragraph (f)(2), (f)(3), and (f)(4) of this section.

(ii) No request or approval by the Administrator is necessary to use best available monitoring methods between January 1, 2011 and December 31, 2011 for sources specified in paragraph (f)(3) of this section.

(iii) No request or approval by the Administrator is necessary to use best available monitoring methods between January 1, 2011 and December 31, 2011 for sources specified in paragraph (f)(4) of this section.

(iv) No request or approval by the Administrator is necessary to use best available monitoring methods for data that cannot reasonably be obtained between January 1, 2011 and December 31, 2011 for sources not listed in paragraph (f)(2), (f)(3), and (f)(4) of this section.

(6) [Reserved]

(7) [Reserved]

(8) Requests for extension of the use of best available monitoring methods beyond 2011 for sources listed in paragraphs (f)(2), (f)(3), (f)(4), and (f)(5)(iv) of this section.

(i) Timing of Request. EPA does not anticipate a need for best available monitoring methods beyond 2011, but for all reporting years after 2011, best available monitoring methods will be considered for unique or unusual circumstances which include data collection methods that do not meet safety regulations, technical infeasibility, or counter to other local, State, or Federal regulations. For use of best available monitoring methods in 2012, an initial notice of intent to request best available monitoring methods must be submitted by December 31, 2011. Any notice of intent submitted prior to the effective date of this rule cannot be used to meet this December 31, 2011 deadline; a new notice of intent must be signed and submitted by the designated representative. Owners or operators

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that submit both a timely notice of intent and extension request consistent with §98.234(f)(8)(ii) can automatically use BAMM through June 30, 2012, for the specific parameters identified in their notification of intent and best available monitoring methods request regardless of whether the best available monitoring methods request is ultimately approved. Owners or operators that submit a notice of intent but do not follow up with a best available monitoring methods request by March 30, 2012 cannot use best available monitoring methods in 2012. For 2012, when an owner or operator has submitted a notice of intent and a subsequent best available monitoring method extension request, use of best available monitoring methods will be valid, upon approval by the Administrator, until the date indicated in the approval or until December 31, 2012, whichever is earlier.

For reporting years after 2012 a new request to use best available monitoring methods must be submitted by September 30th of the year prior to the reporting year for which use of best available monitoring methods is sought.

(ii) Content of request. Requests must contain the following information:

(A) A list of specific source categories and parameters for which the owner or operator is seeking use of best available monitoring methods.

(B) For each specific source for which an owner or operator is requesting use of best available monitoring methods, a description of the unique or unusual circumstances, such as data collection methods that do not meet safety regulations, technical infeasibility, or specific laws or regulations that are counter to data collection methods that conflict with each specific source.

(C) A detailed explanation and supporting documentation of how and when the owner or operator will comply with all of the subpart W reporting requirements for which use of best available monitoring methods are sought.

(iii) Approval criteria. To obtain approval to use best available monitoring methods after December 31, 2011, the owner or operator must submit a request demonstrating to the Administrator’s satisfaction that the owner or operator faces unique or unusual circumstances which include, by way of example and not in limitation, clearly demonstrated data collection methods that do not meet safety regulations, technical infeasibility, or counter to other local, State, or Federal regulations, along with the reasons the owner or operator cannot otherwise address the unique or unusual circumstances as required to be demonstrated in this paragraph.

(g) For the purposes of fulfilling requirements in 40 CFR §98.233(f) and (g) which require measurements to be taken every other year beginning in the first year of data collection, reporters have the option of taking the first measurement in 2012 to satisfy the requirements for the 2011–2012 data collection cycle.

(h) [Reserved]
§ 98.236 Data reporting requirements.

In addition to the information required by §98.3(c), each annual report must contain reported emissions and related information as specified in this section.

(a) Report annual emissions in metric tons of CO$_2$e for each GHG separately for each of the industry segments listed in paragraphs (a)(1) through (8) of this section.
   (1) Onshore petroleum and natural gas production.
   (2) Offshore petroleum and natural gas production.
   (3) Onshore natural gas processing.
   (4) Onshore natural gas transmission compression.
   (5) Underground natural gas storage.
   (6) LNG storage.
   (7) LNG import and export.
   (8) Natural gas distribution.

(b) For offshore petroleum and natural gas production, report emissions of CH$_4$, CO$_2$, and N$_2$O as applicable to the source type (in metric tons CO$_2$e per year at standard conditions) individually for all of the emissions source types listed in the most recent BOEMRE study.

(c) Report the information listed in this paragraph for each applicable source type in metric tons of CO$_2$e for each GHG. If a facility operates under more than one industry segment, each piece of equipment should be reported under the unit’s respective majority use segment. When a source type listed under this paragraph routes gas to flare, separately report the emissions that were vented directly to the atmosphere without flaring, and the emissions that resulted from flaring the gas. Both the vented and flared emissions will be reported under the respective source type and not under the flare source type.
   (1) For natural gas pneumatic devices (refer to Equation W–1 of §98.233), report the following:
      (i) Actual count and estimated count separately of natural gas pneumatic high bleed devices as applicable.
      (ii) Actual count and estimated count separately of natural gas pneumatic low bleed devices as applicable.
      (iii) Actual count and estimated count separately of natural gas pneumatic intermittent bleed devices as applicable.
   (2) For natural gas driven pneumatic pumps (refer to Equation W–2 of §98.233), report the following:
      (i) Count of natural gas driven pneumatic pumps.
      (ii) Report annual CO$_2$ and CH$_4$ emissions at the facility level, expressed in metric tons CO$_2$e for each gas, for all natural gas driven pneumatic pumps combined.
   (3) For each acid gas removal unit (refer to Equation W–3 and Equation W–4 of §98.233), report the following:
      (i) Total throughput off the acid gas removal unit using a meter or engineering estimate based on process knowledge or best available data in million cubic feet per year.
      (ii) For Calculation Methodology 1 and Calculation Methodology 2 of §98.233(d), annual average fraction of CO$_2$ content in the vent from the acid gas removal unit (refer to §98.233(d)(6)).
      (iii) For Calculation Methodology 3 of §98.233(d), annual average volume fraction of CO$_2$ content of natural gas into and out of the acid gas removal unit (refer to §98.233(d)(7) and (d)(8)).
      (iv) Report the annual quantity of CO$_2$, expressed in metric tons CO$_2$e, that was recovered from the AGR unit and transferred outside the facility, under subpart PP of this part.
      (v) Report annual CO$_2$ emissions for the AGR unit, expressed in metric tons CO$_2$e.
      (vi) For the onshore natural gas processing industry segment only, report a unique name or ID number for the AGR unit.
      (vii) An indication of which calculation methodology was used for the AGR.
   (4) For dehydrators, report the following:
(i) For each Glycol dehydrator with a throughput greater than or equal to 0.4 MMscfd (refer to §98.233(e)(1)), report the following:
   (A) Glycol dehydrator feed natural gas flow rate in MMscfd, determined by engineering estimate based on best available data.
   (B) Glycol dehydrator absorbent circulation pump type.
   (C) Whether stripper gas is used in glycol dehydrator.
   (D) Whether a flash tank separator is used in glycol dehydrator.
   (E) Type of absorbent.
   (F) Total time the glycol dehydrator is operating in hours.
   (G) Temperature, in degrees Fahrenheit and pressure, in psig, of the wet natural gas.
   (H) Concentration of CH$_4$ and CO$_2$ in wet natural gas.
   (I) What vent gas controls are used (refer to §98.233(e)(3) and (e)(4)).
   (J) For each glycol dehydrator, report annual CO$_2$ and CH$_4$ emissions that resulted from venting gas directly to the atmosphere, expressed in metric tons CO$_2$e for each gas.

(ii) For all glycol dehydrators with a throughput less than 0.4 MMscfd (refer to §98.233, Equation W–5 of §98.233), report the following:
   (A) Count of glycol dehydrators.
   (B) Which vent gas controls are used (refer to §98.233(e)(3) and (e)(4)).
   (C) Report annual CO$_2$ and CH$_4$ emissions at the facility level that resulted from venting gas directly to the atmosphere, expressed in metric tons CO$_2$e for each gas, combined for all glycol dehydrators with annual average daily throughput of less than 0.4 MMscfd.
   (D) Report annual CO$_2$, CH$_4$, and N$_2$O emissions at the facility level that resulted from the flaring of process gas, expressed in metric tons CO$_2$e for each gas, combined for all glycol dehydrators with annual average daily throughput of less than 0.4 MMscfd.

(iii) For absorbent desiccant dehydrators (refer to Equation W–6 of §98.233), report the following:
   (A) Count of desiccant dehydrators.
   (B) Report annual CO$_2$ and CH$_4$ emissions at the facility level, expressed in metric tons CO$_2$e for each gas, for all absorbent desiccant dehydrators combined.
   (5) For well venting for liquids unloading, report the following:
   (i) For Calculation Methodology 1 (refer to Equation W–7 of §98.233), report the following for each tubing diameter group and pressure group combination within each sub-basin category:
      (A) Count of wells vented to the atmosphere.
      (B) Count of plunger lifts. Whether the selected well from the tubing diameter and pressure group combination had a plunger lift (yes/no).
      (C) Cumulative number of unloadings vented to the atmosphere.
      (D) Average flow rate of the measured well venting in cubic feet per hour (refer to §98.233(1)(1)(A)).
      (E) Internal casing diameter or internal tubing diameter in inches, where applicable, and well depth of each well, in feet, selected to represent emissions in that tubing size and pressure combination.
      (F) Casing pressure, in psia, of each well selected to represent emissions in that tubing size group and pressure group combination that does not have a plunger lift.
      (G) Tubing pressure, in psia, of each well selected to represent emissions in that tubing size group and pressure group combination that does not have a plunger lift.
   (ii) For Calculation Methodologies 2 and 3 (refer to Equation W–8 and W–9 of §98.233), report the following for each sub-basin category:
      (A) Count of wells vented to the atmosphere for liquids unloading.
      (B) Count of plunger lifts.
      (C) Cumulative number of unloadings vented to the atmosphere.
      (D) Average internal casing diameter, in inches, of each well, where applicable.
(E) Report annual CO₂ and CH₄ emissions, expressed in metric tons CO₂e for each GHG gas.

(6) For well completions and workovers, report the following for each sub-basin category:
   (i) For gas well completions and workovers with hydraulic fracturing by sub-basin and well type (horizontal or vertical) combination (refer to Equation W–10A and W–10B of §98.233), report the following:
      (A) Total count of completions in calendar year.
      (B) When using Equation W–10A, measured flow rate of backflow during well completion in standard cubic feet per hour.
      (C) Total count of workovers in calendar year that flare gas or vent gas to the atmosphere.
      (D) When using Equation W–10A, measured flow rate of backflow during well workover in standard cubic feet per hour.
      (E) When using Equation W–10A, total number of days of backflow from all wells during completions.
      (F) When using Equation W–10A, total number of days of backflow from all wells during workovers.
   (G) Report number of completions employing purposely designed equipment that separates natural gas from the backflow and the amount of natural gas, in standard cubic feet, recovered using engineering estimate based on best available data.
   (H) Report number of workovers employing purposely designed equipment that separates natural gas from the backflow and the amount of natural gas, in standard cubic feet, recovered using engineering estimate based on best available data.
   (I) Annual CO₂ and CH₄ emissions that resulted from venting gas directly to the atmosphere, expressed in metric tons CO₂e for each gas.
   (J) Annual CO₂, CH₄, and N₂O emissions that resulted from flares, expressed in metric tons CO₂e for each gas.
   (ii) For gas well completions and workovers without hydraulic fracturing (refer to Equation W–13 of §98.233):
      (A) Total count of completions in calendar year.
      (B) Total count of workovers in calendar year that flare gas or vent gas to the atmosphere.
      (C) Total number of days of gas venting to the atmosphere during backflow for completion.
      (D) Annual CO₂ and CH₄ emissions that resulted from venting gas directly to the atmosphere, expressed in metric tons CO₂e for each gas.
      (E) Annual CO₂, CH₄, and N₂O emissions that resulted from flares, expressed in metric tons CO₂e for each gas.

(7) For blowdown vent stack emission source, (refer to Equation W–14A and Equation W–14B of §98.233), report the following:
   (i) For each unique physical volume that is blown down more than once during the calendar year, report the following:
      (A) Total number of blowdowns for each unique physical volume in the calendar year.
      (B) Annual CO₂ and CH₄ emissions, for each unique physical blowdown volume, expressed in metric tons CO₂e for each gas.
      (C) A unique name or ID number for the unique physical volume.
   (ii) For all unique volumes that are blown down once during the calendar year, report the following:
      (A) Total number of blowdowns for all unique physical volumes in the calendar year.
      (B) Annual CO₂ and CH₄ emissions from all unique physical volumes as an aggregate per facility, expressed in metric tons CO₂e for each gas.

(8) For gas emitted from produced oil sent to atmospheric tanks:
   (i) For wellhead gas-liquid separator with oil throughput greater than or equal to 10 barrels per day, using Calculation Methodology 1 and 2 of §98.233(j), report the following by sub-basin category, unless otherwise specified:
      (A) Number of wellhead separators sending oil to atmospheric tanks.
      (B) Estimated average separator temperature, in degrees Fahrenheit, and estimated average pressure, in psig.
      (C) Estimated average sales oil stabilized API gravity, in degrees.
      (D) Count of hydrocarbon tanks at well pads.

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(E) Best estimate of count of stock tanks not at well pads receiving your oil.

(F) Total volume of oil from all wellhead separators sent to tank(s) in barrels per year.

(G) Count of tanks with emissions control measures, either vapor recovery system or flaring, for tanks at well pads.

(H) Best estimate of count of stock tanks assumed to have emissions control measures not at well pads, receiving your oil.

(I) Range of concentrations of flash gas, CH$_4$ and CO$_2$.

(J) Annual CO$_2$ and CH$_4$ emissions that resulted from venting gas to the atmosphere, expressed in metric tons CO$_2$e for each gas, at the sub-basin level for Calculation Methodology 3 or 4 of §98.233(j).

(K) Annual CO$_2$ and CH$_4$ gas quantities that were recovered, expressed in metric tons CO$_2$e for each gas, at the sub-basin level for Calculation Methodology 3 or 4 of §98.233(j).

(L) Annual CO$_2$, CH$_4$, and N$_2$O emissions that resulted from flaring gas, expressed in metric tons CO$_2$e for each gas, at the sub-basin level for Calculation Methodology 3 and 4 of §98.233(j).

(ii) For wells with oil production greater than or equal to 10 barrels per day, using Calculation Methodology 3 and 4 of §98.233(j), report the following:

(A) Total volume of sales oil from all wells in barrels per year.

(B) Total number of wells sending oil directly to tanks.

(C) Total number of wells sending oil to separators off the well pads.

(D) Sales oil API gravity range for wells in (c)(8)(ii)(B) and (c)(8)(ii)(C) of this section, in degrees.

(E) Count of hydrocarbon tanks on well pads.

(F) Count of hydrocarbon tanks, both on and off well pads assumed to have emissions control measures: either vapor recovery system or flaring of tank vapors.

(G) Annual CO$_2$ and CH$_4$ emissions that resulted from venting gas to the atmosphere, expressed in metric tons CO$_2$e for each gas, at the sub-basin level for Calculation Methodology 3 or 4 of §98.233(j).

(H) Annual CO$_2$ and CH$_4$ gas quantities that were recovered, expressed in metric tons CO$_2$e for each gas, at the sub-basin level for Calculation Methodology 3 or 4 of §98.233(j).

(i) Annual CO$_2$, CH$_4$, and N$_2$O emissions that resulted from flaring gas, expressed in metric tons CO$_2$e for each gas, at the sub-basin level for Calculation Methodology 3 and 4 of §98.233(j).

(iii) For wellhead gas-liquid separators and wells with throughput less than 10 barrels per day, using Calculation Methodology 5 of §98.233(j) Equation W–15 of §98.233, report the following:

(A) Number of wellhead separators.

(B) Number of wells without wellhead separators.

(C) Total volume of oil production in barrels per year.

(D) Best estimate of fraction of production sent to tanks with assumed control measures: either vapor recovery system or flaring of tank vapors.

(E) Count of hydrocarbon tanks on well pads.

(F) Annual CO$_2$ and CH$_4$ emissions that resulted from venting gas to the atmosphere, expressed in metric tons CO$_2$e for each gas, at the sub-basin level for Calculation Methodology 5 of §98.233(j).

(G) Annual CO$_2$ and CH$_4$ gas quantities that were recovered, expressed in metric tons CO$_2$e for each gas, at the sub-basin level for Calculation Methodology 5 of §98.233(j).

(H) Annual CO$_2$, CH$_4$, and N$_2$O emissions that resulted from flaring gas, expressed in metric tons CO$_2$e for each gas, at the sub-basin level for Calculation Methodology 5 of §98.233(j).

(iv) If wellhead separator dump valve is functioning improperly during the calendar year (refer to Equation W–16 of §98.233), report the following:
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(A) Count of wellhead separators that dump valve factor is applied.

(B) Annual CO\textsubscript{2} and CH\textsubscript{4} emissions that resulted from venting gas to the atmosphere, expressed in metric tons CO\textsubscript{2}e for each gas, at the sub-basin level for improperly functioning dump valves.

(9) For transmission tank emissions identified using optical gas imaging instrument per §98.234(a) (refer to §98.233(k)), or acoustic leak detection of scrubber dump valves, report the following:

(i) For each vent stack, report annual CO\textsubscript{2} and CH\textsubscript{4} emissions that resulted from venting gas directly to the atmosphere, expressed in metric tons CO\textsubscript{2}e for each gas.

(ii) For each transmission storage tank, report annual CO\textsubscript{2}, CH\textsubscript{4}, and N\textsubscript{2}O emissions that resulted from flaring process gas from the transmission storage tank, expressed in metric tons CO\textsubscript{2}e for each gas.

(iii) A unique name or ID number for the vent stack monitored according to 40 CFR 98.233(k).

(10) For well testing venting and flaring (refer to Equation W–17A or W–17B of §98.233), report the following:

(i) Number of wells tested per basin in calendar year.

(ii) Average gas to oil ratio for each basin.

(iii) Average number of days the well is tested in a basin.

(iv) Report annual CO\textsubscript{2} and CH\textsubscript{4} emissions at the facility level, expressed in metric tons CO\textsubscript{2}e for each gas, emissions from well testing venting.

(v) Report annual CO\textsubscript{2}, CH\textsubscript{4}, and N\textsubscript{2}O emissions at the facility level, expressed in metric tons CO\textsubscript{2}e for each gas, emissions from well testing flaring.

(11) For associated natural gas venting and flaring (refer to Equation W–18 of §98.233), report the following for each basin:

(i) Number of wells venting or flaring associated natural gas in a calendar year.

(ii) Average gas to oil ratio for each basin.

(iii) Report annual CO\textsubscript{2} and CH\textsubscript{4} emissions at the facility level, expressed in metric tons CO\textsubscript{2}e for each gas, emissions from associated natural gas venting.

(iv) Report annual CO\textsubscript{2}, CH\textsubscript{4}, and N\textsubscript{2}O emissions at the facility level, expressed in metric tons CO\textsubscript{2}e for each gas, emissions from associated natural gas flaring.

(12) For flare stacks (refer to Equation W–19, W–20, and W–21 of §98.233), report the following for each flare:

(i) Whether flare has a continuous flow monitor.

(ii) Volume of gas sent to flare in cubic feet per year.

(iii) Percent of gas sent to un-lit flare determined by engineering estimate and process knowledge based on best available data and operating records.

(iv) Whether flare has a continuous gas analyzer.

(v) Flare combustion efficiency.

(vi) Report uncombusted CH\textsubscript{4} emissions, in metric tons CO\textsubscript{2}e (refer to Equation W–19 of §98.233).

(vii) Report uncombusted CO\textsubscript{2} emissions, in metric tons CO\textsubscript{2}e (refer to Equation W–20 of §98.233).

(viii) Report combusted CO\textsubscript{2} emissions, in metric tons CO\textsubscript{2}e (refer to Equation W–21 of §98.233).

(ix) Report N\textsubscript{2}O emissions, in metric tons CO\textsubscript{2}e.

(x) For the natural gas processing industry segment, a unique name or ID number for the flare stack.

(xi) In the case that a CEMS is used to measure CO\textsubscript{2} emissions for the flare stack, indicate that a CEMS was used in the annual report and report the combusted CO\textsubscript{2} and uncombusted CO\textsubscript{2} as a combined number.

(13) For each centrifugal compressor:

(i) For compressors with wet seals in operational mode (refer to Equations W–22 through W–24 of §98.233), report the following for each degassing vent:

(A) Number of wet seals connected to the degassing vent.

(B) Fraction of vent gas recovered for fuel or sales or flared.

(C) Annual throughput in million scf, use an engineering calculation based on best available data.

(D) Type of meters used for making measurements.

(E) Reporter emission factor for wet seal oil degassing vents in cubic feet per hour (refer to Equation W–24 of §98.233).
(F) Total time the compressor is operating in hours.

(G) Report seal oil degassing vent emissions for compressors measured (refer to Equation W–22 of §98.233) and for compressors not measured (refer to Equation W–23 and Equation W–24 of §98.233).

(ii) For wet and dry seal centrifugal compressors in operating mode, (refer to Equations W–22 through W–24 of §98.233), report the following:
   (A) Total time in hours the compressor is in operating mode.
   (B) Reporter emission factor for blowdown vents in cubic feet per hour (refer to Equation W–24 of §98.233).
   (C) Report blowdown vent emissions when in operating mode (refer to Equation W–23 and Equation W–24 of §98.233).

(iii) For wet and dry seal centrifugal compressors in not operating, depressurized mode (refer to Equations W–22 through W–24 of §98.233), report the following:
   (A) Total time in hours the compressor is in shutdown, depressurized mode.
   (B) Reporter emission factor for isolation valve emissions in shutdown, depressurized mode in cubic feet per hour (refer to Equation W–24 of §98.233).
   (C) Report the isolation valve leakage emissions in not operating, depressurized mode in cubic feet per hour (refer to Equation W–23 and Equation W–24 of §98.233).

(iv) Report total annual compressor emissions from all modes of operation (refer to Equation W–24 of §98.233).

(v) For centrifugal compressors in onshore petroleum and natural gas production (refer to Equation W–25 of §98.233), report the following:
   (A) Count of compressors.
   (B) Report emissions (refer to Equation W–25 of §98.233) collectively.

(14) For reciprocating compressors:
   (i) For reciprocating compressors rod packing emissions with or without a vent in operating mode, report the following:
      (A) Annual throughput in million scf, use an engineering calculation based on best available data.
      (B) Total time in hours the reciprocating compressor is in operating mode.
   (C) Report rod packing emissions for compressors measured (refer to Equation W–26 of §98.233) and for compressors not measured (refer to Equation W–27 and Equation W–28 of §98.233).

   (ii) For reciprocating compressors blowdown vents not manifold to rod packing vents, in operating and standby pressurized mode (refer to Equations W–26 through W–28 of §98.233), report the following:
      (A) Total time in hours the compressor is in standby, pressurized mode.
      (B) Reporter emission factor for blowdown vents in cubic feet per hour (refer to §98.233, Equation W–28).
      (C) Report blowdown vent emissions when in operating and standby pressurized modes (refer to Equation W–27 and Equation W–28 of §98.233).

   (iii) For reciprocating compressors in not operating, depressurized mode (refer to Equations W–26 through W–28 of §98.233), report the following:
      (A) Total time the compressor is in not operating, depressurized mode.
      (B) Reporter emission factor for isolation valve emissions in not operating, depressurized mode in cubic feet per hour (refer to Equation W–28 of §98.233).
      (C) Report the isolation valve leakage emissions in not operating, depressurized mode.

   (iv) Report total annual compressor emissions from all modes of operation (refer to Equation W–27 and Equation W–28 of §98.233).

   (v) For reciprocating compressors in onshore petroleum and natural gas production (refer to Equation W–29 of §98.233), report the following:
      (A) Count of compressors.
      (B) Report emissions collectively.

(15) For each component type (major equipment type for onshore production) that uses emission factors for estimating emissions (refer to §98.233(q) and (r))

   (i) For equipment leaks found in each leak survey (refer to §98.233(q)), report the following:
      (A) Total count of leaks found in each complete survey listed by date of survey and each component type for which there is a leaker emission factor in Tables W–2, W–3, W–4, W–5, W–6, and W–7 of this subpart.
(B) For onshore natural gas processing, range of concentrations of CH₄ and CO₂ (refer to Equation W–30 of §98.233).

(C) Annual CO₂ and CH₄ emissions, in metric tons CO₂e for each gas (refer to parameter GHG, in Equation W–30 of §98.233), by component type.

(ii) For equipment leaks calculated using population counts and factors (refer to §98.233(r)), report the following:

(A) For source categories §98.230(a)(4), (a)(5), (a)(6), (a)(7), and (a)(8), total count for each component type in Tables W–2, W–3, W–4, W–5, and W–6 of this subpart for which there is a population emission factor, listed by major heading and component type.

(B) For onshore production (refer to §98.230 paragraph (a)(2)), total count for each type of major equipment in Table W–1B and Table W–1C of this subpart, by facility.

(C) Annual CO₂ and CH₄ emissions, in metric tons CO₂e for each gas (refer to Equation W–31 of §98.233), by component type.

(16) For local distribution companies, report the following:

(i) Total number of above grade T–D transfer stations in the facility.

(ii) Number of years over which all T–D transfer stations will be monitored at least once.

(iii) Number of T–D stations monitored in calendar year.

(iv) Total number of below grade T–D transfer stations in the facility.

(v) Total number of above grade metering-regulating stations (this count will include above grade T–D transfer stations) in the facility.

(vi) Total number of below grade metering-regulating stations (this count will include below grade T–D transfer stations) in the facility.

(vii) [Reserved]

(viii) Leak factor for meter/regulator run developed in Equation W–32 of §98.233.

(ix) Number of miles of unprotected steel distribution mains.

(x) Number of miles of protected steel distribution mains.

(xi) Number of miles of plastic distribution mains.

(xii) Number of miles of cast iron distribution mains.

(xiii) Number of unprotected steel distribution services.

(xiv) Number of protected steel distribution services.

(xv) Number of plastic distribution services.

(xvi) Number of copper distribution services.

(xvii) Annual CO₂ and CH₄ emissions, in metric tons CO₂e for each gas, from all above grade T–D transfer stations combined.

(xviii) Annual CO₂ and CH₄ emissions, in metric tons CO₂e for each gas, from all below grade T–D transfer stations combined.

(xix) Annual CO₂ and CH₄ emissions, in metric tons CO₂e for each gas, from all above grade metering-regulating stations (including T–D transfer stations) combined.

(xx) Annual CO₂ and CH₄ emissions, in metric tons CO₂e for each gas, from all below grade metering-regulating stations (including T–D transfer stations) combined.

(xxii) Annual CO₂ and CH₄ emissions, in metric tons CO₂e for each gas, from all below grade metering-regulating stations (including T–D transfer stations) combined.

(xxii) Annual CO₂ and CH₄ emissions, in metric tons CO₂e for each gas, from all distribution services combined.

(17) For each EOR injection pump blowdown (refer to Equation W–37 of §98.233), report the following:

(i) Pump capacity, in barrels per day.

(ii) Volume of critical phase gas between isolation valves.

(iii) Number of blowdowns per year.

(iv) Critical phase EOR injection gas density.

(v) For each EOR pump, report annual CO₂ and CH₄ emissions, expressed in metric tons CO₂e for each gas.

(vi) For EOR hydrocarbon liquids dissolved CO₂ for each sub-basin category (refer to Equation W–38 of §98.233), report the following:

(i) Volume of crude oil produced in barrels per year.

(ii) Amount of CO₂ retained in hydrocarbon liquids in metric tons per barrel, under standard conditions.

(iii) Report annual CO₂ emissions at the sub-basin level, expressed in metric tons CO₂e.

(19) For onshore CO₂ emissions at natural gas production and natural gas
distribution combustion emissions, report the following:

(i) Cumulative number of external fuel combustion units with a rated heat capacity equal to or less than 5 mmBtu/hr, by type of unit.

(ii) Cumulative number of external fuel combustion units with a rated heat capacity larger than 5 mmBtu/hr, by type of unit.

(iii) Report annual CO$_2$, CH$_4$, and N$_2$O emissions from external fuel combustion units with a rated heat capacity larger than 5 mmBtu/hr, expressed in metric tons CO$_2$e for each gas, by type of unit.

(iv) Cumulative volume of fuel combusted in external fuel combustion units with a rated heat capacity larger than 5 mmBtu/hr, by fuel type.

(v) Cumulative number of internal fuel combustion units, not compressor-drivers, with a rated heat capacity equal to or less than 1 mmBtu/hr or 130 horsepower, by type of unit.

(vi) Report annual CO$_2$, CH$_4$, and N$_2$O emissions from internal combustion units greater than 1 mmBtu/hr, expressed in metric tons CO$_2$e for each gas, by type of unit.

(vii) Cumulative volume of fuel combusted in internal combustion units with a rated heat capacity larger than 1 mmBtu/hr or 130 horsepower, by fuel type.

(d) Report annual throughput as determined by engineering estimate based on best available data for each industry segment listed in paragraphs (a)(1) through (a)(8) of this section.

(e) The records required under §98.3(g)(2)(i) shall include an explanation of how company records, engineering estimation, or best available information are used to calculate each applicable parameter under this subpart.

§98.238 Definitions.

Except as provided in this section, all terms used in this subpart have the same meaning given in the Clean Air Act and subpart A of this part.

Acid gas means hydrogen sulfide (H$_2$S) and/or carbon dioxide (CO$_2$) contaminants that are separated from sour natural gas by an acid gas removal unit.

Acid gas removal unit (AGR) means a process unit that separates hydrogen sulfide and/or carbon dioxide from sour natural gas using liquid or solid absorbents or membrane separators.

Acid gas removal vent emissions mean the acid gas separated from the acid gas absorbing medium (e.g., an amine solution) and released with methane and other light hydrocarbons to the atmosphere or a flare.

Associated with a single well-pad means associated with the hydrocarbon stream as produced from one or more wells located on that single well-pad. The association ends where the stream from a single well-pad is combined with streams from one or more additional single well-pads, where the point of combination is located off that single well-pad. Onshore production storage tanks on or associated with a single well-pad are considered a part of the onshore production facility.

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Number 10 (October 1991) (incorporated by reference, see §98.7) and the Alaska Geological Province Boundary Map, Compiled by the American Association of Petroleum Geologists Committee on Statistics of Drilling in Cooperation with the USGS, 1978 (incorporated by reference, see §98.7).

Component means each metal to metal joint or seal of non-welded connection separated by a compression gasket, screwed thread (with or without thread sealing compound), metal to metal compression, or fluid barrier through which natural gas or liquid can escape to the atmosphere.

Compressor means any machine for raising the pressure of a natural gas or CO\(_2\) by drawing in low pressure natural gas or CO\(_2\) and discharging significantly higher pressure natural gas or CO\(_2\).

Condensate means hydrocarbon and other liquid, including both water and hydrocarbon liquids, separated from natural gas that condenses due to changes in the temperature, pressure, or both, and remains liquid at storage conditions.

Distribution pipeline means a pipeline that is designated as such by the Pipeline and Hazardous Material Safety Administration (PHMSA) 49 CFR 192.3.

Engineering estimation, for purposes of subpart W, means an estimate of emissions based on engineering principles applied to measured and/or approximated physical parameters such as dimensions of containment, actual pressures, actual temperatures, and compositions.

Enhanced oil recovery (EOR) means the use of certain methods such as water flooding or gas injection into existing wells to increase the recovery of crude oil from a reservoir. In the context of this subpart, EOR applies to injection of critical phase or immiscible carbon dioxide into a crude oil reservoir to enhance the recovery of oil.

Equipment leak means those emissions which could not reasonably pass through a stack, chimney, vent, or other functionally-equivalent opening.

Equipment leak detection means the process of identifying emissions from equipment, components, and other point sources.

External combustion means fired combustion in which the flame and products of combustion are separated from contact with the process fluid to which the energy is delivered. Process fluids may be air, hot water, or hydrocarbons. External combustion equipment may include fired heaters, industrial boilers, and commercial and domestic combustion units.

Facility with respect to natural gas distribution for purposes of reporting under this subpart and for the corresponding subpart A requirements means the collection of all distribution pipelines and metering-regulating stations that are operated by a Local Distribution Company (LDC) within a single state that is regulated as a separate operating company by a public utility commission or that are operated as an independent municipally-owned distribution system.

Facility with respect to natural gas distribution for purposes of reporting under this subpart and for the corresponding subpart A requirements means the collection of all distribution pipelines and metering-regulating stations that are operated by a Local Distribution Company (LDC) within a single state that is regulated as a separate operating company by a public utility commission or that are operated as an independent municipally-owned distribution system.

Facility with respect to onshore petroleum and natural gas production for purposes of reporting under this subpart and for the corresponding subpart A requirements means all petroleum or natural gas equipment on a single well-pad or associated with a single well-pad and CO\(_2\) EOR operations that are under common ownership or common control including leased, rented, or contracted activities by an onshore petroleum and natural gas production owner or operator and that are located in a single hydrocarbon basin as defined in §98.238. Where a person or entity owns or operates more than one well in a basin, then all onshore petroleum and natural gas production equipment associated with all wells that the person or entity owns or operates in the basin would be considered one facility.

Farm Taps are pressure regulation stations that deliver gas directly from...
transmission pipelines to generally rural customers. In some cases a nearby LDC may handle the billing of the gas to the customer(s).

Field means oil and gas fields identified in the United States as defined by the Energy Information Administration Oil and Gas Field Code Master List 2008, DOE/EIA 0370(08) (incorporated by reference, see §98.7).

Flare, for the purposes of subpart W, means a combustion device, whether at ground level or elevated, that uses an open or closed flame to combust waste gases without energy recovery.

Flare stack emissions means CO₂ and N₂O from partial combustion of hydrocarbon gas sent to a flare plus CH₄ emissions resulting from the incomplete combustion of hydrocarbon gas in flares.

Forced extraction of natural gas liquids means removal of ethane or higher carbon number hydrocarbons existing in the vapor phase in natural gas, by removing ethane or heavier hydrocarbons derived from natural gas into natural gas liquids by means of a forced extraction process. Forced extraction processes include but are not limited to refrigeration, absorption (lean oil), cryogenic expander, and combinations of these processes. Forced extraction does not include in and of itself, natural gas dehydration, or the collection or gravity separation of water or hydrocarbon liquids from natural gas at ambient temperature or heated above ambient temperatures, or the condensation of water or hydrocarbon liquids through passive reduction in pressure or temperature, or portable dewpoint suppression skids.

Horizontal well means a well bore that has a planned deviation from primarily vertical to a primarily horizontal inclination or declination tracking in parallel with and through the target formation.

Internal combustion means the combustion of a fuel that occurs with an oxidizer (usually air) in a combustion chamber. In an internal combustion engine the expansion of the high-temperature and pressure gases produced by combustion applies direct force to a component of the engine, such as pistons, turbine blades, or a nozzle. This force moves the component over a distance, generating useful mechanical energy. Internal combustion equipment may include gasoline and diesel industrial engines, natural gas-fired reciprocating engines, and gas turbines.

Liquefied natural gas (LNG) means natural gas (primarily methane) that has been liquefied by reducing its temperature to -260 degrees Fahrenheit at atmospheric pressure.

LNG boil-off gas means natural gas in the gaseous phase that vents from LNG storage tanks due to ambient heat leakage through the tank insulation and heat energy dissipated in the LNG by internal pumps.

Meter/regulator run means a series of components used in regulating pressure or metering natural gas flow or both.

Metering-regulating station means a station that meters the flowrate, regulates the pressure, or both, of natural gas in a natural gas distribution facility. This does not include customer meters, customer regulators, or farm taps.

Natural gas means a naturally occurring mixture or process derivative of hydrocarbon and non-hydrocarbon gases found in geologic formations beneath the earth’s surface, of which its constituents include, but are not limited to, methane, heavier hydrocarbons and carbon dioxide. Natural gas may be field quality, pipeline quality, or process gas.

Offshore means seaward of the terrestrial borders of the United States, including waters subject to the ebb and flow of the tide, as well as adjacent bays, lakes or other normally standing waters, and extending to the outer boundaries of the jurisdiction and control of the United States under the Outer Continental Shelf Lands Act.

Onshore petroleum and natural gas production owner or operator means the person or entity who holds the permit to operate petroleum and natural gas wells on the drilling permit or an operating permit where no drilling permit is issued, which operates an onshore petroleum and/or natural gas production facility (as described in
§ 98.238. Where petroleum and natural gas wells operate without a drilling or operating permit, the person or entity that pays the State or Federal business income taxes is considered the owner or operator.

Operating pressure means the containment pressure that characterizes the normal state of gas or liquid inside a particular process, pipeline, vessel or tank.

Pressure groups as applicable to each sub-basin are defined as follows: Less than or equal to 25 psig; greater than 25 psig and less than or equal to 60 psig; greater than 60 psig and less than or equal to 110 psig; greater than 110 psig and less than or equal to 200 psig; and greater than 200 psig. The pressure in the context of pressure groups is either the well shut-in pressure; well casing pressure; or you may use the casing-to-tubing pressure of one well from the same sub-basin multiplied by the tubing pressure for each well in the sub-basin.

Pump means a device used to raise pressure, drive, or increase flow of liquid streams in closed or open conduits.

Pump seals means any seal on a pump drive shaft used to keep methane and/or carbon dioxide containing light liquids from escaping the inside of a pump case to the atmosphere.

Pump seal emissions means hydrocarbon gas released from the seal face between the pump internal chamber and the atmosphere.

Reservoir means a porous and permeable underground natural formation containing significant quantities of hydrocarbon liquids and/or gases.

Residue Gas and Residue Gas Compression mean, respectively, production lease natural gas from which gas liquid products and, in some cases, non-hydrocarbon components have been extracted such that it meets the specifications set by a pipeline transmission company, and/or a distribution company; and the compressors operated by the processing facility, whether inside the processing facility boundary fence or outside the fence-line, that deliver the residue gas from the processing facility to a transmission pipeline.

Separator means a vessel in which streams of multiple phases are gravity separated into individual streams of single phase.

Sub-basin category, for onshore natural gas production, means a subdivision of a basin into the unique combination of wells with the surface coordinates within the boundaries of an individual county and subsurface completion in one or more of each of the following five formation types: Oil, high permeability gas, shale gas, coal seam, or other tight reservoir rock. The distinction between high permeability gas and tight gas reservoirs shall be designated as follows: High permeability gas reservoirs with >0.1 millidarcy permeability, and tight gas reservoirs with ≤0.1 millidarcy permeability. Permeability for a reservoir type shall be determined by engineering estimate. Wells that produce from high permeability gas, shale gas, coal seam, or other tight reservoir rock are considered gas wells; gas wells producing from more than one of these formation types shall be classified into only one type based on the formation with the most contribution to production as determined by engineering knowledge. All wells that produce hydrocarbon liquids and do not meet the definition of a gas well in this sub-basin category definition are considered to be in the oil formation. All emission sources that handle condensate from gas wells in high permeability gas, shale gas, coal seam, or tight reservoir rock formations are considered to be in the formation that the gas well belongs to and not in the oil formation.

Transmission-distribution (T–D) transfer station means a metering-regulating station where a local distribution company takes part or all of the natural gas from a transmission pipeline and puts it into a distribution pipeline.

Transmission pipeline means a Federal Energy Regulatory Commission rate-regulated Interstate pipeline, a state rate-regulated Intrastate pipeline, or a pipeline that falls under the “Hinshaw Exemption” as referenced in section 1(c) of the Natural Gas Act, 15 U.S.C. 717–717 (w)(1994).

Tubing diameter groups are defined as follows: Outer diameter less than or equal to 1 inch; outer diameter greater than 1 inch and less than 2.375 inch;
and outer diameter greater than or equal to 2.375 inch.

**Tubing systems** means piping equal to or less than one half inch diameter as per nominal pipe size.

**Turbine meter** means a flow meter in which a gas or liquid flow rate through the calibrated tube spins a turbine from which the spin rate is detected and calibrated to measure the fluid flow rate.

**Vented emissions** means intentional or designed releases of CH₄ or CO₂ containing natural gas or hydrocarbon gas (not including stationary combustion flue gas), including process designed flow to the atmosphere through seals or vent pipes, equipment blowdown for maintenance, and direct venting of gas used to power equipment (such as pneumatic devices).

**Vertical well** means a well bore that is primarily vertical but has some unintentional deviation or one or more intentional deviations to enter one or more subsurface targets that are offset horizontally from the surface location, intercepting the targets either vertically or at an angle.

**Well testing venting and flaring** means venting and/or flaring of natural gas at the time the production rate of a well is determined for regulatory, commercial, or technical purposes. If well testing is conducted immediately after well completion or workover, then it is considered part of well completion or workover.


### TABLE W–1A OF SUBPART W—DEFAULT WHOLE GAS EMISSION FACTORS FOR ONSHORE PETROLEUM AND NATURAL GAS PRODUCTION

<table>
<thead>
<tr>
<th>Eastern U.S.</th>
<th>Onshore petroleum and natural gas production</th>
<th>Emission factor (scff/hour/component)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Valve</td>
<td></td>
<td>0.640</td>
</tr>
<tr>
<td>Connector</td>
<td></td>
<td>0.083</td>
</tr>
<tr>
<td>Open-ended Line</td>
<td></td>
<td>1.46</td>
</tr>
<tr>
<td>Pressure Relief Valve</td>
<td></td>
<td>0.97</td>
</tr>
<tr>
<td>Low Continuous Bleed Pneumatic Device Vents</td>
<td></td>
<td>1.39</td>
</tr>
<tr>
<td>High Continuous Bleed Pneumatic Device Vents</td>
<td></td>
<td>37.3</td>
</tr>
<tr>
<td>Intermittent Bleed Pneumatic Device Vents</td>
<td></td>
<td>13.5</td>
</tr>
<tr>
<td>Pneumatic Pumps</td>
<td></td>
<td>10.3</td>
</tr>
</tbody>
</table>

**Population Emission Factors—All Components, Gas Service**

| Valve        | 0.04                                |
| Flange       | 0.002                               |
| Connector    | 0.005                               |
| Open-ended Line | 0.04                                |
| Pump         | 0.01                                |
| Other | 0.23                                |

**Population Emission Factors—All Components, Light Crude Service**

| Valve        | 0.0004                             |
| Flange       | 0.0007                             |
| Connector (other) | 0.0002                            |
| Open-ended Line | 0.004                              |
| Other | 0.002                              |

**Population Emission Factors—All Components, Heavy Crude Service**

| Valve        | 2.903                              |
| Connector    | 0.396                              |
| Open-ended Line | 0.748                              |
| Pressure Relief Valve | 4.631                              |
| Low Continuous Bleed Pneumatic Device Vents | 1.77                              |
| High Continuous Bleed Pneumatic Device Vents | 47.4                              |
| Intermittent Bleed Pneumatic Device Vents | 17.1                              |
| Pneumatic Pumps | 10.3                              |

**Western U.S.**

**Population Emission Factors—All Components, Gas Service**

| Valve        | 2.903                              |
| Connector    | 0.396                              |
| Open-ended Line | 0.748                              |
| Pressure Relief Valve | 4.631                              |
| Low Continuous Bleed Pneumatic Device Vents | 1.77                              |
| High Continuous Bleed Pneumatic Device Vents | 47.4                              |
| Intermittent Bleed Pneumatic Device Vents | 17.1                              |
| Pneumatic Pumps | 10.3                              |
### TABLE W–1A TO SUBPART W OF PART 98—DEFAULT AVERAGE COMPONENT COUNTS FOR MAJOR ONSHORE NATURAL GAS PRODUCTION EQUIPMENT

<table>
<thead>
<tr>
<th>Major equipment</th>
<th>Valves</th>
<th>Connectors</th>
<th>Open-ended lines</th>
<th>Pressure relief valves</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Eastern U.S.</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Wellheads</td>
<td>8</td>
<td>38</td>
<td>0.5</td>
<td>0</td>
</tr>
<tr>
<td>Separators</td>
<td>1</td>
<td>6</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>Meters/piping</td>
<td>12</td>
<td>45</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>Compressors</td>
<td>12</td>
<td>57</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>In-line heaters</td>
<td>14</td>
<td>65</td>
<td>2</td>
<td>1</td>
</tr>
<tr>
<td>Dehydrators</td>
<td>24</td>
<td>90</td>
<td>2</td>
<td>2</td>
</tr>
<tr>
<td><strong>Western U.S.</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Wellheads</td>
<td>11</td>
<td>36</td>
<td>1</td>
<td>0</td>
</tr>
<tr>
<td>Separators</td>
<td>34</td>
<td>106</td>
<td>6</td>
<td>2</td>
</tr>
<tr>
<td>Meters/piping</td>
<td>14</td>
<td>51</td>
<td>1</td>
<td>1</td>
</tr>
<tr>
<td>Compressors</td>
<td>73</td>
<td>179</td>
<td>3</td>
<td>4</td>
</tr>
<tr>
<td>In-line heaters</td>
<td>14</td>
<td>65</td>
<td>2</td>
<td>1</td>
</tr>
<tr>
<td>Dehydrators</td>
<td>24</td>
<td>90</td>
<td>2</td>
<td>2</td>
</tr>
</tbody>
</table>

### TABLE W–1B TO SUBPART W OF PART 98—DEFAULT AVERAGE COMPONENT COUNTS FOR MAJOR CRUDE OIL PRODUCTION EQUIPMENT

<table>
<thead>
<tr>
<th>Major equipment</th>
<th>Valves</th>
<th>Flanges</th>
<th>Connectors</th>
<th>Open-ended lines</th>
<th>Other components</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Eastern U.S.</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Wellhead</td>
<td>5</td>
<td>10</td>
<td>4</td>
<td>0</td>
<td>1</td>
</tr>
<tr>
<td>Separator</td>
<td>6</td>
<td>12</td>
<td>10</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>Heater-treater</td>
<td>8</td>
<td>12</td>
<td>20</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>Header</td>
<td>5</td>
<td>10</td>
<td>4</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td><strong>Western U.S.</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Wellhead</td>
<td>5</td>
<td>10</td>
<td>4</td>
<td>0</td>
<td>1</td>
</tr>
<tr>
<td>Separator</td>
<td>6</td>
<td>12</td>
<td>10</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>Heater-treater</td>
<td>8</td>
<td>12</td>
<td>20</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>Header</td>
<td>5</td>
<td>10</td>
<td>4</td>
<td>0</td>
<td>0</td>
</tr>
</tbody>
</table>
## TABLE W–1D OF SUBPART W OF PART 98—
### DESIGNATION OF EASTERN AND WESTERN U.S.

<table>
<thead>
<tr>
<th>Eastern U.S.</th>
<th>Western U.S.</th>
</tr>
</thead>
<tbody>
<tr>
<td>Connecticut</td>
<td>Alabama</td>
</tr>
<tr>
<td>Delaware</td>
<td>Alaska</td>
</tr>
<tr>
<td>Florida</td>
<td>Arizona</td>
</tr>
<tr>
<td>Georgia</td>
<td>Arkansas</td>
</tr>
<tr>
<td>Illinois</td>
<td>California</td>
</tr>
<tr>
<td>Indiana</td>
<td>Colorado</td>
</tr>
<tr>
<td>Kentucky</td>
<td>Hawaii</td>
</tr>
<tr>
<td>Maine</td>
<td>Idaho</td>
</tr>
<tr>
<td>Maryland</td>
<td>Iowa</td>
</tr>
<tr>
<td>Massachusetts</td>
<td>Kansas</td>
</tr>
<tr>
<td>Michigan</td>
<td>Louisiana</td>
</tr>
<tr>
<td>New Hampshire</td>
<td>Minnesota</td>
</tr>
<tr>
<td>New Jersey</td>
<td>Mississippi</td>
</tr>
<tr>
<td>New York</td>
<td>Missouri</td>
</tr>
<tr>
<td>North Carolina</td>
<td>Montana</td>
</tr>
<tr>
<td>Ohio</td>
<td>Nebraska</td>
</tr>
<tr>
<td>Pennsylvania</td>
<td>Nevada</td>
</tr>
<tr>
<td>Rhode Island</td>
<td>New Mexico</td>
</tr>
<tr>
<td>South Carolina</td>
<td>North Dakota</td>
</tr>
<tr>
<td>Tennessee</td>
<td>Oklahoma</td>
</tr>
<tr>
<td>Vermont</td>
<td>Oregon</td>
</tr>
<tr>
<td>Virginia</td>
<td>South Dakota</td>
</tr>
<tr>
<td>West Virginia</td>
<td>Texas</td>
</tr>
<tr>
<td>Wisconsin</td>
<td>Utah</td>
</tr>
<tr>
<td>Washington</td>
<td>Mississippi</td>
</tr>
</tbody>
</table>

 TABLE W–1D OF SUBPART W OF PART 98—
### DESIGNATION OF EASTERN AND WESTERN U.S.—Continued

<table>
<thead>
<tr>
<th>Eastern U.S.</th>
<th>Western U.S.</th>
</tr>
</thead>
</table>

### TABLE W–2 OF SUBPART W—DEFAULT TOTAL HYDROCARBON EMISSION FACTORS FOR
### ONSHORE NATURAL GAS PROCESSING

<table>
<thead>
<tr>
<th>Onshore natural gas processing plants</th>
<th>Emission factor (scf/hour/ component)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Leaker Emission Factors—Compressor Components, Gas Service</td>
<td></td>
</tr>
<tr>
<td>Valve 1</td>
<td>14.84</td>
</tr>
<tr>
<td>Connector</td>
<td>5.59</td>
</tr>
<tr>
<td>Open-Ended Line</td>
<td>17.27</td>
</tr>
<tr>
<td>Pressure Relief Valve</td>
<td>39.66</td>
</tr>
<tr>
<td>Meter</td>
<td>19.33</td>
</tr>
<tr>
<td>Leaker Emission Factors—Non-Compressor Components, Gas Service</td>
<td></td>
</tr>
<tr>
<td>Valve 1</td>
<td>6.42</td>
</tr>
<tr>
<td>Connector</td>
<td>5.71</td>
</tr>
<tr>
<td>Open-Ended Line</td>
<td>11.27</td>
</tr>
<tr>
<td>Pressure Relief Valve</td>
<td>2.01</td>
</tr>
<tr>
<td>Meter</td>
<td>2.93</td>
</tr>
</tbody>
</table>

1 Valves include control valves, block valves and regulator valves.

[76 FR 80592, Dec. 23, 2011]

### TABLE W–3 OF SUBPART W—DEFAULT TOTAL HYDROCARBON EMISSION FACTORS FOR
### ONSHORE NATURAL GAS TRANSMISSION COMPRESSION

<table>
<thead>
<tr>
<th>Onshore natural gas transmission compression</th>
<th>Emission factor (scf/hour/ component)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Leaker Emission Factors—Compressor Components, Gas Service</td>
<td></td>
</tr>
<tr>
<td>Valve 1</td>
<td>14.84</td>
</tr>
<tr>
<td>Connector</td>
<td>5.59</td>
</tr>
<tr>
<td>Open-Ended Line</td>
<td>17.27</td>
</tr>
<tr>
<td>Pressure Relief Valve</td>
<td>39.66</td>
</tr>
<tr>
<td>Meter</td>
<td>19.33</td>
</tr>
<tr>
<td>Leaker Emission Factors—Non-Compressor Components, Gas Service</td>
<td></td>
</tr>
<tr>
<td>Valve 1</td>
<td>6.42</td>
</tr>
<tr>
<td>Connector</td>
<td>5.71</td>
</tr>
<tr>
<td>Open-Ended Line</td>
<td>11.27</td>
</tr>
<tr>
<td>Pressure Relief Valve</td>
<td>2.01</td>
</tr>
<tr>
<td>Meter</td>
<td>2.93</td>
</tr>
</tbody>
</table>

### Population Emission Factors—Gas Service

<p>| Low Continuous Bleed Pneumatic Device Vents 2 | 1.37 |
| High Continuous Bleed Pneumatic Device Vents 2 | 18.20 |</p>
<table>
<thead>
<tr>
<th>Onshore natural gas transmission compression</th>
<th>Emission factor (scf/hour/component)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Intermittent Bleed Pneumatic Device Vents(^1)</td>
<td>2.35</td>
</tr>
</tbody>
</table>

\(^1\) Valves include control valves, block valves and regulator valves.
\(^2\) Emission Factor is in units of "scf/hour/device."

[76 FR 80593, Dec. 23, 2011]

**Table W–4 of Subpart W—Default Total Hydrocarbon Emission Factors for Underground Natural Gas Storage**

<table>
<thead>
<tr>
<th>Underground natural gas storage</th>
<th>Emission factor (scfh/device)</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Leaker Emission Factors—Storage Station, Gas Service</strong></td>
<td></td>
</tr>
<tr>
<td>Valve (^1)</td>
<td>14.84</td>
</tr>
<tr>
<td>Connector</td>
<td>5.59</td>
</tr>
<tr>
<td>Open-Ended Line</td>
<td>17.27</td>
</tr>
<tr>
<td>Pressure Relief Valve</td>
<td>39.66</td>
</tr>
<tr>
<td>Meter</td>
<td>19.33</td>
</tr>
<tr>
<td><strong>Population Emission Factors—Storage Wellheads, Gas Service</strong></td>
<td></td>
</tr>
<tr>
<td>Connector</td>
<td>0.01</td>
</tr>
<tr>
<td>Valve</td>
<td>0.1</td>
</tr>
<tr>
<td>Pressure Relief Valve</td>
<td>0.17</td>
</tr>
<tr>
<td>Open Ended Line</td>
<td>0.03</td>
</tr>
<tr>
<td><strong>Population Emission Factors—Other Components, Gas Service</strong></td>
<td></td>
</tr>
<tr>
<td>Low Continuous Bleed Pneumatic Device Vents(^2)</td>
<td>1.37</td>
</tr>
<tr>
<td>Intermittent Bleed Pneumatic Device Vents(^2)</td>
<td>2.35</td>
</tr>
</tbody>
</table>

\(^1\) Valves include control valves, block valves and regulator valves.
\(^2\) Emission Factor is in units of "scfh/device."

[76 FR 80593, Dec. 23, 2011]

**Table W–5 of Subpart W—Default Methane Emission Factors for Liquefied Natural Gas (LNG) Storage**

<table>
<thead>
<tr>
<th>LNG storage</th>
<th>Emission factor (scfh/device)</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Leaker Emission Factors—LNG Storage Components, LNG Service</strong></td>
<td></td>
</tr>
<tr>
<td>Valve</td>
<td>1.19</td>
</tr>
<tr>
<td>Pump Seal</td>
<td>4.00</td>
</tr>
<tr>
<td>Connector</td>
<td>0.34</td>
</tr>
<tr>
<td>Other (^1)</td>
<td>1.77</td>
</tr>
<tr>
<td><strong>Population Emission Factors—LNG Storage Compressor, Gas Service</strong></td>
<td></td>
</tr>
<tr>
<td>Vapor Recovery Compressor</td>
<td>4.17</td>
</tr>
</tbody>
</table>

\(^1\) "Other" equipment type should be applied for any equipment type other than connectors, pumps, or valves.
\(^2\) Emission Factor is in units of "scfh/device."

[76 FR 80594, Dec. 23, 2011]

**Table W–6 of Subpart W—Default Methane Emission Factors for LNG Import and Export Equipment**

<table>
<thead>
<tr>
<th>LNG import and export equipment</th>
<th>Emission factor (scfh/device)</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Leaker Emission Factors—LNG Terminals Components, LNG Service</strong></td>
<td></td>
</tr>
<tr>
<td>Valve</td>
<td>1.19</td>
</tr>
</tbody>
</table>
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LNG import and export equipment

<table>
<thead>
<tr>
<th>Equipment</th>
<th>Emission factor (scf/hour/component)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Pump Seal</td>
<td>4.00</td>
</tr>
<tr>
<td>Connector</td>
<td>0.34</td>
</tr>
<tr>
<td>Other 1</td>
<td>1.77</td>
</tr>
</tbody>
</table>

Population Emission Factors—LNG Terminals Compressor, Gas Service

<table>
<thead>
<tr>
<th>Equipment</th>
<th>Emission factor (scf/hour/compressor)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Vapor Recovery Compressor 2</td>
<td>4.17</td>
</tr>
</tbody>
</table>

1 “Other” equipment type should be applied for any equipment type other than connectors, pumps, or valves.
2 Emission Factors is in units of “scf/hour/compressor.”

[76 FR 80594, Dec. 23, 2011]

Table W–7 of Subpart W—Default Methane Emission Factors for Natural Gas Distribution

<table>
<thead>
<tr>
<th>Natural gas distribution</th>
<th>Emission factor (scf/hour/component)</th>
</tr>
</thead>
</table>

Leaker Emission Factors—Transmission-Distribution Transfer Station 1 Components, Gas Service

<table>
<thead>
<tr>
<th>Equipment</th>
<th>Emission factor (scf/hour/station)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Connector</td>
<td>1.69</td>
</tr>
<tr>
<td>Block Valve</td>
<td>0.557</td>
</tr>
<tr>
<td>Control Valve</td>
<td>9.34</td>
</tr>
<tr>
<td>Pressure Relief Valve</td>
<td>0.27</td>
</tr>
<tr>
<td>Orifice Meter</td>
<td>0.212</td>
</tr>
<tr>
<td>Regulator</td>
<td>0.772</td>
</tr>
<tr>
<td>Open-ended Line</td>
<td>26.131</td>
</tr>
</tbody>
</table>

Population Emission Factors—Below Grade Metering-Regulating station 2 Components, Gas Service

<table>
<thead>
<tr>
<th>Equipment</th>
<th>Emission factor (scf/hour/mile)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Below Grade M&amp;R Station, Inlet Pressure &gt; 300 psig</td>
<td>1.30</td>
</tr>
<tr>
<td>Below Grade M&amp;R Station, Inlet Pressure 100 to 300 psig</td>
<td>0.20</td>
</tr>
<tr>
<td>Below Grade M&amp;R Station, Inlet Pressure &lt; 100 psig</td>
<td>0.10</td>
</tr>
</tbody>
</table>

Population Emission Factors—Distribution Mains, Gas Service 3

<table>
<thead>
<tr>
<th>Equipment</th>
<th>Emission factor (scf/hour/mile)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Unprotected Steel</td>
<td>12.58</td>
</tr>
<tr>
<td>Protected Steel</td>
<td>0.35</td>
</tr>
<tr>
<td>Plastic</td>
<td>1.13</td>
</tr>
<tr>
<td>Cast Iron</td>
<td>27.25</td>
</tr>
</tbody>
</table>

Population Emission Factors—Distribution Services, Gas Service 4

<table>
<thead>
<tr>
<th>Equipment</th>
<th>Emission factor (scf/hour/number of services)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Unprotected Steel</td>
<td>0.19</td>
</tr>
<tr>
<td>Protected Steel</td>
<td>0.02</td>
</tr>
<tr>
<td>Plastic</td>
<td>0.001</td>
</tr>
<tr>
<td>Copper</td>
<td>0.03</td>
</tr>
</tbody>
</table>

1 Excluding customer meters.
2 Emission Factor is in units of “scf/hour/station.”
3 Emission Factor is in units of “scf/hour/mile.”
4 Emission Factor is in units of “scf/hour/number of services.”

[76 FR 80594, Dec. 23, 2011]

Subpart X—Petrochemical Production

§ 98.240 Definition of the source category.

(a) The petrochemical production source category consists of all processes that produce acrylonitrile, carbon black, ethylene, ethylene dichloride, ethylene oxide, or methanol, except as specified in paragraphs (b) through (g) of this section. The source category includes processes that produce the petrochemical as an intermediate in the on-site production of other chemicals as well as processes that produce the petrochemical as an end product for sale or shipment off-site.

(b) A process that produces a petrochemical as a byproduct is not part of the petrochemical production source category.

821
§ 98.241 Reporting threshold.

You must report GHG emissions under this subpart if your facility contains a petrochemical process as specified in §98.240, and the facility meets the requirements of either §98.2(a)(1) or (2).

§ 98.242 GHGs to report.

You must report the information in paragraphs (a) through (c) of this section:

(a) CO₂, CH₄, and N₂O process emissions from each petrochemical process unit. Process emissions include CO₂ generated by reaction in the process and by combustion of process off-gas in stationary combustion units and flares.

(b) CO₂, CH₄, and N₂O combustion emissions from stationary combustion units.

(c) CO₂ captured. You must report the mass of CO₂ captured under subpart PP of this part (Suppliers of Carbon Dioxide (CO₂) by following the requirements of subpart PP.


§ 98.243 Calculating GHG emissions.

(a) If you route all process vent emissions and emissions from combustion of process off-gas to one or more stacks and use CEMS on each stack to measure CO₂ emissions (except flare stacks), then you must determine process-based GHG emissions in accordance with paragraph (b) of this section. Otherwise, determine process-based GHG...
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emissions in accordance with the procedures specified in paragraph (c) or (d) of this section.

(b) Continuous emission monitoring system (CEMS). Route all process vent emissions and emissions from combustion of process off-gas to one or more stacks and determine CO$_2$ emissions from each stack (except flare stacks) according to the Tier 4 Calculation Methodology requirements in subpart C of this part. For each stack (except flare stacks) that includes emissions from combustion of petrochemical process off-gas, calculate CH$_4$ and N$_2$O emissions in accordance with subpart C of this part (use the Tier 3 methodology, emission factors for “Petroleum” in Table C–2 of subpart C of this part, and either the default high heat value for fuel gas in Table C–1 of subpart C of this part or a calculated HHV, as allowed in Equation C–8 of subpart C of this part). For each flare, calculate CO$_2$, CH$_4$, and N$_2$O emissions using the methodology specified in §98.253(b)(1) through (b)(3).

(c) Mass balance for each petrochemical process unit. Calculate the emissions of CO$_2$ from each process unit, for each calendar month as described in paragraphs (c)(1) through (c)(5) of this section.

(1) For each gaseous and liquid feedstock and product, measure the volume or mass used or produced each calendar month with a flow meter by following the procedures specified in §98.244(b)(2). Alternatively, for liquids, you may calculate the volume used or collected in each month based on measurements of the liquid level in a storage tank at least once per month (and just prior to each change in direction of the level of the liquid) following the procedures specified in §98.244(b)(3). Fuels used for combustion purposes are not considered to be feedstocks.

(2) For each solid feedstock and product, measure the mass used or produced each calendar month by following the procedures specified in §98.244(b)(1).

(3) Collect a sample of each feedstock and product at least once per month and determine the carbon content of each sample according to the procedures of §98.244(b)(4). If multiple valid carbon content measurements are made during the monthly measurement period, average them arithmetically. However, if a particular liquid or solid feedstock is delivered in lots, and if multiple deliveries of the same feedstock are received from the same supply source in a given calendar month, only one representative sample is required. Alternatively, you may use the results of analyses conducted by a fuel or feedstock supplier, provided the sampling and analysis is conducted at least once per month using any of the procedures specified in §98.244(b)(4).

(4) If you determine that the monthly average concentration of a specific compound in a feedstock or product is greater than 99.5 percent by volume (or mass for liquids and solids), then as an alternative to the sampling and analysis specified in paragraph (c)(3) of this section, you may calculate the carbon content assuming 100 percent of that feedstock or product is the specific compound during periods of normal operation. You must maintain records of any determination made in accordance with this paragraph (c)(4) along with all supporting data, calculations, and other information. This alternative may not be used for products during periods of operation when off-specification product is produced. You must re-evaluate determinations made under this paragraph (c)(4) after any process change that affects the feedstock or product composition. You must keep records of the process change and the corresponding composition determinations. If the feedstock or product composition changes so that the average monthly concentration falls below 99.5 percent, you are no longer permitted to use this alternative method.

(5) Calculate the CO$_2$ mass emissions for each petrochemical process unit using Equations X–1 through X–4 of this section.

(1) Gaseous feedstocks and products. Use Equation X–1 of this section to calculate the net annual carbon input or output from gaseous feedstocks and products. Note that the result will be a negative value if there are no gaseous feedstocks in the process but there are gaseous products.
\[ C_g = \sum_{n=1}^{12} \left[ \sum_{i=1}^{j} \left( F_{gf,i,n} \cdot \left( CC_{gf,i,n} \cdot \frac{MW_f}{MVC} \right) - P_{gf,i,n} \cdot \left( CC_{gf,i,n} \cdot \frac{MW_f}{MVC} \right) \right) \right] \]  
(Eq. X-1)

Where:
- \( C_g \) = Annual net contribution to calculated emissions from carbon (C) in gaseous materials (kilograms/year, kg/yr).
- \( (F_{gf,i,n}) \) = Volume of gaseous feedstock \( i \) introduced in month “n” (standard cubic feet, scf).
- \( (CC_{gf,i,n}) \) = Average carbon content of the gaseous feedstock \( i \) for month “n” (kg C per kg of feedstock).
- \( (MW_f) \) = Molecular weight of gaseous feedstock \( i \) (kg/kg-mole).
- \( MVC \) = Molar volume conversion factor (849.5 scf per kg-mole at 68 °F and 14.7 pounds per square inch absolute or 836.6 scf/kg-mole at 60 °F and 14.7 pounds per square inch absolute).
- \( (P_{gf,i,n}) \) = Volume of gaseous product \( i \) produced in month “n” (scf).
- \( (CC_{gp,i,n}) \) = Average carbon content of gaseous product \( i \), including streams containing CO\(_2\) recovered for sale or use in another process, for month “n” (kg C per kg of product).
- \( (MW_{p,i}) \) = Molecular weight of gaseous product \( i \) (kg/kg-mole).
- \( j \) = Number of feedstocks.
- \( k \) = Number of products.

(ii) Liquid feedstocks and products. Use Equation X-2 of this section to calculate the net carbon input or output from liquid feedstocks and products. Note that the result will be a negative value if there are no liquid feedstocks in the process but there are liquid products.

\[ C_l = \sum_{n=1}^{12} \left[ \sum_{i=1}^{j} \left( F_{lf,i,n} \cdot \left( CC_{lf,i,n} \right) - P_{lf,i,n} \cdot \left( CC_{lf,i,n} \right) \right) \right] \]  
(Eq. X-2)

Where:
- \( C_l \) = Annual net contribution to calculated emissions from carbon in liquid materials, including liquid organic wastes (kg/yr).
- \( (F_{lf,i,n}) \) = Volume or mass of liquid feedstock \( i \) introduced in month “n” (gallons or kg).
- \( (CC_{lf,i,n}) \) = Average carbon content of liquid feedstock \( i \) for month “n” (kg C per gallon of feedstock).
- \( (P_{lf,i,n}) \) = Volume or mass of liquid product \( i \) produced in month “n” (gallons or kg).
- \( j \) = Number of feedstocks.
- \( k \) = Number of products.

(iii) Solid feedstocks and products. Use Equation X-3 of this section to calculate the net annual carbon input or output from solid feedstocks and products. Note that the result will be a negative value if there are no solid feedstocks in the process but there are solid products.

\[ C_s = \sum_{n=1}^{12} \left[ \sum_{i=1}^{j} \left( F_{sf,i,n} \cdot \left( CC_{sf,i,n} \right) - P_{sf,i,n} \cdot \left( CC_{sf,i,n} \right) \right) \right] \]  
(Eq. X-3)

Where:
- \( C_s \) = Annual net contribution to calculated emissions from carbon in solid materials (kg/yr).
- \( (F_{sf,i,n}) \) = Volume of solid feedstock \( i \) introduced in month “n” (kg).
- \( (CC_{sf,i,n}) \) = Average carbon content of solid feedstock \( i \) for month “n” (kg C per kg of feedstock).
- \( (P_{sp,i,n}) \) = Mass of solid product \( i \) produced in month “n” (kg).
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(CC)n,i = Average carbon content of solid product i in month “n” (kg C per kg of product).

j = Number of feedstocks.
k = Number of products.

(iv) Annual emissions. Use the results from Equations X-1 through X-3 of this section, as applicable, in Equation X-4 of this section to calculate annual CO₂ emissions.

\[ CO₂ = 0.001 \times \frac{44}{12} \times \left( C_g + C_i + C_s \right) \]  \hspace{1cm} (Eq. X-4)

Where:

\( CO₂ \) = Annual CO₂ mass emissions from process operations and process off-gas combustion (metric tons/year).
0.001 = Conversion factor from kg to metric tons.
44 = Molecular weight of CO₂ (kg/kg-mole).
12 = Atomic weight of carbon (C) (kg/kg-mole).

(d) Optional combustion methodology for ethylene production processes. For each ethylene production process, calculate GHG emissions from combustion units that burn fuel that contains any off-gas from the ethylene process as specified in paragraphs (d)(1) through (d)(5) of this section.

(1) Except as specified in paragraphs (d)(2) and (d)(5) of this section, calculate CO₂ emissions using the Tier 3 or Tier 4 methodology in subpart C of this part.

(2) You may use either Equation C-1 or Equation C-2a in subpart C of this part to calculate CO₂ emissions from combustion of any ethylene process off-gas streams that meet either of the conditions in paragraphs (d)(2)(i) or (d)(2)(ii) of this section (for any default values in the calculation, use the defaults for fuel gas in Table C-1 of subpart C of this part). Follow the otherwise applicable procedures in subpart C to calculate emissions from combustion of all other fuels in the combustion unit.

(i) The annual average flow rate of fuel gas (that contains ethylene process off-gas) in the fuel gas line to the combustion unit, prior to any split to individual burners or ports, does not exceed 345 standard cubic feet per minute at 60 °F and 14.7 pounds per square inch absolute, and a flow meter is not installed at any point in the line supplying fuel gas (that contains ethylene process off-gas) or an upstream common pipe. Calculate the annual average flow rate using company records assuming total flow is evenly distributed over 525,600 minutes per year.

(ii) The combustion unit has a maximum rated heat input capacity of less than 30 mmBtu/hr, and a flow meter is not installed at any point in the line supplying fuel gas (that contains ethylene process off-gas) or an upstream common pipe.

(3) Except as specified in paragraph (d)(5) of this section, calculate CH₄ and N₂O emissions using the applicable procedures in §98.33(c) for the same tier methodology that you used for calculating CO₂ emissions.

(i) For all gaseous fuels that contain ethylene process off-gas, use the emission factors for “Petroleum” in Table C-2 of subpart C of this part (General Stationary Fuel Combustion Sources).

(ii) For Tier 3, use either the default high heat value for fuel gas in Table C-1 of subpart C of this part or a calculated HHV, as allowed in Equation C-8 of subpart C of this part.

(4) You are not required to use the same Tier for each stationary combustion unit that burns ethylene process off-gas.

(5) For each flare, calculate CO₂, CH₄, and N₂O emissions using the methodology specified in §§98.253(b)(1) through (b)(3).


§98.244 Monitoring and QA/QC requirements.

(a) If you use CEMS to determine emissions from process vents, you must comply with the procedures specified in §98.34(c).

(b) If you use the mass balance methodology in §98.243(c), use the procedures specified in paragraphs (b)(1)
through (b)(4) of this section to determine feedstock and product flows and carbon contents.

(1) Operate, maintain, and calibrate belt scales or other weighing devices as described in Specifications, Tolerances, and Other Technical Requirements for Weighing and Measuring Devices NIST Handbook 44 (2009) (incorporated by reference, see §98.7), or follow procedures specified by the measurement device manufacturer. You must recalibrate each weighing device according to one of the following frequencies. You may recalibrate either at the minimum frequency specified by the manufacturer or biennially (i.e., once every two years).

(2) Operate and maintain all flow meters used for gas and liquid feedstocks and products according to the manufacturer's recommended procedures. You must calibrate each of these flow meters as specified in paragraphs (b)(2)(i) and (b)(2)(ii) of this section:

(i) You may use either the calibration methods specified by the flow meter manufacturer or an industry consensus standard method. Each flow meter must meet the applicable accuracy specification in §98.3(1), except as otherwise specified in §§98.3(1)(4) through (1)(6).

(ii) You must recalibrate each flow meter according to one of the following frequencies. You may recalibrate at the minimum frequency specified by the manufacturer, biennially (every two years), or at the interval specified by the industry consensus standard practice used.


(4) Beginning January 1, 2010, use any applicable methods specified in paragraphs (b)(4)(i) through (b)(4)(xiv) of this section to determine the carbon content or composition of feedstocks and products and the average molecular weight of gaseous feedstocks and products. Calibrate instruments in accordance with paragraphs (b)(4)(i) through (b)(4)(xvi), as applicable. For coal used as a feedstock, the samples for carbon content determinations shall be taken at a location that is representative of the coal feedstock used during the corresponding monthly period. For carbon black products, samples shall be taken of each grade or type of product produced during the monthly period. Samples of coal feedstock or carbon black product for carbon content determinations may be either grab samples collected and analyzed monthly or a composite of samples collected more frequently and analyzed monthly. Analyses conducted in accordance with methods specified in paragraphs (b)(4)(i) through (b)(4)(xv) of this section may be performed by the owner or operator, by an independent laboratory, or by the supplier of a feedstock.

(i) ASTM D1945–03, Standard Test Method for Analysis of Natural Gas by Gas Chromatography (incorporated by reference, see §98.7).


(iii) ASTM D2505–88(Reapproved 2004) Standard Test Method for Ethylene, Other Hydrocarbons,
Carbon Dioxide in High-Purity Ethylene by Gas Chromatography (incorporated by reference, see § 98.7).

(iv) ASTM UOP539–97 Refinery Gas Analysis by Gas Chromatography (incorporated by reference, see § 98.7).


(vii) ASTM D3373–08 Standard Test Methods for Instrumental Determination of Carbon, Hydrogen, and Nitrogen in Laboratory Samples of Coal (incorporated by reference, see § 98.7).

(x) Performance Specification 9 in 40 CFR part 60, appendix B for continuous online gas analyzers. The 7-day calibration error test period must be completed prior to the effective date of the rule.


(xii) ASTM D7633–10 Standard Test Method for Carbon Black—Carbon Content (incorporated by reference, see § 98.7).

(xii) The results of chromatographic analysis of a feedstock or product, provided that the gas chromatograph is operated, maintained, and calibrated according to the manufacturer’s instructions.

(xiv) The carbon content results of mass spectrometer analysis of a feedstock or product, provided that the mass spectrometer is operated, maintained, and calibrated according to the manufacturer’s instructions.

(xv) Beginning on January 1, 2010, the methods specified in paragraphs (b)(4)(xv)(A) and (B) of this section may be used as alternatives for the methods specified in paragraphs (b)(4)(i) through (b)(4)(xv) of this section. (A) An industry standard practice for carbon black feedstock oils and carbon black products.

(B) Modifications of existing analytical methods or other methods that are applicable to your process provided that the methods listed in paragraphs (b)(4)(i) through (b)(4)(xiv) of this section are not appropriate because the relevant compounds cannot be detected, the quality control requirements are not technically feasible, or use of the method would be unsafe.

§ 98.245 Procedures for estimating missing data.

For missing feedstock flow rates, product flow rates, and carbon contents, use the same procedures as for missing flow rates and carbon contents for fuels as specified in § 98.35.

§ 98.246 Data reporting requirements.

In addition to the information required by § 98.3(c), each annual report must contain the information specified in paragraphs (a), (b), or (c) of this section, as appropriate for each process unit.

(a) If you use the mass balance methodology in § 98.243(c), you must report the information specified in paragraphs (a)(1) through (a)(11) of this section for each type of petrochemical produced, reported by process unit.

(1) The petrochemical process unit ID number or other appropriate descriptor.

(2) The type of petrochemical produced, names of other products, and names of carbon-containing feedstocks.

(3) Annual CO₂ emissions calculated using Equation X–4 of this subpart.

(4) Each of the monthly volume, mass, and carbon content values used in Equations X–1 through X–3 of this subpart (i.e., the directly measured values, substitute values, or the calculated values based on other measured data such as tank levels or gas composition) and the molecular weights for gaseous feedstocks and products used in Equation X–1 of this subpart, and the temperature (in °F) at which the gaseous feedstock and product volumes used in Equation X–1 of this subpart were determined. Indicate whether you...
used the alternative to sampling and analysis specified in §98.243(c)(4).

(5) Annual quantity of each type of petrochemical produced from each process unit (metric tons).

(6) Name of each method listed in §98.244 used to determine a measured parameter (or description of manufacturer’s recommended method).

(7) [Reserved]

(8) Identification of each combustion unit that burned both process off-gas and supplemental fuel.

(9) If you comply with the alternative to sampling and analysis specified in §98.243(c)(4), the amount of time during which off-specification product was produced, the volume or mass of off-specification product produced, and if applicable, the date of any process change that reduced the composition to less than 99.5 percent.

(10) You may elect to report the flow and carbon content of wastewater, and you may elect to report the annual mass of carbon released in fugitive emissions and in process vents that are not controlled with a combustion device. These values may be estimated based on engineering analyses. These values are not to be used in the mass balance calculation.

(11) If you determine carbon content or composition of a feedstock or product using a method under §98.244(b)(4)(xv)(B), report the information listed in paragraphs (a)(11)(i) through (a)(11)(iv) of this section. Include the information in paragraph (a)(11)(i) of this section in each annual report. Include the information in paragraphs (a)(11)(ii) and (a)(11)(iii) of this section only in the first applicable annual report, and provide any changes to this information in subsequent annual reports.

(a) Name or title of the analytical method.

(ii) A copy of the method. If the method is a modification of a method listed in §§98.244(b)(4)(i) through (xiv), you may provide a copy of only the sections that differ from the listed method.

(iii) An explanation of why an alternative to the methods listed in §§98.244(b)(4)(i) through (xiv) is needed.

(b) If you measure emissions in accordance with §98.243(b), then you must report the information listed in paragraphs (b)(1) through (b)(8) of this section.

(1) The petrochemical process unit ID or other appropriate descriptor, and the type of petrochemical produced.

(2) For CEMS used on stacks for stationary combustion units, report the relevant information required under §98.36 for the Tier 4 calculation methodology. Section 98.36(b)(9)(iii) does not apply for the purposes of this subpart.

(3) For CEMS used on stacks that are not used for stationary combustion units, report the information required under §98.36(e)(2)(vi).

(4) The CO₂ emissions from each stack and the combined CO₂ emissions from all stacks (except flare stacks) that handle process vent emissions and emissions from stationary combustion units that burn process off-gas for the petrochemical process unit. For each stationary combustion unit (or group of combustion units monitored with a single CO₂ CEMS) that burns petrochemical process off-gas, provide an estimate based on engineering judgment of the fraction of the total emissions that is attributable to combustion of off-gas from the petrochemical process unit.

(5) For stationary combustion units that burn process off-gas from the petrochemical process unit, report the information related to CH₄ and N₂O emissions as specified in paragraphs (b)(5)(i) through (b)(5)(iv) of this section.

(i) The CH₄ and N₂O emissions from each stack that is monitored with a CO₂ CEMS, expressed in metric tons of each gas and in metric tons of CO₂e. For each stack provide an estimate based on engineering judgment of the fraction of the total emissions that is attributable to combustion of off-gas from the petrochemical process unit.

(ii) The combined CH₄ and N₂O emissions from all stationary combustion units, expressed in metric tons of each gas and in metric tons of CO₂e.

(iii) The quantity of each type of fuel used in Equation C–8 in §98.33(c) for each stationary combustion unit or group of units (as applicable) during the reporting year, expressed in short tons for solid fuels, gallons for liquid fuels, and scf for gaseous fuels.
(iv) The HHV (either default or annual average from measured data) used in Equation C–8 in §98.33(c) for each stationary combustion unit or group of combustion units (as applicable).

(6) ID or other appropriate descriptor of each stationary combustion unit that burns process off-gas.

(7) Information listed in §98.256(e) of subpart Y of this part for each flare that burns process off-gas.

(8) Annual quantity of each type of petrochemical produced from each process unit (metric tons).

(c) If you comply with the combustion methodology specified in §98.243(d), you must report under this subpart the information listed in paragraphs (c)(1) through (c)(5) of this section.

(1) The ethylene process unit ID or other appropriate descriptor.

(2) For each stationary combustion unit that burns ethylene process off-gas (or group of stationary sources with a common pipe), except flares, the relevant information listed in §98.36 for the applicable Tier methodology. For each stationary combustion unit or group of units (as applicable) that burns ethylene process off-gas, provide an estimate based on engineering judgment of the fraction of the total emissions that is attributable to combustion of off-gas from the ethylene process unit.

(3) Information listed in §98.256(e) of subpart Y of this part for each flare that burns ethylene process off-gas.

(4) Name and annual quantity of each feedstock.

(5) Annual quantity of ethylene produced from each process unit (metric tons).

§98.248 Definitions.

Except as specified in this section, all terms used in this subpart have the same meaning given in the Clean Air Act and subpart A of this part.

Product, as used in §98.243, means each of the following carbon-containing outputs from a process: the petrochemical, recovered byproducts, and liquid organic wastes that are not incinerated onsite. Product does not include process vent emissions, fugitive emissions, or wastewater.
Subpart Y—Petroleum Refineries

§ 98.250 Definition of source category.

(a) A petroleum refinery is any facility engaged in producing gasoline, gasoline blending stocks, naphtha, kerosene, distillate fuel oils, residual fuel oils, lubricants, or asphalt (bitumen) through distillation of petroleum or through redistillation, cracking, or reforming of unfinished petroleum derivatives, except as provided in paragraph (b) of this section.

(b) For the purposes of this subpart, facilities that distill only pipeline transmix (off-spec material created when different specification products mix during pipeline transportation) are not petroleum refineries, regardless of the products produced.

(c) This source category consists of the following sources at petroleum refineries: Catalytic cracking units; fluid coking units; delayed coking units; catalytic reforming units; coke calcining units; asphalt blowing operations; blowdown systems; storage tanks; process equipment components (compressors, pumps, valves, pressure relief devices, flanges, and connectors) in gas service; marine vessel, barge, tanker truck, and similar loading operations; flares; sulfur recovery plants; and non-merchant hydrogen plants (i.e., hydrogen plants that are owned or under the direct control of the refinery owner and operator).

§ 98.251 Reporting threshold.

You must report GHG emissions under this subpart if your facility contains a petroleum refineries process and the facility meets the requirements of either § 98.2(a)(1) or (a)(2).

§ 98.252 GHGs to report.

You must report:

(a) CO₂, CH₄, and N₂O combustion emissions from stationary combustion units and from each flare. Calculate and report the emissions from stationary combustion units under subpart C of this part (General Stationary Fuel Combustion Sources) by following the requirements of subpart C, except for emissions from combustion of fuel gas. For CO₂ emissions from combustion of fuel gas, use either Equation C–5 in subpart C of this part or the Tier 4 methodology in subpart C of this part, unless either of the conditions in paragraphs (a)(1) or (a)(2) of this section are met, in which case use either Equations C–1 or C–2a in subpart C of this part. For CH₄ and N₂O emissions from combustion of fuel gas, use the applicable procedures in § 98.33(c) for the same tier methodology that was used for calculating CO₂ emissions. (Use the default CH₄ and N₂O emission factors for “Petroleum (All fuel types in Table C–1)” in Table C–2 of this part. For Tier 3, use either the default high heat value for fuel gas in Table C–1 of subpart C of this part or a calculated HHV, as allowed in Equation C–8 of subpart C of this part.) You may aggregate units, monitor common stacks, or monitor common (fuel) pipes as provided in § 98.36(c) when calculating and reporting emissions from stationary combustion units. Calculate and report the emissions from flares under this subpart.

(1) The annual average fuel gas flow rate in the fuel gas line to the combustion unit, prior to any split to individual burners or ports, does not exceed 345 standard cubic feet per minute at 60 °F and 14.7 pounds per square inch absolute and either of the conditions in paragraph (a)(1)(i) or (ii) of this section exist. Calculate the annual average flow rate using company records assuming total flow is evenly distributed over 525,600 minutes per year.

(i) A flow meter is not installed at any point in the line supplying fuel gas or an upstream common pipe.

(ii) The fuel gas line contains only vapors from loading or unloading, waste or wastewater handling, and remediation activities that are combusted in a thermal oxidizer or thermal incinerator.

(2) The combustion unit has a maximum rated heat input capacity of less than 30 mmBtu/hr and either of the following conditions exist:

(i) A flow meter is not installed at any point in the line supplying fuel gas or an upstream common pipe; or

(ii) The fuel gas line contains only vapors from loading or unloading, waste or wastewater handling, and remediation activities that are combusted in a thermal oxidizer or thermal incinerator.
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§ 98.253  Calculating GHG emissions.

(a) Calculate GHG emissions required to be reported in §98.252(b) through (i) using the applicable methods in paragraphs (b) through (n) of this section.

(b) For flares, calculate GHG emissions according to the requirements in paragraphs (b)(1) through (b)(3) of this section.

1. Calculate the CO₂ emissions according to the applicable requirements in paragraphs (b)(1)(i) through (b)(1)(iii) of this section.

(1) Flow measurement. If you have a continuous flow monitor on the flare, you must use the measured flow rates when the monitor is operational and the flow rate is within the calibrated range of the measurement device to calculate the flare gas flow. If you do not have a continuous flow monitor on the flare and for periods when the monitor is not operational or the flow rate is outside the calibrated range of the measurement device, you must use engineering calculations, company records, or similar estimates of volumetric flare gas flow.

(ii) Heat value or carbon content measurement. If you have a continuous higher heating value monitor or gas composition monitor on the flare or if you monitor these parameters at least weekly, you must use the measured heat value or carbon content value in calculating the CO₂ emissions from the flare using the applicable methods in paragraphs (b)(1)(ii)(A) and (b)(1)(ii)(B).

(A) If you monitor gas composition, calculate the CO₂ emissions from the flare using either Equation Y–1a or Equation Y–1b of this section. If daily or more frequent measurement data are available, you must use daily values when using Equation Y–1a or Equation Y–1b of this section; otherwise, use weekly values.

\[ \text{CO}_2 = 0.98 \times 0.001 \times \left( \frac{\sum_{p=1}^{n} 44}{12} \times (\text{Flare})_p \times \frac{\text{(MW) }_p}{\text{MVC}} \times (\text{CC})_p \right) \]  

(Eq. Y–1a)

where:

\( \text{CO}_2 = \) Annual CO₂ emissions for a specific fuel type (metric tons/year),

0.98 = Assumed combustion efficiency of a flare,

0.001 = Unit conversion factor (metric tons per kilogram, mt/kg),

n = Number of measurement periods. The minimum value for n is 52 (for weekly measurements); the maximum value for
\[
CO_2 = \sum_{p=1}^{n} \left[ (\text{Flare})_p \times \frac{44}{\text{MVC}} \times 0.001 \times \left( \frac{(%CO_2)_p}{100\%} + \sum_{x=1}^{y} \left( \frac{(%C_x)_p}{100\%} \times \text{CMN}_x \right) \right) \right]
\]

(Eq. Y-1b)

Where:

- \(CO_2\) = Annual \(CO_2\) emissions for a specific fuel type (metric tons/year).
- \(n\) = Number of measurement periods. The minimum value for \(n\) is 52 (for weekly measurements); the maximum value for \(n\) is 366 (for daily measurements during a leap year).
- \(\text{MVC}\) = Molar volume conversion factor (849.5 scf/kg-mole at 68 °F and 14.7 pounds per square inch absolute (psia) or 836.6 scf/kg-mole at 60 °F and 14.7 psia).
- \((%\text{CO}_2)_p\) = Mole percent \(\text{CO}_2\) concentration in the flare gas stream during the measurement period (mole percent = percent by volume).
- \(\text{CMN}_x\) = Carbon mole number of compound “\(x\)" in the flare gas stream (mole carbon atoms per mole compound).
- \((%C_x)_p\) = Mole percent concentration of compound “\(x\)" in the flare gas stream during the measurement period (mole percent = percent by volume).
- \(\text{Flare})_p\) = Volume of flare gas combusted during measurement period (standard cubic feet per period, scf/period). If a mass flow meter is used, measure flare gas flow rate in kg/period and replace the term “\((\text{MW})_p/\text{MVC}\)” with “1”.

(B) If you monitor heat content but do not monitor gas composition, calculate the \(CO_2\) emissions from the flare using Equation Y-2 of this section. If daily or more frequent measurement data are available, you must use daily values when using Equation Y-2 of this section; otherwise, use weekly values.

\[
CO_2 = 0.98 \times 0.001 \times \sum_{p=1}^{n} \left[ (\text{Flare})_p \times (\text{HHV})_p \times \text{EmF} \right]
\]

(Eq. Y-2)

Where:

- \(CO_2\) = Annual \(CO_2\) emissions for a specific fuel type (metric tons/year).
- \((%\text{CO}_2)_p\) = Mole percent \(\text{CO}_2\) concentration in the flare gas stream during the measurement period (mole percent = percent by volume).
- \((%C_x)_p\) = Mole percent concentration of compound “\(x\)" in the flare gas stream (mole percent = percent by volume).
- \(\text{CMN}_x\) = Carbon mole number of compound “\(x\)" in the flare gas stream (mole carbon atoms per mole compound).
n = Number of measurement periods. The minimum value for n is 52 (for weekly measurements); the maximum value for n is 366 (for daily measurements during a leap year).

p = Measurement period index.

(Flare) = Volume of flare gas combusted during measurement period (million (MM) scf/period). If a mass flow meter is used, you must also measure molecular weight and convert the mass flow to a volumetric flow as follows: Flare\[MMscf\] = 0.000001 × Flare[kg] × MVC/(MW), where MVC is the molar volume conversion factor [849.5 scf/kg-mole at 68 °F and 14.7 psia or 836.6 scf/kg-mole at 60 °F and 14.7 psia depending on the standard conditions used when determining (HHV) and (MW), is the average molecular weight of the flare gas combusted during measurement period (kg/kg-mole).

(HHV) = Higher heating value for the flare gas combusted during measurement period (British thermal units per scf, Btu/scf = MMBtu/MMscf). If measurements are taken more frequently than daily, use the arithmetic average of measurement values within the day to calculate a daily average.

EmF = Default CO₂ emission factor of 60 kilograms CO₂/MMBtu (HHV basis).

\[
CO_2 = 0.98 \times 0.001 \times \left( Flare_{norm} \times HHV \times EmF + \sum_{p=1}^{n} \left( Flare_{SSM} \times \frac{(MW)}{MVC} \times (CC) \right) \right)
\]

( Eq. Y-3 )

Where:

CO₂ = Annual CO₂ emissions for a specific fuel type (metric tons/year).
0.98 = Assumed combustion efficiency of a flare.
0.001 = Unit conversion factor (metric tons per kilogram, mt/kg).
Flare\_norm = Annual volume of flare gas combusted during normal operations from company records, (million (MM) standard cubic feet per year, MMscf/year).
HHV = Higher heating value for fuel gas or flare gas from company records (British thermal units per scf, Btu/scf = MMBtu/MMscf).
EmF = Default CO₂ emission factor for flare gas of 60 kilograms CO₂/MMBtu (HHV basis).
n = Number of start-up, shutdown, and malfunction events during the reporting year exceeding 500,000 scf/day.

p = Start-up, shutdown, and malfunction event index.
44 = Molecular weight of CO₂ (kg/kg-mole).
12 = Atomic weight of C (kg/kg-mole).
(Flare\_SSM) = Volume of flare gas combusted during indexed start-up, shutdown, or malfunction event from engineering calculations, (scf/event).
(MW) = Average molecular weight of the flare gas, from the analysis results or engineering calculations for the event (kg/kg-mole).
MVC = Molar volume conversion factor [849.5 scf/kg-mole at 68 °F and 14.7 psia or 836.6 scf/kg-mole at 60 °F and 14.7 psia].
(CC) = Average carbon content of the flare gas, from analysis results or engineering calculations for the event (kg C per kg flare gas).

(2) Calculate CH₄ using Equation Y-4 of this section.
\[ CH_4 = \left( \frac{CO_2 \times EmF_{CH4}}{EmF} \right) + CO_2 \times \frac{0.02}{0.98} \times \frac{16}{44} \times f_{CH4} \] (Eq. Y-4)
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\[
CO_2 = \sum_{p=1}^{n} \left[ (Q_r)_p \times \frac{(%CO_2 + %CO)_p}{100\%} \times \frac{44}{MVC} \times 0.001 \right]
\]  
(Eq. Y-6)

Where:

- \(CO_2\) = Annual \(CO_2\) mass emissions (metric tons/year).
- \(Q_r\) = Volumetric flow rate of exhaust gas from the fluid catalytic cracking unit regenerator or fluid coking unit burner prior to the combustion of other fossil fuels (dry standard cubic feet per hour, dscfh).
- \(%CO_2\) = Hourly average percent \(CO_2\) concentration in the exhaust gas stream from the fluid catalytic cracking unit regenerator or fluid coking unit burner (percent by volume—dry basis).
- \(%CO\) = Hourly average percent \(CO\) concentration in the exhaust gas stream from the fluid catalytic cracking unit regenerator or fluid coking unit burner (percent by volume—dry basis).
- \(MVC\) = Molar volume conversion factor (849.5 scf/kg-mole at 68 °F and 14.7 psia or 836.6 scf/kg-mole at 60 °F and 14.7 psia).
- \(0.001\) = Conversion factor (metric ton/kg).
- \(n\) = Number of hours in calendar year.

(ii) Either continuously monitor the volumetric flow rate of exhaust gas from the fluid catalytic cracking unit regenerator or fluid coking unit burner prior to the combustion of other fossil fuels or calculate the volumetric flow rate of this exhaust gas stream using either Equation Y–7a or Equation Y–7b of this section.

\[
Q_r = \frac{(79 \times Q_a + (100 - %O_{axy}) \times Q_{oxy})}{100 - %CO_2 - %CO - %O_2}
\]  
(Eq. Y-7a')

where:

- \(Q_a\) = Volumetric flow rate of air to the fluid catalytic cracking unit regenerator or fluid coking unit burner, as determined from control room instrumentation (dscfh).
- \(Q_{oxy}\) = Volumetric flow rate of oxygen enriched air to the fluid catalytic cracking unit regenerator or fluid coking unit burner as determined from control room instrumentation (dscfh).
- \(%O_2\) = Hourly average percent oxygen concentration in the exhaust gas stream from the fluid catalytic cracking unit regenerator or fluid coking unit burner (percent by volume—dry basis).
- \(%O_{axy}\) = \(O_2\) concentration in oxygen enriched gas stream inlet to the fluid catalytic cracking unit regenerator or fluid coking unit burner based on oxygen purity specifications of the oxygen supply used for enrichment (percent by volume—dry basis).
- \(%CO_2\) = Hourly average percent \(CO_2\) concentration in the exhaust gas stream from the fluid catalytic cracking unit regenerator or fluid coking unit burner (percent by volume—dry basis).
- \(%CO\) = Hourly average percent \(CO\) concentration in the exhaust gas stream from the fluid catalytic cracking unit regenerator or fluid coking unit burner (percent by volume—dry basis). When no auxiliary fuel is burned and a continuous \(CO\) monitor is not required under 40 CFR part 63 subpart UUU, assume \(%CO\) to be zero.

\[
Q_r = \frac{(78.1 \times Q_a + (%N_{2,axy}) \times Q_{oxy})}{%N_{2,exhaust}}
\]  
(Eq. Y-7b')
where:

- \( Q_r \) = Volumetric flow rate of exhaust gas from the fluid catalytic cracking unit regenerator or fluid coking unit burner prior to the combustion of other fossil fuels (dscfh).
- \( Q_a \) = Volumetric flow rate of air to the fluid catalytic cracking unit regenerator or fluid coking unit burner, as determined from control room instrumentation (dscfh).
- \( Q_{oxy} \) = Volumetric flow rate of oxygen enriched air to the fluid catalytic cracking unit regenerator or fluid coking unit burner as determined from control room instrumentation (dscfh).
- \( \%N_{2,oxy} \) = \( N_2 \) concentration in oxygen enriched gas stream inlet to the fluid catalytic cracking unit regenerator or fluid coking unit burner based on measured value or maximum \( N_2 \) impurity specifications of the oxygen supply used for enrichment (percent by volume—dry basis).
- \( \%N_{2,exhaust} \) = Hourly average percent \( N_2 \) concentration in the exhaust gas stream from the fluid catalytic cracking unit regenerator or fluid coking unit burner (percent by volume—dry basis).

(iii) If you have a CO boiler that uses auxiliary fuels or combusts materials other than catalytic cracking unit or fluid coking unit exhaust gas, you must determine the \( CO_2 \) emissions resulting from the combustion of these fuels or other materials following the requirements in subpart C and report those emissions by following the requirements of subpart C of this part.

(3) For catalytic cracking units and fluid coking units with rated capacities of 10,000 barrels per stream day (bbls/sd) or less that do not use a continuous \( CO_2 \) CEMS for the final exhaust stack, comply with the requirements in paragraph (c)(3)(i) of this section or paragraphs (c)(3)(ii) and (c)(3)(iii) of this section, as applicable.

(i) If you continuously or no less frequently than daily monitor the \( O_2 \), \( CO_2 \), and (if necessary) CO concentrations in the exhaust stack from the catalytic cracking unit regenerator or fluid coking unit burner prior to the combustion of other fossil fuels, you must calculate the \( CO_2 \) emissions according to the requirements of paragraphs (c)(2)(i) through (c)(2)(ii) of this section, except that daily averages are allowed and the summation can be performed on a daily basis.

(ii) If you do not monitor at least daily the \( O_2 \), \( CO_2 \), and (if necessary) CO concentrations in the exhaust stack from the catalytic cracking unit regenerator or fluid coking unit burner prior to the combustion of other fossil fuels, calculate the \( CO_2 \) emissions from each catalytic cracking unit and fluid coking unit using Equation Y-8 of this section.

\[
CO_2 = Q_{unit} \times (CBF \times 0.001) \times CC \times \frac{44}{12} \quad \text{(Eq. Y-8)}
\]

Where:

- \( CO_2 \) = Annual \( CO_2 \) mass emissions (metric tons/year).
- \( Q_{unit} \) = Annual throughput of unit from company records (barrels (bbls) per year, bbl/yr).
- \( CBF \) = Coke burn-off factor from engineering calculations (kg coke per barrel of feed); default for catalytic cracking units = 7.3; default for fluid coking units = 11.
- 0.001 = Conversion factor (metric ton/kg).
- \( CC \) = Carbon content of coke based on measurement or engineering estimate (kg C per kg coke); default = 0.94.
- \( 44/12 \) = Ratio of molecular weight of \( CO_2 \) to \( C \) (kg \( CO_2 \) per kg \( C \)).

(iii) If you have a CO boiler that uses auxiliary fuels or combusts materials other than catalytic cracking unit or fluid coking unit exhaust gas, you must determine the \( CO_2 \) emissions resulting from the combustion of these fuels or other materials following the requirements in subpart C of this part (General Stationary Fuel Combustion Sources) and report those emissions by following the requirements of subpart C of this part.

(4) Calculate \( CH_4 \) emissions using either unit-specific measurement data, a unit-specific emission factor based on a source test of the unit, or Equation Y-9 of this section.
where:

CH₄ = Annual methane emissions from coke burn-off (metric tons CH₄/year).

CO₂ = Emission rate of CO₂ from coke burn-off calculated in paragraphs (c)(1), (c)(2), (e)(1), (e)(2), (g)(1), or (g)(2) of this section, as applicable (metric tons/year).

EmF₁ = Default CO₂ emission factor for petroleum coke from Table C-1 of subpart C of this part (General Stationary Fuel Combustion Sources) (kg CO₂/MMBtu).

EmF₂ = Default CH₄ emission factor for "PetroleumProducts" from Table C-2 of subpart C of this part (General Stationary Fuel Combustion Sources) (kg CH₄/MMBtu).

(5) Calculate N₂O emissions using either unit specific measurement data, a unit-specific emission factor based on a source test of the unit, or Equation Y-10 of this section.

\[
\begin{align*}
N₂O & = \left( CO₂ \times \frac{EmF₁}{EmF₃} \right) \quad \text{(Eq. Y-10)} \\
\end{align*}
\]

where:

N₂O = Annual nitrous oxide emissions from coke burn-off (mt N₂O/year).

CO₂ = Emission rate of CO₂ from coke burn-off calculated in paragraphs (c)(1), (c)(2), (e)(1), (e)(2), (g)(1), or (g)(2) of this section, as applicable (metric tons/year).

EmF₁ = Default CO₂ emission factor for petroleum coke from Table C-1 of subpart C of this part (General Stationary Fuel Combustion Sources) (kg CO₂/MMBtu).

EmF₃ = Default N₂O emission factor for "PetroleumProducts" from Table C-2 of subpart C of this part (kg N₂O/MMBtu).

(d) For fluid coking units that use the flexicoking design, the GHG emissions from the resulting use of the low value fuel gas must be accounted for only once. Typically, these emissions will be accounted for using the methods described in subpart C of this part (General Stationary Fuel Combustion Sources). Alternatively, you may use the methods in paragraph (c) of this section provided that you do not otherwise account for the subsequent combustion of this low value fuel gas.

(e) For catalytic reforming units, calculate the CO₂ emissions using the applicable methods described in paragraphs (e)(1) through (e)(3) of this section and calculate the CH₄ and N₂O emissions using the methods described in paragraphs (c)(4) and (c)(5) of this section, respectively.

(1) If you operate and maintain a CEMS that measures CO₂ emissions according to subpart C of this part (General Stationary Fuel Combustion Sources), you must calculate CO₂ emissions as provided in paragraphs (c)(1)(i) and (c)(1)(ii) of this section. Other catalytic reforming units must either install a CEMS that complies with the Tier 4 Calculation Methodology in subpart C of this part, or follow the requirements of paragraph (e)(2) or (e)(3) of this section.

(2) If you continuously or no less frequently than daily monitor the O₂, CO₂, and (if necessary) CO concentrations in the exhaust stack from the catalytic reforming unit catalyst regenerator prior to the combustion of other fossil fuels, you must calculate the CO₂ emissions according to the requirements of paragraphs (c)(2)(i) through (c)(2)(iii) of this section.

(3) Calculate CO₂ emissions from the catalytic reforming unit catalyst regenerator using Equation Y-11 of this section.

\[
CO₂ = \sum_{i=1}^{n} \left( CB₉ \times CC \times \frac{44}{12} \times 0.001 \right) \quad \text{(Eq. Y-11)}
\]

where:

CO₂ = Annual CO₂ emissions (metric tons/year).

CB₉ = Coke burn-off quantity per regeneration cycle or measurement period from engineering estimates (kg coke/cycle or kg coke/measurement period).

n = Number of regeneration cycles or measurement periods in the calendar year.
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CC = Carbon content of coke based on measurement or engineering estimate (kg C per kg coke); default = 0.94.

44/12 = Ratio of molecular weight of CO\(_2\) to C (kg CO\(_2\) per kg C).

0.001 = Conversion factor (metric ton/kg).

(f) For on-site sulfur recovery plants and for sour gas sent off site for sulfur recovery, calculate and report CO\(_2\) process emissions from sulfur recovery plants according to the requirements in paragraphs (f)(1) through (f)(5) of this section, or, for non-Claus sulfur recovery plants, according to the requirements in paragraph (j) of this section regardless of the concentration of CO\(_2\) in the vented gas stream. Combustion emissions from the sulfur recovery plant (e.g., from fuel combustion in the Claus burner or the tail gas treatment incinerator) must be reported under subpart C of this part (General Stationary Fuel Combustion Sources). For the purposes of this subpart, the sour gas stream for which monitoring is required according to paragraphs (f)(2) through (f)(5) of this section is not considered a fuel.

(1) If you operate and maintain a CEMS that measures CO\(_2\) emissions according to subpart C of this part, you must calculate CO\(_2\) emissions under this subpart by following the Tier 4 Calculation Methodology specified in §98.33(a)(4) and all associated requirements for Tier 4 in subpart C of this part (General Stationary Fuel Combustion Sources). You must monitor fuel use in the Claus burner, tail gas incinerator, or other combustion sources that discharge via the final exhaust stack from the sulfur recovery plant and calculate the combustion emissions from the fuel use according to subpart C of this part. Calculate the process emissions from the sulfur recovery plant as the difference in the CO\(_2\) CEMS emissions and the calculated combustion emissions associated with the sulfur recovery plant final exhaust stack. Other sulfur recovery plants must either install a CEMS that complies with the Tier 4 Calculation Methodology in subpart C, or follow the requirements of paragraphs (f)(2) through (f)(5) of this section, or (for non-Claus sulfur recovery plants only) follow the requirements in paragraph (j) of this section to determine CO\(_2\) emissions for the sulfur recovery plant.

(2) Flow measurement. If you have a continuous flow monitor on the sour gas feed to the sulfur recovery plant, you must use the measured flow rates when the monitor is operational to calculate the sour gas flow rate. If you do not have a continuous flow monitor on the sour gas feed to the sulfur recovery plant, you must use engineering calculations, company records, or similar estimates of volumetric sour gas flow.

(3) Carbon content. If you have a continuous gas composition monitor capable of measuring carbon content on the sour gas feed to the sulfur recovery plant or if you monitor gas composition for carbon content on a routine basis, you must use the measured carbon content value. Alternatively, you may develop a site-specific carbon content factor using limited measurement data or engineering estimates or use the default factor of 0.20.

(4) Calculate the CO\(_2\) emissions from each sulfur recovery plant using Equation Y–12 of this section.

\[
CO_2 = F_{SG} \times \frac{44}{MVC} \times MF_C \times 0.001 \quad \text{(Eq. Y-12)}
\]

Where:

- \(CO_2\) = Annual CO\(_2\) emissions (metric tons/year).
- \(F_{SG}\) = Volumetric flow rate of sour gas feed (including sour water stripper gas) to the sulfur recovery plant (scf/year).
- 44 = Molecular weight of CO\(_2\) (kg/kg-mole).
- MVC = Molar volume conversion factor (849.5 scf/kg-mole at 68 °F and 14.7 psia or 836.6 scf/kg-mole at 60 °F and 14.7 psia).
- \(MF_C\) = Mole fraction of carbon in the sour gas to the sulfur recovery plant (kg-mole C/kg-mole gas); default = 0.20.
- 0.001 = Conversion factor, kg to metric tons.
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(5) If tail gas is recycled to the front of the sulfur recovery plant and the recycled flow rate and carbon content is included in the measured data under paragraphs (f)(2) and (f)(3) of this section, respectively, then the annual CO₂ emissions calculated in paragraph (f)(4) of this section must be corrected to avoid double counting these emissions. You may use engineering estimates to perform this correction or assume that the corrected CO₂ emissions are 95 percent of the uncorrected value calculated using Equation Y–12 of this section.

(g) For coke calcining units, calculate GHG emissions according to the applicable provisions in paragraphs (g)(1) through (g)(3) of this section.

(1) If you operate and maintain a CEMS that measures CO₂ emissions according to subpart C of this part, you must calculate and report CO₂ emissions under this subpart by following the Tier 4 Calculation Methodology specified in §98.33(a)(4) and all associated requirements for Tier 4 in subpart C of this part (General Stationary Fuel Combustion Sources). You must monitor fuel use in the coke calcining unit that discharges via the final exhaust stack from the coke calcining unit and calculate the combustion emissions from the fuel use according to subpart C of this part. Calculate the process emissions from the coke calcining unit as the difference in the CO₂ CEMS emissions and the calculated combustion emissions associated with the coke calcining unit final exhaust stack. Other coke calcining units must either install a CEMS that complies with the Tier 4 Calculation Methodology in subpart C of this part, or follow the requirements of paragraph (g)(2) of this section.

(2) Calculate the CO₂ emissions from the coke calcining unit using Equation Y–13 of this section.

\[
CO_2 = \frac{44}{12} \times (M_{in} \times \text{CC}_{GC} - (M_{out} + M_{dust}) \times \text{CC}_{MPC}) \quad (\text{Eq. Y-13})
\]

Where:

- \(CO_2\) = Annual CO₂ emissions (metric tons/year).
- \(M_{in}\) = Annual mass of green coke fed to the coke calcining unit from facility records (metric tons/year).
- \(CC_{GC}\) = Average mass fraction carbon content of green coke from facility measurement data (metric ton carbon/metric ton green coke).
- \(M_{out}\) = Annual mass of marketable petroleum coke produced by the coke calcining unit from facility records (metric tons petroleum coke/year).
- \(M_{dust}\) = Annual mass of petroleum coke dust removed from the process through the dust collection system of the coke calcining unit from facility records (metric ton petroleum coke dust/year).
- \(CC_{MPC}\) = Average mass fraction carbon content of marketable petroleum coke produced by the coke calcining unit from facility measurement data (metric ton carbon/metric ton petroleum coke).
- 44 = Molecular weight of CO₂ (kg/kg-mole).
- 12 = Atomic weight of C (kg/kg-mole).

(3) For all coke calcining units, use the CO₂ emissions from the coke calcining unit calculated in paragraphs (g)(1) or (g)(2), as applicable, and calculate CH₄ using the methods described in paragraph (c)(4) of this section and N₂O emissions using the methods described in paragraph (c)(5) of this section.

(h) For asphalt blowing operations, calculate CO₂ and CH₄ emissions according to the requirements in paragraph (j) of this section regardless of the CO₂ and CH₄ concentrations or according to the applicable provisions in paragraphs (h)(1) and (h)(2) of this section.

(1) For uncontrolled asphalt blowing operations or asphalt blowing operations controlled by vapor scrubbing, calculate CO₂ and CH₄ emissions using Equations Y–14 and Y–15 of this section, respectively.

\[
CO_2 = (Q_{AB} \times EF_{AB,CO2}) \quad (\text{Eq. Y-14})
\]
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Where:

\( \text{CO}_2 \) = Annual \( \text{CO}_2 \) emissions from uncontrolled asphalt blowing (metric tons \( \text{CO}_2 \)/year).

\( Q_{AB} \) = Quantity of asphalt blown (million barrels per year, MMbbl/year).

\( \text{EF}_{AB,\text{CO}_2} \) = Emission factor for \( \text{CO}_2 \) from uncontrolled asphalt blowing from facility-specific test data (metric tons \( \text{CO}_2 \)/MMbbl asphalt blown); default = 1,100.

\( CH_4 = \left( Q_{AB} \times EF_{AB,CH_4} \right) \quad \text{(Eq. Y-15)} \)

Where:

\( CH_4 \) = Annual methane emissions from uncontrolled asphalt blowing (metric tons \( CH_4 \)/year).

\( Q_{AB} \) = Quantity of asphalt blown (million barrels per year, MMbbl/year).

\( \text{EF}_{AB,\text{CH}_4} \) = Emission factor for \( CH_4 \) from uncontrolled asphalt blowing from facility-specific test data (metric tons \( CH_4 \)/MMbbl asphalt blown); default = 580.

\( EQ = 0.98 \times \left( Q_{AB} \times CEF_{AB} \times \frac{44}{12} \right) \quad \text{(Eq. Y-16a)} \)

where:

\( \text{CO}_2 \) = Annual \( \text{CO}_2 \) emissions from controlled asphalt blowing (metric tons \( \text{CO}_2 \)/year).

0.98 = Assumed combustion efficiency of thermal oxidizer or flare.

\( Q_{AB} \) = Quantity of asphalt blown (MMbbl/year).

\( CEF_{AB} \) = Carbon emission factor from asphalt blowing from facility-specific test data (metric tons C/MMbbl asphalt blown); default = 2,750.

44 = Molecular weight of \( \text{CO}_2 \) (kg/kg-mole).

12 = Atomic weight of C (kg/kg-mole).

\( EQ = Q_{AB} \times \left( EEF_{AB,\text{CO}_2} + 0.98 \times \left( CEF_{AB} \times \frac{44}{12} - EEF_{AB,\text{CO}_2} \right) \right) \quad \text{(Eq. Y-16b)} \)

where:

\( \text{CO}_2 \) = Annual \( \text{CO}_2 \) emissions from controlled asphalt blowing (metric tons \( \text{CO}_2 \)/year).

\( Q_{AB} \) = Quantity of asphalt blown (MMbbl/year).

0.98 = Assumed combustion efficiency of thermal oxidizer or flare.

\( \text{EF}_{AB,\text{CO}_2} \) = Emission factor for \( \text{CO}_2 \) from uncontrolled asphalt blowing from facility-specific test data (metric tons \( \text{CO}_2 \)/MMbbl asphalt blown); default = 1,100.

\( CEF_{AB} \) = Carbon emission factor from asphalt blowing from facility-specific test data (metric tons C/MMbbl asphalt blown); default = 2,750.

44 = Molecular weight of \( \text{CO}_2 \) (kg/kg-mole).

12 = Atomic weight of C (kg/kg-mole).

\( CH_4 = 0.02 \times \left( Q_{AB} \times EF_{AB,CH_4} \right) \quad \text{(Eq. Y-17)} \)

where:

\( CH_4 \) = Annual methane emissions from controlled asphalt blowing (metric tons \( CH_4 \)/year).

0.02 = Fraction of methane uncombusted in thermal oxidizer or flare based on assumed 98% combustion efficiency.

\( Q_{AB} \) = Quantity of asphalt blown (million barrels per year, MMbbl/year).
(i) For delayed coking units, calculate the \( \text{CH}_4 \) emissions from the depressurization of the coking unit vessel (i.e., the “coke drum”) to atmosphere using either of the methods provided in paragraphs (i)(1) or (i)(2), provided no water or steam is added to the vessel once it is vented to the atmosphere. You must use the method in paragraph (i)(1) of this section if you add water or steam to the vessel after it is vented to the atmosphere.

(1) Use the process vent method in paragraph (j) of this section to calculate the \( \text{CH}_4 \) emissions from the depressurization of the coke drum or vessel regardless of the \( \text{CH}_4 \) concentration and also calculate the \( \text{CH}_4 \) emissions from the subsequent opening of the vessel for coke cutting operations using Equation Y–18 of this section. If you have coke drums or vessels of different dimensions, use the process vent method in paragraph (j) of this section and Equation Y–18 for each set of coke drums or vessels of the same size and sum the resultant emissions across each set of coke drums or vessels to calculate the \( \text{CH}_4 \) emissions for all delayed coking units.

\[
\text{CH}_4 = \left( N \times H \times \frac{P_{\text{CC}} + 14.7}{14.7} \times \frac{\pi \times D^2}{4} \times \frac{16}{M_{\text{V}} \times M_{\text{MF}}} \times \text{MF}_{\text{CH}_4} \times 0.001 \right)
\]

(Eq. Y–18)

Where:
- \( \text{CH}_4 \) = Annual methane emissions from the delayed coking unit vessel opening (metric ton/year).
- \( N \) = Cumulative number of vessel openings for all delayed coking unit vessels of the same dimensions during the year.
- \( H \) = Height of coking unit vessel (feet).
- \( P_{\text{CC}} \) = Gauge pressure of the coking vessel when opened to the atmosphere prior to coke cutting or, if the alternative method provided in paragraph (i)(2) of this section is used, gauge pressure of the coking vessel when depressurization gases are first routed to the atmosphere (pounds per square inch, psig).
- \( 14.7 \) = Assumed atmospheric pressure (pounds per square inch, psi).
- \( f_{\text{void}} \) = Volumetric void fraction of coking vessel prior to steaming (cf gas/cf of vessel); default = 0.6.
- \( D \) = Diameter of coking unit vessel (feet).
- \( M_{\text{V}} \) = Molar volume conversion factor (849.5 scf/kg-mole at 68 °F and 14.7 psia or 836.6 scf/kg-mole at 60 °F and 14.7 psia).
- \( M_{\text{MF}} \) = Mole fraction of methane in coking vessel gas (kg-mole \( \text{CH}_4 \)/kg-mole gas, wet basis); default value is 0.01.
- \( 0.001 \) = Conversion factor (metric ton/kg).

(2) Calculate the \( \text{CH}_4 \) emissions from the depressurization vent and subsequent opening of the vessel for coke cutting operations using Equation Y–18 of this section and the pressure of the coking vessel when the depressurization gases are first routed to the atmosphere. If you have coke drums or vessels of different dimensions, use Equation Y–18 for each set of coke drums or vessels of the same size and sum the resultant emissions across each set of coke drums or vessels to calculate the \( \text{CH}_4 \) emissions for all delayed coking units.

(j) For each process vent not covered in paragraphs (a) through (i) of this section that can reasonably be expected to contain greater than 2 percent by volume \( \text{CO}_2 \) or greater than 0.5 percent by volume of \( \text{CH}_4 \) or greater than 0.01 percent by volume (100 parts per million) of \( \text{N}_2\text{O} \), calculate GHG emissions using the Equation Y–19 of this section. You must use Equation Y–19 of this section to calculate \( \text{CH}_4 \) emissions for catalytic reforming unit depressurization and purge vents when methane is used as the purge gas or if you elected this method as an alternative to the methods in paragraphs (f), (h), or (k) of this section.
\[
E_x = \sum_{p=1}^{N} \left( (VR)_p \times (MF)_p \times \frac{MW_x}{MVC} \times (VT)_p \times 0.001 \right) \quad \text{(Eq. Y-19)}
\]

Where:
- \( E_x \) = Annual emissions of each GHG from process vent (metric ton/yr).
- \( N \) = Number of venting events per year.
- \( P \) = Index of venting events.
- \( (VR)_p \) = Average volumetric flow rate of process gas during the event (scf per hour) from measurement data, process knowledge, or engineering estimates.
- \( (MF)_p \) = Mole fraction of GHG \( x \) in process vent during the event (kg-mol of GHG \( x \)/kg-mol vent gas) from measurement data, process knowledge, or engineering estimates.
- \( MW_x \) = Molecular weight of GHG \( x \) (kg/kg-mole); use 44 for CO\(_2\) or N\(_2\)O and 16 for CH\(_4\).
- \( MVC \) = Molar volume conversion factor (849.5 scf/kg-mole at 68° F and 14.7 psia or 836.6 scf/kg-mole at 60° F and 14.7 psia).
- \( (VT)_p \) = Venting time for the event, (hours).
- 0.001 = Conversion factor (metric ton/kg).

(k) For uncontrolled blowdown systems, you must calculate CH\(_4\) emissions either using the methods for process vents in paragraph (j) of this section regardless of the CH\(_4\) concentration or using Equation Y20 of this section. Blowdown systems where the uncondensed gas stream is routed to a flare or similar control device is considered to be controlled and is not required to estimate emissions under this paragraph (k).

\[
CH_4 = \left( Q_{Ref} \times EF_{BD} \times \frac{16}{MVC} \times 0.001 \right) \quad \text{(Eq. Y-20)}
\]

Where:
- \( CH_4 \) = Methane emission rate from blowdown systems (mt CH\(_4\)/year).
- \( Q_{Ref} \) = Quantity of crude oil plus the quantity of intermediate products received from offsite that are processed at the facility (MMbbl/year).
- \( EF_{BD} \) = Methane emission factor for uncontrolled blowdown systems (scf CH\(_4\)/MMbbl); default is 137,000.
- 16 = Molecular weight of CH\(_4\) (kg/kg-mole).
- \( MVC \) = Molar volume conversion factor (849.5 scf/kg-mole at 68° F and 14.7 psia or 836.6 scf/kg-mole at 60° F and 14.7 psia).
- 0.001 = Conversion factor (metric ton/kg).

(1) For equipment leaks, calculate CH\(_4\) emissions using the method specified in either paragraph (1)(1) or (1)(2) of this section.

(1) Use process-specific methane composition data (from measurement data or process knowledge) and any of the emission estimation procedures provided in the Protocol for Equipment Leak Emissions Estimates (EPA–453/R–95–017, NTIS PB96–175401).

(2) Use Equation Y–21 of this section.

\[
CH_4 = (0.4 \times N_{CD} + 0.2 \times N_{PU1} + 0.1 \times N_{PU2} + 4.3 \times N_{H2} + 6 \times N_{FGS}) \quad \text{(Eq. Y-21)}
\]

Where:
- \( CH_4 \) = Annual methane emissions from equipment leaks (metric ton/year).
- \( N_{CD} \) = Number of atmospheric crude oil distillation columns at the facility.
- \( N_{PU1} \) = Cumulative number of catalytic cracking units, coking units (delayed or fluid), hydrocracking, and full-range distillation columns (including depropanizer and debutanizer distillation columns) at the facility.
- \( N_{PU2} \) = Cumulative number of hydrotreating/hydrorefining units, catalytic reforming units, and visbreaking units at the facility.
- \( N_{H2} \) = Total number of hydrogen plants at the facility.
- \( N_{FGS} \) = Total number of fuel gas systems at the facility.
(m) For storage tanks, except as provided in paragraph (m)(4) of this section, calculate CH₄ emissions using the applicable methods in paragraphs (m)(1) through (m)(3) of this section.

(1) For storage tanks other than those processing unstabilized crude oil, you must either calculate CH₄ emissions from storage tanks that have a vapor-phase methane concentration of 0.5 volume percent or more using tank-specific methane composition data (from measurement data or product knowledge) and the emission estimation methods provided in AP 42, Section 7.1 (incorporated by reference, see §98.7) or estimate CH₄ emissions from storage tanks using Equation Y–22 of this section.

\[ CH_4 = 0.1 \times Q_{Ref} \times \left( \frac{16}{MVC} \right) \times 0.001 \]  
(Eq. Y-22)

Where:
- \( CH_4 \) = Annual methane emissions from storage tanks (metric tons/yr).
- \( Q_{Ref} \) = Quantity of crude oil plus the quantity of intermediate products received from off site that are processed at the facility (MMbbl/year).
- \( 0.1 \) = Default emission factor for storage tanks (metric ton CH₄/MMbbl).
- \( Q_{Ref} \) = Quantity of crude oil plus the quantity of intermediate products received from off site that are processed at the facility (MMbbl/year).
- \( MFC_{CH4} \) = Average mole fraction of CH₄ in vent gas from the unstabilized crude oil storage tanks from facility measurements (kg-mole CH₄/kg-mole gas); use 0.27 as a default if measurement data are not available.
- \( 995,000 \) = Correlation Equation factor (scf gas per MMbbl per psig).
- \( 16 \) = Molecular weight of CH₄ (kg/kg-mole).
- \( MVC \) = Molar volume conversion factor (849.5 scf/kg-mole at 68 °F and 14.7 psia or 836.6 scf/kg-mole at 60 °F and 14.7 psia).
- \( 0.001 \) = Conversion factor (metric ton/kg).

(2) For storage tanks that process unstabilized crude oil, calculate CH₄ emissions from the storage of unstabilized crude oil using either tank-specific methane composition data (from measurement data or product knowledge) and direct measurement of the gas generation rate or by using Equation Y–23 of this section.

\[ CH_4 = (995,000 \times Q_{un} \times D_P) \times \frac{16}{MF_{CH4}} \times \frac{16}{MVC} \times 0.001 \]  
(Eq. Y-23)

Where:
- \( CH_4 \) = Annual methane emissions from storage tanks (metric tons/yr).
- \( Q_{un} \) = Quantity of unstabilized crude oil received at the facility (MMbbl/year).
- \( D_P \) = Pressure differential from the previous storage pressure to atmospheric pressure (pounds per square inch, psig).
- \( MF_{CH4} \) = Average mole fraction of CH₄ in vent gas from the unstabilized crude oil storage tanks from facility measurements (kg-mole CH₄/kg-mole gas); use 0.27 as a default if measurement data are not available.
- \( 995,000 \) = Correlation Equation factor (scf gas per MMbbl per psig).
- \( 16 \) = Molecular weight of CH₄ (kg/kg-mole).
- \( MVC \) = Molar volume conversion factor (849.5 scf/kg-mole at 68 °F and 14.7 psia or 836.6 scf/kg-mole at 60 °F and 14.7 psia).
- \( 0.001 \) = Conversion factor (metric ton/kg).

(3) You do not need to calculate CH₄ emissions from storage tanks that meet any of the following descriptions:
- (i) Units permanently attached to conveyances such as trucks, trailers, rail cars, barges, or ships;
- (ii) Pressure vessels designed to operate in excess of 204.9 kilopascals and without emissions to the atmosphere;
- (iii) Bottoms receivers or sumps;
- (iv) Vessels storing wastewater; or
- (v) Reactor vessels associated with a manufacturing process unit.

(n) For crude oil, intermediate, or product loading operations for which the vapor-phase concentration of methane is 0.5 volume percent or more, calculate CH₄ emissions from loading operations using vapor-phase methane composition data (from measurement data or process knowledge) and the emission estimation procedures provided in AP 42, Section 5.2 (incorporated by reference, see §98.7). For loading operations in which the vapor-phase concentration of methane is less than 0.5 volume percent, you may assume zero methane emissions.

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combustion sources must meet the applicable monitoring and QA/QC requirements in §98.34.

(b) All gas flow meters, gas composition monitors, and heating value monitors that are used to provide data for the GHG emissions calculations in this subpart for sources other than those subject to the requirements in paragraph (a) of this section shall be calibrated according to the procedures specified by the manufacturer, or according to the procedures in the applicable methods specified in paragraphs (c) through (g) of this section. In the case of gas flow meters, all gas flow meters must meet the calibration accuracy requirements in §98.3(i). All gas flow meters, gas composition monitors, and heating value monitors must be recalibrated at the applicable frequency specified in paragraph (b)(1) or (b)(2) of this section.

(1) You must recalibrate each gas flow meter according to one of the following frequencies. You may recalibrate at the minimum frequency specified by the manufacturer, biennially (every two years), or at the interval specified by the industry consensus standard practice used.

(2) You must recalibrate each gas composition monitor and heating value monitor according to one of the following frequencies. You may recalibrate at the minimum frequency specified by the manufacturer, annually, or at the interval specified by the industry standard practice used.

(c) For flare or sour gas flow meters and gas flow meters used to comply with the requirements in §98.253(j), operate, calibrate, and maintain the flow meter according to one of the following. You may use the procedures specified by the flow meter manufacturer, or a method published by a consensus-based standards organization. Consensus-based standards organizations include, but are not limited to, the following: ASTM International (100 Barr Harbor Drive, P.O. Box CB700, West Conshohocken, Pennsylvania 19428–B2959, (800) 262–1373, http://www.astm.org), the American National Standards Institute (ANSI, 1819 L Street, NW., 6th floor, Washington, DC 20036, (202) 289–8220, http://www.ansi.org), the American Gas Association (AGA, 400 North Capitol Street, NW., 4th Floor, Washington, DC 20001, (202) 824–7000, http://www.aga.org), the American Society of Mechanical Engineers (ASME, Three Park Avenue, New York, NY 10016–5990, (800) 843–2763, http://www.asme.org), the American Petroleum Institute (API, 1220 L Street, NW., Washington, DC 20005–4070, (202) 682–8000, http://www.api.org), and the North American Energy Standards Board (NAESB, 801 Travis Street, Suite 1675, Houston, TX 77002, (713) 356–0060, http://www.api.org).

(d) Except as provided in paragraph (g) of this section, determine gas composition and, if required, average molecular weight of the gas using any of the following methods. Alternatively, the results of chromatographic analysis of the fuel may be used, provided that the gas chromatograph is operated, maintained, and calibrated according to the manufacturer’s instructions; and the methods used for operation, maintenance, and calibration of the gas chromatograph are documented in the written Monitoring Plan for the unit under §98.3(g)(5).

(1) Method 18 at 40 CFR part 60, appendix A–6.

(2) ASTM D1945–03 Standard Test Method for Analysis of Natural Gas by Gas Chromatography (incorporated by reference, see §98.7).

(3) ASTM D1946–90 (Reapproved 2006) Standard Practice for Analysis of Reformed Gas by Gas Chromatography (incorporated by reference, see §98.7).

(4) GPA 2261–00 Analysis for Natural Gas and Similar Gaseous Mixtures by Gas Chromatography (incorporated by reference, see §98.7).

(5) UOP539–97 Refinery Gas Analysis by Gas Chromatography (incorporated by reference, see §98.7).


(e) Determine flare gas higher heating value using any of the following methods. Alternatively, the results of chromatographic analysis of the fuel may be used, provided that the gas chromatograph is operated, maintained, and calibrated according to the
manufacturer's instructions; and the methods used for operation, maintenance, and calibration of the gas chromatograph are documented in the written Monitoring Plan for the unit under §98.3(g)(5).

(1) ASTM D4809–06 Standard Test Method for Heat of Combustion of Liquid Hydrocarbon Fuels by Bomb Calorimeter (Precision Method) (incorporated by reference, see §98.7).


(f) For gas flow meters used to comply with the requirements in §98.253(c)(2)(ii), install, operate, calibrate, and maintain each gas flow meter according to the requirements in 40 CFR 63.1572(c) and the following requirements.

(1) Locate the flow monitor at a site that provides representative flow rates. Avoid locations where there is swirling flow or abnormal velocity distributions due to upstream and downstream disturbances.

(2) [Reserved]

(3) Use a continuous monitoring system capable of correcting for the temperature, pressure, and moisture content to output flow in dry standard cubic feet (standard conditions as defined in §98.6).

(g) For exhaust gas CO₂, CO, O₂ composition monitors used to comply with the requirements in §98.253(c)(2), install, operate, calibrate, and maintain exhaust gas composition monitors according to the requirements in 40 CFR 60.105a(b)(2) or 40 CFR 63.1572(c) or according to the manufacturer’s specifications and requirements.

(h) Determine the mass of petroleum coke as required by Equation Y–13 of this subpart using mass measurement equipment meeting the requirements for commercial weighing equipment as described in Specifications, Tolerances, and Other Technical Requirements For Weighing and Measuring Devices, NIST Handbook 44 (2009) (incorporated by reference, see §98.7). Calibrate the measurement device according to the procedures specified by NIST handbook 44 (incorporated by reference, see §98.7) or the procedures specified by the manufacturer. Recalibrate either biennially or at the minimum frequency specified by the manufacturer.

(i) Determine the carbon content of petroleum coke as required by Equation Y–13 of this subpart using any one of the following methods. Calibrate the measurement device according to procedures specified by the method or procedures specified by the measurement device manufacturer.


(3) ASTM D5373–08 Standard Test Methods for Instrumental Determination of Carbon, Hydrogen, and Nitrogen in Laboratory Samples of Coal (incorporated by reference, see §98.7).

(j) Determine the quantity of petroleum process streams using company records. These quantities include the quantity of asphalt blown, quantity of crude oil plus the quantity of intermediate products received from off site, and the quantity of unstabilized crude oil received at the facility.

(k) The owner or operator shall document the procedures used to ensure the accuracy of the estimates of fuel usage, gas composition, and heating value including but not limited to calibration of weighing equipment, fuel flow meters, and other measurement devices. The estimated accuracy of measurements made with these devices shall
§ 98.255 Procedures for estimating missing data.

A complete record of all measured parameters used in the GHG emissions calculations is required (e.g., concentrations, flow rates, fuel heating values, carbon content values). Therefore, whenever a quality-assured value of a required parameter is unavailable (e.g., if a CEMS malfunctions during unit operation or if a required fuel sample is not taken), a substitute data value for the missing parameter shall be used in the calculations.

(a) For stationary combustion sources, use the missing data procedures in subpart C of this part.

(b) For each missing value of the heat content, carbon content, or molecular weight of the fuel, substitute the arithmetic average of the quality-assured values of that parameter immediately preceding and immediately following the missing data incident. If the “after” value is not obtained by the end of the reporting year, you may use the “before” value for the missing data substitution. If, for a particular parameter, no quality-assured data are available prior to the missing data incident, the substitute data value shall be the first quality-assured value obtained after the missing data period.

(c) For missing CO₂, CO, O₂, CH₄, or N₂O concentrations, gas flow rate, and percent moisture, the substitute data values shall be the best available estimate(s) of the parameter(s), based on all available process data (e.g., processing rates, operating hours, etc.). The owner or operator shall document and keep records of the procedures used for all such estimates.

(d) For hydrogen plants, use the missing data procedures in subpart P of this part.

§ 98.256 Data reporting requirements.

In addition to the reporting requirements of §98.3(c), you must report the information specified in paragraphs (a) through (q) of this section.

(a) For combustion sources, follow the data reporting requirements under subpart C of this part (General Stationary Fuel Combustion Sources).

(b) For hydrogen plants, follow the data reporting requirements under subpart P of this part (Hydrogen Production).

(c)–(d) [Reserved]

(e) For flares, owners and operators shall report:

(1) The flare ID number (if applicable).

(2) A description of the type of flare (steam assisted, air-assisted).

(3) A description of the flare service (general facility flare, unit flare, emergency only or back-up flare).

(4) The calculated CO₂, CH₄, and N₂O annual emissions for each flare, expressed in metric tons of each pollutant emitted.

(5) A description of the method used to calculate the CO₂ emissions for each flare (e.g., reference section and equation number).

(6) If you use Equation Y–1a of this subpart, an indication of whether daily or weekly measurement periods are used, the annual volume of flare gas combusted (in scf/year) and the annual average molecular weight (in kg/kg-mole), the molar volume conversion factor (in scf/kg-mole), and annual average carbon content of the flare gas (in kg carbon per kg flare gas).

(7) If you use Equation Y–1b of this subpart, an indication of whether daily or weekly measurement periods are used, the annual volume of flare gas combusted (in scf/year), the molar volume conversion factor (in scf/kg-mole), the annual average CO₂ concentration (volume or mole percent), the number of carbon containing compounds other than CO₂ in the flare gas stream, and for each of the carbon containing compounds other than CO₂ in the flare gas stream:

(i) The annual average concentration of the compound (volume or mole percent).

(ii) The carbon mole number of the compound (moles carbon per mole compound).

(8) If you use Equation Y–2 of this subpart, an indication of whether daily or weekly measurement periods are used, the annual volume of flare gas...
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combusted (in million (MM) scf/year), the annual average higher heating value of the flare gas (in mmBtu/mmscf), and an indication of whether the annual volume of flare gas combusted and the annual average higher heating value of the flare gas were determined using standard conditions of 68 °F and 14.7 psia or 60 °F and 14.7 psia.

(9) If you use Equation Y–3 of this subpart, the annual volume of flare gas combusted (in MMscf/year) during normal operations, the annual average higher heating value of the flare gas (in mmBtu/mmscf), the number of SSM events exceeding 500,000 scf/day, the volume of gas flared (in scf/event), the average molecular weight (in kg/kg-mole), the molar volume conversion factor (in scf/kg-mole), and carbon content of the flare gas (in kg carbon per kg flare) for each SSM event over 500,000 scf/day.

(10) The fraction of carbon in the flare gas contributed by methane used in Equation Y–4 of this subpart and the basis for its value.

(f) For catalytic cracking units, traditional fluid coking units, and catalytic reforming units, owners and operators shall report:

(1) The unit ID number (if applicable).

(2) A description of the type of unit (fluid catalytic cracking unit, thermal catalytic cracking unit, traditional fluid coking unit, or catalytic reforming unit).

(3) Maximum rated throughput of the unit, in bbl/stream day.

(4) The calculated CO$_2$, CH$_4$, and N$_2$O annual emissions for each unit, expressed in metric tons of each pollutant emitted.

(5) A description of the method used to calculate the CO$_2$ emissions for each unit (e.g., reference section and equation number).

(6) If you use a CEMS, the relevant information required under §98.36 for the Tier 4 Calculation Methodology, the CO$_2$ annual emissions as measured by the CEMS (unadjusted to remove CO$_2$ combustion emissions associated with additional units, if present) and the process CO$_2$ emissions as calculated according to §98.253(c)(1)(ii). Report the CO$_2$ annual emissions associated with sources other than those from the coke burn-off in the applicable subpart (e.g., subpart C of this part in the case of a CO boiler).

(7) If you use Equation Y–6 of this subpart, the annual average exhaust gas flow rate, %CO$_2$, %CO, and the molar volume conversion factor (in scf/kg-mole).

(8) If you use Equation Y–7a of this subpart, the annual average flow rate of inlet air and oxygen-enriched air, %O$_2$, %O$_{oxy}$, %CO$_2$, and %CO.

(9) If you use Equation Y–7b of this subpart, the annual average flow rate of inlet air and oxygen-enriched air, %N$_2$, and %N$_{exhaust}$.

(10) If you use Equation Y–8 of this subpart, the coke burn-off factor, annual throughput of unit, and the average carbon content of coke and the basis for the value.

(11) Indicate whether you use a measured value, a unit-specific emission factor, or a default emission factor for CH$_4$ emissions. If you use a unit-specific emission factor for CH$_4$, report the unit-specific emission factor for CH$_4$, the units of measure for the unit-specific factor, the activity data for calculating emissions (e.g., if the emission factor is based on coke burn-off rate, the annual quantity of coke burned), and the basis for the factor.

(12) Indicate whether you use a measured value, a unit-specific emission factor, or a default emission factor for N$_2$O emissions. If you use a unit-specific emission factor for N$_2$O, report the unit-specific emission factor for N$_2$O, the units of measure for the unit-specific factor, the activity data for calculating emissions (e.g., if the emission factor is based on coke burn-off rate, the annual quantity of coke burned), and the basis for the factor.

(13) If you use Equation Y–11 of this subpart, the number of regeneration cycles or measurement periods during the reporting year, the average coke burn-off quantity per cycle or measurement period, and the average carbon content of the coke.

(g) For fluid coking unit of the flexicoking type, the owner or operator shall report:

(1) The unit ID number (if applicable).

(2) A description of the type of unit.
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(3) Maximum rated throughput of the unit, in bbl/stream day.

(4) Indicate whether the GHG emissions from the low heat value gas are accounted for in subpart C of this part or § 98.253(c).

(5) If the GHG emissions for the low heat value gas are calculated at the flexicoking unit, also report the calculated annual CO₂, CH₄, and N₂O emissions for each unit, expressed in metric tons of each pollutant emitted, and the applicable equation input parameters specified in paragraphs (f)(7) through (f)(13) of this section.

(h) For sulfur recovery plants and for emissions from sour gas sent off-site for sulfur recovery, the owner and operator shall report:

(1) The plant ID number (if applicable).

(2) Maximum rated throughput of each independent sulfur recovery plant, in metric tons sulfur produced/stream day, a description of the type of sulfur recovery plant, and an indication of the method used to calculate CO₂ annual emissions for the sulfur recovery plant (e.g., CO₂ CEMS, Equation Y–12, or process vent method in § 98.253(j)).

(3) The calculated CO₂ annual emissions for each sulfur recovery plant, expressed in metric tons sulfur sent off-site for sulfur recovery, expressed in metric tons.

(4) If you use Equation Y–12 of this subpart, the annual volumetric flow to the sulfur recovery plant (in scf/year), the molar volume conversion factor (in scf/kg-mole), and the annual average mole fraction of carbon in the sour gas (in kg-mole C/kg-mole gas).

(5) If you recycle tail gas to the front of the sulfur recovery plant, indicate whether the recycled flow rate and carbon content are included in the measured data under § 98.253(f)(2) and (3). Indicate whether a correction for CO₂ emissions in the tail gas was used in Equation Y–12. If so, then report the value of the correction, the annual volume of recycled tail gas (in scf/year) and the annual average mole fraction of carbon in the tail gas (in kg-mole C/kg-mole gas). Indicate whether you used the default (95%) or a unit specific correction, and if used, report the approach used.

(6) If you use a CEMS, the relevant information required under § 98.36 for the Tier 4 Calculation Methodology, the CO₂ annual emissions as measured by the CEMS and the annual process CO₂ emissions calculated according to § 98.253(f)(1). Report the CO₂ annual emissions associated with fuel combustion subpart C of this part (General Stationary Fuel Combustion Sources).

(7) If you use the process vent method in § 98.253(j) for a non-Claus sulfur recovery plant, the relevant information required under paragraph (l)(5) of this section.

(i) For coke calcining units, the owner and operator shall report:

(1) The unit ID number (if applicable).

(2) Maximum rated throughput of the unit, in metric tons coke calcined/stream day.

(3) The calculated CO₂, CH₄, and N₂O annual emissions for each unit, expressed in metric tons of each pollutant emitted.

(4) A description of the method used to calculate the CO₂ emissions for each unit (e.g., reference section and equation number).

(5) If you use Equation Y–13 of this subpart, annual mass and carbon content of green coke fed to the unit, the annual mass and carbon content of marketable coke produced, the annual mass of coke dust removed from the process through dust collection systems, and an indication of whether coke dust is recycled to the unit (e.g., all dust is recycled, a portion of the dust is recycled, or none of the dust is recycled).

(6) If you use a CEMS, the relevant information required under § 98.36 for the Tier 4 Calculation Methodology, the CO₂ annual emissions as measured by the CEMS and the annual process CO₂ emissions calculated according to § 98.253(g)(1).

(7) Indicate whether you use a measured value, a unit-specific emission factor or a default for CH₄ emissions. If you use a unit-specific emission factor for CH₄, the unit-specific emission factor for CH₄, the units of measure for the unit-specific factor, the activity data for calculating emissions (e.g., if the emission factor is based on coke burn-off rate, the annual quantity of
(8) Indicate whether you use a measured value, a unit-specific emission factor, or a default emission factor for \( \text{N}_2\text{O} \) emissions. If you use a unit-specific emission factor for \( \text{N}_2\text{O} \), report the unit-specific emission factor for \( \text{N}_2\text{O} \), the units of measure for the unit-specific factor, the activity data for calculating emissions (e.g., if the emission factor is based on coke burn-off rate, the annual quantity of coke burned), and the basis for the factor.

(j) For asphalt blowing operations, the owner or operator shall report:

1. The unit ID number (if applicable).
2. The quantity of asphalt blown (in million bbl) at the unit in the reporting year.
3. The type of control device used to reduce methane (and other organic) emissions from the unit.
4. The calculated annual \( \text{CO}_2 \) and \( \text{CH}_4 \) emissions for each unit, expressed in metric tons of each pollutant emitted.
5. If you use Equation Y–14 of this subpart, the \( \text{CO}_2 \) emission factor used and the basis for the value.
6. If you use Equation Y–15 of this subpart, the \( \text{CH}_4 \) emission factor used and the basis for the value.
7. If you use Equation Y–16 of this subpart, the carbon emission factor used and the basis for the value.
8. If you use Equation Y–16b of this subpart, the \( \text{CO}_2 \) emission factor used and the basis for its value and the carbon emission factor used and the basis for its value.
9. If you use Equation Y–17 of this subpart, the \( \text{CH}_4 \) emission factor used and the basis for the value.

(k) For delayed coking units, the owner or operator shall report:

1. The cumulative annual \( \text{CH}_4 \) emissions (in metric tons of \( \text{CH}_4 \)) for all delayed coking units at the facility.
2. A description of the method used to calculate the \( \text{CH}_4 \) emissions for each unit (e.g., reference section and equation number).
3. The total number of delayed coking units at the facility, the total number of delayed coking drums at the facility, and for each coke drum or vessel: The dimensions, the typical gauge pressure of the coking drum when first vented to the atmosphere, typical void fraction, the typical drum outage (i.e., the unfilled distance from the top of the drum, in feet), the molar volume conversion factor (in scf/kg-mole), and annual number of coke-cutting cycles.

(l) For each set of coking drums that are the same dimensions: The number of coking drums in the set, the height and diameter of the coke drums (in feet), the cumulative number of vessel openings for all delayed coking drums in the set, the typical venting pressure (in psig), void fraction (in cf gas/cf of vessel), and the mole fraction of methane in coking gas (in kg-mole CF\(_4\)/kg-mole gas, wet basis).

(m) The basis for the volumetric void fraction of the coke vessel prior to steaming and the basis for the mole fraction of methane in the coking gas.

1. For each process vent subject to §98.253(j), the owner or operator shall report:
   1. The vent ID number (if applicable).
   2. The unit or operation associated with the emissions.
   3. The type of control device used to reduce methane (and other organic) emissions from the unit, if applicable.
   4. The calculated annual \( \text{CO}_2 \), \( \text{CH}_4 \), and \( \text{N}_2\text{O} \) emissions for each vent, expressed in metric tons of each pollutant emitted.
   5. The annual volumetric flow discharged to the atmosphere (in scf), and an indication of the measurement or estimation method, annual average mole fraction of each GHG above the concentration threshold or otherwise required to be reported and an indication of the measurement or estimation method, the molar volume conversion factor (in scf/kg-mole), and for intermittent vents, the number of venting events and the cumulative venting time.

   (m) For uncontrolled blowdown systems, the owner or operator shall report:
   1. An indication of whether the uncontrolled blowdown emission are reported under §98.253(k) or §98.253(j) or a statement that the facility does not have any uncontrolled blowdown systems.
(2) The cumulative annual CH₄ emissions (in metric tons of CH₄) for uncontrolled blowdown systems.

(3) For uncontrolled blowdown systems reporting under §98.253(k), the total quantity (in million bbl) of crude oil plus the quantity of intermediate products received from off site that are processed at the facility in the reporting year, the methane emission factor used for uncontrolled blowdown systems, the basis for the value, and the molar volume conversion factor (in scf/kg-mole).

(4) For uncontrolled blowdown systems reporting under §98.253(j), the relevant information required under paragraph (l)(5) of this section.

(n) For equipment leaks, the owner or operator shall report:
   (1) The cumulative CH₄ emissions (in metric tons of each pollutant emitted) for all equipment leak sources.
   (2) The method used to calculate the reported equipment leak emissions.
   (3) The number of each type of emission source listed in Equation Y–21 of this subpart at the facility.

(o) For storage tanks, the owner or operator shall report:
   (1) The cumulative annual CH₄ emissions (in metric tons of CH₄) for all storage tanks, except for those used to process unstabilized crude oil.
   (2) For storage tanks other than those processing unstabilized crude oil:
      (i) The method used to calculate the reported storage tank emissions for storage tanks other than those processing unstabilized crude (i.e., either AP 42, Section 7.1 (incorporated by reference, see §98.7), or Equation Y–22 of this section).
      (ii) The total quantity (in MMbbl) of crude oil plus the quantity of intermediate products received from off site that are processed at the facility in the reporting year.
   (3) The cumulative CH₄ emissions (in metric tons of CH₄) for storage tanks used to process unstabilized crude oil or a statement that the facility did not receive any unstabilized crude oil during the reporting year.
   (4) For storage tanks that process unstabilized crude oil:
      (i) The method used to calculate the reported unstabilized crude oil storage tank emissions.
      (ii) The quantity of unstabilized crude oil received during the calendar year (in MMbbl).
      (iii) The average pressure differential (in psi).
      (iv) The molar volume conversion factor (in scf/kg-mole).
      (v) The average mole fraction of CH₄ in vent gas from unstabilized crude oil storage tanks and the basis for the mole fraction.
      (vi) If you did not use Equation Y–23, the tank-specific methane composition data and the gas generation rate data used to estimate the cumulative CH₄ emissions for storage tanks used to process unstabilized crude oil.

(5) The method used to calculate the reported storage tank emissions for storage tanks processing unstabilized crude oil.

(6) The quantity of unstabilized crude oil received during the calendar year (in MMbbl), the average pressure differential (in psi), and the mole fraction of CH₄ in vent gas from the unstabilized crude oil storage tank, and the basis for the mole fraction.

(7) The tank-specific methane composition data and the gas generation rate data, if you did not use Equation Y–23.

(p) For loading operations, the owner or operator shall report:
   (1) The cumulative annual CH₄ emissions (in metric tons of each pollutant emitted) for loading operations.
   (2) The quantity and types of materials loaded by vessel type (barge, tanker, marine vessel, etc.) that have an equilibrium vapor-phase concentration of methane of 0.5 volume percent or greater, and the type of vessels in which the material is loaded.
   (3) The type of control system used to reduce emissions from the loading of material with an equilibrium vapor-phase concentration of methane of 0.5 volume percent or greater, and the type of vessels in which the material is loaded.

(q) Name of each method listed in §98.254 or a description of manufacturer’s recommended method used to determine a measured parameter.

§ 98.263 Calculating GHG emissions.

You must calculate and report the annual process CO₂ emissions from each wet-process phosphoric acid process line using the procedures in either paragraph (a) or (b) of this section.

(a) Calculate and report under this subpart the process CO₂ emissions by operating and maintaining a CEMS according to the Tier 4 Calculation Methodology specified in §98.33(a)(4) and all associated requirements for Tier 4 in subpart C of this part (General Stationary Fuel Combustion Sources).

(b) Calculate and report under this subpart the process CO₂ emissions using the procedures in paragraphs (b)(1) and (b)(2) of this section.

(i) Calculate the annual CO₂ mass emissions from each wet-process phosphoric acid process line using the methods in paragraphs (b)(1)(i) or (ii) of this section, as applicable.

(ii) If your process measurement provides the inorganic carbon content of phosphate rock as an output, calculate and report the process CO₂ emissions from each wet-process phosphoric acid process line using Equation Z–1a of this section:

\[
E_m = \sum_{i=1}^{b} \sum_{n=1}^{z} (IC_{n,i} \times P_{n,i}) \times \frac{2000 \times 44}{2205 \times 12}
\]  

(Eq. Z–1a)

where:

- \(E_m\) = Annual CO₂ mass emissions from a wet-process phosphoric acid process line \(m\) according to this Equation Z–1a (metric tons).
- \(IC_{n,i}\) = Inorganic carbon content of a grab sample batch of phosphate rock by origin \(i\) obtained during month \(n\), from the carbon analysis results (percent by weight, expressed as a decimal fraction).
- \(P_{n,i}\) = Mass of phosphate rock by origin \(i\) consumed in month \(n\) by wet-process phosphoric acid process line \(m\) (tons).
§ 98.264 Monitoring and QA/QC requirements.

(a) You must obtain a monthly grab sample of phosphate rock directly from the rock being fed to the process line before it enters the mill using one of the following methods. You may conduct the representative bulk sampling using a method published by a consensus standards organization, or you may use industry consensus standard practice methods, including but not limited to the Phosphate Mining States Methods Used and Adopted by the Association of Fertilizer and Phosphate Chemists (AFPC) (P.O. Box 1645, Bartow, Florida 33831, (863) 534–9755, http://afpc.net, paul.mcafee@mosaicco.com). If phosphate rock is obtained from more than one origin in a month, you must obtain a sample from each origin of rock or obtain a composite representative sample.

(c) If GHG emissions from a wet-process phosphoric acid process line are vented through the same stack as any combustion unit or process equipment that reports CO₂ emissions using a CEMS that complies with the Tier 4 Calculation Methodology in subpart C of this part (General Stationary Fuel Combustion Sources), then the calculation methodology in paragraph (b) of this section shall not be used to calculate process emissions. The owner or operator shall report under this subpart the combined stack emissions according to the Tier 4 Calculation Methodology in §98.33(a)(4) and all associated requirements for Tier 4 in subpart C of this part.

(ii) If your process measurement provides the CO₂ emissions directly as an output, calculate and report the process CO₂ emissions from each wet-process phosphoric acid process line using Equation Z–1b of this section:

\[ E_m = \sum_{i=1}^{b} \sum_{n=1}^{z} \left( CO_{2n,i} \ast P_{n,i} \right) \ast \frac{2000}{2205} \]  
(Eq. Z-1b)

where:
- \( E_m \) = Annual CO₂ mass emissions from a wet-process phosphoric acid process line m according to this Equation Z-1b (metric tons).
- \( CO_{2n,i} \) = Carbon dioxide emissions of a grab sample batch of phosphate rock by origin i obtained during month n (percent by weight, expressed as a decimal fraction).
- \( P_{n,i} \) = Mass of phosphate rock by origin i consumed in month n by wet-process phosphoric acid process line m (tons).
- \( z \) = Number of months during which the process line m operates.
- \( b \) = Number of different types of phosphate rock in month, by origin. If the grab sample is a composite sample of rock from more than one origin, \( b=1 \).
- 2000/2205 = Conversion factor to convert tons to metric tons.

\( \frac{44}{12} = \) Ratio of molecular weights, CO₂ to carbon.

(2) You must determine the total emissions from the facility using Equation Z-2 of this section:

\( CO_2 = \sum_{m=1}^{p} E_m \)  
(Eq. Z-2)

Where:
- \( CO_2 \) = Annual process CO₂ emissions from phosphoric acid production facility (metric tons/year).
- \( E_m \) = Annual process CO₂ emissions from wet-process phosphoric acid process line m (metric tons/year).
- \( p \) = Number of wet-process phosphoric acid process lines.

(b) You must determine the carbon dioxide or inorganic carbon content of each monthly grab sample of phosphate rock (consumed in the production of
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phosphoric acid). You may use a method published by a consensus standards organization, or you may use industry consensus standard practice methods, including but not limited to the Phosphate Mining States Methods Used and Adopted by AFPC (P.O. Box 1645, Bartow, Florida 33831, (863) 534–9755, http://afpc.net, paul.mcafee@mosaicco.com).

(c) You must determine the mass of phosphate rock consumed each month (by origin) in each wet-process phosphoric acid process line. You can use existing plant procedures that are used for accounting purposes (such as sales records) or you can use data from existing monitoring equipment that is used to measure total mass flow of phosphorous-bearing feed under 40 CFR part 60 or part 63.


§ 98.265 Procedures for estimating missing data.

(a) For each missing value of the inorganic carbon content of phosphate rock or carbon dioxide (by origin), you must use the appropriate default factor provided in Table Z–1 this subpart. Alternatively, you must determine a substitute data value by calculating the arithmetic average of the quality-assured values of inorganic carbon contents of phosphate rock of origin i from samples immediately preceding and immediately following the missing data incident. You must document and keep records of the procedures used for all such estimates.

(a) For each missing value of the inorganic carbon content of phosphate rock (by origin), you must use the appropriate default factor provided in Table Z–1 of this subpart. Alternatively, you must determine substitute data value by calculating the arithmetic average of the quality-assured values of inorganic carbon contents of phosphate rock of origin i (see Equation Z–1 of this subpart) from samples immediately preceding and immediately following the missing data incident. If no quality-assured data on inorganic carbon contents of phosphate rock of origin i are available prior to the missing data incident, the substitute data value shall be the first quality-assured value for inorganic carbon contents for phosphate rock of origin i obtained after the missing data period.

(b) For each missing value of monthly mass consumption of phosphate rock (by origin), you must use the best available estimate based on all available process data or data used for accounting purposes.


§ 98.266 Data reporting requirements.

In addition to the information required by §98.3(c), each annual report must contain the information specified in paragraphs (a) through (f) of this section.

(a) Annual phosphoric acid production by origin (as listed in Table Z–1 to this subpart) of the phosphate rock (tons).

(b) Annual phosphoric acid permitted production capacity (tons).

(c) Annual arithmetic average percent inorganic carbon or carbon dioxide in phosphate rock from monthly records (percent by weight, expressed as a decimal fraction).

(d) Annual phosphate rock consumption from monthly measurement records by origin, (as listed in Table Z–1 to this subpart) (tons).

(e) If you use a CEMS to measure CO₂ emissions, then you must report the information in paragraphs (e)(1) and (e)(2) of this section.

(1) The identification number of each wet-process phosphoric acid process line.

(2) The annual CO₂ emissions from each wet-process phosphoric acid process line (metric tons) and the relevant information required under 40 CFR 98.36 (e)(2)(vi) for the Tier 4 Calculation Methodology.

(f) If you do not use a CEMS to measure emissions, then you must report the information in paragraphs (f)(1) through (f)(9) of this section.

(1) Identification number of each wet-process phosphoric acid process line.

(2) Annual CO₂ emissions from each wet-process phosphoric acid process line (metric tons) as calculated by either Equation Z–1a or Equation Z–1b of this subpart.
(3) Annual phosphoric acid permitted production capacity (tons) for each wet-process phosphoric acid process line (metric tons).

(4) Method used to estimate any missing values of inorganic carbon content or carbon dioxide content of phosphate rock for each wet-process phosphoric acid process line.

(5) Monthly inorganic carbon content of phosphate rock for each wet-process phosphoric acid process line for which Equation Z–1a is used (percent by weight, expressed as a decimal fraction), or CO₂ (percent by weight, expressed as a decimal fraction) for which Equation Z–1b is used.

(6) Monthly mass of phosphate rock consumed by origin, (as listed in Table Z–1 of this subpart) in production for each wet-process phosphoric acid process lines.

(7) Number of wet-process phosphoric acid process lines.

(8) Number of times missing data procedures were used to estimate phosphate rock consumption (months) and inorganic carbon contents of the phosphate rock (months).

(9) Annual process CO₂ emissions from phosphoric acid production facility (metric tons).


§ 98.267 Records that must be retained.

In addition to the records required by §98.3(g), you must retain the records specified in paragraphs (a) through (c) of this section for each wet-process phosphoric acid production facility.

(a) Monthly mass of phosphate rock consumed by origin (as listed in Table Z–1 of this subpart) (tons).

(b) Records of all phosphate rock purchases and/or deliveries (if vertically integrated with a mine).

(c) Documentation of the procedures used to ensure the accuracy of monthly phosphate rock consumption by origin, (as listed in Table Z–1 of this subpart).

§ 98.268 Definitions.

All terms used in this subpart have the same meaning given in the Clean Air Act and subpart A of this part.

Table Z–1 to Subpart Z of Part 98—Default Chemical Composition of Phosphate Rock by Origin

<table>
<thead>
<tr>
<th>Origin</th>
<th>Total carbon (percent by weight)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Central Florida</td>
<td>1.6</td>
</tr>
<tr>
<td>North Florida</td>
<td>1.76</td>
</tr>
<tr>
<td>North Carolina (Calcined)</td>
<td>0.76</td>
</tr>
<tr>
<td>Idaho (Calcined)</td>
<td>0.60</td>
</tr>
<tr>
<td>Morocco</td>
<td>1.56</td>
</tr>
</tbody>
</table>

Subpart AA—Pulp and Paper Manufacturing

§ 98.270 Definition of source category.

(a) The pulp and paper manufacturing source category consists of facilities that produce market pulp (i.e., stand-alone pulp facilities), manufacture pulp and paper (i.e., integrated facilities), produce paper products from purchased pulp, produce secondary fiber from recycled paper, convert paper into paperboard products (e.g., containers), or operate coating and laminating processes.

(b) The emission units for which GHG emissions must be reported are listed in paragraphs (b)(1) through (b)(5) of this section:

(1) Chemical recovery furnaces at kraft and soda mills (including recovery furnaces that burn spent pulping liquor produced by both the kraft and semichemical process).

(2) Chemical recovery combustion units at sulfite facilities.

(3) Chemical recovery combustion units at stand-alone semichemical facilities.

(4) Pulp mill lime kilns at kraft and soda facilities.

(5) Systems for adding makeup chemicals (CaCO₃, Na₂CO₃) in the chemical recovery areas of chemical pulp mills.

§ 98.271 Reporting threshold.

You must report GHG emissions under this subpart if your facility contains a pulp and paper manufacturing process and the facility meets the requirements of either §98.2(a)(1) or (a)(2).
§ 98.272 GHGs to report.

You must report the emissions listed in paragraphs (a) through (f) of this section:

(a) CO₂, biogenic CO₂, CH₄, and N₂O emissions from each kraft or soda chemical recovery furnace.

(b) CO₂, biogenic CO₂, CH₄, and N₂O emissions from each sulfite chemical recovery combustion unit.

(c) CO₂, biogenic CO₂, CH₄, and N₂O emissions from each stand-alone semichemical chemical recovery furnace.

(d) CO₂, biogenic CO₂, CH₄, and N₂O emissions from each kraft or soda pulp mill lime kiln.

(e) CO₂ emissions from addition of makeup chemicals (CaCO₃, Na₂CO₃) in the chemical recovery areas of chemical pulp mills.

(f) CO₂, CH₄, and N₂O combustion emissions from each stationary combustion unit. You must calculate and report these emissions under subpart C of this part (General Stationary Fuel Combustion Sources) by following the requirements of subpart C.

§ 98.273 Calculating GHG emissions.

(a) For each chemical recovery furnace located at a kraft or soda facility, you must determine CO₂, biogenic CO₂, CH₄, and N₂O emissions using the procedures in paragraphs (a)(1) through (a)(3) of this section. CH₄ and N₂O emissions must be calculated as the sum of emissions from combustion of fossil fuels and combustion of biomass in spent liquor solids.

(b) For each chemical recovery unit located at a sulfite or stand-alone semichemical facility, you must determine CO₂, CH₄, and N₂O emissions from direct measurement of fossil fuels consumed, default or site-specific HHV, and default emissions factors according to the Tier 1 methodology for stationary combustion sources in §98.33(a)(1). A higher tier from §98.33(a) may be used to calculate fossil fuel-based CO₂ emissions if the respective monitoring and QA/QC requirements described in §98.34 are met.

(c) For each chemical recovery unit located at a sulfite or stand-alone semichemical facility, you must determine CH₄ and N₂O emissions from direct measurement of fossil fuels consumed, default or site-specific HHV, and default or site-specific emissions factors, according to Equation AA–1 of this section:

\[
CO₂, CH₄, \text{ or } N₂O \text{ from biomass} = (0.90718) \times \text{Solids} \times \text{HHV} \times EF \quad \text{(Eq. AA–1)}
\]

Where:

- CO₂, CH₄, or N₂O from Biomass = Biogenic CO₂ emissions or emissions of CH₄ or N₂O from spent liquor solids combustion (metric tons per year).
- Solids = Mass of spent liquor solids combusted (short tons per year) determined according to §98.274(b).
- HHV = Annual high heat value of the spent liquor solids (mmBtu per kilogram) determined according to §98.274(b).
- (EF) = Default or site-specific emission factor for CO₂, CH₄, or N₂O, from Table AA–1 of this subpart (kg CO₂, CH₄, or N₂O per mmBtu).
- 0.90718 = Conversion factor from short tons to metric tons.

(b) For each chemical recovery combustion unit located at a sulfite or stand-alone semichemical facility, you must determine CO₂, CH₄, and N₂O emissions using the procedures in paragraphs (b)(1) through (b)(4) of this section:

(1) Calculate fossil CO₂ emissions from fossil fuels from direct measurement of fossil fuels consumed, and default emissions factors according to the Tier 1 Calculation Methodology for stationary combustion sources in §98.33(a)(1). A higher tier from §98.33(a) may be used to calculate fossil fuel-based CO₂ emissions if the respective monitoring and QA/QC requirements described in §98.34 are met.

(2) Calculate fossil fuel-based CH₄ and N₂O emissions from direct measurement of fossil fuels consumed, default or site-specific HHV, and default emissions factors and convert to metric tons of CO₂ equivalent according to the methodology for stationary combustion sources in §98.33(c).

(3) Calculate biogenic CO₂ emissions and emissions of CH₄ and N₂O from biomass using measured quantities of spent liquor solids fired, site-specific HHV, and default or site-specific emissions factors, according to Equation AA–1 of this section.
(3) Calculate biogenic CO$_2$ emissions using measured quantities of spent liquor solids fired and the carbon content of the spent liquor solids, according to Equation AA-2 of this section:

$$Biogenic \ CO_2 = \frac{44}{12} \times \text{Solids} \times CC \times (0.90718) \quad (\text{Eq. AA-2})$$

Where:

- Biogenic CO$_2$ = Annual CO$_2$ mass emissions for spent liquor solids combustion (metric tons per year).
- Solids = Mass of the spent liquor solids combusted (short tons per year) determined according to §98.274(b).
- CC = Annual carbon content of the spent liquor solids, determined according to §98.274(b) (percent by weight, expressed as a decimal fraction, e.g., 95% = 0.95).
- $\frac{44}{12}$ = Ratio of molecular weights, CO$_2$ to carbon.
- 0.90718 = Conversion from short tons to metric tons.

(4) Calculate CH$_4$ and N$_2$O emissions from biomass using Equation AA-1 of this section and the default CH$_4$ and N$_2$O emissions factors for kraft facilities in Table AA–1 of this subpart and convert the CH$_4$ or N$_2$O emissions to metric tons of CO$_2$ equivalent by multiplying each annual CH$_4$ and N$_2$O emissions total by the appropriate global warming potential (GWP) factor from Table A–1 of subpart A of this part.

(c) For each pulp mill lime kiln located at a kraft or soda facility, you must determine CO$_2$, CH$_4$, and N$_2$O emissions using the procedures in paragraphs (c)(1) through (c)(3) of this section:

(1) Calculate CO$_2$ emissions from fossil fuel from direct measurement of fossil fuels consumed and default HHV and default emissions factors, according to the Tier 1 Calculation Methodology for stationary combustion sources in §98.33(a)(1). A higher tier from §98.33(a) may be used to calculate fossil fuel-based CO$_2$ emissions if the respective monitoring and QA/QC requirements described in §98.34 are met.

(2) Calculate CH$_4$ and N$_2$O emissions from fossil fuel from direct measurement of fossil fuels consumed, default or site-specific HHV, and default emissions factors and convert to metric tons of CO$_2$ equivalent according to the methodology for stationary combustion sources in §98.33(c); use the default HHV listed in Table C–1 of subpart C and the default CH$_4$ and N$_2$O emissions factors listed in Table AA–2 of this subpart.

(3) Biogenic CO$_2$ emissions from conversion of CaCO$_3$ to CaO are included in the biogenic CO$_2$ estimates calculated for the chemical recovery furnace in paragraph (a)(3) of this section.

(d) For makeup chemical use, you must calculate CO$_2$ emissions by using direct or indirect measurement of the quantity of chemicals added and ratios of the molecular weights of CO$_2$ and the makeup chemicals, according to Equation AA-3 of this section:

$$CO_2 = M_{(CaCO_3)} \times \frac{44}{100} + M_{(Na_2CO_3)} \times \frac{44}{105.99} \times 1000 \text{ kg/metric ton} \quad (\text{Eq. AA-3})$$

Where:

- CO$_2$ = CO$_2$ mass emissions from makeup chemicals (kilograms/yr).
- $M_{(CaCO_3)}$ = Make-up quantity of CaCO$_3$ used for the reporting year (metric tons per year).
- $M_{(Na_2CO_3)}$ = Make-up quantity of Na$_2$CO$_3$ used for the reporting year (metric tons per year).
- 44 = Molecular weight of CO$_2$.
- 100 = Molecular weight of CaCO$_3$.
- 105.99 = Molecular weight of Na$_2$CO$_3$. 856
§ 98.275 Monitoring and QA/QC requirements.
(a) Each facility subject to this subpart must quality assure the GHG emissions data according to the applicable requirements in §98.34. All QA/QC data must be available for inspection upon request.
(b) Fuel properties needed to perform the calculations in Equations AA–1 and AA–2 of this subpart must be determined according to paragraphs (b)(1) through (b)(3) of this section.
(1) High heat values of black liquor must be determined no less than annually using T684 om–06 Gross Heating Value of Black Liquor, TAPPI (incorporated by reference, see §98.7). If measurements are performed more frequently than annually, then the high heat value used in Equation AA–1 of this subpart must be based on the average of the representative measurements made during the year.
(2) The annual mass of spent liquor solids must be determined using either of the methods specified in paragraph (b)(2)(i) or (b)(2)(ii) of this section.
   (i) Measure the mass of spent liquor solids annually (or more frequently) using T–650 om–05 Solids Content of Black Liquor, TAPPI (incorporated by reference in §98.7). If measurements are performed more frequently than annually, then the mass of spent liquor solids used in Equation AA–1 of this subpart must be based on the average of the representative measurements made during the year.
   (ii) Determine the annual mass of spent liquor solids based on records of measurements made with an online measurement system that determines the mass of spent liquor solids fired in a chemical recovery furnace or chemical recovery combustion unit.
(3) Carbon analyses for spent pulping liquor must be determined no less than annually using ASTM D5373–08 Standard Test Methods for Instrumental Determination of Carbon, Hydrogen, and Nitrogen in Laboratory Samples of Coal (incorporated by reference, see §98.7). If measurements using ASTM D5373–08 are performed more frequently than annually, then the spent pulping liquor carbon content used in Equation AA–2 of this subpart must be based on the average of the representative measurements made during the year.
(c) Each facility must keep records that include a detailed explanation of how company records of measurements are used to estimate GHG emissions. The owner or operator must also document the procedures used to ensure the accuracy of the measurements of fuel, spent liquor solids, and makeup chemical usage, including, but not limited to calibration of weighing equipment, fuel flow meters, and other measurement devices. The estimated accuracy of measurements made with these devices must be recorded and the technical basis for these estimates must be provided. The procedures used to convert spent pulping liquor flow rates to units of mass (i.e., spent liquor solids firing rates) also must be documented.
(d) Records must be made available upon request for verification of the calculations and measurements.

§ 98.275 Procedures for estimating missing data.
A complete record of all measured parameters used in the GHG emissions calculations is required. Therefore, whenever a quality-assured value of a required parameter is unavailable (e.g., if a meter malfunctions during unit operation or if a required sample is not taken), a substitute data value for the missing parameter shall be used in the calculations, according to the requirements of paragraphs (a) through (c) of this section:
(a) There are no missing data procedures for measurements of heat content and carbon content of spent pulping liquor. A re-test must be performed if the data from any annual measurements are determined to be invalid.
(b) For missing measurements of the mass of spent liquor solids or spent pulping liquor flow rates, use the lesser value of either the maximum mass or fuel flow rate for the combustion unit, or the maximum mass or flow rate that the fuel meter can measure.
(c) For the use of makeup chemicals (carbonates), the substitute data value shall be the best available estimate of
makeup chemical consumption, based on available data (e.g., past accounting records, production rates). The owner or operator shall document and keep records of the procedures used for all such estimates.

§ 98.276 Data reporting requirements.

In addition to the information required by §98.3(c) and the applicable information required by §98.36, each annual report must contain the information in paragraphs (a) through (k) of this section as applicable:

(a) Annual emissions of CO₂, biogenic CO₂, CH₄, biogenic CH₄, N₂O, and biogenic N₂O (metric tons per year).

(b) Annual quantities fossil fuels by type used in chemical recovery furnaces and chemical recovery combustion units in short tons for solid fuels, gallons for liquid fuels and scf for gaseous fuels.

(c) Annual mass of the spent liquor solids combusted (short tons per year), and basis for determining the annual mass of the spent liquor solids combusted (whether based on T650 om–05 Solids Content of Black Liquor, TAPPI (incorporated by reference, see §98.7) or an online measurement system).

(d) The high heat value (HHV) of the spent liquor solids used in Equation AA–1 of this subpart (mmBtu per kilogram).

(e) The default or site-specific emission factor for CO₂, CH₄, or N₂O, used in Equation AA–1 of this subpart (kg CO₂, CH₄, or N₂O per mmBtu).

(f) The carbon content (CC) of the spent liquor solids, used in Equation AA–2 of this subpart (percent by weight, expressed as a decimal fraction, e.g., 95% = 0.95).

(g) Annual quantities of fossil fuels by type used in pulp mill lime kilns in short tons for solid fuels, gallons for liquid fuels and scf for gaseous fuels.

(h) Make-up quantity of CaCO₃ used for the reporting year (metric tons per year) used in Equation AA–3 of this subpart.

(i) Make-up quantity of Na₂CO₃ used for the reporting year (metric tons per year) used in Equation AA–3 of this subpart.

(j) Annual quantity of makeup chemicals used.

(k) Annual steam purchases (pounds of steam per year).

(l) Annual production of pulp and/or paper products produced (metric tons).


§ 98.277 Records that must be retained.

In addition to the information required by §98.3(g), you must retain the records in paragraphs (a) through (f) of this section.

(a) GHG emission estimates (including separate estimates of biogenic CO₂) for each emissions source listed under §98.270(b).

(b) Annual analyses of spent pulping liquor HHV for each chemical recovery furnace at kraft and soda facilities.

(c) Annual analyses of spent pulping liquor carbon content for each chemical recovery combustion unit at a sulfate or semichemical pulp facility.

(d) Annual quantity of spent liquor solids combusted in each chemical recovery furnace and chemical recovery combustion unit, and the basis for determining the annual quantity of spent liquor solids combusted (whether based on T650 om–05 Solids Content of Black Liquor, TAPPI (incorporated by reference, see §98.7) or an online measurement system). If an online measurement system is used, you must retain records of the calculations used to determine the annual quantity of spent liquor solids combusted from the continuous measurements.

(e) Annual steam purchases.

(f) Annual quantities of makeup chemicals used.

§ 98.278 Definitions.

All terms used in this subpart have the same meaning given in the Clean Air Act and subpart A of this part.
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Table AA–1 to Subpart AA of Part 98—Kraft Pulping Liquor Emissions Factors for Biomass-Based CO₂, CH₄, and N₂O

<table>
<thead>
<tr>
<th>Wood furnish</th>
<th>CO₂</th>
<th>CH₄</th>
<th>N₂O</th>
</tr>
</thead>
<tbody>
<tr>
<td>North American Softwood</td>
<td>94.4</td>
<td>0.030</td>
<td>0.005</td>
</tr>
<tr>
<td>North American Hardwood</td>
<td>93.7</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Bagasse</td>
<td>95.5</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Bamboo</td>
<td>93.7</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Straw</td>
<td>95.1</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

*a Includes emissions from both the recovery furnace and pulp mill lime kiln.

Table AA–2 to Subpart AA of Part 98—Kraft Lime Kiln and Calciner Emissions Factors for Fossil Fuel-Based CH₄ and N₂O

<table>
<thead>
<tr>
<th>Fuel</th>
<th>CH₄</th>
<th>N₂O</th>
<th>CH₄</th>
<th>N₂O</th>
</tr>
</thead>
<tbody>
<tr>
<td>Residual Oil</td>
<td></td>
<td></td>
<td></td>
<td>0.0003</td>
</tr>
<tr>
<td>Distillate Oil</td>
<td></td>
<td></td>
<td>0.0027</td>
<td>0.0004</td>
</tr>
<tr>
<td>Natural Gas</td>
<td></td>
<td></td>
<td></td>
<td>0.0001</td>
</tr>
<tr>
<td>Biogas</td>
<td></td>
<td></td>
<td></td>
<td>0.0001</td>
</tr>
<tr>
<td>Petroleum coke</td>
<td></td>
<td></td>
<td>NA</td>
<td>NA</td>
</tr>
</tbody>
</table>

*a Emission factors for kraft calciners are not available.

[75 FR 79166, Dec. 17, 2010]

Subpart BB—Silicon Carbide Production

§ 98.280 Definition of the source category.

Silicon carbide production includes any process that produces silicon carbide for abrasive purposes.

§ 98.281 Reporting threshold.

You must report GHG emissions under this subpart if your facility contains a silicon carbide production process and the facility meets the requirements of either § 98.2(a)(1) or (a)(2).

§ 98.282 GHGs to report.

You must report:

(a) CO₂ and CH₄ process emissions from all silicon carbide process units or furnaces combined.

(b) CO₂, CH₄, and N₂O emissions from each stationary combustion unit. You must report these emissions under subpart C of this part (General Stationary Fuel Combustion Sources) by following the requirements of subpart C.

§ 98.283 Calculating GHG emissions.

You must calculate and report the annual process CO₂ emissions from each silicon carbide process unit or production furnace using the procedures in either paragraph (a) or (b) of this section. You must determine CH₄ process emissions in accordance with the procedures specified in paragraph (d) of this section.

(a) Calculate and report under this subpart the process CO₂ emissions by operating and maintaining CEMS according to the Tier 4 Calculation Methodology specified in § 98.33(a)(4) and all associated requirements for Tier 4 in subpart C of this part (General Stationary Fuel Combustion Sources).

(b) Calculate and report under this subpart the process CO₂ emissions using the procedures in paragraphs (b)(1) and (b)(2) of this section.

(1) Use Equation BB–1 of this section to calculate the facility-specific emissions factor for determining CO₂ emissions. The carbon content must be measured monthly and used to calculate a monthly CO₂ emissions factor:
§ 98.284 Monitoring and QA/QC requirements.

(a) You must measure your consumption of petroleum coke using plant instruments used for accounting purposes including direct measurement weighing the petroleum coke fed into the furnaces or as measured by the applicable method incorporated by reference in §98.7 according to §98.284(c) (percent by weight expressed as a decimal fraction).

(b) Use Equation BB–2 of this section to calculate annual CO₂ process emissions from all silicone carbide production:

\[ \text{CO}_2 = \sum_{n=1}^{12} \left( T_n \times EF_{CO2,n} \right) \times \frac{2000}{2205} \]  
(Eq. BB-2)

Where:
- \( EF_{CO2,n} \) = \( CO_2 \) emissions factor in month \( n \) (metric tons \( CO_2 \)/metric ton of petroleum coke consumed).
- 0.65 = Adjustment factor for the amount of carbon in silicon carbide product (assuming 35 percent of carbon input is in the carbide product).
- \( CCF_n \) = Carbon content factor for petroleum coke consumed in month \( n \) from the supplier or as measured by the applicable method incorporated by reference in §98.7 (percent by weight expressed as a decimal fraction).
- \( 44/12 \) = Ratio of molecular weights, \( CO_2 \) to carbon.

(c) If GHG emissions from a silicon carbide production furnace or process unit are vented through the same stack as any combustion unit or process equipment that reports \( CO_2 \) emissions using a CEMS that complies with the Tier 4 Calculation Methodology in subpart C of this part (General Stationary Fuel Combustion Sources), then the calculation methodology in paragraph (b) of this section shall not be used to calculate process emissions. The owner or operator shall report under this subpart the combined stack emissions according to the Tier 4 Calculation Methodology in §98.33(a)(4) and all associated requirements for Tier 4 in subpart C of this part.

(d) You must calculate annual process \( CH_4 \) emissions from all silicon carbide production combined using Equation BB–3 of this section:

\[ CH_4 = \sum_{n=1}^{12} \left( T_n \times 10.2 \right) \times \frac{2000}{2205} \times 0.001 \]  
(Eq. BB-3)

Where:
- \( CH_4 \) = Annual \( CH_4 \) emissions from silicon carbide production facility (metric tons \( CH_4 \)).
- \( T_n \) = Petroleum coke consumption in month \( n \) (tons).
- 10.2 = \( CH_4 \) emissions factor (kg \( CH_4 \)/metric ton coke).
- \( 2000/2205 \) = Conversion factor to convert tons to metric tons.
- 0.001 = Conversion factor from kilograms to metric tons.

n = Number of month.
your process (by belt scales or a similar device) or through the use of purchase records.

(b) You must document the procedures used to ensure the accuracy of monthly petroleum coke consumption measurements.

(c) For CO₂ process emissions, you must determine the monthly carbon content of the petroleum coke using reports from the supplier. Alternatively, facilities can measure monthly carbon contents of the petroleum coke using ASTM D3176-89 (Reapproved 2002) Standard Practice for Ultimate Analysis of Coal and Coke (incorporated by reference, see §98.7) and ASTM D5373-08 Standard Test Methods for Instrumental Determination of Carbon, Hydrogen, and Nitrogen in Laboratory Samples of Coal (incorporated by reference, see §98.7).

(d) For quality assurance and quality control of the supplier data, you must conduct an annual measurement of the carbon content of the petroleum coke using ASTM D3176-89 and ASTM D5373-08 Standard Test Methods for Instrumental Determination of Carbon, Hydrogen, and Nitrogen in Laboratory Samples of Coal (incorporated by reference, see §98.7).

§98.286 Data reporting requirements.

In addition to the information required by §98.3(c), each annual report must contain the information specified in paragraphs (a) or (b) of this section, as applicable for each silicon carbide production facility.

(a) If a CEMS is used to measure process CO₂ emissions, you must report under this subpart the relevant information required for the Tier 4 Calculation Methodology in §98.36 and the information listed in this paragraph (a):

(1) Annual consumption of petroleum coke (tons).

(2) Annual production of silicon carbide (tons).

(3) Annual production capacity of silicon carbide (tons).

(4) CO₂ emissions factor calculated for each month (metric tons CO₂/metric ton of petroleum coke consumed).

(5) Sampling analysis results for carbon content of consumed petroleum coke as determined for QA/QC of supplier data under §98.284(d) (percent by weight expressed as a decimal fraction).

(b) If a CEMS is not used to measure process CO₂ emissions, you must report the information listed in this paragraph (b) for all furnaces combined:

(1) Monthly consumption of petroleum coke (tons).

(2) Annual production of silicon carbide (tons).

(3) Annual production capacity of silicon carbide (tons).

(4) Carbon content factor of petroleum coke from the supplier or as measured by the applicable method in §98.284(c) for each month (percent by weight expressed as a decimal fraction).

(5) Whether carbon content of the petroleum coke is based on reports from the supplier or through self measurement using applicable ASTM standard method.

(6) CO₂ emissions factor calculated for each month (metric tons CO₂/metric ton of petroleum coke consumed).

(7) Sampling analysis results for carbon content of consumed petroleum coke as determined for QA/QC of supplier data under §98.284(d) (percent by weight expressed as a decimal fraction).
§ 98.287 Records that must be retained.

In addition to the records required by §98.3(g), you must retain the records specified in paragraphs (a) and (b) of this section for each silicon carbide production facility.

(a) If a CEMS is used to measure CO₂ emissions, you must retain under this subpart the records required for the Tier 4 Calculation Methodology in §98.37 and the information listed in this paragraph (a):

1. Records of all petroleum coke purchases.
2. Annual operating hours.

(b) If a CEMS is not used to measure emissions, you must retain records for the information listed in paragraph (b):

1. Records of all analyses and calculations conducted for reported data listed in §98.286(b).
2. Records of all petroleum coke purchases.
3. Annual operating hours.

§ 98.288 Definitions.

All terms used in this subpart have the same meaning given in the Clean Air Act and subpart A of this part.

Subpart CC—Soda Ash Manufacturing

§ 98.290 Definition of the source category.

(a) A soda ash manufacturing facility is any facility with a manufacturing line that produces soda ash by one of the methods in paragraphs (a)(1) through (3) of this section:

1. Calcining trona.
2. Calcining sodium sesquicarbonate.
3. Using a liquid alkaline feedstock process that directly produces CO₂.

(b) In the context of the soda ash manufacturing industry, “calcining” means the thermal/chemical conversion of the bicarbonate fraction of the feedstock to sodium carbonate.

§ 98.291 Reporting threshold.

You must report GHG emissions under this subpart if your facility contains a soda ash manufacturing process and the facility meets the requirements of either §98.2(a)(1) or (a)(2).

§ 98.292 GHGs to report.

You must report:

(a) CO₂ process emissions from each soda ash manufacturing line combined.

(b) CO₂ combustion emissions from each soda ash manufacturing line.

(c) CH₄ and N₂O combustion emissions from each soda ash manufacturing line. You must calculate and report these emissions under subpart C of this part (General Stationary Fuel Combustion Sources) by following the requirements of subpart C.

(d) CO₂, CH₄, and N₂O emissions from each stationary combustion unit other than soda ash manufacturing lines. You must calculate and report these emissions under subpart C of this part (General Stationary Fuel Combustion Sources) by following the requirements of subpart C.

§ 98.293 Calculating GHG emissions.

You must calculate and report the annual process CO₂ emissions from each soda ash manufacturing line using the procedures specified in paragraph (a) or (b) of this section.

(a) For each soda ash manufacturing line that meets the conditions specified in §98.33(b)(4)(i) or (b)(4)(ii), you must calculate and report under this subpart the combined process and combustion CO₂ emissions by operating and maintaining a CEMS to measure CO₂ emissions according to the Tier 4 Calculation Methodology specified in §98.33(a)(4) and all associated requirements for Tier 4 in subpart C of this part (General Stationary Fuel Combustion Sources).

(b) For each soda ash manufacturing line that is not subject to the requirements in paragraph (a) of this section, calculate and report the process CO₂ emissions from the soda ash manufacturing line by using the procedure in either paragraphs (b)(1), (b)(2), or (b)(3) of this section; and the combustion CO₂
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emissions using the procedure in paragraph (b)(4) of this section.

(1) Calculate and report under this subpart the combined process and combustion CO₂ emissions by operating and maintaining a CEMS to measure CO₂ emissions according to the Tier 4 Calculation Methodology specified in §98.33(a)(4) and all associated requirements for Tier 4 in subpart C of this part (General Stationary Fuel Combustion Sources).

(2) Use either Equation CC–1 or Equation CC–2 of this section to calculate annual CO₂ process emissions from each manufacturing line that calcines trona to produce soda ash:

\[
E_k = \sum_{n=1}^{12} \left[ \left( IC_{Tn} \times (T_{tn})_n \right) \times \frac{2000}{2205} \times \frac{0.097}{1} \right] \quad \text{(Eq. CC-1)}
\]

\[
E_k = \sum_{n=1}^{12} \left[ \left( IC_{sa} \times (T_{sa})_n \right) \times \frac{2000}{2205} \times \frac{0.138}{1} \right] \quad \text{(Eq. CC-2)}
\]

Where:

\( E_k \) = Annual CO₂ process emissions from each manufacturing line, k (metric tons).

\( (IC_{Tn})_n \) = Inorganic carbon content (percent by weight, expressed as a decimal fraction) in trona input, from the carbon analysis results for month n. This represents the ratio of trona to trona ore.

\( (IC_{sa})_n \) = Inorganic carbon content (percent by weight, expressed as a decimal fraction) in soda ash output, from the carbon analysis results for month n. This represents the purity of the soda ash produced.

\( (T_{tn})_n \) = Mass of trona input in month n (tons).

\( (T_{sa})_n \) = Mass of soda ash output in month n (tons).

\( \frac{2000}{2205} \) = Conversion factor to convert tons to metric tons.

\( \frac{0.097}{1} \) = Ratio of ton of CO₂ emitted for each ton of trona.

\( \frac{0.138}{1} \) = Ratio of ton of CO₂ emitted for each ton of soda ash produced.

(3) Site-specific emission factor method. Use Equations CC-3, CC-4, and CC-5 of this section to determine annual CO₂ process emissions from manufacturing lines that use the liquid alkaline feedstock process to produce soda ash. You must conduct an annual performance test and measure CO₂ emissions and flow rates at all process vents from the mine water stripper/evaporator for each manufacturing line and calculate CO₂ emissions as described in paragraphs (b)(3)(i) through (b)(3)(iv) of this section.

(i) During the performance test, you must measure the process vent flow from each process vent during the test and calculate the average rate for the test period in metric tons per hour.

(ii) Using the test data, you must calculate the hourly CO₂ emission rate using Equation CC-3 of this section:

\[
ER_{CO2} = \left( (C_{CO2} \times 10000) \times 2.59 \times 10^{-9} \times 44 \right) \times (Q \times 60) \times 4.53 \times 10^{-4}
\]  

Where:

\( ER_{CO2} \) = CO₂ mass emission rate (metric tons/hour).

\( C_{CO2} \) = Hourly CO₂ concentration (percent CO₂) as determined by §98.294(c).

10000 = Parts per million per percent

2.59 \times 10^{-9} = Conversion factor (pounds-mole/dscf/ppm).

44 = Pounds per pound-mole of carbon dioxide.

Q = Stack gas volumetric flow rate per minute (dscfm).

60 = Minutes per hour

4.53 \times 10^{-4} = Conversion factor (metric tons/pound).

(iii) Using the test data, you must calculate a CO₂ emission factor for the
§ 98.294 Monitoring and QA/QC requirements.

Section 98.293 provides three different procedures for emission calculations. The appropriate paragraphs (a) through (c) of this section should be used for the procedure chosen.

(a) If you determine your emissions using § 98.293(b)(2) (Equation CC-1 of this subpart) you must:

(1) Determine the monthly inorganic carbon content of the trona from a weekly composite analysis for each soda ash manufacturing line, using a modified version of ASTM E359–00 (Reapproved 2005)e1, Standard Test Methods for Analysis of Soda Ash (Sodium Carbonate) (incorporated by reference, see § 98.7). Although ASTM E359–00 (Reapproved 2005) el uses manual titration, suitable autotititators may also be used for this determination.

(2) Measure the mass of trona input produced by each soda ash manufacturing line on a monthly basis using belt scales or methods used for accounting purposes.

(3) Document the procedures used to ensure the accuracy of the monthly measurements of trona consumed.

(b) If you calculate CO₂ process emissions based on soda ash production (§ 98.293(b)(2) Equation CC-2 of this subpart), you must:

(1) Determine the inorganic carbon content of the soda ash (i.e., soda ash purity) using ASTM E359–00 (Reapproved 2005) el Standard Test Methods for Analysis of Soda Ash (Sodium Carbonate) (incorporated by reference, see § 98.7). Although ASTM E359–00 (Reapproved 2005) el uses manual titration, suitable autotititators may also be used for this determination.

(2) Measure the mass of soda ash produced by each soda ash manufacturing line on a monthly basis using belt scales, by weighing the soda ash at the truck or rail loadout points of your facility, or methods used for accounting purposes.

(3) Document the procedures used to ensure the accuracy of the monthly measurements of soda ash produced.

(c) If you calculate CO₂ emissions using the site-specific emission factor method in § 98.293(b)(3), you must:

\[ EF_{CO2} = \frac{ER_{CO2}}{V_t \times 4.53 \times 10^{-4}} \]  
(Eq. CC-4)

Where:

\( EF_{CO2} \) = CO₂ emission factor (metric tons CO₂/metric ton of process vent flow from mine water stripper/evaporator).

\( ER_{CO2} \) = CO₂ mass emission rate (metric tons/hour).

\( V_t \) = Process vent flow rate from mine water stripper/evaporator during annual performance test (pounds/hour).

\( 4.53 \times 10^{-4} \) = Conversion factor (metric tons/pound)

(iv) You must calculate annual CO₂ process emissions from each manufacturing line using Equation CC-5 of this section:

\[ E_k = EF_{CO2} \times (V_a \times 0.453) \times H \]  
(Eq. CC-5)

Where:

\( E_k \) = Annual CO₂ process emissions for each manufacturing line, k (metric tons).

\( EF_{CO2} \) = CO₂ emission factor (metric tons CO₂/metric ton of process vent flow from mine water stripper/evaporator).

\( V_a \) = Annual process vent flow rate from mine water stripper/evaporator (thousand pounds/hour).

\( H \) = Annual operating hours for the each manufacturing line.

\( 0.453 \) = Conversion factor (metric tons/thousand pounds).
(1) Conduct an annual performance test that is based on representative performance (i.e., performance based on normal operating conditions) of the affected process.

(2) Sample the stack gas and conduct three emissions test runs of 1 hour each.

(3) Conduct the stack test using EPA Method 3A at 40 CFR part 60, appendix A–2 to measure the CO2 concentration, Method 2, 2A, 2C, 2D, or 2F at 40 CFR part 60, appendix A–1 or Method 26 at 40 CFR part 60, appendix A–2 to determine the stack gas volumetric flow rate. All QA/QC procedures specified in the reference test methods and any associated performance specifications apply. For each test, the facility must prepare an emission factor determination report that must include the items in paragraphs (c)(3)(i) through (c)(3)(iii) of this section.

(i) Analysis of samples, determination of emissions, and raw data.

(ii) All information and data used to derive the emissions factor(s).

(iii) You must determine the average process vent flow rate from the mine water stripper/evaporater during each test and document how it was determined.

(4) You must also determine the annual vent flow rate from the mine water stripper/evaporater from monthly information using the same plant instruments or procedures used for accounting purposes (i.e., volumetric flow meter).


§ 98.296 Data reporting requirements.
In addition to the information required by §98.3(c), each annual report must contain the information specified in paragraphs (a) or (b) of this section, as appropriate for each soda ash manufacturing facility.

(a) If a CEMS is used to measure CO2 emissions, then you must report under this subpart the relevant information required under §98.36 and the following information in this paragraph (a):

(1) Annual consumption of trona or liquid alkaline feedstock for each manufacturing line (tons).

(2) Annual production of soda ash for each manufacturing line (tons).
§ 98.297 Records that must be retained.

In addition to the records required by §98.3(g), you must retain the records specified in paragraphs (a) and (b) of this section for each soda ash manufacturing line.

(a) If a CEMS is used to measure CO₂ emissions, then you must retain under this subpart the records required for the Tier 4 Calculation Methodology specified in subpart C of this part and the information listed in this paragraph (a):

(1) Monthly production of soda ash (tons).

(2) Monthly consumption of trona or liquid alkaline feedstock (tons).

(3) Annual production of soda ash for each manufacturing line (tons).

(4) Annual production capacity of soda ash for each manufacturing line (tons).

(5) Monthly consumption of trona or liquid alkaline feedstock for each manufacturing line (tons).

(6) Monthly production of soda ash for each manufacturing line (tons).

(7) Inorganic carbon content factor of trona or soda ash (depending on use of Equations CC–1 or CC–2 of this subpart) as measured by the applicable method in §98.294(b) or (c) for each month (percent by weight expressed as a decimal fraction).

(8) Whether CO₂ emissions for each manufacturing line were calculated using a trona input method as described in Equation CC–1 of this subpart, a soda ash output method as described in Equation CC–2 of this subpart, or a site-specific emission factor method as described in Equations CC–3 through CC–5 of this subpart.

(b) If a CEMS is not used to measure emissions, then you must retain records for the information listed in this paragraph (b):

(1) Records of all analyses and calculations conducted for determining all reported data as listed in §98.296(b).

(2) If using Equation CC–1 or CC–2 of this subpart, weekly inorganic carbon content factor of trona or soda ash, depending on method chosen, as measured by the applicable method in §98.294(b) (percent by weight expressed as a decimal fraction).

(3) Annual operating hours for each manufacturing line used to produce soda ash (hours).

(4) You must document the procedures used to ensure the accuracy of the monthly trona consumption or soda ash production measurements including, but not limited to, calibration of weighing equipment and other measurement devices. The estimated accuracy of measurements made with these devices must also be recorded, and the
technical basis for these estimates must be provided.

(5) If you produce soda ash using the liquid alkaline feedstock process and use the site-specific emission factor method to estimate emissions (§98.293(b)(3)) then you must also retain the following relevant information:
   (i) Records of performance test results.
   (ii) You must document the procedures used to ensure the accuracy of the annual average vent flow measurements including, but not limited to, calibration of flow rate meters and other measurement devices. The estimated accuracy of measurements made with these devices must also be recorded, and the technical basis for these estimates must be provided.

§ 98.298 Definitions.
All terms used in this subpart have the same meaning given in the Clean Air Act and subpart A of this part.

Subpart DD—Electrical Transmission and Distribution Equipment Use

SOURCE: 75 FR 74855, Dec. 1, 2010, unless otherwise noted.

§ 98.300 Definition of the source category.
(a) The electrical transmission and distribution equipment use source category consists of all electric transmission and distribution equipment and servicing inventory insulated with or containing sulfur hexafluoride (SF₆) or perfluorocarbons (PFCs) used within an electric power system. Electric transmission and distribution equipment and servicing inventory includes, but is not limited to:
   (1) Gas-insulated substations.
   (2) Circuit breakers.
   (3) Switchgear, including closed-pressure and hermetically sealed-pressure switchgear and gas-insulated lines containing SF₆ or PFCs.
   (4) Gas containers such as pressurized cylinders.
   (5) Gas carts.
   (6) Electric power transformers.
   (7) Other containers of SF₆ or PFC.

§ 98.301 Reporting threshold.
(a) You must report GHG emissions from an electric power system if the total nameplate capacity of SF₆ and PFC containing equipment (excluding hermetically sealed-pressure equipment) located within the facility, when added to the total nameplate capacity of SF₆ and PFC containing equipment (excluding hermetically sealed-pressure equipment) that is not located within the facility but is under common ownership or control, exceeds 17,820 pounds and the facility meets the requirements of §98.2(a)(1).

(b) A facility other than an electric power system that is subject to this part because of emissions from any other source category listed in Table A–3 or A–4 in subpart A of this part is not required to report emissions under subpart DD of this part unless the total nameplate capacity of SF₆ and PFC containing equipment located within that facility exceeds 17,820 pounds.

§ 98.302 GHGs to report.
You must report total SF₆ and PFC emissions from your facility (including emissions from fugitive equipment leaks, installation, servicing, equipment decommissioning and disposal, and from storage cylinders) resulting from the transmission and distribution servicing inventory and equipment listed in §98.300(a). For acquisitions of equipment containing or insulated with SF₆ or PFCs, you must report emissions from the equipment after the title to the equipment is transferred to the electric power transmission or distribution entity.

§ 98.303 Calculating GHG emissions.
(a) Calculate the annual SF₆ and PFC emissions using the mass-balance approach in Equation DD–1 of this section:
§ 98.304 Monitoring and QA/QC requirements.

(a) For calendar year 2011 monitoring, you may follow the provisions of §98.3(d)(1) through (d)(2) for best available monitoring methods rather than follow the monitoring requirements of this section. For purposes of this subpart, any reference in §98.3(d)(1) through (d)(2) to 2010 means 2011, to March 31 means June 30, and to April 1 means July 1. Any reference to the effective date in §98.3(d)(1) through (d)(2) means February 28, 2011.

(b) You must adhere to the following QA/QC methods for reviewing the completeness and accuracy of reporting:

1. Review inputs to Equation DD–1 of this section to ensure inputs and outputs to the company’s system are included.

2. Do not enter negative inputs and confirm that negative emissions are not calculated. However, the Decrease in SF₆ Inventory and the Net Increase in Total Nameplate Capacity may be calculated as negative numbers.

3. Ensure that beginning-of-year inventory matches end-of-year inventory from the previous year.

4. Ensure that in addition to SF₆ purchased from bulk gas distributors, SF₆ purchased from Original Equipment Manufacturers (OEM) and SF₆ returned to the facility from off-site recycling are also accounted for among the total additions.

(c) Ensure the following QA/QC methods are employed throughout the year:

1. Ensure that cylinders returned to the gas supplier are consistently weighed on a scale that is certified to be accurate and precise to within 2 pounds of the scale’s capacity and is periodically recalibrated per the manufacturer’s specifications. Either measure residual gas (the amount of gas remaining in returned cylinders) or have the gas supplier measure it. If the gas supplier weighs the residual gas, obtain from the gas supplier a detailed monthly accounting, within ±2 pounds, of residual gas amounts in the cylinders returned to the gas supplier.

2. Ensure that cylinders weighed for the beginning and end of year inventory measurements are weighed on a scale that is certified to be accurate to within 2 pounds of the scale’s capacity and is periodically recalibrated per the manufacturer’s specifications. All scales used to measure quantities that are to be reported under §98.306 must be calibrated using calibration procedures specified by the scale manufacturer. Calibration must be performed...
prior to the first reporting year. After the initial calibration, recalibration must be performed at the minimum frequency specified by the manufacturer.

(3) Ensure all substations have provided information to the manager compiling the emissions report (if it is not already handled through an electronic inventory system).

(d) GHG Monitoring Plans, as described in §98.3(g)(5), must be completed by April 1, 2011.

§ 98.305 Procedures for estimating missing data.

A complete record of all measured parameters used in the GHG emissions calculations is required. Replace missing data, if needed, based on data from equipment with a similar nameplate capacity for SF$_6$ and PFC, and from similar equipment repair, replacement, and maintenance operations.

§ 98.306 Data reporting requirements.

In addition to the information required by §98.3(c), each annual report must contain the following information for each electric power system, by chemical:

(a) Nameplate capacity of equipment (pounds) containing SF$_6$, and nameplate capacity of equipment (pounds) containing each PFC:

1. Existing at the beginning of the year (excluding hermetically sealed-pressure switchgear).
2. New during the year (all SF$_6$-insulated equipment, including hermetically sealed-pressure switchgear).
3. Retired during the year (all SF$_6$-insulated equipment, including hermetically sealed-pressure switchgear).

(b) Transmission miles (length of lines carrying voltages above 35 kilovolt).

(c) Distribution miles (length of lines carrying voltages at or below 35 kilovolt).

(d) Pounds of SF$_6$ and PFC stored in containers, but not in energized equipment, at the beginning of the year.

(e) Pounds of SF6 and PFC stored in containers, but not in energized equipment, at the end of the year.

(f) Pounds of SF$_6$ and PFC purchased in bulk from chemical producers or distributors.

(g) Pounds of SF$_6$ and PFC purchased from equipment manufacturers or distributors with or inside equipment, including hermetically sealed-pressure switchgear.

(h) Pounds of SF$_6$ and PFC returned to facility after off-site recycling.

(i) Pounds of SF$_6$ and PFC in bulk and contained in equipment sold to other entities.

(j) Pounds of SF$_6$ and PFC returned to suppliers.

(k) Pounds of SF$_6$ and PFC sent off-site for recycling.

(l) Pounds of SF$_6$ and PFC sent off-site for destruction.

§ 98.307 Records that must be retained.

In addition to the information required by §98.3(g), you must retain records of the information reported and listed in §98.306.

§ 98.308 Definitions.

Except as specified in this section, all terms used in this subpart have the same meaning given in the Clean Air Act and subpart A of this part.

Facility, with respect to an electric power system, means the electric power system as defined in this paragraph. An electric power system is comprised of all electric transmission and distribution equipment insulated with or containing SF$_6$ or PFCs that is linked through electric power transmission or distribution lines and functions as an integrated unit, that is owned, serviced, or maintained by a single electric power transmission or distribution entity (or multiple entities with a common owner), and that is located between: (1) The point(s) at which electric energy is obtained from an electricity generating unit or a different electric power transmission or distribution entity that does not have a common owner, and (2) the point(s) at which any customer or another electric power transmission or distribution entity that does not have a common owner receives the electric energy. The facility also includes servicing inventory for such equipment that contains SF$_6$ or PFCs.
§ 98.310  Electric power transmission or distribution entity means any entity that transmits, distributes, or supplies electricity to a consumer or other user, including any company, electric cooperative, public electric supply corporation, a similar Federal department (including the Bureau of Reclamation or the Corps of Engineers), a municipally owned electric department offering service to the public, an electric public utility district, or a jointly owned electric supply project.

Operator, for the purposes of this subpart, means any person who operates or supervises a facility, excluding a person whose sole responsibility is to ensure reliability, balance load or otherwise address electricity flow.

Subpart EE—Titanium Dioxide Production

§ 98.310 Definition of the source category.

The titanium dioxide production source category consists of facilities that use the chloride process to produce titanium dioxide.

§ 98.311 Reporting threshold.

You must report GHG emissions under this subpart if your facility contains a titanium dioxide production process and the facility meets the requirements of either §98.2(a)(1) or (a)(2).

§ 98.312 GHGs to report.

(a) You must report CO\(_2\) process emissions from each chloride process line as required in this subpart.

(b) You must report CO\(_2\), CH\(_4\), and N\(_2\)O emissions from each stationary combustion unit under subpart C of this part (General Stationary Fuel Combustion Sources) by following the requirements of subpart C.

§ 98.313 Calculating GHG emissions.

You must calculate and report the annual process CO\(_2\) emissions for each chloride process line using the procedures in either paragraph (a) or (b) of this section.

(a) Calculate and report under this subpart the process CO\(_2\) emissions by operating and maintaining a CEMS according to the Tier 4 Calculation Methodology specified in §98.33(a)(4) and all associated requirements for Tier 4 in subpart C of this part (General Stationary Fuel Combustion Sources).

(b) Calculate and report under this subpart the annual process CO\(_2\) emissions for each chloride process line by determining the mass of calcined petroleum coke consumed in each line as specified in paragraphs (b)(1) through (b)(3) of this section. Use Equation EE–1 of this section to calculate annual combined process CO\(_2\) emissions from all process lines and use Equation EE–2 of this section to calculate annual process CO\(_2\) emissions for each process line. If your facility generates carbon-containing waste, use Equation EE–3 of this section to estimate the annual quantity of carbon-containing waste generated and its carbon contents according to §98.314(e) and (f):

(1) You must calculate the annual CO\(_2\) process emissions from all process lines at the facility using Equation EE–1 of this section:

\[
CO_2 = \sum_{p=1}^{m} E_p \quad \text{(Eq. EE-1)}
\]

Where:

- \(CO_2\) = Annual CO\(_2\) emissions from titanium dioxide production facility (metric tons/ year).
- \(E_p\) = Annual CO\(_2\) emissions from chloride process line \(p\) (metric tons), determined using Equation EE–2 of this section.
- \(p\) = Process line.
- \(m\) = Number of separate chloride process lines located at the facility.

(2) You must calculate the annual CO\(_2\) process emissions from each process line at the facility using Equation EE–2 of this section:

\[
E_p = \sum_{n=1}^{12} \frac{44}{12} C_{p,n} \frac{2000}{2205} CCF_n \quad \text{(Eq. EE-2)}
\]
Where:

\[ E_p = \text{Annual CO}_2 \text{ mass emissions from chloride process line } p \text{ (metric tons).} \]

\[ C_{p,n} = \text{Calcined petroleum coke consumption for process line } p \text{ in month } n \text{ (tons).} \]

\[ 44/12 = \text{Ratio of molecular weights, CO}_2 \text{ to carbon.} \]

\[ 2000/2205 = \text{Conversion of tons to metric tons.} \]

\[ CCF_n = \text{Carbon content factor for petroleum coke consumed in month } n \text{ from the supplier or as measured by the applicable method incorporated by reference in §98.7 according to §98.314(c) (percent by weight expressed as a decimal fraction).} \]

\[ n = \text{Number of month.} \]

(3) If facility generates carbon-containing waste, you must calculate the total annual quantity of carbon-containing waste produced from all process lines using Equation EE–3 of this section and its carbon contents according to §98.314(e) and (f):

\[ \text{TWC} = \frac{1}{12} \sum_{p=1}^{m} \sum_{n=1}^{12} WC_{p,n} \quad \text{(Eq. EE-3)} \]

Where:

\[ \text{TWC} = \text{Annual production of carbon-containing waste from titanium dioxide production facility (tons).} \]

\[ WC_{p,n} = \text{Production of carbon-containing waste in month } n \text{ from chloride process line } p \text{ (tons).} \]

\[ p = \text{Process line.} \]

\[ m = \text{Total number of process lines.} \]

\[ n = \text{Number of month.} \]

(c) If GHG emissions from a chloride process line are vented through the same stack as any combustion unit or process equipment that reports CO\(_2\) emissions using a CEMS that complies with the Tier 4 Calculation Methodology in subpart C of this part (General Stationary Fuel Combustion Sources), then the calculation methodology in paragraph (b) of this section shall not be used to calculate process CO\(_2\) emissions. The owner or operator shall report under this subpart the combined stack emissions according to the Tier 4 Calculation Methodology in §98.33(a)(4) and all associated requirements for Tier 4 in subpart C of this part.

§ 98.314 Monitoring and QA/QC requirements.

(a) You must measure your consumption of calcined petroleum coke using plant instruments used for accounting purposes including direct measurement weighing the petroleum coke fed into your process (by belt scales or a similar device) or through the use of purchase records.

(b) You must document the procedures used to ensure the accuracy of monthly calcined petroleum coke consumption measurements.

(c) You must determine the carbon content of the calcined petroleum coke each month based on reports from the supplier. Alternatively, facilities can measure monthly carbon contents of the petroleum coke using ASTM D3176–89 (Reapproved 2002) Standard Practice for Ultimate Analysis of Coal and Coke (incorporated by reference, see §98.7) and ASTM D5373–08 Standard Test Methods for Instrumental Determination of Carbon, Hydrogen, and Nitrogen in Laboratory Samples of Coal (incorporated by reference, see §98.7).

(d) For quality assurance and quality control of the supplier data, you must conduct an annual measurement of the carbon content from a representative sample of the petroleum coke consumed using ASTM D3176–89 and ASTM D5373–08.

(e) You must determine the quantity of carbon-containing waste generated from each titanium dioxide production line on a monthly basis using plant instruments used for accounting purposes including direct measurement weighing the carbon-containing waste not used during the process (by belt scales or a similar device) or through the use of sales records.

(f) You must determine the carbon contents of the carbon-containing waste from each titanium production line on an annual basis by collecting and analyzing a representative sample of the material using ASTM D3176–89 and ASTM D5373–08.

§ 98.316 Data reporting requirements.

In addition to the information required by §98.3(c), each annual report must contain the information specified in paragraphs (a) or (b) of this section, as applicable for each titanium dioxide production line.

(a) If a CEMS is used to measure CO₂ emissions, then you must report the relevant information required under §98.36(e)(2)(vi) for the Tier 4 Calculation Methodology and the following information in this paragraph (a):

(1) Identification number of each process line.

(2) Annual consumption of calcined petroleum coke (tons).

(3) Annual production of titanium dioxide (tons).

(4) Annual production capacity of titanium dioxide (tons).

(b) If a CEMS is not used to measure CO₂ emissions, then you must report the information listed in this paragraph (b):

(1) Identification number of each process line.

(2) Annual CO₂ emissions from each chloride process line (metric tons/year).

(3) Annual consumption of calcined petroleum coke for each process line (tons).

(4) Annual production of titanium dioxide for each process line (tons).

(5) Annual production capacity of titanium dioxide for each process line (tons).

(6) Calcined petroleum coke consumption for each process line (tons).

(7) Annual production of carbon-containing waste for each process line (tons), if applicable.

(8) Monthly production of titanium dioxide for each process line (tons).

(9) Monthly carbon content factor of petroleum coke (percent by weight expressed as a decimal fraction).

(10) Whether monthly carbon content of the petroleum coke is based on reports from the supplier or through self measurement using applicable ASTM standard methods.

(11) Carbon content for carbon-containing waste for each process line (percent by weight expressed as a decimal fraction).

(12) If carbon content of petroleum coke is based on self measurement, the ASTM standard methods used.

(13) Sampling analysis results of carbon content of petroleum coke as determined for QA/QC of supplier data under §98.314(d) (percent by weight expressed as a decimal fraction).

(14) Number of separate chloride process lines located at the facility.

(15) The number of times in the reporting year that missing data procedures were followed to measure the carbon contents of petroleum coke (number of months); petroleum coke consumption (number of months); carbon-containing waste generated (number of months); and carbon contents of the carbon-containing waste (number of times during year).

§ 98.317 Records that must be retained.

In addition to the records required by §98.3(g), you must retain the records specified in paragraphs (a) and (b) of this section for each titanium dioxide production facility.

(a) If a CEMS is used to measure CO\textsubscript{2} emissions, then you must retain under this subpart required for the Tier 4 Calculation Methodology in §98.37 and the information listed in this paragraph (a):

1. Records of all calcined petroleum coke purchases.
2. Annual operating hours for each titanium dioxide process line.

(b) If a CEMS is not used to measure CO\textsubscript{2} emissions, then you must retain records for the information listed in this paragraph:

1. Records of all calcined petroleum coke purchases (tons).
2. Records of all analyses and calculations conducted for all reported data as listed in §98.316(b).
3. Sampling analysis results for carbon content of consumed calcined petroleum coke (percent by weight expressed as a decimal fraction).
4. Sampling analysis results for the carbon content of carbon containing waste (percent by weight expressed as a decimal fraction), if applicable.
5. Monthly production of carbon-containing waste (tons).
6. You must document the procedures used to ensure the accuracy of the monthly petroleum coke consumption and quantity of carbon-containing waste measurement including, but not limited to, calibration of weighing equipment and other measurement devices. The estimated accuracy of measurements made with these devices must also be recorded, and the technical basis for these estimates must be provided.
7. Annual operating hours for each titanium dioxide process line (hours).

§ 98.318 Definitions.

All terms used in this subpart have the same meaning given in the Clean Air Act and subpart A of this part.
§ 98.322 GHGs to report.

(a) You must report CH₄ liberated from ventilation and degasification systems.

(b) You must report CH₄ destruction from systems where gas is sold, used onsite, or otherwise destroyed (including by flaring).

(c) You must report net CH₄ emissions from ventilation and degasification systems.

(d) You must report under this subpart the CO₂ emissions from coal mine gas CH₄ destruction occurring at the facility, where the gas is not a fuel input for energy generation or use (e.g., flaring).

(e) You must report under subpart C of this part (General Stationary Fuel Combustion Sources) the CO₂, CH₄, and N₂O emissions from each stationary fuel combustion unit by following the requirements of subpart C. Report emissions from both the combustion of collected coal mine CH₄ and any other fuels.

(f) An underground coal mine that is subject to this part because emissions from source categories described in Tables A–3, A–4 or A–5 of subpart A of this part, or from stationary combustion (subpart C of this part), is not required to report emissions under this subpart unless the coal mine liberates 36,500,000 actual cubic feet (acf) or more of methane per year from its ventilation system.

[75 FR 39763, July 12, 2010, as amended at 76 FR 73901, Nov. 29, 2011]

§ 98.323 Calculating GHG emissions.

(a) For each ventilation shaft, vent hole, or centralized point into which CH₄ from multiple shafts and/or vent holes are collected, you must calculate the quarterly CH₄ liberated from the ventilation system using Equation FF–1 of this section. You must measure CH₄ content, flow rate, temperature, pressure, and moisture content of the gas using the procedures outlined in § 98.324.

\[
\text{CH}_4 = n \left( V \times \text{MCF} \times \frac{C}{100\%} \times \frac{520^\circ R}{T} \times \frac{P}{1 \text{ atm}} \times \frac{0.454}{1,440} \times \frac{0.0423}{1,000} \right) \quad (\text{Eq. FF–1})
\]

Where:

\( \text{CH}_4 \) = Quarterly CH₄ liberated from a ventilation monitoring point (metric tons CH₄).

\( V \) = Volumetric flow rate for the quarter (cfm) based on sampling or a flow rate meter. If a flow rate meter is used and the meter automatically corrects for temperature and pressure, replace “520°R/T × P/1 atm” with “1”.

\( \text{MCF} \) = Moisture correction factor for the measurement period, volumetric basis.

\( n \) = The number of days in the quarter where active ventilation of mining operations is taking place at the monitoring point.

\( 0.0423 \) = Density of CH₄ at 520 °R (60 °F) and 1 atm (lb/scf).

\( 520^\circ R \) = 520 degrees Rankine.

\( T \) = Temperature at which flow is measured (°R) for the quarter.

\( P \) = Pressure at which flow is measured (atm) for the quarter.

The annual average barometric pressure from the nearest NOAA weather service station may be used as a default.

\( 1,440 \) = Conversion factor (min/day).

\( 0.454/1,000 \) = Conversion factor (metric ton/lb).

(1) Consistent with MSHA inspections, the quarterly periods are:

(i) January 1–March 31.

(ii) April 1–June 30.

(iii) July 1–September 30.

(iv) October 1–December 31.

(2) Values of V, C, T, P, and (fH₂O), if applicable, must be based on measurements taken at least once each quarter.
Environmental Protection Agency § 98.323

(3) If a facility has more than one monitoring point, the facility must calculate total CH$_4$ liberated from ventilation systems (CH$_4$VTotal) as the sum of the CH$_4$ from all ventilation monitoring points in the mine, as follows:

$$CH_{4VTotal} = \sum_{i=1}^{m} (CH_4^V)$$  (Eq. FF-2)

Where:

- CH$_4$VTotal = Total quarterly CH$_4$ liberated from ventilation systems (metric tons CH$_4$).
- CH$_4^V$ = Quarterly CH$_4$ liberated from each ventilation monitoring point (metric tons CH$_4$).
- m = Number of ventilation monitoring points.

(b) For each monitoring point in the degasification system (this could be at each degasification well and/or vent hole, or at more centralized points into which CH$_4$ from multiple wells and/or vent holes are collected), you must calculate the weekly CH$_4$ liberated from the mine using CH$_4$ measured weekly or more frequently (including by CEMS) according to 98.234(c), CH$_4$ content, flow rate, temperature, pressure, and moisture content, and Equation FF–3 of this section.

$$CH_4^D_{i} = \frac{V_i \times MCF \times \frac{C_i}{100\%} \times 0.0423 \times \frac{520^\circ R \times P_i}{1 \text{ atm}} \times 1.440 \times \frac{0.454}{1,000}}{1,440 \times 0.454/1,000}$$  (Eq. FF-3)

Where:

- CH$_4^D$ = Weekly CH$_4$ liberated from at the monitoring point (metric tons CH$_4$).
- V$_i$ = Measured volumetric flow rate for the days in the week when the degasification system is in operation at that monitoring point, based on sampling or a flow rate meter (cfm). If a flow rate meter is used and the meter automatically corrects for temperature and pressure, replace “520°R/T$_i \times P_i/1 \text{ atm}”$ with “1”.
- MCF$_i$ = Moisture correction factor for the measurement period, volumetric basis.
  - 0 when $V_i$ and $C_i$ are measured on a dry basis or if both are measured on a wet basis.
  - 1 when $V_i$ and $C_i$ are measured on a dry basis.
  - 1/(1-$f_{H_2O}$) when $V_i$ is measured on a wet basis.
  - $f_{H_2O}$ = Moisture content of the CH$_4$ emitted during the measurement period, volumetric basis (cubic feet water per cubic feet emitted gas).
  - $C_i$ = CH$_4$ concentration of gas for the days in the week when the degasification system is in operation at that monitoring point (%).
- n = The number of days in the week that the system is operational at that measurement point.
- $0.0423 = \text{Density of CH}_4 \text{ at } 520^\circ R (60^\circ F) \text{ and } 1 \text{ atm (lb/scf)}$.
- $520^\circ R = 520 \text{ degrees Rankine}$.
- $T_i = \text{Temperature at which flow is measured (°R)}$.
- $P_i = \text{Pressure at which flow is measured (atm)}$.
- 1.440 = Conversion factor (minutes/day).
- 0.454/1,000 = Conversion factor (metric ton/ lb).

(1) Values for V, C, T, P, and (fH$_2$O), if applicable, must be based on measurements taken at least once each calendar week with at least 3 days between measurements. If measurements are taken more frequently than once per week, then use the average value for all measurements taken that week. If continuous measurements are taken, then use the average values over the time period of continuous monitoring when the continuous monitoring equipment is properly functioning.

(2) Quarterly total CH$_4$ liberated from degasification systems for the mine should be determined as the sum of CH$_4$ liberated determined at each of the monitoring points in the mine, summed over the number of weeks in the quarter, as follows:
\[
\text{CH}_4\text{Total} = \sum_{i=1}^{m} \sum_{j=1}^{w} (\text{CH}_4\text{D})_{i,j} \quad \text{(Eq. FF-4)}
\]

Where:
- \(\text{CH}_4\text{Total}\) = Quarterly \(\text{CH}_4\) liberated from all degasification monitoring points (metric tons \(\text{CH}_4\)).
- \(\text{CH}_4\text{D}\) = Weekly \(\text{CH}_4\) liberated from a degasification monitoring point (metric tons \(\text{CH}_4\)).
- \(m\) = Number of monitoring points.
- \(w\) = Number of weeks in the quarter during which the degasification system is operated.

(c) If gas from degasification system wells or ventilation shafts is sold, used onsite, or otherwise destroyed (including by flaring), you must calculate the quarterly \(\text{CH}_4\) destroyed for each destruction device and each point of off-site transport to a destruction device, using Equation FF-5 of this section.

You must measure \(\text{CH}_4\) content and flow rate according to the provisions in §98.324, and calculate the methane routed to the destruction device (\(\text{CH}_4\text{D}\)) using either Equation FF-1 or Equation FF-3 of this section, as applicable.

\[
\text{CH}_4\text{Destroyed} = \text{CH}_4 \times \text{DE} \quad \text{(Eq. FF-5)}
\]

Where:
- \(\text{CH}_4\text{Destroyed}\) = Quarterly \(\text{CH}_4\) destroyed (metric tons).
- \(\text{CH}_4\) = Quarterly \(\text{CH}_4\) routed to the destruction device or offsite transfer point (metric tons).
- \(\text{DE}\) = Destruction efficiency (lesser of manufacturer’s specified destruction efficiency and 0.99). If the gas is transported off-site for destruction, use \(\text{DE} = 1\).

(1) Calculate total \(\text{CH}_4\) destroyed as the sum of the methane destroyed at all destruction devices (onsite and offsite), using Equation FF-6 of this section.

\[
\text{CH}_4\text{Destroyed Total} = \sum_{i=1}^{d} (\text{CH}_4\text{Destroyed})_i \quad \text{(Eq. FF-6)}
\]

Where:
- \(\text{CH}_4\text{Destroyed Total}\) = Quarterly total \(\text{CH}_4\) destroyed at the mine (metric tons \(\text{CH}_4\)).
- \(\text{CH}_4\text{Destroyed}^\text{ onsite}\) = Quarterly \(\text{CH}_4\) destroyed from each destruction device or offsite transfer point.
- \(d\) = Number of onsite destruction devices and points of offsite transport.

(2) [Reserved]

(d) You must calculate the quarterly measured net \(\text{CH}_4\) emissions to the atmosphere using Equation FF-7 of this section.

\[
\text{CH}_4\text{ emitted (net)} = \text{CH}_4\text{VTotal} + \text{CH}_4\text{DTotal} - \text{CH}_4\text{DestroyedTotal} \quad \text{(Eq. FF-7)}
\]

Where:
- \(\text{CH}_4\text{ emitted (net)}\) = Quarterly \(\text{CH}_4\) emissions from the mine (metric tons).
- \(\text{CH}_4\text{VTotal}\) = Quarterly sum of the \(\text{CH}_4\) liberated from all mine ventilation monitoring points (\(\text{CH}_4\text{V}\)), calculated using Equation FF-2 of this section (metric tons).
- \(\text{CH}_4\text{Total}\) = Quarterly sum of the \(\text{CH}_4\) liberated from all mine degasification monitoring points (\(\text{CH}_4\text{D}\)), calculated using Equation FF-4 of this section (metric tons).
- \(\text{CH}_4\text{DestroyedTotal}\) = Quarterly sum of the measured \(\text{CH}_4\) destroyed from all mine ventilation and degasification systems, calculated using Equation FF-6 of this section (metric tons).

(e) For the methane collected from degasification and/or ventilation systems that is destroyed on site and is not a fuel input for energy generation or use (those emissions are monitored and reported under Subpart C of this
part), you must estimate the CO$_2$ emissions using Equation FF–8 of this section.

$$CO_2 = CH_4_{\text{Destroyed onsite}} \times \frac{44}{16}$$  (Eq. FF–8)

Where:
- CO$_2$ = Total quarterly CO$_2$ emissions from CH$_4$ destruction (metric tons).
- CH$_4$$_{\text{Destroyed onsite}}$ = Quarterly sum of the CH$_4$ destroyed, calculated as the sum of CH$_4$ destroyed for each onsite, non-energy use, as calculated individually in Equation FF–5 of this section (metric tons).
- $\frac{44}{16}$ = Ratio of molecular weights of CO$_2$ to CH$_4$. 

[75 FR 39763, July 12, 2010, as amended at 76 FR 73901, Nov. 29, 2011]

§ 98.324 Monitoring and QA/QC requirements.

(a) For calendar year 2011 monitoring, the facility may submit a request to the Administrator to use one or more best available monitoring methods as listed in §98.3(d)(1)(i) through (iv). The request must be submitted no later than October 12, 2010 and must contain the information in §98.3(d)(2)(ii). To obtain approval, the request must demonstrate to the Administrator’s satisfaction that it is not reasonably feasible to acquire, install, and operate a required piece of monitoring equipment by January 1, 2011. The use of best available monitoring methods will not be approved beyond December 31, 2011.

(b) For CH$_4$ liberated from ventilation systems, determine whether CH$_4$ will be monitored from each ventilation well and shaft, from a centralized monitoring point, or from a combination of the two options. Operators are allowed flexibility for aggregating emissions from more than one ventilation well or shaft, as long as emissions from all are addressed, and the methodology for calculating total emissions documented. Monitor by one of the following options:

1. Collect quarterly or more frequent grab samples (with no fewer than 6 weeks between measurements) for methane concentration and make quarterly measurements of flow rate, temperature, pressure, and moisture content, if applicable. The sampling and measurements must be made at the same locations as Mine Safety and Health Administration (MSHA) inspection samples are taken, and should be taken when the mine is operating under normal conditions. You must follow MSHA sampling procedures as set forth in the MSHA Handbook entitled, General Coal Mine Inspection Procedures and Inspection Tracking System Handbook Number: PH–08–V–1, January 1, 2008 (incorporated by reference, see §98.7). You must record the date of sampling, flow, temperature, pressure, and moisture measurements, the methane concentration (percent), the bottle number of samples collected, and the location of the measurement or collection.

2. Obtain results of the quarterly (or more frequent) testing performed by MSHA for the methane flowrate. At the same location and within seven days of the MSHA sampling, make measurements of temperature and pressure using the same procedures specified in paragraph (b)(1) of this section. The annual average barometric pressure from the nearest National Oceanic and Atmospheric Administration (NOAA) weather service station may be used as a default for pressure. If the MSHA data for methane flow is provided in the units of actual cubic feet of methane per day, the methane flow data is inserted into Equation FF–1 of this section in place of the value for V and the variables MCF, C/100%, and 1440 are removed from the equation.

3. Monitor emissions through the use of one or more continuous emission monitoring systems (CEMS). If operators use CEMS as the basis for emissions reporting, they must provide documentation on the process for using
data obtained from their CEMS to estimate emissions from their mine ventilation systems.

(c) For CH\textsubscript{4} liberated at degasification systems, determine whether CH\textsubscript{4} will be monitored from each well and gob gas vent hole, from a centralized monitoring point, or from a combination of the two options. Operators are allowed flexibility for aggregating emissions from more than one well or gob gas vent hole, as long as emissions from all are addressed, and the methodology for calculating total emissions is documented. Monitor both gas volume and methane concentration by one of the following two options:

(1) Monitor emissions through the use of one or more continuous emissions monitoring systems (CEMS). If operators use CEMS as the basis for emissions reporting, they must provide documentation on the process for using data obtained from their CEMS to estimate emissions from their mine ventilation systems.

(2) Collect weekly (once each calendar week, with at least three days between measurements) or more frequent samples, for all degasification wells and gob gas vent holes. Determine weekly or more frequent flow rates, methane concentration, temperature, and pressure from these degasification wells and gob gas vent holes. Methane composition should be determined either by submitting samples to a lab for analysis, or from the use of methanometers at the degasification well site. Follow the sampling protocols for sampling of methane emissions from ventilation shafts, as described in §98.324(b)(1). You must record the date of sampling, flow, temperature, pressure, and moisture measurements, the methane concentration (percent), the bottle number of samples collected, and the location of the measurement or collection.

(3) If the CH\textsubscript{4} concentration is determined on a dry basis and flow is determined on a wet basis or CH\textsubscript{4} concentration is determined on a wet basis and flow is determined on a dry basis, and the flow meter does not automatically correct for moisture content, determine the moisture content in the gas in a location near or representative of the location of:

(i) The gas flow meter at least once each calendar week; if measuring with CEMS. If only one measurement is made each calendar week, there must be at least three days between measurements; and

(ii) The grab sample, at the time of the sample.

(d) Monitoring must adhere to one of the methods specified in paragraphs (d)(1) through (d)(2) of this section.


(2) As an alternative to the gas chromatography methods provided in paragraph (d)(1) of this section, you may use gaseous organic concentration analyzers and a correction factor to calculate the CH\textsubscript{4} concentration following the requirements in paragraphs (d)(2)(i) through (d)(2)(ii) of this section.

(i) Use Method 25A or 25B at 40 CFR part 60, appendix A–7 to determine gaseous organic concentration as required in §98.323 and in paragraphs (b) and (c) of this section. You must calibrate the instrument with CH\textsubscript{4} and determine the total gaseous organic concentration as carbon (or as CH\textsubscript{4}; K=1 in Equation 25A–1 of Method 25A at 40 CFR part 60, appendix A–7).

(ii) Determine a correction factor that will be used with the gaseous organic concentrations measured in paragraph (i) of this section. The correction factor must be determined at the routine sampling location no less frequently than once a reporting year following the requirements in paragraphs (d)(2)(ii)(A) through (d)(2)(ii)(C) of this section.

(A) Take a minimum of three grab samples of the gas with a minimum of 20 minutes between samples and determine the methane composition of the gas using one of the methods specified in paragraph (d)(1) of this section.

(B) As soon as practical after each grab sample is collected and prior to
the collection of a subsequent grab sample, determine the gaseous organic concentration of the gas using either Method 25A or 25B at 40 CFR part 60, appendix A–7 as specified in paragraph (d)(2)(i) of this section.

(C) Determine the arithmetic average methane concentration and the arithmetic average gaseous organic concentration of the samples analyzed according to paragraphs (d)(2)(ii)(A) and (d)(2)(ii)(B) of this section, respectively, and calculate the non-methane organic carbon correction factor as the ratio of the average methane concentration to the average total gaseous organic concentration. If the ratio exceeds 1, use 1 for the correction factor.

(iii) Calculate the CH_4 concentration as specified in Equation FF–9 of this section:

\[ C_{CH_4} = f_{NMOC} \times C_{TGOC} \quad (Eq. \ FF–9) \]

Where:
- \( C_{CH_4} \) = Methane (CH_4) concentration in the gas (volume %) for use in Equations FF–1 and FF–3 of this subpart.
- \( f_{NMOC} \) = Correction factor from the most recent determination of the correction factor as specified in paragraph (d)(2)(ii) of this section (unitless).
- \( C_{TGOC} \) = Gaseous organic carbon concentration measured using Method 25A or 25B at 40 CFR part 60, appendix A–7 during routine monitoring of the gas (volume %).

(e) All flow meters and gas composition monitors that are used to provide data for the GHG emissions calculations shall be calibrated prior to the first reporting year, using the applicable methods specified in paragraphs (d), and (e)(1) through (e)(7) of this section. Alternatively, calibration procedures specified by the manufacturer may be used. Flow meters and gas composition monitors shall be re-calibrated either at the minimum frequency specified by the manufacturer or annually. The operator shall operate, maintain, and calibrate a gas composition monitor capable of measuring the concentration of CH_4 in the gas using one of the methods specified in paragraph (d) of this section. The operator shall operate, maintain, and calibrate the flow meter using any of the following test methods or follow the procedures specified by the flow meter manufacturer. Flow meters must meet the accuracy requirements in §98.3(i).


(f) For CH_4 destruction, CH_4 must be monitored at each onsite destruction device and each point of offsite transport for combustion using continuous monitors of gas routed to the device or point of offsite transport.

(g) All temperature, pressure, and moisture content monitors must be operated and calibrated using the procedures and frequencies specified by the manufacturer.

(h) If applicable, the owner or operator shall document the procedures used to ensure the accuracy of gas flow rate, gas composition, temperature, pressure, and moisture content measurements. These procedures include, but are not limited to, calibration of flow meters, and other measurement
§ 98.325 Procedures for estimating missing data.

(a) A complete record of all measured parameters used in the GHG emissions calculations is required. Therefore, whenever a quality-assured value of a required parameter is unavailable (e.g., if a meter malfunctions during unit operation or if a required fuel sample is not taken), a substitute data value for the missing parameter shall be used in the calculations, in accordance with paragraph (b) of this section.

(b) For each missing value of CH\textsubscript{4} concentration, flow rate, temperature, pressure, and moisture content for ventilation and degasification systems, the substitute data value shall be the arithmetic average of the quality-assured values of that parameter immediately preceding and immediately following the missing data incident. If, for a particular parameter, no quality-assured data are available prior to the missing data incident, the substitute data value shall be the first quality-assured value obtained after the missing data period.

§ 98.326 Data reporting requirements.

In addition to the information required by §98.3(c), each annual report must contain the following information for each mine:

(a) Quarterly CH\textsubscript{4} liberated from each ventilation monitoring point (CH\textsubscript{4vm}), (metric tons CH\textsubscript{4}).

(b) Weekly CH\textsubscript{4} liberated from each degasification system monitoring point (metric tons CH\textsubscript{4}).

(c) Quarterly CH\textsubscript{4} destruction at each ventilation and degasification system destruction device or point of offsite transport (metric tons CH\textsubscript{4}).

(d) Quarterly CH\textsubscript{4} emissions (net) from all ventilation and degasification systems (metric tons CH\textsubscript{4}).

(e) Quarterly CO\textsubscript{2} emissions from on-site destruction of coal mine gas CH\textsubscript{4}, where the gas is not a fuel input for energy generation or use (e.g., flaring) (metric tons CO\textsubscript{2}).

(f) Quarterly volumetric flow rate for each ventilation monitoring point (scfm), date and location of each measurement, and method of measurement (quarterly sampling or continuous monitoring), used in Equation FF–1 of this subpart.

(g) Quarterly CH\textsubscript{4} concentration for each ventilation monitoring point, dates and locations of each measurement and method of measurement (sampling or continuous monitoring).

(h) Weekly volumetric flow rate used to calculate CH\textsubscript{4} liberated from degasification systems (cfm) and method of measurement (sampling or continuous monitoring), used in Equation FF–3 of this subpart.

(i) Quarterly CEMS CH\textsubscript{4} concentration (%) used to calculate CH\textsubscript{4} liberated from degasification systems (average from daily data), or quarterly CH\textsubscript{4} concentration data based on results from weekly sampling data (C).

(j) Weekly volumetric flow rate used to calculate CH\textsubscript{4} flow to each destruction device and each point of offsite transport (cfm).

(k) Weekly CH\textsubscript{4} concentration (%) used to calculate CH\textsubscript{4} flow to each destruction device and each point of offsite transport (C).

(l) Dates in quarterly reporting period where active ventilation of mining operations is taking place.

(m) Dates in quarterly reporting period where degasification of mining operations is taking place.

(n) Dates in quarterly reporting period when continuous monitoring equipment is not properly functioning, if applicable.

(o) Temperatures (°R), pressure (atm), and moisture content used in Equation FF–1 and FF–3 of this subpart, and the gaseous organic concentration correction factor, if Equation FF–9 was required.

(p) For each destruction device, a description of the device, including an indication of whether destruction occurs at the coal mine or off-site. If destruction occurs at the mine, also report an indication of whether a back-up destruction device is present at the mine.
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§ 98.333 Calculating GHG emissions.

You must calculate and report the annual process CO₂ emissions using the procedures specified in either paragraph (a) or (b) of this section.

(a) Calculate and report under this subpart the process or combined process and combustion CO₂ emissions by operating and maintaining a CEMS according to the Tier 4 Calculation Methodology in §98.33(a)(4) and all associated requirements for Tier 4 in subpart C of this part (General Stationary Fuel Combustion Sources).

(b) Calculate and report under this subpart the process CO₂ emissions by following paragraphs (b)(1) and (b)(2) of this section.

(1) For each Waelz kiln or electrothermic furnace at your facility used for zinc production, you must determine the mass of carbon in each carbon-containing material, other than fuel, that is fed, charged, or otherwise introduced into each Waelz kiln and electrothermic furnace at your facility for each year and calculate annual CO₂ process emissions from each affected unit at your facility using Equation GG–1 of this section. For electrothermic furnaces, carbon containing input materials include carbon electrodes and carbonaceous reducing...
§ 98.334 Monitoring and QA/QC requirements.

If you determine CO₂ emissions using the carbon input procedure in §98.333(b)(1) and (b)(2), you must meet the requirements specified in paragraphs (a) and (b) of this section.

(a) Determine the mass of each solid carbon-containing input material consumed using facility instruments, procedures, or records used for accounting purposes including direct measurement weighing or through the use of purchase records, some plant instruments, or procedures that are used for accounting purposes (such as weigh hoppers, belt weigh feeders, weighed purchased quantities in shipments or containers, combination of bulk density and volume measurements, etc.). Record the total mass for the materials...
§ 98.336 Data reporting requirements.

In addition to the information required by §98.3(c), each annual report must contain the information specified in paragraphs (a) or (b) of this section, as applicable, for each Waelz kiln or electrothermic furnace.

(a) If a CEMS is used to measure CO\textsubscript{2} emissions, then you must report under this subpart the relevant information required for the Tier 4 Calculation Methodology in §98.36 and the information listed in this paragraph (a):

1) Annual zinc product production capacity (tons).

2) Annual production quantity for each zinc product (tons).

3) Annual facility production quantity for each zinc product (tons).

4) Number of Waelz kilns at each facility used for zinc production.

5) Number of electrothermic furnaces at each facility used for zinc production.

(b) If a CEMS is not used to measure CO\textsubscript{2} emissions, then you must report the information listed in this paragraph (b):

1) Identification number and annual process CO\textsubscript{2} emissions from each individual Waelz kiln or electrothermic furnace (metric tons).
§ 98.337 Records that must be retained.

In addition to the records required by §98.3(g), you must retain the records specified in paragraphs (a) through (b) of this section for each zinc production facility.

(a) If a CEMS is used to measure emissions, then you must retain under this subpart the records required for the Tier 4 Calculation Methodology in §98.37 and the information listed in this paragraph (a):

1. Monthly facility production quantity for each zinc product (tons).
2. Annual operating hours for all Waelz kilns and electrothermic furnaces used in zinc production.

(b) If a CEMS is not used to measure emissions, you must also retain the records specified in paragraphs (b)(1) through (b)(7) of this section.

1. Records of all analyses and calculations conducted for data reported as listed in §98.336(b).
2. Annual operating hours for Waelz kilns and electrothermic furnaces used in zinc production.
3. Monthly production quantity for each zinc product (tons).
4. Monthly mass of zinc bearing materials, flux materials (e.g., limestone, dolomite), and carbonaceous materials (e.g., coal, coke) charged to the kiln or furnace (tons).
5. Monthly mass of carbon electrode consumed in for each electrothermic furnace (tons).
6. Sampling and analysis records for carbon content of electrode materials.
7. You must keep records that include a detailed explanation of how company records of measurements are used to estimate the carbon input to

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(2) Annual zinc product production capacity (tons).
(3) Annual production quantity for each zinc product (tons).
(4) Number of Waelz kilns at each facility used for zinc production.
(5) Number of electrothermic furnaces at each facility used for zinc production.
(6) Annual mass of each carbon-containing input material charged to each kiln or furnace (including zinc bearing material, flux materials (e.g., limestone, dolomite), carbon electrode, and other carbonaceous materials (e.g., coal, coke)) (tons).
(7) Carbon content of each carbon-containing input material charged to each kiln or furnace (including zinc bearing material, flux materials, and other carbonaceous materials) from the annual carbon analysis or from information provided by the material supplier for each kiln or furnace (percent by weight, expressed as a decimal fraction).
(8) Whether carbon content of each carbon-containing input material charged to each kiln or furnace is based on reports from the supplier or through self measurement using applicable ASTM standard method.
(9) If carbon content of each carbon-containing input material charged to each kiln or furnace is based on self measurement, the ASTM Standard Test Method used.
(10) Carbon content of the carbon electrode used in each furnace from the annual carbon analysis or from information provided by the material supplier (percent by weight, expressed as a decimal fraction).
(11) Whether carbon content of the carbon electrode used in each furnace is based on reports from the supplier or through self measurement using applicable ASTM standard method.
(12) If carbon content of carbon electrode used in each furnace is based on self measurement, the ASTM standard method used.
(13) If you use the missing data procedures in §98.335(b), you must report how the monthly mass of carbon-containing materials with missing data was determined and the number of months the missing data procedures were used.

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each Waelz kiln or electrothermic furnace, as applicable to your facility, including documentation of any materials excluded from Equation GG–1 of this subpart that contribute less than 1 percent of the total carbon inputs to the process. You also must document the procedures used to ensure the accuracy of the measurements of materials fed, charged, or placed in an affected unit including, but not limited to, calibration of weighing equipment and other measurement devices. The estimated accuracy of measurements made with these devices must also be recorded, and the technical basis for these estimates must be provided.

§ 98.338 Definitions.
All terms used in this subpart have the same meaning given in the Clean Air Act and subpart A of this part.

Subpart HH—Municipal Solid Waste Landfills
§ 98.340 Definition of the source category.
(a) This source category applies to municipal solid waste (MSW) landfills that accepted waste on or after January 1, 1980.

(b) This source category does not include Resource Conservation and Recovery Act (RCRA) Subtitle C or Toxic Substances Control Act (TSCA) hazardous waste landfills, construction and demolition waste landfills, or industrial waste landfills.

(c) This source category consists of the following sources at municipal solid waste (MSW) landfills: Landfills, landfill gas collection systems, and landfill gas destruction devices (including flares).


§ 98.341 Reporting threshold.
You must report GHG emissions under this subpart if your facility contains a MSW landfill and the facility meets the requirements of §98.2(a)(1).

§ 98.342 GHGs to report.
(a) You must report CH₄ generation and CH₄ emissions from landfills.

(b) You must report CH₄ destruction resulting from landfill gas collection and combustion systems.

(c) You must report under subpart C of this part (General Stationary Fuel Combustion Sources) the emissions of CO₂, CH₄, and N₂O from each stationary combustion unit following the requirements of subpart C.

§ 98.343 Calculating GHG emissions.
(a) For all landfills subject to the reporting requirements of this subpart, calculate annual modeled CH₄ generation using Equation HH–1 of this section.

\[
G_{CH_4} = \sum_{x=S}^{T} \left( W_x \times MCF \times DOC \times F \times 16 \times e^{-4(T-x-1)} - e^{-4(T-x)} \right) \]  

(Eq. HH-1)

Where:

- \( G_{CH_4} \) = Modeled methane generation rate in reporting year \( T \) (metric tons CH₄).
- \( x \) = Year in which waste was disposed.
- \( S \) = Start year of calculation. Use the year 1960 or the opening year of the landfill, whichever is more recent.
- \( T \) = Reporting year for which emissions are calculated.
- \( W_x \) = Quantity of waste disposed in the landfill in year \( x \) from measurement data, tipping fee receipts, or other company records (metric tons, as received (wet weight)).
- \( MCF \) = Methane correction factor (fraction).
- \( DOC \) = Degradable organic carbon from Table HH-1 of this subpart or measurement data, if available (fraction (metric tons C/metric ton waste)).
DOC = Fraction of DOC dissimilated (fraction). Use the default value of 0.5.

F = Fraction by volume of CH\textsubscript{4} in landfill gas from measurement data on a dry basis, if available (fraction); default is 0.5.

k = Rate constant from Table HH–1 to this subpart (yr\textsuperscript{−1}). Select the most applicable k value for the majority of the past 10 years (or operating life, whichever is shorter).

(2) For years when material-specific waste quantity data are available, apply Equation HH–1 of this section for each waste quantity type and sum the CH\textsubscript{4} generation rates for all waste types to calculate the total modeled CH\textsubscript{4} generation rate for the landfill.

Use the appropriate parameter values for k, DOC, MCF, DOC\textsubscript{F}, and F shown in Table HH–1 of this subpart. The annual quantity of each type of waste disposed must be calculated as the sum of the daily quantities of waste (of that type) disposed. You may use the bulk waste parameters for a portion of your waste materials when using the material-specific modeling approach for mixed waste streams that cannot be designated to a specific material type. For years when waste composition data are not available, use the bulk waste parameter values for k and DOC in Table HH–1 to this subpart for the total quantity of waste disposed in those years.

(3) Beginning in the first emissions reporting year and for each year thereafter, if scales are in place, you must determine the annual quantity of waste disposed of in the landfill using either of the following methods:

(A) Weigh using mass scales each vehicle or container used to haul waste as it enters the landfill or disposal area; weigh using mass scales each vehicle or container after it has off-loaded the waste; determine the quantity of waste received from the individual load as the difference in the two mass measurements; and determine the annual quantity of waste received as the sum of all waste loads received during the year.

(B) Weigh using mass scales each vehicle or container used to haul waste as it enters the landfill or disposal area; determine a representative tare weight by vehicle or container type by weighing no less than 5 of each type of vehicle or container after it has off-loaded the waste; determine the quantity of waste received from the individual load as the difference between the measured weight in and the tare weight determined for that container/vehicle type; and determine the annual quantity of waste received as the sum of all waste loads received during the year.

(ii) Determine the working capacity in units of mass for each type of container or vehicle used to haul waste to the landfill (e.g., using volumetric capacity and waste density measurements; direct measurement of a selected number of passenger vehicles and light duty pick-up trucks; or similar methods); record the number of
loads received at the landfill by vehicle/container type; calculate the annual mass per vehicle/container type as the mass product of the number of loads of that vehicle/container multiplied by its working capacity; and calculate the annual quantity of waste received as the sum of the annual mass per vehicle/container type across all of the vehicle/container types used to haul waste to the landfill.

(4) For years prior to the first emissions reporting year, use methods in paragraph (a)(3) of this section when waste disposal quantity data are readily available. When waste disposal quantity data are not readily available, \( W_X \) shall be estimated using one of the applicable methods in paragraphs (a)(4)(i) through (a)(4)(iii) of this section. You must determine which method is most applicable to the conditions and disposal history of your facility. Historical waste disposal quantities should only be determined once, as part of the first annual report, and the same values should be used for all subsequent annual reports, supplemented by the next year’s data on new waste disposal.

(i) Assume all prior years waste disposal quantities are the same as the waste quantity in the first year for which waste quantities are available.

(ii) Use the estimated population served by the landfill in each year, the values for national average per capita waste disposal rates found in Table HH–2 to this subpart, and calculate the waste quantity landfilled using Equation HH–2 of this section.

\[
W_X = POP_X \times WDR_X \quad \text{(Eq. HH-2)}
\]

where:

\( W_X \) = Quantity of waste placed in the landfill in year \( x \) (metric tons, wet basis).

\( POP_X \) = Population served by the landfill in year \( x \) from city population, census data, or other estimates (capita).

\( WDR_X \) = Average per capita waste disposal rate for year \( x \) from Table HH–2 to this subpart (metric tons per capita per year, wet basis; tons/cap/yr).

(iii) Use a constant average waste disposal quantity calculated using Equation HH–3 of this section for each year the landfill was in operation (i.e., from the first year accepting waste until the last year for which waste disposal data is unavailable, inclusive).

\[
W_X = \frac{LFC}{(YrData - YrOpen + 1)} \quad \text{(Eq. HH-3)}
\]

where:

\( W_X \) = Quantity of waste placed in the landfill in year \( x \) (metric tons, wet basis).

\( LFC \) = Landfill capacity or, for operating landfills, capacity of the landfill used (or the total quantity of waste-in-place) at the end of the year prior to the year when waste disposal data are available from design drawings or engineering estimates (metric tons).

\( YrData \) = Year in which the landfill last received waste or, for operating landfills, the year prior to the first reporting year when waste disposal data is first available from company records, or best available data.

\( YrOpen \) = Year in which the landfill first received waste from company records or best available data. If no data are available for estimating \( YrOpen \) for a closed landfill, use 30 years as the default operating life of the landfill.

(b) For landfills with gas collection systems, calculate the quantity of \( \text{CH}_4 \) destroyed according to the requirements in paragraphs (b)(1) and (b)(2) of this section.

(1) If you continuously monitor the flow rate, \( \text{CH}_4 \) concentration, temperature, pressure, and, if necessary, moisture content of the landfill gas that is collected and routed to a destruction device (before any treatment equipment) using a monitoring meter specifically for \( \text{CH}_4 \) gas, as specified in §98.344, you must use this monitoring system and calculate the quantity of \( \text{CH}_4 \) content recovered for destruction using Equation HH–4 of this section. A fully integrated system that directly reports \( \text{CH}_4 \) content requires no other calculation than summing the results of all monitoring periods for a given year.
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\[
R = \sum_{n=1}^{N} \left( V_n \times (K_{MC})_n \times \frac{(C_n)_{100\%}}{100} \times \frac{0.0423 \times 520^\circ R}{(T)_n} \times \frac{(P)_n}{1 \text{ atm}} \times \frac{0.454}{1,000} \right) \quad \text{(Eq. HH-4)}
\]

where:

- \( R \) = Annual quantity of recovered CH\(_4\) (metric tons CH\(_4\)).
- \( N \) = Total number of measurement periods in a year. Use daily averaging periods for a continuous monitoring system and \( N = 365 \) (or \( N = 366 \) for leap years). For weekly sampling, as provided in paragraph (b)(2) of this section, use \( N = 52 \).
- \( n \) = Index for measurement period.
- \( V_n \) = Cumulative volumetric flow for the measurement period in actual cubic feet (acf). If the flow rate meter automatically corrects for temperature and pressure, replace “520°R/(T) × (P) × 1 atm” with “1”.
- \( (K_{MC})_n \) = Moisture correction term for the measurement period, volumetric basis, as follows: \( (K_{MC})_n = 1 \) when \( V_n \) and \( C_n \) are both measured on a dry basis or if both are measured on a wet basis; \( (K_{MC})_n = 1/(1-\frac{(f_{H2O})_n}{(1-\frac{f_{H2O}}{1})}) \) when \( V_n \) is measured on a wet basis and \( C_n \) is measured on a dry basis; and \( (K_{MC})_n = 1/(1-\frac{f_{H2O}}{1}) \) when \( V_n \) is measured on a dry basis and \( C_n \) is measured on a wet basis.
- \( f_{H2O} \) = Average moisture content of landfill gas during the measurement period, volumetric basis (cubic feet water per cubic feet landfill gas).
- \( (C_{CH4})_n \) = Average CH\(_4\) concentration of landfill gas for the measurement period (volume %).
- 0.0423 = Density of CH\(_4\) lb/cfm at 520°R or 60 degrees Fahrenheit and 1 atm.
- \( (T)_n \) = Average temperature at which flow is measured for the measurement period (°R).
- \( (P)_n \) = Average pressure at which flow is measured for the measurement period (atm).
- 0.454/1,000 = Conversion factor (metric ton/lb).

(i) Continuously monitor gas flow rate and determine the cumulative volume of landfill gas each week and the cumulative volume of landfill gas each year that is collected and routed to a destruction device (before any treatment equipment). Under this option, the gas flow meter is not required to automatically correct for temperature, pressure, or, if necessary, moisture content. If the gas flow meter is not equipped with automatic correction for temperature, pressure, or, if necessary, moisture content, you must determine these parameters as specified in paragraph (b)(2)(iii) of this section.

(ii) Determine the CH\(_4\) concentration in the landfill gas that is collected and routed to a destruction device (before any treatment equipment) in a location near or representative of the location of the gas flow meter at least once each calendar week; if only one measurement is made each calendar week, there must be at least three days between measurements.

(iii) If the gas flow meter is not equipped with automatic correction for temperature, pressure, or, if necessary, moisture content:

(A) Determine the temperature and pressure in the landfill gas that is collected and routed to a destruction device (before any treatment equipment) in a location near or representative of the location of the gas flow meter at least once each calendar week; if only one measurement is made each calendar week, there must be at least three days between measurements.

(B) If the CH\(_4\) concentration is determined on a dry basis and flow is determined on a wet basis or CH\(_4\) concentration is determined on a wet basis and flow is determined on a dry basis, and the flow meter does not automatically correct for moisture content, determine the moisture content in the landfill gas that is collected and routed to a destruction device (before any treatment equipment) in a location near or representative of the location of the
gas flow meter at least once each calendar week; if only one measurement is made each calendar week, there must be at least three days between measurements.

(c) For all landfills, calculate CH\textsubscript{4} generation (adjusted for oxidation in cover materials) and actual CH\textsubscript{4} emissions (taking into account any CH\textsubscript{4} recovery, and oxidation in cover materials) according to the applicable methods in paragraphs (c)(1) through (c)(3) of this section.

(1) Calculate CH\textsubscript{4} generation, adjusted for oxidation, from the modeled CH\textsubscript{4} (\(G_{\text{CH}_4}\) from Equation HH–1 of this section) using Equation HH–5 of this section.

\[
MG = G_{\text{CH}_4} \times (1 - OX) \quad \text{(Eq. HH-5)}
\]

Where:

\(MG\) = Methane generation, adjusted for oxidation, from the landfill in the reporting year (metric tons CH\textsubscript{4}).

\(G_{\text{CH}_4}\) = Modeled methane generation rate in reporting year from Equation HH–1 of this section (metric tons CH\textsubscript{4}).

\(OX\) = Oxidation fraction. Use the default value of 0.1 (10%).

(2) For landfills that do not have landfill gas collection systems, the CH\textsubscript{4} emissions are equal to the CH\textsubscript{4} generation (MG) calculated in Equation HH–5 of this section.

(3) For landfills with landfill gas collection systems, calculate CH\textsubscript{4} emissions using the methodologies specified in paragraphs (c)(3)(i) and (c)(3)(ii) of this section.

(i) Calculate CH\textsubscript{4} emissions from the modeled CH\textsubscript{4} generation and measured CH\textsubscript{4} recovery using Equation HH–6 of this section.

\[
\text{Emissions} = \left[ (G_{\text{CH}_4} - R) \times (1 - OX) + R \times (1 - (DE \times f_{\text{Dest}})) \right] \quad \text{(Eq. HH-6)}
\]

Where:

\(E\text{missions}\) = Methane emissions from the landfill in the reporting year (metric tons CH\textsubscript{4}).

\(G_{\text{CH}_4}\) = Modeled methane generation rate in reporting year from Equation HH–1 of this section or the quantity of recovered CH\textsubscript{4} from Equation HH–4 of this section, whichever is greater (metric tons CH\textsubscript{4}).

\(R\) = Quantity of recovered CH\textsubscript{4} from Equation HH–4 of this section (metric tons CH\textsubscript{4}).

\(OX\) = Oxidation fraction. Use the oxidation fraction default value of 0.1 (10%).

\(DE\) = Destruction efficiency (lesser of manufacturer's specified destruction efficiency and 0.99). If the gas is transported off-site for destruction, use \(DE = 1\).

\(f_{\text{Dest}}\) = Fraction of hours the destruction device was operating (annual operating hours/8760 hours per year). If the gas is destroyed in a back-up flare (or similar device) or if the gas is transported off-site for destruction, use \(f_{\text{Dest}} = 1\).

(ii) Calculate CH\textsubscript{4} generation and CH\textsubscript{4} emissions using measured CH\textsubscript{4} recovery and estimated gas collection efficiency and Equations HH–7 and HH–8 of this section.

\[
MG = \frac{R}{CExf_{\text{Rec}}} \times (1 - OX) \quad \text{(Eq. HH-7)}
\]

\[
\text{Emissions} = \left[ \left( \frac{R}{CExf_{\text{Rec}}} - R \right) \times (1 - OX) + R \times (1 - (DE \times f_{\text{Dest}})) \right] \quad \text{(Eq. HH-8)}
\]

Where:

\(MG\) = Methane generation, adjusted for oxidation, from the landfill in the reporting year (metric tons CH\textsubscript{4}).

\(R\) = Quantity of recovered CH\textsubscript{4} from Equation HH–4 of this section (metric tons CH\textsubscript{4}).

\(E\text{missions}\) = Methane emissions from the landfill in the reporting year (metric tons CH\textsubscript{4}).
§ 98.344 Monitoring and QA/QC requirements.

(a) Mass measurement equipment used to determine the quantity of waste landfilled on or after January 1, 2010 must meet the requirements for weighing equipment as described in “Specifications, Tolerances, and Other Technical Requirements For Weighing and Measuring Devices” NIST Handbook 44 (2009) (incorporated by reference, see §98.7).

(b) For landfills with gas collection systems, operate, maintain, and calibrate a gas composition monitor capable of measuring the concentration of CH\textsubscript{4} in the recovered landfill gas using one of the methods specified in paragraphs (b)(1) through (b)(5) of this section or as specified by the manufacturer. Gas composition monitors shall be calibrated prior to the first reporting year and recalibrated either annually or at the minimum frequency specified by the manufacturer, whichever is more frequent, or whenever the error in the midrange calibration check exceeds ± 10 percent.

(1) Method 18 at 40 CFR part 60, appendix A–6.

(2) ASTM D1945–03, Standard Test Method for Analysis of Natural Gas by Gas Chromatography (incorporated by reference, see §98.7).

(3) ASTM D1946–90 (Reapproved 2006), Standard Practice for Analysis of Reformatted Gas by Gas Chromatography (incorporated by reference, see §98.7).

(4) GPA Standard 2261–00, Analysis for Natural Gas and Similar Gaseous Mixtures by Gas Chromatography.

(5) UOP539–97 Refinery Gas Analysis by Gas Chromatography (incorporated by reference, see §98.7).

(i) Use Method 25A or 25B at 40 CFR part 60, appendix A–7 to determine total gaseous organic concentration. You must calibrate the instrument with methane and determine the total gaseous organic concentration as carbon (or as methane; K=1 in Equation 25A–1 of Method 25A at 40 CFR part 60, appendix A–7).

(ii) Determine a non-methane organic carbon correction factor at the routine sampling location no less frequently than once a reporting year following the requirements in paragraphs (b)(6)(i) through (b)(6)(iii) of this section.

(A) Take a minimum of three grab samples of the landfill gas with a minimum of 20 minutes between samples and determine the methane composition of the landfill gas using one of the methods specified in paragraphs (b)(1) through (b)(5) of this section.

(B) As soon as practical after each grab sample is collected and prior to the collection of a subsequent grab sample, determine the total gaseous organic concentration of the landfill gas using either Method 25A or 25B at 40 CFR part 60, appendix A–7 as specified in paragraph (b)(6)(i) of this section.

(C) Determine the arithmetic average methane concentration and the arithmetic average total gaseous organic concentration of the samples analyzed according to paragraphs (b)(6)(i)(A) and (b)(6)(ii)(B) of this section, respectively, and calculate the non-methane organic carbon correction factor as the ratio of the average methane concentration to the average total gaseous organic concentration.
organic concentration. If the ratio exceeds 1, use 1 for the non-methane organic carbon correction factor.

(iii) Calculate the methane concentration as specified in Equation HH–9 of this section.

\[ C_{\text{CH}_4} = f_{\text{NMOC}} \times C_{\text{TGOC}} \quad \text{(Eq. HH-9)} \]

Where:

- \( C_{\text{CH}_4} \) = Methane concentration in the landfill gas (volume %) for use in Equation HH–4 of this subpart.
- \( f_{\text{NMOC}} \) = Non-methane organic carbon correction factor from the most recent determination of the non-methane organic carbon correction factor as specified in paragraph (b)(6)(ii) of this section (unitless).
- \( C_{\text{TGOC}} \) = Total gaseous organic carbon concentration measured using Method 25A or 25B at 40 CFR part 60, appendix A–7 during routine monitoring of the landfill gas (volume %).

(c) For landfills with gas collection systems, install, operate, maintain, and calibrate a gas flow meter capable of measuring the volumetric flow rate of the recovered landfill gas using one of the methods specified in paragraphs (c)(1) through (c)(8) of this section or as specified by the manufacturer. Each gas flow meter shall be recalibrated either biennially (every 2 years) or at the minimum frequency specified by the manufacturer. Except as provided in §98.343(b)(2)(1), each gas flow meter must be capable of correcting for the temperature and pressure and, if necessary, moisture content.


(8) Method 2A or 2D at 40 CFR part 60, appendix A–1.

(d) All temperature, pressure, and if necessary, moisture content monitors must be calibrated using the procedures and frequencies specified by the manufacturer.

(e) The owner or operator shall document the procedures used to ensure the accuracy of the estimates of disposal quantities and, if applicable, gas flow rate, gas composition, temperature, pressure, and moisture content measurements. These procedures include, but are not limited to, calibration of weighing equipment, fuel flow meters, and other measurement devices. The estimated accuracy of measurements made with these devices shall also be recorded, and the technical basis for these estimates shall be provided.

§98.345 Procedures for estimating missing data.

A complete record of all measured parameters used in the GHG emissions calculations is required. Therefore, whenever a quality-assured value of a required parameter is unavailable (e.g., if a meter malfunctions during unit operation or if a required fuel sample is not taken), a substitute data value for the missing parameter shall be used in the calculations, according to the requirements in paragraphs (a) through (c) of this section.

(a) For each missing value of the \( \text{CH}_4 \) content, the substitute data value shall be the arithmetic average of the quality-assured values of that parameter immediately preceding and immediately following the missing data incident. If the “after” value is not obtained by the end of the reporting year, you may use the “before” value for the missing data substitution. If, for a particular parameter, no quality-assured
§ 98.346 Data reporting requirements.

In addition to the information required by §98.3(c), each annual report must contain the following information for each landfill.

(a) A classification of the landfill as "open" (actively received waste in the reporting year) or "closed" (no longer receiving waste), the year in which the landfill first started accepting waste for disposal, the last year the landfill accepted waste (for open landfills, enter the estimated year of landfill closure), the capacity (in metric tons) of the landfill, an indication of whether leachate recirculation is used during the reporting year and its typical frequency of use over the past 10 years (e.g., used several times a year for the past 10 years, used at least once a year for the past 10 years, used occasionally but not every year over the past 10 years, not used), an indication as to whether scales are present at the landfill, and the waste disposal quantity for each year of landfilling required to be included when using Equation HH–1 of this subpart (in metric tons, wet weight).

(b) Method for estimating reporting year and historical waste disposal quantities, reason for its selection, and the range of years it is applied. For years when waste quantity data are determined using the methods in §98.343(a)(3), report separately the quantity of waste determined using the methods in §98.343(a)(3)(i) and the quantity of waste determined using the methods in §98.343(a)(3)(ii). For historical waste disposal quantities that were not determined using the methods in §98.343(a)(3), provide the population served by the landfill for each year the Equation HH–2 of this subpart is applied, if applicable, or, for open landfills using Equation HH–3 of this subpart, provide the value of landfill capacity (LFC) used in the calculation.

(c) Waste composition for each year required for Equation HH–1 of this subpart, in percentage by weight, for each waste category listed in Table HH–1 to this subpart that is used in Equation HH–1 of this subpart to calculate the annual modeled CH₄ generation.

(d) For each waste type used to calculate CH₄ generation using Equation HH–1 of this subpart, you must report:

(1) Degradable organic carbon (DOC), methane correction factor (MCF), and fraction of DOC dissimilated (DOCₜ) values used in the calculations. If an MCF value other than the default of 1 is used, provide an indication of whether active aeration of the waste in the landfill was conducted during the reporting year, a description of the aeration system, including aeration blower capacity, the fraction of the landfill containing waste affected by the aeration, the total number of hours during the year the aeration blower was operated, and other factors used as a basis for the selected MCF value.

(2) Decay rate (k) value used in the calculations.

(e) Fraction of CH₄ in landfill gas (F) and an indication of whether the fraction of CH₄ was determined based on measured values or the default value.

(f) The surface area of the landfill containing waste (in square meters), identification of the type of cover material used (as either organic cover, clay cover, sand cover, or other soil mixtures). If multiple cover types are used, the surface area associated with each cover type.
g) The modeled annual methane generation rate for the reporting year (metric tons CH\(_4\)) calculated using Equation HH–1 of this subpart.

h) For landfills without gas collection systems, the annual methane emissions (i.e., the methane generation, adjusted for oxidation, calculated using Equation HH–5 of this subpart), reported in metric tons CH\(_4\), and an indication of whether passive vents and/or passive flares (vents or flares that are not considered part of the gas collection system as defined in §98.6) are present at this landfill.

i) For landfills with gas collection systems, you must report:
   1) Total volumetric flow of landfill gas collected for destruction for the reporting year (cubic feet at 520 °R or 60 degrees Fahrenheit and 1 atm).
   2) Annual average CH\(_4\) concentration of landfill gas collected for destruction (percent by volume).
   3) Monthly average temperature and pressure for each month at which flow is measured for landfill gas collected for destruction, or statement that temperature and/or pressure is incorporated into internal calculations run by the monitoring equipment.
   4) An indication as to whether flow was measured on a wet or dry basis, an indication as to whether CH\(_4\) concentration was measured on a wet or dry basis, and if required for Equation HH–4 of this subpart, monthly average moisture content for each month at which flow is measured for landfill gas collected for destruction.
   5) An indication of whether destruction occurs at the landfill facility or off-site. If destruction occurs at the landfill facility, also report an indication of whether a back-up destruction device is present at the landfill, the annual operating hours for the primary destruction device, the annual operating hours for the back-up destruction device (if present), and the destruction efficiency used (percent).
   6) Annual quantity of recovered CH\(_4\) (metric tons CH\(_4\)) calculated using Equation HH–4 of this subpart.
   7) A description of the gas collection system (manufacturer, capacity, and number of wells), the surface area (square meters) and estimated waste depth (meters) for each area specified in Table HH–3 to this subpart, the estimated gas collection system efficiency for landfills with this gas collection system, the annual operating hours of the gas collection system, and an indication of whether passive vents and/or passive flares (vents or flares that are not considered part of the gas collection system as defined in §98.6) are present at the landfill.

(8) Methane generation corrected for oxidation calculated using Equation HH–5 of this subpart, reported in metric tons CH\(_4\).

(9) Methane generation (G\(_{CH4}\)) value used as an input to Equation HH–6 of this subpart. Specify whether the value is modeled (G\(_{CH4}\) from HH–1 of this subpart) or measured (R from Equation HH–4 of this subpart).

(10) Methane generation corrected for oxidation calculated using Equation HH–7 of this subpart, reported in metric tons CH\(_4\).

(11) Methane emissions calculated using Equation HH–6 of this subpart, reported in metric tons CH\(_4\).

(12) Methane emissions calculated using Equation HH–8 of this subpart, reported in metric tons CH\(_4\).

§ 98.347 Records that must be retained.

In addition to the information required by §98.3(g), you must retain the calibration records for all monitoring equipment, including the method or manufacturer’s specification used for calibration. You must retain records of all measurements made to determine tare weights and working capacities by vehicle/container type if these are used to determine the annual waste quantities.

§ 98.348 Definitions.

Except as specified in this section, all terms used in this subpart have the same meaning given in the Clean Air Act and subpart A of this part. Construction and demolition (C&D) waste landfill means a solid waste disposal facility subject to the requirements of part 257, subparts A or B of...
this chapter that receives construction and demolition waste and does not receive hazardous waste (defined in § 261.3 of this chapter) or industrial solid waste (defined in § 258.2 of this chapter) or municipal solid waste (as defined in § 96.6) other than residential lead-based paint waste. A C&D waste landfill typically receives any one or more of the following types of solid wastes: Roadwork material, excavated material, demolition waste, construction/renovation waste, and site clearance waste.

*Destruction device* means a flare, thermal oxidizer, boiler, turbine, internal combustion engine, or any other combustion unit used to destroy or oxidize methane contained in landfill gas.

*Industrial waste landfill* means any landfill other than a municipal solid waste landfill, a RCRA Subtitle C hazardous waste landfill, or a TSCA hazardous waste landfill, in which industrial solid waste, such as a RCRA Subtitle D wastes (nonhazardous industrial solid waste, defined in § 257.2 of this chapter), commercial solid wastes, or conditionally exempt small quantity generator wastes, is placed. An industrial waste landfill includes all disposal areas at the facility.

*Solid waste* has the meaning established by the Administrator pursuant to the Solid Waste Disposal Act (42 U.S.C.A. 6901 et seq.).

*Working capacity* means the maximum volume or mass of waste that is actually placed in the landfill from an individual or representative type of container (such as a tank, truck, or roll-off bin) used to convey wastes to the landfill, taking into account that the container may not be able to be 100 percent filled and/or 100 percent emptied for each load.

(75 FR 66473, Oct. 28, 2010)

### Table HH–1 to Subpart HH of Part 98—Emissions Factors, Oxidation Factors and Methods

<table>
<thead>
<tr>
<th>Factor</th>
<th>Default value</th>
<th>Units</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>DOC and k values—Bulk waste option</strong></td>
<td></td>
<td></td>
</tr>
<tr>
<td>DOC (bulk waste)</td>
<td>0.20</td>
<td>Weight fraction, wet basis.</td>
</tr>
<tr>
<td>k (precipitation plus recirculated leachate &lt;20 inches/year)</td>
<td>0.038</td>
<td>yr⁻¹</td>
</tr>
<tr>
<td>k (precipitation plus recirculated leachate 20–40 inches/year)</td>
<td>0.057</td>
<td>yr⁻¹</td>
</tr>
<tr>
<td>k (precipitation plus recirculated leachate &gt;40 inches/year)</td>
<td>0.02</td>
<td>yr⁻¹</td>
</tr>
<tr>
<td><strong>DOC and k values—Modified bulk MSW option</strong></td>
<td></td>
<td></td>
</tr>
<tr>
<td>DOC (bulk MSW, excluding inerts and C&amp;D waste)</td>
<td>0.31</td>
<td>Weight fraction, wet basis.</td>
</tr>
<tr>
<td>DOC (inerts, e.g., glass, plastics, metal, concrete)</td>
<td>0.00</td>
<td>Weight fraction, wet basis.</td>
</tr>
<tr>
<td>DOC (C&amp;D waste)</td>
<td>0.08</td>
<td>Weight fraction, wet basis.</td>
</tr>
<tr>
<td>k (bulk MSW, excluding inerts and C&amp;D waste)</td>
<td>0.02 to 0.057</td>
<td>yr⁻¹</td>
</tr>
<tr>
<td>k (inerts, e.g., glass, plastics, metal, concrete)</td>
<td>0.02 to 0.04</td>
<td>yr⁻¹</td>
</tr>
<tr>
<td><strong>DOC and k values—Waste composition option</strong></td>
<td></td>
<td></td>
</tr>
<tr>
<td>DOC (food waste)</td>
<td>0.15</td>
<td>Weight fraction, wet basis.</td>
</tr>
<tr>
<td>DOC (garden)</td>
<td>0.2</td>
<td>Weight fraction, wet basis.</td>
</tr>
<tr>
<td>DOC (paper)</td>
<td>0.4</td>
<td>Weight fraction, wet basis.</td>
</tr>
<tr>
<td>DOC (wood and straw)</td>
<td>0.43</td>
<td>Weight fraction, wet basis.</td>
</tr>
<tr>
<td>DOC (textiles)</td>
<td>0.24</td>
<td>Weight fraction, wet basis.</td>
</tr>
<tr>
<td>DOC (diapers)</td>
<td>0.24</td>
<td>Weight fraction, wet basis.</td>
</tr>
<tr>
<td>DOC (sewage sludge)</td>
<td>0.05</td>
<td>Weight fraction, wet basis.</td>
</tr>
<tr>
<td>DOC (inerts, e.g., glass, plastics, metal, cement)</td>
<td>0.00</td>
<td>Weight fraction, wet basis.</td>
</tr>
<tr>
<td>k (food waste)</td>
<td>0.06 to 0.185</td>
<td>yr⁻¹</td>
</tr>
<tr>
<td>k (garden)</td>
<td>0.05 to 0.1</td>
<td>yr⁻¹</td>
</tr>
<tr>
<td>k (paper)</td>
<td>0.04 to 0.06</td>
<td>yr⁻¹</td>
</tr>
<tr>
<td>k (wood and straw)</td>
<td>0.04 to 0.06</td>
<td>yr⁻¹</td>
</tr>
<tr>
<td>k (textiles)</td>
<td>0.04 to 0.06</td>
<td>yr⁻¹</td>
</tr>
<tr>
<td>k (diapers)</td>
<td>0.05 to 0.1</td>
<td>yr⁻¹</td>
</tr>
<tr>
<td>k (sewage sludge)</td>
<td>0.06 to 0.185</td>
<td>yr⁻¹</td>
</tr>
<tr>
<td>k (inerts e.g., glass, plastics, metal, concrete)</td>
<td>0.00</td>
<td>yr⁻¹</td>
</tr>
</tbody>
</table>

**Other parameters—All MSW landfills**

| MCF | 1. |
| DOC | 0.5. |
Recirculated leachate (in inches/year) is the total volume of leachate recirculated from company records or engineering estimates divided by the area of the portion of the landfill containing waste with appropriate unit conversions. Alternatively, landfills that use leachate recirculation can elect to use the k value of 0.057 rather than calculating the recirculated leachate rate.

Use the lesser value when precipitation plus recirculated leachate is less than 20 inches/year. Use the greater value when precipitation plus recirculated leachate is greater than 20 inches/year. Use the average of the range of values when precipitation plus recirculated leachate is 20 to 40 inches/year (inclusive). Alternatively, landfills that use leachate recirculation can elect to use the greater value rather than calculating the recirculated leachate rate.

Use the lesser value when the potential evapotranspiration rate exceeds the mean annual precipitation rate plus recirculated leachate. Use the greater value when the potential evapotranspiration rate does not exceed the mean annual precipitation rate plus recirculated leachate. Alternatively, landfills that use leachate recirculation can elect to use the greater value rather than assessing the potential evapotranspiration rate or recirculated leachate rate.

<table>
<thead>
<tr>
<th>Year</th>
<th>Waste per capita ton/cap/yr</th>
<th>% to SWDS</th>
</tr>
</thead>
<tbody>
<tr>
<td>1950</td>
<td>0.63</td>
<td>100</td>
</tr>
<tr>
<td>1951</td>
<td>0.63</td>
<td>100</td>
</tr>
<tr>
<td>1952</td>
<td>0.63</td>
<td>100</td>
</tr>
<tr>
<td>1953</td>
<td>0.63</td>
<td>100</td>
</tr>
<tr>
<td>1954</td>
<td>0.63</td>
<td>100</td>
</tr>
<tr>
<td>1955</td>
<td>0.63</td>
<td>100</td>
</tr>
<tr>
<td>1956</td>
<td>0.63</td>
<td>100</td>
</tr>
<tr>
<td>1957</td>
<td>0.63</td>
<td>100</td>
</tr>
<tr>
<td>1958</td>
<td>0.63</td>
<td>100</td>
</tr>
<tr>
<td>1959</td>
<td>0.63</td>
<td>100</td>
</tr>
<tr>
<td>1960</td>
<td>0.63</td>
<td>100</td>
</tr>
<tr>
<td>1961</td>
<td>0.64</td>
<td>100</td>
</tr>
<tr>
<td>1962</td>
<td>0.64</td>
<td>100</td>
</tr>
<tr>
<td>1963</td>
<td>0.65</td>
<td>100</td>
</tr>
<tr>
<td>1964</td>
<td>0.65</td>
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</tr>
<tr>
<td>1965</td>
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<tr>
<td>1966</td>
<td>0.66</td>
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<tr>
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<td>1968</td>
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<td>1973</td>
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<tr>
<td>1978</td>
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<tr>
<td>1979</td>
<td>0.75</td>
<td>100</td>
</tr>
<tr>
<td>1980</td>
<td>0.75</td>
<td>100</td>
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</tbody>
</table>

Environmental Protection Agency

Pt. 98, Subpt. HH, Table HH–3

<table>
<thead>
<tr>
<th>Factor</th>
<th>Default value</th>
<th>Units</th>
</tr>
</thead>
<tbody>
<tr>
<td>F</td>
<td>0.5</td>
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</tr>
<tr>
<td>OX</td>
<td>0.1</td>
<td></td>
</tr>
<tr>
<td>DE</td>
<td>0.99</td>
<td></td>
</tr>
</tbody>
</table>

EDITORIAL NOTE: At 75 FR 66474, October 28, 2010, Table HH–2 to subpart HH was amended; however, the amendment could not be incorporated as instructed.

Table HH–3 to Subpart HH of Part 98—Landfill Gas Collection Efficiencies

<table>
<thead>
<tr>
<th>Description</th>
<th>Landfill Gas Collection Efficiency</th>
</tr>
</thead>
<tbody>
<tr>
<td>A1: Area with no waste in-place</td>
<td>Not applicable; do not use this area in the calculation.</td>
</tr>
<tr>
<td>A2: Area without active gas collection, regardless of cover type</td>
<td>CE2: 0%.</td>
</tr>
<tr>
<td>A3: Area with daily soil cover and active gas collection</td>
<td>CE3: 60%.</td>
</tr>
<tr>
<td>A4: Area with an intermediate soil cover, or a final soil cover not meeting the criteria for A5 below, and active gas collection</td>
<td>CE4: 75%.</td>
</tr>
<tr>
<td>A5: Area with a final soil cover of 3 feet or thicker of clay and/or geomembrane cover system and active gas collection</td>
<td>CE5: 95%.</td>
</tr>
<tr>
<td>Area weighted average collection efficiency for landfills</td>
<td>CEave1 = (A2<em>CE2 + A3</em>CE3 + A4<em>CE4 + A5</em>CE5)/(A2+A3+A4+A5).</td>
</tr>
</tbody>
</table>
Subpart II—Industrial Wastewater Treatment

Subpart II—Industrial Wastewater Treatment

§ 98.350 Definition of source category.

(a) This source category consists of anaerobic processes used to treat industrial wastewater and industrial wastewater treatment sludge at facilities that perform the operations listed in this paragraph.

(1) Pulp and paper manufacturing.
(2) Food processing.
(3) Ethanol production.
(4) Petroleum refining.

(b) An anaerobic process is a procedure in which organic matter in wastewater, wastewater treatment sludge, or other material is degraded by micro-organisms in the absence of oxygen, resulting in the generation of CO₂ and CH₄.

This source category consists of the following: anaerobic reactors, anaerobic lagoons, anaerobic sludge digesters, and biogas destruction devices (for example, burners, boilers, turbines, flares, or other devices).

(1) An anaerobic reactor is an enclosed vessel used for anaerobic wastewater treatment (e.g., upflow anaerobic sludge blanket, fixed film).

(2) An anaerobic sludge digester is an enclosed vessel in which wastewater treatment sludge is degraded anaerobically.

(3) Anaerobic lagoon is a lined or unlined earthen basin used for wastewater treatment, in which oxygen is absent throughout the depth of the basin, except for a shallow surface zone. Anaerobic lagoons are not equipped with surface aerators. Anaerobic lagoons are classified as deep (depth more than 2 meters) or shallow (depth less than 2 meters).

(c) This source category does not include municipal wastewater treatment plants or separate treatment of sanitary wastewater at industrial sites.

§ 98.351 Reporting threshold.

You must report GHG emissions under this subpart if your facility meets all of the conditions under paragraphs (a) or (b) of this section:

(a) Petroleum refineries and pulp and paper manufacturing.

(1) The facility is subject to reporting under subpart Y of this part (Petroleum Refineries) or subpart AA of this part (Pulp and Paper Manufacturing).

(2) The facility meets the requirements of either §98.2(a)(1) or (2).

(3) The facility operates an anaerobic process to treat industrial wastewater and/or industrial wastewater treatment sludge.

(b) Ethanol production and food processing facilities.

(1) The facility performs an ethanol production or food processing operation, as defined in §98.358 of this subpart.

(2) The facility meets the requirements of §98.2(a)(2).

(3) The facility operates an anaerobic process to treat industrial wastewater and/or industrial wastewater treatment sludge.

§ 98.352 GHGs to report.

(a) You must report CH₄ generation, CH₄ emissions, and CH₄ recovered from treatment of industrial wastewater at each anaerobic lagoon and anaerobic reactor.

(b) You must report CH₄ emissions and CH₄ recovered from each anaerobic sludge digester.

(c) You must report CH₄ emissions and CH₄ destruction resulting from each biogas collection and biogas destruction device.

(d) You must report under subpart C of this part (General Stationary Fuel Combustion Sources) the emissions of CO₂, CH₄, and N₂O from each stationary combustion unit associated with the biogas destruction device, if present, by following the requirements of subpart C of this part.

§ 98.353 Calculating GHG emissions.

(a) For each anaerobic reactor and anaerobic lagoon, estimate the annual mass of CH₄ generated according to the
applicable requirements in paragraphs (a)(1) through (a)(2) of this section.

(1) If you measure the concentration of organic material entering the anaerobic reactors or anaerobic lagoon using methods for the determination of chemical oxygen demand (COD), then estimate annual mass of CH₄ generated using Equation II–1 of this section.

\[
CH_4 G_n = \sum_{n=1}^{52} \left[ Flow_w \times COD_w \times B_o \times MCF \times 0.001 \right] 
\]  
(Eq. II-1)

Where:
- \( CH_4 G_n \) = Annual mass CH₄ generated from the nth anaerobic wastewater treatment process (metric tons).
- \( n \) = Index for processes at the facility, used in Equation II–7.
- \( w \) = Index for weekly measurement period.
- \( Flow_w \) = Volume of wastewater sent to an anaerobic wastewater treatment process in week \( w \) (m³/week), measured as specified in §98.354(d).
- \( COD_w \) = Average weekly concentration of chemical oxygen demand of wastewater entering an anaerobic wastewater treatment process for week \( w \) (kg/m³), measured as specified in §98.354(b) and (c).
- \( B_o \) = Maximum CH₄ producing potential of wastewater (kg CH₄/kg COD), use the value 0.25.
- \( MCF \) = CH₄ conversion factor, based on relevant values in Table II–1 of this subpart.
- \( 0.001 \) = Conversion factor from kg to metric tons.

(2) If you measure the concentration of organic material entering an anaerobic reactor or anaerobic lagoon using methods for the determination of 5-day biochemical oxygen demand (BOD₅), then estimate annual mass of CH₄ generated using Equation II–2 of this section.

\[
CH_4 G_n = \sum_{w=1}^{52} \left[ Flow_w \times BOD_{5,w} \times B_o \times MCF \times 0.001 \right] 
\]  
(Eq. II-2)

Where:
- \( CH_4 G_n \) = Annual mass of CH₄ generated from the wastewater treatment process \( n \) (metric tons).
- \( n \) = Index for processes at the facility, used in Equation II–7.
- \( w \) = Index for weekly measurement period.
- \( Flow_w \) = Volume of wastewater sent to an anaerobic wastewater treatment process in week \( w \) (m³/week), measured as specified in §98.354(d).
- \( BOD_{5,w} \) = Average weekly concentration of 5-day biochemical oxygen demand of wastewater entering an anaerobic wastewater treatment process for week \( w \) (kg/m³), measured as specified in §98.354(b) and (c).
- \( B_o \) = Maximum CH₄ producing potential of wastewater (kg CH₄/kg BOD₅), use the value 0.6.
- \( MCF \) = CH₄ conversion factor, based on relevant values in Table II–1 to this subpart.
- \( 0.001 \) = Conversion factor from kg to metric tons.

(b) For each anaerobic reactor and anaerobic lagoon from which biogas is not recovered, estimate annual CH₄ emissions using Equation II–3 of this section.

\[
CH_4 E_n = CH_4 G_n 
\]  
(Eq. II-3)

Where:
- \( CH_4 E_n \) = Annual mass of CH₄ emissions from the wastewater treatment process \( n \) from which biogas is not recovered (metric tons).
- \( CH_4 G_n \) = Annual mass of CH₄ generated from the wastewater treatment process \( n \), as calculated in Equation II–1 or II–2 of this section (metric tons).

(c) For each anaerobic sludge digester, anaerobic reactor, or anaerobic lagoon from which some biogas is recovered, estimate the annual mass of CH₄ recovered according to the requirements in paragraphs (c)(1) and (c)(2) of this section. To estimate the annual
mass of CH₄ recovered, you must continuously monitor biogas flow rate and determine the volume of biogas each week and the cumulative volume of biogas each year that is collected and routed to a destruction device as specified in §98.354(b). If the gas flow meter is not equipped with automatic correction for temperature, pressure, or, if necessary, moisture content, you must determine these parameters as specified in paragraph (c)(2)(ii) of this section.

(1) If you continuously monitor CH₄ concentration and if necessary, temperature, pressure, and moisture content required as specified in §98.354(f) of the biogas that is collected and routed to a destruction device using a monitoring meter specifically for CH₄ gas, as specified in §98.354(g), you must use this monitoring system and calculate the quantity of CH₄ recovered for destruction using Equation II-4 of this section. A fully integrated system that directly reports CH₄ quantity requires only the summing of results of all monitoring periods for a given year.

\[ R_n = \sum_{m=L}^{M} \left( V_m \cdot (K_{MC})_m \cdot \frac{(C_{CH₄})_m}{100\%} \cdot 0.0423 \cdot \frac{520^°R}{P_m} \cdot \frac{(T_m)}{1\ atm} \cdot \frac{0.454}{1,000} \right) \]  

(Eq. II-4)

Where:
- \( R_n \) = Annual quantity of CH₄ recovered from the nth anaerobic reactor, sludge digester, or lagoon (metric tons CH₄/yr).
- \( m \) = Index for processes at the facility, used in Equation II-7.
- \( M \) = Total number of measurement periods in a year. Use \( M = 365 \) (\( M = 366 \) for leap years) for daily averaging of continuous monitoring, as provided in paragraph (c)(1) of this section. Use \( M = 52 \) for weekly sampling, as provided in paragraph (c)(2) of this section.
- \( m \) = Index for measurement period.
- \( V_m \) = Cumulative volumetric flow for the measurement period in actual cubic feet (acf). If no biogas was recovered during a monitoring period, use zero.
- \( (K_{MC})_m \) = Moisture correction term for the measurement period, volumetric basis.
  - 1 when \( (V)_m \) and \( (C_{CH₄})_m \) are measured on a dry basis or if both are measured on a wet basis.
  - 1\( - (f_{MC20})_m \) when \( (V)_m \) is measured on a wet basis and \( (C_{CH₄})_m \) is measured on a dry basis.
  - 0\( - (f_{MC20})_m \) when \( (V)_m \) is measured on a dry basis and \( (C_{CH₄})_m \) is measured on a wet basis.
- \( (f_{MC20})_m \) = Average moisture content of biogas during the measurement period, volumetric basis, (cubic feet water per cubic feet biogas).
- \( (C_{CH₄})_m \) = Average CH₄ concentration of biogas during the measurement period, (volume %).
- 0.0423 = Density of CH₄ lb/cf at 520 °R or 60 °F and 1 atm.
- 520 °R = 520 degrees Rankine.

(2) If you do not continuously monitor CH₄ concentration according to paragraph (c)(1) of this section, you must determine the CH₄ concentration, temperature, pressure, and, if necessary, moisture content of the biogas that is collected and routed to a destruction device according to the requirements in paragraphs (c)(2)(i) through (c)(2)(ii) of this section and calculate the quantity of CH₄ recovered for destruction using Equation II-4 of this section.

(1) Determine the CH₄ concentration in the biogas that is collected and routed to a destruction device in a location near or representative of the location of the gas flow meter at least once each calendar week; if only one measurement is made each calendar week, there must be at least three days between measurements. For a given calendar
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week, you are not required to determine CH$_4$ concentration if the cumulative volume of biogas for that calendar week, determined as specified in paragraph (c) of this section, is zero.

(ii) If the gas flow meter is not equipped with automatic correction for temperature, pressure, or, if necessary, moisture content:

(A) Determine the temperature and pressure in the biogas that is collected and routed to a destruction device in a location near or representative of the location of the gas flow meter at least once each calendar week; if only one measurement is made each calendar week, there must be at least three days between measurements.

(B) If the CH$_4$ concentration is determined on a dry basis and biogas flow is determined on a wet basis, or CH$_4$ concentration is determined on a wet basis and biogas flow is determined on a dry basis, and the flow meter does not automatically correct for moisture content, determine the moisture content in the biogas that is collected and routed to a destruction device in a location near or representative of the location of the gas flow meter at least once each calendar week that the cumulative biogas flow measured as specified in §98.354(h) is greater than zero; if only one measurement is made each calendar week, there must be at least three days between measurements.

(d) For each anaerobic sludge digester, anaerobic reactor, or anaerobic lagoon from which some quantity of biogas is recovered, you must estimate both the annual mass of CH$_4$ that is generated, but not recovered, according to paragraph (d)(1) of this section and the annual mass of CH$_4$ emitted according to paragraph (d)(2) of this section.

(1) Estimate the annual mass of CH$_4$ that is generated, but not recovered, using Equation II–5 of this section.

\[
CH_4L_n = R_n \times \left( \frac{1}{CE} - 1 \right)
\]  

(Eq. II-5)

Where:

\(CH_4L_n = \text{Leakage at the anaerobic process } n\) (metric tons CH$_4$).
\(R_n = \text{Annual quantity of CH}_4 \text{ recovered from the } n\text{th anaerobic reactor, anaerobic lagoon, or anaerobic sludge digester, as calculated in Equation II–4 of this section (metric tons CH}_4\).
\(CE = \text{CH}_4 \text{ collection efficiency of anaerobic process } n\), as specified in Table II–2 of this subpart (decimal).

(2) For each anaerobic sludge digester, anaerobic reactor, or anaerobic lagoon from which some quantity of biogas is recovered, estimate the annual mass of CH$_4$ emitted using Equation II–6 of this section.

\[
CH_4E_n = CH_4L_n + R_n \times \left(1 - \left( DE_1 \times f_{Dest-1}\right) + (DE_2 \times f_{Dest-2})\right)
\]  

(Eq. II-6)

Where:

\(CH_4E_n = \text{Annual quantity of CH}_4 \text{ emitted from the process } n\) from which biogas is recovered (metric tons).
\(n = \text{Index for processes at the facility, used in Equation II-7.}\)
\(CH_4L_n = \text{Leakage at the anaerobic process } n\), as calculated in Equation II–5 of this section (metric tons CH$_4$).
\(R_n = \text{Annual quantity of CH}_4 \text{ recovered from the } n\text{th anaerobic reactor or anaerobic sludge digester, as calculated in Equation II–4 of this section (metric tons CH}_4\).
\(DE_1 = \text{Primary destruction device CH}_4 \text{ destruction efficiency (lesser of manufacturer’s specified destruction efficiency and 0.99).}\)
\(DE_2 = \text{Back-up destruction device CH}_4 \text{ destruction efficiency (lesser of manufacturer’s specified destruction efficiency and 0.99).}\)
\(f_{Dest-1} = \text{Fraction of hours the primary destruction device was operating (device operating hours/hours in the year).}\)
If the biogas is transported off-site for destruction, use \(f_{Dest-1} = 1\).
\(f_{Dest-2} = \text{Fraction of hours the back-up destruction device was operating (device operating hours/hours in the year).}\)

(e) Estimate the total mass of CH$_4$ emitted from all anaerobic processes from which biogas is not recovered (calculated in Eq. II–3) and all anaerobic processes from which some biogas is recovered (calculated in Equation II–6) using Equation II–7 of this section.
\[ CH_4 E_T = \sum_{n=1}^{j} CH_4 E_n \]  
(Eq. II-7)

Where:
- \( CH_4 E_T \) = Annual mass \( CH_4 \) emitted from all anaerobic processes at the facility (metric tons).
- \( n \) = Index for processes at the facility.
- \( CH_4 E_n \) = Annual mass of \( CH_4 \) emissions from process \( n \) (metric tons).
- \( j \) = Total number of processes from which methane is emitted.

[75 FR 39767, July 12, 2010, as amended at 76 FR 73903, Nov. 29, 2011]

§ 98.354 Monitoring and QA/QC requirements.

(a) For calendar year 2011 monitoring, the facility may submit a request to the Administrator to use one or more best available monitoring methods as listed in §98.3(d)(1)(i) through (iv). The request must be submitted no later than October 12, 2010 and must contain the information in §98.3(d)(2)(ii). To obtain approval, the request must demonstrate to the Administrator's satisfaction that it is not reasonably feasible to acquire, install, and operate a required piece of monitoring equipment by January 1, 2011. The use of best available monitoring methods will not be approved beyond December 31, 2011.

(b) You must determine the concentration of organic material in wastewater treated anaerobically using analytical methods for COD or BOD₅ specified in 40 CFR 136.3 Table 1B. For the purpose of determining concentrations of wastewater influent to the anaerobic wastewater treatment process, samples may be diluted to the concentration range of the approved method, but the calculated concentration of the undiluted wastewater must be used for calculations and reporting required by this subpart.

(c) You must collect samples representing wastewater influent to the anaerobic wastewater treatment process, following all preliminary and primary treatment steps (e.g., after grit removal, primary clarification, oil-water separation, dissolved air flotation, or similar solids and oil separation processes). You must collect and analyze samples for COD or BOD₅ concentration at least once each calendar week that the anaerobic wastewater treatment process is operating; if only one measurement is made each calendar week, there must be at least three days between measurements. You must collect a sample that represents the average COD or BOD₅ concentration of the waste stream over a 24-hour sampling period. You must collect a minimum of four sample aliquots per 24-hour period and composite the aliquots for analysis. Collect a flow-proportional composite sample (either constant time interval between samples with sample volume proportional to stream flow, or constant sample volume with time interval between samples proportional to stream flow). Follow sampling procedures and techniques presented in Chapter 5, Sampling, of the “NPDES Compliance Inspection Manual,” (incorporated by reference, see §98.7) or Section 7.1.3, Sample Collection Methods, of the “U.S. EPA NPDES Permit Writers’ Manual,” (incorporated by reference, see §98.7).

(d) You must measure the flowrate of wastewater entering anaerobic wastewater treatment process at least once each calendar week that the process is operating; if only one measurement is made each calendar week, there must be at least three days between measurements. You must measure the flowrate for the 24-hour period for which you collect samples analyzed for COD or BOD₅ concentration. The flow measurement location must correspond to the location used to collect samples analyzed for COD or BOD₅ concentration. You must measure the flowrate using one of the methods specified in paragraphs (d)(1) through (d)(5) of this section or as specified by the manufacturer.


(e) All wastewater flow measurement devices must be calibrated prior to the first year of reporting and recalibrated either biennially (every 2 years) or at the minimum frequency specified by the manufacturer. Wastewater flow measurement devices must be calibrated using the procedures specified by the device manufacturer.

(f) For each anaerobic process (such as anaerobic reactor, sludge digester, or lagoon) from which biogas is recovered, you must make the measurements or determinations specified in paragraphs (f)(1) through (f)(3) of this section.

(1) You must continuously measure the biogas flow rate as specified in paragraph (h) of this section and determine the cumulative volume of biogas recovered.

(2) You must determine the \( \text{CH}_4 \) concentration of the recovered biogas as specified in paragraph (g) of this section at a location near or representative of the location of the gas flow meter. You must determine \( \text{CH}_4 \) concentration either continuously or intermittently. If you determine the concentration intermittently, you must determine the concentration at least once each calendar week that the cumulative biogas flow measured as specified in paragraph (h) of this section is greater than zero, with at least three days between measurements.

(3) As specified in §98.353(c) and paragraph (h) of this section, you must determine temperature, pressure, and moisture content as necessary to accurately determine the biogas flow rate and \( \text{CH}_4 \) concentration. You must determine temperature and pressure if the gas flow meter or gas composition monitor do not automatically correct for temperature or pressure. You must measure moisture content of the recovered biogas if the biogas flow rate is measured on a wet basis and the \( \text{CH}_4 \) concentration is measured on a dry basis. You must also measure the moisture content of the recovered biogas if the biogas flow rate is measured on a dry basis and the \( \text{CH}_4 \) concentration is measured on a wet basis.

(g) For each anaerobic process (such as anaerobic reactor, sludge digester, or lagoon) from which biogas is recovered, operate, maintain, and calibrate a gas composition monitor capable of measuring the concentration of \( \text{CH}_4 \) in the recovered biogas using one of the methods specified in paragraphs (g)(1) through (g)(6) of this section or as specified by the manufacturer.

(1) Method 18 at 40 CFR part 60, appendix A–6.

(2) ASTM D1945–03, Standard Test Method for Analysis of Natural Gas by Gas Chromatography (incorporated by reference, see §98.7).

(3) ASTM D1946–90 (Reapproved 2006), Standard Practice for Analysis of Reformed Gas by Gas Chromatography (incorporated by reference, see §98.7).

(4) GPA Standard 2261–00, Analysis for Natural Gas and Similar Gaseous Mixtures by Gas Chromatography (incorporated by reference, see §98.7).

(5) ASTM UOP539–97 Refinery Gas Analysis by Gas Chromatography (incorporated by reference, see §98.7).

(6) As an alternative to the gas chromatography methods provided in paragraphs (g)(1) through (g)(5) of this section, you may use total gaseous organic concentration analyzers and calculate the \( \text{CH}_4 \) concentration following the requirements in paragraphs (g)(6)(i) through (g)(6)(iii) of this section.

(i) Use Method 25A or 25B at 40 CFR part 60, appendix A–7 to determine total gaseous organic concentration. You must calibrate the instrument with \( \text{CH}_4 \) and determine the total gaseous organic concentration as carbon (or as \( \text{CH}_4; K=1 \) in Equation 25A–1 of Method 25A at 40 CFR part 60, appendix A–7).

(ii) Determine a non-methane organic carbon correction factor at the routine sampling location no less frequently than once a reporting year following the requirements in paragraphs (g)(6)(ii)(A) through (g)(6)(ii)(C) of this section.
(A) Take a minimum of three grab samples of the biogas with a minimum of 20 minutes between samples and determine the methane composition of the biogas using one of the methods specified in paragraphs (g)(1) through (g)(5) of this section.

(B) As soon as practical after each grab sample is collected and prior to the collection of a subsequent grab sample, determine the total gaseous organic concentration of the biogas using either Method 25A or 25B at 40 CFR part 60, appendix A-7 as specified in paragraph (g)(6)(i) of this section.

(C) Determine the arithmetic average methane concentration and the arithmetic average total gaseous organic concentration of the samples analyzed according to paragraphs (g)(6)(ii)(A) and (g)(6)(ii)(B) of this section, respectively, and calculate the non-methane organic carbon correction factor as the ratio of the average methane concentration to the average total gaseous organic concentration. If the ratio exceeds 1, use 1 for the non-methane organic carbon correction factor.

(iii) Calculate the CH\(_4\) concentration as specified in Equation II–8 of this section.

\[
C_{CH4} = f_{NMOC} \times C_{TGOC} \quad \text{(Eq. II-8)}
\]

Where:

- \(C_{CH4}\) = Methane (CH\(_4\)) concentration in the biogas (volume \%) for use in Equation II–4 of this subpart.

- \(f_{NMOC}\) = Non-methane organic carbon correction factor from the most recent determination of the non-methane organic carbon correction factor as specified in paragraph (g)(6)(ii) of this section (unitless).

- \(C_{TGOC}\) = Total gaseous organic carbon concentration measured using Method 25A or 25B at 40 CFR part 60, appendix A-7 during routine monitoring of the biogas (volume \%).

(h) For each anaerobic process (such as an anaerobic reactor, sludge digester, or lagoon) from which biogas is recovered, install, operate, maintain, and calibrate a gas flow meter capable of continuously measuring the volumetric flow rate of the recovered biogas using one of the methods specified in paragraphs (h)(1) through (h)(8) of this section or as specified by the manufacturer, recalibrate each gas flow meter either biennially (every 2 years) or at the minimum frequency specified by the manufacturer. Except as provided in \$98.353(c)(2)(iii), each gas flow meter must be capable of correcting for the temperature and pressure and, if necessary, moisture content.


8. Method 2A or 2D at 40 CFR part 60, appendix A–1.

(i) All temperature, pressure, and moisture content monitors required as specified in paragraph (f) of this section must be calibrated using the procedures and frequencies where specified by the device manufacturer, if not specified use an industry accepted or industry standard practice.

(j) All equipment (temperature, pressure, and moisture content monitors and gas flow meters and gas composition monitors) must be maintained as specified by the manufacturer.

(k) If applicable, the owner or operator must document the procedures used to ensure the accuracy of measurements of COD or BOD\(_5\) concentration, wastewater flow rate, biogas flow rate, biogas composition, temperature,
§ 98.356 Data reporting requirements.

In addition to the information required by §98.3(c), each annual report must contain the following information for each wastewater treatment system.

(a) A description or diagram of the industrial wastewater treatment system, identifying the processes used to treat industrial wastewater and industrial wastewater treatment sludge. Indicate how the processes are related to each other and identify the anaerobic processes. Provide a unique identifier for each anaerobic process, indicate the average depth in meters of each anaerobic lagoon, and indicate whether biogas generated by each anaerobic process is recovered. The anaerobic processes must be identified as:

(1) Anaerobic reactor.
(2) Anaerobic deep lagoon (depth more than 2 meters).
(3) Anaerobic shallow lagoon (depth less than 2 meters).
(4) Anaerobic sludge digester.

(b) For each anaerobic wastewater treatment process (reactor, deep lagoon, or shallow lagoon) you must report:

(1) Weekly average COD or BOD₅ concentration of wastewater entering each anaerobic wastewater treatment process, for each week the anaerobic process was operated.
(2) Volume of wastewater entering each anaerobic wastewater treatment process for each week the anaerobic process was operated.
(3) Maximum CH₄ production potential (B₀) used as an input to Equation II–1 or II–2 of this subpart, from Table II–1 to this subpart.
(4) Methane conversion factor (MCF) used as an input to Equation II–1 or II–2 of this subpart, from Table II–1 to this subpart.
(5) Annual mass of CH₄ generated by each anaerobic wastewater treatment process, calculated using Equation II–1 or II–2 of this subpart.

(c) For each anaerobic wastewater treatment process from which biogas is not recovered, you must report the annual CH₄ emissions, calculated using Equation II–3 of this subpart.

(d) For each anaerobic wastewater treatment process and anaerobic sludge...
digester from which some biogas is recovered, you must report:

(1) Annual quantity of CH\textsubscript{4} recovered from the anaerobic process calculated using Equation II–4 of this subpart.

(2) Total weekly volumetric biogas flow for each week (up to 52 weeks/year) that biogas is collected for destruction.

(3) Weekly average CH\textsubscript{4} concentration for each week that biogas is collected for destruction.

(4) Weekly average biogas temperature for each week at which flow is measured for biogas collected for destruction, or statement that temperature is incorporated into monitoring equipment internal calculations.

(5) Whether flow was measured on a wet or dry basis, whether CH\textsubscript{4} concentration was measured on a wet or dry basis, and if required for Equation II–4 of this subpart, weekly average moisture content for each week at which flow is measured for biogas collected for destruction, or statement that moisture content is incorporated into monitoring equipment internal calculations.

(6) Weekly average biogas pressure for each week at which flow is measured for biogas collected for destruction, or statement that pressure is incorporated into monitoring equipment internal calculations.

(7) CH\textsubscript{4} collection efficiency (CE) used in Equation II–5 of this subpart.

(8) Whether destruction occurs at the facility or off-site. If destruction occurs at the facility, also report whether a back-up destruction device is present at the facility, the annual operating hours for the primary destruction device, the annual operating hours for the back-up destruction device (if present), the destruction efficiency for the primary destruction device, and the destruction efficiency for the back-up destruction device (if present).

(9) For each anaerobic process from which some biogas is recovered, you must report the annual CH\textsubscript{4} emissions, as calculated by Equation II–6 of this subpart.

(e) The total mass of CH\textsubscript{4} emitted from all anaerobic processes from which biogas is not recovered (calculated in Equation II–5 of this subpart) and from all anaerobic processes from which some biogas is recovered (calculated in Equation II–6 of this subpart) using Equation II–7 of this subpart.

[75 FR 39767, July 12, 2010, as amended at 76 FR 73905, Nov. 29, 2011]

§ 98.357 Records that must be retained.

In addition to the information required by §98.3(g), you must retain the calibration records for all monitoring equipment, including the method or manufacturer’s specification used for calibration.

§ 98.358 Definitions.

Except as provided below, all terms used in this subpart have the same meaning given in the CAA and subpart A of this part.

Biogas means the combination of CO\textsubscript{2}, CH\textsubscript{4}, and other gases produced by the biological breakdown of organic matter in the absence of oxygen.

Ethanol production means an operation that produces ethanol from the fermentation of sugar, starch, grain, or cellulosic biomass feedstocks, or the production of ethanol synthetically from petrochemical feedstocks, such as ethylene or other chemicals.

Food processing means an operation used to manufacture or process meat, poultry, fruits, and/or vegetables as defined under NAICS 3116 (Meat Product Manufacturing) or NAICS 3114 (Fruit and Vegetable Preserving and Specialty Food Manufacturing). For information on NAICS codes, see http://www.census.gov/eos/www/naics/.

Industrial wastewater means water containing wastes from an industrial process. Industrial wastewater includes water which comes into direct contact with or results from the storage, production, or use of any raw material, intermediate product, finished product, by-product, or waste product. Examples of industrial wastewater include, but are not limited to, paper mill white water, wastewater from equipment cleaning, wastewater from air pollution control devices, rinse water, contaminated stormwater, and contaminated cooling water.
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Industrial wastewater treatment sludge means solid or semi-solid material resulting from the treatment of industrial wastewater, including but not limited to biosolids, screenings, grit, scum, and settled solids.

Wastewater treatment system means the collection of all processes that treat or remove pollutants and contaminants, such as soluble organic matter, suspended solids, pathogenic organisms, and chemicals from wastewater prior to its reuse or discharge from the facility.

### Table II–1 to Subpart II—Emission Factors

<table>
<thead>
<tr>
<th>Factors</th>
<th>Default value</th>
<th>Units</th>
</tr>
</thead>
<tbody>
<tr>
<td>B&lt;sub&gt;0&lt;/sub&gt;—for facilities monitoring COD</td>
<td>0.25</td>
<td>Kg CH&lt;sub&gt;4&lt;/sub&gt;/kg COD</td>
</tr>
<tr>
<td>B&lt;sub&gt;0&lt;/sub&gt;—for facilities monitoring BOD&lt;sub&gt;5&lt;/sub&gt;</td>
<td>0.60</td>
<td>Kg CH&lt;sub&gt;4&lt;/sub&gt;/kg BOD&lt;sub&gt;5&lt;/sub&gt;</td>
</tr>
<tr>
<td>MCF—an aerobic reactor</td>
<td>0.8</td>
<td>Fraction.</td>
</tr>
<tr>
<td>MCF—an aerobic deep lagoon (depth more than 2 m)</td>
<td>0.8</td>
<td>Fraction.</td>
</tr>
<tr>
<td>MCF—an aerobic shallow lagoon (depth less than 2 m)</td>
<td>0.2</td>
<td>Fraction.</td>
</tr>
</tbody>
</table>

### Table II–2 to Subpart II—Collection Efficiencies of Anaerobic Processes

<table>
<thead>
<tr>
<th>Anaerobic process type</th>
<th>Cover type</th>
<th>Methane collection efficiency</th>
</tr>
</thead>
<tbody>
<tr>
<td>Covered anaerobic lagoon (biogas capture)</td>
<td>Bank to bank, impermeable</td>
<td>0.975</td>
</tr>
<tr>
<td>Anaerobic sludge digester; anaerobic reactor</td>
<td>Modular, impermeable</td>
<td>0.70</td>
</tr>
<tr>
<td>Enclosed Vessel</td>
<td></td>
<td>0.99</td>
</tr>
</tbody>
</table>

### Subpart JJ—Manure Management

§ 98.360 Definition of the source category.

(a) This source category consists of livestock facilities with manure management systems that emit 25,000 metric tons CO<sub>2</sub> eq or more per year.

(1) Table JJ–1 presents the minimum average annual animal population by animal group that is estimated to emit 25,000 metric tons CO<sub>2</sub> eq or more per year. Facilities with an average annual animal population, as described in § 98.363(a)(1) and (2), below those listed in Table JJ–1 do not need to report under this rule. A facility with an annual animal population that exceeds those listed in Table JJ–1 should conduct a more thorough analysis to determine applicability.

(2) (i) If a facility has more than one animal group present (e.g., swine and poultry), the facility must determine if they are required to report by calculating the combined animal group factor (CAGF) using equation JJ–1:

\[
\text{CAGF} = \sum \text{Animal Groups} \left( \frac{\text{AAP}_{AG, \text{Facility}}}{\text{APTL}_{AG}} \right) \quad (\text{Eq. JJ-1})
\]

Where:

- CAGF = Combined Animal Group Factor
- \(\text{AAP}_{AG, \text{Facility}}\) = Average annual animal population at the facility, by animal group
- \(\text{APTL}_{AG}\) = Animal population threshold level, as specified in Table JJ–1 of this section

(ii) If the calculated CAGF for a facility is less than 1, the facility is not required to report under this rule. If the CAGF is equal to or greater than 1, the facility must use more detailed applicability tables and tools to determine if they are required to report under this rule.

(b) A manure management system (MMS) is a system that stabilizes and/or stores livestock manure, litter, or manure wastewater in one or more of
the following system components: Uncovered anaerobic lagoons, liquid/slurry systems with and without crust covers (including but not limited to ponds and tanks), storage pits, digesters, solid manure storage, dry lots (including feedlots), high-rise houses for poultry production (poultry without litter), poultry production with litter, deep bedding systems for cattle and swine, manure composting, and aerobic treatment.

(c) This source category does not include system components at a livestock facility that are unrelated to the stabilization and/or storage of manure such as daily spread or pasture/range/paddock systems or land application activities or any method of manure utilization that is not listed in §98.360(b).

(d) This source category does not include manure management activities located off site from a livestock facility or off-site manure composting operations.

§ 98.361 Reporting threshold.

Livestock facilities must report GHG emissions under this subpart if the facility meets the reporting threshold as defined in 98.360(a) above, contains a manure management system as defined in 98.360(b) above, and meets the requirements of §98.2(a)(1).

§ 98.362 GHGs to report.

(a) Livestock facilities must report annual aggregate CH₄ and N₂O emissions for the following MMS components at the facility:

1. Uncovered anaerobic lagoons.
2. Liquid/slurry systems (with and without crust covers, and including but not limited to ponds and tanks).
3. Storage pits.
4. Digesters, including covered anaerobic lagoons.
5. Solid manure storage.
6. Dry lots, including feedlots.
7. High-rise houses for poultry production (poultry without litter).
8. Poultry production with litter.
10. Manure composting.

(b) A livestock facility that is subject to this rule only because of emissions from manure management system components is not required to report emissions from subparts C through PP (other than subpart JJ) of this part.

(c) A livestock facility that is subject to this part because of emissions from source categories described in subparts C through PP of this part is not required to report emissions under subpart JJ of this part unless emissions from manure management systems are 25,000 metric tons CO₂e per year or more.

§ 98.363 Calculating GHG emissions.

(a) For all manure management system components listed in 98.360(b) except digesters, estimate the annual CH₄ emissions and sum for all the components to obtain total emissions from the manure management system for all animal types using Equation JJ–1.

\[
\text{CH}_4 \text{ Emissions}_{\text{MMS}} \text{ (metric tons/yr)} = \sum_{\text{animal type}} \left[ \sum_{\text{MMS component}} \left[ \text{TVS}_{\text{AT}} \times \text{VS}_{\text{MMS}} \times \text{VS} \times \text{days/yr} \times B \times \text{MCF}_{\text{MMS}} \times 0.662 \text{ kg CH}_4/\text{m}^3 \times 1 \text{ metric ton/1000 kg} \right] \right]
\]  

(Eq. JJ-2)

Where:

\(\text{MMS component} = \text{Manure management systems component.}\)

\(\text{TVS}_{\text{AT}} = \text{Total volatile solids excreted by animal type, calculated using Equation JJ–3 of this section (kg/day).}\)

\(\text{VS}_{\text{MMS}} = \text{Fraction of the total manure for each animal type that is managed in MMS component MMS, assumed to be equivalent to the fraction of VS in each MMS component.}\)

\(\text{VS}_{\text{at}} = \text{Volatile solids removal through solid separation; if solid separation occurs prior to the MMS component, use a default value from Table JJ–4 of this section; if no solid separation occurs, this value is set to 0.}\)

\(\text{B}_{\text{MMS}} = \text{Maximum CH}_4\text{-producing capacity for each animal type, as specified in Table JJ–2 of this section (m}^3 \text{ CH}_4/\text{kg VS).}\)

\(\text{MCF}_{\text{MMS}} = \text{CH}_4\text{ conversion factor for the MMS component, as specified in Table JJ–5 of this section (decimal).}\)
\[
TVS_{AT} = \text{Population}_{AT} \times TAM_{AT} \times VS_{AT}/1000 \quad (\text{Eq. JJ-3})
\]

Where:
- \( \text{TVS}_{AT} \) = Daily total volatile solids excreted per animal type (kg/day).
- \( \text{Population}_{AT} \) = Average annual animal population contributing manure to the manure management system by animal type (head) (see description in §98.363(a)(i) and (ii) below).
- \( \text{TAM}_{AT} \) = Typical animal mass for each animal type, using either default values in Table JJ-2 of this section or farm-specific data (kg/head).
- \( \text{VS}_{AT} \) = Volatile solids excretion rate for each animal type, using default values in Table JJ-2 or JJ-3 of this section (kg VS/day/1000 kg animal mass).

(1) Average annual animal populations for static populations (e.g., dairy cows, breeding swine, layers) must be estimated by performing an animal inventory or review of facility records once each reporting year.

(2) Average annual animal populations for growing populations (meat animals such as beef and veal cattle, market swine, broilers, and turkeys) must be estimated each year using the average number of days each animal is kept at the facility and the number of animals produced annually, and an equation similar or equal to Equation JJ-4 below, adapted from Equation 10.1 in 2006 IPCC Guidelines for National Greenhouse Gas Inventories, Volume 4, Chapter 10.

\[
\text{Population}_{AT} = \text{Days onsite}_{AT} \times \left( \frac{\text{NAPA}_{AT}}{365} \right) \quad (\text{Eq. JJ-4})
\]

Where:
- \( \text{Population}_{AT} \) = Average annual animal population (by animal type).
- \( \text{Days onsite}_{AT} \) = Average number of days the animal is kept at the facility, by animal type.
- \( \text{NAPA}_{AT} \) = Number of animals produced annually, by animal type.

(b) For each digester, calculate the total amount of \( \text{CH}_4 \) emissions, and then sum the emissions from all digesters, as shown in Equation JJ-5 of this section.

\[
\text{H}_4 \text{ Emissions}_{AD} = \sum_{i} (\text{CH}_4 C - \text{CH}_4 D + \text{CH}_4 L) \quad (\text{Eq. JJ-5})
\]

Where:
- \( \text{CH}_4 \text{ Emissions}_{AD} \) = \( \text{CH}_4 \) emissions from anaerobic digestion (metric tons/yr).
- \( \text{AD} \) = Number of anaerobic digesters at the manure management facility.
- \( \text{CH}_4 C \) = \( \text{CH}_4 \) flow to digester combustion device, calculated using Equation JJ-6 of this section (metric tons \( \text{CH}_4/\text{yr} \)).
- \( \text{CH}_4 D \) = \( \text{CH}_4 \) destruction at digesters, calculated using Equation JJ-11 of this section (metric tons \( \text{CH}_4/\text{yr} \)).
- \( \text{CH}_4 L \) = Leakage at digesters calculated using Equation JJ-12 of this section (metric tons \( \text{CH}_4/\text{yr} \)).

(1) For each digester, calculate the annual \( \text{CH}_4 \) flow to the combustion device (\( \text{CH}_4 C \)) using Equation JJ-6 of this section. A fully integrated system that directly reports the quantity of \( \text{CH}_4 \) flow to the digester combustion device requires only summing the results of all monitoring periods for a given year to obtain \( \text{CH}_4 C \).
§ 98.363

\[ CH_4C = \left( \frac{V \times C}{100\%} \times 0.0423 \times \frac{520^\circ R}{T} \times \frac{P}{1 \text{ atm}} \times \frac{0.454 \text{ metric ton}}{1,000 \text{ pounds}} \right) \]  
(Eq. JJ-6)

Where:

- \( CH_4C \) = \( CH_4 \) flow to digester combustion device (metric tons \( CH_4/yr \)).
- \( V \) = Average annual volumetric flow rate, calculated in Equation JJ-7 of this subsection (cubic feet \( CH_4/yr \)).
- \( C \) = Average annual \( CH_4 \) concentration of digester gas, calculated in Equation JJ-8 of this section (% , wet basis).
- 0.0423 = Density of \( CH_4 \) lb/scf (at 520 °R or 60 °F and 1 atm).
- \( T \) = Average annual temperature at which flow is measured, calculated in Equation JJ-9 of this section (°R).
- \( P \) = Average annual pressure at which flow is measured, calculated in Equation JJ-10 of this section (atm).

(2) For each digester, calculate the average annual volumetric flow rate, \( CH_4 \) concentration of digester gas, temperature, and pressure at which flow are measured using Equations JJ-7 through JJ-10 of this section.

\[ V = \frac{\sum_{n=1}^{OD} V_n \times 1,440 \text{ minutes}}{OD} \]  
(Eq. JJ-7)

Where:

- \( V \) = Average annual volumetric flow rate (cubic feet \( CH_4/yr \)).
- \( OD \) = Operating days, number of days per year that that the digester was operating (days/yr).
- \( V_n \) = Daily average volumetric flow rate for day \( n \), as determined from daily monitoring as specified in §98.364 (acfm).

\[ C = \frac{\sum_{n=1}^{OD} C_n}{OD} \]  
(Eq. JJ-8)

Where:

- \( C \) = Average annual \( CH_4 \) concentration of digester gas (% , wet basis).
- \( OD \) = Operating days, number of days per year that the digester was operating (days/yr).
- \( C_n \) = Average daily \( CH_4 \) concentration of digester gas for day \( n \), as determined from daily monitoring as specified in §98.364 (% , wet basis).

\[ P = \frac{\sum_{n=1}^{OD} P_n}{OD} \]  
(Eq. JJ-10)

Where:

- \( P \) = Average annual pressure at which flow is measured (atm).
- \( OD \) = Operating days, number of days per year that the digester was operating (days/yr).
- \( P_n \) = Pressure at which flow is measured for day \( n \) (atm).

(3) For each digester, calculate the \( CH_4 \) destruction at the digester combustion device using Equation JJ-11 of this section.

\[ T = \frac{\sum_{n=1}^{OD} T_n}{OD} \]  
(Eq. JJ-9)
Environmental Protection Agency § 98.363

\[ \text{CH}_4D = \text{CH}_4 \times \text{DE} \times \text{OH}/\text{Hours} \quad \text{(Eq. JJ-11)} \]

Where:
- \( \text{CH}_4D \) = \( \text{CH}_4 \) destruction at digester combustion device (metric tons/yr).
- \( \text{CH}_4C \) = Annual quantity of \( \text{CH}_4 \) flow to digester combustion device, as calculated in Equation JJ-6 of this section (metric tons \( \text{CH}_4 \)).
- \( \text{DE} \) = \( \text{CH}_4 \) destruction efficiency from flaring or burning in engine (lesser of manufacturer’s specified destruction efficiency and 0.99). If the gas is transported off-site for destruction, use \( \text{DE} = 1 \).
- \( \text{OH} \) = Number of hours combustion device is functioning in reporting year. \( \text{Hours} = \text{Hours in reporting year} \).

(4) For each digester, calculate the \( \text{CH}_4 \) leakage using Equation JJ-12 of this section.

\[ \text{CH}_4L = \text{CH}_4 \times \left( \frac{1}{\text{CE}} - 1 \right) \quad \text{(Eq. JJ-12)} \]

Where:
- \( \text{CH}_4L \) = Leakage at digesters (metric tons/yr).
- \( \text{CH}_4C \) = Annual quantity of \( \text{CH}_4 \) flow to digester combustion device, as calculated in Equation JJ-6 of this section (metric tons \( \text{CH}_4 \)).
- \( \text{CE} \) = \( \text{CH}_4 \) collection efficiency of anaerobic digester, as specified in Table JJ-6 of this section (decimal).

(c) For each MMS component, estimate the annual \( \text{N}_2\text{O} \) emissions and sum for all MMS components to obtain total emissions from the manure management system for all animal types using Equation JJ-13 of this section.

\[
\text{Direct } \text{N}_2\text{O} \text{ Emissions (metric tons/year)} = \sum_{\text{animal types}} \left[ \sum_{\text{MMS components}} \text{N}_{\text{ex,MMSC}} \times \text{N}_{\text{ex,MMSC}} \times \frac{\text{EF}_{\text{MMSC}} \times 365 \text{ days/yr}}{44 \text{ N}_2\text{O}/28 \text{ N}_2\text{O} - N \times 1 \text{ metric ton/1000 kg}} \right]
\]

Where:
- \( \text{N}_{\text{ex,AT}} \) = Daily total nitrogen excreted per animal type, calculated using Equation JJ-14 of this section (kg N/day).
- \( \text{N}_{\text{ex,MMSC}} \) = Fraction of the total manure for each animal type that is managed in MMS component MMSC, assumed to be equivalent to the fraction of \( \text{N}_{\text{ex}} \) in each MMS component.
- \( \text{N}_{\text{ex}} \) = Nitrogen removal through solid separation: if solid separation occurs prior to the MMS component, use a default value from Table JJ-4 of this section; if no solid separation occurs, this value is set to 0.
- \( \text{EF}_{\text{MMSC}} \) = Emission factor for MMS component, as specified in Table JJ-7 of this section (kg \( \text{N}_2\text{O}-\text{N}/\text{kg N} \)).

\[ \text{N}_{\text{ex,AT}} = \text{Population}_{\text{AT}} \times \text{TAM}_{\text{AT}} \times \text{N}_{\text{AT}}/1000 \quad \text{(Eq. JJ-14)} \]

Where:
- \( \text{N}_{\text{ex,AT}} \) = Total nitrogen excreted per animal type (kg/day).
- \( \text{Population}_{\text{AT}} \) = Average annual animal population contributing manure to the manure management system by animal type (head) (see description in §98.363(a)(1) and (ii)).
- \( \text{TAM}_{\text{AT}} \) = Typical animal mass by animal type, using either default values in Table JJ-2 of this section or farm-specific data (kg/head).
\[ N_{ir} = \text{Nitrogen excretion rate by animal type, using default values in Tables JJ–2 or JJ–3 of this section (kg N/day/1000 kg animal mass).} \]

(d) Estimate the annual total facility emissions using Equation JJ–15 of this section.

\[ \text{Total Emissions (metric tons CO}_2\text{e/yr)} = \left[ (\text{CH}_4 \text{ emissions}_{\text{MMS}} + \text{CH}_4 \text{ emissions}_{\text{AAD}}) \times 21 \right] + \left[ \text{Direct N}_2\text{O emissions} \times 310 \right] \]

Where:
- \( \text{CH}_4 \text{ emissions}_{\text{MMS}} \) = From Equation JJ–2 of this section.
- \( \text{CH}_4 \text{ emissions}_{\text{AAD}} \) = From Equation JJ–5 of this section.
- \( 21 = \text{Global Warming Potential of CH}_4 \)
- \( \text{Direct N}_2\text{O emissions} = \text{From Equation JJ–13 of this section.} \)
- \( 310 = \text{Global Warming Potential of N}_2\text{O.} \)

§ 98.364 Monitoring and QA/QC requirements.

(a) Perform an annual animal inventory or review of facility records (for static populations) or population calculation (for growing populations) to determine the average annual animal population for each animal type (see description in §§ 98.363(a)(1) and (2)).

(b) Perform an analysis on your operation to determine the fraction of total manure by weight for each animal type that is managed in each on-site manure management system component. If your system changes from previous reporting periods, you must reevaluate the fraction of total manure managed in each system component.

(c) The \( \text{CH}_4 \) concentration of gas from digesters must be determined using ASTM D1946–90 (Reapproved 2006) Standard Practice for Analysis of Reformed Gas by Gas Chromatography (incorporated by reference, see § 98.7).

All gas composition monitors shall be calibrated prior to the first reporting year for biogas methane and carbon dioxide content using ASTM D1946–90 (Reapproved 2006) Standard Practice for Analysis of Reformed Gas by Gas Chromatography (incorporated by reference, see § 98.7).

All temperature and pressure monitors must be calibrated using the procedures and frequencies specified by the manufacturer. All equipment (temperature and pressure monitors) shall be maintained as specified by the manufacturer.

(e) For digesters with gas collection systems, install, operate, maintain, and calibrate a gas flow meter capable of measuring the volumetric flow rate to provide data for the GHG emissions calculations, using the applicable methods specified in paragraphs (e)(1) through (e)(6) of this section or as specified by the manufacturer.


(f) If applicable, the owner or operator shall document the procedures used to ensure the accuracy of gas flow rate, gas composition, temperature, and pressure measurements. These procedures include, but are not limited to, calibration of fuel flow meters and other measurement devices. The estimated accuracy of measurements made with these devices shall also be recorded, and the technical basis for these estimates shall be provided.
(g) Each gas flow meter shall be calibrated prior to the first reporting year and recalibrated either annually or at the minimum frequency specified by the manufacturer, whichever is more frequent. Each gas flow meter must have a rated accuracy of \( \pm 5 \) percent or lower and be capable of correcting for the temperature and pressure and, if the gas composition monitor determines \( \text{CH}_4 \) concentration on a dry basis, moisture content.

\section*{§ 98.365 Procedures for estimating missing data.}

(a) A complete record of all measured parameters used in the GHG emissions calculations is required. Therefore, whenever a quality-assured value of a required parameter is unavailable (e.g., if a meter malfunctions during unit operation or if a required fuel sample is not taken), a substitute data value for the missing parameter shall be used in the calculations, according to the requirements in paragraph (b) of this section.

(b) For missing gas flow rates or \( \text{CH}_4 \) content data, the substitute data value shall be the arithmetic average of the quality-assured values of that parameter immediately preceding and immediately following the missing data incident. If, for a particular parameter, no quality-assured data are available prior to the missing data incident, the substitute data value shall be the first quality-assured value obtained after the missing data period.

\section*{§ 98.366 Data reporting requirements.}

(a) In addition to the information required by §98.3(c), each annual report must contain the following information:

1. List of manure management system components at the facility.
2. Fraction of manure from each animal type that is handled in each manure management system component.
3. Average annual animal population (for each animal type) for static populations or the results of Equation JJ–4 for growing populations.
4. Average number of days that growing animals are kept at the facility (for each animal type).
5. The number of animals produced annually for growing populations (for each animal type).
6. Typical animal mass (for each animal type).
8. \( \text{CH}_4 \) emissions from manure management system components listed in §98.360(b), except digesters (results of Equation JJ–2).
9. VS value used (for each animal type).
10. \( B_0 \) value used (for each animal type).
11. Methane conversion factor used for each MMS component.
12. Average ambient temperature used to select each methane conversion factor.
13. \( \text{N}_2\text{O} \) emissions (results of Equation JJ–13).
14. \( N \) value used for each animal type.
15. \( \text{N}_2\text{O} \) emission factor selected for each MMS component.

(b) Facilities with anaerobic digesters must also report:

1. \( \text{CH}_4 \) emissions from anaerobic digesters (results of Equation JJ–5).
2. \( \text{CH}_4 \) flow to the digester combustion device for each digester (results of Equation JJ–6, or value from fully integrated monitoring system as described in 98.363(b)).
3. \( \text{CH}_4 \) destruction for each digester (results of Equation JJ–11).
4. \( \text{CH}_4 \) leakage for each digester (results of Equation JJ–12).
5. Total annual volumetric biogas flow for each digester (results of Equation JJ–7).
6. Average annual \( \text{CH}_4 \) concentration for each digester (results of Equation JJ–8).
7. Average annual temperature at which gas flow is measured for each digester (results of Equation JJ–9).
8. Average annual gas flow pressure at which gas flow is measured for each digester (results of Equation JJ–10).
9. Destruction efficiency used for each digester.
10. Number of days per year that each digester was operating.
11. Collection efficiency used for each digester.
§ 98.367 Records that must be retained.

In addition to the information required by §98.363(g), you must retain the calibration records for all monitoring equipment, including the method or manufacturer’s specification used for calibration.

§ 98.368 Definitions.

All terms used in this subpart have the same meaning given in the Clean Air Act and subpart A of this part.

TABLE JJ–1 TO SUBPART JJ OF PART 98—ANIMAL POPULATION THRESHOLD LEVEL BELOW WHICH FACILITIES ARE NOT REQUIRED TO REPORT EMISSIONS UNDER SUBPART JJ

<table>
<thead>
<tr>
<th>Animal Group</th>
<th>Average Annual Animal Population (Head)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Beef</td>
<td>29,300</td>
</tr>
<tr>
<td>Dairy</td>
<td>3,200</td>
</tr>
<tr>
<td>Swine</td>
<td>34,100</td>
</tr>
<tr>
<td>Poultry</td>
<td></td>
</tr>
<tr>
<td>Layers</td>
<td>723,600</td>
</tr>
<tr>
<td>Broilers</td>
<td>38,160,000</td>
</tr>
<tr>
<td>Turkeys</td>
<td>7,710,000</td>
</tr>
</tbody>
</table>

1 The threshold head populations in this table were calculated using the most conservative assumptions (high VS and N values, maximum ambient temperatures, and the application of an uncertainty factor) to ensure that facilities at or near the 25,000 metric ton CO₂-e threshold level were not excluded from reporting.

2 For facilities with more than one animal group present refer to §98.360 (2) to estimate the combined animal group factor (CAGF), which is used to determine if a facility may be required to report.

3 For all animal groups except dairy, the average annual animal population represents the total number of animals present at the facility. For dairy facilities, the average annual animal population represents the number of mature dairy cows present at the facility (note that heifers and calves were included in the emission estimates for dairy facilities using the assumption that the average annual animal population of heifers and calves at dairy facilities are equal to 30 percent of the mature dairy cow average annual animal population, therefore the average annual population for dairy facilities should not include heifers and calves, only dairy cows).

TABLE JJ–2 TO SUBPART JJ OF PART 98—WASTE CHARACTERISTICS DATA

<table>
<thead>
<tr>
<th>Animal Type</th>
<th>Typical Animal Mass (kg)</th>
<th>Volatile Solids Excretion Rate (kg VS/day/1000 kg animal mass)</th>
<th>Nitrogen Excretion Rate (kg N/day/1000 kg animal mass)</th>
<th>Maximum Methane Generation Potential, B, (m³ CH₄/kg VS added)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Dairy Cows</td>
<td>604</td>
<td>See Table JJ–3</td>
<td>See Table JJ–3</td>
<td>0.24</td>
</tr>
<tr>
<td>Dairy Heifers</td>
<td>476</td>
<td>See Table JJ–3</td>
<td>See Table JJ–3</td>
<td>0.17</td>
</tr>
<tr>
<td>Dairy Calves</td>
<td>118</td>
<td>6.41</td>
<td>0.30</td>
<td>0.17</td>
</tr>
<tr>
<td>Feedlot Steers</td>
<td>420</td>
<td>See Table JJ–3</td>
<td>See Table JJ–3</td>
<td>0.33</td>
</tr>
<tr>
<td>Feedlot Heifers</td>
<td>420</td>
<td>See Table JJ–3</td>
<td>See Table JJ–3</td>
<td>0.33</td>
</tr>
<tr>
<td>Market Swine &lt;60 lbs</td>
<td>16</td>
<td>8.80</td>
<td>0.60</td>
<td>0.48</td>
</tr>
<tr>
<td>Market Swine 60–119 lbs</td>
<td>41</td>
<td>5.40</td>
<td>0.42</td>
<td>0.48</td>
</tr>
<tr>
<td>Market Swine &gt;180 lbs</td>
<td>68</td>
<td>5.40</td>
<td>0.42</td>
<td>0.48</td>
</tr>
<tr>
<td>Breeding Swine</td>
<td>91</td>
<td>5.40</td>
<td>0.42</td>
<td>0.48</td>
</tr>
<tr>
<td>Feedlot Sheep</td>
<td>198</td>
<td>2.60</td>
<td>0.24</td>
<td>0.48</td>
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<tr>
<td>Goats</td>
<td>25</td>
<td>9.20</td>
<td>0.42</td>
<td>0.36</td>
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<tr>
<td>Horses</td>
<td>64</td>
<td>9.50</td>
<td>0.45</td>
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<tr>
<td>Hens &gt;1 yr</td>
<td>450</td>
<td>10.00</td>
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<tr>
<td>Pullets</td>
<td>1.8</td>
<td>10.09</td>
<td>0.83</td>
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<tr>
<td>Other Chickens</td>
<td>1.8</td>
<td>10.09</td>
<td>0.62</td>
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<tr>
<td>Broilers</td>
<td>0.9</td>
<td>15.00</td>
<td>1.10</td>
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</tr>
<tr>
<td>Turkeys</td>
<td>6.8</td>
<td>9.70</td>
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<tr>
<td>State</td>
<td>Dairy cows</td>
<td>Dairy heifers</td>
<td>Feedlot steer</td>
<td>Feedlot heifers</td>
</tr>
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<td>3.98</td>
<td>4.35</td>
</tr>
<tr>
<td>Oregon</td>
<td>9.40</td>
<td>8.35</td>
<td>4.06</td>
<td>4.46</td>
</tr>
<tr>
<td>Pennsylvania</td>
<td>9.25</td>
<td>8.35</td>
<td>3.98</td>
<td>4.35</td>
</tr>
<tr>
<td>Rhode Island</td>
<td>8.94</td>
<td>8.35</td>
<td>4.36</td>
<td>4.87</td>
</tr>
<tr>
<td>South Carolina</td>
<td>9.05</td>
<td>8.35</td>
<td>4.15</td>
<td>4.58</td>
</tr>
<tr>
<td>South Dakota</td>
<td>9.45</td>
<td>8.35</td>
<td>4.01</td>
<td>4.39</td>
</tr>
<tr>
<td>Tennessee</td>
<td>8.60</td>
<td>8.35</td>
<td>4.48</td>
<td>5.02</td>
</tr>
<tr>
<td>Texas</td>
<td>9.51</td>
<td>8.35</td>
<td>3.95</td>
<td>4.32</td>
</tr>
<tr>
<td>Utah</td>
<td>9.70</td>
<td>8.35</td>
<td>3.88</td>
<td>4.22</td>
</tr>
<tr>
<td>Vermont</td>
<td>9.03</td>
<td>8.35</td>
<td>4.10</td>
<td>4.52</td>
</tr>
<tr>
<td>Virginia</td>
<td>9.02</td>
<td>8.35</td>
<td>3.98</td>
<td>4.35</td>
</tr>
<tr>
<td>Washington</td>
<td>10.36</td>
<td>8.35</td>
<td>4.07</td>
<td>4.47</td>
</tr>
<tr>
<td>West Virginia</td>
<td>8.13</td>
<td>8.35</td>
<td>4.65</td>
<td>5.25</td>
</tr>
<tr>
<td>Wisconsin</td>
<td>9.34</td>
<td>8.35</td>
<td>3.95</td>
<td>4.31</td>
</tr>
<tr>
<td>Wyoming</td>
<td>9.29</td>
<td>8.35</td>
<td>4.17</td>
<td>4.61</td>
</tr>
</tbody>
</table>

Table JJ–3 to Subpart JJ of Part 98—State-Specific Volatile Solids (VS) and Nitrogen (N) Excretion Rates for Cattle

<table>
<thead>
<tr>
<th>Type of solids separation</th>
<th>Volatile solids removal (decimal)</th>
<th>Nitrogen removal (decimal)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Gravity</td>
<td>0.60</td>
<td>0.60</td>
</tr>
<tr>
<td>Mechanical</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Stationary Screen</td>
<td>0.20</td>
<td>0.10</td>
</tr>
<tr>
<td>Vibrating Screen</td>
<td>0.15</td>
<td>0.15</td>
</tr>
<tr>
<td>Screw Press</td>
<td>0.25</td>
<td>0.15</td>
</tr>
<tr>
<td>Centrifuge</td>
<td>0.50</td>
<td>0.25</td>
</tr>
<tr>
<td>Roller drum</td>
<td>0.25</td>
<td>0.15</td>
</tr>
<tr>
<td>Belt press/screen</td>
<td>0.50</td>
<td>0.30</td>
</tr>
</tbody>
</table>

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**Table JJ–5 to Subpart JJ of Part 98—Methane Conversion Factors**

<table>
<thead>
<tr>
<th>Manure Management System Component</th>
<th>Cool</th>
<th>Temperate</th>
<th>Warm</th>
</tr>
</thead>
<tbody>
<tr>
<td>Uncovered Anaerobic Lagoon</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Covered anaerobic lagoon (biogas capture)</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Liquid/slurry (with crust cover)</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Liquid/slurry (w/o crust cover)</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Storage pits &lt;1 month</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Storage pits &gt;1 month</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Solid manure storage</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Dry loco (including feedlots)</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>High-rise houses for poultry production (without litter)</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Poultry production with litter</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Deep bedding systems for cattle and swine (&lt;1 month)</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Deep bedding systems for cattle and swine (&gt;1 month)</td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

**Table JJ–6 to Subpart JJ of Part 98—Collection Efficiencies of Anaerobic Digesters**

<table>
<thead>
<tr>
<th>Anaerobic digester type</th>
<th>Cover type</th>
<th>Methane collection efficiency</th>
</tr>
</thead>
<tbody>
<tr>
<td>Covered anaerobic lagoon (biogas capture)</td>
<td>Bank to bank, impermeable</td>
<td>0.975</td>
</tr>
<tr>
<td>Complete mix, fixed film, or plug flow digester</td>
<td>Modular, impermeable</td>
<td>0.70</td>
</tr>
<tr>
<td>Enclosed Vessel</td>
<td></td>
<td>0.99</td>
</tr>
</tbody>
</table>
TABLE JJ–7 TO SUBPART JJ OF PART 98—NITROUS OXIDE EMISSION FACTORS (KG N₂O-N/KG KJDL N)

<table>
<thead>
<tr>
<th>Manure management system component</th>
<th>N₂O emission factor</th>
</tr>
</thead>
<tbody>
<tr>
<td>Uncovered anaerobic lagoon</td>
<td>0</td>
</tr>
<tr>
<td>Liquid/Slurry (with crust cover)</td>
<td>0.005</td>
</tr>
<tr>
<td>Liquid/Slurry (without crust cover)</td>
<td>0</td>
</tr>
<tr>
<td>Storage pits</td>
<td>0.002</td>
</tr>
<tr>
<td>Digesters</td>
<td>0</td>
</tr>
<tr>
<td>Solid manure storage</td>
<td>0.005</td>
</tr>
<tr>
<td>Dry lots (including feedlots)</td>
<td>0.02</td>
</tr>
<tr>
<td>High-rise house for poultry (poultry without litter)</td>
<td>0.001</td>
</tr>
<tr>
<td>Poultry production with litter</td>
<td>0.001</td>
</tr>
<tr>
<td>Deep bedding for cattle and swine (active mix)</td>
<td>0.07</td>
</tr>
<tr>
<td>Deep bedding for cattle and swine (no mix)</td>
<td>0.01</td>
</tr>
<tr>
<td>Manure Composting (in vessel)</td>
<td>0.006</td>
</tr>
<tr>
<td>Manure Composting (intensive)</td>
<td>0.1</td>
</tr>
<tr>
<td>Manure Composting (passive)</td>
<td>0.01</td>
</tr>
<tr>
<td>Manure Composting (static)</td>
<td>0.006</td>
</tr>
<tr>
<td>Aerobic Treatment (forced aeration)</td>
<td>0.005</td>
</tr>
<tr>
<td>Aerobic Treatment (natural aeration)</td>
<td>0.01</td>
</tr>
</tbody>
</table>

Subpart KK [Reserved]

Subpart LL—Suppliers of Coal-based Liquid Fuels

§ 98.380 Definition of the source category.

This source category consists of producers, importers, and exporters of products listed in Table MM–1 of subpart MM that are coal-based (coal-to-liquid products).

(a) A producer is the owner or operator of a coal-to-liquids facility. A coal-to-liquids facility is any facility engaged in converting coal into liquid products using a process involving conversion of coal into gas and then into liquids (e.g., Fischer-Tropsch) or conversion of coal directly into liquids (i.e., direct liquefaction).

(b) An importer or exporter shall have the same meaning given in §98.6.

§ 98.381 Reporting threshold.

Any supplier of coal-to-liquid products who meets the requirements of §98.2(a)(4) must report GHG emissions.

§ 98.382 GHGs to report.

You must report the CO₂ emissions that would result from the complete combustion or oxidation of fossil-fuel based products that you produce, use as feedstock, import, or export during the calendar year. Additionally, producers must report CO₂ emissions that would result from the complete combustion or oxidation of any biomass co-processed with fossil fuel-based feedstocks.

§ 98.383 Calculating GHG emissions.

You must follow the calculation methodologies of §98.393 as if they applied to the appropriate coal-to-liquid product supplier (i.e., calculation methodologies for refiners apply to producers of coal-to-liquid products and calculation methodologies for importers and exporters of petroleum products apply to importers and exporters of coal-to-liquid products).

(a) In calculation methodologies in §98.393 for petroleum products or petroleum-based products, suppliers of coal-to-liquid products shall also include coal-to-liquid products.

(b) In calculation methodologies in §98.393 for non-crude feedstocks or non-crude petroleum feedstocks, producers of coal-to-liquid products shall also include coal-to-liquid products that enter the facility to be further processed or otherwise used on site.

(c) In calculation methodologies in §98.393 for petroleum feedstocks, suppliers of coal-to-liquid products shall also include coal and coal-to-liquid products that enter the facility to be further processed or otherwise used on site.

§ 98.384 Monitoring and QA/QC requirements.

You must follow the monitoring and QA/QC requirements in §98.394 as if they applied to the appropriate coal-to-liquid product supplier. Any monitoring and QA/QC requirement for petroleum products in §98.394 also applies to coal-to-liquid products.

§ 98.385 Procedures for estimating missing data.

You must follow the procedures for estimating missing data in §98.395 as if they applied to the appropriate coal-to-liquid product supplier. Any procedure for estimating missing data for petroleum products in §98.395 also applies to coal-to-liquid products.
§ 98.386 Data reporting requirements.

In addition to the information required by § 98.3(c), the following requirements apply:

(a) Producers shall report the following information for each coal-to-liquid facility:

(1) For each product listed in Table MM–1 of subpart MM of this part that enters the coal-to-liquid facility to be further processed or otherwise used on site, report the annual quantity in metric tons or barrels by each quantity measurement standard method or other industry standard practice used. For natural gas liquids, quantity shall reflect the individual components of the product.

(2) For each product listed in Table MM–1 of subpart MM of this part that enters the coal-to-liquid facility to be further processed or otherwise used on site, report the total annual quantity in metric tons or barrels. For natural gas liquids, quantity shall reflect the individual components of the product.

(3) For each feedstock reported in paragraph (a)(2) of this section that was produced by blending a fossil fuel-based product with a biomass-based product, report the percent of the volume reported in paragraph (a)(2) of this section that is fossil fuel-based (excluding any denaturant that may be present in any ethanol product).

(4) Each standard method or other industry standard practice used to measure each quantity reported in paragraph (a)(1) of this section.

(5) For each product (leaving the coal-to-liquid facility) listed in Table MM–1 of subpart MM of this part, report the annual quantity in metric tons or barrels by each quantity measurement standard method or other industry standard practice used. For natural gas liquids, quantity shall reflect the individual components of the product. Those products that enter the facility, but are not reported in (a)(1), shall not be reported under this paragraph.

(6) For each product (leaving the coal-to-liquid facility) listed in Table MM–1 of subpart MM of this part, report the total annual quantity in metric tons or barrels. For natural gas liquids, quantity shall reflect the individual components of the product. Those products that enter the facility, but are not reported in (a)(2), shall not be reported under this paragraph.

(7) For each product reported in paragraph (a)(6) of this section that was produced by blending a fossil fuel-based product with a biomass-based product, report the percent of the volume reported in paragraph (a)(6) of this section that is fossil fuel-based (excluding any denaturant that may be present in any ethanol product).

(8) Each standard method or other industry standard practice used to measure each quantity reported in paragraph (a)(5) of this section.

(9) For every feedstock reported in paragraph (a)(2) of this section for which Calculation Methodology 2 of subpart MM of this part was used to determine an emissions factor, report:

(i) The number of samples collected according to § 98.394(c).

(ii) The sampling standard method used.

(iii) The carbon share test results in percent mass.

(iv) The standard method used to test carbon share.

(v) The calculated CO₂ emissions factor.

(10) For every non-solid feedstock reported in paragraph (a)(2) of this section for which Calculation Methodology 2 of subpart MM of this part was used to determine an emissions factor, report:

(i) The density test results in metric tons per barrel.

(ii) The standard method used to test density.

(11) For every product reported in paragraph (a)(6) of this section for which Calculation Methodology 2 of this subpart was used to determine an emissions factor, report:

(i) The number of samples collected according to § 98.394(c).

(ii) The sampling standard method used.

(iii) The carbon share test results in percent mass.

(iv) The standard method used to test carbon share.

(v) The calculated CO₂ emissions factor.
(12) For every non-solid product reported in paragraph (a)(6) of this section for which Calculation Methodology 2 of subpart MM of this part was used to determine an emissions factor, report:
   (i) The density test results in metric tons per barrel.
   (ii) The standard method used to test density.

(13) For each specific type of biomass that enters the coal-to-liquid facility to be co-processed with fossil fuel-based feedstock to produce a product reported in paragraph (a)(6) of this section, report the total annual quantity in metric tons or barrels.

(14) For each specific type of biomass that enters the coal-to-liquid facility to be co-processed with fossil fuel-based feedstock to produce a product reported in paragraph (a)(6) of this section, report the annual quantity in metric tons or barrels by each quantity measurement standard method or other industry standard practice used.

(15) Each standard method or other industry standard practice used to measure each quantity reported in paragraph (a)(3) of this section.

(16) The CO$_2$ emissions in metric tons that would result from the complete combustion or oxidation of each feedstock reported in paragraph (a)(2) of this section that were calculated according to §98.393(b) or (h).

(17) The CO$_2$ emissions in metric tons that would result from the complete combustion or oxidation of each product (leaving the coal-to-liquid facility) reported in paragraph (a)(6) of this section that were calculated according to §98.393(a) or (h).

(18) Annual CO$_2$ emissions in metric tons that would result from the complete combustion or oxidation of each type of biomass feedstock co-processed with fossil fuel-based feedstocks reported in paragraph (a)(3) of this section, calculated according to §98.393(c).

(19) Annual CO$_2$ emissions that would result from the complete combustion or oxidation of all products, calculated according to §98.393(d).

(20) Annual quantity of bulk NGLs in metric tons or barrels received for processing during the reporting year.

(b) In addition to the information required by §98.3(c), each importer shall report all of the following information at the corporate level:

(1) For each product listed in Table MM–1 of subpart MM of this part, report the annual quantity in metric tons or barrels by each quantity measurement standard method or other industry standard practice used. For natural gas liquids, quantity shall reflect the individual components of the product.

(2) For each product listed in Table MM–1 of subpart MM of this part, report the total annual quantity in metric tons or barrels. For natural gas liquids, quantity shall reflect the individual components of the product as listed in Table MM–1 of subpart MM of this part.

(3) For each product reported in paragraph (b)(2) of this section that was produced by blending a fossil fuel-based product with a biomass-based product, report the percent of the volume reported in paragraph (b)(2) of this section that is fossil fuel-based (excluding any denaturant that may be present in any ethanol product).

(4) Each standard method or other industry standard practice used to measure each quantity reported in paragraph (b)(1) of this section.

(5) For each product reported in paragraph (b)(2) of this section for which Calculation Methodology 2 of this subpart was used to determine an emissions factor, report:
   (i) The number of samples collected according to §98.394(c)
   (ii) The sampling standard method used.
   (iii) The carbon share test results in percent mass.
   (iv) $\text{CO}_2$ emissions method used to test carbon share.
   (v) The calculated CO$_2$ emissions factor in metric tons.

(6) For each non-solid product reported in paragraph (b)(2) of this section for which Calculation Methodology 2 of this subpart was used to determine an emissions factor, report:
   (i) The density test results in metric tons per barrel.
   (ii) The standard method used to test density.

(7) The CO$_2$ emissions in metric tons that would result from the complete
combustion or oxidation of each imported product reported in paragraph (b)(2) of this section, calculated according to §98.393(a).

(8) The total sum of CO₂ emissions that would result from the complete combustion or oxidation of all imported products, calculated according to §98.393(e).

(c) In addition to the information required by §98.3(c), each exporter shall report all of the following information at the corporate level:

(1) For each product listed in Table MM–1 of subpart MM of this part, report the annual quantity in metric tons or barrels by each quantity measurement standard method or other industry standard practice used. For natural gas liquids, quantity shall reflect the individual components of the product.

(2) For each product listed in Table MM–1 of subpart MM of this part, report the total annual quantity in metric tons or barrels. For natural gas liquids, quantity shall reflect the individual components of the product.

(3) For each product reported in paragraph (c)(2) of this section that was produced by blending a fossil fuel-based product with a biomass-based product, report the percent of the volume reported in paragraph (c)(2) of this section that is fossil fuel-based (excluding any denaturant that may be present in any ethanol product).

(4) Each standard method or other industry standard practice used to measure each quantity reported in paragraph (c)(1) of this section.

(5) For each product reported in paragraph (c)(2) of this section that was produced by blending a fossil fuel-based product with a biomass-based product, report the percent of the volume reported in paragraph (c)(2) of this section that is fossil fuel-based (excluding any denaturant that may be present in any ethanol product).

(6) The CO₂ emissions in metric tons that would result from the complete combustion or oxidation of each imported product reported in paragraph (b)(2) of this section, calculated according to §98.393(a).

(d) Blended feedstock and products.

(1) Producers, exporters, and importers must report the following information for each blended product and feedstock where emissions were calculated according to §98.393(i):

(i) Volume or mass of each blending component.

(ii) The CO₂ emissions in metric tons that would result from the complete combustion or oxidation of each blended feedstock or product, using Equation MM–12 or Equation MM–13 of §98.393.

(iii) Whether it is a blended feedstock or a blended product.

(2) For a product that enters the facility to be further refined or otherwise used on site that is a blended feedstock, producers must meet the reporting requirements of paragraphs (a)(1) and (a)(2) of this section by reflecting the individual components of the blended feedstock.

(3) For a product that is produced, imported, or exported that is a blended product, producers, importers, and exporters must meet the reporting requirements of paragraphs (a)(1) and (a)(2) of this section, as applicable, by reflecting the individual components of the blended product.


§98.387 Records that must be retained.

You must retain records according to the requirements in §98.397 as if they applied to the appropriate coal-to-liquid product supplier (e.g., retaining
Environmental Protection Agency

§ 98.393 Calculating GHG emissions.

(a) Calculation for individual products produced, imported, or exported.

(1) Except as provided in paragraphs (h) and (i) of this section, any refiner, importer, or exporter shall calculate CO\(_2\) emissions from each individual petroleum product and natural gas liquid using Equation MM–1 of this section.

\[
\text{CO}_2i = \text{Product}_i \times \text{EF}_i \quad \text{(Eq. MM-1)}
\]

Where:

\(\text{CO}_2i\) = Annual CO\(_2\) emissions that would result from the complete combustion or oxidation of each petroleum product or natural gas liquid “\(i\)” (metric tons).

\(\text{Product}_i\) = Annual volume of product “\(i\)” produced, imported, or exported by the reporting party (barrels). For refiners, this volume only includes products ex refinery gate, and excludes products that entered the refinery but are not reported under § 98.396(a)(1). For natural gas liquids, volumes shall reflect the individual components of the product as listed in Table MM–1 to subpart MM.

\(\text{EF}_i\) = Product-specific CO\(_2\) emission factor (metric tons CO\(_2\) per barrel).

(2) In the event that an individual petroleum product is produced as a solid rather than liquid any refiner, importer, or exporter shall calculate CO\(_2\) emissions using Equation MM–1 of this section.

Where:

\(\text{CO}_2i\) = Annual CO\(_2\) emissions that would result from the complete combustion or oxidation of each petroleum product “\(i\)” (metric tons).

\(\text{Product}_i\) = Annual mass of product “\(i\)” produced, imported, or exported by the reporting party (metric tons). For refiners, this mass only includes products ex refinery gate.

\(\text{EF}_i\) = Product-specific CO\(_2\) emission factor (metric tons CO\(_2\) per metric ton of product).

(b) Calculation for individual products that enter a refinery as a non-crude feedstock.

(1) Except as provided in paragraphs (h) and (i) of this section, any refiner
§ 98.393

shall calculate CO₂ emissions from each non-crude feedstock using Equation MM-2 of this section.

\[ CO_{2j} = \text{Feedstock}_j \times EF_{j} \]  

(Eq. MM-2)

Where:

- \( CO_{2j} \) = Annual \( CO_2 \) emissions that would result from the complete combustion or oxidation of each non-crude feedstock “\( j \)” (metric tons).
- \( \text{Feedstock}_j \) = Annual volume of a petroleum product or natural gas liquid “\( j \)” that enters the refinery to be further refined or otherwise used on site (barrels). For natural gas liquids, volumes shall reflect the individual components of the product as listed in table MM-1 of this subpart.
- \( EF_{j} \) = Feedstock-specific \( CO_2 \) emission factor (metric tons \( CO_2 \) per barrel).

(2) In the event that a non-crude feedstock enters a refinery as a solid rather than liquid, the refiner shall calculate \( CO_2 \) emissions using Equation MM-2 of this section.

Where:

- \( CO_{2j} \) = Annual \( CO_2 \) emissions that would result from the complete combustion or oxidation of each non-crude feedstock “\( j \)” (metric tons).
- \( \text{Feedstock}_j \) = Annual mass of a petroleum product “\( j \)” that enters the refinery to be further refined or otherwise used on site (metric tons).
- \( EF_{j} \) = Feedstock-specific \( CO_2 \) emission factor (metric tons \( CO_2 \) per metric ton of feedstock).

(c) Calculation for biomass co-processed with petroleum feedstocks.

(1) Refiners shall calculate \( CO_2 \) emissions from each type of biomass that enters a refinery and is co-processed with petroleum feedstocks using Equation MM-3 of this section.

\[ CO_{2m} = \text{Biomass}_m \times EF_{m} \]  

(Eq. MM-3)

Where:

- \( CO_{2m} \) = Annual \( CO_2 \) emissions that would result from the complete combustion or oxidation of each type of biomass “\( m \)” (metric tons).
- \( \text{Biomass}_m \) = Annual volume of a specific type of biomass that enters the refinery and is co-processed with petroleum feedstocks to produce a petroleum product reported under paragraph (a) of this section (barrels).
- \( EF_{m} \) = Biomass-specific \( CO_2 \) emission factor (metric tons \( CO_2 \) per barrel).

(2) In the event that biomass enters a refinery as a solid rather than liquid and is co-processed with petroleum feedstocks, the refiner shall calculate \( CO_2 \) emissions from each type of biomass using Equation MM-3 of this section.

Where:

- \( CO_{2m} \) = Annual \( CO_2 \) emissions that would result from the complete combustion or oxidation of each type of biomass “\( m \)” (metric tons).
- \( \text{Biomass}_m \) = Total annual mass of a specific type of biomass that enters the refinery to be co-processed with petroleum feedstocks to produce a petroleum product reported under paragraph (a) of this section (metric tons).
- \( EF_{m} \) = Biomass-specific \( CO_2 \) emission factor (metric tons \( CO_2 \) per metric ton of biomass).

(d) Summary calculation for refinery products.

Refiners shall calculate annual \( CO_2 \) emissions from all products using Equation MM-4 of this section.

\[ CO_{2r} = \sum (CO_{2j}) - \sum (CO_{2j}) - \sum (CO_{2m}) \]  

(Eq. MM-4)

Where:

- \( CO_{2r} \) = Annual \( CO_2 \) emissions that would result from the complete combustion or oxidation of all petroleum products and natural gas liquids (ex refinery gate) minus non-crude feedstocks and any biomass to be co-processed with petroleum feedstocks.
- \( CO_{2j} \) = Annual \( CO_2 \) emissions that would result from the complete combustion or oxidation of each petroleum product or natural gas liquid “\( j \)” (metric tons).
- \( CO_{2m} \) = Annual \( CO_2 \) emissions that would result from the complete combustion or oxidation of each type of biomass “\( m \)” (metric tons).

(e) Summary calculation for importer and exporter products.

Importers and exporters shall calculate annual \( CO_2 \) emissions from all products using Equation MM-4 of this section.

\[ CO_{2i} = \sum (CO_{2i}) - \sum (CO_{2i}) - \sum (CO_{2i}) \]  

(Eq. MM-4)

Where:

- \( CO_{2i} \) = Annual \( CO_2 \) emissions that would result from the complete combustion or oxidation of each non-crude feedstock “\( j \)” (metric tons).
- \( CO_{2m} \) = Annual \( CO_2 \) emissions that would result from the complete combustion or oxidation of each type of biomass “\( m \)” (metric tons).

(f) Summary calculation for importer and exporter products.

Importers and exporters shall calculate annual \( CO_2 \) emissions from all products using Equation MM-4 of this section.

\[ CO_{2e} = \sum (CO_{2e}) - \sum (CO_{2e}) - \sum (CO_{2e}) \]  

(Eq. MM-4)
emissions from all petroleum products and natural gas liquids imported or exported, respectively, using Equations MM-1 and MM-5 of this section.

\[ \text{CO}_2x = \sum \left( \text{CO}_2i \right) \]  

(Eq. MM-5)

Where:

\( \text{CO}_2x \) = Annual \( \text{CO}_2 \) emissions that would result from the complete combustion or oxidation of all petroleum products and natural gas liquids.

\( \text{CO}_2i \) = Annual \( \text{CO}_2 \) emissions that would result from the complete combustion or oxidation of each petroleum product or natural gas liquid "i" (metric tons).

(f) Emission factors for petroleum products and natural gas liquids. The emission factor (\( \text{EF}_{ij} \)) for each petroleum product and natural gas liquid shall be determined using either of the calculation methods described in paragraphs (f)(1) or (f)(2) of this section. The same calculation method must be used for the entire quantity of the product for the reporting year. For refiners, the quantity of a product that enters a refinery (i.e., a non-crude feedstock) is considered separate from the quantity of a product ex refinery gate.

(1) Calculation Method 1. To determine the emission factor (i.e., \( \text{EF}_i \), in Equation MM-1) for solid products, multiply the default carbon share factor (i.e., percent carbon by mass) in column B of Table MM-1 to this subpart for the appropriate product by \( 44/12 \). For all other products, use the default \( \text{CO}_2 \) emission factor listed in column C of Table MM-1 of this subpart for the appropriate product.

(2) Calculation Method 2.

(i) For solid products, develop emission factors according to Equation MM-6 of this section using a value of 1 for density and direct measurements of carbon share according to methods set forth in §98.394(c). For all other products, develop emission factors according to Equation MM-6 of this section using direct measurements of density and carbon share according to methods set forth in §98.394(c).

\[ \text{EF}_{ij} = \text{Density} \times \text{Carbon Share} \times \left( \frac{44}{12} \right) \]  

(Eq. MM-6)

Where:

\( \text{EF}_{ij} \) = Emission factor of the petroleum product or natural gas liquid (metric tons \( \text{CO}_2 \) per barrel or per metric ton of product).

Density = Density of the petroleum product or natural gas liquid (metric tons per barrel for non-solid products, 1 for solid products).

Carbon share = Percent of total mass that carbon represents in the petroleum product or natural gas liquid, expressed as a fraction (e.g., 75% would be expressed as 0.75 in the above equation).

\( 44/12 \) = Conversion factor for carbon to carbon dioxide.

(ii) If you use a standard method that involves gas chromatography to determine the percent mass of each component in a product, calculate the product’s carbon share using Equation MM-7 of this section.

\[ \text{Carbon Share} = \sum \left( \%\text{Composition}_{i...n} \times \%\text{Mass}_{i...n} \right) \]  

(Eq. MM-7)

Where:

Carbon Share = Percent of total mass that carbon represents in the petroleum product or natural gas liquid.

\%\text{Composition}_{i...n} = Percent of total mass that each molecular component in the petroleum product or natural gas liquid represents as determined by the procedures in the selected standard method.

\%\text{Mass}_{i...n} = Percent of total mass that carbon represents in each molecular component of the petroleum product or natural gas liquid.

(g) Emission factors for biomass co-processed with petroleum feedstocks. Refiners shall use the most appropriate default \( \text{CO}_2 \) emission factor (\( \text{EF}_m \)) for biomass
in Table MM-2 of this subpart to calculate CO\textsubscript{2} emissions in paragraph (c) of this section.

(h) Special procedures for blended biomass-based fuels. In the event that some portion of a petroleum product is biomass-based and was not derived by coprocessing biomass and petroleum feedstocks together (i.e., the petroleum product was produced by blending a petroleum-based product with a biomass-based fuel), the reporting party shall calculate emissions for the petroleum product according to one of the methods in paragraphs (h)(1) through (h)(4) of this section, as appropriate.

(1) A reporter using Calculation Methodology 1 to determine the emission factor of a petroleum product shall calculate the CO\textsubscript{2} emissions associated with that product using Equation MM-8 of this section in place of Equation MM-1 of this section.

\[ \text{CO}_{2i} = \text{Product}_i \times \text{EF}_i \times \%\text{Vol}_i \]  
(Eq. MM-8)

Where:
- CO\textsubscript{2i} = Annual CO\textsubscript{2} emissions that would result from the complete combustion or oxidation of each petroleum product “i” (metric tons).
- Product\textsubscript{i} = Annual volume of each petroleum product “i” produced, imported, or exported by the reporting party (barrels). For refiners, this volume only includes products ex refinery gate.
- EF\textsubscript{i} = Petroleum product-specific CO\textsubscript{2} emission factor (metric tons CO\textsubscript{2} per barrel) from Table MM-1 of this subpart.
- %Vol\textsubscript{i} = Percent volume of product “i” that is petroleum-based, not including any denaturant that may be present in any ethanol product, expressed as a fraction (e.g., 75% would be expressed as 0.75 in the above equation).

(2) A refinery using Calculation Methodology 1 of this subpart to determine the emission factor of a non-crude petroleum feedstock shall calculate the CO\textsubscript{2} emissions associated with that feedstock using Equation MM-9 of this section in place of Equation MM-2 of this section.

\[ \text{CO}_{2j} = \text{Feedstock}_j \times \text{EF}_j \times \%\text{Vol}_j \]  
(Eq. MM-9)

Where:
- CO\textsubscript{2j} = Annual CO\textsubscript{2} emissions that would result from the complete combustion or oxidation of each non-crude feedstock “j” (metric tons).
- Feedstock\textsubscript{j} = Annual volume of each petroleum product “j” that enters the refinery as a feedstock to be further refined or otherwise used on site (barrels).
- EF\textsubscript{j} = Non-crude petroleum feedstock-specific CO\textsubscript{2} emission factor (metric tons CO\textsubscript{2} per barrel).
- %Vol\textsubscript{j} = Percent volume of feedstock “j” that is petroleum-based, not including any denaturant expressed as a fraction (e.g., 75% would be expressed as 0.75 in the above equation).

(3) Calculation Method 2 procedures for products.

(1) A reporter using Calculation Method 2 of this subpart to determine the emission factor of a petroleum product that does not contain denatured ethanol must calculate the CO\textsubscript{2} emissions associated with that product using Equation MM-10 of this section in place of Equation MM-1 of this section.

\[ \text{CO}_{2i} = (\text{Product}_i \times \text{EF}_i) - (\text{Product}_i \times \text{EF}_m \times \%\text{Vol}_m) \]  
(Eq. MM-10)
where:

\[ \text{CO}_{2i} = \text{Annual CO}_2 \text{ emissions that would result from the complete combustion or oxidation of each product \text{‘}i\text{’} (metric tons).} \]

\[ \text{Product}_i = \text{Annual volume of each petroleum product \text{‘}i\text{’} produced, imported, or exported by the reporting party (barrels).} \]

For refiners, this volume only includes products ex refinery gate.

\[ \text{EF}_i = \text{Product-specific CO}_2 \text{ emission factor (metric tons CO}_2 \text{ per barrel).} \]

\[ \text{EF}_m = \text{Default CO}_2 \text{ emission factor from Table MM–2 to subpart MM that most closely represents the component of product \text{‘}i\text{’} that is biomass-based.} \]

\[ \% \text{Vol}_m = \text{Percent volume of petroleum product \text{‘}i\text{’} that is biomass-based, expressed as a fraction (e.g., 75% would be expressed as 0.75 in the above equation).} \]

(ii) In the event that a petroleum product contains denatured ethanol, importers and exporters must follow Calculation Method 1 procedures in paragraph (h)(1) of this section; and refiners must sample the petroleum portion of the blended biomass-based fuel prior to blending and calculate CO\(_2\) emissions using Equation MM–10a of this section.

\[ \text{CO}_{2i} = \text{Product}_i \times \text{EF}_i \quad \text{(Eq. MM-10a)} \]

where:

\[ \text{CO}_{2i} = \text{Annual CO}_2 \text{ emissions that would result from the complete combustion or oxidation of each biomass-blended fuel \text{‘}i\text{’} (metric tons).} \]

\[ \text{Product}_p = \text{Annual volume of the petroleum-based portion of each biomass blended fuel \text{‘}i\text{’} produced by the refiner (barrels).} \]

\[ \text{EF}_i = \text{Petroleum product-specific CO}_2 \text{ emission factor (metric tons CO}_2 \text{ per barrel).} \]

(4) Calculation Method 2 procedures for non-crude feedstocks.

(i) A refiner using Calculation Method 2 of this subpart to determine the emission factor of a non-crude petroleum feedstock that does not contain denatured ethanol must calculate the CO\(_2\) emissions associated with that feedstock using Equation MM–11 of this section in place of Equation MM–2 of this section.

\[ \text{CO}_{2j} = \left( \text{Feedstock}_j \times \text{EF}_j \right) - \left( \text{Feedstock}_j \times \text{EF}_m \times \% \text{Vol}_m \right) \quad \text{(Eq. MM-11)} \]

where:

\[ \text{CO}_{2j} = \text{Annual CO}_2 \text{ emissions that would result from the complete combustion or oxidation of each non-crude feedstock \text{‘}j\text{’} (metric tons).} \]

\[ \text{Feedstock}_j = \text{Annual volume of each petroleum product \text{‘}j\text{’} that enters the refinery to be further refined or otherwise used on site (barrels).} \]

\[ \text{EF}_j = \text{Feedstock-specific CO}_2 \text{ emission factor (metric tons CO}_2 \text{ per barrel).} \]

\[ \text{EF}_m = \text{Default CO}_2 \text{ emission factor from Table MM–2 to subpart MM that most closely represents the component of petroleum product \text{‘}j\text{’} that is biomass-based.} \]

\[ \% \text{Vol}_m = \text{Percent volume of non-crude feedstock \text{‘}j\text{’} that is biomass-based, expressed as a fraction (e.g., 75% would be expressed as 0.75 in the above equation).} \]

(ii) In the event that a non-crude feedstock contains denatured ethanol, refiners must follow Calculation Method 1 procedures in paragraph (h)(2) of this section.

(i) Optional procedures for blended products that do not contain biomass.

(1) In the event that a reporter produces, imports, or exports a blended product that does not include biomass, the reporter may calculate emissions for the blended product according to the method in paragraph (i)(2) of this section. In the event that a refiner receives a blended non-crude feedstock that does not include biomass, the refiner may calculate emission for the blended non-crude feedstock according to the method in paragraph (i)(3) of this section. The procedures in this section may be used only if all of the following criteria are met:

(i) The reporter knows the relative proportion of each component of the blend (i.e., the mass or volume percentage).

(ii) Each component of blended product ‘‘i’’ or blended non-crude feedstock ‘‘j’’ meets the strict definition of a product listed in Table MM–1 to subpart MM.
(iii) The blended product or non-crude feedstock is not comprised entirely of natural gas liquids.
(iv) The reporter uses Calculation Method 1.
(v) Solid components are blended only with other solid components.
(2) The reporter must calculate emissions for the blended product using Equation MM-12 of this section in place of Equation MM-1 of this section.

\[
\text{CO}_2 = \sum \left[ \text{Blending Component}_{i...n} \times EF_{i...n} \right] \quad (\text{Eq. MM-12})
\]

where:
- \(\text{CO}_2\) = Annual \(\text{CO}_2\) emissions that would result from the complete combustion or oxidation of a blended product “\(i\)’’ (metric tons).
- \(\text{Blending Component}_{i...n}\) = Annual volume or mass of each blending component that is blended (barrels or metric tons).
- \(EF_{i...n}\) = \(\text{CO}_2\) emission factors specific to each blending component (metric tons \(\text{CO}_2\) per barrel or per metric ton of product).
- \(n\) = Number of blending components blended into blended product “\(i\)’’.

(3) For refineries, the reporter must calculate emissions for the blended non-crude feedstock using Equation MM-13 of this section in place of Equation MM-2 of this section.

\[
\text{CO}_2 = \sum \left[ \text{Blending Component}_{i...n} \times EF_{i...n} \right] \quad (\text{Eq. MM-13})
\]

where:
- \(\text{CO}_2\) = Annual \(\text{CO}_2\) emissions that would result from the complete combustion or oxidation of a blended non-crude feedstock “\(j\)’’ (metric tons).
- \(\text{Blending Component}_{i...n}\) = Annual volume or mass of each blending component that is blended (barrels or metric tons).
- \(EF_{i...n}\) = \(\text{CO}_2\) emission factors specific to each blending component (metric tons \(\text{CO}_2\) per barrel or per metric ton of product).
- \(n\) = Number of blending components blended into blended non-crude feedstock “\(j\)’’.

(4) For refineries, if a blending component “\(k\)’’ used in paragraph (i)(2) of this section enters the refinery before blending as non-crude feedstock:

(i) The emissions that would result from the complete combustion or oxidation of non-crude feedstock “\(k\)’’ must still be calculated separately using Equation MM-2 of this section and applied in Equation MM-4 of this section.

(ii) The quantity of blending component “\(k\)’’ applied in Equation MM-12 of this section and the quantity of non-crude feedstock “\(k\)’’ applied in Equation MM-2 of this section must be determined using the same method or practice.

§ 98.394 Monitoring and QA/QC requirements.

(a) Determination of quantity.

(1) The quantity of petroleum products, natural gas liquids, and biomass, as well as the quantity of crude oil measured on site at a refinery, shall be determined as follows:

(i) Where an appropriate standard method published by a consensus-based standards organization exists, such a method shall be used. Consensus-based standards organizations include, but are not limited to, the following: ASTM International, the American National Standards Institute (ANSI), the American Gas Association (AGA), the
American Society of Mechanical Engineers (ASME), the American Petroleum Institute (API), and the North American Energy Standards Board (NAESB).

(ii) Where no appropriate standard method developed by a consensus-based standards organization exists, industry standard practices shall be followed.

(iii) For products that are liquid at 60 degrees Fahrenheit and one standard atmosphere, all measurements of quantity shall be temperature-adjusted and pressure-adjusted to these conditions. For all other products, reporters shall use appropriate standard conditions specified in the standard method; if temperature and pressure conditions are not specified in the standard method, or if a reporter uses an industry standard practice to determine quantity, the reporter shall use appropriate standard conditions according to established industry practices.

(2) All measurement equipment (including, but not limited to, flow meters and tank gauges) used for compliance with this subpart shall be appropriate for the standard method or industry standard practice followed under paragraph (a)(1)(i) or (a)(1)(ii) of this section.

(3) The quantity of crude oil not measured on site at a refinery shall be determined according to one of the following methods. You may use an appropriate standard method published by a consensus-based standards organization or you may use an industry standard practice.

(b) Equipment Calibration.

(1) All measurement equipment shall be calibrated prior to its first use for reporting under this subpart, using an appropriate standard method published by a consensus-based standards organization or you may use an industry standard practice.

(2) Measurement equipment shall be recalibrated at the minimum frequency specified by the standard method used or by the equipment manufacturer’s directions.

(c) Procedures for Calculation Methodology 2 of this subpart.

(1) Reporting parties shall collect one sample of each petroleum product or natural gas liquid on any day of each calendar month of the reporting year in which the quantity of that product was measured in accordance with the requirements of this subpart. For example, if a given product was measured as entering the refinery continuously throughout the reporting year, twelve samples of that product shall be collected over the reporting year, one on any day of each calendar month of that year. If a given product was only measured from April 15 through June 10 of the reporting year, a refiner would collect three samples during that year, one during each of the calendar months of April, May and June on a day when the product was measured as either entering or exiting the refinery. Each sample shall be collected using an appropriate standard method published by a consensus-based standards organization.

(2) Mixing and handling of samples shall be performed using an appropriate standard method published by a consensus-based standards organization.

(3) Density measurement.

(i) For all products that are not solid, reporters shall test for density using an appropriate standard method published by a consensus-based standards organization.

(ii) The density value for a given petroleum product shall be generated by either making a physical composite of all of the samples collected for the reporting year and testing that single sample or by measuring the individual samples throughout the year and defining the representative density value for the sample set by numerical means, i.e., a mathematical composite. If a physical composite is chosen as the option to obtain the density value, the reporter shall submit each of the individual samples collected during the reporting year to the laboratory responsible for generating the composite sample.

(iii) For physical composites, the reporter shall handle the individual samples and the laboratory shall mix them in accordance with an appropriate standard method published by a consensus-based standards organization.

(iv) All measurements of density shall be temperature-adjusted and pressure-adjusted to the conditions assumed for determining the quantities.
§ 98.395 Procedures for estimating missing data.

(a) Determination of quantity. Whenever the quality assurance procedures in §98.394(a) cannot be followed to measure the quantity of one or more petroleum products, natural gas liquids, types of biomass, feedstocks, or crude oil batches during any period (e.g., if a meter malfunctions), the following missing data procedures shall be used:

(1) For quantities of a product that are purchased or sold, a period of missing data shall be substituted using a reporter’s established procedures for billing purposes in that period as agreed to by the party selling or purchasing the product.

(2) For quantities of a product that are not purchased or sold but of which the custody is transferred, a period of missing data shall be substituted using a reporter’s established procedures for tracking purposes in that period as agreed to by the party involved in custody transfer of the product.
(b) **Determination of emission factor.** Whenever any of the procedures in §98.394(c) cannot be followed to develop an emission factor for any reason, Calculation Methodology 1 of this subpart must be used in place of Calculation Methodology 2 of this subpart for the entire reporting year.

(c) **Determination of API gravity and sulfur content of crude oil.** For missing data on sulfur content or API gravity, the substitute data value shall be the arithmetic average of the quality-assured values of API gravity or sulfur content in the batch preceding and the batch immediately following the missing data incident. If no quality-assured data are available prior to the missing data incident, the substitute data value shall be the first quality-assured values for API gravity and sulfur content obtained from the batch after the missing data period.

§ 98.396 Data reporting requirements.

In addition to the information required by §98.3(c), the following requirements apply:

(a) Refiners shall report the following information for each facility:

1. For each petroleum product or natural gas liquid listed in table MM–1 of this subpart that enters the refinery to be further refined or otherwise used on site, report the annual quantity in metric tons or barrels by each quantity measurement standard method or other industry standard practice used. For natural gas liquids, quantity shall reflect the individual components of the product.

2. For each petroleum product or natural gas liquid listed in Table MM–1 of this subpart that enters the refinery to be further refined or otherwise used on site, report the annual quantity in metric tons or barrels. For natural gas liquids, quantity shall reflect the individual components of the product. Petroleum products and natural gas liquids that enter the refinery, but are not reported in (a)(1), shall not be reported under this paragraph.

3. For each feedstock reported in paragraph (a)(2) of this section that was produced by blending a petroleum-based product with a biomass-based product, report the percent of the volume reported in paragraph (a)(2) of this section that is petroleum-based (excluding any denaturant that may be present in any ethanol product).

4. Each standard method or other industry standard practice used to measure each quantity reported in paragraph (a)(1) of this section.

5. For each petroleum product and natural gas liquid (ex refinery gate) listed in Table MM–1 of this subpart, report the annual quantity in metric tons or barrels by each quantity measurement standard method or other industry standard practice used. For natural gas liquids, quantity shall reflect the individual components of the product. Petroleum products and natural gas liquids that enter the refinery, but are not reported in (a)(1), shall not be reported under this paragraph.

6. For each petroleum product and natural gas liquid (ex refinery gate) listed in Table MM–1 of this subpart, report the annual quantity in metric tons or barrels. For natural gas liquids, quantity shall reflect the individual components of the product. Petroleum products and natural gas liquids that enter the refinery, but are not reported in (a)(2), shall not be reported under this paragraph.

7. For each product reported in paragraph (a)(6) of this section that was produced by blending a petroleum-based product with a biomass-based product, report the percent of the volume reported in paragraph (a)(6) of this section that is petroleum-based (excluding any denaturant that may be present in any ethanol product).

8. Each standard method or other industry standard practice used to measure each quantity reported in paragraph (a)(5) of this section.

9. For every feedstock reported in paragraph (a)(2) of this section for which Calculation Methodology 2 of this subpart was used to determine an emissions factor, report:

   i. The number of samples collected according to §98.394(c)

   ii. The sampling standard method used.

   iii. The carbon share test results in percent mass.

   iv. The standard method used to test carbon share.

   v. The calculated CO₂ emissions factor in metric tons.
(10) For every non-solid feedstock reported in paragraph (a)(2) of this section for which Calculation Methodology 2 of this subpart was used to determine an emissions factor, report:
   (i) The density test results in metric tons per barrel.
   (ii) The standard method used to test density.

(11) For every petroleum product and natural gas liquid reported in paragraph (a)(6) of this section for which Calculation Methodology 2 of this subpart was used to determine an emissions factor, report:
   (i) The number of samples collected according to §98.394(c).
   (ii) The sampling standard method used.
   (iii) The carbon share test results in percent mass.
   (iv) The standard method used to test carbon share.
   (v) The calculated CO$_2$ emissions factor in metric tons CO$_2$ per barrel or per metric ton of product.

(12) For every non-solid petroleum product and natural gas liquid reported in paragraph (a)(6) for which Calculation Methodology 2 was used to determine an emissions factor, report:
   (i) The density test results in metric tons per barrel.
   (ii) The standard method used to test density.

(13) For each specific type of biomass that enters the refinery to be co-processed with petroleum feedstocks to produce a petroleum product reported in paragraph (a)(6) of this section, report the annual quantity in metric tons or barrels by each quantity measurement standard method or other industry standard practice used.

(14) For each specific type of biomass that enters the refinery to be co-processed with petroleum feedstocks to produce a petroleum product reported in paragraph (a)(6) of this section, report the annual quantity in metric tons or barrels provided by each quantity measurement standard method or other industry standard practice used.

(15) Each standard method or other industry standard practice used to measure each quantity reported in paragraph (a)(13) of this section.

(16) The CO$_2$ emissions in metric tons that would result from the complete combustion or oxidation of each petroleum product and natural gas liquid (ex-refinery gate) reported in paragraph (a)(6) of this section that were calculated according to §98.393(a) or (h).

(17) The CO$_2$ emissions in metric tons that would result from the complete combustion or oxidation of each feedstock reported in paragraph (a)(2) of this section that were calculated according to §98.393(b) or (h).

(18) The CO$_2$ emissions in metric tons that would result from the complete combustion or oxidation of each type of biomass feedstock co-processed with petroleum feedstocks reported in paragraph (a)(13) of this section, calculated according to §98.393(c).

(19) The sum of CO$_2$ emissions that would result from the complete combustion or oxidation of all products, calculated according to §98.393(d).

(20) All of the following information for all crude oil feedstocks used at the refinery:
   (i) Batch volume in barrels.
   (ii) Weighted average API gravity representing the batch at the point of entry at the refinery.
   (iii) Weighted average sulfur content representing the batch at the point of entry at the refinery.
   (iv) Country of origin, of the batch, if known and data in paragraphs (a)(20)(v) and (a)(20)(vi) of this section are unknown.
   (v) EIA crude stream code and crude stream name of the batch, if known.
   (vi) Generic name for the crude stream and the appropriate EIA two-letter country or state and production area code of the batch, if known and no appropriate EIA crude stream code exists.

(21) The quantity of bulk NGLs in metric tons or barrels received for processing during the reporting year.

(22) Volume of crude oil in barrels that you injected into a crude oil supply or reservoir. A volume of crude oil that entered the refinery, but was not reported in paragraphs (a)(2) or (a)(20), shall not be reported under this paragraph.

(23) Special provisions for 2010. For reporting year 2010 only, a refiner that knows the information under a specific tier of the batch definition in 40 CFR 98.398, but does not have the necessary data collection and management in...
place to readily report this information, can use the next most appropriate tier of the batch definition for reporting batch information under paragraph 98.396(a)(20).

(b) In addition to the information required by §98.3(c), each importer shall report all of the following information at the corporate level:

(1) For each petroleum product and natural gas liquid listed in Table MM–1 of this subpart, report the annual quantity in metric tons or barrels by each quantity measurement standard method or other industry standard practice used. For natural gas liquids, quantity shall reflect the individual components of the product.

(2) For each petroleum product and natural gas liquid listed in Table MM–1 of this subpart, report the annual quantity in metric tons or barrels by each quantity measurement standard method or other industry standard practice used. For natural gas liquids, quantity shall reflect the individual components of the product as listed in Table MM–1 of this subpart.

(3) For each product reported in paragraph (b)(2) of this section that was produced by blending a petroleum-based product with a biomass-based product, report the percent of the volume reported in paragraph (b)(2) of this section that is petroleum-based (excluding any denaturant that may be present in any ethanol product).

(4) Each standard method or other industry standard practice used to measure each quantity reported in paragraph (b)(1) of this section.

(5) For each product reported in paragraph (b)(2) of this section for which Calculation Methodology 2 of this subpart was used to determine an emissions factor, report:

(i) The number of samples collected according to §98.394(c).

(ii) The sampling standard method used.

(iii) The carbon share test results in percent mass.

(iv) The standard method used to test carbon share.

(v) The calculated CO₂ emissions factor in metric tons CO₂ per barrel or per metric ton of product.

(6) For each non-solid product reported in paragraph (b)(2) of this section for which Calculation Methodology 2 of this subpart was used to determine an emissions factor, report:

(i) The density test results in metric tons per barrel.

(ii) The standard method used to test density.

(7) The CO₂ emissions in metric tons that would result from the complete combustion or oxidation of each imported petroleum product and natural gas liquid reported in paragraph (b)(2) of this section, calculated according to §98.393(a).

(8) The sum of CO₂ emissions that would result from the complete combustion oxidation of all imported products, calculated according to §98.393(e).

(c) In addition to the information required by §98.3(c), each exporter shall report all of the following information at the corporate level:

(1) For each petroleum product and natural gas liquid listed in Table MM–1 of this subpart, report the annual quantity in metric tons or barrels by each quantity measurement standard method or other industry standard practice used. For natural gas liquids, quantity shall reflect the individual components of the product.

(2) For each petroleum product and natural gas liquid listed in Table MM–1 of this subpart, report the annual quantity in metric tons or barrels. For natural gas liquids, quantity shall reflect the individual components of the product.

(3) For each product reported in paragraph (c)(2) of this section that was produced by blending a petroleum-based product with a biomass-based product, report the percent of the volume reported in paragraph (c)(2) of this section that is petroleum-based (excluding any denaturant that may be present in any ethanol product).

(4) Each standard method or other industry standard practice used to measure each quantity reported in paragraph (c)(1) of this section.

(5) For each product reported in paragraph (c)(2) of this section for which Calculation Methodology 2 of this subpart was used to determine an emissions factor, report:

(i) The number of samples collected according to §98.394(c).

(ii) The sampling standard method used.
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(iii) The carbon share test results in percent mass.

(iv) The standard method used to test carbon share.

(v) The calculated CO$_2$ emissions factor in metric tons CO$_2$ per barrel or per metric ton of product.

(6) For each non-solid product reported in paragraph (c)(2) of this section for which Calculation Methodology 2 of this subpart used was used to determine an emissions factor, report:

(i) The density test results in metric tons per barrel.

(ii) The standard method used to test density.

(7) The CO$_2$ emissions in metric tons that would result from the complete combustion or oxidation of each exported petroleum product and natural gas liquid reported in paragraph (c)(2) of this section, calculated according to § 98.393(a).

(8) The sum of CO$_2$ emissions that would result from the complete combustion or oxidation of all exported products, calculated according to § 98.393(e).

(d) Blended non-crude feedstock and products.

(1) Refineries, exporters, and importers must report the following information for each blended product and non-crude feedstock where emissions were calculated according to § 98.393(i):

(i) Volume or mass of each blending component.

(ii) The CO$_2$ emissions in metric tons that would result from the complete combustion or oxidation of each blended non-crude feedstock or product, using Equation MM–12 or Equation MM–13 of this section.

(iii) Whether it is a blended non-crude feedstock or a blended product.

(2) For a product that enters the refinery to be further refined or otherwise used on site that is a blended non-crude feedstock, refineries shall maintain metering, gauging, and other records normally maintained in the course of business to document product and feedstock flows including the date of initial calibration and the frequency of recalibration for the measurement equipment used.

(c) Reporters shall retain laboratory reports, calculations and worksheets used to estimate the CO$_2$ emissions of the quantities of petroleum products, natural gas liquids, biomass, and feedstocks reported under this subpart.

(d) Reporters shall maintain laboratory reports, calculations and worksheets used in the measurement of density and carbon share for any petroleum product or natural gas liquid for which CO$_2$ emissions were calculated using Calculation Methodology 2.

(e) Estimates of missing data shall be documented and records maintained showing the calculations.

(f) Reporters described in this subpart shall also retain all records described in §98.3(g).

§98.397 Records that must be retained.

(a) All reporters shall retain copies of all reports submitted to EPA under §98.396. In addition, all reporters shall maintain sufficient records to support information contained in those reports, including but not limited to information on the characteristics of their feedstocks and products.

(b) Reporters shall maintain records to support quantities that are reported under this subpart, including records documenting any estimations of missing data and the number of calendar days in the reporting year for which substitute data procedures were followed. For all reported quantities of petroleum products, natural gas liquids, and biomass, as well as crude oil quantities measured on site at a refinery, reporters shall maintain metering, gauging, and other records normally maintained in the course of business to document product and feedstock flows including the date of initial calibration and the frequency of recalibration for the measurement equipment used.

(c) Reporters shall retain laboratory reports, calculations and worksheets used to estimate the CO$_2$ emissions of the quantities of petroleum products, natural gas liquids, biomass, and feedstocks reported under this subpart.

(d) Reporters shall maintain laboratory reports, calculations and worksheets used in the measurement of density and carbon share for any petroleum product or natural gas liquid for which CO$_2$ emissions were calculated using Calculation Methodology 2.

(e) Estimates of missing data shall be documented and records maintained showing the calculations.

(f) Reporters described in this subpart shall also retain all records described in §98.3(g).
§ 98.398 Definitions.

Except as specified in this section, all terms used in this subpart have the same meaning given in the Clean Air Act and subpart A of this part.

*Batch* means either a volume of crude oil that enters a refinery or the components of such volume (e.g., the volumes of different crude streams that are blended together and then delivered to a refinery). The batch volume is the first appropriate tier in the following list:

1. Up to an annual volume of a type of crude oil identified by a generic code is known.
2. Up to an annual volume of a type of crude oil identified by an EIA crude stream code, if the EIA crude stream code is known.
3. Up to a calendar month of crude oil volume from a single known country of origin if the crude stream name is unknown.
4. Up to a calendar month of crude oil volume from the United States if the crude stream name and production area are unknown.
5. Up to a calendar month of crude oil volume if the country of origin is unknown.

[75 FR 66478, Oct. 28, 2010]

### Table MM–1 to Subpart MM of Part 98—Default Factors for Petroleum Products and Natural Gas Liquids

<table>
<thead>
<tr>
<th>Products</th>
<th>Column A: carbon density (metric tons/bbl)</th>
<th>Column B: carbon share (% of mass)</th>
<th>Column C: emission factor (metric tons CO₂/bbl)</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Finished Motor Gasoline</strong></td>
<td></td>
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<tr>
<td>Conventional—Summer</td>
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<td></td>
<td></td>
</tr>
<tr>
<td>Regular</td>
<td>0.1181</td>
<td>86.66</td>
<td>0.3753</td>
</tr>
<tr>
<td>Midgrade</td>
<td>0.1183</td>
<td>86.63</td>
<td>0.3758</td>
</tr>
<tr>
<td>Premium</td>
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<td>0.3763</td>
</tr>
<tr>
<td>Conventional—Winter</td>
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<td></td>
<td></td>
</tr>
<tr>
<td>Regular</td>
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<td>86.50</td>
<td>0.3663</td>
</tr>
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<td>0.1161</td>
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<td>0.3684</td>
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<td>0.3670</td>
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<tr>
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<td><strong>Blendstocks</strong></td>
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<tr>
<td>CBGB—Summer</td>
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<tr>
<td>Regular</td>
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<td>0.3753</td>
</tr>
<tr>
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<tr>
<td>CBGB—Winter</td>
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<tr>
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<td>0.3670</td>
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<tr>
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<td></td>
</tr>
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<td>Regular</td>
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<td>Midgrade</td>
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<td>0.3763</td>
</tr>
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<td>Products</td>
<td>Column A: density (metric tons/ bbl)</td>
<td>Column B: carbon share (% of mass)</td>
<td>Column C: emission factor (metric tons CO2/bbl)</td>
</tr>
<tr>
<td>----------------------------------------------</td>
<td>-------------------------------------</td>
<td>-----------------------------------</td>
<td>-----------------------------------------------</td>
</tr>
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<td><strong>Oxynogenates</strong></td>
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<td>0.4264</td>
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<td>Low Sulfur</td>
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<td>0.4264</td>
</tr>
<tr>
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<td>Ultra Low Sulfur</td>
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<td>Kerosene-Type Jet Fuel</td>
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<td>Kerosene</td>
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<td>0.4264</td>
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<td>Diesel—Other</td>
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<td>86.47</td>
<td>0.4604</td>
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<td><strong>Petrochemical Feedstocks</strong></td>
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<td>Naphthas (&lt; 401 °F)</td>
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<td>84.11</td>
<td>0.3571</td>
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<tr>
<td>Other Oils (&gt; 401 °F)</td>
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<td>87.30</td>
<td>0.4550</td>
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<td><strong>Unfinished Oils</strong></td>
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<tr>
<td>Heavy Gas Oils</td>
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<td>Residuum</td>
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<tr>
<td><strong>Other Petroleum Products and Natural Gas Liquids</strong></td>
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<td>Aviation Gasoline</td>
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<td>Special Naphthas</td>
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<td>Waxes</td>
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<td>Asphalt and Road Oil</td>
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<td>Still Gas</td>
<td>0.1405</td>
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<td>0.4033</td>
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<td>Ethane</td>
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<td>0.0903</td>
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<td>0.2835</td>
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<td>Propane</td>
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<td>0.2349</td>
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<td>Propylene</td>
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<td>0.2521</td>
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<td>Butane</td>
<td>0.0911</td>
<td>82.66</td>
<td>0.2761</td>
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<tr>
<td>Butylene</td>
<td>0.0935</td>
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<td>0.2936</td>
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<tr>
<td>Isobutane</td>
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<td>Isobutylene</td>
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<td>85.63</td>
<td>0.2936</td>
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<tr>
<td>Pentanes Plus</td>
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<td>83.63</td>
<td>0.3235</td>
</tr>
<tr>
<td>Miscellaneous Products</td>
<td>0.1389</td>
<td>85.49</td>
<td>0.4326</td>
</tr>
</tbody>
</table>

1. In the case of products blended with some portion of biomass-based fuel, the carbon share in Table MM-1 of this subpart represents only the petroleum-based components.

2. Products that are derived entirely from biomass should not be reported, but products that were derived from both biomass and a petroleum product (i.e., co-processed) should be reported as the petroleum product that it most closely represents.

### Table MM-2 to Subpart MM of Part 98—Default Factors for Biomass-Based Fuels and Biomass

<table>
<thead>
<tr>
<th>Biomass-based fuel and biomass</th>
<th>Column A: Density (metric tons/bbl)</th>
<th>Column B: Carbon share (% of mass)</th>
<th>Column C: Emission factor (metric tons CO2/bbl)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Ethanol (100%)</td>
<td>0.1267</td>
<td>52.14</td>
<td>0.2422</td>
</tr>
<tr>
<td>Biodiesel (100%, methyl ester)</td>
<td>0.1396</td>
<td>77.30</td>
<td>0.3957</td>
</tr>
</tbody>
</table>
Subpart NN—Suppliers of Natural Gas and Natural Gas Liquids

§ 98.400 Definition of the source category.
This supplier category consists of natural gas liquids fractionators and local natural gas distribution companies.

(a) Natural gas liquids fractionators are installations that fractionate natural gas liquids (NGLs) into their constituent liquid products (ethane, propane, normal butane, isobutane or pentanes plus) for supply to downstream facilities.

(b) Local Distribution Companies (LDCs) are companies that own or operate distribution pipelines, not interstate pipelines or intrastate pipelines, that physically deliver natural gas to end users and that are regulated as separate operating companies by State public utility commissions or that operate as independent municipally-owned distribution systems.

(c) This supply category does not consist of the following facilities:

(1) Field gathering and boosting stations.

(2) Natural gas processing plants that separate NGLs from natural gas and produce bulk or y-grade NGLs but do not fractionate these NGLs into their constituent products.

(3) Facilities that meet the definition of refineries and report under subpart MM of this part.

(4) Facilities that meet the definition of petrochemical plants and report under subpart X of this part.

§ 98.401 Reporting threshold.
Any supplier of natural gas and natural gas liquids that meets the requirements of § 98.2(a)(4) must report GHG emissions.

§ 98.402 GHGs to report.

(a) NGL fractionators must report the CO2 emissions that would result from the complete combustion or oxidation of the annual quantity of ethane, propane, normal butane, isobutane, and pentanes plus that is produced and sold or delivered to others.

(b) LDCs must report the CO2 emissions that would result from the complete combustion or oxidation of the annual volumes of natural gas provided to end-users on their distribution systems.

§ 98.403 Calculating GHG emissions.

(a) LDCs and fractionators shall, for each individual product reported under this part, calculate the estimated CO2 emissions that would result from the complete combustion or oxidation of the products supplied using either of Calculation Methodology 1 or 2 of this subpart:

(1) Calculation Methodology 1. NGL fractionators shall estimate CO2 emissions that would result from the complete combustion or oxidation of the product(s) supplied using Equation NN–1 of this section. LDCs shall estimate CO2 emissions that would result from the complete combustion or oxidation of the product received at the city gate using Equation NN–1. For each product, use the default value for higher heating value and CO2 emission factor in Table NN–1 of this subpart. Alternatively, for each product, a reporter-specific higher heating value and CO2 emission factor may be used, in place of one or both defaults provided they are developed using methods outlined in § 98.404. For each product, you must use the same volume unit throughout the equation.
\[
CO_{2i} = 1 \times 10^{-3} \sum Fuel_h \times HHV_h \times EF_h \quad \text{(Eq. NN-1)}
\]

Where:
- \( CO_{2i} \) = Annual \( CO_2 \) mass emissions that would result from the combustion or oxidation of each product “\( h \)” for redelivery to all recipients (metric tons).
- \( Fuel_h \) = Total annual volume of product “\( h \)” supplied (volume per year, in thousand standard cubic feet (Mscf) for natural gas and bbl for NGLs).
- \( HHV_h \) = Higher heating value of product “\( h \)” supplied (MMBtu/Mscf or MMBtu/bbl).
- \( EF_h \) = \( CO_2 \) emission factor of product “\( h \)” (kg \( CO_2 \)/MMBtu).
- \( 1 \times 10^{-3} \) = Conversion factor from kilograms to metric tons (MT/kg).

(2) **Calculation Methodology**

NGL fractionators shall estimate \( CO_2 \) emissions that would result from the complete combustion or oxidation of the product(s) supplied using Equation NN–2 of this section. LDCs shall estimate \( CO_2 \) emissions that would result from the complete combustion or oxidation of the product received at the city gate using Equation NN–2. For each product, use the default \( CO_2 \) emission factor found in Table NN–2 of this subpart. Alternatively, for each product, a reporter-specific \( CO_2 \) emission factor may be used in place of the default factor, provided it is developed using methods outlined in §98.404. For each product, you must use the same volume unit throughout the equation.

\[
CO_{2j} = \sum_{h} Fuel_h \times EF_h \quad \text{(Eq. NN-2)}
\]

Where:
- \( CO_{2j} \) = Annual \( CO_2 \) mass emissions that would result from the combustion or oxidation of each product “\( h \)” (metric tons).
- \( Fuel_h \) = Total annual volume of product “\( h \)” supplied (bbl or Mscf per year).
- \( EF_h \) = \( CO_2 \) emission factor of product “\( h \)” (MT \( CO_2 \)/bbl, or MT \( CO_2 \)/Mscf).

(b) Each LDC shall follow the procedures below.

(1) For natural gas that is received for redelivery to downstream gas transmission pipelines and other local distribution companies, use Equation NN–3 of this section and the default values for the \( CO_2 \) emission factors found in Table NN–2 of this subpart. Alternatively, reporter-specific \( CO_2 \) emission factors may be used, provided they are developed using methods outlined in §98.404.

\[
CO_{2j} = Fuel \times EF \quad \text{(Eq. NN-3)}
\]

Where:
- \( CO_{2j} \) = Annual \( CO_2 \) mass emissions that would result from the combustion or oxidation of natural gas for redelivery to transmission pipelines or other LDCs (metric tons).
- \( Fuel \) = Total annual volume of natural gas supplied (Mscf per year).
- \( EF \) = Fuel-specific \( CO_2 \) emission factor (MT \( CO_2 \)/Mscf).

(2)(i) For natural gas delivered to each meter registering a supply equal to or greater than 460,000 Mscf per year, use Equation NN–4 of this section and the default values for the \( CO_2 \) emission factors found in Table NN–2 of this subpart. Alternatively, reporter-specific \( CO_2 \) emission factors may be used, provided they are developed using methods outlined in §98.404.

\[
CO_{2k} = Fuel \times EF \quad \text{(Eq. NN-4)}
\]

Where:
- \( CO_{2k} \) = Annual \( CO_2 \) mass emissions that would result from the combustion or oxidation of natural gas received by end-users that receive a supply equal to or greater than 460,000 Mscf per year (metric tons).
- \( Fuel \) = Total annual volume of natural gas supplied (Mscf per year).
- \( EF \) = Fuel-specific \( CO_2 \) emission factor (MT \( CO_2 \)/Mscf).

(3) For natural gas received by the LDC at the city gate that is injected into on-system storage, and/or liquefied and stored, use Equation NN–5 of this section and the default value for the \( CO_2 \) emission factors found in Table NN–2 of this subpart. Alternatively, a reporter-specific \( CO_2 \) emission factor may be used, provided it is developed using methods outlined in §98.404.
Where:

\( \text{CO}_2 \) = Annual \( \text{CO}_2 \) mass emissions that would result from the combustion or oxidation of the net natural gas that is liquefied and/or stored and not used for deliveries by the LDC within the reported year (metric tons).

\( \text{Fuel}_1 \) = Total annual volume of natural gas received by the LDC at the city gate and stored on-system or liquefied and stored in the reporting year (Mscf per year).

\( \text{Fuel}_2 \) = Total annual volume of natural gas that is used for deliveries in the reporting year that was not otherwise accounted for in Equation NN–1 or NN–2 of this section (Mscf per year). This primarily includes natural gas previously stored on-system or liquefied and stored that is removed from storage and used for deliveries to customers or other LDCs by the LDC within the reporting year. This also includes natural gas that bypassed the city gate and was delivered directly to LDC systems from producers or natural gas processing plants from local production.

\( \text{EF} \) = Fuel-specific \( \text{CO}_2 \) emission factor (MT \( \text{CO}_2 / \text{Mscf} \)).

\( \text{CO}_2 \) = Annual \( \text{CO}_2 \) mass emissions that would result from the combustion or oxidation of natural gas delivered to LDC customers not covered in paragraph (b)(2) of this section (metric tons).

\( \text{CO}_2i \) = Annual \( \text{CO}_2 \) mass emissions that would result from the combustion or oxidation of natural gas received at the city gate as calculated in paragraph (a)(1) or (a)(2) of this section (metric tons).

\( \text{CO}_2j \) = Annual \( \text{CO}_2 \) mass emissions that would result from the combustion or oxidation of natural gas delivered to transmission pipelines or other LDCs as calculated in paragraph (b)(1) of this section (metric tons).

\( \text{CO}_2k \) = Annual \( \text{CO}_2 \) mass emissions that would result from the combustion or oxidation of natural gas received by end-users that receive a supply equal to or greater than 460,000 Mscf per year as calculated in paragraph (b)(2) of this section (metric tons).

\( \text{CO}_2l \) = Annual \( \text{CO}_2 \) mass emissions that would result from the combustion or oxidation of natural gas received by the LDC and liquefied and stored but not used for deliveries within the reported year as calculated in paragraph (b)(3) of this section (metric tons).

(c) Each NGL fractionator shall follow the following procedures.

(1)(i) For fractionated NGLs received by the reporter from other NGL fractionators, you shall use Equation NN–7 of this section and the default values for the \( \text{CO}_2 \) emission factors found in Table NN–2 of this subpart.

(ii) Alternatively, reporter-specific \( \text{CO}_2 \) emission factors may be used, provided they are developed using methods outlined in §98.404.

\( \text{CO}_2 \) = Annual \( \text{CO}_2 \) mass emissions that would result from the combustion or oxidation of each fractionated NGL product “g” received from other fractionators (metric tons).

\( \text{Fuel}_g \) = Total annual volume of each NGL product “g” received (bbls).

\( \text{EF}_g \) = Fuel-specific \( \text{CO}_2 \) emission factor of NGL product “g” (MT \( \text{CO}_2 / \text{bbl} \)).

(2) Calculate the total \( \text{CO}_2 \) equivalent emissions that would result from the combustion or oxidation of fractionated NGLs supplied less the quantity received by other fractionators using Equation NN–8 of this section.

\( \text{CO}_2 \) = Annual \( \text{CO}_2 \) mass emissions that would result from the combustion or oxidation of natural gas delivered to LDC customers not covered in paragraph (b)(2) of this section (metric tons).

\( \text{CO}_2i \) = Annual \( \text{CO}_2 \) mass emissions that would result from the combustion or oxidation of natural gas delivered to transmission pipelines or other LDCs as calculated in paragraph (b)(1) of this section (metric tons).

\( \text{CO}_2j \) = Annual \( \text{CO}_2 \) mass emissions that would result from the combustion or oxidation of natural gas delivered to transmission pipelines or other LDCs as calculated in paragraph (b)(1) of this section (metric tons).

\( \text{CO}_2k \) = Annual \( \text{CO}_2 \) mass emissions that would result from the combustion or oxidation of natural gas received by end-users that receive a supply equal to or greater than 460,000 Mscf per year as calculated in paragraph (b)(2) of this section (metric tons).

\( \text{CO}_2l \) = Annual \( \text{CO}_2 \) mass emissions that would result from the combustion or oxidation of natural gas received by the LDC and liquefied and stored but not used for deliveries within the reported year as calculated in paragraph (b)(3) of this section (metric tons).

\( \text{CO}_2m \) = Annual \( \text{CO}_2 \) mass emissions that would result from the combustion or oxidation of each fractionated NGL product “g” received from other fractionators (metric tons).

\( \text{Fuel}_g \) = Total annual volume of each NGL product “g” received (bbls).

\( \text{EF}_g \) = Fuel-specific \( \text{CO}_2 \) emission factor of NGL product “g” (MT \( \text{CO}_2 / \text{bbl} \)).

\( \text{CO}_2i \) = Annual \( \text{CO}_2 \) mass emissions that would result from the combustion or oxidation of natural gas delivered to LDC customers not covered in paragraph (b)(2) of this section (metric tons).

\( \text{CO}_2j \) = Annual \( \text{CO}_2 \) mass emissions that would result from the combustion or oxidation of natural gas delivered to transmission pipelines or other LDCs as calculated in paragraph (b)(1) of this section (metric tons).

\( \text{CO}_2k \) = Annual \( \text{CO}_2 \) mass emissions that would result from the combustion or oxidation of natural gas received by end-users that receive a supply equal to or greater than 460,000 Mscf per year as calculated in paragraph (b)(2) of this section (metric tons).

\( \text{CO}_2l \) = Annual \( \text{CO}_2 \) mass emissions that would result from the combustion or oxidation of natural gas received by the LDC and liquefied and stored but not used for deliveries within the reported year as calculated in paragraph (b)(3) of this section (metric tons).

\( \text{CO}_2 \) = Annual \( \text{CO}_2 \) mass emissions that would result from the combustion or oxidation of each fractionated NGL product “g” received from other fractionators (metric tons).

\( \text{Fuel}_g \) = Total annual volume of each NGL product “g” received (bbls).

\( \text{EF}_g \) = Fuel-specific \( \text{CO}_2 \) emission factor of NGL product “g” (MT \( \text{CO}_2 / \text{bbl} \)).
§ 98.404 Monitoring and QA/QC requirements.

(a) Determination of quantity.

(1) NGL fractionators and LDCs shall determine the quantity of NGLs and natural gas using methods in common use in the industry for billing purposes as audited under existing Sarbanes Oxley regulations.

(i) Where an appropriate standard method published by a consensus-based standards organization exists, such a method shall be used. Consensus-based standards organizations include, but are not limited to, the following: ASTM International, the American National Standards Institute (ANSI), the American Gas Association (AGA), the American Society of Mechanical Engineers (ASME), the American Petroleum Institute (API), and the North American Energy Standards Board (NAESB).

(ii) Where no appropriate standard method developed by a consensus-based standards organization exists, industry standard practices shall be followed.

(2) NGL fractionators and LDCs shall base the minimum frequency of the product quantity measurements, to be summed to the annual quantity reported, on the reporter’s standard practices for commercial operations.

(i) For NGL fractionators the minimum frequency of measurements shall be the measurements taken at custody transfers summed to the annual reportable volume.

(ii) For natural gas the minimum frequency of measurement shall be based on the LDC’s standard measurement schedules used for billing purposes and summed to the annual reportable volume.

(3) NGL fractionators shall use measurement for NGLs at custody transfer meters or at such meters that are used to determine the NGL product slate delivered from the fractionation facility.

(4) If a NGL fractionator supplies a product not listed in Table NN–1 of this subpart that is a mixture or blend of two or more products listed in Tables NN–1 and NN–2 of this subpart, the NGL fractionator shall report the quantities of the constituents of the mixtures or blends separately.

(5) For an LDC using Equation NN–1 or NN–2 of this subpart, the point(s) of measurement for the natural gas volume supplied shall be the LDC city gate meter(s).

(i) If the LDC makes its own quantity measurements according to established business practices, its own measurements shall be used.

(ii) If the LDC does not make its own quantity measurements according to established business practices, it shall use its delivering pipeline invoiced measurements for natural gas deliveries to the LDC city gate, used in determining daily system sendout.

(6) An LDC using Equation NN–3 of this subpart shall measure natural gas at the custody transfer meters.

(7) An LDC using Equation NN–4 of this subpart shall measure natural gas at the customer meters. The reporter shall consider the volume delivered through a single particular meter at a single particular location as the volume delivered to an individual enduser.

(8) An LDC using Equation NN–5 of this subpart shall measure natural gas as follows:

(i) Fuel\(_1\) shall be measured at the on-system storage injection meters and/or at the meters measuring natural gas to be liquefied.

(ii) Fuel\(_2\) shall be measured at the meters used for measuring on-system storage withdrawals and/or LNG vaporization injection. If Fuel\(_2\) is from a source other than storage, the appropriate meter shall be used to measure the quantity.

(9) An LDC shall measure all natural gas under the following standard industry temperature and pressure conditions: Cubic foot of gas at a temperature of 60 degrees Fahrenheit and at an
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absolute pressure of fourteen and seventy-three hundredths (14.73) pounds per square inch.

(b) Determination of higher heating values (HHV).

(1) When a reporter uses the default HHV provided in this section to calculate Equation NN–1 of this subpart, the appropriate value shall be taken from Table NN–1 of this subpart.

(2) When a reporter uses a reporter-specific HHV to calculate Equation NN–1 of this subpart, an appropriate standard test published by a consensus-based standards organization shall be used. Consensus-based standards organizations include, but are not limited to, the following: AGA and GPA.

(i) If an LDC makes its own HHV measurements according to established business practices, then its own measurements shall be used.

(ii) If an LDC does not make its own measurements according to established business practices, it shall use its delivering pipeline measurements.

(c) Determination of emission factor (EF).

(1) When a reporter used the default EF provided in this section to calculate Equation NN–1 of this subpart, the appropriate value shall be taken from Table NN–1 of this subpart.

(2) When a reporter used the default EF provided in this section to calculate Equation NN–2, NN–3, NN–4, NN–5, or NN–7 of this subpart, the appropriate value shall be taken from Table NN–2 of this subpart.

(3) When a reporter uses a reporter-specific EF, the reporter shall use an appropriate standard method published by a consensus-based standards organization to conduct compositional analysis necessary to determine reporter-specific CO₂ emission factors. Consensus-based standards organizations include, but are not limited to, the following: AGA and GPA.

(d) Equipment Calibration.

(1) Equipment used to measure quantities in Equations NN–1, NN–2, and NN–5 of this subpart shall be calibrated to its first use for reporting under this subpart, using a suitable standard method published by a consensus based standards organization or according to the equipment manufacturer’s directions.

(2) Equipment used to measure quantities in Equations NN–1, NN–2, and NN–5 of this subpart shall be recalibrated at the frequency specified by the standard method used or by the manufacturer’s directions.

§ 98.405 Procedures for estimating missing data.

(a) Whenever a quality-assured value of the quantity of natural gas liquids or natural gas supplied during any period is unavailable (e.g., if a flow meter malfunctions), a substitute data value for the missing quantity measurement must be used in the calculations according to paragraphs (b) and (c) of this section.

(b) Determination of quantity.

(1) NGL fractionators shall substitute meter records provided by pipeline(s) for all pipeline receipts of NGLs; by manifests for deliveries made to trucks or rail cars; or metered quantities accepted by the entities purchasing the output from the fractionator whether by pipeline or by truck or rail car. In cases where the metered data from the receiving pipeline(s) or purchasing entities are not available, fractionators may substitute estimates based on contract quantities required to be delivered under purchase or delivery contracts with other parties.

(2) LDCs shall either substitute their delivering pipeline metered deliveries at the city gate or substitute nominations and scheduled delivery quantities for the period when metered values of actual deliveries are not available.

(c) Determination of HHV and EF.

(1) Whenever an LDC that makes its own HHV measurements according to established business practices cannot follow the quality assurance procedures for developing a reporter-specific HHV, as specified in §98.404, during any period for any reason, the reporter shall use either its delivering pipeline measurements or the default HHV provided in Table NN–1 of this part for that period.

(2) Whenever an LDC that does not make its own HHV measurements according to established business practices or an NGL fractionator cannot follow the quality assurance procedures for developing a reporter-specific
HHV, as specified in § 98.404, during any period for any reason, the reporter shall use the default HHV provided in Table NN–1 of this part for that period.

(3) Whenever a NGL fractionator cannot follow the quality assurance procedures for developing a reporter-specific HHV, as specified in § 98.404, during any period for any reason, the NGL fractionator shall use the default HHV provided in Table NN–1 of this part for that period.

(4) Whenever a reporter cannot follow the quality assurance procedures for developing a reporter-specific EF, as specified in § 98.404, during any period for any reason, the reporter shall use the default EF provided in § 98.408 for that period.

§ 98.406 Data reporting requirements.

(a) In addition to the information required by § 98.3(c), the annual report for each NGL fractionator covered by this rule shall contain the following information.

(1) Annual quantity (in barrels) of each NGL product supplied to downstream facilities in the following product categories: ethane, propane, normal butane, isobutane, and pentanes plus.

(2) Annual quantity (in barrels) of each NGL product received from other NGL fractionators in the following product categories: ethane, propane, normal butane, isobutane, and pentanes plus.

(3) Annual volumes in Mscf of natural gas received for processing.

(4) Annual quantity (in barrels) of y-grade, bulk NGLs received from others for fractionation.

(5) Annual quantity (in barrels) of propane that the NGL fractionator odorizes at the facility and delivers to others.

(6) Annual CO₂ emissions (metric tons) that would result from the complete combustion or oxidation of the quantities in paragraphs (a)(1) and (a)(2) of this section, calculated in accordance with § 98.403(a) and (c)(1).

(7) Annual CO₂ mass emissions (metric tons) that would result from the combustion or oxidation of fractionated NGLs supplied less the quantity received by other fractionators, calculated in accordance with § 98.403(c)(2).

(b) In addition to the information required by § 98.3(c), the annual report for each LDC shall contain the following information.

(1) Annual volume in Mscf of natural gas received by the LDC at its city gate stations for redelivery on the LDC's distribution system, including for use by the LDC.

(2) Annual volume in Mscf of natural gas placed into storage.

(3) Annual volume in Mscf of vaporized liquefied natural gas (LNG) produced at on-system vaporization facilities for delivery on the distribution system that is not accounted for in paragraph (b)(1) of this section.

(4) Annual volume in Mscf of natural gas withdrawn from on-system storage (that is not delivered to the city gate) for delivery on the distribution system.

(5) Annual volume in Mscf of natural gas delivered directly to LDC systems from producers or natural gas processing plants from local production.

(6) Annual volume in Mscf of natural gas delivered to downstream gas transmission pipelines and other local distribution companies.

(7) Annual volume in Mscf of natural gas delivered by LDC to each meter registering supply equal to or greater than 460,000 Mscf during the calendar year.

(8) The total annual CO₂ mass emissions (metric tons) associated with the volumes in paragraphs (b)(1) through (b)(7) of this section, calculated in accordance with § 98.403(a) and (b)(1) through (b)(3).

(9) Annual CO₂ emissions (metric tons) that would result from the complete combustion or oxidation of the
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annual supply of natural gas to end-users registering less than 460,000 Mcf, calculated in accordance with §98.403(b)(4).

(10) The specific industry standard used to develop the volume reported in paragraph (b)(1) of this section.

(11) If the LDC developed reporter-specific EFs or HHVs, report the following:

(i) The specific industry standard(s) used to develop reporter-specific higher heating value(s) and/or emission factor(s), pursuant to §98.404(b)(2) and (c)(3).

(ii) The developed HHV(s).

(iii) The developed EF(s).

(12) The customer name, address, and meter number of each meter reading used to report in paragraph (b)(7) of this section.

(i) If known, report the EIA identification number of each LDC customer.

(ii) [Reserved]

(13) The annual volume in Mcf of natural gas delivered by the local distribution company to each of the following end-use categories. For definitions of these categories, refer to EIA Form 176 (Annual Report of Natural Gas and Supplemental Gas Supply & Disposition) and Instructions.

(i) Residential consumers.

(ii) Commercial consumers.

(iii) Industrial consumers.

(iv) Electricity generating facilities.

(c) Each reporter shall report the number of days in the reporting year for which substitute data procedures were used for the following purpose:

(1) To measure quantity.

(2) To develop HHV(s).

§98.407 Records that must be retained.

In addition to the information required by §98.3(g), each annual report must contain the following information:

(a) Records of all meter readings and documentation to support volumes of natural gas and NGLs that are reported under this part.

(b) Records documenting any estimates of missing metered data and showing the calculations of the values used for the missing data.

(c) Calculations and worksheets used to estimate CO₂ emissions for the volumes reported under this part.

(d) Records related to the large end-users identified in §98.406(b)(7).

(e) Records relating to measured Btu content or carbon content showing specific industry standards used to develop reporter-specific higher heating values and emission factors.

(f) Records of such audits as required by Sarbanes Oxley regulations on the accuracy of measurements of volumes of natural gas and NGLs delivered to customers or on behalf of customers.

§98.408 Definitions.

All terms used in this subpart have the same meaning given in the Clean Air Act and subpart A of this part.

### Table NN–1 to Subpart HH of Part 98—Default Factors for Calculation Methodology 1 of This Subpart

<table>
<thead>
<tr>
<th>Fuel</th>
<th>Default high heating value factor</th>
<th>Default CO₂ emission factor (kg CO₂/ MMBtu)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Natural Gas</td>
<td>1.028 MMBtu/Mscf</td>
<td>53.02</td>
</tr>
<tr>
<td>Propane</td>
<td>3.822 MMBtu/bbl</td>
<td>61.46</td>
</tr>
<tr>
<td>Normal butane</td>
<td>4.242 MMBtu/bbl</td>
<td>65.15</td>
</tr>
<tr>
<td>Ethane</td>
<td>4.032 MMBtu/bbl</td>
<td>62.64</td>
</tr>
<tr>
<td>Isobutane</td>
<td>4.074 MMBtu/bbl</td>
<td>64.91</td>
</tr>
<tr>
<td>Pentanes plus</td>
<td>4.620 MMBtu/bbl</td>
<td>70.02</td>
</tr>
</tbody>
</table>


[75 FR 66479, Oct. 28, 2010]
TABLE NN–2 TO SUBPART HH OF PART 98—LOOKUP DEFAULT VALUES FOR CALCULATION METHODOLOGY 2 OF THIS SUBPART

<table>
<thead>
<tr>
<th>Fuel</th>
<th>Default CO₂ emission value (MT CO₂/Unit)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Natural Gas</td>
<td></td>
</tr>
<tr>
<td>Propane</td>
<td></td>
</tr>
<tr>
<td>Normal butane</td>
<td></td>
</tr>
<tr>
<td>Ethane</td>
<td></td>
</tr>
<tr>
<td>Isobutane</td>
<td></td>
</tr>
<tr>
<td>Pentanes plus</td>
<td></td>
</tr>
</tbody>
</table>

[75 FR 66479, Oct. 28, 2010]

Subpart OO—Suppliers of Industrial Greenhouse Gases

§ 98.410 Definition of the source category.
(a) The industrial gas supplier source category consists of any facility that produces a fluorinated GHG or nitrous oxide, any bulk importer of fluorinated GHGs or nitrous oxide, and any bulk exporter of fluorinated GHGs or nitrous oxide.
(b) To produce a fluorinated GHG means to manufacture a fluorinated GHG from any raw material or feedstock chemical. Producing a fluorinated GHG includes the manufacture of a fluorinated GHG as an isolated intermediate for use in a process that will result in its transformation either at or outside of the production facility. Producing a fluorinated GHG also includes the creation of a fluorinated GHG (with the exception of HFC-23) that is captured and shipped off site for any reason, including destruction. Producing a fluorinated GHG does not include the reuse or recycling of a fluorinated GHG, the creation of HFC-23 during the production of HCFC-22, the creation of intermediates that are created and transformed in a single process with no storage of the intermediates, or the creation of fluorinated GHGs that are released or destroyed at the production facility before the production measurement at §98.414(a).
(c) To produce nitrous oxide means to produce nitrous oxide by thermally decomposing ammonium nitrate (NH₄NO₃). Producing nitrous oxide does not include the reuse or recycling of nitrous oxide or the creation of by-products that are released or destroyed at the production facility.


§ 98.411 Reporting threshold.
Any supplier of industrial greenhouse gases who meets the requirements of §98.2(a)(4) must report GHG emissions.

§ 98.412 GHGs to report.
You must report the GHG emissions that would result from the release of the nitrous oxide and each fluorinated GHG that you produce, import, export, transform, or destroy during the calendar year.

§ 98.413 Calculating GHG emissions.
(a) Calculate the total mass of each fluorinated GHG or nitrous oxide produced annually, except for amounts that are captured solely to be shipped off site for destruction, by using Equation OO-1 of this section:

\[ P = \sum_{p=1}^{n} P_p \quad (\text{Eq. OO-1}) \]

\( P \) = Mass of fluorinated GHG or nitrous oxide produced annually.
\( P_p \) = Mass of fluorinated GHG or nitrous oxide produced over the period “p”.

(b) Calculate the total mass of each fluorinated GHG or nitrous oxide produced over the period “p” by using Equation OO-2 of this section:

\[ P_p = O_p - U_p \quad (\text{Eq. OO-2}) \]

Where:
§ 98.414 Monitoring and QA/QC requirements.

(a) The mass of fluorinated GHGs or nitrous oxide coming out of the production process shall be measured using flowmeters, weigh scales, or a combination of volumetric and density measurements with an accuracy and precision of one percent of full scale or better. If the measured mass includes more than one fluorinated GHG, the concentrations of each of the fluorinated GHGs, other than low-concentration constituents, shall be measured as set forth in paragraph (n) of this section. For each fluorinated GHG, the mean of the concentrations of that fluorinated GHG (mass fraction) measured under paragraph (n) of this section shall be multiplied by the mass measurement to obtain the mass of that fluorinated GHG coming out of the production process.

(b) The mass of any used fluorinated GHGs or used nitrous oxide added back into the production process upstream of the output measurement in paragraph (a) of this section shall be measured using flowmeters, weigh scales, or a combination of volumetric and density measurements with an accuracy and precision of one percent of full scale or better. If the mass in paragraph (a) of this section is measured by weighing containers that include returned heels as well as newly produced fluorinated GHGs, the returned heels shall be considered used fluorinated GHGs for purposes of this paragraph (b) of this section and §98.413(b).

(c) The mass of fluorinated GHGs or nitrous oxide fed into the transformation process shall be measured using flowmeters, weigh scales, or a combination of volumetric and density measurements with an accuracy and precision of one percent of full scale or better.

(d) The fraction of the fluorinated GHGs or nitrous oxide fed into the transformation process that is actually transformed shall be estimated considering yield calculations or quantities of unreacted fluorinated GHGs or nitrous oxide permanently removed from the process and recovered, destroyed, or emitted.

(e) The mass of fluorinated GHG or nitrous oxide sent to another facility for transformation shall be measured using flowmeters, weigh scales, or a combination of volumetric and density measurements with an accuracy and precision of one percent of full scale or better.

(f) The mass of fluorinated GHG sent to another facility for destruction shall be measured using flowmeters, weigh scales, or a combination of volumetric and density measurements with an accuracy and precision of one percent of full scale or better. If the measured mass includes more than trace concentrations of materials other than the fluorinated GHG, the concentration of the fluorinated GHG shall be estimated...
considering current or previous representative concentration measurements and other relevant process information. This concentration (mass fraction) shall be multiplied by the mass measurement to obtain the mass of the fluorinated GHG sent to another facility for destruction.

(g) You must estimate the share of the mass of fluorinated GHGs in paragraph (f) of this section that is comprised of fluorinated GHGs that are not included in the mass produced in §98.413(a) because they are removed from the production process as byproducts or other wastes.

(h) You must measure the mass of each fluorinated GHG that is fed into the destruction device and that was previously produced as defined at §98.410(b). Such fluorinated GHGs include but are not limited to quantities that are shipped to the facility by another facility for destruction and quantities that are returned to the facility for reclamation but are found to be irretrievably contaminated and are therefore destroyed. You must use flowmeters, weigh scales, or a combination of volumetric and density measurements with an accuracy and precision of one percent of full scale or better. If the measured mass includes more than trace concentrations of materials other than the fluorinated GHG being destroyed, you must estimate the concentrations of the fluorinated GHG being destroyed considering current or previous representative concentration measurements and other relevant process information. You must multiply this concentration (mass fraction) by the mass measurement to obtain the mass of the fluorinated GHG fed into the destruction device.

(i) Very small quantities of fluorinated GHGs that are difficult to measure because they are entrained in other media such as destroyed filters and destroyed sample containers are exempt from paragraphs (f) and (h) of this section.

(j) [Reserved]

(k) For purposes of Equation 00-4 of this subpart, the destruction efficiency can be equated to the destruction efficiency determined during a previous performance test of the destruction device or, if no performance test has been done, the destruction efficiency provided by the manufacturer of the destruction device.

(l) In their estimates of the mass of fluorinated GHGs destroyed, fluorinated GHG production facilities that destroy fluorinated GHGs shall account for any temporary reductions in the destruction efficiency that result from any startups, shutdowns, or malfunctions of the destruction device, including departures from the operating conditions defined in state or local permitting requirements and/or oxidizer manufacturer specifications.

(m) Calibrate all flow meters, weigh scales, and combinations of volumetric and density measures that are used to measure or calculate quantities that are to be reported under this subpart prior to the first year for which GHG emissions are reported under this part. Calibrations performed prior to the effective date of this rule satisfy this requirement. Recalibrate all flow meters, weigh scales, and combinations of volumetric and density measures at the minimum frequency specified by the manufacturer. Use NIST-traceable standards and suitable methods published by a consensus standards organization (e.g., ASTM, ASME, ISO, or others).

(n) If the mass coming out of the production process includes more than one fluorinated GHG, you shall measure the concentrations of all of the fluorinated GHGs, other than low-concentration constituents, as follows:

(1) Analytical Methods. Use a quality-assured analytical measurement technology capable of detecting the analyte of interest at the concentration of interest and use a procedure validated with the analyte of interest at the concentration of interest. Where standards for the analyte are not available, a chemically similar surrogate may be used. Acceptable analytical measurement technologies include but are not limited to gas chromatography (GC) with an appropriate detector, infrared (IR), fourier transform infrared (FTIR), and nuclear magnetic resonance (NMR). Acceptable methods include EPA Method 18 in appendix A–1 of 40 CFR part 60; EPA Method 320 in appendix A of 40 CFR part 63; the Protocol for Measuring Destruction or Removal of...
(2) Documentation in GHG Monitoring Plan. Describe the analytical method(s) used under paragraph (n)(1) of this section in the site GHG Monitoring Plan as required under §98.3(g)(5). At a minimum, include in the description of the method a description of the analytical measurement equipment and procedures, quantitative estimates of the method’s accuracy and precision for the analytes of interest at the concentrations of interest, as well as a description of how these accuracies and precisions were estimated, including the validation protocol used.

(3) Frequency of measurement. Perform the measurements at least once by February 15, 2011 if the fluorinated GHG product is being produced on December 17, 2010. Perform the measurements within 60 days of commencing production of any fluorinated GHG product that was not being produced on December 17, 2010. Repeat the measurements if an operational or process change occurs that could change the identities or significantly change the concentrations of the fluorinated GHG constituents of the fluorinated GHG product. Complete the repeat measurements within 60 days of the operational or process change.

(4) Measure all product grades. Where a fluorinated GHG is produced at more than one purity level (e.g., pharmaceutical grade and refrigerant grade), perform the measurements for each purity level.

(5) Number of samples. Analyze a minimum of three samples of the fluorinated GHG product that have been drawn under conditions that are representative of the process producing the fluorinated GHG product. If the relative standard deviation of the measured concentrations of any of the fluorinated GHG constituents (other than low-concentration constituents) is greater than or equal to 15 percent, draw and analyze enough additional samples to achieve a total of at least six samples of the fluorinated GHG product.

(o) All analytical equipment used to determine the concentration of fluorinated GHGs, including but not limited to gas chromatographs and associated detectors, IR, FTIR and NMR devices, shall be calibrated at a frequency needed to support the type of analysis specified in the site GHG Monitoring Plan as required under §§98.414(n) and 98.3(g)(5) of this part. Quality assurance samples at the concentrations of concern shall be used for the calibration. Such quality assurance samples shall consist of or be prepared from certified standards of the analytes of concern where available; if not available, calibration shall be performed by a method specified in the GHG Monitoring Plan.

(p) Isolated intermediates that are produced and transformed at the same facility are exempt from the monitoring requirements of this section.

(q) Low-concentration constituents are exempt from the monitoring and QA/QC requirements of this section.

sent to another facility for transformation, or sent to another facility for destruction, the substitute value of that parameter shall be a secondary mass measurement where such a measurement is available. For example, if the mass produced is usually measured with a flowmeter at the inlet to the day tank and that flowmeter fails to meet an accuracy or precision test, malfunctions, or is rendered inoperable, then the mass produced may be estimated by calculating the change in volume in the day tank and multiplying it by the density of the product. Where a secondary mass measurement is not available, the substitute value of the parameter shall be an estimate based on a related parameter. For example, if a flowmeter measuring the mass fed into a destruction device is rendered inoperable, then the mass fed into the destruction device may be estimated using the production rate and the previously observed relationship between the production rate and the mass flow rate into the destruction device.

§ 98.416 Data reporting requirements.

In addition to the information required by §98.3(c), each annual report must contain the following information:

(a) Each fluorinated GHG or nitrous oxide production facility shall report the following information:

(1) Mass in metric tons of each fluorinated GHG or nitrous oxide produced at that facility by process, except for amounts that are captured solely to be shipped off site for destruction.

(2) Mass in metric tons of each fluorinated GHG that is destroyed at that facility and that was previously produced as defined at §98.410(b). Quantities to be reported under this paragraph (a)(2) of this section include but are not limited to quantities that are shipped to the facility by another facility for destruction and quantities that are returned to the facility for reclamation but are found to be irretrievably contaminated and are therefore destroyed.

(b) Total mass in metric tons of each fluorinated GHG or nitrous oxide sent to another facility for transformation.

(c) Total mass in metric tons of each fluorinated GHG sent to another facility for destruction, except fluorinated GHGs that are not included in the mass produced in §98.413(a) because they are removed from the production process as by-products or other wastes. Quantities to be reported under this paragraph (a)(3) of this section include, for example, fluorinated GHGs that are returned to the facility for reclamation but are found to be irretrievably contaminated and are therefore sent to another facility for destruction.

(d) Total mass in metric tons of each fluorinated GHG that is sent to another facility for destruction and that is not included in the mass produced in §98.414(a) because it is removed from the production process as a byproduct or other waste.

(e) Names and addresses of facilities to which any fluorinated GHG or nitrous oxide is shipped to another facility for destruction.
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fluorinated GHGs were sent for transformation, and the quantities (metric tons) of nitrous oxide and of each fluorinated GHG that were sent to each for transformation.

(15) Names and addresses of facilities to which any fluorinated GHGs were sent for destruction, and the quantities (metric tons) of each fluorinated GHG that were sent to each for destruction.

(16) Where missing data have been estimated pursuant to § 98.415, the reason the data were missing, the length of time the data were missing, the method used to estimate the missing data, and the estimates of those data.

(b) By March 31, 2011 or within 60 days of commencing fluorinated GHG destruction, whichever is later, a fluorinated GHG production facility or importer that destroys fluorinated GHGs shall submit a one-time report containing the following information for each destruction process:

(1) Destruction efficiency (DE).

(2) Methods used to determine the destruction efficiency.

(3) Methods used to record the mass of fluorinated GHG destroyed.

(4) Chemical identity of the fluorinated GHG(s) used in the performance test conducted to determine DE.

(5) Name of all applicable federal or state regulations that may apply to the destruction process.

(6) If any process changes affect unit destruction efficiency or the methods used to record mass of fluorinated GHG destroyed, then a revised report must be submitted to reflect the changes. The revised report must be submitted to EPA within 60 days of the change.

(c) Each bulk importer of fluorinated GHGs or nitrous oxide shall submit an annual report that summarizes its imports at the corporate level, except for shipments including less than twenty-five kilograms of fluorinated GHGs or nitrous oxide, transshipments, and heels that meet the conditions set forth at §98.417(e). The report shall contain the following information for each import:

(1) Total mass in metric tons of nitrous oxide and each fluorinated GHG imported in bulk, including each fluorinated GHG constituent of the fluorinated GHG product that makes up between 0.5 percent and 100 percent of the product by mass.

(2) Total mass in metric tons of nitrous oxide and each fluorinated GHG imported in bulk and sold or transferred to persons other than the importer for use in processes resulting in the transformation or destruction of the chemical.

(3) Date on which the fluorinated GHGs or nitrous oxide were imported.

(4) Port of entry through which the fluorinated GHGs or nitrous oxide passed.

(5) Country from which the imported fluorinated GHGs or nitrous oxide were imported.

(6) Commodity code of the fluorinated GHGs or nitrous oxide shipped.

(d) Each bulk exporter of fluorinated GHGs or nitrous oxide shall submit an annual report that summarizes its exports at the corporate level, except for shipments including less than twenty-five kilograms of fluorinated GHGs or nitrous oxide, transshipments, and heels. The report shall contain the following information for each export:

(1) Total mass in metric tons of nitrous oxide and each fluorinated GHG exported in bulk.

(2) Names and addresses of the exporter and the recipient of the exports.

(3) Exporter’s Employee Identification Number.
§ 98.417 Records that must be retained.

(a) In addition to the data required by §98.3(g), the fluorinated GHG production facility shall retain the following records:

(1) Dated records of the data used to estimate the data reported under §98.416.

(2) Records documenting the initial and periodic calibration of the analytical equipment (including but not limited to GC, IR, FTIR, or NMR), weigh scales, flowmeters, and volumetric and density measures used to measure the quantities reported under this subpart, including the manufacturer directions or industry standards used for calibration pursuant to §98.414(m) and (o).

(3) Dated records of the total mass in metric tons of each reactant fed into the F–GHG or nitrous oxide production process, by process.

(4) Dated records of the total mass in metric tons of the reactants, by-products, and other wastes permanently removed from the F–GHG or nitrous oxide production process, by process.

(b) In addition to the data required by paragraph (a) of this section, any fluorinated GHG production facility that destroys fluorinated GHGs shall keep records of test reports and other information documenting the facility’s one-time destruction efficiency report in §98.416(b).
(c) In addition to the data required by §98.3(g), the bulk importer shall retain the following records substantiating each of the imports that they report:
(1) A copy of the bill of lading for the import.
(2) The invoice for the import.
(3) The U.S. Customs entry form.

(d) In addition to the data required by §98.3(g), the bulk exporter shall retain the following records substantiating each of the exports that they report:
(1) A copy of the bill of lading for the export and
(2) The invoice for the export.

(e) Every person who imports a container with a heel that is not reported under §98.416(c) shall keep records of the amount brought into the United States that document that the residual amount in each shipment is less than 10 percent of the volume of the container and will:
(1) Remain in the container and be included in a future shipment.
(2) Be recovered and transformed.
(3) Be recovered and destroyed.
(4) Be recovered and included in a future shipment.

(f) Isolated intermediates that are produced and transformed at the same facility are exempt from the recordkeeping requirements of this section.

(g) Low-concentration constituent means, for purposes of fluorinated GHG production and export, a fluorinated GHG constituent of a fluorinated GHG product that occurs in the product in concentrations below 0.1 percent by mass. For purposes of fluorinated GHG import, low-concentration constituent means a fluorinated GHG constituent of a fluorinated GHG product that occurs in the product in concentrations below 0.5 percent by mass. Low-concentration constituents do not include fluorinated GHGs that are deliberately combined with the product (e.g., to affect the performance characteristics of the product).

[75 FR 79169, Dec. 17, 2010]

Subpart PP—Suppliers of Carbon Dioxide

§ 98.420 Definition of the source category.

(a) The carbon dioxide (CO₂) supplier source category consists of the following:
(1) Facilities with production process units that capture a CO₂ stream for purposes of supplying CO₂ for commercial applications or that capture and maintain custody of a CO₂ stream in order to sequester or otherwise inject it underground. Capture refers to the initial separation and removal of CO₂ from a manufacturing process or any other process.
(2) Facilities with CO₂ production wells that extract or produce a CO₂ stream for purposes of supplying CO₂ for commercial applications or that extract and maintain custody of a CO₂ stream in order to sequester or otherwise inject it underground.
(3) Importers or exporters of bulk CO₂.

(b) This source category is focused on upstream supply. It does not cover:
(1) Storage of CO₂ above ground or in geologic formations.
(2) Use of CO₂ in enhanced oil and gas recovery.
(3) Transportation or distribution of CO₂.

§ 98.418 Definitions.

Except as provided below, all of the terms used in this subpart have the same meaning given in the Clean Air Act and subpart A of this part. If a conflict exists between a definition provided in this subpart and a definition provided in subpart A, the definition in this subpart shall take precedence for the reporting requirements in this subpart.

Isolated intermediate means a product of a process that is stored before subsequent processing. An isolated intermediate is usually a product of chemical synthesis. Storage of an isolated intermediate marks the end of a process. Storage occurs at any time the intermediate is placed in equipment used solely for storage.

Low-concentration constituent means, for purposes of fluorinated GHG production and export, a fluorinated GHG constituent of a fluorinated GHG product that occurs in the product in concentrations below 0.1 percent by mass. For purposes of fluorinated GHG import, low-concentration constituent means a fluorinated GHG constituent of a fluorinated GHG product that occurs in the product in concentrations below 0.5 percent by mass. Low-concentration constituents do not include fluorinated GHGs that are deliberately combined with the product (e.g., to affect the performance characteristics of the product).
(4) Purification, compression, or processing of CO₂.
(5) On-site use of CO₂ captured on site.

(c) This source category does not include CO₂ imported or exported in equipment, such as fire extinguishers.

§ 98.421 Reporting threshold.
Any supplier of CO₂ who meets the requirements of § 98.2(a)(4) of subpart A of this part must report the mass of CO₂ captured, extracted, imported, or exported.

§ 98.422 GHGs to report.
(a) Mass of CO₂ captured from production process units.
(b) Mass of CO₂ extracted from CO₂ production wells.
(c) Mass of CO₂ imported.
(d) Mass of CO₂ exported.


§ 98.423 Calculating CO₂ supply.
(a) Except as allowed in paragraph (b) of this section, calculate the annual mass of CO₂ captured, extracted, imported, or exported through each flow meter in accordance with the procedures specified in either paragraph (a)(1) or (a)(2) of this section. If multiple flow meters are used, you shall calculate the annual mass of CO₂ for all flow meters according to the procedures specified in paragraph (a)(3) of this section.

(1) For each mass flow meter, you shall calculate quarterly the mass of CO₂ in a CO₂ stream in metric tons by multiplying the mass flow by the composition data, according to Equation PP–1 of this section. Mass flow and composition data measurements shall be made in accordance with § 98.424 of this subpart.

\[
\text{CO}_2,u = \sum_{p=1}^{4} Q_{p,u} \times C_{\text{CO}_2,p,u} \quad \text{(Eq. PP-1)}
\]

Where:
- CO₂,u = Annual mass of CO₂ (metric tons) through flow meter u.
- CCO₂,p,u = Quarterly CO₂ concentration measurement in flow for flow meter u in quarter p (wt. %CO₂).
- Qp,u = Quarterly mass flow rate measurement for flow meter u in quarter p (metric tons).
- p = Quarter of the year.
- u = Flow meter.

(2) For each volumetric flow meter, you shall calculate quarterly the mass of CO₂ in a CO₂ stream in metric tons by multiplying the volumetric flow by the concentration and density data, according to Equation PP–2 of this section. Volumetric flow, concentration and density data measurements shall be made in accordance with § 98.424 of this section.

\[
\text{CO}_2,u = \sum_{p=1}^{4} Q_p \times D_p \times C_{\text{CO}_2,p} \quad \text{(Eq. PP-2)}
\]

Where:
- CO₂,u = Annual mass of CO₂ (metric tons) through flow meter u.
- CCO₂,p = Quarterly CO₂ concentration measurement in flow for flow meter u in quarter p (measured as either volume % CO₂ or weight % CO₂).
- Qp = Quarterly volumetric flow rate measurement for flow meter u in quarter p (standard cubic meters).
- Dp = Density of CO₂ in quarter p (metric tons CO₂ per standard cubic meter) for flow meter u if CCO₂,p is measured as volume % CO₂, or density of the whole CO₂ stream for flow meter u (metric tons per standard cubic meters).
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(3) To aggregate data, use either Equation PP-3a or PP-3b in this paragraph, as appropriate.

\[
\text{CO}_2 = \sum_{p=1}^{U} \text{CO}_2_{u} \quad \text{(Eq. PP-3a)}
\]

where:

- CO\textsubscript{1} = Total annual mass of CO\textsubscript{2} (metric tons).
- CO\textsubscript{2,u} = Annual mass of CO\textsubscript{2} (metric tons) through flow meter u.
- u = Flow meter.

\[
\text{CO}_2 = \sum_{p=1}^{U} \text{CO}_2_{u} - \sum_{p=1}^{V} \text{CO}_2_{v} \quad \text{(Eq. PP-3b)}
\]

where:

- CO\textsubscript{1} = Total annual mass of CO\textsubscript{2} (metric tons).
- CO\textsubscript{2,u} = Annual mass of CO\textsubscript{2} (metric tons) through main flow meter u.
- CO\textsubscript{2,v} = Annual mass of CO\textsubscript{2} (metric tons) through subsequent flow meter v for use on site.
- u = Main flow meter.
- v = Subsequent flow meter.

(b) As an alternative to paragraphs (a)(1) through (3) of this section for CO\textsubscript{2} that is supplied in containers, calculate the annual mass of CO\textsubscript{2} supplied in containers delivered by each CO\textsubscript{2} stream in accordance with the procedures specified in either paragraph (b)(1) or (b)(2) of this section. If multiple CO\textsubscript{2} streams are used to deliver CO\textsubscript{2} to containers, you shall calculate the annual mass of CO\textsubscript{2} supplied in containers delivered by all CO\textsubscript{2} streams according to the procedures specified in paragraph (b)(3) of this section.

(1) For each CO\textsubscript{2} stream that delivers CO\textsubscript{2} to containers, for which mass is measured, you shall calculate CO\textsubscript{2} supply in containers using Equation PP-1 of this section.

where:

- CO\textsubscript{2,u} = Annual mass of CO\textsubscript{2} (metric tons) supplied in containers delivered by CO\textsubscript{2} stream u.
- C\textsubscript{CO2,p,u} = Quarterly CO\textsubscript{2} concentration measurement of CO\textsubscript{2} stream u that delivers CO\textsubscript{2} to containers in quarter p (wt. %CO\textsubscript{2}).
- Q\textsubscript{p,u} = Quarterly mass of contents supplied in all containers delivered by CO\textsubscript{2} stream u in quarter p (metric tons).
- D\textsubscript{p} = Quarterly CO\textsubscript{2} density determination for CO\textsubscript{2} stream u in quarter p (metric tons per standard cubic meter) if CO\textsubscript{2,p} is
§ 98.424 Monitoring and QA/QC requirements.

(a) Determination of quantity.

(1) Reporters following the procedures in §98.423(a) shall determine quantity using a flow meter or meters located in accordance with this paragraph.

(i) If the CO₂ stream is segregated such that only a portion is captured for commercial application or for injection, you must locate the flow meter according to the following:

(A) For reporters following the procedures in §98.423(a)(3)(i), you must locate the flow meter(s) after the point of segregation.

(B) For reporters following the procedures in paragraph (a)(3)(ii) of §98.423, you must locate the main flow meter(s) on the captured CO₂ stream(s) prior to the point of segregation and the subsequent flow meter(s) on the CO₂ stream(s) for on-site use after the point of segregation. You may only follow the procedures in paragraph (a)(3)(ii) of §98.423 if the CO₂ stream(s) for on-site use is/are the only diversion(s) from the main, captured CO₂ stream(s) after the main flow meter location(s).

(ii) Reporters that do not have a mass flow meter or volumetric flow meter installed to measure the flow of the CO₂ stream that meets the requirements of paragraph (a)(1)(i) of this section shall base calculations in §98.423 of this subpart on the mass flow meter or volumetric flow meter located at the point of off-site transfer.

(2) Reporters following the procedures in paragraph (b) of §98.423 shall determine quantity in accordance with this paragraph.

(i) Reporters that supply CO₂ in containers using weigh bills, scales, or load cells shall measure the mass of contents of each CO₂ container to which the CO₂ stream is delivered, sum the mass of contents supplied in all containers to which the CO₂ stream is delivered during each quarter, sample the CO₂ stream delivering CO₂ to containers on a quarterly basis to determine the composition of the CO₂ stream, and apply Equation PP-1.

\[
CO₂ = \sum_{p=1}^{i} Q
\]

where:

\( CO₂ \) = Annual mass of CO₂ (metric tons).
\( Q \) = Annual mass in all CO₂ containers imported or exported during the reporting year (metric tons).


CO₂ \( p \), CO₂ \( u \), and CO₂ \( u \) are Annual mass of CO₂ (metric tons) supplied in containers delivered by CO₂ stream \( p \), CO₂ stream \( u \) that delivers to containers, and CO₂ stream that delivers to containers, respectively.

(3) To aggregate data, sum the mass of CO₂ supplied in containers delivered by all CO₂ streams in accordance with Equation PP-3a of this section.

where:

\( CO₂ = \text{Annual mass of CO₂ (metric tons) supplied in containers delivered by all CO₂ streams.} \)

\( CO₂ \) = Annual mass of CO₂ (metric tons) supplied in containers delivered by CO₂ stream \( u \).
\( u \) = CO₂ stream that delivers to containers.

(c) Importers or exporters that import or export CO₂ in containers shall calculate the total mass of CO₂ imported or exported in metric tons based on summing the mass in each CO₂ container using weigh bills, scales, or load cells according to Equation PP-4 of this section.

\[ \text{(Eq. PP-4)} \]

\( CO₂ = \text{Annual mass of CO₂ (metric tons).} \)
\( Q = \text{Annual mass in all CO₂ containers imported or exported during the reporting year (metric tons).} \)

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(ii) Reporters that supply CO₂ in containers using loaded container volumes shall measure the volume of contents of each CO₂ container to which the CO₂ stream is delivered, sum the volume of contents supplied in all containers to which the CO₂ stream is delivered during each quarter, sample the CO₂ stream on a quarterly basis to determine the composition of the CO₂ stream, determine the density quarterly, and apply Equation PP–2.

(3) Importers or exporters that import or export CO₂ in containers shall measure the mass in each CO₂ container using weigh bills, scales, or load cells and sum the mass in all containers imported or exported during the reporting year.

(4) All flow meters, scales, and load cells used to measure quantities that are reported in §98.423 of this subpart shall be operated and calibrated according to the following procedure:

(i) You shall use an appropriate standard method published by a consensus-based standards organization if such a method exists. Consensus-based standards organizations include, but are not limited to, the following: ASTM International, the American National Standards Institute (ANSI), the American Gas Association (AGA), the American Society of Mechanical Engineers (ASME), the American Petroleum Institute (API), and the North American Energy Standards Board (NAESB).

(ii) Where no appropriate standard method developed by a consensus-based standards organization exists, you shall follow industry standard practices.

(iii) You must ensure that any flow meter calibrations performed are NIST traceable.

(5) Reporters using Equation PP–2 of this subpart and measuring CO₂ concentration as weight % CO₂ shall determine the density of the CO₂ stream on a quarterly basis in order to calculate the mass of the CO₂ stream according to one of the following procedures:


(ii) You may follow an industry standard method.

(b) Determination of concentration. (1) Reporters using Equation PP–1 or PP–2 of this subpart shall sample the CO₂ stream on a quarterly basis to determine the composition of the CO₂ stream.

(2) Methods to measure the composition of the CO₂ stream must conform to applicable chemical analytical standards. Acceptable methods include, but are not limited to, the U.S. Food and Drug Administration food-grade specifications for CO₂ (see 21 CFR 184.1240) and ASTM standard E1747–95 (Re-approved 2005) Standard Guide for Purity of Carbon Dioxide Used in Supercritical Fluid Applications (ASTM International, 100 Barr Harbor Drive, P.O. Box CB700, West Conshohocken, Pennsylvania 19428–B2959, (800) 262–1373, http://www.astm.org).

(c) You shall convert the density of the CO₂ stream(s) and all measured volumes of carbon dioxide to the following standard industry temperature and pressure conditions: Standard cubic meters at a temperature of 60 degrees Fahrenheit and at an absolute pressure of 1 atmosphere. If you apply the density value for CO₂ at standard conditions, you must use 0.001868 metric tons per standard cubic meter.

§ 98.425 Procedures for estimating missing data.

(a) Whenever the quality assurance procedures in §98.424(a)(1) of this subpart cannot be followed to measure quarterly mass flow or volumetric flow of CO₂, the most appropriate of the following missing data procedures shall be followed:

(1) A quarterly CO₂ mass flow or volumetric flow value that is missing may be substituted with a quarterly value measured during another quarter of the current reporting year.

(2) A quarterly CO₂ mass flow or volumetric flow value that is missing may be substituted with a quarterly value measured during the same quarter from the past reporting year.

(3) If a mass or volumetric flow meter is installed to measure the CO₂ stream, you may substitute data from a mass or volumetric flow meter measuring the CO₂ stream transferred for any period during which the installed meter is inoperable.

(4) The mass or volumetric flow used for purposes of product tracking and billing according to the reporter’s established procedures may be substituted for any period during which measurement equipment is inoperable.


§ 98.426 Data reporting requirements.

In addition to the information required by §98.3(c) of subpart A of this part, the annual report shall contain the following information, as applicable:

(a) If you use Equation PP–1 of this subpart, report the following information for each mass flow meter or CO₂ stream that delivers CO₂ to containers:

(1) Annual mass in metric tons of CO₂.

(2) Quarterly mass in metric tons of CO₂.

(3) Quarterly concentration of the CO₂ stream.

(4) The standard used to measure CO₂ concentration.

(5) The location of the flow meter in your process chain in relation to the points of CO₂ stream capture, dehydration, compression, and other processing.

(b) If you use Equation PP–2 of this subpart, report the following information for each volumetric flow meter or CO₂ stream that delivers CO₂ to containers:

(1) Annual mass in metric tons of CO₂.

(2) Quarterly volume in standard cubic meters of CO₂.
(3) Quarterly concentration of the CO₂ stream in volume or weight percent.

(4) Report density as follows:

(i) Quarterly density of CO₂ in metric tons per standard cubic meter if you report the concentration of the CO₂ stream in paragraph (b)(3) of this section in weight percent.

(ii) Quarterly density of the CO₂ stream in metric tons per standard cubic meter if you report the concentration of the CO₂ stream in paragraph (b)(3) of this section in volume percent.

(5) The method used to measure density.

(6) The standard used to measure CO₂ concentration.

(7) The location of the flow meter in your process chain in relation to the points of CO₂ stream capture, dehydration, compression, and other processing.

(c) For the aggregated annual mass of CO₂ emissions calculated using Equation PP–3a or PP–3b, report the following:

(1) If you use Equation PP–3a of this subpart, report the annual CO₂ mass in metric tons from all flow meters and CO₂ streams that deliver CO₂ to containers.

(2) If you use Equation PP–3b of this subpart, report:

(i) The total annual CO₂ mass through main flow meter(s) in metric tons.

(ii) The total annual CO₂ mass through subsequent flow meter(s) in metric tons.

(iii) The total annual CO₂ mass supplied in metric tons.

(iv) The location of each flow meter in relation to the point of segregation.

(d) If you use Equation PP–4 of this subpart, report at the corporate level the annual mass of CO₂ in metric tons in all CO₂ containers that are imported or exported.

(e) Each reporter shall report the following information:

(1) The type of equipment used to measure the total flow of the CO₂ stream or the total mass or volume in CO₂ containers.

(2) The standard used to operate and calibrate the equipment reported in (a)(1) of this section.

(3) The number of days in the reporting year for which substitute data procedures were used for the following purpose:

(i) To measure quantity.

(ii) To measure concentration.

(iii) To measure density.

(f) Report the aggregated annual quantity of CO₂ in metric tons that is transferred to each of the following end use applications, if known:

(1) Food and beverage.

(2) Industrial and municipal wastewater treatment.

(3) Metal fabrication, including welding and cutting.

(4) Greenhouse uses for plant growth.

(5) Fumigants (e.g., grain storage) and herbicides.

(6) Pulp and paper.

(7) Cleaning and solvent use.

(8) Fire fighting.

(9) Transportation and storage of explosives.

(10) Enhanced oil and natural gas recovery.

(11) Long-term storage (sequestration).

(12) Research and development.

(13) Other.

(g) Each production process unit that captures a CO₂ stream for purposes of supplying CO₂ for commercial applications or in order to sequester or otherwise inject it underground when custody of the CO₂ is maintained shall report the percentage of that stream, if any, that is biomass-based during the reporting year.


§ 98.427 Records that must be retained.

In addition to the records required by §98.3(g) of subpart A of this part, you must retain the records specified in paragraphs (a) through (c) of this section, as applicable.

(a) The owner or operator of a facility containing production process units must retain quarterly records of captured or transferred CO₂ streams and composition.

(b) The owner or operator of a CO₂ production well facility must maintain quarterly records of the mass flow or volumetric flow of the extracted or
transferred \( CO_2 \) stream and concentration and density if volumetric flow meters are used.

(c) Importers or exporters of \( CO_2 \) must retain annual records of the mass flow, volumetric flow, and mass of \( CO_2 \) imported or exported.

§ 98.428 Definitions.

All terms used in this subpart have the same meaning given in the Clean Air Act and subpart A of this part.

Subpart QQ—Importers and Exporters of Fluorinated Greenhouse Gases Contained in Pre-Charged Equipment or Closed-Cell Foams

SOURCE: 75 FR 74856, Dec. 1, 2010, unless otherwise noted.

§ 98.430 Definition of the source category.

(a) The source category, importers and exporters of fluorinated GHGs contained in pre-charged equipment or closed-cell foams, consists of any entity that imports or exports pre-charged equipment that contains a fluorinated GHG, and any entity that imports or exports closed-cell foams that contain a fluorinated GHG.

§ 98.431 Reporting threshold.

Any importer or exporter of fluorinated GHGs contained in pre-charged equipment or closed-cell foams who meets the requirements of §98.2(a)(4) must report each fluorinated GHG contained in the imported or exported pre-charged equipment or closed-cell foams.

§ 98.432 GHGs to report.

You must report the mass of each fluorinated GHG contained in pre-charged equipment or closed-cell foams that you import or export during the calendar year. For imports and exports of closed-cell foams where you do not know the identity and mass of the fluorinated GHG, you must report the mass of fluorinated GHG in \( CO_2 \)e.

§ 98.433 Calculating GHG contained in pre-charged equipment or closed-cell foams.

(a) The total mass of each fluorinated GHG imported and exported inside equipment or foams must be estimated using Equation QQ–1 of this section:

\[
I = \sum_t S_t \cdot N_t \cdot 0.001 \quad (\text{Eq. QQ–1})
\]

where:
- \( I \) = Total mass of the fluorinated GHG imported or exported annually (metric tons).
- \( t \) = Equipment/foam type containing the fluorinated GHG.
- \( S_t \) = Mass of fluorinated GHG per unit of equipment type \( t \) or foam type \( t \) (charge per piece of equipment or cubic foot of foam, kg).
- \( N_t \) = Number of units of equipment type \( t \) or foam type \( t \) imported or exported annually (pieces of equipment or cubic feet of foam).
- 0.001 = Factor converting kg to metric tons.

(b) When the identity and mass of fluorinated GHGs in a closed-cell foam is unknown to the importer or exporter, the total mass in \( CO_2 \)e for the fluorinated GHGs imported and exported inside closed-cell foams must be estimated using Equation QQ–2 of this section:

\[
I = \sum_t S_t \cdot N_t \cdot 0.001 \quad (\text{Eq. QQ–2})
\]
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Data reporting requirements.

(a) Each importer of fluorinated GHGs contained in pre-charged equipment or closed-cell foams must submit an annual report that summarizes its imports at the corporate level, except for transshipments, as specified:

(1) Total mass in metric tons of each fluorinated GHG imported in pre-charged equipment or closed-cell foams.

(2) For each type of pre-charged equipment with a unique combination of charge size and charge type, the identity of the fluorinated GHG used as a refrigerant or electrical insulator, charge size (holding charge, if applicable), and number imported.

(3) For closed-cell foams that are imported inside of appliances, the identity of the fluorinated GHG contained in the foam in each appliance, the mass of the fluorinated GHG contained in the foam in each appliance, and the number of appliances imported with each unique combination of mass and identity of fluorinated GHG within the closed-cell foams.

(4) For closed cell-foams that are not imported inside of appliances, the identity of the fluorinated GHG in the foam, the density of the fluorinated GHG in the foam (kg fluorinated GHG/cubic foot), and the volume of foam imported (cubic feet) for each type of closed-cell foam with a unique combination of fluorinated GHG density and identity.

(5) Dates on which the pre-charged equipment or closed-cell foams were imported.

(b) If the importer does not know the identity and mass of the fluorinated GHGs within the closed-cell foam, the importer must report the following:

(i) Total mass in metric tons of CO$_2$e of the fluorinated GHGs imported in closed-cell foams.

(ii) For closed-cell foams that are imported inside of appliances, the mass of the fluorinated GHGs in CO$_2$e contained in the foam in each appliance and the number of appliances imported for each type of appliance.

(iii) For closed-cell foams that are not imported inside of appliances, the mass in CO$_2$e of the fluorinated GHGs in the foam (kg CO$_2$e/cubic foot) and the volume of foam imported (cubic feet) for each type of closed-cell foam.

(iv) Dates on which the closed-cell foams were imported.

(v) Name of the foam manufacturer for each type of closed-cell foam where
the identity and mass of the fluorinated GHGs is unknown.

(vi) Certification that the importer was unable to obtain information on the identity and mass of the fluorinated GHGs within the closed-cell foam from the closed-cell foam manufacturer or manufacturers.

(b) Each exporter of fluorinated GHGs contained in pre-charged equipment or closed-cell foams must submit an annual report that summarizes its exports at the corporate level, except for transshipments, as specified:

(1) Total mass in metric tons of each fluorinated GHG exported in pre-charged equipment or closed-cell foams.

(2) For each type of pre-charged equipment with a unique combination of charge size and charge type, the identity of the fluorinated GHG used as a refrigerant or electrical insulator, charge size (including holding charge, if applicable), and number exported.

(3) For closed-cell foams that are exported inside of appliances, the identity of the fluorinated GHG contained in the foam in each appliance, the mass of the fluorinated GHG contained in the foam in each appliance, and the number of appliances exported with each unique combination of mass and identity of fluorinated GHG within the closed-cell foams.

(4) For closed-cell foams that are not exported inside of appliances, the identity of the fluorinated GHG in the foam, the density of the fluorinated GHG in the foam (kg fluorinated GHG/cubic foot), and the volume of foam exported (cubic feet) for each type of closed-cell foam with a unique combination of fluorinated GHG density and identity.

(5) Dates on which the pre-charged equipment or closed-cell foams were exported.

(6) If the exporter does not know the identity and mass of the fluorinated GHG within the closed-cell foam, the exporter must report the following:

(i) Total mass in metric tons of CO$_2$e of the fluorinated GHGs exported in closed-cell foams.

(ii) For closed-cell foams that are exported inside of appliances, the mass of the fluorinated GHGs in CO$_2$e contained in the foam in each appliance and the number of appliances imported for each type of appliance.

(iii) For closed-cell foams that are not exported inside of appliances, the mass in CO$_2$e of the fluorinated GHGs in the foam (kg CO$_2$e/cubic foot) and the volume of foam imported (cubic feet) for each type of closed-cell foam.

(iv) Dates on which the closed-cell foams were exported.

(v) Name of the foam manufacturer for each type of closed-cell foam where the identity and mass of the fluorinated GHG is unknown.

(vi) Certification that the exporter was unable to obtain information on the identity and mass of the fluorinated GHGs within the closed-cell foam from the closed-cell foam manufacturer or manufacturers.

§ 98.437 Records that must be retained.

(a) In addition to the data required by §98.3(g), importers of fluorinated GHGs in pre-charged equipment and closed-cell foams must retain the following records substantiating each of the imports that they report:

(1) A copy of the bill of lading for the import.

(2) The invoice for the import.

(3) The U.S. Customs entry form.

(4) Ports of entry through which the pre-charged equipment or closed-cell foams passed.

(5) Countries from which the pre-charged equipment or closed-cell foams were imported.

(6) For importers that report the mass of fluorinated GHGs within closed-cell foams on a CO$_2$e basis, correspondence or other documents that show the importer was unable to obtain information on the identity and mass of fluorinated GHG within closed-cell foams from the foam manufacturer.

(b) In addition to the data required by §98.3(g), exporters of fluorinated GHGs in pre-charged equipment and closed-cell foams must retain the following records substantiating each of the exports that they report:

(1) A copy of the bill of lading for the export and

(2) The invoice for the export.
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§ 98.438 Definitions.

Except as provided in this section, all of the terms used in this subpart have the same meaning given in the Clean Air Act and subpart A of this part. If a conflict exists between a definition provided in this subpart and a definition provided in subpart A, the definition in this subpart must take precedence for the reporting requirements in this subpart.

Appliance means any device which contains and uses a fluorinated greenhouse gas refrigerant and which is used for household or commercial purposes, including any air conditioner, refrigerator, chiller, or freezer.

Closed-cell foam means any foam product, excluding packaging foam, that is constructed with a closed-cell structure and a blowing agent containing a fluorinated GHG. Closed-cell foams include but are not limited to polyurethane (PU) appliance foam, PU continuous and discontinuous panel foam, PU one component foam, PU spray foam, extruded polystyrene (XPS) boardstock foam, and XPS sheet foam. Packaging foam means foam used exclusively during shipment or storage to temporarily enclose items.

Electrical equipment means gas-insulated substations, circuit breakers, other switchgear, gas-insulated lines, or power transformers.

Fluorinated GHG refrigerant means, for purposes of this subpart, any substance consisting in part or whole of a fluorinated greenhouse gas and that is used for heat transfer purposes and provides a cooling effect.

Pre-charged appliance means any appliance charged with fluorinated greenhouse gas refrigerant prior to sale or distribution or offer for sale or distribution in interstate commerce. This includes both appliances that contain the full charge necessary for operation and appliances that contain a partial "holding" charge of the fluorinated greenhouse gas refrigerant (e.g., for shipment purposes).

Pre-charged appliance component means any portion of an appliance, including but not limited to condensers, compressors, line sets, and coils, that is charged with fluorinated greenhouse gas refrigerant prior to sale or distribution or offer for sale or distribution in interstate commerce.

Pre-charged equipment means any pre-charged appliance, pre-charged appliance component, pre-charged electrical equipment, or pre-charged electrical equipment component.

Pre-charged electrical equipment means any electrical equipment, including but not limited to gas-insulated substations, circuit breakers, other switchgear, gas-insulated lines, or power transformers containing a fluorinated GHG prior to sale or distribution, or offer for sale or distribution in interstate commerce. This includes both equipment that contain the full charge necessary for operation and equipment that contain a partial "holding" charge of the fluorinated GHG (e.g., for shipment purposes).

Pre-charged electrical equipment component means any portion of electrical equipment that is charged with SF₆ or PFCs prior to sale or distribution or offer for sale or distribution in interstate commerce.
Subpart RR—Geologic Sequestration of Carbon Dioxide

SOURCE: 75 FR 75078, Dec. 1, 2010, unless otherwise noted.

§ 98.440 Definition of the source category.
(a) The geologic sequestration of carbon dioxide (CO\textsubscript{2}) source category comprises any well or group of wells that inject a CO\textsubscript{2} stream for long-term containment in subsurface geologic formations.
(b) This source category includes all wells permitted as Class VI under the Underground Injection Control program.
(c) This source category does not include a well or group of wells where a CO\textsubscript{2} stream is being injected in subsurface geologic formations to enhance the recovery of oil or natural gas unless one of the following applies:
   (1) The owner or operator injects the CO\textsubscript{2} stream for long-term containment in subsurface geologic formations and has chosen to submit a proposed monitoring, reporting, and verification (MRV) plan to EPA and received an approved plan from EPA.
   (2) The well is permitted as Class VI under the Underground Injection Control program.
(d) Exemption for research and development projects. Research and development projects shall receive an exemption from reporting under this subpart for the duration of the research and development activity.
   (1) Process for obtaining an exemption. If you are a research and development project, you must submit the information in paragraph (d)(2) of this section to EPA by the time you would otherwise required to submit an MRV plan under §98.448. EPA will use this information to verify that the project is a research and development project.
   (2) Content of submission. A submission in support of an exemption as a research and development project must contain the following information:
      (i) The planned duration of CO\textsubscript{2} injection for the project.
      (ii) The planned annual CO\textsubscript{2} injection volumes during this time period.
      (iii) The research purposes of the project.
      (iv) The source and type of funding for the project.
   (v) The class and duration of Underground Injection Control permit or, for an offshore facility not subject to the Safe Drinking Water Act, a description of the legal instrument authorizing geologic sequestration.
   (3) Determination by the Administrator.
      (i) The Administrator shall determine if a project meets the definition of research and development project within 60 days of receipt of the submission of a request for exemption. In making this determination, the Administrator shall take into account any information you submit demonstrating that the planned duration of CO\textsubscript{2} injection for the project and the planned annual CO\textsubscript{2} injection volumes during the duration of the project are consistent with the purpose of the research and development project.
      (ii) Any appeal of the Administrator’s determination is subject to the provisions of part 78 of this chapter.
      (iii) A project that the Administrator determines is not eligible for an exemption as a research and development project must submit a proposed MRV plan to EPA within 180 days of the Administrator’s determination. You may request one extension of up to an additional 180 days in which to submit the proposed MRV plan.

§ 98.441 Reporting threshold.
(a) You must report under this subpart if any well or group of wells within your facility injects any amount of CO\textsubscript{2} for long-term containment in subsurface geologic formations. There is no threshold.
(b) Request for discontinuation of reporting. The requirements of §98.2(i) do not apply to this subpart. Once a well or group of wells is subject to the requirements of this subpart, the owner or operator must continue for each year thereafter to comply with all requirements of this subpart, including the requirement to submit annual reports, until the Administrator has issued a final decision on an owner or operator’s request to discontinue reporting.
   (1) Timing of request. The owner or operator of a facility may submit a request to discontinue reporting any
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§ 98.443 Calculating CO₂ geologic sequestration.

You must calculate the mass of CO₂ sequestered using injection equations (Equations RR–4 to RR–6 of this section), production/recycling equations (Equations RR–7 to RR–9 of this section), surface leakage equations (Equation RR–10 of this section), and sequestration equations (Equations RR–11 and RR–12 of this section). For your first year of reporting, you must calculate CO₂ sequestered starting from the date set forth in your approved MRV plan.

(a) You must calculate and report the annual mass of CO₂ received by pipeline using the procedures in paragraphs (a)(1) or (a)(2) of this section and the procedures in paragraph (a)(3) of this section, if applicable.

(1) For a mass flow meter, you must calculate the total annual mass of CO₂ in a CO₂ stream received in metric tons by multiplying the mass flow by the CO₂ concentration in the flow, according to Equation RR–1 of this section. You must collect these data quarterly. Mass flow and concentration data measurements must be made in accordance with §98.444.

\[
CO_{2T,r} = \sum_{p=1}^{4} (Q_{r,p} - S_{r,p}) \times C_{CO_2,r} \quad (\text{Eq. RR-1})
\]

where:

- \(CO_{2T,r}\) = Net annual mass of CO₂ received through flow meter \(r\) (metric tons).
- \(Q_{r,p}\) = Quarterly mass flow through a receiving flow meter \(r\) in quarter \(p\) (metric tons).
- \(S_{r,p}\) = Quarterly mass flow through a sending flow meter \(r\) in quarter \(p\) (metric tons).
- \(C_{CO_2,r}\) = CO₂ concentration in the flow.
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$S_{r,p}$ = Quarterly mass flow through a receiving flow meter $r$ that is redelivered to another facility without being injected into your well in quarter $p$ (metric tons).

$C_{CO_2,p,r}$ = Quarterly $CO_2$ concentration measurement in flow for flow meter $r$ in quarter $p$ (wt. percent $CO_2$, expressed as a decimal fraction).

$p$ = Quarter of the year.

$r$ = Receiving flow meter.

(2) For a volumetric flow meter, you must calculate the total annual mass of $CO_2$ in a $CO_2$ stream received in metric tons by multiplying the volumetric flow at standard conditions by the $CO_2$ concentration in the flow and the density of $CO_2$ at standard conditions, according to Equation RR–2 of this section. You must collect these data quarterly. Volumetric flow and concentration data measurements must be made in accordance with §98.444.

$$CO_{2T,r} = \sum_{p=1}^{4} \left( Q_{r,p} - S_{r,p} \right) \times D \times C_{CO_2,p,r} \quad (Eq. \ RR-2)$$

where:

$CO_{2T,r}$ = Net annual mass of $CO_2$ received through flow meter $r$ (metric tons).

$Q_{r,p}$ = Quarterly volumetric flow through a receiving flow meter $r$ in quarter $p$ at standard conditions (standard cubic meters).

$S_{r,p}$ = Quarterly volumetric flow through a receiving flow meter $r$ that is redelivered to another facility without being injected into your well in quarter $p$ (standard cubic meters).

$D$ = Density of $CO_2$ at standard conditions (metric tons per standard cubic meter): 0.0018682.

$C_{CO_2,p,r}$ = Quarterly $CO_2$ concentration measurement in flow for flow meter $r$ in quarter $p$ (wt. percent $CO_2$, expressed as a decimal fraction).

$p$ = Quarter of the year.

$r$ = Receiving flow meter.

(3) If you receive $CO_2$ through more than one flow meter, you must sum the mass of all $CO_2$ received in accordance with the procedure specified in Equation RR-3 of this section.

$$CO_2 = \sum_{r=1}^{g} CO_{2T,r} \quad (Eq. \ RR-3)$$

where:

$CO_2$ = Total net annual mass of $CO_2$ received (metric tons).

$CO_{2T,r}$ = Net annual mass of $CO_2$ received (metric tons) as calculated in Equation RR-1 or RR-2 for flow meter $r$.

$r$ = Receiving flow meter.

(b) You must calculate and report the annual mass of $CO_2$ received in containers using the procedures in paragraphs (b)(1) or (b)(2) of this section.

(1) If you are measuring the mass of contents in a container under the provisions of §98.444(a)(2)(i), you must calculate the $CO_2$ received for injection in containers using Equation RR-1 of this section.

where:

$CO_{2r}$ = Net annual mass of $CO_2$ received in containers $r$ (metric tons).

$C_{CO_2,p,r}$ = Quarterly $CO_2$ concentration measurement of contents in containers $r$ in quarter $p$ (wt. percent $CO_2$, expressed as a decimal fraction).

$Q_{r,p}$ = Quarterly mass of contents in containers $r$ in quarter $p$ (metric tons).

$S_{r,p}$ = Quarterly mass of contents in containers $r$ redelivered to another facility without being injected into your well in quarter $p$ (metric tons).

$p$ = Quarter of the year.

$r$ = Containers.

(2) If you are measuring the volume of contents in a container under the provisions of §98.444(a)(2)(ii), you must calculate the $CO_2$ received for injection in containers using Equation RR-2 of this section.
where:

\( \text{CO}_2 \text{T}_r \) = Net annual mass of CO\(_2\) received in containers \( r \) (metric tons).

\( \text{C}_{\text{CO}_2,p,r} \) = Quarterly CO\(_2\) concentration measurement of contents in containers \( r \) in quarter \( p \) (vol. percent CO\(_2\), expressed as a decimal fraction).

\( Q_r,p \) = Quarterly volume of contents in containers \( r \) in quarter \( p \) (standard cubic meters).

\( S_{r,p} \) = Quarterly mass of contents in containers \( r \) redelivered to another facility without being injected into your well in quarter \( p \) (metric tons).

\( D \) = Density of the CO\(_2\) received in containers at standard conditions (metric tons per standard cubic meter): 0.0018682.

\( p \) = Quarter of the year.

(1) You must report the annual mass of CO\(_2\) injected in accordance with the procedures specified in paragraphs (c)(1) through (c)(3) of this section.

(1) If you use a mass flow meter to measure the flow of an injected CO\(_2\) stream, you must calculate annually the total mass of CO\(_2\) (in metric tons) in the CO\(_2\) stream injected each year in metric tons by multiplying the mass flow by the CO\(_2\) concentration in the flow, according to Equation RR–4 of this section. Mass flow and concentration data measurements must be made in accordance with §98.444.

\[ \text{CO}_2,u = \sum_{p=1}^{4} Q_{p,u} \times C_{\text{CO}_2,p,u} \quad \text{(Eq. RR–4)} \]

where:

\( \text{CO}_2,u \) = Annual CO\(_2\) mass injected (metric tons) as measured by flow meter \( u \).

\( Q_{p,u} \) = Quarterly mass flow rate measurement for flow meter \( u \) in quarter \( p \) (metric tons per quarter).

\( C_{\text{CO}_2,p,u} \) = Quarterly CO\(_2\) concentration measurement in flow for flow meter \( u \) in quarter \( p \) (wt. percent CO\(_2\), expressed as a decimal fraction).

\( p \) = Quarter of the year.

\( u \) = Flow meter.

(2) If you use a volumetric flow meter to measure the flow of an injected CO\(_2\) stream, you must calculate annually the total mass of CO\(_2\) (in metric tons) in the CO\(_2\) stream injected each year in metric tons by multiplying the volumetric flow at standard conditions by the CO\(_2\) concentration in the flow and the density of CO\(_2\) at standard conditions, according to Equation RR–5 of this section. Volumetric flow and concentration data measurements must be made in accordance with §98.444.

\[ \text{CO}_2,u = \sum_{p=1}^{4} Q_{p,u} \times D \times C_{\text{CO}_2,p,u} \quad \text{(Eq. RR–5)} \]

where:

\( \text{CO}_2,u \) = Annual CO\(_2\) mass injected (metric tons) as measured by flow meter \( u \).

\( Q_{p,u} \) = Quarterly volumetric flow rate measurement for flow meter \( u \) in quarter \( p \) at standard conditions (standard cubic meters per quarter).

\( D \) = Density of CO\(_2\) at standard conditions (metric tons per standard cubic meter): 0.0018682.

\( C_{\text{CO}_2,p,u} \) = CO\(_2\) concentration measurement in flow for flow meter \( u \) in quarter \( p \) (vol. percent CO\(_2\), expressed as a decimal fraction).

\( p \) = Quarter of the year.

\( u \) = Flow meter.

(3) To aggregate injection data for all wells covered under this subpart, you must sum the mass of all CO\(_2\) injected through all injection wells in accordance with the procedure specified in Equation RR–6 of this section.
where:

\( CO_{21} \) = Total annual CO\(_2\) mass injected (metric tons) through all injection wells.

\( CO_{2,u} \) = Annual CO\(_2\) mass injected (metric tons) as measured by flow meter \( u \).

\( u \) = Flow meter.

(d) You must calculate the annual mass of CO\(_2\) produced from oil or gas production wells or from other fluid wells for each separator that sends a stream of gas into a recycle or end use system in accordance with the procedures specified in paragraphs (d)(1) through (d)(3) of this section. You must account for any CO\(_2\) that is produced and not processed through a separator. You must account only for wells that produce the CO\(_2\) that was injected into the well or wells covered by this source category.

(1) For each gas-liquid separator for which flow is measured using a mass flow meter, you must calculate annually the total mass of CO\(_2\) produced from an oil or other fluid stream in metric tons that is separated from the fluid by multiplying the mass flow rate by the CO\(_2\) concentration in the gas flow, according to Equation RR–7 of this section. You must collect these data quarterly. Volumetric flow and concentration data measurements must be made in accordance with §98.444.

\[
CO_{2,w} = \sum_{p=1}^{4} Q_{p,w} \times C_{CO_{2,p,w}} \quad \text{(Eq. RR–7)}
\]

Where:

\( CO_{2,w} \) = Annual CO\(_2\) mass produced (metric tons) through separator \( w \).

\( Q_{p,w} \) = Quarterly gas flow rate measurement for separator \( w \) in quarter \( p \) (metric tons).

\( C_{CO_{2,p,w}} \) = Quarterly CO\(_2\) concentration measurement in flow for separator \( w \) in quarter \( p \) (wt. percent CO\(_2\), expressed as a decimal fraction).

\( p \) = Quarter of the year.

\( w \) = Separator.

(2) For each gas-liquid separator for which flow is measured using a volumetric flow meter, you must calculate annually the total mass of CO\(_2\) produced from an oil or other fluid stream in metric tons that is separated from the fluid by multiplying the volumetric gas flow at standard conditions by the CO\(_2\) concentration in the gas flow and the density of CO\(_2\) at standard conditions, according to Equation RR–8 of this section. You must collect these data quarterly. Volumetric flow and concentration data measurements must be made in accordance with §98.444.

\[
CO_{2,w} = \sum_{p=1}^{4} Q_{p,w} \times D \times C_{CO_{2,p,w}} \quad \text{(Eq. RR–8)}
\]

Where:

\( CO_{2,w} \) = Annual CO\(_2\) mass produced (metric tons) through separator \( w \).

\( Q_{p,w} \) = Volumetric gas flow rate measurement for separator \( w \) in quarter \( p \) at standard conditions (standard cubic meters).

\( D \) = Density of CO\(_2\) at standard conditions (metric tons per standard cubic meter): 0.0018682.

\( C_{CO_{2,p,w}} \) = CO\(_2\) concentration measurement in flow for separator \( w \) in quarter \( p \) (vol. percent CO\(_2\), expressed as a decimal fraction).
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p = Quarter of the year.
w = Separator.

(3) To aggregate production data, you must sum the mass of all of the CO₂ separated at each gas-liquid separator in accordance with the procedure specified in Equation RR-9 of this section. You must assume that the total CO₂ measured at the separator(s) represents a percentage of the total CO₂ produced. In order to account for the percentage of CO₂ produced that is estimated to remain with the produced oil or other fluid, you must multiply the quarterly mass of CO₂ measured at the separator(s) by a percentage estimated using a methodology in your approved MRV plan. If fluids containing CO₂ from injection wells covered under this source category are produced and not processed through a gas-liquid separator, the concentration of CO₂ in the produced fluids must be measured at a flow meter located prior to reinjection or reuse using methods in §98.444(f)(1). The considerations you intend to use to calculate CO₂ from produced fluids for the mass balance equation must be described in your approved MRV plan in accordance with §98.448(d)(5).

\[
CO_{2P} = (1+X) \times \sum_{w=1}^{w} CO_{2,w} \quad \text{(Eq. RR-9)}
\]

Where:
- \( CO_{2P} \) = Total annual CO₂ mass produced (metric tons) through all separators in the reporting year.
- \( CO_{2,w} \) = Annual CO₂ mass produced (metric tons) through separator w in the reporting year.
- \( X \) = Entrained CO₂ in produced oil or other fluid divided by the CO₂ separated through all separators in the reporting year (weight percent CO₂, expressed as a decimal fraction).
- w = Separator.

(e) You must report the annual mass of CO₂ that is emitted by surface leakage in accordance with your approved MRV plan. You must calculate the total annual mass of CO₂ emitted from all leakage pathways in accordance with the procedure specified in Equation RR-10 of this section.

\[
CO_{2E} = \sum_{x=1}^{x} CO_{2,x} \quad \text{(Eq. RR-10)}
\]

where:
- \( CO_{2E} \) = Total annual CO₂ mass emitted by surface leakage (metric tons) in the reporting year.
- \( CO_{2,x} \) = Annual CO₂ mass emitted (metric tons) at leakage pathway x in the reporting year.
- x = Leakage pathway.

(f) You must report the annual mass of CO₂ that is sequestered in subsurface geologic formations in the reporting year in accordance with the procedures specified in paragraphs (f)(1) and (f)(2) of this section.

(1) If you are actively producing oil or natural gas or if you are producing any other fluids, you must calculate the annual mass of CO₂ that is sequestered in the underground subsurface formation in the reporting year in accordance with the procedure specified in Equation RR-11 of this section.

\[
CO_{2} = CO_{2I} - CO_{2P} - CO_{2E} - CO_{2FI} - CO_{2FP} \quad \text{(Eq. RR-11)}
\]
§ 98.444 Monitoring and QA/QC requirements.

(a) CO\textsubscript{2} received.

(1) Except as provided in paragraph (a)(4) of this section, you must determine the quarterly flow rate of CO\textsubscript{2} received by pipeline by following the most appropriate of the following procedures:

(i) You may measure flow rate at the receiving custody transfer meter prior to any subsequent processing operations at the facility and collect the flow rate quarterly.

(ii) If you took ownership of the CO\textsubscript{2} in a commercial transaction, you may use the quarterly flow rate data from the sales contract if it is a one-time transaction or from invoices or manifests if it is an ongoing commercial transaction with discrete shipments.

(iii) If you inject CO\textsubscript{2} received from a production process unit that is part of your facility, you may use the quarterly CO\textsubscript{2} flow rate that was measured at the equivalent of a custody transfer meter following procedures provided in subpart PP of this part. To be the equivalent of a custody transfer meter, a meter must measure the flow of CO\textsubscript{2} being transported to an injection well to the same degree of accuracy as a meter used for commercial transactions.

(2) Except as provided in paragraph (a)(4) of this section, you must determine the quarterly mass or volume of contents in all containers if you receive CO\textsubscript{2} in containers by following the most appropriate of the following procedures:

(i) You may measure the mass of contents of containers summed quarterly using weigh bills, scales, or load cells.

(ii) You may determine the volume of the contents of containers summed quarterly.

(iii) If you took ownership of the CO\textsubscript{2} in a commercial transaction, you may use the quarterly mass or volume of contents from the sales contract if it is

\[ \text{CO}_2 = \text{CO}_2\text{I} - \text{CO}_2\text{E} - \text{CO}_2\text{FI} \]  

(Eq. RR-12)
a one-time transaction or from invoices or manifests if it is an ongoing commercial transaction with discrete shipments.

(3) Except as provided in paragraph (a)(4) of this section, you must determine a quarterly concentration of the CO$_2$ received that is representative of all CO$_2$ received in that quarter by following the most appropriate of the following procedures:

(i) You may sample the CO$_2$ stream at least once per quarter at the point of receipt and measure its CO$_2$ concentration.

(ii) If you took ownership of the CO$_2$ in a commercial transaction for which the sales contract was contingent on CO$_2$ concentration, and if the supplier of the CO$_2$ sampled the CO$_2$ stream in a quarter and measured its concentration per the sales contract terms, you may use the CO$_2$ concentration data from the sales contract for that quarter.

(iii) If you inject CO$_2$ from a production process unit that is part of your facility, you may report the quarterly CO$_2$ concentration of the CO$_2$ stream supplied that was measured following the procedures provided in subpart PP of this part.

(4) If the CO$_2$ you receive is wholly injected and is not mixed with any other supply of CO$_2$, you may report the annual mass of CO$_2$ injected that you determined following the requirements under paragraph (b) of this section as the total annual mass of CO$_2$ received instead of using Equation RR–1 or RR–2 of this subpart to calculate CO$_2$ received.

(5) You must assume that the CO$_2$ you receive meets the definition of a CO$_2$ stream unless you can trace it through written records to a source other than a CO$_2$ stream.

(b) CO$_2$ injected.

(1) You must select a point or points of measurement at which the CO$_2$ stream(s) is representative of the CO$_2$ stream(s) being injected. You may use as the point or points of measurement the location(s) of the flow meter(s) used to comply with the flow monitoring and reporting provisions in your Underground Injection Control permit.

(2) You must measure flow rate of CO$_2$ injected with a flow meter and collect the flow rate quarterly.

(3) You must sample the injected CO$_2$ stream at least once per quarter immediately upstream or downstream of the flow meter used to measure flow rate of that CO$_2$ stream and measure the CO$_2$ concentration of the sample.

(c) CO$_2$ produced.

(1) The point of measurement for the quantity of CO$_2$ produced from oil or other fluid production wells is a flow meter directly downstream of each separator that sends a stream of gas into a recycle or end use system.

(2) You must sample the produced gas stream at least once per quarter immediately upstream or downstream of the flow meter used to measure flow rate of that gas stream and measure the CO$_2$ concentration of the sample.

(3) You must measure flow rate of gas produced with a flow meter and collect the flow rate quarterly.

(d) CO$_2$ emissions from equipment leaks and vented emissions of CO$_2$. If you have equipment located on the surface between the flow meter used to measure injection quantity and the injection wellhead or between the flow meter used to measure production quantity and the production wellhead, you must follow the monitoring and QA/QC requirements specified in subpart W of this part for the equipment.

(e) Measurement devices.

(1) All flow meters must be operated continuously except as necessary for maintenance and calibration.

(2) You must calibrate all flow meters used to measure quantities reported in §98.446 according to the calibration and accuracy requirements in §98.3(1).

(3) You must operate all measurement devices according to one of the following. You may use an appropriate standard method published by a consensus-based standards organization if such a method exists or an industry standard practice. Consensus-based standards organizations include, but are not limited to, the following: ASTM International, the American National Standards Institute (ANSI), the American Gas Association (AGA), the
American Society of Mechanical Engineers (ASME), the American Petroleum Institute (API), and the North American Energy Standards Board (NAESB).

(4) You must ensure that any flow meter calibrations performed are National Institute of Standards and Technology (NIST) traceable.

(f) General.

(1) If you measure the concentration of any CO\textsubscript{2} quantity for reporting, you must measure according to one of the following. You may use an appropriate standard method published by a consensus-based standards organization if such a method exists or an industry standard practice.

(2) You must convert all measured volumes of CO\textsubscript{2} to the following standard industry temperature and pressure conditions for use in Equations RR–2, RR–5 and RR–8 of this subpart: Standard cubic meters at a temperature of 60 degrees Fahrenheit and at an absolute pressure of 1 atmosphere.

(3) For 2011, you may follow the provisions of §98.3(d)(1) through (2) for best available monitoring methods only for parameters required by paragraphs (a) and (b) of §98.443 rather than follow the monitoring requirements of paragraph (a) of this section. For purposes of this subpart, any reference to the year 2010 in §98.3(d)(1) through (2) shall mean 2011.

§98.445 Procedures for estimating missing data.

A complete record of all measured parameters used in the GHG quantities calculations is required. Whenever the monitoring procedures cannot be followed, you must use the following missing data procedures:

(a) A quarterly flow rate of CO\textsubscript{2} received that is missing must be estimated as follows:

(1) Another calculation methodology listed in §98.444(a)(1) must be used if possible.

(2) If another method listed in §98.444(a)(1) cannot be used, a quarterly flow rate value that is missing must be estimated using a representative flow rate value from the nearest previous time period.

(b) A quarterly mass or volume of contents in containers received that is missing must be estimated as follows:

(1) Another calculation methodology listed in §98.444(a)(2) must be used if possible.

(2) If another method listed in §98.444(a)(2) cannot be used, a quarterly mass or volume value that is missing must be estimated using a representative mass or volume value from the nearest previous time period.

(c) A quarterly CO\textsubscript{2} concentration of a CO\textsubscript{2} stream received that is missing must be estimated as follows:

(1) Another calculation methodology listed in §98.444(a)(3) must be used if possible.

(2) If another method listed in §98.444(a)(3) cannot be used, a quarterly concentration value that is missing must be estimated using a representative concentration value from the nearest previous time period.

(d) A quarterly quantity of CO\textsubscript{2} injected that is missing must be estimated using a representative quantity of CO\textsubscript{2} injected from the nearest previous period of time at a similar injection pressure.

(e) For any values associated with CO\textsubscript{2} emissions from equipment leaks and vented emissions of CO\textsubscript{2} from surface equipment at the facility that are reported in this subpart, missing data estimation procedures should be followed in accordance with those specified in subpart W of this part.

(f) The quarterly quantity of CO\textsubscript{2} produced from subsurface geologic formations that is missing must be estimated using a representative quantity of CO\textsubscript{2} produced from the nearest previous period of time.

(g) You must estimate the mass of CO\textsubscript{2} emitted by surface leakage that is missing as required by your approved MRV plan.

(h) You must estimate other missing data as required by your approved MRV plan.

§98.446 Data reporting requirements.

In addition to the information required by §98.3(c), report the information listed in this section.
(a) If you receive CO₂ by pipeline, report the following for each receiving flow meter:

(1) The total net mass of CO₂ received (metric tons) annually.

(2) If a volumetric flow meter is used to receive CO₂ report the following unless you reported yes to paragraph (a)(4) of this section:
   (i) The volumetric flow through a receiving flow meter at standard conditions (in standard cubic meters) in each quarter.
   (ii) The volumetric flow through a receiving flow meter that is redelivered to another facility without being injected into your well (in standard cubic meters) in each quarter.
   (iii) The CO₂ concentration in the flow (volume percent CO₂ expressed as a decimal fraction) in each quarter.

(3) If a mass flow meter is used to receive CO₂ report the following unless you reported yes to paragraph (a)(4) of this section:
   (i) The mass flow through a receiving flow meter (in metric tons) in each quarter.
   (ii) The mass flow through a receiving flow meter that is redelivered to another facility without being injected into your well (in metric tons) in each quarter.
   (iii) The CO₂ concentration in the flow (weight percent CO₂ expressed as a decimal fraction) in each quarter.

(4) If the CO₂ received is wholly injected and not mixed with any other supply of CO₂, report whether you followed the procedures in §98.444(a)(4).

(5) The standard or method used to calculate each value in paragraphs (a)(2) through (a)(3) of this section.

(6) The number of times in the reporting year for which substitute data procedures were used to calculate values reported in paragraphs (a)(2) and (a)(3) of this section.

(b) If you receive CO₂ in containers, report:

(1) The mass (in metric tons) or volume at standard conditions (in standard cubic meters) of contents in containers received in each quarter.

(2) The concentration of CO₂ of contents in containers (volume or wt. percent CO₂ expressed as a decimal fraction) in each quarter.

(3) The mass (in metric tons) or volume (in standard cubic meters) of contents in containers that is redelivered to another facility without being injected into your well in each quarter.

(4) The net mass of CO₂ received (in metric tons) annually.

(5) The standard or method used to calculate each value in paragraphs (b)(1) and (b)(2) of this section.

(6) The number of times in the reporting year for which substitute data procedures were used to calculate values reported in paragraphs (b)(1) and (b)(2) of this section.

(c) If you use more than one receiving flow meter, report the total net mass of CO₂ received (metric tons) through all flow meters annually.

(d) The source of the CO₂ received according to the following categories:

(1) CO₂ production wells.
(2) Electric generating unit.
(3) Ethanol plant.
(4) Pulp and paper mill.
(5) Natural gas processing.
(6) Gasification operations.
(7) Other anthropogenic source.
(8) Discontinued enhanced oil and gas recovery project.
(9) Unknown.

(e) Report the date that you began collecting data for calculating total amount sequestered according to §98.448(a)(7) of this subpart.

(f) Report the following. If the date specified in paragraph (e) of this section is during the reporting year for this annual report, report the following starting on the date specified in paragraph (e) of this section.

(1) For each injection flow meter (mass or volumetric), report:
   (i) The mass of CO₂ injected (metric tons) annually.
   (ii) The CO₂ concentration in flow (volume or weight percent CO₂ expressed as a decimal fraction) in each quarter.
   (iii) If a volumetric flow meter is used, the volumetric flow rate at standard conditions (in standard cubic meters) in each quarter.
(iv) If a mass flow meter is used, the mass flow rate (in metric tons) in each quarter.

(v) A numerical identifier for the flow meter.

(vi) Whether the flow meter is mass or volumetric.

(vii) The standard used to calculate each value in paragraphs (f)(1)(ii) through (f)(1)(iv) of this section.

(viii) The number of times in the reporting year for which substitute data procedures were used to calculate values reported in paragraphs (f)(4)(ii) through (f)(4)(iv) of this section.

(ix) The location of the flow meter.

(2) The total CO$_2$ in injected (metric tons) in the reporting year as calculated in Equation RR–6 of this subpart.

(3) For CO$_2$ emissions from equipment leaks and vented emissions of CO$_2$, report the following:

(i) The mass of CO$_2$ emitted (in metric tons) annually from equipment leaks and vented emissions of CO$_2$ from equipment located on the surface between the flow meter used to measure injection quantity and the injection wellhead.

(ii) The mass of CO$_2$ emitted (in metric tons) annually from equipment leaks and vented emissions of CO$_2$ from equipment located on the surface between the production wellhead and the flow meter used to measure production quantity.

(4) For each separator flow meter (mass or volumetric), report:

(i) CO$_2$ mass produced (metric tons) annually.

(ii) CO$_2$ concentration in flow (volume or weight percent CO$_2$ expressed as a decimal fraction) in each quarter.

(iii) If a volumetric flow meter is used, volumetric flow rate at standard conditions (standard cubic meters) in each quarter.

(iv) If a mass flow meter, mass flow rate (metric tons) in each quarter.

(v) A numerical identifier for the flow meter.

(vi) Whether the flow meter is mass or volumetric.

(vii) The standard used to calculate each value in paragraphs (f)(4)(ii) through (f)(4)(iv) of this section.

(viii) The number of times in the reporting year for which substitute data procedures were used to calculate values reported in paragraphs (f)(4)(ii) through (f)(4)(iv) of this section.

(5) The entrained CO$_2$ in produced oil or other fluid divided by the CO$_2$ separated through all separators in the reporting year (weight percent CO$_2$ expressed as a decimal fraction) used as the value for X in Equation RR–9 of this subpart and as determined according to your EPA-approved MRV plan.

(6) Annual CO$_2$ produced in the reporting year as calculated in Equation RR–9 of this subpart.

(7) For each leakage pathway through which CO$_2$ emissions occurred, report:

(i) A numerical identifier for the leakage pathway.

(ii) The CO$_2$ (metric tons) emitted through that pathway in the reporting year.

(8) Annual CO$_2$ mass emitted (metric tons) by surface leakage in the reporting year as calculated by Equation RR–10 of this subpart.

(9) Annual CO$_2$ (metric tons) sequestered in subsurface geologic formations in the reporting year as calculated by Equation RR–11 or RR–12 of this subpart.

(10) Cumulative mass of CO$_2$ (metric tons) reported as sequestered in subsurface geologic formations in all years since the well or group of wells became subject to reporting requirements under this subpart.

(11) Date that the most recent MRV plan was approved by EPA and the MRV plan approval number that was issued by EPA.

(12) An annual monitoring report that contains the following components:

(i) A narrative history of the monitoring efforts conducted over the previous calendar year, including a listing of all monitoring equipment that was operated, its period of operation, and any relevant tests or surveys that were conducted.

(ii) A description of any changes to the monitoring program that you concluded were not material changes warranting submission of a revised MRV plan under §98.448(d).

(iii) A narrative history of any monitoring anomalies that were detected in
the previous calendar year and how they were investigated and resolved.

(iv) A description of any surface leakages of CO₂, including a discussion of all methodologies and technologies involved in detecting and quantifying the surface leakages and any assumptions and uncertainties involved in calculating the amount of CO₂ emitted.

(13) If a well is permitted under the Underground Injection Control program, for each injection well, report:

(i) The well identification number used for the Underground Injection Control permit.

(ii) The Underground Injection Control permit class.

(14) If an offshore well is not subject to the Safe Drinking Water Act, for each injection well, report any well identification number and any identification number used for the legal instrument authorizing geologic sequestration.


§ 98.447 Records that must be retained.

(a) You must follow the record retention requirements specified by §98.3(g). In addition to the records required by §98.3(g), you must retain the records specified in paragraphs (a)(1) through (7) of this section, as applicable. You must retain all required records for at least 3 years.

(1) Quarterly records of CO₂ received, including mass flow rate of contents of containers (mass or volumetric) at standard conditions and operating conditions, operating temperature and pressure, and concentration of these streams.

(2) Quarterly records of produced CO₂, including mass flow or volumetric flow at standard conditions and operating conditions, operating temperature and pressure, and concentration of these streams.

(3) Quarterly records of injected CO₂ including mass flow or volumetric flow at standard conditions and operating conditions, operating temperature and pressure, and concentration of these streams.

(4) Annual records of information used to calculate the CO₂ emitted by surface leakage from leakage pathways.

(5) Annual records of information used to calculate the CO₂ emitted from equipment leaks and vented emissions of CO₂ from equipment located on the surface between the flow meter used to measure injection quantity and the injection wellhead.

(6) Annual records of information used to calculate the CO₂ emitted from equipment leaks and vented emissions of CO₂ from equipment located on the surface between the production wellhead and the flow meter used to measure production quantity.

(7) Any other records as specified for retention in your EPA-approved MRV plan.

(b) You must complete your monitoring plans, as described in §98.3(g)(5), by April 1 of the year you begin collecting data.


§ 98.448 Geologic sequestration monitoring, reporting, and verification (MRV) plan.

(a) Contents of MRV plan. You must develop and submit to the Administrator a proposed MRV plan for monitoring, reporting, and verification of geologic sequestration at your facility. Your proposed MRV plan must contain the following components:

(1) Delineation of the maximum monitoring area and the active monitoring areas. The first period for your active monitoring area will begin from the date determined in your MRV plan through the date at which the plan calls for the first expansion of the monitoring area. The length of each monitoring period can be any time interval chosen by you that is greater than 1 year.

(2) Identification of potential surface leakage pathways for CO₂ in the maximum monitoring area and the likelihood, magnitude, and timing, of surface leakage of CO₂ through these pathways.

(3) A strategy for detecting and quantifying any surface leakage of CO₂.

(4) A strategy for establishing the expected baselines for monitoring CO₂ surface leakage.
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(5) A summary of the considerations you intend to use to calculate site-specific variables for the mass balance equation. This includes, but is not limited to, considerations for calculating CO₂ emissions from equipment leaks and vented emissions of CO₂ between the injection flow meter and injection well and/or the production flow meter and production well, and considerations for calculating CO₂ in produced fluids.

(6) If a well is permitted under the Underground Injection Control program, for each injection well, report the well identification number used for the Underground Injection Control permit and the Underground Injection Control permit class. If the well is not yet permitted, and you have applied for an Underground Injection Control permit, report the well identification numbers in the permit application. If an offshore well is not subject to the Safe Drinking Water Act, for each injection well, report any well identification number and any identification number used for the legal instrument authorizing geologic sequestration. If you are submitting your Underground Injection Control permit application as part of your proposed MRV plan, you must notify EPA when the permit has been approved. If you are an offshore facility not subject to the Safe Drinking Water Act, and are submitting your application for the legal instrument authorizing geologic sequestration as part of your proposed MRV plan, you must notify EPA when the legal instrument authorizing geologic sequestration has been approved.

(7) Proposed date to begin collecting data for calculating total amount sequestered according to equation RR–11 or RR–12 of this subpart. This date must be after expected baselines as required by paragraph (a)(4) of this section and the leakage detection and quantification strategy as required by paragraph (a)(3) of this section is implemented in the initial AMA.

(b) Timing. You must submit a proposed MRV plan to EPA according to the following schedule:

(1) You must submit a proposed MRV plan to EPA by June 30, 2011 if you were issued a final Underground Injection Control permit authorizing the injection of CO₂ into the subsurface on or before December 31, 2010. You will be allowed to request one extension of up to an additional 180 days in which to submit your proposed MRV plan.

(2) You must submit a proposed MRV plan to EPA within 180 days of receiving a final Underground Injection Control permit authorizing the injection of CO₂ into the subsurface. If your facility is an offshore facility not subject to the Safe Drinking Water Act, you must submit a proposed MRV plan to EPA within 180 days of receiving authorization to begin geologic sequestration of CO₂. You will be allowed to request one extension of the submittal date of up to an additional 180 days.

(3) If you are injecting a CO₂ stream in subsurface geologic formations to enhance the recovery of oil or natural gas and you are not permitted as Class VI under the Underground Injection Control program, you may opt to submit an MRV plan at any time.

(4) If EPA determines that your proposed MRV plan is incomplete, you must submit an updated MRV plan within 45 days of EPA notification, unless otherwise specified by EPA.

(c) Final MRV plan. The Administrator will issue a final MRV plan within a reasonable period of time. The Administrator’s final MRV plan is subject to the provisions of part 78 of this chapter. Once the MRV plan is final and no longer subject to administrative appeal under part 78 of this chapter, you must implement the plan starting on the day after the day on which the plan becomes final and is no longer subject to such appeal.

(d) MRV plan revisions. You must revise and submit the MRV plan within 180 days to the Administrator for approval if any of the following in paragraphs (d)(1) through (d)(4) of this section applies. You must include the reason(s) for the revisions in your submittal.

(1) A material change was made to monitoring and/or operational parameters that was not anticipated in the original MRV plan. Examples of material changes include but are not limited to: Large changes in the volume of CO₂ injected; the construction of new injection wells not identified in the
MRV plan; failures of the monitoring system including monitoring system sensitivity, performance, location, or baseline; changes to surface land use that affects baseline or operational conditions; observed plume location that differs significantly from the predicted plume area used for developing the MRV plan; a change in the maximum monitoring area or active monitoring area; or a change in monitoring technology that would result in coverage or detection capability different from the MRV plan.

(2) A change in the permit class of your Underground Injection Control permit.

(3) If you are notified by EPA of substantive errors in your MRV plan or monitoring report.

(4) You choose to revise your MRV plan for any other reason in any reporting year.

(e) Revised MRV plan. The requirements of paragraph (c) of this section apply to any submission of a revised MRV plan. You must continue reporting under your currently approved plan while awaiting approval of a revised MRV plan.

(f) Format. Each proposed MRV plan or revision and each annual report must be submitted electronically in a format specified by the Administrator.

(g) Certificate of representation. You must submit a certificate of representation according to the provisions in §98.4 at least 60 days before submission of your MRV plan, your research and development exemption request, your MRV plan submission extension request, or your initial annual report under this part, whichever is earlier.

§98.449 Definitions.

Except as provided below, all terms used in this subpart have the same meaning given in the Clean Air Act and subpart A of this part.

Active monitoring area is the area that will be monitored over a specific time interval from the first year of the period (n) to the last year in the period (t). The boundary of the active monitoring area is established by superimposing two areas:

1. The area projected to contain the free phase CO₂ plume at the end of year t, plus an all around buffer zone of one-half mile or greater if known leakage pathways extend laterally more than one-half mile.

2. The area projected to contain the free phase CO₂ plume at the end of year t+5.

CO₂ received means the CO₂ stream that you receive to be injected for the first time into a well on your facility that is covered by this subpart. CO₂ received includes, but is not limited to, a CO₂ stream from a production process unit inside your facility and a CO₂ stream that was injected into a well on another facility, removed from a discontinued enhanced oil or natural gas or other production well, and transferred to your facility.

Equipment leak means those emissions that could not reasonably pass through a stack, chimney, vent, or other functionally-equivalent opening.

Expected baseline is the anticipated value of a monitored parameter that is compared to the measured monitored parameter.

Maximum monitoring area means the area that must be monitored under this regulation and is defined as equal to or greater than the area expected to contain the free phase CO₂ plume until the CO₂ plume has stabilized plus an all-around buffer zone of at least one-half mile.

Research and development project means a project for the purpose of investigating practices, monitoring techniques, or injection verification, or engaging in other applied research, that will enable safe and effective long-term containment of a CO₂ stream in subsurface geologic formations, including research and short duration CO₂ injection tests conducted as a precursor to long-term storage.

Separator means a vessel in which streams of multiple phases are gravity separated into individual streams of single phase.

Surface leakage means the movement of the injected CO₂ stream from the injection zone to the surface, and into the atmosphere, indoor air, oceans, or surface water.
§ 98.450 Definition of the source category.

The electrical equipment manufacturing or refurbishment category consists of processes that manufacture or refurbish gas-insulated substations, circuit breakers, other switchgear, gas-insulated lines, or power transformers (including gas-containing components of such equipment) containing sulfurhexafluoride (SF₆) or perfluorocarbons (PFCs). The processes include equipment testing, installation, manufacturing, decommissioning and disposal, refurbishing, and storage in gas cylinders and other containers.

§ 98.451 Reporting threshold.

You must report GHG emissions under this subpart if your facility contains an electrical equipment manufacturing or refurbishing process and the facility meets the requirements of §98.2(a)(1). Electrical equipment manufacturing and refurbishing facilities covered by this rule are those that have total annual purchases of SF₆ and PFCs that exceed 23,000 pounds.

§ 98.452 GHGs to report.

(a) You must report SF₆ and PFC emissions at the facility level. Annual emissions from the facility must include SF₆ and PFC emissions from equipment that is installed at an off-site electric power transmission or distribution location whenever emissions from installation activities (e.g., filling) occur before the title to the equipment is transferred to the electric power transmission or distribution entity.

(b) You must report CO₂, N₂O and CH₄ emissions from each stationary combustion unit. You must calculate and report these emissions under subpart C of this part (General Stationary Fuel Combustion Sources) by following the requirements of subpart C of this part.

§ 98.453 Calculating GHG emissions.

(a) For each electrical equipment manufacturer or refurbisher, estimate the annual SF₆ and PFC emissions using the mass-balance approach in Equation SS–1 of this section:

\[
\text{User Emissions} = (\text{Decrease in SF}_6 \text{ Inventory}) + (\text{Acquisitions of SF}_6) - (\text{Disbursements of SF}_6) \\
\text{Eq. SS–1}
\]

where:

- Decrease in SF₆ Inventory = (Pounds of SF₆ stored in containers at the beginning of the year) – (Pounds of SF₆ stored in containers at the end of the year).
- Acquisitions of SF₆ = (Pounds of SF₆ purchased from chemical producers or suppliers in bulk) + (Pounds of SF₆ returned by equipment users) + (Pounds of SF₆ returned to site after off-site recycling).
- Disbursements of SF₆ = (Pounds of SF₆ contained in new equipment delivered to customers) + (Pounds of SF₆ delivered to equipment users in containers) + (Pounds of SF₆ returned to suppliers) + (Pounds of
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SF₆ sent off site for recycling) + (Pounds of SF₆ sent off site for destruction).

(b) Use the mass-balance method in paragraph (a) of this section to estimate emissions of PFCs associated with the manufacture or refurbishment of power transformers, substituting the relevant PFC(s) for SF₆ in Equation SS–1 of this section.

(c) Estimate the disbursements of SF₆ or PFCs sent to customers in new equipment or cylinders or sent off-site for other purposes including for recycling, for destruction or to be returned to suppliers using Equation SS–2 of this section:

\[ D_{GHI} = \sum_{p=1}^{n} Q_p \]  

(Eq. SS–2)

where:

- \( D_{GHI} \) = The annual disbursement of SF₆ or PFCs sent to customers in new equipment or cylinders or sent off-site for other purposes including for recycling, for destruction or to be returned to suppliers.
- \( Q_p \) = The mass of SF₆ or PFCs charged into equipment or containers over the period p sent to customers or sent off-site for other purposes including for recycling, for destruction or to be returned to suppliers.
- \( n \) = The number of periods in the year.

(d) Estimate the mass of SF₆ or PFCs disbursed to customers in new equipment or cylinders over the period p by monitoring the mass flow of the SF₆ or PFCs into the new equipment or cylinders using a flowmeter or by weighing containers before and after gas from containers is used to fill equipment or cylinders.

(e) If the mass of SF₆ or the PFC disbursed to customers in new equipment or cylinders over the period p is estimated by weighing containers before and after gas from containers is used to fill equipment or cylinders, estimate this quantity using Equation SS–3 of this section:

\[ Q_p = M_B - M_E - E_L \]  

(Eq. SS–3)

where:

- \( Q_p \) = The mass of SF₆ or the PFC charged into equipment or containers over the period p sent to customers or sent off-site for other purposes including for recycling, for destruction or to be returned to suppliers.
- \( M_B \) = The mass of the contents of the containers used to fill equipment or cylinders at the beginning of period p.
- \( M_E \) = The mass of the contents of the containers used to fill equipment or cylinders at the end of period p.
- \( E_L \) = The mass of SF₆ or the PFC emitted during the period p downstream of the containers used to fill equipment or cylinders and in cases where a flowmeter is used, downstream of the flowmeter during the period p (e.g., emissions from hoses or other flow lines that connect the container to the equipment or cylinder that is being filled).

(f) If the mass of SF₆ or the PFC disbursed to customers in new equipment or cylinders over the period p is determined using a flowmeter, estimate this quantity using Equation SS–4 of this section:

\[ Q_p = M_{mr} - E_L \]  

(Eq. SS–4)

where:

- \( Q_p \) = The mass of SF₆ or the PFC charged into equipment or containers over the period p sent to customers or sent off-site for other purposes including for recycling, for destruction or to be returned to suppliers.
- \( M_{mr} \) = The mass of the SF₆ or PFC that has flowed through the flowmeter during the period p.
- \( E_L \) = The mass of SF₆ or the PFC emitted during the period p downstream of the containers used to fill equipment or cylinders and in cases where a flowmeter is used, downstream of the flowmeter during the period p (e.g., emissions from hoses or other flow lines that connect the container to the equipment or cylinder that is being filled).
§ 98.454  Monitoring and QA/QC requirements.

(a) For calendar year 2011 monitoring, you may follow the provisions of §98.3(d)(1) through (d)(2) for best available monitoring methods rather than follow the monitoring requirements of this section. For purposes of this subpart, any reference in §98.3(d)(1) through (d)(2) to 2010 means 2011. March 31 means June 30, and April 1 means July 1. Any reference to the effective date in §98.3(d)(1) through (d)(2) means February 28, 2011.

(b) Ensure that all the quantities required by the equations of this subpart have been measured using either flowmeters with an accuracy and precision of ±1 percent of full scale or better or scales with an accuracy and precision of ±1 percent of the filled weight (gas plus tare) of the containers of SF₆ or PFCs that are typically weighed on the scale. For scales that are generally
used to weigh cylinders containing 115 pounds of gas when full, this equates to ±1 percent of the sum of 115 pounds and approximately 120 pounds tare, or slightly more than ±2 pounds. Account for the tare weights of the containers. You may accept gas masses or weights provided by the gas supplier e.g., for the contents of cylinders containing new gas or for the heels remaining in cylinders returned to the gas supplier if the supplier provides documentation verifying that accuracy standards are met; however, you remain responsible for the accuracy of these masses and weights under this subpart.

(c) All flow meters, weigh scales, and combinations of volumetric and density measures that are used to measure or calculate quantities under this subpart must be calibrated using calibration procedures specified by the flowmeter, scale, volumetric or density measure equipment manufacturer. Calibration must be performed prior to the first reporting year. After the initial calibration, recalibration must be performed at the minimum frequency specified by the manufacturer.

(d) For purposes of Equations SS–5 of this subpart, the emission factor for the valve-hose combination (EF_C) must be estimated using measurements and/or engineering assessments or calculations based on chemical engineering principles or physical or chemical laws or properties. Such assessments or calculations may be based on, as applicable, the internal volume of hose or line that is open to the atmosphere during coupling and decoupling activities, the internal pressure of the hose or line, the time the hose or line is open to the atmosphere during coupling and decoupling activities, the frequency with which the hose or line is purged and the flow rate during purges. You must develop a value for EF_C (or use an industry-developed value) for each combination of hose and valve fitting, to use in Equation SS–5 of this subpart. The value for EF_C must be determined for each combination of hose and valve fitting of a given diameter or size. The calculation must be recalculated annually to account for changes to the specifications of the valves or hoses that may occur throughout the year.

(e) Electrical equipment manufacturers and refurbishers must account for SF_6 or PFC emissions that occur as a result of unexpected events or accidental losses, such as a malfunctioning hose or leak in the flow line, during the filling of equipment or containers for disbursement by including these losses in the estimated mass of SF_6 or the PFC emitted downstream of the container or flowmeter during the period p.

(f) If the mass of SF_6 or the PFC disbursed to customers in new equipment over the period p is determined by assuming that it is equal to the equipment’s nameplate capacity or, in cases where equipment is shipped with a partial charge, equal to its partial shipping charge, equipment samples for conducting the nameplate capacity tests must be selected using the following stratified sampling strategy in this paragraph. For each make and model, group the measurement conditions to reflect predictable variability in the facility’s filling practices and conditions (e.g., temperatures at which equipment is filled). Then, independently select equipment samples at random from each make and model under each group of conditions. To account for variability, a certain number of these measurements must be performed to develop a robust and representative average nameplate capacity (or shipping charge) for each make, model, and group of conditions. A Student T distribution calculation should be conducted to determine how many samples are needed for each make, model, and group of conditions as a function of the relative standard deviation of the sample measurements. To determine a sufficiently precise estimate of the nameplate capacity, the number of measurements required must be calculated to achieve a precision of one percent of the true mean, using a 95 percent confidence interval. To estimate the nameplate capacity for a given make and model, you must use the lowest mean value among the different groups of conditions, or provide justification for the use of a different mean value for the group of conditions that represents the typical practices and conditions for that make and model. Measurements can be conducted using SF_6.
§ 98.455 Procedures for estimating missing data.

A complete record of all measured parameters used in the GHG emissions calculations is required. Replace missing data, if needed, based on data from similar manufacturing operations, and from similar equipment testing and decommissioning activities for which data are available.

§ 98.456 Data reporting requirements.

In addition to the information required by §98.3(c), each annual report must contain the following information for each chemical at the facility level:

(a) Pounds of SF₆ and PFCs stored in containers at the beginning of the year.

(b) Pounds of SF₆ and PFCs stored in containers at the end of the year.

(c) Pounds of SF₆ and PFCs purchased in bulk.

(d) Pounds of SF₆ and PFCs returned by equipment users with or inside equipment.

(e) Pounds of SF₆ and PFCs returned to site from off site after recycling.

(f) Pounds of SF₆ and PFCs inside new equipment delivered to customers.

(g) Pounds of SF₆ and PFCs delivered to equipment users in containers.

(h) Pounds of SF₆ and PFCs returned to suppliers.

(i) Pounds of SF₆ and PFCs sent off site for destruction.

(j) Pounds of SF₆ and PFCs returned to site from off site after recycling.

(k) The nameplate capacity of the equipment, in pounds, delivered to customers with SF₆ or PFCs inside, if different from the quantity in paragraph (f) of this section.

(l) A description of the engineering methods and calculations used to determine emissions from hoses or other flow lines that connect the container to the equipment that is being filled.

(m) The values for EFₖ for each hose and valve combination and the associated valve fitting sizes and hose diameters.

(n) The total number of fill operations for each hose and valve combination, or, Fᵢₖ of Equation SS–5 of this subpart.

(o) The mean value for each make, model, and group of conditions if the mass of SF₆ or the PFC disbursed to customers in new equipment over the period p is determined by assuming that it is equal to the equipment's nameplate capacity or, in cases where equipment is shipped with a partial charge, equal to its partial shipping charge.

(p) The number of samples and the upper and lower bounds on the 95 percent confidence interval for each make, model, and group of conditions if the mass of SF₆ or the PFC disbursed to customers in new equipment over the period p is determined by assuming that it is equal to the equipment's nameplate capacity or, in cases where equipment is shipped with a partial charge, equal to its partial shipping charge.

(q) Pounds of SF₆ and PFCs used to fill equipment at off-site electric power transmission or distribution locations, or Mᵢₖ of Equation SS–6 of this subpart.
(r) Pounds of SF₆ and PFCs used to charge the equipment prior to leaving the electrical equipment manufacturer or refurbishment facility, or Mₑ, of Equation SS–6 of this subpart.

(s) The nameplate capacity of the equipment, in pounds, installed at off-site electric power transmission or distribution locations used to determine emissions from installation, or Nₑ, of Equation SS–6 of this subpart.

(t) For any missing data, you must report the reason the data were missing, the parameters for which the data were missing, the substitute parameters used to estimate emissions in their absence, and the quantity of emissions thereby estimated.

§ 98.457 Records that must be retained.

In addition to the information required by §98.3(g), you must retain the following records:

(a) All information reported and listed in §98.456.

(b) Accuracy certifications and calibration records for all scales and monitoring equipment, including the method or manufacturer’s specification used for calibration.

(c) Certifications of the quantity of gas, in pounds, charged into equipment at the electrical equipment manufacturer or refurbishment facility as well as the actual quantity of gas, in pounds, charged into equipment at installation.

(d) Check-out and weigh-in sheets and procedures for cylinders.

(e) Residual gas amounts, in pounds, in cylinders sent back to suppliers.

(f) Invoices for gas purchases and sales.

(g) GHG Monitoring Plans, as described in §98.3(g)(5), must be completed by April 1, 2011.

§ 98.458 Definitions.

All terms used in this subpart have the same meaning given in the CAA and subpart A of this part.

Subpart TT—Industrial Waste Landfills

Source: 75 FR 39773, July 12, 2010, unless otherwise noted.

§ 98.460 Definition of the source category.

(a) This source category applies to industrial waste landfills that accepted waste on or after January 1, 1980, and that are located at a facility whose total landfill design capacity is greater than or equal to 300,000 metric tons.

(b) An industrial waste landfill is a landfill other than a municipal solid waste landfill, a RCRA Subtitle C hazardous waste landfill, or a TSCA hazardous waste landfill, in which industrial solid waste, such as RCRA Subtitle D wastes (non-hazardous industrial solid waste, defined in 40 CFR 257.2), commercial solid wastes, or conditionally exempt small quantity generator wastes, is placed. An industrial waste landfill includes all disposal areas at the facility.

(c) This source category does not include:

(1) Construction and demolition waste landfills.

(2) Industrial waste landfills that only receive one or more of the following inert waste materials:

(i) Coal combustion or incinerator ash (e.g., fly ash).

(ii) Cement kiln dust.

(iii) Rocks and/or soil from excavation and construction and similar activities.

(iv) Glass.

(v) Non-chemically bound sand (e.g., green foundry sand).

(vi) Clay, gypsum, or pottery cull.

(vii) Bricks, mortar, or cement.

(ix) Furnace slag.

(x) Materials used as refractory (e.g., alumina, silicon, fire clay, fire brick).

(xi) Plastics (e.g., polyethylene, polypropylene, polystyrene, polyvinyl chloride).

(xii) Other waste material that has a volatile solids concentration of 0.5 weight percent (on a dry basis) or less.

(d) This source category consists of the following sources at industrial waste landfills: Landfills, gas collection systems at landfills, and destruction devices for landfill gases (including flares).
§ 98.461 Reporting threshold.
You must report GHG emissions under this subpart if your facility contains an industrial waste landfill meeting the criteria in §98.460 and the facility meets the requirements of §98.2(a)(2). For the purposes of §98.2(a)(2), the emissions from the industrial waste landfill are to be determined using the methane generation corrected for oxidation as determined using Equation TT–6 of this subpart times the global warming potential for methane in Table A–1 of subpart A of this part.

§ 98.462 GHGs to report.
(a) You must report CH₄ generation and CH₄ emissions from industrial waste landfills.
(b) You must report CH₄ destruction resulting from landfill gas collection and destruction devices, if present.
(c) You must report under subpart C of this part (General Stationary Fuel Combustion Sources) the emissions of CO₂, CH₄, and N₂O from each stationary combustion unit associated with the landfill gas destruction device, if present, by following the requirements of subpart C of this part.

§ 98.463 Calculating GHG emissions.
(a) For each industrial waste landfill subject to the reporting requirements of this subpart, calculate annual modeled CH₄ generation according to the applicable requirements in paragraphs (a)(1) through (a)(3) of this section. Apply Equation TT–1 of this section for each waste stream disposed of in the landfill and sum the CH₄ generation rates for all waste streams disposed of in the landfill to calculate the total annual modeled CH₄ generation rate for the landfill.

1. Calculate annual modeled CH₄ generation using Equation TT–1 of this section.

\[ G_{CH_4} = \sum_{X=S}^{T} \left( W_x \times DOC_x \times MCF \times DOC_F \times F \times \frac{16}{12} \times \left( e^{-k(T-x-1)} - e^{-k(T-1)} \right) \right) \]  

(Eq. TT–1)

Where:
- \( G_{CH_4} \) = Modeled methane generation in reporting year \( T \) (metric tons CH₄).
- \( X \) = Year in which waste was disposed.
- \( S \) = Start year of calculation. Use the year 1960 or the opening year of the landfill, whichever is more recent.
- \( T \) = Reporting year for which emissions are calculated.
- \( W_x \) = Quantity of waste disposed in the industrial waste landfill in year \( X \) from measurement data and/or other company records (metric tons, as received (wet weight)).
- \( DOC_x \) = Degradable organic carbon for waste disposed in year \( X \) from Table TT–1 to this subpart or from measurement data [as specified in paragraph (a)(3) of this section], if available (fraction [metric tons C/metric ton waste]).
- \( DOC_F \) = Fraction of DOC dissimilated (fraction); use the default value of 0.5.
- \( MCF \) = Methane correction factor (fraction). Use the default value of 1 unless there is active aeration of waste within the landfill during the reporting year. If there is active aeration of waste within the landfill during the reporting year, use either the default value of 1 or select an alternative value no less than 0.5 based on site-specific aeration parameters.
- \( F_x \) = Fraction by volume of CH₄ in landfill gas (fraction, dry basis, corrected to 0% oxygen). If you have a gas collection system, use the annual average CH₄ concentration from measurement data for the current reporting year; otherwise, use the default value of 0.5.
- \( k \) = Decay rate constant from Table TT–1 to this subpart (yr⁻¹). Select the most applicable \( k \) value for the majority of the past 10 years (or operating life, whichever is shorter).

2. Waste stream quantities. Determine annual waste quantities as specified in paragraphs (a)(2)(i) through (ii) of this section for each year starting with January 1, 1960 or the year the landfills first accepted waste if after January 1, 1960, up until the most recent reporting year. The choice of method for determining waste quantities will vary according to the availability of historical data. Beginning in the first emissions reporting year (2011 or later) and for
each year thereafter, use the procedures in paragraph (a)(2)(i) of this section to determine waste stream quantities. These procedures should also be used for any year prior to the first emissions reporting year for which the data are available. For other historical years, use paragraph (a)(2)(i) of this section, where waste disposal records are available, and use the procedures outlined in paragraph (a)(2)(ii) of this section when waste disposal records are unavailable, to determine waste stream quantities. Historical disposal quantities deposited (i.e., prior to the first year in which monitoring begins) should only be determined once, as part of the first annual report, and the same values should be used for all subsequent annual reports, supplemented by the next year’s data on new waste disposal.

(i) Determine the quantity of waste in metric tons as received, i.e., wet weight) disposed of in the landfill separately for each waste stream by any one or a combination of the following methods.

(A) Direct mass measurements.

(B) Direct volume measurements multiplied by waste stream density determined from periodic density measurement data or process knowledge.

(C) Mass balance procedures, determining the mass of waste as the difference between the mass of the process inputs and the mass of the process outputs.

(D) The number of loads (e.g., trucks) multiplied by the mass of waste per load based on the working capacity of the container or vehicle.

(ii) Determine the historical disposal quantities for landfills using the Waste Disposal Factor approach in paragraphs (a)(2)(ii)(A) and (B) of this section when historical production or processing data are available. If production or processing data are available for a given year, you must use Equation TT-2 of this section for that year. Determine historical disposal quantities using the method specified in paragraph (a)(2)(ii)(C) of this section when historical production or processing data are not available, and for waste streams received from an off-site facility when historical disposal quantities cannot be determined using the methods specified in paragraph (a)(2)(i) of this section.

(A) Determining Waste Disposal Factor: For each waste stream disposed of in the landfill, calculate the average waste disposal rate per unit of production or unit throughput using all available waste quantity data and corresponding production or processing rates for the process generating that waste or, if appropriate, the facility, using Equation TT-2 of this section.

\[
WDF = \left[ \sum_{i=1}^{N} \left( \frac{W_i}{N \times P_x} \right) \right] \quad \text{(Eq. TT-2)}
\]

Where:

- \(WDF\): Average waste disposal factor as determined for the first annual report required for this industrial waste landfill (metric tons per production unit).
- \(X\): Year in which waste was disposed. Include only those years for which disposal and production data are both available; the years do not need to be sequential.
- \(Y_1\): First year in which disposal and production/throughput data are both available.
- \(Y_2\): First year for which GHG emissions from this industrial waste landfill must be reported.
- \(N\): Number of years for which disposal and production/throughput data are both available.
- \(W_x\): Quantity of waste placed in the industrial waste landfill in year \(X\) from measurement data and/or other company records (metric tons, as received (wet weight)).
- \(P_x\): Quantity of product produced or feedstock entering the process or facility in year \(X\) from measurement data and/or other company records (production units). You must use the same basis for all years in the calculation. That is, \(P_x\) must be determined based on production (quantity of product produced) for all “\(N\)” years or \(P_x\) must be determined based on throughput (quantity of feedstock) for all “\(N\)” years.

(B) Calculate waste: For each waste stream disposed of in the landfill, calculate the waste disposal quantities for historic years in which direct waste disposal measurements are not available using historical production data and Equation TT-3 of this section.

\[
W_x = WDF \times P_x \quad \text{(Eq. TT-3)}
\]

Where:

- \(X\): Historic year in which waste was disposed.
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Wx = Calculated quantity of waste placed in the landfill in year X (metric tons).
WDF = Average waste disposal factor from Equation TT-2 of this section (metric tons per production unit).
Px = Quantity of product produced or feedstock entering the process or facility in year X from measurement data and/or other company records (production units). You must use the same basis forPx(either production only or throughput only) as used to determine WDF in Equation TT-2 of this section.

\[
W_x = \frac{LFC}{(YrData - YrOpen + 1)} \quad \text{(Eq. TT-4a,)}
\]

Where:
Wx = Quantity of waste placed in the landfill in year X (metric tons, wet basis). This annual bulk waste disposal quantity applies for all years from “YrOpen” to “YrData” inclusive.
LFC = Capacity of the landfill used (or the total quantity of waste-in-place) at the end of the “YrData” from design drawings or engineering estimates (metric tons). For closed landfills for which waste quantity data are not available, use the landfill’s design capacity.
YrData = The year prior to the year when waste disposal data are first available for all subsequent years from company records or from Equation TT-3 of this section. For landfills for which waste quantity data are not available, the year in which the landfill last received waste.
YrOpen = Year 1960 or the year in which the landfill first received waste from company records, whichever is more recent. If no data are available for estimating YrOpen for a closed landfill, use 1960 as the default “YrOpen” for the landfill.

\[
W_x = \frac{WIP - \sum_{n=1}^{NYrData} W_{\text{meas},n}}{(YrLast - YrOpen + 1 - NYrData)} \quad \text{(Eq. TT-4b,)}
\]

Where:
Wx = Quantity of waste placed in the landfill in year X (metric tons, wet basis). This annual bulk waste disposal quantity applies for all years for which waste quantity data are not available from company records or from Equation TT-3 of this section.
WIP = Quantity of waste in-place at the start of the reporting year from design drawings or engineering estimates (metric tons). For closed landfills for which waste in-place quantities are not available, use the landfill’s design capacity.
W_{\text{meas},n} = Annual quantity of waste placed in the landfill for the nth measurement year from company records or from Equation TT-3 of this section.
YrLast = The last year, prior to the reporting year, that the landfill received waste.
YrOpen = Year 1960 or the year in which the landfill first received waste from company records, whichever is more recent. If no data are available for estimating YrOpen for a closed landfill, use 1960 as the default “YrOpen” for the landfill.
NYrData = The number of years for which annual waste disposal quantities are available from company records or from Equation TT-3 of this section from YrOpen to YrLast inclusive.

(3) Degradable organic content (DOC).
For any year, X, in Equation TT-1 of this section, use either the applicable default DOC values provided in Table
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TT–1 of this subpart or determine values for DOC, as specified in paragraphs (a)(3)(i) through (iv) of this section. When developing historical waste quantity data, you may use default DOC values from Table TT–1 of this subpart for certain years and determined values for DOC, for other years. The historical values for DOC or DOC must be developed only for the first annual report required for the industrial waste landfill; and used for all subsequent annual reports (e.g., if DOC for year x=1990 was determined to be 0.15 in the first reporting year, you must use 0.15 for the 1990 DOC value for all subsequent annual reports).

(i) For the first year in which GHG emissions from this industrial waste landfill must be reported, determine the DOC value of each waste stream disposed of in the landfill no less frequently than once per quarter using the methods specified in §98.464(b). Calculate annual DOC for each waste stream as the arithmetic average of all DOC values for that waste stream that were measured during the year.

(ii) For subsequent years (after the first year in which GHG emissions from this industrial waste landfill must be reported), either use the DOC, of each waste stream calculated for the most recent reporting year for which DOC values were determined according to paragraph (a)(3)(i) of this section, or determine new DOC values for that year following the requirements in paragraph (a)(2)(ii)(C) of this section. You must determine new DOC values following the requirements in paragraph (a)(3)(i) of this section if changes in the process operations occurred during the previous reporting year that can reasonably be expected to alter the characteristics of the waste stream, such as the water content or volatile solids concentration. Should changes to the waste stream occur, you must revise the GHG Monitoring Plan as required in §98.3(g)(5)(iii) and report the new DOC value according to the requirements of §98.466.

(iii) If DOC measurement data for each waste stream are available according to the methods specified in §98.464(b) for years prior to the first year in which GHG emissions from this industrial waste landfill must be reported, determine DOC, for each waste stream as the arithmetic average of all DOC values for that waste stream that were measured in Year X. A single measurement value is acceptable for determining DOC, for years prior to the first reporting year.

(iv) For historical years for which DOC measurement data, determined according to the methods specified in §98.464(b), are not available, determine the historical values for DOC, using the applicable methods specified in paragraphs (a)(3)(iv)(A) and (B) of this section. Determine these historical values for DOC, only for the first annual report required for this industrial waste landfill; historical values for DOC, calculated for this first annual report should be used for all subsequent annual reports.

(A) For years in which waste stream-specific disposal quantities are determined (as required in paragraphs (a)(2)(i)(A) and (B) of this section), calculate the average DOC value for a given waste stream as the arithmetic average of all DOC measurements of that waste stream that follow the methods provided in §98.464(b), including any measurement values for years prior to the first reporting year and the four measurement values required in the first reporting year. Use the resulting waste-specific average DOC value for all applicable years (i.e., years in which waste stream-specific disposal quantities are determined) for which direct DOC measurement data are not available.

(B) For years for which bulk waste disposal quantities are determined according to paragraphs (a)(2)(i)(C) of this section, calculate the weighted average bulk DOC value according to the following: Calculate the average DOC value for each waste stream as the arithmetic average of all DOC measurements of that waste stream that follows the methods provided in §98.464(b) (generally, this will include only the DOC values determined in the first year in which GHG emissions from this industrial waste landfill must be reported); calculate the average annual disposal quantity for each waste stream as the arithmetic average of the annual disposal quantities for each year in which waste stream-specific
disposal quantities have been determined; and calculate the bulk waste DOC value using Equation TT-5 of this section. Use the bulk waste DOC value as DOC<sub>b</sub> for all years for which bulk waste disposal quantities are determined according to paragraphs (a)(2)(i)(C) of this section.

\[
DOC_{bulk} = \frac{\sum_{n=1}^{N} (DOC_{ave,n} \times W_{ave,n})}{\sum_{n=1}^{N} W_{ave,n}} \quad \text{(Eq. TT-5)}
\]

Where:
- \(DOC_{bulk}\) = Degradable organic content value for bulk historical waste placed in the landfill (mass fraction).
- \(N\) = Number of different waste streams placed in the landfill.
- \(n\) = Index for waste stream.
- \(DOC_{ave,n}\) = Average degradable organic content value for waste stream “n” based on available measurement data (mass fraction).
- \(W_{ave,n}\) = Average annual quantity of waste stream “n” placed in the landfill for years in which waste stream-specific disposal quantities have been determined (metric tons per year, wet basis).

(b) For each landfill, calculate CH<sub>4</sub> generation (adjusted for oxidation in cover materials) and CH<sub>4</sub> emissions (taking into account any CH<sub>4</sub> recovery, if applicable, and oxidation in cover materials) according to the applicable methods in paragraphs (b)(1) through (b)(3) of this section.

(1) For each landfill, calculate CH<sub>4</sub> generation, adjusted for oxidation, from the modeled CH<sub>4</sub> (\(G_{CH_4}\) from Equation TT-1 of this section) using Equation TT-6 of this section.

\[
MG = G_{CH_4} \times (1 - OX) \quad \text{(Eq. TT-6)}
\]

Where:
- \(MG\) = Methane generation, adjusted for oxidation, from the landfill in the reporting year (metric tons CH<sub>4</sub>).
- \(G_{CH_4}\) = Modeled methane generation rate in reporting year from Equation TT-1 of this section (metric tons CH<sub>4</sub>).
- \(OX\) = Oxidation fraction. Use the default value of 0.1 (10 percent).

(2) For landfills that do not have landfill gas collection systems operating during the reporting year, the CH<sub>4</sub> emissions are equal to the CH<sub>4</sub> generation (MG) calculated in Equation TT-6 of this section.

(3) For landfills with landfill gas collection systems in operation during any portion of the reporting year, perform all of the calculations specified in paragraphs (b)(3)(i) through (iv) of this section.

(i) Calculate the quantity of CH<sub>4</sub> recovered according to the requirements at §98.343(b).

(ii) Calculate CH<sub>4</sub> emissions using the Equation HH-6 of §98.343(c)(3)(i), except use \(G_{CH_4}\) determined using Equation TT-1 of this section in Equation HH-6 of §98.343(c)(3)(i).

(iii) Calculate CH<sub>4</sub> generation (MG) from the quantity of CH<sub>4</sub> recovered using Equation HH-7 of §98.343(c)(3)(ii).

(iv) Calculate CH<sub>4</sub> emissions from the quantity of CH<sub>4</sub> recovered using Equation HH-8 of §98.343(c)(3)(ii).

[75 FR 39773, July 12, 2010, as amended at 76 FR 73907, Nov. 29, 2011]
(b) For each waste stream placed in the landfill during the reporting year for which you choose to determine volatile solids concentration for the purposes of §98.460(c)(2)(xii) or choose to determine a landfill-specific DOC\textsubscript{X} for use in Equation TT-1 of this subpart, you must collect and test a representative sample of that waste stream using the methods specified in paragraphs (b)(1) through (b)(4) of this section.

1. Develop and follow a sampling plan to collect a representative sample (in terms of composition and moisture content) of each waste stream placed in the landfill for which testing is elected.

2. Determine the percent total solids and the percent volatile solids of each sample following Standard Method 2540G "Total, Fixed, and Volatile Solids in Solid and Semisolid Samples" (incorporated by reference; see §98.7).

3. For the purposes of §98.460(c)(2)(xii), the volatile solids concentration (weight percent on a dry basis) is the percent volatile solids determined using Standard Method 2540G "Total, Fixed, and Volatile Solids in Solid and Semisolid Samples" (incorporated by reference; see §98.7).

4. Determine DOC value of a waste stream by either using at least a 60-day anaerobic biodegradation test as specified in paragraph (b)(4)(i) of this section or by estimating the DOC value based on the total and volatile solids measurements as specified in paragraph (b)(4)(ii) of this section.

(i) Perform an anaerobic biodegradation test and determine the DOC value of a waste stream following the procedures and requirements in paragraphs (b)(4)(i)(A) through (E) of this section.

(A) You may use the procedures published by a consensus-based standards organization to conduct a minimum of a 60-day anaerobic biodegradation test. Consensus-based standards organizations include, but are not limited to, the following: ASTM International (100 Barr Harbor Drive, P.O. Box CB700, West Conshohocken, Pennsylvania 19428–B2999, (800) 262–1373, http://www.astm.org), the American National Standards Institute (ANSI, 1819 L Street, NW., 6th floor, Washington, DC 20036, (202) 293–8020, http://wwwansi.org), the American Society of Mechanical Engineers (ASME, Three Park Avenue, New York, NY 10016–5990, (800) 843–2763, http://www.asme.org), and the North American Energy Standards Board (NAESB, 801 Travis Street, Suite 1675, Houston, TX 77002, (713) 356–0060, http://www.api.org).

(B) Use a minimum of four samples: Two waste stream samples, a control sample using a known substrate (such as ethanol), and a digester sludge blank sample. Each waste stream sample must be appropriately ground to ensure the waste material is fully exposed to the anaerobic digester sludge.

(C) Determine the net mass of carbon degraded in the control sample as the difference in the results of the control sample and the digester sludge blank sample. Each waste stream sample and the digester sludge blank sample must be appropriately ground to ensure the waste material is fully exposed to the anaerobic digester sludge.

(D) Determine the fraction of carbon degraded in the control sample as the net mass of carbon degraded in the control sample divided by the mass of carbon added via the substrate material in the control sample. If less than 50 percent of the theoretical mass of carbon in the control sample is degraded, the test run is invalid.

(E) Determine the DOC of each waste sample using Equation TT-7 of this section. If the DOC values for the two waste stream samples differ by more than 20 percent, the test run is invalid. The DOC of the waste stream is determined as the average DOC value of the two waste stream samples determined during a valid test.

\[
\text{DOC}_{\text{X}} = \left( \frac{1}{\text{DOC}_F} \right) \left( \frac{\text{MCD}_{\text{sample,X}}}{\text{M}_{\text{sample,X}}} \right) \left( \frac{\text{MCD}_{\text{control}}}{\text{MC}_{\text{control}}} \right) \quad \text{(Eq. TT-7)}
\]
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Where:

DOC\text{X} = Degradable organic content of the waste stream in Year X (weight fraction, wet basis)

DOC\text{F} = Fraction of DOC dissimilated (fraction); use the default value of 0.5.

MCD\text{sample,}\text{X} = Mass of carbon degraded in the waste stream sample in Year X as determined in paragraph (b)(4)(i)(C) of this section [milligrams (mg)].

M\text{sample,}\text{X} = Mass of waste stream sample used in the anaerobic degradation test in Year X (mg, wet basis).

MCD\text{control} = Mass of carbon degraded in the control sample as determined in paragraph (b)(4)(i)(B) of this section (mg).

MC\text{control} = Mass of carbon added to the control sample via the substrate material in the anaerobic degradation (mg).

(ii) Calculate the waste stream-specific DOC\text{X} value using Equation TT-8 of this section.

DOC\text{X} = F\text{DOC} \times \frac{% \text{Volatile Solids}_{X}}{100%} \times \frac{% \text{Total Solids}_{X}}{100%}

(\text{Eq. TT-8})

Where:

DOC\text{X} = Degradable organic content of waste stream in Year X (weight fraction, wet basis)

F\text{DOC} = Fraction of the volatile residue that is degradable organic carbon (weight fraction). Use a default value of 0.6.

% Volatile Solids\text{X} = Percent volatile solids determined using Standard Method 2540G “Fixed, and Volatile Solids in Solid and Semisolid Samples” (incorporated by reference; see §98.7) for Year X [milligrams (mg) volatile solids per 100 mg dried solids].

% Total Solids\text{X} = Percent total solids determined using Standard Method 2540G “Total, Fixed, and Volatile Solids in Solid and Semisolid Samples” (incorporated by reference; see §98.7) for Year X (mg dried solids per 100 mg wet waste).

(c) For each waste stream for which you choose to determine volatile solids concentration for the purposes of paragraph §98.460(c)(2)(xii), and that was historically managed in the landfill but was not received during the first reporting year, you must determine volatile solids concentration of the waste stream as initially placed in the landfill using the methods specified in paragraph (c)(1) or (c)(2) of this section, as applicable.

(1) If you can identify a similar waste stream to the waste stream that was historically managed in the landfill, you may determine the volatile solids concentration of the historically managed waste stream using process knowledge. You must document the basis for volatile solids concentration as determined through process knowledge.

(d) For landfills with gas collection systems, operate, maintain, and calibrate a gas composition monitor capable of measuring the concentration of CH\text{4} according to the requirements specified at §98.344(b).

(e) For landfills with gas collection systems, install, operate, maintain, and calibrate a gas flow meter capable of measuring the volumetric flow rate of the recovered landfill gas according to the requirements specified at §98.344(c).

(f) For landfills with gas collection systems, all temperature, pressure, and if applicable, moisture content monitors must be calibrated using the procedures and frequencies specified by the manufacturer.

(g) For landfills electing to measure the fraction by volume of CH\text{4} in landfill gas (F), follow the requirements in paragraphs (g)(1) and (g)(2) of this section.

(1) Use a gas composition monitor capable of measuring the concentration of CH\text{4} on a dry basis that is properly operated, calibrated, and maintained according to the requirements specified at §98.344(b). You must either use a gas composition monitor that is also capable of measuring the O\text{2} concentration...
correcting for excess (infiltration) air or you must operate, maintain, and calibrate a second monitor capable of measuring the \(O_2\) concentration on a dry basis according to the manufacturer’s specifications.

(2) Use Equation TT–9 of this section to correct the measured \(\text{CH}_4\) concentration to 0% oxygen. If multiple \(\text{CH}_4\) concentration measurements are made during the reporting year, determine \(F\) separately for each measurement made during the reporting year, and use the results to determine the arithmetic average value of \(F\) for use in Equation TT–1 of this part.

\[
F = \left( \frac{C_{\text{CH}_4}}{100\%} \right) \times \left[ \frac{20.9}{20.9 - %O_2} \right]
\]  
(Eq. TT–9)

Where:
- \(F\) = Fraction by volume of \(\text{CH}_4\) in landfill gas (fraction, dry basis, corrected to 0% oxygen).
- \(C_{\text{CH}_4}\) = Measured \(\text{CH}_4\) concentration in landfill gas (volume %, dry basis).
- \(20.9\) = Defined \(O_2\) correction basis (volume %, dry basis).
- \(20.9\) = \(O_2\) concentration in air (volume %, dry basis).
- \(%O_2\) = Measured \(O_2\) concentration in landfill gas (volume %, dry basis).

(b) For industrial waste landfills with gas collection systems, follow the procedures for estimating missing data specified in §98.345(a) and (b).

§ 98.466 Data reporting requirements.

In addition to the information required by §98.3(c), each annual report must contain the following information for each landfill.

(a) Report the following general landfill information:

1. A classification of the landfill as “open” (actively received waste in the reporting year) or “closed” (no longer receiving waste).
2. The year in which the landfill first started accepting waste for disposal.
3. The last year the landfill accepted waste (for open landfills, enter the estimated year of landfill closure).
4. The capacity (in metric tons) of the landfill.
5. An indication of whether leachate recirculation is used during the reporting year and its typical frequency of use over the past 10 years (e.g., used several times a year for the past 10 years, used at least once a year for the past 10 years, used occasionally but not every year over the past 10 years, not used).

(b) Report the following waste characterization and modeling information:

1. The number of waste streams (including “Other Industrial Solid Waste (not otherwise listed)” for which Equation TT–1 of this subpart is used to calculate modeled \(\text{CH}_4\) generation.
2. A description of each waste stream (including the types of materials in each waste stream) for which \(\text{CH}_4\) generation is modeled.

§ 98.465 Procedures for estimating missing data.

(a) A complete record of all measured parameters used in the GHG emissions calculations is required. Therefore, whenever a quality-assured value of a required parameter is unavailable (e.g., if a meter malfunctions during unit operation or if a required fuel sample is not taken), a substitute data value for the missing parameter shall be used in the calculations, in accordance with paragraph (b) of this section.
Equation TT–1 of this subpart is used to calculate modeled CH₄ generation.

(3) The fraction of CH₄ in the landfill gas, F, (volume fraction, dry basis, corrected to 0% oxygen) for the reporting year and an indication as to whether this was the default value or a value determined through measurement data.

(4) The methane correction factor (MCF) value used in the calculations. If an MCF value other than the default of 1 is used, provide a description of the aeration system, including aeration blower capacity, the fraction of the landfill containing waste affected by the aeration, the total number of hours during the year the aeration blower was operated, and other factors used as a basis for the selected MCF value.

(c) For each waste stream identified in paragraph (b) of this section, report the following information:

(1) The decay rate (k) value used in the calculations.

(2) The method(s) for estimating historical waste disposal quantities and the range of years for which each method applies.

(3) If Equation TT–2 of this subpart is used, provide:

(i) The total number of years (N) for which disposal and production data are both available.

(ii) The year, the waste disposal quantity and production quantity for each year used in Equation TT–2 of this subpart to calculate the average waste disposal factor (WDF).

(iii) The average waste disposal factor (WDF) calculated for the waste stream.

(4) If Equation TT–4 of this subpart is used, provide:

(i) The value of landfill capacity (LFC).

(ii) YrData.

(iii) YrOpen.

(d) For each year of landfilling starting with the “Start Year” (S) and each year thereafter up to the current reporting year, report the following information:

(1) The calendar year for which the following data elements apply.

(2) The quantity of waste (Wₓ) disposed of in the landfill (metric tons, wet weight) for the specified year for each waste stream identified in paragraph (b) of this section.

(3) The degradable organic carbon (DOCₓ) value (mass fraction) for the specified year and an indication as to whether this was the default value from Table TT–1 to this subpart, a measured value using a 60-day anaerobic biodegradation test as specified in §98.464(b)(4)(i), or a value based on total and volatile solids measurements as specified in §98.464(b)(4)(ii). If DOCₓ was determined by a 60-day anaerobic biodegradation test, specify the test method used.

(e) Report the following information describing the landfill cover material:

(1) The type of cover material used (as either organic cover, clay cover, sand cover, or other soil mixtures).

(2) For each type of cover material used, the surface area (in square meters) at the start of the reporting year for the landfill sections that contain waste and that are associated with the selected cover type.

(f) The modeled annual methane generation (GCH₄) for the reporting year (metric tons CH₄) calculated using Equation TT–1 of this subpart.

(g) For landfills without gas collection systems, provide:

(1) The annual methane emissions (i.e., the methane generation (MG), adjusted for oxidation, calculated using Equation TT–6 of this subpart), reported in metric tons CH₄.

(2) An indication of whether passive vents and/or passive flares (vents or flares that are not considered part of the gas collection system as defined in §98.6) are present at this landfill.

(h) For landfills with gas collection systems, in addition to the reporting requirements in paragraphs (a) through (f) of this section, you must report according to §98.346(i).

[75 FR 39773, July 12, 2010, as amended at 76 FR 73909, Nov. 29, 2011]
Environmental Protection Agency

§ 98.460(c)(2)(xii) or used to determine landfill-specific DOC values.
[76 FR 73910, Nov. 29, 2011]

§ 98.468 Definitions.

Except as provided below, all terms used in this subpart have the same meaning given in the CAA and subpart A of this part.

Construction and demolition (C&D) waste landfill means a solid waste disposal facility subject to the requirements of subparts A or B of part 257 of this chapter that receives construction and demolition waste and does not receive hazardous waste (defined in § 261.3 of this chapter) or industrial solid waste (defined in § 258.2 of this chapter) or municipal solid waste (defined in § 98.6 of this part) other than residential lead-based paint waste. A C&D waste landfill typically receives any one or more of the following types of solid wastes: roadwork material, excavated material, demolition waste, construction/renovation waste, and site clearance waste.

Design capacity means the maximum amount of solid waste a landfill can accept. For the purposes of this subpart, for landfills that have a permit, the design capacity can be determined in terms of volume or mass in the most recent permit issued by the state, local, or Tribal agency responsible for regulating the landfill, plus any inplace waste not accounted for in the most recent permit. If the owner or operator chooses to convert the design capacity from volume to mass to determine its design capacity, the calculation must include a site-specific density. If the design capacity is within 10 percent of the applicability threshold in § 98.460(a) and there is a change in the production process that can reasonably be expected to change the site-specific waste density, the site-specific waste density must be redetermined and the design capacity must be recalculated based on the new waste density.

Solid waste has the meaning established by the Administrator pursuant to the Solid Waste Disposal Act (42 U.S.C.A. 6901 et seq.).

Waste stream means industrial solid waste material that is generated by a specific manufacturing process or client. For wastes generated at the facility that includes the industrial waste landfill, a waste stream is the industrial solid waste material generated by a specific processing unit at that facility. For industrial solid wastes that are received from off-site facilities, a waste stream can be defined as each waste shipment or group of waste shipments received from a single client or group of clients that produce industrial solid wastes with similar waste properties.

[75 FR 39773, July 12, 2010, as amended at 76 FR 73910, Nov. 29, 2011]

<table>
<thead>
<tr>
<th>Industry/Waste Type</th>
<th>DOC (weight fraction, wet basis)</th>
<th>k [dry climate] (yr⁻¹)</th>
<th>k [moderate climate] (yr⁻¹)</th>
<th>k [wet climate] (yr⁻¹)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Food Processing</td>
<td>0.22</td>
<td>0.06</td>
<td>0.12</td>
<td>0.18</td>
</tr>
<tr>
<td>Pulp and Paper</td>
<td>0.20</td>
<td>0.02</td>
<td>0.03</td>
<td>0.04</td>
</tr>
<tr>
<td>Wood and Wood Product</td>
<td>0.43</td>
<td>0.02</td>
<td>0.03</td>
<td>0.04</td>
</tr>
<tr>
<td>Construction and Demolition</td>
<td>0.08</td>
<td>0.02</td>
<td>0.03</td>
<td>0.04</td>
</tr>
<tr>
<td>Inert Waste (i.e., wastes listed in § 98.460(c)(2))</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>Other Industrial Solid Waste (not otherwise listed)</td>
<td>0.20</td>
<td>0.02</td>
<td>0.04</td>
<td>0.06</td>
</tr>
</tbody>
</table>

*The applicable climate classification is determined based on the annual rainfall plus the recirculated leachate application rate. Recirculated leachate application rate (in inches/year) is the total volume of leachate recirculated from company records or engineering estimates and applied to the landfill divided by the area of the portion of the landfill containing waste (with appropriate unit conversions).

(1) Dry climate = precipitation plus recirculated leachate less than 20 inches/year
(2) Moderate climate = precipitation plus recirculated leachate from 20 to 40 inches/year (inclusive)
(3) Wet climate = precipitation plus recirculated leachate greater than 40 inches/year.

Alternatively, landfills that use leachate recirculation can elect to use the k value for wet climate rather than calculating the recirculated leachate rate.

(1)'Dry climate = precipitation plus recirculated leachate less than 20 inches/year.
(2)'Moderate climate = precipitation plus recirculated leachate from 20 to 40 inches/year (inclusive).
(3)'Wet climate = precipitation plus recirculated leachate greater than 40 inches/year.
§ 98.470 Definition of the source category.

(a) The injection of carbon dioxide (CO₂) source category comprises any well or group of wells that inject a CO₂ stream into the subsurface.

(b) If you report under subpart RR of this part for a well or group of wells, you are not required to report under this subpart for that well or group of wells.

(c) A facility that is subject to this part only because it is subject to subpart UU of this part is not required to report emissions under subpart C of this part or any other subpart listed in §98.2(a)(1) or (a)(2).

§ 98.471 Reporting threshold.

(a) You must report under this subpart if your facility injects any amount of CO₂ into the subsurface.

(b) For purposes of this subpart, any reference to CO₂ emissions in §98.2(i) shall mean CO₂ received.

§ 98.472 GHGs to report.

You must report the mass of CO₂ received.

§ 98.473 Calculating CO₂ received.

(a) You must calculate and report the annual mass of CO₂ received by pipeline using the procedures in paragraphs (a)(1) or (a)(2) of this section and the procedures in paragraph (a)(3) of this section, if applicable.

(1) For a mass flow meter, you must calculate the total annual mass of CO₂ in a CO₂ stream received in metric tons by multiplying the mass flow by the CO₂ concentration in the flow, according to Equation UU-1 of this section. You must collect these data quarterly. Mass flow and concentration data measurements must be made in accordance with §98.474.

\[
CO_{2T,r} = \sum_{p=1}^{4} (Q_{r,p} - S_{r,p}) \times C_{CO_2,p,r} \quad \text{(Eq. UU-1)}
\]

where:

\( CO_{2T,r} \) = Net annual mass of CO₂ received through flow meter r (metric tons).
\( Q_{r,p} \) = Quarterly mass flow through a receiving flow meter r in quarter p (metric tons).
\( S_{r,p} \) = Quarterly mass flow through a receiving flow meter r that is redelivered to another facility without being injected into your well in quarter p (metric tons).
\( C_{CO_2,p,r} \) = Quarterly CO₂ concentration measurement in flow for flow meter r in quarter p (wt. percent CO₂, expressed as a decimal fraction).
\( p \) = Quarter of the year.

(2) For a volumetric flow meter, you must calculate the total annual mass of CO₂ in a CO₂ stream received in metric tons by multiplying the volumetric flow at standard conditions by the CO₂ concentration in the flow and the density of CO₂ at standard conditions, according to Equation UU-2 of this section. You must collect these data quarterly. Volumetric flow and concentration data measurements must be made in accordance with §98.474.

\[
CO_{2T,r} = \sum_{p=1}^{4} (Q_{r,p} - S_{r,p}) \times D \times C_{CO_2,p,r} \quad \text{(Eq. UU-2)}
\]
where:

\( \text{CO}_{2 \text{T}, r} \) = Net annual mass of CO\(_2\) received through flow meter \( r \) (metric tons).

\( Q_{r,p} \) = Quarterly volumetric flow through a receiving flow meter \( r \) in quarter \( p \) at standard conditions (standard cubic meters).

\( S_{r,p} \) = Quarterly volumetric flow through a receiving flow meter \( r \) that is redelivered to another facility without being injected into your well in quarter \( p \) (standard cubic meters).

\( D \) = Density of CO\(_2\) at standard conditions (metric tons per standard cubic meter): 0.0018704.

\[ \text{CO}_2 = \sum_{r=1}^{p} \text{CO}_{2 \text{T}, r} \quad \text{(Eq. UU-3)} \]

where:

\( \text{CO}_2 \) = Total net annual mass of CO\(_2\) received (metric tons).

\( \text{CO}_{2 \text{T}}, r \) = Net annual mass of CO\(_2\) received (metric tons) as calculated in Equation UU-1 or UU-2 for flow meter \( r \).

\( r \) = Receiving flow meter.

(b) You must calculate and report the annual mass of CO\(_2\) received in containers using the procedures specified in either paragraph (b)(1) or (b)(2) of this section.

(1) If you are measuring the mass of contents in a container under the provisions of §98.474(a)(2)(i), you must calculate the CO\(_2\) received in containers using Equation UU-1 of this section.

where:

\( \text{CO}_{2 \text{T}}, r \) = Annual mass of CO\(_2\) received in containers \( r \) (metric tons).

\( C_{\text{CO}_2, p,r} \) = Quarterly CO\(_2\) concentration measurement of contents in containers \( r \) in quarter \( p \) (wt. percent CO\(_2\), expressed as a decimal fraction).

\( Q_{r,p} \) = Quarterly mass of contents in containers \( r \) in quarter \( p \) (metric tons).

\( S_{r,p} \) = Quarterly mass of contents in containers \( r \) that is redelivered to another facility without being injected into your well in quarter \( p \) (standard cubic meters).

\( p \) = Quarter of the year.

\( r \) = Containers.

(2) If you are measuring the volume of contents in a container under the provisions of §98.474(a)(2)(ii), you must calculate the CO\(_2\) received in containers using Equation UU-2 of this section.

where:

\( \text{CO}_{2 \text{T}}, r \) = Quarterly CO\(_2\) concentration measurement in flow for flow meter \( r \) in quarter \( p \) (vol. percent CO\(_2\), expressed as a decimal fraction).

\( p \) = Quarter of the year.

\( r \) = Receiving flow meter.

(3) If you receive CO\(_2\) through more than one flow meter, you must sum the mass of all CO\(_2\) received in accordance with the procedure specified in Equation UU-3 of this section.

§ 98.474 Monitoring and QA/QC requirements.

(a) CO\(_2\) received.

(i) You must determine the quarterly flow rate of CO\(_2\) received by pipeline by following the most appropriate of the following procedures:

(ii) If you took ownership of the CO\(_2\) in a commercial transaction, you may use the quarterly flow rate data from the sales contract if it is a one-time transaction or from invoices or manifests if it is an ongoing commercial transaction with discrete shipments.
(iii) If you inject CO₂ from a production process unit that is part of your facility, you may use the quarterly CO₂ flow rate that was measured at the equivalent of a custody transfer meter following procedures provided in subpart PP of this part. To be the equivalent of a custody transfer meter, a meter must measure the flow of CO₂ being transported to an injection well to the same degree of accuracy as a meter used for commercial transactions.

(2) You must determine the quarterly mass or volume of contents in all containers if you receive CO₂ in containers by the most appropriate of the following procedures:

(i) You may measure the mass of contents of containers summed quarterly using weigh bills, scales, or load cells.

(ii) You may determine the volume of the contents of containers summed quarterly.

(iii) If you took ownership of the CO₂ in a commercial transaction, you may use the quarterly mass or volume of contents from the sales contract if it is a one-time transaction or from invoices or manifests if it is an ongoing commercial transaction with discrete shipments.

(3) You must determine a quarterly concentration of the CO₂ received that is representative of all CO₂ received in that quarter by following the most appropriate of the following procedures:

(i) You may sample the CO₂ stream at least once per quarter at the point of receipt and measure its CO₂ concentration.

(ii) If you took ownership of the CO₂ in a commercial transaction for which the sales contract was contingent on CO₂ concentration, and if the supplier of the CO₂ sampled the CO₂ stream in a quarter and measured its concentration per the sales contract terms, you may use the CO₂ concentration data from the sales contract for that quarter.

(iii) If you inject CO₂ from a production process unit that is part of your facility, you may report the quarterly CO₂ concentration of the CO₂ stream supplied that was measured following procedures provided in subpart PP of this part as the quarterly CO₂ concentration of the CO₂ stream received.

(4) You must assume that the CO₂ you receive meets the definition of a CO₂ stream unless you can trace it through written records to a source other than a CO₂ stream.

(b) Measurement devices.

(1) All flow meters must be operated continuously except as necessary for maintenance and calibration.

(2) You must calibrate all flow meters used to measure quantities reported in §98.476 according to the calibration and accuracy requirements in §98.3(1).

(3) You must operate all measurement devices according to one of the following. You may use an appropriate standard method published by a consensus-based standards organization if such a method exists or an industry standard practice. Consensus-based standards organizations include, but are not limited to, the following: ASTM International, the American National Standards Institute (ANSI), the American Gas Association (AGA), the American Society of Mechanical Engineers (ASME), the American Petroleum Institute (API), and the North American Energy Standards Board (NAESB).

(4) You must ensure that any flow meter calibrations performed are National Institute of Standards and Technology (NIST) traceable.

(c) General.

(1) If you measure the concentration of any CO₂ quantity for reporting, you must measure according to one of the following. You may use an appropriate standard method published by a consensus-based standards organization if such a method exists or an industry standard practice.

(2) You must convert all measured volumes of CO₂ to the following standard industry temperature and pressure conditions for use in Equations UU–2 of this subpart: standard cubic meters at a temperature of 60 degrees Fahrenheit and at an absolute pressure of 1 atmosphere.

(3) For 2011, you may follow the provisions of §98.3(d)(1) through (2) for best available monitoring methods rather than follow the monitoring requirements of this section. For purposes of this subpart, any reference to
§ 98.475 Procedures for estimating missing data.

A complete record of all measured parameters used in the GHG quantities calculations is required.

(a) Whenever the monitoring procedures for all facilities that used flow meters covered under this subpart cannot be followed to measure flow, the following missing data procedures must be followed:

(1) Another calculation methodology listed in §98.474(a)(1) must be used if possible.

(2) If another method listed in §98.474(a)(1) cannot be used, a quarterly flow rate value that is missing must be estimated using a representative flow rate value from the nearest previous time period.

(b) Whenever the monitoring procedures of this subpart cannot be followed to measure quarterly quantity of CO₂ received in containers, the most appropriate of the following missing data procedures must be followed:

(1) Another calculation methodology listed in §98.474(a)(2) must be used if possible.

(2) If another method listed in §98.474(a)(2) cannot be used, a quarterly mass or volume that is missing must be estimated using a representative flow rate value from the nearest previous time period.

(c) Whenever the monitoring procedures cannot be followed to measure CO₂ concentration, the following missing data procedures must be followed:

(1) Another calculation methodology listed in §98.474(a)(3) must be used if possible.

(2) If another method listed in §98.474(a)(3) cannot be used, a quarterly concentration value that is missing must be estimated using a representative concentration value from the nearest previous time period.

§ 98.476 Data reporting requirements.

If you are subject to this part and report under this subpart, you are not required to report the information in §98.3(c)(4) for this subpart. In addition to the information required by §98.3(c)(1) through §98.3(c)(3) and by §98.3(c)(5) through §98.3(c)(9), you must report the information listed in this section.

(a) If you receive CO₂ by pipeline, report the following for each receiving flow meter:

(1) The total net mass of CO₂ received (metric tons) annually.

(2) If a volumetric flow meter is used to receive CO₂:

(i) The volumetric flow through a receiving flow meter at standard conditions (in standard cubic meters) in each quarter.

(ii) The volumetric flow through a receiving flow meter that is redelivered to another facility without being injected into your well (in standard cubic meters) in each quarter.

(iii) The CO₂ concentration in the flow (volume percent CO₂ expressed as a decimal fraction) in each quarter.

(3) If a mass flow meter is used to receive CO₂:

(i) The mass flow through a receiving flow meter (in metric tons) in each quarter.

(ii) The mass flow through a receiving flow meter that is redelivered to another facility without being injected into your well (in metric tons) in each quarter.

(iii) The CO₂ concentration in the flow (weight percent CO₂ expressed as a decimal fraction) in each quarter.

(b) If you receive CO₂ in containers, report:

(1) The mass (in metric tons) or volume at standard conditions (in standard cubic meters) of contents in containers in each quarter.

(2) The concentration of CO₂ in contents in containers (volume or weight percent CO₂ expressed as a decimal fraction) in each quarter.

(3) The mass (in metric tons) or volume (in standard cubic meters) of contents in containers that is redelivered.

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§ 98.477 Records that must be retained.

(a) You must follow the record retention requirements specified by §98.3(g). In addition to the records required by §98.3(g), you must retain quarterly records of CO₂ received, including mass flow rate or contents of containers (mass or volumetric) at standard conditions and operating conditions, operating temperature and pressure, and concentration of these streams. You must retain all required records for at least 3 years.

(b) You must complete your monitoring plans, as described in §98.3(g)(5), by April 1 of the year you begin collecting data.

§ 98.478 Definitions.

Except as provided below, all terms used in this subpart have the same meaning given in the Clean Air Act and subpart A of this part.

CO₂ received means the CO₂ stream that you receive to be injected for the first time into a well on your facility that is covered by this subpart. CO₂ received includes, but is not limited to, a CO₂ stream from a production process unit inside your facility and a CO₂ stream that was injected into a well on another facility, removed from a discontinued enhanced oil or natural gas or other production well, and transferred to your facility.

PART 99 [RESERVED]