# Subpart Da - Standards of Performance for Electric Utility Steam Generating Units Which Construction Is Commenced After September 18, 1978

## Applicability - §60.40a

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| General | Facilities to which this subpart applies are each electric utility steam generating units listed below:<br>1.) Any facility that is capable of combusting more than 73 megawatts (250 million Btu/hour) heat input of fossil fuel (either alone or in combination with any other fuel); and<br>2.) Any facility for which construction or modification is commenced after September 18, 1978.<br>3.) Any electric utility combined cycle gas turbines which are capable of combusting more than 73 megawatts (250 million Btu/hour) heat input of fossil fuel in the steam generator. Only emissions resulting from combustion of fuels in the steam generating unit are subject to this subpart. (The gas turbine emissions are subject to subpart GG.)<br>4.) Any change to an existing fossil-fuel-fired steam generating unit to accommodate the use of combustible materials, other than fossil fuels, shall not bring that unit under the applicability of this subpart.<br>5.) Any change to an existing steam generating unit originally designed to fire gaseous or liquid fossil fuels, to accommodate the use of any other fuel (fossil or nonfossil) shall not bring that unit under the applicability of this subpart. |

## Emission Standards

| Source | SOx - §60.43a | NOx - §60.44a | PM - §60.42a |
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| General | 1.) The emission reduction requirements under this section do not apply to any affected facility that is operated under an $SO_2$ commercial demonstration permit issued by the Administrator in accordance with the provisions of §60.45a.<br>2.) Compliance with the emission limitation and percent reduction requirements under this section are both determined on a 30-day rolling average basis. | The emission limits under §60.44a (a) does not apply to facilities combusting coal-derived liquid fuel operating under a commercial demonstration permit. | Facility shall not emit gases which exhibit greater than 20 percent opacity (6-minute average), except for one 6-minute period per hour of not more than 27 percent opacity. |
| Facilities which combust solid fuel or solid-derived fuel | 1.) Facility may not emit greater than 520 ng/J (1.20 lb/million Btu) heat input and 10 percent of the potential combustion concentration (90 percent reduction), or<br>2.) Facility may not emit greater than 30 percent of the potential combustion concentration (70 percent reduction), when emissions are less than 260 ng/J (0.60 lb/million Btu) heat input. | | |

| Source | SOx - §60.43a | NOx - §60.44a | PM - §60.42a |
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| Facilities which combust liquid or gaseous fuels (except for liquid or gaseous fuels derived from solid fuels | 1.) Facility may not emit greater than 340 ng/J (0.80 lb/million Btu) heat input and 10 percent of the potential combustion concentration (90 percent reduction), or<br>2.) Facility may not emit greater than 100 percent of the potential combustion concentration (zero percent reduction) when emissions are less than 86 ng/J (0.20 lb/million Btu) heat input. | | |
| Facilities which combust solid solvent refined coal (SRC-I) | 1.) Facility may not emit greater than 520 ng/J (1.20 lb/million Btu) heat input and 15 percent of the potential combustion concentration (85 percent reduction)<br>2.) Compliance with the emission limitation is determined on a 30-day rolling average basis.<br>3.) Compliance with the percent reduction requirement is determined on a 24-hour basis. | | |
| Facilities which:<br>1.) Combusts 100 percent anthracite,<br>2.) Is classified as a resource recovery facility, or<br>3.) Is located in a noncontinental area and combusts solid fuel or solid-derived fuel. | Facility may not emit greater than 520 ng/J (1.20 lb/million Btu) heat input | | |
| Facilities which are located in a noncontinental area and combusts liquid or gaseous fuels (excluding solid-derived fuels). | Facility may not emit greater than 340 ng/J (0.80 lb/million Btu) heat input. | | |

| Source | SOx - §60.43a | NOx - §60.44a | PM - §60.42a |
|---|---|---|---|
| Facilities that combust different fuels simultaneously | 1.) If emissions of sulfur dioxide to the atmosphere are greater than 260 ng/J (0.60 lb/million Btu) the applicable standard is determined by proration using the following formula:<br>Es=(340x+520 y)/100 and %Ps=10<br>See §60.43a (h) (1) for variables and units<br>2.) If emissions of sulfur dioxide to the atmosphere are equal to or less than 260 ng/J (0.60 lb/million Btu) heat input the applicable standard is determined by proration using the following formula:<br>Es=(340x+520 y)/100 and<br>%Ps=(10x+30 y)/100<br>See §60.43a (h) (1) for variables and units | Facility must determine the standards by proration using the following formula:<br>En=[86*w+130*x+210*y+260*z+340*v]/100<br>*See §60.44a (c) for variables and units | |
| Facilities that combust gaseous fuels | | 1.) Facility may not emit greater than 210 ng.J (0.50 lb/MMBtu) heat input if fuel is coal-derived.<br>2.) Facility may not emit greater than 86 ng/J (0.20 lb/MMBtu) heat input for all other gaseous fuel types.<br>3.) Facility must reduce the potential combustion potential concentration by 25 percent. | Facility shall not emit greater than 13 ng/J (0.03 lb/million Btu) heat input derived from the combustion gaseous fuel |
| Facilities that combust liquid fuels | | 1.) Facility may not emit greater than 210 ng/J (0.50 lb/MMBtu) heat input if combusting either coal derived fuels or shale oil.<br>2.) Facility may not emit greater than 130 ng/J (0.30 lb/MMBtu) heat input for all other fuels<br>3.) Facility must reduce the potential combustion concentration by 30 percent. | 1.) Facility shall not emit greater than 30 percent of potential combustion concentration (70 percent reduction) when combusting liquid fuel.<br>2.) Facility shall not emit greater than 13 ng/J (0.03 lb/million Btu) heat input derived from the combustion of liquid fuel. |
| Facilities that combust solid fuels | | 1. Facility may not emit greater than 340 ng/J (0.80 lb/MMBtu) heat input if more than 25 percent of the fuel is lignite mined in ND, SD,MT, and is combusted in a slag furnace.<br>2. Facility must reduce the potential combustion concentration by 65 percent. | 1.) Facility shall not emit greater than 1 percent of the potential combustion concentration (99 percent reduction) when combusting solid fuel.<br>2.) Facility shall not emit greater than 13 ng/J (0.03 lb/million Btu) heat input derived from the combustion of solid fuel. |

| Source | SOx - §60.43a | NOx - §60.44a | PM - §60.42a |
|---|---|---|---|
| Facilities that combust Bituminous or Anthracite coal or other fuels | | 1.) Facility may not emit greater than 260 ng/J ( 0.60 lb/MMBtu) heat input.<br>2.) Facility must reduce the potential combustion concentration by 65 percent. | |
| Facilities that combust Subituminous coal | | 1.) Facility may not emit greater than 210 ng/J ( 0.50 lb/MMBtu) heat input.<br>2.) Facility must reduce the potential combustion concentration by 65 percent. | |

## Commercial Demonstration Permit - §60.45a

| Source | All Emissions |
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| General | 1.) Facilities proposing to demonstrate an emerging technology may apply to the Administrator for a commercial demonstration permit. Commercial demonstration permits may be issued only by the Administrator, and this authority will not be delegated.<br>2.) Commercial demonstration permits may not exceed the equivalent MW electrical generation capacity for any one technology category found in §6.45a (e),<br>3.) The total equivalent MW electrical generation capacity for all commercial demonstration plants may not exceed 15,000 MW. |
| Facilities that combust solid solvent refined coal (SRC-I) and who is issued a commercial demonstration permit | Facility is not subject to the SO2 emission reduction requirements under §60.43a(c) but must, as a minimum, reduce SO2 emissions to 20 percent of the potential combustion concentration (80 percent reduction) for each 24-hour period of steam generator operation and to less than 520 ng/J (1.20 lb/million Btu) heat input on a 30-day rolling average basis. |
| Fluidized bed combustion electric utility steam generator (atmospheric or pressurized) who is issued a commercial demonstration permit | Facility is not subject to the SO2 emission reduction requirements under §60.43a(a) but must, as a minimum, reduce SO2 emissions to 15 percent of the potential combustion concentration (85 percent reduction) on a 30-day rolling average basis and to less than 520 ng/J (1.20 lb/million Btu) heat input on a 30-day rolling average basis. |
| Facilities that combusts coal-derived liquid fuel and who is issued a commercial demonstration permit | Facility is not subject to the applicable NOx emission limitation and percent reduction under §60.44a(a) but must, as a minimum, reduce emissions to less than 300 ng/J (0.70 lb/million Btu) heat input on a 30-day rolling average basis. |

## Compliance provisions - §60.46a

| Source | SOx | NOx | PM |
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| General | 1.) The sulfur dioxide emission standards apply at all times except during periods of startup, shutdown, or when both emergency conditions exist and the procedures under paragraph (d) of this section are implemented.<br>2.) During emergency conditions in the principal company, an affected facility with a malfunctioning flue gas desulfurization system may be operated if sulfur dioxide emissions are minimized by one of the methods found in §60.46a (d) (1-3).<br>3.) After the initial performance test compliance with the sulfur dioxide emission limitations and percentage reduction requirements is based on the average emission rate for 30 successive boiler operating days.<br>4.) A separate performance test is completed at the end of each boiler operating day after the initial performance test, and a new 30 day average emission rate for sulfur dioxide and a new percent reduction for sulfur dioxide are calculated to show compliance with the standards.<br>5.) For the initial performance test compliance with the sulfur dioxide emission limitations and percent reduction requirements is based on the average emission rates for sulfur dioxide, and percent reduction for sulfur dioxide for the first 30 successive boiler operating days.<br>6.) The initial performance test is the only test in which at least 30 days prior notice is required unless otherwise specified by the Administrator.<br>7.) The initial performance test is to be scheduled so that the first boiler operating day of the 30 successive boiler operating days is completed within 60 days after achieving the maximum production rate at which the affected facility will be operated, but not later than 180 days after initial startup of the facility.<br>8.) Compliance is determined by calculating the arithmetic average of all hourly emission rates for $SO_2$ for the 30 successive boiler operating days, except for data obtained during emergency conditions. Compliance with the percentage reduction requirement for $SO_2$ is determined based on the average inlet and average outlet $SO_2$ emission rates for the 30 successive boiler operating days.<br>9.) If an owner or operator has not obtained the minimum quantity of emission data as required, compliance of the affected facility for the day on which the 30-day period ends may be determined by the Administrator by following the applicable procedures in section 7 of Method 19. | 1.) Compliance with the nitrogen oxides emission limitation under §60.44a(a) constitutes compliance with the percent reduction requirements under §60.44a(a)(2)<br>2.) The nitrogen oxides emission standards under §60.44a apply at all times except during periods of startup, shutdown, or malfunction.<br>3.) After the initial performance test compliance with the nitrogen oxides emission limitations is based on the average emission rate for 30 successive boiler operating days.<br>4.) A separate performance test is completed at the end of each boiler operating day after the initial performance test, and a new 30 day average emission rate for nitrogen oxides.<br>5.) For the initial performance test compliance with the nitrogen oxides emission limitation is based on the average emission rates for nitrogen oxides, for the first 30 successive boiler operating days.<br>6.) The initial performance test is the only test in which at least 30 days prior notice is required unless otherwise specified by the Administrator.<br>7.) The initial performance test is to be scheduled so that the first boiler operating day of the 30 successive boiler operating days is completed within 60 days after achieving the maximum production rate at which the affected facility will be operated, but not later than 180 days after initial startup of the facility.<br>8.) Compliance is determined by calculating the arithmetic average of all hourly emission rates for $NO_x$ for the 30 successive boiler operating days, except for data obtained during startup, shutdown, malfunction.<br>9.) If an owner or operator has not obtained the minimum quantity of emission data as required, compliance of the affected facility for the day on which the 30-day period ends may be determined by the Administrator by following the applicable procedures in section 7 of Method 19. | 1.) Compliance with the particulate matter emission limitation under §60.42a(a)(1) constitutes compliance with the percent reduction requirements for particulate matter under §60.42a(a)(2) and (3).<br>2.) The particulate matter emission standards apply at all times except during periods of startup, shutdown, or malfunction. |

## Emission monitoring - §60.47a

| Source | All Emissions |
|---|---|
| General | 1.) Facility shall obtain emission data for at least 18 hours in at least 22 out of 30 successive boiler operating days. If this minimum data requirement cannot be met with a continuous monitoring system, the owner or operator shall supplement emission data with other monitoring systems approved by the Administrator or the reference methods and procedures as described in §60.47a (h)<br>2.) The 1-hour averages required under paragraph §60.13(h) are expressed in ng/J (lbs/million Btu) heat input and used to calculate the average emission rates under §60.46a. The 1-hour averages are calculated using the data points required under §60.13(b). At least two data points must be used to calculate the 1-hour averages.<br>3.) When it becomes necessary to supplement continuous monitoring system data to meet the minimum data requirements in paragraph (6) of this section, the owner or operator shall use the reference methods and procedures as specified in §60.47a (h) (1-4).<br>4.) Acceptable alternative methods and procedures are given in §60.47a (j).<br>5.) Facility shall use the methods and procedures found in §60.47a (i) (1-5) to conduct monitoring system performance evaluations under §60.13(c) and calibration checks under §60.13(d). Acceptable alternative methods and procedures are given in §60.47a (j). |

| Source | SOx | NOx | PM |
|---|---|---|---|
| General | 1.) Facility shall install, calibrate, maintain, and operate a continuous monitoring system, and record the output of the system, for measuring sulfur dioxide emissions, except where natural gas is the only fuel combusted. For specific requirements see§60.47a (b) (1-3)<br>2.) Facility shall install, calibrate, maintain, and operate a continuous monitoring system, and record the output of the system, for measuring the oxygen or carbon dioxide content of the flue gases at each location where sulfur dioxide is monitored<br>3.) The continuous monitoring systems are operated and data recorded during all periods of operation of the affected facility including periods of startup, shutdown, malfunction or emergency conditions, except for continuous monitoring system breakdowns, repairs, calibration checks, and zero and span adjustments. | 1.) Facility shall install, calibrate, maintain, and operate a continuous monitoring system, and record the output of the system, for measuring nitrogen oxides emissions discharged to the atmosphere.<br>2.) Facility shall install, calibrate, maintain, and operate a continuous monitoring system, and record the output of the system, for measuring the oxygen or carbon dioxide content of the flue gases at each location where nitrogen oxide emissions are monitored.<br>3.) The continuous monitoring systems are operated and data recorded during all periods of operation of the affected facility including periods of startup, shutdown, malfunction or emergency conditions, except for continuous monitoring system breakdowns, repairs, calibration checks, and zero and span adjustments. | 1.) Facility shall install, calibrate, maintain, and operate a continuous monitoring system, and record the output of the system, for measuring the opacity of emissions.<br>2.) If opacity interference due to water droplets exists in the stack (for example, from the use of an FGD system), the opacity is monitored upstream of the interference (at the inlet to the FGD system).<br>3.) If opacity interference is experienced at all locations (both at the inlet and outlet of the sulfur dioxide control system), alternate parameters indicative of the particulate matter control system's performance are monitored (subject to the approval of the Administrator). |

## Compliance determination procedures and methods - §60.48a

| Source | SOx | NOx | PM |
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| General | 1.) Facility shall use as reference methods and procedures the methods in appendix A of this part or the methods and procedures as specified in this section.<br>2.) Acceptable alternative methods are given in paragraph (e) of this section.<br>3.) Section 60.8(f) does not apply to this section for SOx.<br>4.) Facility shall determine compliance with the SO2 standards as follows:<br>a.) The percent of potential SO2 emissions (%Ps) to the atmosphere shall be computed using the following equation: %Ps=[(100-%Rf) (100-%Rg)]/100<br>*See §60.48a (1) for variables and units<br>b.) The procedures in Method 19 may be used to determine percent reduction (%Rf) of sulfur by such processes as fuel pretreatment (physical coal cleaning, hydrodesulfurization of fuel oil, etc.), coal pulverizers, and bottom and flyash interactions. This determination is optional.<br>c.) The procedures in Method 19 shall be used to determine the percent SO2 reduction (%Rg of any SO2 control system). Alternatively, a combination of an "as fired" fuel monitor and emission rates measured after the control system, following the procedures in Method 19, may be used if the percent reduction is calculated using the average emission rate from the SO2 control device and the average SO2 input rate from the "as fired" fuel analysis for 30 successive boiler operating days.<br>5.) The appropriate procedures in Method 19 shall be used to determine the emission rate.<br>6.) The continuous monitoring system in §60.47a (b) and (d) shall be used to determine the concentrations of SO2 and CO2 or O2.<br>7.) Alternate prorcedures may be found in §60.48a (e-f) | 1. Facility shall use as reference methods and procedures the methods in appendix A of this part or the methods and procedures as specified in this section.<br>2. Acceptable alternative methods are given in paragraph (e) of this section.<br>3. Section 60.8(f) does not apply to this section for NOx.<br>4. Facility shall determine compliance with the NOx standard as follows:<br>a.) The appropriate procedures in Method 19 shall be used to determine the emission rate of NOx.<br>b.) The continous monitoring system in § 60.47a (c) and (d) shall be used to determine the concentrations of NOx and CO2 or O2.<br>5.) Alternate prorcedures may be found in §60.48a (e-f) | 1.) Facility shall use as reference methods and procedures the methods in appendix A of this part or the methods and procedures as specified in this section.<br>2.) Acceptable alternative methods are given in paragraph (5) of this section.<br>3.) Facility shall determine compliance with the particulate matter standards as follows:<br>a.) The dry basis F factor (O2) procedures in Method 19 shall be used to compute the emission rate of particulate matter.<br>b.) For the particular matter concentration, Method 5 shall be used at affected facilities without wet FGD systems and Method 5B shall be used after wet FGD systems. For specific requirements see §60.48a (b) (2) (i-ii).<br>4.) Method 9 and the procedures in §60.11 shall be used to determine opacity.<br>5.) Alternate prorcedures may be found in §60.48a (e-f) |

## **Reporting Requirements** - §60.49a

<table>
<tr><td>Source</td><td colspan="2">All emissions</td></tr>
<tr><td>General</td><td colspan="2">1.) The performance test data from the initial performance test and from the performance evaluation of the continuous monitors (including the transmissometer) are submitted to the Administrator.<br>2.) If the minimum quantity of emission data is not obtained for any 30 successive boiler operating days, the information obtained under the requirements of §60.46a(h) is reported to the Administrator for that 30- day period.<br>3.) If any standards are exceeded during emergency conditions because of control system malfunction, the owner or operator of the affected facility shall submit a signed statement including the information found in §60.49a (d).<br>4.) If fuel pretreatment credit toward the sulfur dioxide emission standard under §60.43a is claimed, the owner or operator of the affected facility shall submit a signed statement including the information found in §60.49a(e).<br>5.) Facility shall submit a signed statement indicating if any changes were made in operation of the emission control system during the period of data unavailability. Operations of the control system and affected facility during periods of data unavailability are to be compared with operation of the control system and affected facility before and following the period of data unavailability.<br>6.) Facility shall submit a signed statement including the information found in §60.49a(g).</td></tr>
<tr><td></td><td>SOx & NOx</td><td>PM</td></tr>
<tr><td></td><td>1.) The following information is reported to the Administrator for each 24-hour period:<br>a.) Calendar date.<br>b.) The average sulfur dioxide and nitrogen oxide emission rates (ng/J or lb/million Btu) for each 30 successive boiler operating days, ending with the last 30-day period in the quarter; reasons for non-compliance with the emission standards; and, description of corrective actions taken.<br>c.) Percent reduction of the potential combustion concentration of sulfur dioxide for each 30 successive boiler operating days, ending with the last 30-day period in the quarter; reasons for non-compliance with the standard; and, description of corrective actions taken.<br>d.) Identification of the boiler operating days for which pollutant or dilutent data have not been obtained by an approved method for at least 18 hours of operation of the facility; justification for not obtaining sufficient data; and description of corrective actions taken.<br>e.) Identification of the times when emissions data have been excluded from the calculation of average emission rates because of startup, shutdown, malfunction (NOx only), emergency conditions (SO2 only), or other reasons, and justification for excluding data for reasons other than startup, shutdown, malfunction, or emergency conditions.<br>f.) Identification of "F" factor used for calculations, method of determination, and type of fuel combusted.<br>g.) Identification of times when hourly averages have been obtained based on manual sampling methods.<br>h.) Identification of the times when the pollutant concentration exceeded full span of the continuous monitoring system.<br>i.) Description of any modifications to the continuous monitoring system which could affect the ability of the continuous monitoring system to comply with Performance Specifications 2 or 3.</td><td>1.) For the purposes of the reports required under § 60.7, periods of excess emissions are defined as all 6-minute periods during which the average opacity exceeds the applicable opacity standards.<br>2.) Opacity levels in excess of the applicable opacity standard and the date of such excesses are to be submitted to the Administrator each calendar quarter.<br>3.) The owner or operator of an affected facility shall submit the written reports required under this section and subpart A to the Administrator for every calendar quarter.<br>4.) All quarterly reports shall be postmarked by the 30th day following the end of each calendar quarter.</td></tr>
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