SC DEPARTMENT *of* ENVIRONMENTAL SERVICES

Bureau of Air Quality
PSD Construction Permit

Dominion Energy South Carolina, Inc. Canadys Station
13139 Augusta Highway
Walterboro, South Carolina 29488
Colleton County

In accordance with the provisions of the Pollution Control Act, Sections 48-1-50(5), 48-1-100(A), and 48-1-110(a), the 1976 Code of Laws of South Carolina, as amended, and South Carolina Regulation 61-62, Air Pollution Control Regulations and Standards, the Bureau of Air Quality authorizes the construction of this facility and the equipment specified herein in accordance with the plans, specifications, and other information submitted in the construction permit application received on April 24, 2026, as amended. All official correspondence, plans, permit applications, and written statements are an integral part of the permit. Any false information or misrepresentation in the application for a construction permit may be grounds for permit revocation.

The construction and subsequent operation of this facility is subject to and conditioned upon the terms, limitations, standards, and schedules contained herein or as specified by this permit and its accompanying attachments.

Permit Number: PSD-50000027 v1.0
Agency Air Number: 0740-0002

Issue Date: DRAFT

Steve McCaslin, P. E., Director
Air Permitting Division
Bureau of Air Quality

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RECORD OF REVISIONS	
Date	**Description of Changes**

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A. PROJECT DESCRIPTION, EQUIPMENT, AND CONTROL DEVICE(S)

Permission is hereby granted to construct three (3) independent, advanced-class, multi-shaft, one-on-one (1x1) combined cycle combustion turbine (CCCT) power trains. Each power train will include a combustion turbine-generator (CTG), a heat recovery steam generator (HRSG) equipped with supplementary firing (duct burners), and a steam turbine-generator (STG), configured to operate in a combined cycle arrangement. Each CCCT will be equipped with selective catalytic reduction (SCR) for the control of nitrogen oxides (NO_x) and an oxidative catalyst (OXCAT) for the control of carbon monoxide (CO), volatile organic compounds (VOC), and organic hazardous air pollutants (HAPs). Water injection will also be available for control of NO_x when using fuel oil in the combustion turbines. Ancillary equipment will include: one (1) natural gas-fired auxiliary boiler, three (3) diesel-fired emergency generators, two (2) diesel-fired emergency fire water pumps, four (4) natural gas-fired fuel gas heaters, sixty six (66) sulfur hexafluoride (SF6) high-voltage circuit breakers, two (2) three-million gallon aboveground storage tanks (ASTs) for fuel oil, three (3) 4000-gallon diesel belly tanks, two (2) 300-gallon diesel belly tanks, six (6) inlet chiller towers, three (3) delugable air-cooled heat exchangers, and fugitive emission components (valves, flanges, etc.).

A.1 EQUIPMENT

Equipment ID	Equipment Description	Control Device ID	Emission Point ID
CT1	Combined Cycle Combustion Turbine Nominally Rated at 4,115 Million Btu/hr Heat Input Firing Natural Gas and 3,495 Million Btu/hr Heat Input Firing Fuel Oil	SCR1, OXCAT1, WIN1	ST01
DB1	Duct Burner Nominally Rated at 851.5 Million Btu/hr Heat Input Firing Natural Gas	SCR1, OXCAT1	ST01
CT2	Combined Cycle Combustion Turbine Nominally Rated at 4,115 Million Btu/hr Heat Input Firing Natural Gas and 3,495 Million Btu/hr Heat Input Firing Fuel Oil	SCR2, OXCAT2, WIN2	ST02
DB2	Duct Burner Nominally Rated at 851.5 Million Btu/hr Heat Input Firing Natural Gas	SCR2, OXCAT2	ST02
CT3	Combined Cycle Combustion Turbine Nominally Rated at 4,115 Million Btu/hr Heat Input Firing Natural Gas and 3,495 Million Btu/hr Heat Input Firing Fuel Oil	SCR3, OXCAT3, WIN3	ST03
DB3	Duct Burner Nominally Rated at 851.5 Million Btu/hr Heat Input Firing Natural Gas	SCR3, OXCAT3	ST03
AB1	Auxiliary Boiler Rated at 99.8 Million Btu/hr Heat Input Firing Natural Gas	None	ST04
EG1	Diesel-Fired Emergency Generator Engine Nominally Rated at 2,760 KW	None	ST05
EG2	Diesel-Fired Emergency Generator Engine Nominally Rated at 2,760 KW	None	ST06
EG3	Diesel-Fired Emergency Generator Engine Nominally Rated at 2,760 KW	None	ST07
FP1	Diesel-Fired Fire Water Pump Engine Nominally Rated at 315 bhp	None	ST08
FP2	Diesel-Fired Fire Water Pump Engine Nominally Rated at 315 bhp	None	ST09

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A.1 EQUIPMENT

Equipment ID	Equipment Description	Control Device ID	Emission Point ID
FUGNG	Piping Components	None	FUG1
EGBT1	4000-gallon Diesel Belly Tank	None	FUG2
EGBT2	4000-gallon Diesel Belly Tank	None	FUG3
EGBT3	4000-gallon Diesel Belly Tank	None	FUG4
FPBT1	300-gallon Diesel Belly Tank	None	FUG5
FPBT2	300-gallon Diesel Belly Tank	None	FUG6
AST1	3-Million Gallon, Fixed Roof Fuel Oil Storage Tank #1	None	FUG7
AST2	3-Million Gallon, Fixed Roof Fuel Oil Storage Tank #2	None	FUG8
FUGSF6	Sixty-six (66) SF6 Circuit Breakers	None	FUG9
HT1	Natural Gas-Fired Fuel Gas Heater #1, 20 Million Btu/hr	None	ST10
HT2	Natural Gas-Fired Fuel Gas Heater #2, 20 Million Btu/hr	None	ST11
HT3	Natural Gas-Fired Fuel Gas Heater #3, 20 Million Btu/hr	None	ST12
HT4	Natural Gas-Fired Low Pressure Heater, 3.0 Million Btu/hr	None	ST13
COOL1	Inlet Chiller Cooling Tower w/ 4 Cells	DRIFT1	IC01
COOL2	Inlet Chiller Cooling Tower w/ 4 Cells	DRIFT2	IC02
COOL3	Inlet Chiller Cooling Tower w/ 4 Cells	DRIFT3	IC03
COOL4	Inlet Chiller Cooling Tower w/ 4 Cells	DRIFT4	IC04
COOL5	Inlet Chiller Cooling Tower w/ 4 Cells	DRIFT5	IC05
COOL6	Inlet Chiller Cooling Tower w/ 4 Cells	DRIFT6	IC06
DELUGE1	Delugable Cooling System w/ 4 Wet Cells & 4 Dry Cells	DRIFT7	DCS01
DELUGE2	Delugable Cooling System w/ 4 Wet Cells & 4 Dry Cells	DRIFT8	DCS02
DELUGE3	Delugable Cooling System w/ 4 Wet Cells & 4 Dry Cells	DRIFT9	DCS03

A.2 CONTROL DEVICES

Control Device ID	Control Device Description	Pollutant(s) Controlled	Emission Point ID
SCR1	Selective Catalytic Reduction System	NO_x	ST01
SCR2	Selective Catalytic Reduction System	NO_x	ST02
SCR3	Selective Catalytic Reduction System	NO_x	ST03
OXCAT1	Oxidation Catalyst	CO, VOC	ST01
OXCAT2	Oxidation Catalyst	CO, VOC	ST02
OXCAT3	Oxidation Catalyst	CO, VOC	ST03
WIN1	Water Injection	NO_x	ST01
WIN2	Water Injection	NO_x	ST02
WIN3	Water Injection	NO_x	ST03
DRIFT1	High Efficiency Drift Eliminator	PM, PM_{10}, $PM_{2.5}$	IC01
DRIFT2	High Efficiency Drift Eliminator	PM, PM_{10}, $PM_{2.5}$	IC02
DRIFT3	High Efficiency Drift Eliminator	PM, PM_{10}, $PM_{2.5}$	IC03
DRIFT4	High Efficiency Drift Eliminator	PM, PM_{10}, $PM_{2.5}$	IC04

A.2 CONTROL DEVICES

Control Device ID	Control Device Description	Pollutant(s) Controlled	Emission Point ID
DRIFT5	High Efficiency Drift Eliminator	PM, PM_{10}, $PM_{2.5}$	IC05
DRIFT6	High Efficiency Drift Eliminator	PM, PM_{10}, $PM_{2.5}$	IC06
DRIFT7	Drift Eliminator	PM, PM_{10}, $PM_{2.5}$	DCS01
DRIFT8	Drift Eliminator	PM, PM_{10}, $PM_{2.5}$	DCS02
DRIFT9	Drift Eliminator	PM, PM_{10}, $PM_{2.5}$	DCS03

B. LIMITATIONS, MONITORING, AND REPORTING

Condition Number	Conditions
B.1	**Equipment ID:** CT1, CT2, CT3, DB1, DB2, DB3 **Control Device ID:** SCR1, OXCAT1, WIN1, SCR2, OXCAT2, WIN2, SCR3, OXCAT3, WIN3 (S.C. Regulation 61-62.1, Section II(J)(2)) The owner or operator shall inspect, calibrate, adjust, and maintain continuous monitoring systems, monitoring devices, and gauges in accordance with manufacturer's specifications or good engineering practices. The owner or operator shall maintain on file all measurements including continuous monitoring system or monitoring device performance measurements; all continuous monitoring system performance evaluations; all continuous monitoring system or monitoring device calibration checks; adjustments and maintenance performed on these systems or devices; and all other information required in a permanent form suitable for inspection by Department personnel. (S.C. Regulation 61-62.1, Section II(J)(1)(d)) Sources required to have continuous emission monitors shall submit reports as specified in applicable parts of the permit, law, regulations, or standards.
B.2	**Equipment ID:** CT1, CT2, CT3, DB1, DB2, DB3 **Control Device ID:** SCR1, OXCAT1, WIN1, SCR2, OXCAT2, WIN2, SCR3, OXCAT3, WIN3 (S.C. Regulation 61-62.1, Section II(J)(2)) All gauges shall be readily accessible and easily read by operating personnel and Department personnel (i.e. on ground level or easily accessible roof level). Monitoring parameter readings (e.g., pressure drop readings, flow rates, etc.) and inspection checks shall be maintained in logs (written or electronic), along with any corrective action taken when deviations occur. Each occurrence of operation outside the operational ranges, including date and time, cause, and corrective action taken, shall be recorded and kept on site. Exceedance of operational range shall not be considered a violation of an emission limit of this permit, unless the exceedance is also accompanied by other information demonstrating that a violation of an emission limit has taken place. Reports of these occurrences shall be submitted semiannually. If there were no occurrences during the reporting period, then documentation shall be submitted to indicate such. Any alternative method for monitoring control device performance must be preapproved by the Department and

<table>
<tr><th colspan="2">B. LIMITATIONS, MONITORING, AND REPORTING</th></tr>
<tr><th>Condition Number</th><th>Conditions</th></tr>
<tr><td></td><td>shall be incorporated into the permit as set forth in S.C. Regulation 61-62.1 Section II.</td></tr>
<tr><td>B.3</td><td>Equipment ID: CT1, CT2, CT3, DB1, DB2, DB3
Control Device ID: SCR1, OXCAT1, WIN1, SCR2, OXCAT2, WIN2, SCR3, OXCAT3, WIN3

(S.C. Regulation 61-62.1, Section IV) All emissions points, duct work and other locations that are required to be tested, shall be designed and constructed in a manner to facilitate testing in accordance with applicable EPA approved source testing methods; including, but not be limited to, methods specifying test port location and sizing criteria.

For any source test required under an applicable standard or permit condition, the owner, operator, or representative shall comply with S.C. Regulation 61-62.1, Section IV - Source Tests.

Unless approved otherwise by the Department, the owner, operator, or representative shall ensure that source tests are conducted while the source is operating at the maximum expected production rate or other production rate or operating parameter which would result in the highest emissions for the pollutants being tested. Some sources may have to spike fuels or raw materials to avoid being subjected to a more restrictive feed or process rate. Any source test performed at a production rate less than the rated capacity may result in permit limits on emission rates, including limits on production if necessary.

When conducting source tests subject to this section, the owner, operator, or representative shall provide the following:
• Department access to the facility to observe source tests;
• Sampling ports adequate for test methods;
• Safe sampling site(s);
• Safe access to sampling site(s);
• Utilities for sampling and testing equipment; and
• Equipment and supplies necessary for safe testing of a source.

The owner or operator shall comply with any limits that result from conducting a source test at less than rated capacity. A copy of the most recent Department issued source test summary letter, whether it imposes a limit or not, shall be maintained with the operating permit, for each source that is required to conduct a source test.

Site-specific test plans and amendments, notifications, and source test reports shall be submitted to the Department.</td></tr>
<tr><td>B.4</td><td>Equipment ID: CT1, CT2, CT3, DB1, DB2, DB3
Control Device ID: SCR1, OXCAT1, WIN1, SCR2, OXCAT2, WIN2, SCR3, OXCAT3, WIN3

(S.C. Regulation 61-62.1, Section II(J)(2), S.C. Regulation 61-62.5, Standard No. 7 (BACT)) These sources are permitted to burn only natural gas and No.2 fuel oil as fuel. The use of any other substances as fuel is prohibited without prior written approval from the Department.</td></tr>
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B. LIMITATIONS, MONITORING, AND REPORTING	
Condition Number	**Conditions**
B.5	**Equipment ID:** DB1, DB2, DB3 **Control Device ID:** SCR1, OXCAT1, SCR2, OXCAT2, SCR3, OXCAT3 (S.C. Regulation 61-62.1, Section II(J)(2), S.C. Regulation 61-62.5, Standard No. 7 (BACT)) These sources are permitted to burn only natural gas as fuel. The use of any other substances as fuel is prohibited without prior written approval from the Department.
B.6	**Equipment ID:** DB1, DB2, DB3 **Control Device ID:** SCR1, OXCAT1, WIN1, SCR2, OXCAT2, WIN2, SCR3, OXCAT3, WIN3 (S.C. Regulation 61-62.5, Standard No. 1, Section I) The fuel burning sources shall not discharge into the ambient air smoke which exceeds opacity of 20%. The owner or operator shall, to the extent practicable, maintain and operate any source including associated air pollution control equipment in a manner consistent with good air pollution control practices for minimizing emissions. (S.C. Regulation 61-62.5, Standard No. 1, Section II) The maximum allowable discharge of particulate matter resulting from these sources is 0.6 pounds per million BTU input. (S.C. Regulation 61-62.5, Standard No. 1, Section III) The maximum allowable discharge of sulfur dioxide (SO_2) resulting from these sources is 2.3 pounds per million BTU input.
B.7	**Equipment ID:** CT1, DB1, CT2, DB2, CT3, DB3, EG1, EG2, EG3, FP1, FP2, FUGNG, EGBT1, EGBT2, EGBT3, FPBT1, FPBT2, AST1, AST2, FUGSF6, COOL1, COOL2, COOL3, COOL4, COOL5, COOL6, DELUGE1, DELUGE2, DELUGE3 **Control Device ID:** SCR1, OXCAT1, WIN1, SCR2, OXCAT2, WIN2, SCR3, OXCAT3, WIN3, DRIFT1, DRIFT2, DRIFT3, DRIFT4, DRIFT5, DRIFT6, DRIFT7, DRIFT8, DRIFT9 (S.C. Regulation 61-62.5, Standard No. 4, Section IX) Where construction or modification began after December 31, 1985, emissions from these sources (including fugitive emissions) shall not exhibit an opacity greater than 20%, each. (S.C. Regulation 61-62.1, Section II(J)(2)) The owner or operator shall perform a visual inspection on a semiannual basis of sources subject to opacity limits. The inspection shall occur during normal source operation. No periodic monitoring for opacity will be required for sources during periods that only natural gas is being combusted. Logs shall be kept to record all visual inspections, noting color, duration, density (heavy or light), cause, and corrective action taken for any abnormal emissions. If a source did not operate during the required visual inspection time frame, the log shall indicate such. The owner or operator shall submit semiannual reports. The report shall include records of abnormal emissions, if any, and corrective actions taken. If only natural gas was combusted or if the unit did not operate during the semiannual period, the report shall state so. Visual inspection means a qualitative observation of opacity during daylight hours. The observer does not need to be certified to conduct valid visual inspections. However, at a minimum, the observer should be trained and knowledgeable about the effects on visibility of emissions caused by

B. LIMITATIONS, MONITORING, AND REPORTING	
Condition Number	**Conditions**
	background contrast, ambient lighting, and observer position relative to lighting, wind, and the presence of uncombined water.
B.8	**Equipment ID:** CT1, CT2, CT3, DB1, DB2, DB3 **Control Device ID:** SCR1, OXCAT1, WIN1, SCR2, OXCAT2, WIN2, SCR3, OXCAT3, WIN3 (S.C. Regulation 61-62.5, Standard No. 7 (BACT Limits for PM filterable, PM_{10} and $PM_{2.5}$)): The maximum allowable discharge for each of filterable particulate matter (PM filterable), particulate matter less than 10 microns in diameter (PM_{10}), and particulate matter less than 2.5 microns in diameter ($PM_{2.5}$) resulting from each of these sources is less than or equal to 0.009 lb/Million Btu pounds per hour based on a 3-hour average when burning natural gas during normal operations. The maximum allowable discharge for each of PM filterable, PM_{10} and $PM_{2.5}$ resulting from each of these sources is less than or equal to 0.027 lb/Million Btu based on a 3-hour average when burning fuel oil during normal operations. This limit does not include emissions from the duct burners which will not operate when fuel oil is used.
B.9	**Equipment ID:** CT1, CT2, CT3, DB1, DB2, DB3 **Control Device ID:** SCR1, OXCAT1, WIN1, SCR2, OXCAT2, WIN2, SCR3, OXCAT3, WIN3 (S.C. Regulation 61-62.5, Standard No. 7 (BACT Monitoring for PM filterable, PM_{10} and $PM_{2.5}$)): An initial source test for PM filterable, PM_{10}, and $PM_{2.5}$ emissions shall be conducted within 180 days after startup. The source test will be used to show compliance with the PM, PM_{10}, and $PM_{2.5}$ limits during normal operations while burning natural gas and while burning fuel oil.
B.10	**Equipment ID:** CT1, CT2, CT3 **Control Device ID:** SCR1, OXCAT1, WIN1, SCR2, OXCAT2, WIN2, SCR3, OXCAT3, WIN3 (S.C. Regulation 61-62.5, Standard No. 7 (BACT Monitoring for PM filterable, PM_{10}, $PM_{2.5}$, SO_2 and Sulfuric Acid Mist) Fuel oil sulfur content shall be less than or equal to 15 part per million by weight. Fuel oil supplier certification shall be obtained for each batch of oil received and stored on site. Reports of the recorded sulfur content shall be submitted semiannually.
B.11	**Equipment ID:** CT1, CT2, CT3, DB1, DB2, DB3, AB1, HT1, HT2, HT3, HT4 **Control Device ID:** SCR1, OXCAT1, WIN1, SCR2, OXCAT2, WIN2, SCR3, OXCAT3, WIN3 (S.C. Regulation 61-62.5, Standard No. 7 (BACT Monitoring for PM filterable, PM_{10}, $PM_{2.5}$, SO_2 and Sulfuric Acid Mist) Natural gas sulfur content shall be less than or equal to 0.5 gr/100 scf calculated on a 12 month rolling average. Periodic fuel monitoring and/or fuel supplier certifications shall be used to determine the average monthly sulfur content. Reports of the twelve-month rolling average, calculated for each

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B. LIMITATIONS, MONITORING, AND REPORTING	
Condition Number	**Conditions**
	month in the reporting period, shall be submitted semiannually.
B.12	**Equipment ID:** CT1, CT2, CT3, DB1, DB2, DB3 (S.C. Regulation 61-62.5, Standard No. 7 (BACT Monitoring for PM filterable, PM_{10}, and $PM_{2.5}$)): Inlet dry filters shall be operational and in place at all times when the turbines are operating, except during periods of turbine malfunction or mechanical failure. The owner or operator shall develop an operation, maintenance, and monitoring (OM&M) plan for the inspection and regular cleaning or replacement of the dry filters. The OM&M plan shall be submitted to the Director of the Air Permitting Division no later than 180 days after start of operation. Subsequent updates to the plan shall be submitted to the Director of the Air Permitting Division for review and approval prior to the new plan taking effect. Records of malfunctions, mechanical failures, inspections, cleaning, and replacement of the dry filters shall be maintained in logs (written or electronic) and maintained on site.
B.13	**Equipment ID:** AB1 (S.C. Regulation 61-62.5, Standard No. 7 (BACT Monitoring for PM filterable, PM_{10} and $PM_{2.5}$, SO_2, NO_x, CO, and VOC) This source is limited to a 10% capacity factor and 2,000 hours of operation annually. These operational limits exclude periods of initial commissioning of the CCCTs power trains. The owner or operator shall maintain heat input records, hours of operation, and any other records necessary to determine the capacity factor and hours of operation. The capacity factor and hours of operation shall be calculated on a monthly basis, and a twelve month rolling sum shall be calculated for the capacity factor and hours of operation. Reports of the calculated values and the twelve-month rolling sums, calculated for each month in the reporting period, shall be submitted semiannually.
B.14	**Equipment ID:** EG1, EG2, EG3, FP1, FP2 (S.C. Regulation 61-62.5, Standard No. 7 (BACT Monitoring for PM filterable, PM_{10} and $PM_{2.5}$ and SO_2)) These sources are permitted to burn only ultra-low sulfur diesel (less than or equal to 15 ppmw sulfur content) as fuel. The use of any other substances as fuel is prohibited without prior written approval from the Department. Fuel oil supplier certification shall be obtained for each batch of oil received and stored on site. Reports of the recorded sulfur content shall be maintained on site.
B.15	**Equipment ID:** CT1, CT2, CT3, DB1, DB2, DB3 **Control Device ID:** OXCAT1, OXCAT2, OXCAT3 (S.C. Regulation 61-62.5, Standard No. 7 (BACT Limits for CO and VOC)): The maximum allowable discharge of CO for resulting from each of these sources is less than or equal to 3.5 ppmvd at 15% O_2 based on a 4-hour rolling average when burning natural gas and less

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B. LIMITATIONS, MONITORING, AND REPORTING	
Condition Number	**Conditions**
	than or equal to 5 ppmvd at 15% O_2 based on a 4-hour rolling average when burning fuel oil during normal operations. The maximum allowable discharge of VOC for resulting from each of these sources is less than or equal to 2 ppmvd at 15% O_2 based on a 4-hour rolling average when burning natural gas and less than or equal to 2 ppmvd at 15% O_2 based on a 4-hour rolling average when burning fuel oil during normal operations. The maximum annual CO emissions combined for all three turbines are limited to 2,745.41 tons on a rolling 12-month basis, including periods of SU/SD. The maximum annual VOC emissions combined for all three turbines are limited to 967.98 tons on a rolling 12-month basis, including periods of SU/SD.
B.16	**Equipment ID:** CT1, CT2, CT3, DB1, DB2, DB3 **Control Device ID:** OXCAT1, OXCAT2, OXCAT3 (S.C. Regulation 61-62.5, Standard No. 7 (BACT Monitoring for CO and VOC)): An initial source test for VOC emissions shall be conducted within 180 days after startup. The source test will be used to show compliance with the VOC limit during normal operations while burning natural gas and while burning fuel oil.
B.17	**Equipment ID:** CT1, CT2, CT3, DB1, DB2, DB3 **Control Device ID:** OXCAT1, OXCAT2, OXCAT3 (S.C. Regulation 61-62.5, Standard No. 7 (BACT Monitoring for CO and VOC)): The owner or operator shall install, operate and maintain a CO continuous emission monitor system (CEMs). The CEMs must be installed, evaluated, and operated according to the "Monitoring Requirements" in 40 CFR 60.13 and applicable provisions of 40 CFR Part 75. The CEMs shall record CO emissions at least every 15 minutes in order to determine 4-hour rolling averages and monthly totals to determine annual CO emissions. To demonstrate the CO CEMs is operating properly, the facility shall develop a CEMs monitoring plan which should include a schedule for periodic monitoring, maintenance, and data substitution. The plan shall be submitted to the Department for review at least 30 days following startup. The CO CEMs shall be used to determine excess emissions. Excess emissions are defined as the applicable compliance period (4-operating-hours), during which the average CO emissions from the CCCTs measured by the CEMS is greater than the applicable maximum allowable CO emissions limit of 3.5 ppmvd at 15% O_2 based on a 4-hour rolling average when burning natural gas and less than or equal to 5 ppmvd at 15% O_2 based on a 4-hour rolling average when burning fuel oil. Excess emissions must be reported semiannually.

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B. LIMITATIONS, MONITORING, AND REPORTING	
Condition Number	**Conditions**
B.18	**Equipment ID:** CT1, CT2, CT3, DB1, DB2, DB3 **Control Device ID:** OXCAT1, OXCAT2, OXCAT3 (S.C. Regulation 61-62.5, Standard No. 7 (BACT Monitoring for CO and VOC)): The owner or operator shall install, operate and maintain temperature indicators at the inlet to each catalyst bed during source operation. Temperature readings shall be recorded at least every 15 minutes and maintained on site. Facilities with automated data collection may collect monitoring data on a more frequent basis and calculate the daily average. Readings collected when the source is shutdown or not operating may not be used in the calculation. The owner or operator must get approval from the Department for an increased frequency/averaging plan prior to using averaging for parametric monitoring. The owner or operator shall continue to record daily calculated monitoring averages using the approved increased frequency/averaging plan unless prior approval is obtained from the Department for changing the plan. Operational ranges for the monitored parameters shall be established to ensure proper operation of the pollution control equipment. These operational ranges for the monitored parameters shall be derived from source test data and vendor certification, which demonstrate the proper operation of the equipment. Prior to the first source test, the facility shall use manufacturer's recommendations for operational ranges. The manufacturer's recommendations must be maintained on site. These ranges and supporting documentation (certification from manufacturer, source test results, 30 days of normal readings, opacity readings, etc.) shall be submitted to the Department when the final test report is due. Operating ranges may be updated following submittal to the Department.
B.19	**Equipment ID:** CT1, CT2, CT3, DB1, DB2, DB3 **Control Device ID:** SCR1, OXCAT1, WIN1, SCR2, OXCAT2, WIN2, SCR3, OXCAT3, WIN3 (S.C. Regulation 61-62.5, Standard No. 7 (BACT Monitoring for CO, VOC and NO_x)): Startup and shutdown events are limited to 2,928.50 hours per rolling 12-month period, pooled across all three (3) of the CCCT power trains. A startup is defined as the duration from combustion turbine ignition until the power train has ramped up to the target operational load. A hot start occurs when the steam turbine has been shut down for less than or equal to 8 hours, a warm start occurs when the steam turbine has been shut down for between 8 and 72 hours, and a cold start occurs when the steam turbine has been shut down for more than 72 hours. Shutdowns are defined as the period between initiation of the combustion turbine shutdown sequence and flame off of the combustion turbine. The owner or operator must record the actual startup/shutdown hours daily to determine the monthly total. The type of startups shall also be included in this report. Reports of the 12-month rolling total for each month in the reporting period shall be submitted semiannually.
B.20	**Equipment ID:** AB1, HT1, HT2, HT3, HT4 (S.C. Regulation 61-62.5, Standard No. 7 (BACT Limits for CO and VOC)): In order to maintain good combustion practices, an operation and maintenance plan shall be developed for each source and

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B. LIMITATIONS, MONITORING, AND REPORTING	
Condition Number	**Conditions**
	maintained on site.
B.21	**Equipment ID:** EGBT01, EGBT02, EGBT03, FPBT01, FPBT02, AST1, AST2 (S.C. Regulation 61-62.5, Standard No. 7 (BACT for VOC)): Each tank shall only use submerged filling techniques when fuel is added. The tanks shall contain equipment designed for submerged filling such as drop tubes. An external visual inspection of the tanks and filling equipment shall be conducted annually. Records of these inspections and any corrective actions shall be maintained on site.
B.22	**Equipment ID:** CT1, CT2, CT3, DB1, DB2, DB3 **Control Device ID:** SCR1, OXCAT1, WIN1, SCR2, OXCAT2, WIN2, SCR3, OXCAT3, WIN3 (S.C. Regulation 61-62.5, Standard No. 7 (BACT Limits for NO_x)): The maximum allowable discharge for NO_x resulting from each of these sources during normal operations is less than or equal to 2 ppmvd at 15% O_2 based on a 24-hour rolling average when burning natural gas. The maximum allowable discharge for NO_x resulting from each of these sources during normal operations less than or equal to 5 ppmvd at 15% O_2 based on a 24-hour rolling average when burning fuel oil. This limit does not include emissions from the duct burners that do not operate when the combustion turbines use fuel oil. (S.C. Regulation 61-62.5, Standard No. 7 (BACT Monitoring for NO_x)): The owner or operator shall operate a NO_x continuous emission monitor (CEMs) on each combustion turbine. The CEMs shall be operated and maintained in accordance with the requirements of 40 CFR 60 Subpart KKKKa and 40 CFR 75. Excess emissions shall be determined according to the requirements of 40 CFR 60 Subpart KKKKa. You must submit reports of excess emissions semiannually.
B.23	**Equipment ID:** CT1, CT2, CT3 **Control Device ID:** SCR1, OXCAT1, WIN1, SCR2, OXCAT2, WIN2, SCR3, OXCAT3, WIN3 (S.C. Regulation 61-62.5, Standard No. 7 (BACT Limits for NO_x During Startups and Shutdowns and Alternate Operating Scenarios Such as Fuel Transfers)): The facility is limited to 2928.5 start-up and shut down hours per rolling 12 month period, with no more than 996 of those hours when firing fuel oil. During periods of turbine tuning and/or operating at less than 70 percent of the base load rating, the facility shall comply with the 96 ppmvd at 15% O2 based on a 4-hour rolling average.

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B. LIMITATIONS, MONITORING, AND REPORTING	
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	The owner or operator shall document the duration of each startup and shutdown event and use CEMs data required by 40 CFR KKKKa to determine the NO_x emissions for each hour in the startup or shutdown sequence. You must submit reports of excess emissions semiannually.
B.24	**Equipment ID:** CT1, CT2, CT3 **Control Device ID:** SCR1, OXCAT1, WIN1, SCR2, OXCAT2, WIN2, SCR3, OXCAT3, WIN3 (S.C. Regulation 61-62.5, Standard No. 7 (BACT monitoring for NO_x and GHG)): Excluding startup and shutdown hours, each combustion turbine is permitted to burn fuel oil no more than 720 hours annually based on a 12 month rolling sum. The owner or operator must record hours of operation using fuel oil monthly and calculate yearly hours on a twelve-month rolling sum. Reports of the calculated values and the twelve-month rolling sum, calculated for each month in the reporting period, shall be submitted semiannually.
B.25	**Equipment ID:** CT1, CT2, CT3, DB1, DB2, DB3 **Control Device ID:** SCR1, OXCAT1, WIN1, SCR2, OXCAT2, WIN2, SCR3, OXCAT3, WIN3 (S.C. Regulation 61-62.5, Standard No. 7 (BACT Limit for GHG (as CO_2)): The CO_2 emissions from each source are limited to: • less than or equal to 2,610,340 tons per 12-month rolling period. • Any applicable New Source Performance Standards for limiting CO_2 emissions as codified at 40 CFR Part 60, including without limitation, as applicable, under Subpart TTTT and/or Subpart TTTTa. The owner or operator shall maintain heat input records and any other records necessary to determine CO_2 emissions. CO_2 emissions shall be calculated on a monthly basis, and a twelve month rolling sum shall be calculated for total CO_2 emissions. Reports of the calculated values and the twelve-month rolling sum, calculated for each month in the reporting period, shall be submitted semiannually. An algorithm, including example calculations and emission factors, explaining the method used to determine emission rates shall only be included in the initial report. Subsequent submittals of the algorithm are required within 30 days of the change if the algorithm or basis for emissions is modified or the Department requests additional information. If GHGs are no longer regulated NSR pollutants as defined in SC R 61-62.5(B)(44), then these two GHG BACT limitations shall no longer apply to the affected equipment at the facility.
B.26	**Equipment ID:** FUGSF6 (S.C. Regulation 61-62.5, Standard No. 7 (BACT for GHG)): The owner or operator shall install operate and maintain density alarms on each circuit breaker that shall notify the operator when a low pressure event has occurred. If a low pressure event occurs, then the owner or operator shall take

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	all appropriate measures to limit emissions. Each alarm shall be in place and operational whenever the circuit breakers are in use. The owner or operator shall record each low pressure event and the corrective action taken. Reports of these occurrences shall be submitted semiannually. If there were no occurrences during the reporting period, then documentation shall be submitted to indicate such.
B.27	**Equipment ID:** FUGNG (S.C. Regulation 61-62.5, Standard No. 7 (BACT for VOC and GHG) The owner or operator shall perform weekly audio/visual/olfactory (AVO) on the natural gas piping components for the purpose of detecting leaks. An AVO leak detection and repair program shall be developed to address any leaks identified by the AVO inspections. The AVO program shall be submitted to the Department for review within 180 days of initial startup. Records of the AVO inspections and any corrective actions shall be maintained on-site.
B.28	**Equipment ID:** COOL1, COOL2, COOL3, COOL4, COOL5, COOL6 **Control Device ID:** DRIFT1, DRIFT2, DRIFT3, DRIFT4, DRIFT5, DRIFT6 (S.C. Regulation 61-62.5, Standard No. 7 (BACT for PM, PM_{10}, $PM_{2.5}$) The owner or operator shall install, operate and maintain high efficiency drift eliminators (HEDES) on each inlet cooling tower. Operation and maintenance checks shall be made on at least a monthly basis. The records of malfunctions, mechanical failures, and any corrective actions shall be documented and kept on-site. Each HEDES shall be in place and operational whenever processes controlled by the HEDES are running, except during periods of HEDES malfunction or mechanical failure.
B.29	**Equipment ID:** DELUGE1, DELUGE2, DELUGE3 **Control Device ID:** DRIFT7, DRIFT8, DRIFT9 (S.C. Regulation 61-62.5, Standard No. 7 (BACT for PM, PM_{10}, $PM_{2.5}$) The owner or operator shall install, operate and maintain drift eliminators on each inlet cooling tower. Operation and maintenance checks shall be made on at least a monthly basis. The records of malfunctions, mechanical failures, and any corrective actions shall be documented and kept on-site. Each drift eliminator shall be in place and operational whenever processes controlled by the drift eliminator are running, except during periods of drift eliminator malfunction or mechanical failure.
B.30	**Equipment ID:** CTG1, CTG2, CTG3, DB1, DB2, DB3 **Control Device ID:** SCR1, OXCAT1, WIN1, SCR2, OXCAT2, WIN2, SCR3, OXCAT3, WIN3 (S.C. Regulation 61-62.60; 40 CFR 60) These sources are subject to New Source Performance Standards (NSPS), Subpart A, General Provisions and Subpart KKKKa, Standards of Performance for Stationary Combustion Turbines, as applicable. These sources shall comply with all applicable requirements of Subparts A (applicable as shown in Table # 3 of KKKKa) and KKKKa.
B.31	**Equipment ID:** CTG1, CTG2, CTG3, DB1, DB2, DB3 **Control Device ID:** SCR1, OXCAT1, WIN1, SCR2, OXCAT2, WIN2, SCR3, OXCAT3, WIN3

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	§ 60.4320a What NO_X emissions standard must I meet? (a) For each stationary combustion turbine you must not discharge into the atmosphere from the affected facility any gases that contain an amount of NO_X that exceeds the applicable emissions standard and be in accordance with the requirements specified in paragraph (b) of this section. If you choose to use NO_X CEMS, input-based emission rates and standards are determined on a 4-operating-hour rolling basis and output-based emission rates and standards are determined on a 30-operating-day rolling basis. Mass-based emission rates are determined on both a 4-operating-hour and 12-calendar-month rolling basis. (b) For the purpose of determining compliance with the applicable emissions standard, you must also meet the requirements specified in paragraphs (b)(1) through (4) of this section, as applicable to your affected facility. (1) The NO_X emission standard that is applicable to your affected facility shall be determined on an operating-hour basis, unless you elect to use the alternative provided for in paragraph (b)(2) of this section. Determining the hourly NO_X emission standards for your affected facility requires recording hourly data and maintaining records according to the requirements in § 60.4390a. For hours with multiple emission standards, the applicable standard for that hour is determined based on the condition, excluding periods of monitor downtime, that corresponds to the highest emissions standard. For example, if your affected facility operates at 70 percent or less of its base load rating for any portion of the hour, the emission limit(s) in table 1 to this subpart for combustion turbines operating at 70 percent or less of base load rating shall apply for that hour. (2) As an alternative to the requirements specified in paragraph (b)(1) of this section, you may elect to use the lowest NO_X emission standard that is applicable to your affected facility, as determined using table 1 to this subpart, for the entire required compliance period. (3) During each operating hour when only natural gas is combusted, you must meet the NO_X emission standard as determined by the applicable size category in table 1 or 2 to this subpart, as applicable, which corresponds to a stationary combustion turbine firing natural gas for that operating hour. During each operating hour when the heat input (based on the HHV of the fuels) of the combustion turbine engine is less than 50 percent natural gas (*i.e.,* 50 percent or greater non-natural gas), as defined in § 60.4420a, at any point during an operating hour, you must meet the NO_X emission standard as determined by the applicable size category in table 1 or 2 to this subpart, as applicable, which corresponds to a stationary combustion turbine firing fuels other than natural gas for that operating hour. During each operating hour when the heat input to the combustion turbine engine is greater than 50 percent natural gas, as defined in § 60.4420a, during an entire operating hour while combusting some portion of non-natural gas fuels, you must meet the NO_X emission standard as determined by prorating the applicable NO_X standards,

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	based on the applicable size category in table 1 or 2 to this subpart, as applicable, by the heat input from each fuel type. (d) You must meet the applicable NO_X emissions standard to your affected facility during all times that the affected facility is operating (including periods of startup, shutdown, and malfunction).
B.32	**Equipment ID:** CTG1, CTG2, CTG3, DB1, DB2, DB3 **Control Device ID:** SCR1, OXCAT1, WIN1, SCR2, OXCAT2, WIN2, SCR3, OXCAT3, WIN3 § 60.4325a What emission limit must I meet for NO_X if my turbine burns both natural gas and distillate oil? You must meet the emission limits specified in table 1 or 2 to this subpart. If your turbine operates below 70 percent of the base load rating at any point during an operating hour, the part load standard is applicable during the entire operating hour. For non-part load operating hours, if your stationary combustion turbine's heat input is greater than or equal to 50 percent fuels other than natural gas at any point during an operating hour, your combustion turbine must meet the corresponding limit for non-natural gas. For non-part load operating hours when your total heat input is greater than 50 percent natural gas while combusting some portion of non-natural gas fuels, you must meet the corresponding emissions standard as determined by prorating the applicable NO_X standards, based on the applicable size category in table 1 or 2 to this subpart, as applicable, by the heat input from each fuel type.
B.33	**Equipment ID:** CTG1, CTG2, CTG3, DB1, DB2, DB3 **Control Device ID:** SCR1, OXCAT1, WIN1, SCR2, OXCAT2, WIN2, SCR3, OXCAT3, WIN3 § 60.4330a What SO_2 emissions standard must I meet? (a) Except as provided for in paragraphs (b) through (e) of this section, for each new, modified, or reconstructed stationary combustion turbine you must not cause to be discharged from the affected facility and into the atmosphere any gases that contain an amount of SO_2 exceeding either: (1) 110 nanograms per Joule (ng/J) (0.90 pounds per megawatt-hour (lb/MWh)) gross energy output; or (2) 26 ng SO_2/J (0.060 lb SO_2/MMBtu) heat input.
B.34	**Equipment ID:** CTG1, CTG2, CTG3, DB1, DB2, DB3 **Control Device ID:** SCR1, OXCAT1, WIN1, SCR2, OXCAT2, WIN2, SCR3, OXCAT3, WIN3 § 60.4333a What are my general requirements for complying with this subpart? (a) You must operate and maintain your stationary combustion turbine, air pollution control equipment, and monitoring equipment in a manner consistent with good air pollution control

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	practices for minimizing emissions at all times, including during startup, shutdown, and malfunction. (b) If you own or operate a stationary combustion turbine subject to a NO_X emissions standard in § 60.4320a, you must conduct an initial performance test according to § 60.8 using the applicable methods in § 60.4400a or § 60.4405a. Thereafter, unless you perform continuous monitoring consistent with § 60.4335a, § 60.4340a, or § 60.4345a, you must conduct subsequent performance tests according to the applicable requirements in paragraphs (b)(1) through (6) of this section. (c) For each stationary combustion turbine subject to a NO_X emissions standard in § 60.4320a, you must demonstrate continuous compliance using a continuous emissions monitoring system (CEMS) for measuring NO_X emissions according to the provisions in § 60.4345a. If your stationary combustion turbine is equipped with a NO_X CEMS, those measurements must be used to determine excess emissions. (d) An owner or operator of a stationary combustion turbine subject to an SO_2 emissions standard in § 60.4330a must demonstrate compliance using one of the methods specified in paragraphs (d)(1) through (4) of this section. (1) Conduct an initial performance test according to § 60.8 and use the applicable methods in § 60.4415a. Thereafter, you must conduct subsequent performance tests within 12 calendar months following the date the previous performance test was conducted. An affected facility that has not operated for the 60 calendar days prior to the due date of a performance test is not required to perform the subsequent performance test until 45 calendar days after the next operating day; (2) Conduct an initial performance test according to § 60.8 and use the applicable methods in § 60.4415a. Thereafter, conduct subsequent fuel sulfur analyses using the applicable methods specified in § 60.4360a and at the frequency specified in § 60.4370a; (3) Conduct an initial performance test according to § 60.8 and use the applicable methods in § 60.4415a. Thereafter, maintain records (such as a current, valid purchase contract, tariff sheet, or transportation contract) documenting that total sulfur content for the initial and subsequent fuel combusted in your stationary combustion turbine at all times does not exceed applicable conditions specified in § 60.4370a; or (4) Conduct an initial performance test according to § 60.8 using the applicable methods in § 60.4415a. Thereafter, continue to monitor SO_2 emissions using a CEMS according to the requirements specified in § 60.4374a. (e) If you elect to comply with an input-based standard (lb/MMBtu or ppm) and your affected facility

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	includes use of one or more heat recovery steam generating units, then you must determine compliance with the applicable NO_X and SO_2 emission standards according to the procedures specified in paragraph (e)(1) or (2) of this section as applicable to the heat recovery steam generating unit configuration used for your affected facility. (1) For a configuration where a single combustion turbine engine is exhausted through the heat recovery steam generating unit, you must measure both the emissions at the exhaust stack for the heat recovery steam generating unit and the fuel flow to the combustion turbine engine and any associated duct burners. (f) If you elect to comply with an output-based standard (lb/MWh) and your affected facility includes use of one or more heat recovery steam generating units, then you must determine compliance with the applicable NO_X and SO_2 emission standards according to the procedures in paragraph (f)(1), (2), or (3) of this section as applicable to the heat recovery steam generating unit configuration used for your affected facility. (1) For a configuration where a single combustion turbine engine is exhausted through the heat recovery steam generating unit, you must measure both the emissions at the exhaust stack for the heat recovery steam generating unit and the total electrical, mechanical energy, and useful thermal output of the stationary combustion turbine (as applicable). (g) If you elect to comply with the mass-based standard, you must demonstrate continuous compliance using either a CEMS for measuring NO_X emissions according to the provisions in § 60.4345a or using the methodology in appendix E to part 75 of this chapter.
B.35	**Equipment ID:** CTG1, CTG2, CTG3, DB1, DB2, DB3 **Control Device ID:** SCR1, OXCAT1, WIN1, SCR2, OXCAT2, WIN2, SCR3, OXCAT3, WIN3 § 60.4345a How do I demonstrate compliance with my NO_X emissions standard using a NO_X CEMS? (a) Each CEMS measuring NO_X emissions used to meet the requirements of this subpart, must meet the requirements in paragraphs (a)(1) through (6) of this section. (1) You must install, certify, maintain, and operate a NO_X monitor to determine the hourly average NO_X emissions in the units of the standard with which you are complying. (2) If you elect to comply with an input-based or mass-based emissions standard, you must install, calibrate, maintain, and operate either a fuel flow meter (or flow meters) or an O_2 or CO_2 CEMS and a stack flow monitor to continuously measure the heat input to the affected facility. (3) If you elect to comply with an output-based emissions standard, you must also install, calibrate, maintain, and operate both a watt meter (or meters) to continuously measure the gross

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	electrical output from the affected facility and either a fuel flow meter (or flow meters) or an O_2 or CO_2 CEMS and a stack flow monitor. If you have a CHP combustion turbine and elect to comply with an output-based emissions standard, you must also install, calibrate, maintain, and operate meters to continuously determine the total useful recovered thermal energy. For steam this includes flow rate, temperature, and pressure. If you have a direct mechanical drive application and elect to comply with the output-based emissions standard you must submit a plan to the Administrator or delegated authority for approval of how energy output will be determined. (4) If you elect to comply with the part-load NO_X emissions standard, you must install, calibrate, maintain, and operate either a fuel flow meter (or flow meters) or an O_2 or CO_2 CEMS and a stack flow monitor to continuously measure the heat input to the affected facility. (5) If you elect to comply with the temperature dependent NO_X emissions standard, you must install, calibrate, maintain, and operate a thermometer to continuously monitor the ambient temperature. (6) If you combust natural gas with fuels other than natural gas and elect to comply with the fuels other than natural gas NO_X emissions standard, you must install, calibrate, maintain, and operate a device to continuously monitor when a fuel other than natural gas fuel is combusted in the combustion turbine engine. (b) Each NO_X CEMS must be installed and certified according to Performance Specification 2 (PS 2) in appendix B to this part. The span value must be 125 percent of the highest applicable standard or highest anticipated hourly NO_X emissions rate. Alternatively, span values determined according to section 2.1.2 in appendix A to part 75 may be used. For stationary combustion turbines that do not use post-combustion technology to reduce emissions of NO_X to comply with the requirements of this subpart, you may use NO_X and diluent CEMS that are installed and certified according to appendix A to part 75 in lieu of Procedure 1 in appendix F to this part and the requirements of § 60.13, except that the relative accuracy test audit (RATA) of the CEMS must be performed on a lb/MMBtu basis. For stationary combustion turbines that use post-combustion technology to reduce emissions of NO_X to comply with the requirements of this subpart, you may use NO_X and diluent CEMS that are installed and certified according to appendix A to part 75 in lieu of Procedure 1 in appendix F to this part and the requirements of § 60.13 with approval from the Administrator or delegated authority, except that the relative accuracy test audit (RATA) of the CEMS must be performed on a lb/MMBtu basis. (c) During each full operating hour, both the NO_X monitor and the diluent monitor must complete a minimum of one cycle of operation (sampling, analyzing, and data recording) for each 15-minute quadrant of the hour. For partial operating hours, at least one data point must be obtained with each monitor for each quadrant of the hour in which the unit operates. For operating hours in which required quality assurance and maintenance activities are performed on the CEMS, a

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	minimum of two data points (one in each of two quadrants) are required for each monitor. (d) Each fuel flow meter must be installed, calibrated, maintained, and operated according to the manufacturer's instructions. Alternatively, fuel flow meters that meet the installation, certification, and quality assurance requirements in appendix D to part 75 of this chapter are acceptable for use under this subpart. (e) Each watt meter, steam flow meter, and each pressure or temperature measurement device must be installed, calibrated, maintained, and operated according to manufacturer's instructions. (f) You must develop, submit to the Administrator or delegated authority for approval, maintain, and adhere to an on-site quality assurance (QA) plan for all of the continuous monitoring equipment you use to comply with this subpart. At a minimum, such a QA plan must address the requirements of § 60.13(d), (e), and (h). For the CEMS and fuel flow meters, the owner or operator of a stationary combustion turbine that does not use post-combustion technology to reduce emissions of NO_X to comply with the requirements of this subpart may, with approval of the Administrator or delegated authority, satisfy the requirements of this paragraph (f) by implementing the QA program and plan described in section 1 in appendix B to part 75 of this chapter in lieu of the requirements in § 60.13(d)(1). (g) At a minimum, non-out-of-control CEMS hourly averages shall be obtained for 90 percent of all operating hours on a 30-operating-day rolling average basis.
B.36	**Equipment ID:** CTG1, CTG2, CTG3, DB1, DB2, DB3 **Control Device ID:** SCR1, OXCAT1, WIN1, SCR2, OXCAT2, WIN2, SCR3, OXCAT3, WIN3 § 60.4350a How do I use the NO_X CEMS data to determine excess emissions? (a) If you demonstrate continuous compliance using a CEMS for measuring NO_X emissions, excess emissions are defined as the applicable compliance period for the stationary combustion turbine (either 4-operating-hours, 30-operating-days, or 12-calendar-month), during which the average NO_X emissions from your affected facility measured by the CEMS is greater than the applicable maximum allowable NO_X emissions standard specified in § 60.4320a as determined using the procedures specified in this section that apply to your stationary combustion turbine. (b) The NO_X CEMS data for each operating hour as measured according to the requirements in § 60.4345a must be used to determine the hourly average NO_X emissions. The hourly average for a given operating hour is the average of all data points for the operating hour. However, for any periods during which the NO_X, diluent, flow, watt, steam pressure, or steam temperature monitors (as applicable) are out-of-control, the data points are not used in determining the hourly average NO_X emissions. All data points that are not collected during out-of-control periods must be used to

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	determine the hourly average NO_X emissions. (c) For each operating hour in which an hourly average is obtained, the data acquisition and handling system must calculate and record the hourly average NO_X emissions in units of lb/MMBtu or lbs, as applicable, using the appropriate equation from EPA Method 19 in appendix A-7 to this part. For any hour in which the hourly average O_2 concentration exceeds 19.0 percent O_2 (or the hourly average CO_2 concentration is less than 1.0 percent CO_2), a diluent cap value of 19.0 percent O_2 or 1.0 percent CO_2 (as applicable) may be used in the emission calculations. (d) Data used to meet the requirements of this subpart shall not include substitute data values derived from the missing data procedures of part 75 of this chapter, nor shall the data be bias adjusted according to the procedures of part 75. For units complying with the 12-calendar-month mass-based standard, emissions for hours of missing data shall be estimated by using the average emissions rate of non-out-of-control hours within ±10 percent of the hour of missing data within the 12-calendar-month period. If non-out-of-control data is not available, the maximum hourly emissions rate during the 12-calendar-month period shall be used. (e) All required fuel flow rate, steam flow rate, temperature, pressure, and megawatt data must be reduced to hourly averages. However, for any periods during which the flow, watt, steam pressure, or steam temperature monitors (as applicable) are out-of-control, the data points are not used in determining the appropriate hourly average value. (f) Calculate the hourly average NO_X emissions rate, in units of the emissions standard under § 60.4320a, using lb/MMBtu or ppm for units complying with the input-based standard, using lbs for units complying with the mass-based standard, or lb/MWh or kg/MWh for units complying with the output-based standard: (1) The gross or net energy output is calculated as the sum of the total electrical and mechanical energy generated by the combustion turbine engine; the additional electrical or mechanical energy (if any) generated by the steam turbine following the heat recovery steam generating unit; the total useful thermal energy output that is not used to generate additional electricity or mechanical output, expressed in equivalent MWh, minus the auxiliary load as calculated using equations 1 and 2 to this paragraph (f)(1): Equation 1 to Paragraph (f)(1) $P = \frac{(Pe)_t}{T} + \frac{(Pe)_c}{T} - Pe_A + P_s + P_o$ (Eq. 1) Where: P = Gross or net energy output of the stationary combustion turbine system in MWh; $(Pe)_t$ = Electrical or mechanical energy output of the combustion turbine engine in MWh;

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	$(Pe)_c$ = Electrical or mechanical energy output (if any) of the steam turbine in MWh; Pe_A = Electric energy used for any auxiliary loads in MWh (only applicable to owners/operators electing to demonstrate compliance on a net output basis); P_s = Useful thermal energy of the steam, measured relative to ISO conditions, not used to generate additional electric or mechanical output, in MWh; P_o = Other useful heat recovery, measured relative to ISO conditions, not used for steam generation or performance enhancement of the stationary combustion turbine; and T = Electric Transmission and Distribution Factor. Equal to 0.95 for CHP combustion turbine where at least 20.0 percent of the total gross useful energy output consists of electric or direct mechanical output and 20.0 percent of the total gross useful energy output consists of useful thermal output on an annual basis. Equal to 1.0 for all other combustion turbines. Equation 2 to Paragraph (f)(1) $P_s = \frac{Q_m \times H}{3.413 \times 10^6\ Btu/MWh}$ (Eq. 2) Where: P_s = Useful thermal energy of the steam, measured relative to ISO conditions, not used to generate additional electric or mechanical output, in MWh; Q_m = Measured steam flow in lb; H = Enthalpy of the steam at measured temperature and pressure relative to ISO conditions, in Btu/lb; and 3.413×10^6 = Conversion factor from Btu to MWh. (2) For mechanical drive applications complying with the output-based standard, use equation 3 to this paragraph (f)(2): Equation 3 to Paragraph (f)(2) $E = \frac{(NO_x)_m}{BL \times AL}$ (Eq. 3) Where: E = NO_X emissions rate in lb/MWh; $(NO_X)_m$ = NO_X emissions rate in lb/h; BL = Manufacturer's base load rating of turbine, in MW; and AL = Actual load as a percentage of the base load rating. (g) For each stationary combustion turbine demonstrating compliance on a heat input-based emissions standard, excess NO_X emissions are determined on a 4-operating-hour averaging period basis using the NO_X CEMS data and procedures specified in paragraphs (g)(1) and (2) of this section

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	as applicable to the NO_X emissions standard in table 1 to this subpart. (1) For each 4-operating-hour period, compute the 4-operating-hour rolling average NO_X emissions as the heat input weighted average of the hourly average of NO_X emissions for a given operating hour and the 3 operating hours preceding that operating hour using the applicable equation in paragraph (g)(2) of this section. Calculate a 4-operating-hour rolling average NO_X emissions rate for any 4-operating-hour period when you have valid CEMS data for at least 3 of those hours (*e.g.,* a valid 4-operating-hour rolling average NO_X emissions rate cannot be calculated if 1 or more continuous monitors was out-of-control for the entire hour for more than 1 hour during the 4-operating-hour period). (2) If you elect to comply with the applicable heat input-based emissions rate standard, calculate both the 4-operating-hour rolling average NO_X emissions rate and the applicable 4-operating-hour rolling average NO_X emissions standard, calculated using hourly values in table 1 to this subpart, using equation 4 to this paragraph (g)(2). Equation 4 to Paragraph (g)(2) $E = \frac{\sum_{i=1}^{4} (E_i \times Q_i)}{\sum_{i=1}^{4} Q_i}$ (Eq. 4) Where: E = 4-operating-hour rolling average NO_X emissions (lb/MMBtu or ng/J); E_i = Hourly average NO_X emissions rate or emissions standard for operating hour “i” (lb/MMBtu or ng/J); and Q_i = Total heat input to stationary combustion turbine for operating hour “i” (MMBtu or J as appropriate). (h) (1) For each combustion turbine demonstrating compliance on an output-based standard, you must determine excess emissions on a 30-operating-day rolling average basis. The measured emissions rate is the NO_X emissions measured by the CEMS for a given operating day and the 29 operating days preceding that day. Once each day, calculate a new 30-operating-day average measured emissions rate using all hourly average values based on non-out-of-control NO_X emission data for all operating hours during the previous 30-operating-day operating period. Report any 30-operating-day periods for which you have less than 90 percent data availability as monitor downtime. If you elect to comply with the applicable output-based emissions rate standard, calculate the measured emissions rate using equation 5 to this paragraph (h)(1) and calculate the applicable emissions standard using equation 6 to this paragraph (h)(1). If you elect

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	to comply with the applicable output-based emissions rate standard and determine the heat input on an hourly basis, calculate the 30-operating-day rolling average NO_X emissions rate using equation 5, and determine the applicable 30-operating-day rolling average NO_X emissions standard, calculated using values in table 1 to this subpart, using equation 6. Hours are not subcategorized by load for the purposes of determining the applicable output-based standard. The emissions standard for all hours, regardless of load, is the otherwise applicable full load emissions standard. Equation 5 to Paragraph (h)(1) $$E = \frac{\sum_{i=1}^{n} (E_i \times Q_i)}{\sum_{i=1}^{n} P_i} \quad \text{(Eq. 5)}$$ Where: E = 30-operating-day average NO_X measured emissions rate combustion turbines (lb/MWh or ng/J); E_i = Hourly average NO_X emissions rate or emissions standard for non-out-of-control operating hour "i" (lb/MMBtu or ng/J); Q_i = Total heat input to stationary combustion turbine for non-out-of-control operating hour "i" (MMBtu or J as appropriate); P_i = Total gross or net energy output from stationary combustion turbine for non-out-of-control operating hour "i" (MWh or J); and n = Total number of operating non-out-of-control hours in the 30-operating-day period. Equation 6 to Paragraph (h)(1) $$E = E_{NG} \times \frac{H_{NG}}{H_T} + E_{non-NG} \times \frac{H_{non-NG}}{H_T} \qquad (Eq. 6)$$ Where: E = 30-operating-day rolling NO_X emissions standard (lb/MWh or kg/MWh); E_{NG} = 30-operating-day emissions standard for natural gas-fired combustion turbines (lb/MWh or kg/MWh); E_{non-NG} = 30-operating-day emissions standard for non-natural gas-fired combustion turbines (lb/MWh or kg/MWh); H_{NG} = Hours of operation combusting natural gas during the 30-operating-day period; H_{non-NG} = Hours of operation combusting non-natural gas fuels during the 30-operating-day period; and H_T = Total hours of operation during the 30-operating-day period. (2) If you elect to comply with the applicable output-based emissions rate standard and elect to not determine the heat input on an hourly basis, the applicable 30-operating-day emissions

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	rolling NO_X standard is the most stringent standard applicable to the combustion turbine. The 30-operating-day rolling NO_X emissions rate is determined as the sum of the hourly emissions divided by the sum of the gross or net output over the 30-operating-day period. (i) For each combustion turbine demonstrating compliance on a mass-based standard, you must determine excess NO_X emissions on both a rolling 4-operating-hour and rolling 12-calendar-month basis using the NO_X CEMS data and procedures specified in paragraphs (i)(1) through (4) of this section as applicable to the NO_X emissions standard in table 2 to this subpart. In addition, during system emergencies each combustion turbine must determine excess NO_X emissions using the procedures specified in paragraph (i)(5) of this section. (1) For each 4-operating-hour period, compute the 4-operating-hour rolling NO_X emissions as the sum of the hourly NO_X emissions for a given operating hour and the 3 operating hours preceding that operating hour. Calculate a 4-operating-hour NO_X emissions rate for any 4-operating-hour period when you have valid CEMS data for at least 3 of those hours (*e.g.*, a valid 4-operating-hour rolling NO_X emissions rate cannot be calculated if 1 or more continuous monitors was out-of-control for the entire hour for more than 1 hour during the 4-operating-hour period). (2) Calculate the applicable 4-operating-hour rolling NO_X emissions standard, calculated using hourly values in table 2 to this subpart, using equation 7 to this paragraph (i)(2). Equation 7 to Paragraph (i)(2) $$E = \sum_{i=1}^{4} (E_i) \text{ (Eq. 7)}$$ Where: E = 4-operating-hour rolling NO_X emissions (kg or lbs); and E_i = Hourly NO_X emissions rate or emissions standard for operating hour "i" (kg or lbs). (3) For each 12-calendar-month period, compute the 12-calendar-month rolling NO_X emissions as the sum of the hourly NO_X emissions for a given month and the 11 calendar months preceding the calendar month. Emissions during system emergencies are not included when calculating the 12-calendar-month emissions rate. (4) Calculate the applicable 12-calendar-month rolling NO_X emissions standard, calculated using hourly values in table 2 to this subpart, using equation 8 to this paragraph (i)(4). Heat input during system emergencies is not included when calculating the 12-calendar-month emissions standard.

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	Equation 8 to Paragraph (i)(4) $E = E_{NG} \times \frac{H_{NG}}{H_T} + E_{Non-NG} \times \frac{H_{non-NG}}{H_T}$ (Eq. 8) Where: E = 12-calendar-month rolling NO_X emissions (tonnes or tons); E_{NG} = 12-calendar-month emissions standard for natural gas-fired combustion turbines (tonnes or tons); $E_{non\text{-}NG}$ = 12-calendar-month emissions standard for non-natural gas-fired combustion turbines (tonnes or tons); H_{NG} = Hours of operation combusting natural gas during the 12-calendar-month period; $H_{non\text{-}NG}$ = Hours of operation combusting non-natural gas fuels during the 12-calendar-month period; and H_T = Total hours of operation during the 12-calendar-month period. (5) During system emergencies during which the owner or operator elects to not include emissions or heat input in the 12-calendar month calculations, the applicable average natural gas-fired emissions standard is 0.83 lb NO_X/MW-rated output (1.8 lb NO_X/MW-rated output when firing non-natural gas) or the current emissions rate necessary to comply with the 12-calendar month natural gas-fired emissions standard of 0.48 tons NO_X/MW-rated output (0.81 tons NO_X/MW-rated output when firing non-natural gas) whichever is more stringent. For example, if a combustion turbine operated for 4,000 hours during the current 12-calendar month period the applicable average natural gas-fired emissions standard during the system emergency would be 0.24 lb NO_X/MW-rated output and the applicable average non-natural gas-fired emissions standard during the system emergency would be 0.41 lb NO_X/MW-rated output.
B.37	**Equipment ID:** CTG1, CTG2, CTG3, DB1, DB2, DB3 **Control Device ID:** SCR1, OXCAT1, WIN1, SCR2, OXCAT2, WIN2, SCR3, OXCAT3, WIN3 § 60.4360a How do I use fuel sulfur analysis to determine the total sulfur content of the fuel combusted in my stationary combustion turbine? (a) If you elect to demonstrate compliance with a SO_2 emissions standard according to § 60.4333a(d)(2), the fuel analyses may be performed either by you, a service contractor retained by you, the fuel vendor, or any other qualified agency as determined by the Administrator or delegated authority using the sampling frequency specified in § 60.4370a. (b) Representative fuel analysis samples may be collected either by an automatic sampling system or manually. For automatic sampling, follow ASTM D5287-97 (Reapproved 2002) (incorporated by reference, see § 60.17) for gaseous fuels or ASTM D4177-95 (Reapproved 2000) (incorporated by reference, see § 60.17) for liquid fuels. For reference purposes when manually collecting gaseous

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	samples, see Gas Processors Association Standard 2166-17 (incorporated by reference, see § 60.17). For reference purposes when manually collecting liquid samples, see either Gas Processors Association Standard 2174-14 or the procedures for manual pipeline sampling in section 14 of ASTM D4057-95 (Reapproved 2000) (both of which are incorporated by reference, see § 60.17). (c) Each collected fuel analysis sample must be analyzed for the total sulfur content of the fuel and heating value using the methods specified in paragraph (c)(1) or (2) of this section, as applicable to the fuel type. (1) For the sulfur content of liquid fuels, ASTM D129-00 (Reapproved 2005), or alternatively D1266-98 (Reapproved 2003), D1552-03, D2622-05, D4294-03, D5453-05, D5623-24, or D7039-24 (all of which are incorporated by reference, see § 60.17). For the heating value of liquid fuels, ASTM D240-19 or D4809-18 (both of which are incorporated by reference, see § 60.17); or (2) For the sulfur content of gaseous fuels, ASTM D1072-90 (Reapproved 1999), or alternatively D3246-05, D4468-85 (Reapproved 2000), D6667-04, or D5504-20 (all of which are incorporated by reference, see § 60.17). If the total sulfur content of the gaseous fuel during the most recent compliance demonstration was less than half the applicable standard, ASTM D4084-05, D4810-88 (Reapproved 1999), D5504-20, or D6228-98 (Reapproved 2003), or Gas Processors Association Standard 2140-17 or 2377-86 (all of which are incorporated by reference, see § 60.17), which measure the major sulfur compounds, may be used. For the heating value of gaseous fuels, ASTM D1826-94 (Reapproved 2003), or alternatively D3588-98 (Reapproved 2003), D4891-89 (Reapproved 2006), or Gas Processors Association Standard 2172-09 (all of which are incorporated by reference, see § 60.17).
B.38	**Equipment ID:** CTG1, CTG2, CTG3, DB1, DB2, DB3 **Control Device ID:** SCR1, OXCAT1, WIN1, SCR2, OXCAT2, WIN2, SCR3, OXCAT3, WIN3 § 60.4370a How frequently must I determine the fuel sulfur content? (a) If you are complying with requirements in § 60.4360a, the total sulfur content of all fuels combusted in each stationary combustion turbine subject to an SO_2 emissions standard in § 60.4330a must be determined according to the schedule specified in paragraph (a)(1) or (2) of this section, as applicable to the fuel type, unless you determine a custom schedule for the stationary combustion turbine according to paragraph (b) of this section. (1) Use one of the total sulfur sampling options and the associated sampling frequency described in sections 2.2.3, 2.2.4.1, 2.2.4.2, and 2.2.4.3 in appendix D to part 75 of this chapter (*i.e.,* flow proportional sampling, daily sampling, sampling from the unit's storage tank after each addition of fuel to the tank or sampling each delivery prior to combining it with liquid fuel already in the intended storage tank).

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	(2) If the fuel is supplied without intermediate bulk storage, the sulfur content value of the gaseous fuel must be determined and recorded once per operating day. (b) As an alternative to the requirements of paragraph (a) of this section, you may implement custom schedules for determination of the total sulfur content of gaseous fuels, based on the design and operation of the affected facility and the characteristics of the fuel supply using the procedures provided in either paragraph (b)(1) or (2) of this section. Either you or the fuel vendor may perform the sampling. As an alternative to using one of these procedures, you may use a custom schedule that has been substantiated with data and approved by the Administrator or delegated authority as a change in monitoring prior to being used to comply with the applicable standard in § 60.4330a. (1) You may determine and implement a custom sulfur sampling schedule for your stationary combustion turbine using the procedure specified in paragraphs (b)(1)(i) through (iv) of this section. (i) Obtain daily total sulfur content measurements for 30 consecutive operating days, using the applicable methods specified in this subpart. Based on the results of the 30 daily samples, the required frequency for subsequent monitoring of the fuel's total sulfur content must be as specified in paragraph (b)(1)(ii), (iii), or (iv) of this section, as applicable. (ii) If none of the 30 daily measurements of the fuel's total sulfur content exceeds half the applicable standard, subsequent sulfur content monitoring may be performed at 12-month intervals provided the fuel source or supplier does not change. If any of the samples taken at 12-month intervals has a total sulfur content greater than half but less than the applicable standard, follow the procedures in paragraph (b)(1)(iii) of this section. If any measurement exceeds the applicable standard, follow the procedures in paragraph (b)(1)(iv) of this section. (iii) If at least one of the 30 daily measurements of the fuel's total sulfur content is greater than half but less than the applicable standard, but none exceeds the applicable standard, then: (A) Collect and analyze a sample every 30 days for 3 months. If any sulfur content measurement exceeds the applicable standard, follow the procedures in paragraph (b)(1)(iv) of this section. Otherwise, follow the procedures in paragraph (b)(1)(iii)(B) of this section. (B) Begin monitoring at 6-month intervals for 12 months. If any sulfur content measurement exceeds the applicable standard, follow the procedures in paragraph (b)(1)(iv) of this section. Otherwise, follow the procedures in paragraph (b)(1)(iii)(C) of this section. (C) Begin monitoring at 12-month intervals. If any sulfur content measurement exceeds the applicable standard, follow the procedures in paragraph (b)(1)(iv) of this section. Otherwise,

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	continue to monitor at this frequency. (iv) If a sulfur content measurement exceeds the applicable standard, immediately begin daily monitoring according to paragraph (b)(1)(i) of this section. Daily monitoring must continue until 30 consecutive daily samples, each having a sulfur content no greater than the applicable standard, are obtained. At that point, the applicable procedures of paragraph (b)(1)(ii) or (iii) of this section must be followed. (2) You may use the data collected from the 720-hour sulfur sampling demonstration described in section 2.3.6 in appendix D to part 75 of this chapter to determine and implement a sulfur sampling schedule for your stationary combustion turbine using the procedure specified in paragraphs (b)(2)(i) through (iii) of this section. (i) If the maximum fuel sulfur content obtained from any of the 720 hourly samples does not exceed half the applicable standard, then the minimum required sampling frequency must be one sample at 12-month intervals. (ii) If any sample result exceeds half the applicable standard, but none exceeds the applicable standard, follow the provisions of paragraph (b)(1)(iii) of this section. (iii) If the sulfur content of any of the 720 hourly samples exceeds the applicable standard, follow the provisions of paragraph (b)(1)(iv) of this section.
B.39	**Equipment ID:** CTG1, CTG2, CTG3, DB1, DB2, DB3 **Control Device ID:** SCR1, OXCAT1, WIN1, SCR2, OXCAT2, WIN2, SCR3, OXCAT3, WIN3 § 60.4375a What reports must I submit? (a) An owner or operator of a stationary combustion turbine that elects to continuously monitor parameters or emissions, or to periodically determine the fuel sulfur content under this subpart, must submit reports of excess emissions and monitor downtime, according to § 60.7(c). Excess emissions must be reported for all periods of unit operation, including startup, shutdown, and malfunction. (b) The notification requirements of § 60.8 apply to the initial and subsequent performance tests. (c) An owner or operator of an affected facility complying with § 60.4333a(b)(3) must notify the Administrator or delegated authority within 15 calendar days after the facility recommences operation. (d) An owner or operator of an affected facility complying with § 60.4333a(b)(4) must notify the Administrator or delegated authority within 15 calendar days after the facility has operated more

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	than 168 operating hours since the date the previous performance test was required to be conducted. (e) Within 60 days after the date of completing each performance test or continuous emissions monitoring systems (CEMS) performance evaluation that includes a relative accuracy test audit (RATA), you must submit the results following the procedures specified in paragraph (g) of this section. You must submit the report in a file format generated using the EPA's Electronic Reporting Tool (ERT). Alternatively, you may submit an electronic file consistent with the extensible markup language (XML) schema listed on the EPA's ERT website (*https://www.epa.gov/electronic-reporting-air-emissions/electronic-reporting-tool-ert*) accompanied by the other information required by § 60.8(f)(2) in PDF format. (f) You must submit to the Administrator semiannual reports of the following recorded information. Beginning on January 15, 2027, or once the report template for this subpart has been available on the Compliance and Emissions Data Reporting Interface (CEDRI) website (*https://www.epa.gov/electronic-reporting-air-emissions/cedri*) for one year, whichever date is later, submit all subsequent reports using the appropriate electronic report template on the CEDRI website for this subpart and following the procedure specified in paragraph (g) of this section. The date report templates become available will be listed on the CEDRI website. Unless the Administrator or delegated State agency or other authority has approved a different schedule for submission of reports, the report must be submitted by the deadline specified in this subpart, regardless of the method in which the report is submitted. (g) If you are required to submit notifications or reports following the procedure specified in this paragraph (g), you must submit notifications or reports to the EPA via the Compliance and Emissions Data Reporting Interface (CEDRI), which can be accessed through the EPA's Central Data Exchange (CDX) (*https://cdx.epa.gov/*). The EPA will make all the information submitted through CEDRI available to the public without further notice to you. Do not use CEDRI to submit information you claim as CBI. Although we do not expect persons to assert a claim of CBI, if you wish to assert a CBI claim for some of the information in the report or notification, you must submit a complete file in the format specified in this subpart, including information claimed to be CBI, to the EPA following the procedures in paragraphs (g)(1) and (2) of this section. Clearly mark the part or all of the information that you claim to be CBI. Information not marked as CBI may be authorized for public release without prior notice. Information marked as CBI will not be disclosed except in accordance with procedures set forth in 40 CFR part 2. All CBI claims must be asserted at the time of submission. Anything submitted using CEDRI cannot later be claimed CBI. Furthermore, under CAA section 114(c), emissions data is not entitled to confidential treatment, and the EPA is required to make emissions data available to the public. Thus, emissions data will not be protected as CBI and will be made publicly available. You must submit the same file submitted to the CBI office with the CBI omitted to the EPA via the EPA's CDX as described earlier in this paragraph (g). (1) The preferred method to receive CBI is for it to be transmitted electronically using email

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	attachments, File Transfer Protocol, or other online file sharing services. Electronic submissions must be transmitted directly to the OAQPS CBI Office at the email address *oaqps_cbi@epa.gov,* and as described above, should include clear CBI markings. ERT files should be flagged to the attention of the Group Leader, Measurement Policy Group; all other files should be flagged to the attention of the Stationary Combustion Turbine Sector Lead. If assistance is needed with submitting large electronic files that exceed the file size limit for email attachments, and if you do not have your own file sharing service, please email *oaqps_cbi@epa.gov* to request a file transfer link. (2) If you cannot transmit the file electronically, you may send CBI information through the postal service to the following address: U.S. EPA, Attn: OAQPS Document Control Officer, Mail Drop: C404-02, 109 T.W. Alexander Drive, P.O. Box 12055, RTP, NC 27711. In addition to the OAQPS Document Control Officer, ERT files should also be sent to the attention of the Group Leader, Measurement Policy Group, and all other files should also be sent to the attention of the Stationary Combustion Turbine Sector Lead. The mailed CBI material should be double wrapped and clearly marked. Any CBI markings should not show through the outer envelope. (h) If you are required to electronically submit a report through CEDRI in the EPA's CDX, you may assert a claim of EPA system outage for failure to timely comply with that reporting requirement. To assert a claim of EPA system outage, you must meet the requirements outlined in paragraphs (h)(1) through (7) of this section. (1) You must have been or will be precluded from accessing CEDRI and submitting a required report within the time prescribed due to an outage of either the EPA's CEDRI or CDX systems. (2) The outage must have occurred within the period of time beginning 5 business days prior to the date that the submission is due. (3) The outage may be planned or unplanned. (4) You must submit notification to the Administrator in writing as soon as possible following the date you first knew, or through due diligence should have known, that the event may cause or has caused a delay in reporting. (5) You must provide to the Administrator a written description identifying: (i) The date(s) and time(s) when CDX or CEDRI was accessed and the system was unavailable; (ii) A rationale for attributing the delay in reporting beyond the regulatory deadline to EPA system outage;

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	(iii) A description of measures taken or to be taken to minimize the delay in reporting; and (iv) The date by which you propose to report, or if you have already met the reporting requirement at the time of the notification, the date you reported. (6) The decision to accept the claim of EPA system outage and allow an extension to the reporting deadline is solely within the discretion of the Administrator. (7) In any circumstance, the report must be submitted electronically as soon as possible after the outage is resolved. (i) If you are required to electronically submit a report through CEDRI in the EPA's CDX, you may assert a claim of *force majeure* for failure to timely comply with that reporting requirement. To assert a claim of *force majeure,* you must meet the requirements outlined in paragraphs (i)(1) through (5) of this section. (1) You may submit a claim if a *force majeure* event is about to occur, occurs, or has occurred or there are lingering effects from such an event within the period of time beginning 5 business days prior to the date the submission is due. For the purposes of this section, a *force majeure* event is defined as an event that will be or has been caused by circumstances beyond the control of the affected facility, its contractors, or any entity controlled by the affected facility that prevents you from complying with the requirement to submit a report electronically within the time period prescribed. Examples of such events are acts of nature (*e.g.,* hurricanes, earthquakes, or floods), acts of war or terrorism, or equipment failure or safety hazard beyond the control of the affected facility (*e.g.,* large scale power outage). (2) You must submit notification to the Administrator in writing as soon as possible following the date you first knew, or through due diligence should have known, that the event may cause or has caused a delay in reporting. (3) You must provide to the Administrator: (i) A written description of the *force majeure* event; (ii) A rationale for attributing the delay in reporting beyond the regulatory deadline to the *force majeure* event; (iii) A description of measures taken or to be taken to minimize the delay in reporting; and (iv) The date by which you propose to report, or if you have already met the reporting

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	requirement at the time of the notification, the date you reported. (4) The decision to accept the claim of *force majeure* and allow an extension to the reporting deadline is solely within the discretion of the Administrator. (5) In any circumstance, the reporting must occur as soon as possible after the *force majeure* event occurs. (j) Any records required to be maintained by this subpart that are submitted electronically via the EPA's CEDRI may be maintained in electronic format. This ability to maintain electronic copies does not affect the requirement for facilities to make records, data, and reports available upon request to a delegated air agency or the EPA as part of an on-site compliance evaluation.
B.40	**Equipment ID:** CTG1, CTG2, CTG3, DB1, DB2, DB3 **Control Device ID:** SCR1, OXCAT1, WIN1, SCR2, OXCAT2, WIN2, SCR3, OXCAT3, WIN3 § 60.4380a How are NO_X excess emissions and monitor downtime reported? (a) For a stationary combustion turbine that uses water or steam to fuel ratio monitoring and is subject to the reporting requirements under § 60.4375a(a), periods of excess emissions and monitor downtime must be reported as specified in paragraphs (a)(1) through (3) of this section. (1) An excess emission that must be reported is any operating hour for which the 4-operating-hour rolling average steam or water to fuel ratio, as measured by the continuous monitoring system, is less than the acceptable steam or water to fuel ratio needed to demonstrate compliance with § 60.4320a, as established during the most recent performance test. Any operating hour during which no water or steam is injected into the turbine when the specific conditions require water or steam injection for NO_X control will also be considered an excess emission. (2) A period of monitor downtime that must be reported is any operating hour in which water or steam is injected into the turbine, but the parametric data needed to determine the steam or water to fuel ratio are unavailable or out-of-control. (3) Each report must include the average steam or water to fuel ratio, average fuel consumption, and the stationary combustion turbine load during each excess emission. (b) For reports required under § 60.4375a(a), periods of excess emissions and monitor downtime for stationary combustion turbines using a CEMS, excess emissions are reported as specified in paragraphs (b)(1) and (2) of this section. (1) An excess emission that must be reported is any unit operating period in which the 4-

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	operating-hour average NO_X emissions rate, 30-operating-day rolling average NO_X emissions rate, 4-hour mass-based emissions rate, or the 12-calendar-month mass-based emissions rate exceeds the applicable emissions standard in § 60.4320a as determined in § 60.4350a. (2) A period of monitor downtime that must be reported is any operating hour in which the data for any of the following parameters that you use to calculate the emission rate, as applicable, used to determine compliance, are either missing or out-of-control: NO_X concentration, CO_2 or O_2 concentration, stack flow rate, heat input rate, steam flow rate, steam temperature, steam pressure, or megawatts. You are only required to monitor parameters used for compliance purposes. (c) For reports required under § 60.4375a(a), periods of excess emissions and monitor downtime for stationary combustion turbines using combustion parameters or parameters that document proper operation of the NO_X emission controls excess emissions and monitor downtime are reported as specified in paragraphs (c)(1) and (2) of this section. (1) Excess emissions that must be reported are each 4-operating-hour rolling average in which any monitored parameter (as averaged over the 4-operating-hour period) does not achieve the target value or is outside the acceptable range defined in the parameter monitoring plan for the unit. (2) Periods of monitor downtime that must be reported are each operating hour in which any of the required parametric data that are used to calculate the emission rate, as applicable, used to determine compliance, are either not recorded or are out-of-control.
B.41	**Equipment ID:** CTG1, CTG2, CTG3, DB1, DB2, DB3 **Control Device ID:** SCR1, OXCAT1, WIN1, SCR2, OXCAT2, WIN2, SCR3, OXCAT3, WIN3 § 60.4385a How are SO_2 excess emissions and monitor downtime reported? (a) If you choose the option to monitor the sulfur content of the fuel, excess emissions and monitor downtime are defined as follows: (1) For samples obtained using daily sampling, flow proportional sampling, or sampling from the unit's storage tank, excess emissions occur each operating hour included in the period beginning on the date and hour of any sample for which the sulfur content of the fuel being fired in the stationary combustion turbine exceeds the applicable standard and ending on the date and hour that a subsequent sample is taken that demonstrates compliance with the sulfur standard. (2) If the option to sample each delivery of fuel oil has been selected, you must immediately switch to one of the other oil sampling options (*i.e.,* daily sampling, flow proportional sampling, or sampling from the unit's storage tank) if the sulfur content of a delivery exceeds 0.05 weight

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<tr><th colspan="2">B. LIMITATIONS, MONITORING, AND REPORTING</th></tr>
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<tr><td></td><td>percent, 0.15 weight percent, or 0.40 weight percent as applicable. You must continue to use one of the other sampling options until all of the oil from the delivery has been combusted, and you must evaluate excess emissions according to paragraph (a) of this section. When all of the fuel from the delivery has been combusted, you may resume using the as-delivered sampling option.

(3) A period of monitor downtime begins when a required sample is not taken by its due date. A period of monitor downtime also begins on the date and hour of a required sample, if invalid results are obtained. The period of monitor downtime ends on the date and hour of the next valid sample.

(b) If you choose the option to maintain records of the fuel sulfur content, excess emissions are defined as any period during which you combust a fuel that you do not have appropriate fuel records or that fuel contains sulfur greater than the applicable standard.</td></tr>
<tr><td>B.42</td><td>Equipment ID: CTG1, CTG2, CTG3, DB1, DB2, DB3
Control Device ID: SCR1, OXCAT1, WIN1, SCR2, OXCAT2, WIN2, SCR3, OXCAT3, WIN3

§ 60.4390a What records must I maintain?

(a) You must maintain records of your information used to demonstrate compliance with this subpart as specified in § 60.7.

(b) An owner or operator of a stationary combustion turbine that uses the other fuels, part-load, or low temperature NO_X standards in the compliance demonstration must maintain concurrent records of the hourly heat input, percent load, ambient temperature, and emissions data as applicable.

(c) An owner or operator of a stationary combustion turbine that uses the tuning NO_X standard in the compliance demonstration must identify the hours on which the maintenance was performed and a description of the maintenance.

(d) An owner or operator of a stationary combustion turbine that demonstrates compliance using the output-based standard must maintain concurrent records of the total gross or net energy output and emissions data.

(e) An owner or operator of a stationary combustion turbine that demonstrates compliance using the water or steam to fuel ratio or a parameter continuous monitoring system must maintain continuous records of the appropriate parameters.

(f) An owner or operator of a stationary combustion turbine complying with the fuel-based SO_2 standard must maintain records of the results of all fuel analyses or a current, valid purchase contract, tariff sheet, or transportation contract.</td></tr>
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<tr><th colspan="2">B. LIMITATIONS, MONITORING, AND REPORTING</th></tr>
<tr><th>Condition Number</th><th>Conditions</th></tr>
<tr><td>B.43</td><td>Equipment ID: CTG1, CTG2, CTG3, DB1, DB2, DB3
Control Device ID: SCR1, OXCAT1, WIN1, SCR2, OXCAT2, WIN2, SCR3, OXCAT3, WIN3

§ 60.4395a When must I submit my reports?

Consistent with § 60.7(c), all reports required under § 60.7(c) must be electronically submitted via CEDRI by the 30th day following the end of each 6-month period.</td></tr>
<tr><td>B.44</td><td>Equipment ID: CTG1, CTG2, CTG3, DB1, DB2, DB3
Control Device ID: SCR1, OXCAT1, WIN1, SCR2, OXCAT2, WIN2, SCR3, OXCAT3, WIN3

§ 60.4405a How do I conduct a performance test if I use a NO_X CEMS?

(a) If you use a CEMS the performance test must be performed according to the procedures specified in paragraph (b) of this section.

(b) The initial performance test must use the procedure specified in paragraphs (b)(1) through (4) of this section.

(1) Perform a minimum of nine RATA reference method runs, with a minimum time per run of 21 minutes, at a single load level, within ±30 percent of 100 percent of the base load rating while the source is combusting the fuel that is a normal primary fuel for that source. You may perform testing at the highest achievable load point, if at least 70 percent of the base load rating cannot be achieved in practice. The ambient temperature must be greater than 0 °F during the RATA runs. The Administrator or delegated authority may approve performance testing below 0 °F if the timing of the required performance test and environmental conditions make it impractical to test at ambient conditions greater than 0 °F.

(2) For each RATA run, concurrently measure the heat input to the unit using a fuel flow meter (or flow meters) or the methodologies in appendix F to part 75 of this chapter, and for units complying with the output-based standard, measure the electrical and thermal output from the unit.

(3) Use the test data both to demonstrate compliance with the applicable NO_X emissions standard under § 60.4320a and to provide the required reference method data for the RATA of the CEMS described under § 60.4342a.

(4) Compliance with the applicable emissions standard in § 60.4320a is achieved if the sum of the NO_X emissions divided by the heat input (or gross or net energy output) for all the RATA runs, expressed in units of lb/MMBtu, ppm, lb/MWh, or kgs, does not exceed the emissions standard.</td></tr>
<tr><td>B.45</td><td>Equipment ID: CTG1, CTG2, CTG3, DB1, DB2, DB3
Control Device ID: SCR1, OXCAT1, WIN1, SCR2, OXCAT2, WIN2, SCR3, OXCAT3, WIN3</td></tr>
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§ 60.4415a How do I conduct performance tests to demonstrate compliance with my SO_2 emissions standard?

(a) If you are an owner or operator of an affected facility complying with the fuel-based standard must submit fuel records (such as a current, valid purchase contract, tariff sheet, transportation contract, or results of a fuel analysis) to satisfy the requirements of § 60.8.

(b) If you are an owner or operator of an affected facility complying with the SO_2 emissions standard must conduct the performance test by measuring the SO_2 emissions in the stationary combustion turbine exhaust gases using the methods in either paragraph (b)(1) or (2) of this section.

(1) Measure the SO_2 concentration using EPA Method 6, 6C, or 8 in appendix A-4 to this part or EPA Method 20 in appendix A-7 to this part. For units complying with the output-based standard, concurrently measure the stack gas flow rate, using EPA Methods 1 and 2 in appendix A-1 to this part, and measure and record the electrical and thermal output from the unit. Then use equation 1 to this paragraph (b)(1) to calculate the SO_2 emissions rate:

Equation 1 to Paragraph (b)(1)

$$E = \frac{1.664 \times 10^{-7} \times (SO_2)_c \times Q_{std}}{P} \quad \text{(Eq. 1)}$$

Where:
E = SO_2 emissions rate, in lb/MWh;
1.664×10^{-7} = Conversion constant, in lb/dscf-ppm;
$(SO_2)_c$ = Average SO_2 concentration for the run, in ppm;
Q_{std} = Average stack gas volumetric flow rate, in dscf/h; and

P = Average gross electrical and mechanical energy output of the stationary combustion turbine, in MW (for simple cycle operation), for combined cycle operation, the sum of all electrical and mechanical output from the combustion and steam turbines, or, for CHP operation, the sum of all electrical and mechanical output from the combustion and steam turbines plus all useful recovered thermal output not used for additional electric or mechanical generation or to enhance the performance of the stationary combustion turbine, in MW, calculated according to § 60.4350a(f)(2).

(2) Measure the SO_2 and diluent gas concentrations, using either EPA Method 6, 6C, or 8 in appendix A-4 to this part and EPA Method 3A in appendix A-2 to this part, or EPA Method 20 in appendix A-7 to this part. Concurrently measure the heat input to the unit, using a fuel flowmeter (or flowmeters), an O_2 or CO_2 CEMS along with a stack flow monitor, or the methodologies in appendix F to part 75 of this chapter, and for units complying with the output based standard

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<table>
<tr><th colspan="2">B. LIMITATIONS, MONITORING, AND REPORTING</th></tr>
<tr><th>Condition Number</th><th>Conditions</th></tr>
<tr><td></td><td>measure the electrical and thermal output of the unit. Use EPA Method 19 in appendix A-7 to this part to calculate the SO_2 emissions rate in lb/MMBtu. Then, use equations 1 and, if necessary, 2, 3, and 4 in § 60.4374a to calculate the SO_2 emissions rate in lb/MWh.</td></tr>
<tr><td>B.46</td><td>Equipment ID: CTG1, CTG2, CTG3, DB1, DB2, DB3
Control Device ID: SCR1, OXCAT1, WIN1, SCR2, OXCAT2, WIN2, SCR3, OXCAT3, WIN3

(S.C. Regulation 61-62.60; 40 CFR 60) These sources are subject to New Source Performance Standards (NSPS), Subpart A, General Provisions and Subpart TTTTa, Standards of Performance for Greenhouse Gas Emissions for Modified Coal-Fired Steam Electric Generating Units and New Construction and Reconstruction Stationary Combustion Turbine Electric Generating Units, as applicable. These sources shall comply with all applicable requirements of Subparts A (applicable as shown in Table # 3 of TTTTa) and TTTTa.</td></tr>
<tr><td>B.47</td><td>Equipment ID: CTG1, CTG2, CTG3, DB1, DB2, DB3
Control Device ID: SCR1, OXCAT1, WIN1, SCR2, OXCAT2, WIN2, SCR3, OXCAT3, WIN3

§ 60.5520a What CO_2 emissions standard must I meet?

(a) For each affected EGU subject to this subpart, you must not discharge from the affected EGU any gases that contain CO_2 in excess of the applicable CO_2 emission standard specified in table 1 to this subpart, consistent with paragraphs (b), (c), and (d) of this section, as applicable.

Table 1 to Subpart TTTTa of Part 60—CO2 Emission Standards for Affected Stationary Combustion Turbines That Commenced Construction or Reconstruction After May 23, 2023 (Gross or Net Energy Output-Based Standards Applicable as Approved by the Administrator)

[Note: Numerical values of 1,000 or greater have a minimum of 3 significant figures and numerical values of less than 1,000 have a minimum of 2 significant figures]

<table>
<tr><th>Affected EGU category</th><th>CO_2 emission standard</th></tr>
<tr><td>Base load combustion turbines</td><td>For 12-operating month averages beginning before January 2032, 360 to 560 kg CO_2/MWh (800 to 1,250 lb CO_2/MWh) of gross energy output; or 370 to 570 kg CO_2/MWh (820 to 1,280 lb CO_2/MWh) of net energy output as determined by the procedures in § 60.5525a.

For 12-operating month averages beginning after December 2031, 43 to 67 kg CO_2/MWh (100 to 150 lb CO_2/MWh) of gross energy output; or 42 to 64 kg CO_2/MWh (97 to 139 lb CO_2/MWh) of net energy output as determined by the procedures in § 60.5525a.</td></tr>
</table>
</td></tr>
</table>

<table>
<tr><th colspan="2">B. LIMITATIONS, MONITORING, AND REPORTING</th></tr>
<tr><th>Condition Number</th><th>Conditions</th></tr>
<tr><td></td><td>
<table>
<tr><td>Intermediate load combustion turbines</td><td>530 to 710 kg CO_2/MWh (1,170 to 1,560 lb CO_2/MWh) of gross energy output; or 540 to 700 kg CO_2/MWh (1,190 to 1,590 lb CO_2/MWh) of net energy output as determined by the procedures in § 60.5525a.</td></tr>
<tr><td>Low load combustion turbines</td><td>Between 50 to 69 kg CO_2/GJ (120 to 160 lb CO_2/MMBtu) of heat input as determined by the procedures in § 60.5525a.</td></tr>
</table>

(b) Except as specified in paragraphs (c) and (d) of this section, you must comply with the applicable gross or net energy output standard, and your operating permit must include monitoring, recordkeeping, and reporting methodologies based on the applicable gross or net energy output standard. For the remainder of this subpart (for sources that do not qualify under paragraphs (c) and (d) of this section), where the term “gross or net energy output” is used, the term that applies to you is “gross energy output.”

(d) Owners or operators of a stationary combustion turbine that maintain records of electric sales to demonstrate that the stationary combustion turbine is subject to a heat input-based standard in table 1 to this subpart that are only permitted to burn one or more uniform fuels, as described in paragraph (d)(1) of this section, are only subject to the monitoring requirements in paragraph (d)(1). Owners or operators of all other stationary combustion turbines that maintain records of electric sales to demonstrate that the stationary combustion turbines are subject to a heat input-based standard in table 1 are only subject to the requirements in paragraph (d)(2) of this section.

(1) Owners or operators of stationary combustion turbines that are only permitted to burn fuels with a consistent chemical composition (*i.e.,* uniform fuels) that result in a consistent emission rate of 69 kilograms per gigajoule (kg/GJ) (160 lb CO_2/MMBtu) or less are not subject to any monitoring or reporting requirements under this subpart. These fuels include, but are not limited to hydrogen, natural gas, methane, butane, butylene, ethane, ethylene, propane, naphtha, propylene, jet fuel, kerosene, No. 1 fuel oil, No. 2 fuel oil, and biodiesel. Stationary combustion turbines qualifying under this paragraph are only required to maintain purchase records for permitted fuels.
</td></tr>
<tr><td>B.48</td><td>
Equipment ID: CTG1, CTG2, CTG3, DB1, DB2, DB3
Control Device ID: SCR1, OXCAT1, WIN1, SCR2, OXCAT2, WIN2, SCR3, OXCAT3, WIN3

§ 60.5525a What are my general requirements for complying with this subpart?

Combustion turbines qualifying under § 60.5520a(d)(1) are not subject to any requirements in this section other than the requirement to maintain fuel purchase records for permitted fuel(s). For all other affected sources, compliance with the applicable CO_2 emission standard of this subpart shall be determined on a 12-operating-month rolling average basis. See table 1 to this subpart for the applicable CO_2 emission standards.
</td></tr>
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	(a) You must be in compliance with the emission standards in this subpart that apply to your affected EGU at all times. However, you must determine compliance with the emission standards only at the end of the applicable operating month, as provided in paragraph (a)(1) of this section. (1) For each affected EGU subject to a CO_2 emissions standard based on a 12-operating-month rolling average, you must determine compliance monthly by calculating the average CO_2 emissions rate for the affected EGU at the end of the initial and each subsequent 12-operating-month period. (2) Consistent with § 60.5520a(d)(2), if your affected stationary combustion turbine is subject to an input-based CO_2 emissions standard, you must determine the total heat input in GJ or MMBtu from natural gas (HTIPng) and the total heat input from all other fuels combined (HTIPo) using one of the methods under § 60.5535a(d)(2). You must then use the following equation to determine the applicable emissions standard during the compliance period: Equation 1 to Paragraph (a)(2) $CO_2\ emissions\ standard = \frac{(50 \text{ x } HTIP_{ng}) + (69 \text{ x } HTIP_O)}{HTIP_{ng} + HTIP_O}$ Where: CO_2 emission standard = the emission standard during the compliance period in units of kg/GJ (or lb/MMBtu). $HTIP_{ng}$ = the heat input in GJ (or MMBtu) from natural gas. $HTIP_o$ = the heat input in GJ (or MMBtu) from all fuels other than natural gas. 50 = allowable emission rate in lb kg/GJ for heat input derived from natural gas (use 120 if electing to demonstrate compliance using lb CO_2/MMBtu). 69 = allowable emission rate in lb kg/GJ for heat input derived from all fuels other than natural gas (use 160 if electing to demonstrate compliance using lb CO_2/MMBtu). (3) Owners/operators of a base load combustion turbine with a base load rating of less than 2,110 GJ/h (2,000 MMBtu/h) and/or an intermediate or base load combustion turbine burning fuels other than natural gas may elect to determine a site-specific emissions rate using one of the following equations. Combustion turbines co-firing hydrogen are not required to use the fuel adjustment parameter. (i) For base load combustion turbines: Equation 2 to Paragraph (a)(3)(i)

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	$CO_2\ emissions\ standard\ = \left[BLER_L + \frac{BLER_S - BLER_L}{\mathrm{BLR}_L - \mathrm{BLR}_S} * (\mathrm{BLR}_L - BLR_A)\right] * [\frac{HIER_A}{HIER_{NG}}]$ Where: CO_2 emission standard = the emission standard during the compliance period in units of kg/MWh (or lb/MWh) $BLER_L$ = Base load emissions standard for natural gas-fired combustion turbines with base load ratings greater than 2,110 GJ/h (2,000 MMBtu/h). 360 kg CO_2/MWh-gross (800 lb CO_2/MWh-gross) or 370 kg CO_2/MWh-net (820 lb CO_2/MWh-net); 43 kg CO_2/MWh-gross (100 lb CO_2/MWh-gross) or 42 kg CO_2/MWh-net (97 lb CO_2/MWh-net); as applicable $BLER_S$ = Base load emissions standard for natural gas-fired combustion turbines with a base load rating of 260 GJ/h (250 MMBtu/h). 410 kg CO_2/MWh-gross (900 lb CO_2/MWh-gross) or 420 kg CO_2/MWh-net (920 lb CO_2/MWh-net); 49 kg CO_2/MWh-gross (108 lb CO_2/MWh-gross) or 50 kg CO_2/MWh-net (110 lb CO_2/MWh-net); as applicable BLR_L = Minimum base load rating of large combustion turbines 2,110 GJ/h (2,000 MMBtu/h) BLR_S = Base load rating of smallest combustion turbine 260 GJ/h (250 MMBtu/h) BLR_A = Base load rating of the actual combustion turbine in GJ/h (or MMBtu/h) $HIER_A$ = Heat input-based emissions rate of the actual fuel burned in the combustion turbine (lb CO_2/MMBtu). Not to exceed 69 kg/GJ (160 lb CO_2/MMBtu) $HIER_{NG}$ = Heat input-based emissions rate of natural gas 50 kg/GJ (120 lb CO_2/MMBtu) (ii) For intermediate load combustion turbines: Equation 3 to Paragraph (a)(3)(ii) $CO_2\ emissions\ standard\ = \mathrm{ILER} * [\frac{HIER_A}{HIER_{NG}}]$ Where: CO_2 emission standard = the emission standard during the compliance period in units of kg/MWh (or lb/MWh) ILER = Intermediate load emissions rate for natural gas-fired combustion turbines. 520 kg/MWh-gross (1,150 lb CO_2/MWh-gross) or 530 kg CO_2/MWh-net (1,160 lb CO_2/MWh-net) or 450 kg/MWh-gross (1,100 lb CO_2/MWh-gross) or 460 kg CO_2/MWh-net (1,110 lb CO_2/MWh-net) as applicable $HIER_A$ = Heat input-based emissions rate of the actual fuel burned in the combustion turbine (lb CO_2/MMBtu). Not to exceed 69 kg/GJ (160 lb CO_2/MMBtu) (b) At all times you must operate and maintain each affected EGU, including associated equipment and monitors, in a manner consistent with safety and good air pollution control practice. The Administrator will determine if you are using consistent operation and maintenance procedures based on information available to the Administrator that may include, but is not limited to, fuel use records, monitoring results, review of operation and maintenance procedures and records, review

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	of reports required by this subpart, and inspection of the EGU. (c) Within 30 days after the end of the initial compliance period (*i.e.,* no more than 30 days after the first 12-operating-month compliance period), you must make an initial compliance determination for your affected EGU(s) with respect to the applicable emissions standard in table 1 to this subpart, in accordance with the requirements in this subpart. The first operating month included in the initial 12-operating-month compliance period shall be determined as follows: (1) For an affected EGU that commences commercial operation (as defined in 40 CFR 72.2), the first month of the initial compliance period shall be the first operating month (as defined in § 60.5580a) after the calendar month in which emissions reporting is required to begin under: (i) Section 60.5555a(c)(3)(i), for units subject to the Acid Rain Program; or (ii) Section 60.5555a(c)(3)(ii), for units that are not in the Acid Rain Program. (2) For a modified or reconstructed EGU that becomes subject to this subpart, the first month of the initial compliance period shall be the first operating month (as defined in § 60.5580a) after the calendar month in which emissions reporting is required to begin under § 60.5555a(c)(3)(iii). (3) Emissions of CO_2 emitted by your affected facility and the output of the affected facility generated when it operated during a system emergency as defined in § 60.5580a are excluded for both applicability and compliance with the relevant standards of performance if you can sufficiently provide the documentation listed in § 60.5560a(i). The relevant standard of performance for affected EGUs that operate during a system emergency depends on the subcategory, as described in paragraphs (c)(3)(i) and (ii) of this section. (i) For intermediate and base load combustion turbines that operate during a system emergency, you comply with the standard for low load combustion turbines specified in table 1 to this subpart. (ii) For modified steam generating units, you must not discharge from the affected EGU any gases that contain CO_2 in excess of 230 lb CO_2/MMBtu.
B.49	**Equipment ID:** CTG1, CTG2, CTG3, DB1, DB2, DB3 **Control Device ID:** SCR1, OXCAT1, WIN1, SCR2, OXCAT2, WIN2, SCR3, OXCAT3, WIN3 § 60.5535a How do I monitor and collect data to demonstrate compliance? (a) Combustion turbines qualifying under § 60.5520a(d)(1) are not subject to any requirements in this section other than the requirement to maintain fuel purchase records for permitted fuel(s). If your combustion turbine uses non-uniform fuels as specified under § 60.5520a(d)(2), you must

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	monitor heat input in accordance with paragraph (c)(1) of this section, and you must monitor CO_2 emissions in accordance with either paragraph (b), (c)(2), or (c)(5) of this section. For all other affected sources, you must prepare a monitoring plan to quantify the hourly CO_2 mass emission rate (tons/h), in accordance with the applicable provisions in 40 CFR 75.53(g) and (h). The electronic portion of the monitoring plan must be submitted using the ECMPS Client Tool and must be in place prior to reporting emissions data and/or the results of monitoring system certification tests under this subpart. The monitoring plan must be updated as necessary. Monitoring plan submittals must be made by the Designated Representative (DR), the Alternate DR, or a delegated agent of the DR (see § 60.5555a(d) and (e)). (b) You must determine the hourly CO_2 mass emissions in kg from your affected EGU(s) according to paragraphs (b)(1) through (5) of this section, or, if applicable, as provided in paragraph (c) of this section. (2) For each continuous monitoring system that you use to determine the CO_2 mass emissions, you must meet the applicable certification and quality assurance procedures in 40 CFR 75.20 and appendices A and B to 40 CFR part 75. (3) You must use only unadjusted exhaust gas volumetric flow rates to determine the hourly CO_2 mass emissions rate from the affected EGU; you must not apply the bias adjustment factors described in Section 7.6.5 of appendix A to 40 CFR part 75 to the exhaust gas flow rate data. (4) You must select an appropriate reference method to setup (characterize) the flow monitor and to perform the on-going RATAs, in accordance with 40 CFR part 75. If you use a Type-S pitot tube or a pitot tube assembly for the flow RATAs, you must calibrate the pitot tube or pitot tube assembly; you may not use the 0.84 default Type-S pitot tube coefficient specified in Method 2. (5) Calculate the hourly CO_2 mass emissions (kg) as described in paragraphs (b)(5)(i) through (iv) of this section. Perform this calculation only for “valid operating hours”, as defined in § 60.5540(a)(1). (i) Begin with the hourly CO_2 mass emission rate (tons/h), obtained either from Equation F-11 in appendix F to 40 CFR part 75 (if CO_2 concentration is measured on a wet basis), or by following the procedure in section 4.2 of appendix F to 40 CFR part 75 (if CO_2 concentration is measured on a dry basis). (ii) Next, multiply each hourly CO_2 mass emission rate by the EGU or stack operating time in hours (as defined in 40 CFR 72.2), to convert it to tons of CO_2. (iii) Finally, multiply the result from paragraph (b)(5)(ii) of this section by 907.2 to convert it from

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	tons of CO_2 to kg. Round off to the nearest kg. (iv) The hourly CO_2 tons/h values and EGU (or stack) operating times used to calculate CO_2 mass emissions are required to be recorded under 40 CFR 75.57(e) and must be reported electronically under 40 CFR 75.64(a)(6). You must use these data to calculate the hourly CO_2 mass emissions. (c) If your affected EGU exclusively combusts liquid fuel and/or gaseous fuel, as an alternative to complying with paragraph (b) of this section, you may determine the hourly CO_2 mass emissions according to paragraphs (c)(1) through (4) of this section. If you use non-uniform fuels as specified in § 60.5520a(d)(2), you may determine CO_2 mass emissions during the compliance period according to paragraph (c)(5) of this section. (1) If you are subject to an output-based standard and you do not install CEMS in accordance with paragraph (b) of this section, you must implement the applicable procedures in appendix D to 40 CFR part 75 to determine hourly EGU heat input rates (MMBtu/h), based on hourly measurements of fuel flow rate and periodic determinations of the gross calorific value (GCV) of each fuel combusted. (2) For each measured hourly heat input rate, use Equation G-4 in appendix G to 40 CFR part 75 to calculate the hourly CO_2 mass emission rate (tons/h). You may determine site-specific carbon-based F-factors (Fc) using Equation F-7b in section 3.3.6 of appendix F to 40 CFR part 75, and you may use these Fc values in the emissions calculations instead of using the default Fc values in the Equation G-4 nomenclature. (3) For each “valid operating hour” (as defined in § 60.5540(a)(1), multiply the hourly tons/h CO_2 mass emission rate from paragraph (c)(2) of this section by the EGU or stack operating time in hours (as defined in 40 CFR 72.2), to convert it to tons of CO_2. Then, multiply the result by 907.2 to convert from tons of CO_2 to kg. Round off to the nearest two significant figures. (4) The hourly CO_2 tons/h values and EGU (or stack) operating times used to calculate CO_2 mass emissions are required to be recorded under 40 CFR 75.57(e) and must be reported electronically under 40 CFR 75.64(a)(6). You must use these data to calculate the hourly CO_2 mass emissions. (5) If you operate a combustion turbine firing non-uniform fuels, as an alternative to following paragraphs (c)(1) through (4) of this section, you may determine CO_2 emissions during the compliance period using one of the following methods: (i) Units firing fuel gas may determine the heat input during the compliance period following the procedure under § 60.107a(d) and convert this heat input to CO_2 emissions using Equation

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	G-4 in appendix G to 40 CFR part 75. (ii) You may use the procedure for determining CO_2 emissions during the compliance period based on the use of the Tier 3 methodology under 40 CFR 98.33(a)(3). (d) Consistent with § 60.5520a, you must determine the basis of the emissions standard that applies to your affected source in accordance with either paragraph (d)(1) or (2) of this section, as applicable: (1) If you operate a source subject to an emissions standard established on an output basis (*e.g.,* lb CO_2 per gross or net MWh of energy output), you must install, calibrate, maintain, and operate a sufficient number of watt meters to continuously measure and record the hourly gross electric output or net electric output, as applicable, from the affected EGU(s). These measurements must be performed using 0.2 class electricity metering instrumentation and calibration procedures as specified under ANSI No. C12.20-2010 (incorporated by reference, see § 60.17). For a combined heat and power (CHP) EGU, as defined in § 60.5580a, you must also install, calibrate, maintain, and operate meters to continuously (*i.e.,* hour-by-hour) determine and record the total useful thermal output. For process steam applications, you will need to install, calibrate, maintain, and operate meters to continuously determine and record the hourly steam flow rate, temperature, and pressure. Your plan shall ensure that you install, calibrate, maintain, and operate meters to record each component of the determination, hour-by-hour. (2) If you operate a source subject to an emissions standard established on a heat-input basis (*e.g.,* lb CO_2/MMBtu) and your affected source uses non-uniform heating value fuels as delineated under § 60.5520a(d), you must determine the total heat input for each fuel fired during the compliance period in accordance with one of the following procedures: (i) Appendix D to 40 CFR part 75; (ii) The procedures for monitoring heat input under § 60.107a(d); (iii) If you monitor CO_2 emissions in accordance with the Tier 3 methodology under 40 CFR 98.33(a)(3), you may convert your CO_2 emissions to heat input using the appropriate emission factor in table C-1 of 40 CFR part 98. If your fuel is not listed in table C-1, you must determine a fuel-specific carbon-based F-factor (Fc) in accordance with section 12.3.2 of EPA Method 19 of appendix A-7 to this part, and you must convert your CO_2 emissions to heat input using Equation G-4 in appendix G to 40 CFR part 75. (e) Consistent with § 60.5520a, if two or more affected EGUs serve a common electric generator, you must apportion the combined hourly gross or net energy output to the individual affected EGUs according to the fraction of the total steam load and/or direct mechanical energy contributed by

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	each EGU to the electric generator. Alternatively, if the EGUs are identical, you may apportion the combined hourly gross or net electrical load to the individual EGUs according to the fraction of the total heat input contributed by each EGU. You may also elect to develop, demonstrate, and provide information satisfactory to the Administrator on alternate methods to apportion the gross or net energy output. The Administrator may approve such alternate methods for apportioning the gross or net energy output whenever the demonstration ensures accurate estimation of emissions regulated under this part. (f) In accordance with §§ 60.13(g) and 60.5520a, if two or more affected EGUs that implement the continuous emission monitoring provisions in paragraph (b) of this section share a common exhaust gas stack you must monitor hourly CO_2 mass emissions in accordance with one of the following procedures: (1) If the EGUs are subject to the same emissions standard in table 1 to this subpart, you may monitor the hourly CO_2 mass emissions at the common stack in lieu of monitoring each EGU separately. If you choose this option, the hourly gross or net energy output (electric, thermal, and/or mechanical, as applicable) must be the sum of the hourly loads for the individual affected EGUs and you must express the operating time as "stack operating hours" (as defined in 40 CFR 72.2). If you attain compliance with the applicable emissions standard in § 60.5520a at the common stack, each affected EGU sharing the stack is in compliance; or (2) As an alternative to the requirements in paragraph (f)(1) of this section, or if the EGUs are subject to different emission standards in table 1 to this subpart, you must either: (i) Monitor each EGU separately by measuring the hourly CO_2 mass emissions prior to mixing in the common stack or (ii) Apportion the CO_2 mass emissions based on the unit's load contribution to the total load associated with the common stack and the appropriate F-factors. You may also elect to develop, demonstrate, and provide information satisfactory to the Administrator on alternate methods to apportion the CO_2 emissions. The Administrator may approve such alternate methods for apportioning the CO_2 emissions whenever the demonstration ensures accurate estimation of emissions regulated under this part. (g) In accordance with §§ 60.13(g) and 60.5520a if the exhaust gases from an affected EGU that implements the continuous emission monitoring provisions in paragraph (b) of this section are emitted to the atmosphere through multiple stacks (or if the exhaust gases are routed to a common stack through multiple ducts and you elect to monitor in the ducts), you must monitor the hourly CO_2 mass emissions and the "stack operating time" (as defined in 40 CFR 72.2) at each stack or duct separately. In this case, you must determine compliance with the applicable emissions standard in table 1 or 2 to this subpart by summing the CO_2 mass emissions measured at the individual stacks

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	or ducts and dividing by the total gross or net energy output for the affected EGU.
B.50	**Equipment ID:** CTG1, CTG2, CTG3, DB1, DB2, DB3 **Control Device ID:** SCR1, OXCAT1, WIN1, SCR2, OXCAT2, WIN2, SCR3, OXCAT3, WIN3 § 60.5540a How do I demonstrate compliance with my CO_2 emissions standard and determine excess emissions? (a) In accordance with § 60.5520a, if you are subject to an output-based emission standard or you burn non-uniform fuels as specified in § 60.5520a(d)(2), you must demonstrate compliance with the applicable CO_2 emission standard in table 1 to this subpart as required in this section. For the initial and each subsequent 12-operating-month rolling average compliance period, you must follow the procedures in paragraphs (a)(1) through (8) of this section to calculate the CO_2 mass emissions rate for your affected EGU(s) in units of the applicable emissions standard (e.g., either kg/MWh or kg/GJ). You must use the hourly CO_2 mass emissions calculated under § 60.5535a(b) or (c), as applicable, and either the generating load data from § 60.5535a(d)(1) for output-based calculations or the heat input data from § 60.5535a(d)(2) for heat-input-based calculations. Combustion turbines firing non-uniform fuels that contain CO_2 prior to combustion (e.g., blast furnace gas or landfill gas) may sample the fuel stream to determine the quantity of CO_2 present in the fuel prior to combustion and exclude this portion of the CO_2 mass emissions from compliance determinations. (1) Each compliance period shall include only “valid operating hours” in the compliance period, *i.e.,* operating hours for which: (i) “Valid data” (as defined in § 60.5580a) are obtained for all of the parameters used to determine the hourly CO_2 mass emissions (kg) and, if a heat input-based standard applies, all the parameters used to determine total heat input for the hour are also obtained; and (ii) The corresponding hourly gross or net energy output value is also valid data (Note: For hours with no useful output, zero is considered to be a valid value). (2) You must exclude operating hours in which: (i) The substitute data provisions of part 75 of this chapter are applied for any of the parameters used to determine the hourly CO_2 mass emissions or, if a heat input-based standard applies, for any parameters used to determine the hourly heat input; (ii) An exceedance of the full-scale range of a continuous emission monitoring system occurs for any of the parameters used to determine the hourly CO_2 mass emissions or, if applicable, to determine the hourly heat input; or

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	(iii) The total gross or net energy output ($P_{gross/net}$) or, if applicable, the total heat input is unavailable. (3) For each compliance period, at least 95 percent of the operating hours in the compliance period must be valid operating hours, as defined in paragraph (a)(1) of this section. (4) You must calculate the total CO_2 mass emissions by summing the valid hourly CO_2 mass emissions values from § 60.5535a for all of the valid operating hours in the compliance period. (5) For each valid operating hour of the compliance period that was used in paragraph (a)(4) of this section to calculate the total CO_2 mass emissions, you must determine Pgross/net (the corresponding hourly gross or net energy output in MWh) according to the procedures in paragraphs (a)(5)(i) and (ii) of this section, as appropriate for the type of affected EGU(s). For an operating hour in which a valid CO_2 mass emissions value is determined according to paragraph (a)(1)(i) of this section, if there is no gross or net electrical output, but there is mechanical or useful thermal output, you must still determine the gross or net energy output for that hour. In addition, for an operating hour in which a valid CO_2 mass emissions value is determined according to paragraph (a)(1)(i) of this section, but there is no (i.e., zero) gross electrical, mechanical, or useful thermal output, you must use that hour in the compliance determination. For hours or partial hours where the gross electric output is equal to or less than the auxiliary loads, net electric output shall be counted as zero for this calculation. (i) Calculate $P_{gross/net}$ for your affected EGU using the following equation. All terms in the equation must be expressed in units of MWh. To convert each hourly gross or net energy output (consistent with § 60.5520a) value reported under part 75 of this chapter to MWh, multiply by the corresponding EGU or stack operating time. Equation 1 to Paragraph (a)(5)(i) $$P_{gross/net} = \frac{(Pe)_{ST}+(Pe)_{CT}+(Pe)_{IE}-(Pe)_{FW}-(Pe)_{A}}{TDF} + [\ (Pt)_{PS} + (Pt)_{HR} + (Pt)_{IE}\ ]\ \text{(Eq. 2)}$$ Where: $P_{gross/net}$ = In accordance with § 60.5520a, gross or net energy output of your affected EGU for each valid operating hour (as defined in § 60.5540a(a)(1)) in MWh. $(Pe)_{ST}$ = Electric energy output plus mechanical energy output (if any) of steam turbines in MWh. $(Pe)_{CT}$ = Electric energy output plus mechanical energy output (if any) of stationary combustion turbine(s) in MWh. $(Pe)_{IE}$ = Electric energy output plus mechanical energy output (if any) of your affected EGU's integrated equipment that provides electricity or mechanical energy to the affected EGU or auxiliary equipment in MWh. $(Pe)_{FW}$ = Electric energy used to power boiler feedwater pumps at steam generating units in MWh.

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	Not applicable to stationary combustion turbines, IGCC EGUs, or EGUs complying with a net energy output based standard. $(Pe)_A$ = Electric energy used for any auxiliary loads in MWh. Not applicable for determining P_{gross}. $(Pt)_{PS}$ = Useful thermal output of steam (measured relative to standard ambient temperature and pressure (SATP) conditions, as applicable) that is used for applications that do not generate additional electricity, produce mechanical energy output, or enhance the performance of the affected EGU. This is calculated using the equation specified in paragraph (a)(5)(ii) of this section in MWh. $(Pt)_{HR}$ = Non steam useful thermal output (measured relative to SATP conditions, as applicable) from heat recovery that is used for applications other than steam generation or performance enhancement of the affected EGU in MWh. $(Pt)_{IE}$ = Useful thermal output (relative to SATP conditions, as applicable) from any integrated equipment is used for applications that do not generate additional steam, electricity, produce mechanical energy output, or enhance the performance of the affected EGU in MWh. TDF = Electric Transmission and Distribution Factor of 0.95 for a combined heat and power affected EGU where at least on an annual basis 20.0 percent of the total gross or net energy output consists of useful thermal output on a 12-operating-month rolling average basis, or 1.0 for all other affected EGUs. (ii) If applicable to your affected EGU (for example, for combined heat and power), you must calculate (Pt)PS using the following equation: Equation 2 to Paragraph (a)(5)(ii) $(Pt)_{PS} = \frac{Q_m \times H}{CF}$ (Eq. 3) Where: Q_m = Measured useful thermal output flow in kg (lb) for the operating hour. H = Enthalpy of the useful thermal output at measured temperature and pressure (relative to SATP conditions or the energy in the condensate return line, as applicable) in Joules per kilogram (J/kg) (or Btu/lb). CF = Conversion factor of 3.6×10^9 J/MWh or 3.413×10^6 Btu/MWh. (6) Sources complying with energy output-based standards must calculate the basis (*i.e.,* denominator) of their actual annual emission rate in accordance with paragraph (a)(6)(i) of this section. Sources complying with heat input based standards must calculate the basis of their actual annual emission rate in accordance with paragraph (a)(6)(ii) of this section. (i) In accordance with § 60.5520a if you are subject to an output-based standard, you must

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	calculate the total gross or net energy output for the affected EGU's compliance period by summing the hourly gross or net energy output values for the affected EGU that you determined under paragraph (a)(5) of this section for all of the valid operating hours in the applicable compliance period. (ii) If you are subject to a heat input-based standard, you must calculate the total heat input for each fuel fired during the compliance period. The calculation of total heat input for each individual fuel must include all valid operating hours and must also be consistent with any fuel-specific procedures specified within your selected monitoring option under § 60.5535(d)(2). (7) If you are subject to an output-based standard, you must calculate the CO_2 mass emissions rate for the affected EGU(s) (kg/MWh) by dividing the total CO_2 mass emissions value calculated according to the procedures in paragraph (a)(4) of this section by the total gross or net energy output value calculated according to the procedures in paragraph (a)(6)(i) of this section. Round off the result to two significant figures if the calculated value is less than 1,000; round the result to three significant figures if the calculated value is greater than 1,000. If you are subject to a heat input-based standard, you must calculate the CO_2 mass emissions rate for the affected EGU(s) (kg/GJ or lb/MMBtu) by dividing the total CO_2 mass emissions value calculated according to the procedures in paragraph (a)(4) of this section by the total heat input calculated according to the procedures in paragraph (a)(6)(ii) of this section. Round off the result to two significant figures. (8) You may exclude CO_2 mass emissions and output generated from your affected EGU from your calculations for hours during which the affected EGU operated during a system emergency, as defined in § 60.5580a, if you can provide the information listed in § 60.5560a(i). While operating during a system emergency, your compliance determination depends on your subcategory or unit type, as listed in paragraphs (a)(8)(i) through (ii) of this section. (i) For affected EGUs in the intermediate or base load subcategory, your CO_2 emission standard while operating during a system emergency is the applicable emission standard for low load combustion turbines. (ii) For affected modified steam generating units, your CO_2 emission standard while operating during a system emergency is 230 lb CO_2/MMBtu. (b) In accordance with § 60.5520a, to demonstrate compliance with the applicable CO_2 emission standard, for the initial and each subsequent 12-operating-month compliance period, the CO_2 mass emissions rate for your affected EGU must be determined according to the procedures specified in paragraph (a)(1) through (8) of this section and must be less than or equal to the applicable CO_2 emissions standard in table 1 to this subpart, or the emissions standard calculated in accordance with § 60.5525a(a)(2).

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	(c) If you are the owner or operator of a new or reconstructed stationary combustion turbine operating in the base load subcategory, are installing add-on controls, and are unable to comply with the applicable Phase 2 CO_2 emission standard specified in table 1 to this subpart due to circumstances beyond your control, you may request a compliance date extension of no longer than one year beyond the effective date of January 1, 2032, and may only receive an extension once. The extension request must contain a demonstration of necessity that includes the following: (1) A demonstration that your affected EGU cannot meet its compliance date due to circumstances beyond your control and you have taken all steps reasonably possible to install the controls necessary for compliance by the effective date up to the point of the delay. The demonstration shall: (i) Identify each affected unit for which you are seeking the compliance extension; (ii) Identify and describe the controls to be installed at each affected unit to comply with the applicable CO_2 emission standard in table 1 to this subpart; (iii) Describe and demonstrate all progress towards installing the controls and that you have acted consistently with achieving timely compliance, including; (A) Any and all contract(s) entered into for the installation of the identified controls or an explanation as to why no contract is necessary or obtainable; (B) Any permit(s) obtained for the installation of the identified controls or, where a required permit has not yet been issued, a copy of the permit application submitted to the permitting authority and a statement from the permit authority identifying its anticipated timeframe for issuance of such permit(s). (iv) Identify the circumstances that are entirely beyond your control and that necessitate additional time to install the identified controls. This may include: (A) Information gathered from control technology vendors or engineering firms demonstrating that the necessary controls cannot be installed or started up by the applicable compliance date listed in table 1 to this subpart; (B) Documentation of any permit delays; or (C) Documentation of delays in construction or permitting of infrastructure (*e.g.,* CO_2 pipelines) that is necessary for implementation of the control technology; (v) Identify a proposed compliance date no later than one year after the applicable compliance

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	date listed in table 1 to this subpart. (2) The Administrator is charged with approving or disapproving a compliance date extension request based on his or her written determination that your affected EGU has or has not made each of the necessary demonstrations and provided all of the necessary documentation according to paragraph (c)(1) of this section. The following must be included: (i) All documentation required as part of this extension must be submitted by you to the Administrator no later than 6 months prior to the applicable effective date for your affected EGU. (ii) You must notify the Administrator of the compliance date extension request at the time of the submission of the request.
B.51	**Equipment ID:** CTG1, CTG2, CTG3, DB1, DB2, DB3 **Control Device ID:** SCR1, OXCAT1, WIN1, SCR2, OXCAT2, WIN2, SCR3, OXCAT3, WIN3 § 60.5550a What notifications must I submit and when? (a) You must prepare and submit the notifications specified in §§ 60.7(a)(1) and (3) and 60.19, as applicable to your affected EGU(s) (see table 3 to this subpart). (b) You must prepare and submit notifications specified in 40 CFR 75.61, as applicable, to your affected EGUs.
B.52	**Equipment ID:** CTG1, CTG2, CTG3, DB1, DB2, DB3 **Control Device ID:** SCR1, OXCAT1, WIN1, SCR2, OXCAT2, WIN2, SCR3, OXCAT3, WIN3 § 60.5555a What reports must I submit and when? (a) You must prepare and submit reports according to paragraphs (a) through (d) of this section, as applicable. (1) For affected EGUs that are required by § 60.5525a to conduct initial and on-going compliance determinations on a 12-operating-month rolling average basis, you must submit electronic quarterly reports as follows. After you have accumulated the first 12-operating months for the affected EGU, you must submit a report for the calendar quarter that includes the twelfth operating month no later than 30 days after the end of that quarter. Thereafter, you must submit a report for each subsequent calendar quarter, no later than 30 days after the end of the quarter. (2) In each quarterly report you must include the following information, as applicable: (i) Each rolling average CO_2 mass emissions rate for which the last (twelfth) operating month in

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	a 12-operating-month compliance period falls within the calendar quarter. You must calculate each average CO_2 mass emissions rate for the compliance period according to the procedures in § 60.5540a. You must report the dates (month and year) of the first and twelfth operating months in each compliance period for which you performed a CO_2 mass emissions rate calculation. If there are no compliance periods that end in the quarter, you must include a statement to that effect; (ii) If one or more compliance periods end in the quarter, you must identify each operating month in the calendar quarter where your EGU violated the applicable CO_2 emission standard; (iii) If one or more compliance periods end in the quarter and there are no violations for the affected EGU, you must include a statement indicating this in the report; (iv) The percentage of valid operating hours in each 12-operating-month compliance period described in paragraph (a)(1) of this section (*i.e.,* the total number of valid operating hours (as defined in § 60.5540a(a)(1)) in that period divided by the total number of operating hours in that period, multiplied by 100 percent); (v) Consistent with § 60.5520a, the CO_2 emissions standard (as identified in table 1 or 2 to this subpart) with which your affected EGU must comply; and (vi) Consistent with § 60.5520a, an indication whether or not the hourly gross or net energy output ($P_{gross/net}$) values used in the compliance determinations are based solely upon gross electrical load. (3) In the final quarterly report of each calendar year, you must include the following: (i) Consistent with § 60.5520a, gross energy output or net energy output sold to an electric grid, as applicable to the units of your emission standard, over the four quarters of the calendar year; and (ii) The potential electric output of the EGU. (b) You must submit all electronic reports required under paragraph (a) of this section using the Emissions Collection and Monitoring Plan System (ECMPS) Client Tool provided by the Clean Air Markets Division in the Office of Atmospheric Programs of EPA. (c) (1) For affected EGUs under this subpart that are also subject to the Acid Rain Program, you must meet all applicable reporting requirements and submit reports as required under subpart G of

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	part 75 of this chapter. (2) For affected EGUs under this subpart that are not in the Acid Rain Program, you must also meet the reporting requirements and submit reports as required under subpart G of part 75 of this chapter, to the extent that those requirements and reports provide applicable data for the compliance demonstrations required under this subpart. (3) (i) For all newly-constructed affected EGUs under this subpart that are also subject to the Acid Rain Program, you must begin submitting the quarterly electronic emissions reports described in paragraph (c)(1) of this section in accordance with 40 CFR 75.64(a), *i.e.,* beginning with data recorded on and after the earlier of: (A) The date of provisional certification, as defined in 40 CFR 75.20(a)(3); or (B) 180 days after the date on which the EGU commences commercial operation (as defined in 40 CFR 72.2). (ii) For newly-constructed affected EGUs under this subpart that are not subject to the Acid Rain Program, you must begin submitting the quarterly electronic reports described in paragraph (c)(2) of this section, beginning with data recorded on and after the date on which reporting is required to begin under 40 CFR 75.64(a), if that date occurs on or after May 23, 2023. (iii) For reconstructed or modified units, reporting of emissions data shall begin at the date on which the EGU becomes an affected unit under this subpart, provided that the ECMPS Client Tool is able to receive and process net energy output data on that date. Otherwise, emissions data reporting shall be on a gross energy output basis until the date that the Client Tool is first able to receive and process net energy output data. (4) If any required monitoring system has not been provisionally certified by the applicable date on which emissions data reporting is required to begin under paragraph (c)(3) of this section, the maximum (or in some cases, minimum) potential value for the parameter measured by the monitoring system shall be reported until the required certification testing is successfully completed, in accordance with 40 CFR 75.4(j), 40 CFR 75.37(b), or section 2.4 of appendix D to part 75 of this chapter (as applicable). Operating hours in which CO_2 mass emission rates are calculated using maximum potential values are not "valid operating hours" (as defined in § 60.5540(a)(1)), and shall not be used in the compliance determinations under § 60.5540. (d) For affected EGUs subject to the Acid Rain Program, the reports required under paragraphs (a)

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	and (c)(1) of this section shall be submitted by: (1) The person appointed as the Designated Representative (DR) under 40 CFR 72.20; or (2) The person appointed as the Alternate Designated Representative (ADR) under 40 CFR 72.22; or (3) A person (or persons) authorized by the DR or ADR under 40 CFR 72.26 to make the required submissions. (e) For affected EGUs that are not subject to the Acid Rain Program, the owner or operator shall appoint a DR and (optionally) an ADR to submit the reports required under paragraphs (a) and (c)(2) of this section. The DR and ADR must register with the Clean Air Markets Division (CAMD) Business System. The DR may delegate the authority to make the required submissions to one or more persons. (f) If your affected EGU captures CO_2 to meet the applicable emission standard, you must report in accordance with the requirements of 40 CFR part 98, subpart PP, and either: (1) Report in accordance with the requirements of 40 CFR part 98, subpart RR, or subpart VV, if injection occurs on-site; (2) Transfer the captured CO_2 to a facility that reports in accordance with the requirements of 40 CFR part 98, subpart RR, or subpart VV, if injection occurs off-site; or (3) Transfer the captured CO_2 to a facility that has received an innovative technology waiver from EPA pursuant to paragraph (g) of this section. (g) Any person may request the Administrator to issue a waiver of the requirement that captured CO_2 from an affected EGU be transferred to a facility reporting under 40 CFR part 98, subpart RR, or subpart VV. To receive a waiver, the applicant must demonstrate to the Administrator that its technology will store captured CO_2 as effectively as geologic sequestration, and that the proposed technology will not cause or contribute to an unreasonable risk to public health, welfare, or safety. In making this determination, the Administrator shall consider (among other factors) operating history of the technology, whether the technology will increase emissions or other releases of any pollutant other than CO_2, and permanence of the CO_2 storage. The Administrator may test the system, or require the applicant to perform any tests considered by the Administrator to be necessary to show the technology's effectiveness, safety, and ability to store captured CO_2 without release. The Administrator may grant conditional approval of a technology, with the approval conditioned on monitoring and reporting of operations. The Administrator may also withdraw approval of the waiver on evidence of releases of CO_2 or other pollutants. The Administrator will

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	provide notice to the public of any application under this provision and provide public notice of any proposed action on a petition before the Administrator takes final action.
B.53	**Equipment ID:** CTG1, CTG2, CTG3, DB1, DB2, DB3 **Control Device ID:** SCR1, OXCAT1, WIN1, SCR2, OXCAT2, WIN2, SCR3, OXCAT3, WIN3 § 60.5560a What records must I maintain? (a) You must maintain records of the information you used to demonstrate compliance with this subpart as specified in § 60.7(b) and (f). (b) (1) For affected EGUs subject to the Acid Rain Program, you must follow the applicable recordkeeping requirements and maintain records as required under subpart F of part 75 of this chapter. (2) For affected EGUs that are not subject to the Acid Rain Program, you must also follow the recordkeeping requirements and maintain records as required under subpart F of part 75 of this chapter, to the extent that those records provide applicable data for the compliance determinations required under this subpart. Regardless of the prior sentence, at a minimum, the following records must be kept, as applicable to the types of continuous monitoring systems used to demonstrate compliance under this subpart: (i) Monitoring plan records under 40 CFR 75.53(g) and (h); (ii) Operating parameter records under 40 CFR 75.57(b)(1) through (4); (iii) The records under 40 CFR 75.57(c)(2), for stack gas volumetric flow rate; (iv) The records under 40 CFR 75.57(c)(3) for continuous moisture monitoring systems; (v) The records under 40 CFR 75.57(e)(1), except for paragraph (e)(1)(x), for CO_2 concentration monitoring systems or O2 monitors used to calculate CO_2 concentration; (vi) The records under 40 CFR 75.58(c)(1), specifically paragraphs (c)(1)(i), (ii), and (viii) through (xiv), for oil flow meters; (vii) The records under 40 CFR 75.58(c)(4), specifically paragraphs (c)(4)(i), (ii), (iv), (v), and (vii) through (xi), for gas flow meters; (viii) The quality-assurance records under 40 CFR 75.59(a), specifically paragraphs (a)(1) through

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	(12) and (15), for CEMS; (ix) The quality-assurance records under 40 CFR 75.59(a), specifically paragraphs (b)(1) through (4), for fuel flow meters; and (x) Records of data acquisition and handling system (DAHS) verification under 40 CFR 75.59(e). (c) You must keep records of the calculations you performed to determine the hourly and total CO_2 mass emissions (tons) for: (1) Each operating month (for all affected EGUs); and (2) Each compliance period, including, each 12-operating-month compliance period. (d) Consistent with § 60.5520a, you must keep records of the applicable data recorded and calculations performed that you used to determine your affected EGU's gross or net energy output for each operating month. (e) You must keep records of the calculations you performed to determine the percentage of valid CO_2 mass emission rates in each compliance period. (f) You must keep records of the calculations you performed to assess compliance with each applicable CO_2 mass emissions standard in table 1 or 2 to this subpart. (g) You must keep records of the calculations you performed to determine any site-specific carbon-based F-factors you used in the emissions calculations (if applicable). (h) For stationary combustion turbines, you must keep records of electric sales to determine the applicable subcategory. (i) You must keep the records listed in paragraphs (i)(1) through (3) of this section to demonstrate that your affected facility operated during a system emergency. (1) Documentation that the system emergency to which the affected EGU was responding was in effect from the entity issuing the alert and documentation of the exact duration of the system emergency; (2) Documentation from the entity issuing the alert that the system emergency included the affected source/region where the affected facility was located; and (3) Documentation that the affected facility was instructed to increase output beyond the planned

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	day-ahead or other near-term expected output and/or was asked to remain in operation outside its scheduled dispatch during emergency conditions from a Reliability Coordinator, Balancing Authority, or Independent System Operator/Regional Transmission Organization.
B.54	**Equipment ID:** CTG1, CTG2, CTG3, DB1, DB2, DB3 **Control Device ID:** SCR1, OXCAT1, WIN1, SCR2, OXCAT2, WIN2, SCR3, OXCAT3, WIN3 § 60.5565a In what form and how long must I keep my records? (a) Your records must be in a form suitable and readily available for expeditious review. (b) You must maintain each record for 5 years after the date of conclusion of each compliance period. (c) You must maintain each record on site for at least 2 years after the date of each occurrence, measurement, maintenance, corrective action, report, or record, according to § 60.7. Records that are accessible from a central location by a computer or other means that instantly provide access at the site meet this requirement. You may maintain the records off site for the remaining year(s) as required by this subpart.
B.55	**Equipment ID:** AB1 (S.C. Regulation 61-62.1, Section II(J)(2)) This source is permitted to burn only natural gas as fuel. The use of any other substances as fuel is prohibited without prior written approval from the Department.
B.56	**Equipment ID:** AB1 (S.C. Regulation 61-62.5, Standard No. 1, Section I) The fuel burning source(s) shall not discharge into the ambient air smoke which exceeds opacity of 20%. The owner or operator shall, to the extent practicable, maintain and operate any source including associated air pollution control equipment in a manner consistent with good air pollution control practices for minimizing emissions. (S.C. Regulation 61-62.5, Standard No. 1, Section II) The maximum allowable discharge of particulate matter resulting from this source is 0.6 pounds per million BTU input. (S.C. Regulation 61-62.5, Standard No. 1, Section III) The maximum allowable discharge of sulfur dioxide (SO_2) resulting from this source is 2.3 pounds per million BTU input.
B.57	**Equipment ID:** AB1, HT1, HT2, HT3 (S.C. Regulation 61-62.60; 40 CFR 60) These sources are subject to New Source Performance Standards (NSPS), Subpart A, General Provisions and Subpart Dc, Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units, as applicable. This source shall comply with all applicable requirements of Subparts A and Dc.
B.58	**Equipment ID:** AB1, HT1, HT2, HT3

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	§60.48c – Reporting and recordkeeping requirements. (g)(1) Except as provided under paragraphs (g)(2) and (g)(3) of this section, the owner or operator of each affected facility shall record and maintain records of the amount of each fuel combusted during each operating day. (2) As an alternative to meeting the requirements of paragraph (g)(1) of this section, the owner or operator of an affected facility that combusts only natural gas, wood, fuels using fuel certification in § 60.48c(f) to demonstrate compliance with the SO_2 standard, fuels not subject to an emissions standard (excluding opacity), or a mixture of these fuels may elect to record and maintain records of the amount of each fuel combusted during each calendar month. (i) All records required under this section shall be maintained by the owner or operator of the affected facility for a period of two years following the date of such record.
B.59	**Equipment ID:** EG1, EG2, EG3, FP1, FP2 (S.C. Regulation 61-62.60; 40 CFR 60) This source is subject to New Source Performance Standards (NSPS), Subpart A, General Provisions and Subpart IIII, Standards of Performance for Stationary Compression Ignition Internal Combustion Engines, as applicable. This source shall comply with all applicable requirements of Subparts A (applicable as shown in Table 8 of IIII) and IIII.
B.60	**Equipment ID:** EG1, EG2, EG3 § 60.4205 What emission standards must I meet for emergency engines if I am an owner or operator of a stationary CI internal combustion engine? (b) Owners and operators of 2007 model year and later emergency stationary CI ICE with a displacement of less than 30 liters per cylinder that are not fire pump engines must comply with the emission standards for new nonroad CI engines in § 60.4202, for all pollutants, for the same model year and maximum engine power for their 2007 model year and later emergency stationary CI ICE.
B.61	**Equipment ID:** FP1, FP2 § 60.4205 What emission standards must I meet for emergency engines if I am an owner or operator of a stationary CI internal combustion engine? (c) Owners and operators of fire pump engines with a displacement of less than 30 liters per cylinder must comply with the emission standards in table 4 to this subpart, for all pollutants. Table 4 to Subpart IIII of Part 60—Emission Standards for Stationary Fire Pump Engines

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<table>
<tr><th colspan="2">B. LIMITATIONS, MONITORING, AND REPORTING</th></tr>
<tr><th>Condition Number</th><th>Conditions</th></tr>
<tr><td></td><td>
<table>
<tr><th rowspan="2">Maximum engine power</th><th rowspan="2">Model year(s)</th><th colspan="3">Emission standards for stationary fire pump engines in g/KW-hr (g/HP-hr)</th></tr>
<tr><th>NMHC + NO_X</th><th>CO</th><th>PM</th></tr>
<tr><td>225≤KW<450 (300≤HP<600)</td><td>2009 + [3]</td><td>4.0 (3.0)</td><td>3.5 (2.6)</td><td>0.20 (0.15)</td></tr>
</table>
[3] In model years 2009-2011, manufacturers of fire pump stationary CI ICE in this engine power category with a rated speed of greater than 2,650 rpm may comply with the emission limitations for 2008 model year engines.
</td></tr>
<tr><td>B.62</td><td>Equipment ID: EG1, EG2, EG3, FP1, FP2

§ 60.4206 How long must I meet the emission standards if I am an owner or operator of a stationary CI internal combustion engine?

Owners and operators of stationary CI ICE must operate and maintain stationary CI ICE that achieve the emission standards as required in §§ 60.4204 and 60.4205 over the entire life of the engine.</td></tr>
<tr><td>B.63</td><td>Equipment ID: EG1, EG2, EG3, FP1, FP2

§ 60.4207 What fuel requirements must I meet if I am an owner or operator of a stationary CI internal combustion engine subject to this subpart?

(b) Beginning October 1, 2010, owners and operators of stationary CI ICE subject to this subpart with a displacement of less than 30 liters per cylinder that use diesel fuel must use diesel fuel that meets the requirements of 40 CFR 1090.305 for nonroad diesel fuel, except that any existing diesel fuel purchased (or otherwise obtained) prior to October 1, 2010, may be used until depleted.</td></tr>
<tr><td>B.64</td><td>Equipment ID: EG1, EG2, EG3, FP1, FP2

§ 60.4209 What are the monitoring requirements if I am an owner or operator of a stationary CI internal combustion engine?

If you are an owner or operator, you must meet the monitoring requirements of this section. In addition, you must also meet the monitoring requirements specified in § 60.4211.

(a) If you are an owner or operator of an emergency stationary CI internal combustion engine that does not meet the standards applicable to non-emergency engines, you must install a non-resettable hour meter prior to startup of the engine.</td></tr>
<tr><td>B.65</td><td>Equipment ID: EG1, EG2, EG3, FP1, FP2

§ 60.4211 What are my compliance requirements if I am an owner or operator of a stationary CI internal combustion engine?</td></tr>
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	(a) If you are an owner or operator and must comply with the emission standards specified in this subpart, you must do all of the following, except as permitted under paragraph (g) of this section: (1) Operate and maintain the stationary CI internal combustion engine and control device according to the manufacturer's emission-related written instructions; (2) Change only those emission-related settings that are permitted by the manufacturer; and (3) Meet the requirements of 40 CFR part 1068, as they apply to you. (c) If you are an owner or operator of a 2007 model year and later stationary CI internal combustion engine and must comply with the emission standards specified in § 60.4204(b) or § 60.4205(b), or if you are an owner or operator of a CI fire pump engine that is manufactured during or after the model year that applies to your fire pump engine power rating in table 3 to this subpart and must comply with the emission standards specified in § 60.4205(c), you must comply by purchasing an engine certified to the emission standards in § 60.4204(b), or § 60.4205(b) or (c), as applicable, for the same model year and maximum (or in the case of fire pumps, NFPA nameplate) engine power. The engine must be installed and configured according to the manufacturer's emission-related specifications, except as permitted in paragraph (g) of this section. (f) If you own or operate an emergency stationary ICE, you must operate the emergency stationary ICE according to the requirements in paragraphs (f)(1) through (3) of this section. In order for the engine to be considered an emergency stationary ICE under this subpart, any operation other than emergency operation, maintenance and testing, and operation in non-emergency situations for 50 hours per year, as described in paragraphs (f)(1) through (3), is prohibited. If you do not operate the engine according to the requirements in paragraphs (f)(1) through (3), the engine will not be considered an emergency engine under this subpart and must meet all requirements for non-emergency engines. (1) There is no time limit on the use of emergency stationary ICE in emergency situations. (2) You may operate your emergency stationary ICE for the purpose specified in paragraph (f)(2)(i) of this section for a maximum of 100 hours per calendar year. Any operation for non-emergency situations as allowed by paragraph (f)(3) of this section counts as part of the 100 hours per calendar year allowed by this paragraph (f)(2). (i) Emergency stationary ICE may be operated for maintenance checks and readiness testing, provided that the tests are recommended by federal, state or local government, the manufacturer, the vendor, the regional transmission organization or equivalent balancing authority and transmission operator, or the insurance company associated with the engine. The owner or operator may petition the Administrator for approval of additional hours to be

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	used for maintenance checks and readiness testing, but a petition is not required if the owner or operator maintains records indicating that federal, state, or local standards require maintenance and testing of emergency ICE beyond 100 hours per calendar year. (3) Emergency stationary ICE may be operated for up to 50 hours per calendar year in non-emergency situations. The 50 hours of operation in non-emergency situations are counted as part of the 100 hours per calendar year for maintenance and testing provided in paragraph (f)(2) of this section. Except as provided in paragraph (f)(3)(i) of this section, the 50 hours per calendar year for non-emergency situations cannot be used for peak shaving or non-emergency demand response, or to generate income for a facility to an electric grid or otherwise supply power as part of a financial arrangement with another entity. (i) The 50 hours per year for non-emergency situations can be used to supply power as part of a financial arrangement with another entity if all of the following conditions are met: (A) The engine is dispatched by the local balancing authority or local transmission and distribution system operator; (B) The dispatch is intended to mitigate local transmission and/or distribution limitations so as to avert potential voltage collapse or line overloads that could lead to the interruption of power supply in a local area or region. (C) The dispatch follows reliability, emergency operation or similar protocols that follow specific NERC, regional, state, public utility commission or local standards or guidelines. (D) The power is provided only to the facility itself or to support the local transmission and distribution system. (E) The owner or operator identifies and records the entity that dispatches the engine and the specific NERC, regional, state, public utility commission or local standards or guidelines that are being followed for dispatching the engine. The local balancing authority or local transmission and distribution system operator may keep these records on behalf of the engine owner or operator. (h) The requirements for operators and prohibited acts specified in 40 CFR 1039.665 apply to owners or operators of stationary CI ICE equipped with AECDs for qualified emergency situations as allowed by 40 CFR 1039.665.
B.66	**Equipment ID:** EG1, EG2, EG3, FP1, FP2 § 60.4214 What are my notification, reporting, and recordkeeping requirements if I am an owner or

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	operator of a stationary CI internal combustion engine? (a) Owners and operators of non-emergency stationary CI ICE that are greater than 2,237 KW (3,000 HP), or have a displacement of greater than or equal to 10 liters per cylinder, or are pre-2007 model year engines that are greater than 130 KW (175 HP) and not certified, must meet the requirements of paragraphs (a)(1) and (2) of this section. (1) Submit an initial notification as required in § 60.7(a)(1). The notification must include the information in paragraphs (a)(1)(i) through (v) of this section. Beginning on February 26, 2025, submit the notification electronically according to paragraph (g) of this section. (i) Name and address of the owner or operator; (ii) The address of the affected source; (iii) Engine information including make, model, engine family, serial number, model year, maximum engine power, and engine displacement; (iv) Emission control equipment; and (v) Fuel used. (2) Keep records of the information in paragraphs (a)(2)(i) through (iv) of this section. (i) All notifications submitted to comply with this subpart and all documentation supporting any notification. (ii) Maintenance conducted on the engine. (iii) If the stationary CI internal combustion is a certified engine, documentation from the manufacturer that the engine is certified to meet the emission standards. (iv) If the stationary CI internal combustion is not a certified engine, documentation that the engine meets the emission standards. (b) If the stationary CI internal combustion engine is an emergency stationary internal combustion engine, the owner or operator is not required to submit an initial notification. Starting with the model years in table 5 to this subpart, if the emergency engine does not meet the standards applicable to non-emergency engines in the applicable model year, the owner or operator must keep records of the operation of the engine in emergency and non-emergency service that are recorded through the non-resettable hour meter. The owner must record the time of operation of

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	the engine and the reason the engine was in operation during that time. (d) If you own or operate an emergency stationary CI ICE with a maximum engine power more than 100 HP that operates for the purpose specified in § 60.4211(f)(3)(i), you must submit an annual report according to the requirements in paragraphs (d)(1) through (3) of this section. (1) The report must contain the following information: (i) Company name and address where the engine is located. (ii) Date of the report and beginning and ending dates of the reporting period. (iii) Engine site rating and model year. (iv) Latitude and longitude of the engine in decimal degrees reported to the fifth decimal place. (vii) Hours spent for operation for the purposes specified in § 60.4211(f)(3)(i), including the date, start time, and end time for engine operation for the purposes specified in § 60.4211(f)(3)(i). The report must also identify the entity that dispatched the engine and the situation that necessitated the dispatch of the engine. (2) The first annual report must cover the calendar year 2015 and must be submitted no later than March 31, 2016. Subsequent annual reports for each calendar year must be submitted no later than March 31 of the following calendar year. (3) The annual report must be submitted electronically using the subpart specific reporting form in the Compliance and Emissions Data Reporting Interface (CEDRI) that is accessed through EPA's Central Data Exchange (CDX) (*https://cdx.epa.gov/*). However, if the reporting form specific to this subpart is not available in CEDRI at the time that the report is due, the written report must be submitted to the Administrator at the appropriate address listed in § 60.4. Beginning on February 26, 2025, submit annual report electronically according to paragraph (g) of this section. (e) Owners or operators of stationary CI ICE equipped with AECDs pursuant to the requirements of 40 CFR 1039.665 must report the use of AECDs as required by 40 CFR 1039.665(e). (f) Beginning on February 26, 2025, within 60 days after the date of completing each performance test required by this subpart, you must submit the results of the performance test required under this section following the procedures specified in paragraphs (f)(1) and (2) of this section. (1) *Data collected using test methods supported by the EPA's Electronic Reporting Tool (ERT) as listed*

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	on the EPA's ERT website (https://www.epa.gov/electronic-reporting-air-emissions/electronic-reporting-tool-ert) at the time of the test. Submit the results of the performance test to the EPA via the Compliance and Emissions Data Reporting Interface (CEDRI), according to paragraph (g) of this section. The data must be submitted in a file format generated using the EPA's ERT. Alternatively, you may submit an electronic file consistent with the extensible markup language (XML) schema listed on the EPA's ERT website. (2) *Data collected using test methods that are not supported by the EPA's ERT as listed on the EPA's ERT website at the time of the test.* The results of the performance test must be included as an attachment in the ERT or an alternate electronic file consistent with the XML schema listed on the EPA's ERT website. Submit the ERT generated package or alternative file to the EPA via CEDRI according to paragraph (g) of this section. (g) If you are required to submit notifications or reports following the procedure specified in this paragraph (g), you must submit notifications or reports to the EPA via the Compliance and Emissions Data Reporting Interface (CEDRI), which can be accessed through the EPA's Central Data Exchange (CDX) (*https://cdx.epa.gov/*). The EPA will make all the information submitted through CEDRI available to the public without further notice to you. Do not use CEDRI to submit information you claim as CBI. Although we do not expect persons to assert a claim of CBI, if you wish to assert a CBI claim for some of the information in the report or notification, you must submit a complete file in the format specified in this subpart, including information claimed to be CBI, to the EPA following the procedures in paragraphs (g)(1) and (2) of this section. Clearly mark the part or all of the information that you claim to be CBI. Information not marked as CBI may be authorized for public release without prior notice. Information marked as CBI will not be disclosed except in accordance with procedures set forth in 40 CFR part 2. All CBI claims must be asserted at the time of submission. Anything submitted using CEDRI cannot later be claimed CBI. Furthermore, under CAA section 114(c), emissions data is not entitled to confidential treatment, and the EPA is required to make emissions data available to the public. Thus, emissions data will not be protected as CBI and will be made publicly available. You must submit the same file submitted to the CBI office with the CBI omitted to the EPA via the EPA's CDX as described earlier in this paragraph (g). (1) The preferred method to receive CBI is for it to be transmitted electronically using email attachments, File Transfer Protocol, or other online file sharing services. Electronic submissions must be transmitted directly to the OAQPS CBI Office at the email address *oaqpscbi@epa.gov*, and as described in paragraph (g) of this section, should include clear CBI markings. ERT files should be flagged to the attention of the Group Leader, Measurement Policy Group; all other files should be flagged to the attention of the Stationary Compression Ignition Internal Combustion Engine Sector Lead. If assistance is needed with submitting large electronic files that exceed the file size limit for email attachments, and if you do not have your own file sharing service, please email *oaqpscbi@epa.gov* to request a file transfer link. (2) If you cannot transmit the file electronically, you may send CBI information through the postal

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	service to the following address: OAQPS Document Control Officer (C404-02), OAQPS, U.S. Environmental Protection Agency, 109 T.W. Alexander Drive, P.O. Box 12055, Research Triangle Park, North Carolina 27711. ERT files should be sent to the attention of the Group Leader, Measurement Policy Group, and all other files should be sent to the attention of the Stationary Compression Ignition Internal Combustion Engine Sector Lead. The mailed CBI material should be double wrapped and clearly marked. Any CBI markings should not show through the outer envelope. (h) If you are required to electronically submit a report through CEDRI in the EPA's CDX, you may assert a claim of EPA system outage for failure to timely comply with that reporting requirement. To assert a claim of EPA system outage, you must meet the requirements outlined in paragraphs (h)(1) through (7) of this section. (1) You must have been or will be precluded from accessing CEDRI and submitting a required report within the time prescribed due to an outage of either the EPA's CEDRI or CDX systems. (2) The outage must have occurred within the period of time beginning five business days prior to the date that the submission is due. (3) The outage may be planned or unplanned. (4) You must submit notification to the Administrator in writing as soon as possible following the date you first knew, or through due diligence should have known, that the event may cause or has caused a delay in reporting. (5) You must provide to the Administrator a written description identifying: (i) The date(s) and time(s) when CDX or CEDRI was accessed and the system was unavailable; (ii) A rationale for attributing the delay in reporting beyond the regulatory deadline to EPA system outage; (iii) A description of measures taken or to be taken to minimize the delay in reporting; and (iv) The date by which you propose to report, or if you have already met the reporting requirement at the time of the notification, the date you reported. (6) The decision to accept the claim of EPA system outage and allow an extension to the reporting deadline is solely within the discretion of the Administrator. (7) In any circumstance, the report must be submitted electronically as soon as possible after the

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B. LIMITATIONS, MONITORING, AND REPORTING	
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	outage is resolved. (i) If you are required to electronically submit a report through CEDRI in the EPA's CDX, you may assert a claim of force majeure for failure to timely comply with that reporting requirement. To assert a claim of force majeure, you must meet the requirements outlined in paragraphs (i)(1) through (5) of this section. (1) You may submit a claim if a force majeure event is about to occur, occurs, or has occurred or there are lingering effects from such an event within the period of time beginning five business days prior to the date the submission is due. For the purposes of this section, a force majeure event is defined as an event that will be or has been caused by circumstances beyond the control of the affected facility, its contractors, or any entity controlled by the affected facility that prevents you from complying with the requirement to submit a report electronically within the time period prescribed. Examples of such events are acts of nature (*e.g.,* hurricanes, earthquakes, or floods), acts of war or terrorism, or equipment failure or safety hazard beyond the control of the affected facility (*e.g.,* large scale power outage). (2) You must submit notification to the Administrator in writing as soon as possible following the date you first knew, or through due diligence should have known, that the event may cause or has caused a delay in reporting. (3) You must provide to the Administrator: (i) A written description of the force majeure event; (ii) A rationale for attributing the delay in reporting beyond the regulatory deadline to the force majeure event; (iii) A description of measures taken or to be taken to minimize the delay in reporting; and (iv) The date by which you propose to report, or if you have already met the reporting requirement at the time of the notification, the date you reported. (4) The decision to accept the claim of force majeure and allow an extension to the reporting deadline is solely within the discretion of the Administrator. (5) In any circumstance, the reporting must occur as soon as possible after the force majeure event occurs. (j) Any records required to be maintained by this subpart that are submitted electronically via the EPA's CEDRI may be maintained in electronic format. This ability to maintain electronic copies does

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B. LIMITATIONS, MONITORING, AND REPORTING	
Condition Number	**Conditions**
	not affect the requirement for facilities to make records, data, and reports available upon request to a delegated air agency or the EPA as part of an on-site compliance evaluation.
B.67	**Equipment ID:** CTG1, CTG2, CTG3, DB1, DB2, DB3 **Control Device ID:** SCR1, OXCAT1, WIN1, SCR2, OXCAT2, WIN2, SCR3, OXCAT3, WIN3 This facility is subject to S.C. Regulation 61-62.72, 40 CFR 72, 73, 74, 75, and 76 and the limits specified in Attachment – Title IV Acid Rain Program. The owner/operator shall comply with the monitoring and reporting requirements as provided in 40 CFR Parts 74, 75 and 76.
B.68	**Equipment ID:** CTG1, CTG2, CTG3, DB1, DB2, DB3 **Control Device ID:** SCR1, OXCAT1, WIN1, SCR2, OXCAT2, WIN2, SCR3, OXCAT3, WIN3 These sources are subject to SC Regulation 61-62.96 Nitrogen Oxides (NO_X) Budget Program and the federal rule requirements of the NO_X SIP Call at subparts A through I of 40 CFR 96 NO_X Budget Trading Program and shall comply with all applicable requirements. The owner or operator shall comply with the monitoring and reporting requirements as provided in 40 CFR Part 96.
B.69	**Equipment ID:** CTG1, CTG2, CTG3, DB1, DB2, DB3 **Control Device ID:** SCR1, OXCAT1, WIN1, SCR2, OXCAT2, WIN2, SCR3, OXCAT3, WIN3 The facility is permitted to use biocides or moisture inhibitors, that are registered per 40 CFR 79, as fuel additives to the fuel oil supply. The facility shall receive advanced written notice prior to using any additive not registered Per 40 CFR 79.
B.70	**Equipment ID:** COOL1, COOL2, COOL3, COOL4, COOL5, COOL6, DELUGE1, DELUGE2, DELUGE3 (S.C. Regulation 61-62.5, Standard No. 4, Section VIII) Particulate matter emissions shall be limited to the rate specified by use of the following equations: For process weight rates less than or equal to 30 tons per hour $E = (F)\ 4.10P^{0.67}$ For process weight rates greater than 30 tons per hour $E = (F)\ (55.0P^{0.11} - 40)$ Where E = the allowable emission rate in pounds per hour P = process weight rate in tons per hour F = effect factor from Table B in S.C. Regulation 61-62.5, Standard No. 4 For the purposes of compliance with this condition, the process boundaries are defined as follows: • Inlet Chiller/COOL1 - Max Process Weight Rate 6000 ton/hr • Inlet Chiller/COOL2 - Max Process Weight Rate 6000 ton/hr • Inlet Chiller/COOL3 - Max Process Weight Rate 6000 ton/hr • Inlet Chiller/COOL4 - Max Process Weight Rate 6000 ton/hr • Inlet Chiller/COOL5 - Max Process Weight Rate 6000 ton/hr • Inlet Chiller/COOL6 - Max Process Weight Rate 6000 ton/hr • Delugable Cooling/ DELUGE1- Max Process Weight Rate 6260 ton/hr • Delugable Cooling/ DELUGE2 - Max Process Weight Rate 6260 ton/hr

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	• Delugable Cooling/ DELUGE3- Max Process Weight Rate 6260 ton/hr

C. NESHAP (40 CFR 61 AND 40 CFR 63)	
Condition Number	**Conditions**
C.1	(40 CFR §63.9(a)(4)(ii) and §63.10(a)(4)(ii)) All NESHAP notifications and reports shall be sent to the Department. Electronic submission of notifications or reports to the United States Environmental Protection Agency (US EPA) via CEDRI (Compliance and Emissions Data Reporting Interface) shall serve as the submission to the Department. CEDRI can be accessed through the EPA's Central Data Exchange (CDX).
C.2	(40 CFR §63.9(a)(4)(ii) and §63.10(a)(4)(ii)) All NESHAP notifications and reports requiring electronic submission to US EPA shall be submitted to EPA via CEDRI. Notifications and reports for specific NESHAP subparts not yet requiring electronic submission may also be submitted via CEDRI. Notifications and the accompanying cover letter for periodic reports not submitted via CEDRI shall be sent to the US EPA Region 4 Air and Radiation Division as required by the applicable subpart.
C.3	**Equipment ID:** CTG1, CTG2, CTG3 **Control Device ID:** SCR01, OXCAT01, WIN01, SCR02, OXCAT02, WIN02, SCR03, OXCAT03, WIN03 (S.C. Regulation 61-62.63; 40 CFR 63) These sources are subject to National Emission Standards for Hazardous Air Pollutants for Source Categories (NESHAP), Subpart A, General Provisions and Subpart YYYY, National Emission Standards for Hazardous Air Pollutants for Stationary Combustion Turbines, as applicable. These sources shall comply with all applicable requirements of Subparts A (applicable as shown in Table 7 of YYYY) and YYYY. Existing affected sources shall be in compliance with the requirements of these Subparts by the compliance date, unless otherwise noted. Any new affected sources shall comply with the requirements of these Subparts upon initial start-up unless otherwise noted.
C.4	**Equipment ID:** AB1, HT1, HT2, HT3, HT4 (S.C. Regulation 61-62.63; 40 CFR 63) This source is subject to National Emission Standards for Hazardous Air Pollutants for Source Categories (NESHAP), Subpart A, General Provisions and Subpart DDDDD, Industrial, Commercial, and Institutional Boilers and Process Heaters, as applicable. This source shall comply with all applicable requirements of Subparts A (applicable as shown in Table 10 of DDDDD) and DDDDD. Existing affected sources shall be in compliance with the requirements of these Subparts by the compliance date, unless otherwise noted. Any new affected sources shall comply with the requirements of these Subparts upon initial start-up unless otherwise noted.
C.5	**Equipment ID:** EG1, EG2, EG3, FP1, FP2 (S.C. Regulation 61-62.63; 40 CFR 63) Affected sources: All Stationary IC Engines: This facility is subject to the provisions of 40 CFR Part 63, National Emission Standards for Hazardous Air Pollutants,

C. NESHAP (40 CFR 61 AND 40 CFR 63)	
Condition Number	**Conditions**
	Subparts A and NESHAP for Stationary Reciprocating Internal Combustion Engines. Existing affected sources shall comply with the applicable provisions by the compliance date specified in Subpart ZZZZ. Any new affected sources shall comply with the requirements of this Subpart upon initial start-up unless otherwise noted.

D. GENERAL FACILITY WIDE	
Condition Number	**Conditions**
D.1	The owner or operator shall comply with S.C. Regulation 61-62.6, Control of Fugitive Particulate Matter, Section III Control of Fugitive Particulate Matter Statewide.
D.2	The permittee shall pay permit fees to the Department in accordance with the requirements of S.C. Regulation 61-30, Environmental Protection Fees.
D.3	In the event of an emergency, as defined in S.C. Regulation 61-62.1, Section II(L), the owner or operator may document an emergency situation through properly signed, contemporaneous operating logs, and other relevant evidence that verify: 1. An emergency occurred, and the owner or operator can identify the cause(s) of the emergency; 2. The permitted source was at the time the emergency occurred being properly operated; 3. During the period of the emergency, the owner or operator took all reasonable steps to minimize levels of emissions that exceeded the emission standards, or other requirements in the permit; and 4. The owner or operator gave a verbal notification of the emergency to the Department within twenty-four (24) hours of the time when emission limitations were exceeded, followed by a written report within thirty (30) days. The written report shall include, at a minimum, the information required by S.C. Regulation 61-62.1, Section II(J)(1)(c)(i) through (J)(1)(c)(viii). The written report shall contain a description of the emergency, any steps taken to mitigate emissions, and corrective actions taken. This provision is in addition to any emergency or upset provision contained in any applicable requirement.
D.4	(S.C. Regulation 61-62.1, Section II(O)) Upon presentation of credentials and other documents as may be required by law, the owner or operator shall allow the Department or an authorized representative to perform the following: 1. Enter the facility where emissions-related activity is conducted, or where records must be kept under the conditions of the permit. 2. Have access to and copy, at reasonable times, any records that must be kept under the conditions of the permit.

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D. GENERAL FACILITY WIDE	
Condition Number	**Conditions**
	3. Inspect any facilities, equipment (including monitoring and air pollution control equipment), practices, or operations regulated or required under this permit. 4. As authorized by the Federal Clean Air Act and/or the S.C. Pollution Control Act, sample or monitor, at reasonable times, substances or parameters for the purpose of assuring compliance with the permit or applicable requirements.
D.5	(S.C. Regulation 61-62.1, Section II(J)(1)(a)) No applicable law, regulation, or standard will be contravened.
D.6	(S.C. Regulation 61-62.1, Section II(J)(1)(e)) Any owner or operator who constructs or operates a source or modification not in accordance with the application submitted pursuant to this regulation or with the terms of any approval to construct, or who commences construction after the effective date of these regulations without applying for and receiving approval hereunder, shall be subject to enforcement action.

E. EMISSIONS INVENTORY REPORTS	
Condition Number	**Conditions**
E.1	All newly permitted and constructed Title V sources and/or Non-attainment Area Sources shall complete and submit an emissions inventory consistent with the schedule approved pursuant to S.C. Regulation 61-62.1, Section III. These Emissions Inventory Reports shall be submitted to the Department. This requirement notwithstanding, an emissions inventory may be required at any time in order to determine the compliance status of any facility.

F. GENERAL RECORD KEEPING AND REPORTING	
Condition Number	**Conditions**
F.1	(S.C. Regulation 61-62.1, Section II(J)(1)(g)) A copy of the Department issued construction and/or operating permit must be kept readily available at the facility at all times. The owner or operator shall maintain such operational records; make reports; install, use, and maintain monitoring equipment or methods; sample and analyze emissions or discharges in accordance with prescribed methods at locations, intervals, and procedures as the Department shall prescribe; and provide such other information as the Department reasonably may require. All records required to demonstrate compliance with the limits established under this permit shall be maintained on site for a period of at least five (5) years from the date the record was generated and shall be made available to a Department representative upon request.

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F. GENERAL RECORD KEEPING AND REPORTING	
Condition Number	**Conditions**
F.2	The owner or operator shall submit reports required in this permit in a timely manner and according to the reporting schedule established through the Department's approved electronic permitting system.
F.3	All reports and notifications required under this permit shall be submitted to the Department.
F.4	(S.C. Regulation 61-62.1, Section II(J)(1)(c)) For sources not required to have continuous emission monitors, any malfunction of air pollution control equipment or system, process upset, or other equipment failure which results in discharges of air contaminants lasting for one (1) hour or more and which are greater than those discharges described for normal operation in the permit application, shall be reported to the Department within twenty-four (24) hours after the beginning of the occurrence and a written report shall be submitted to the Department within thirty (30) days. The written report shall include, at a minimum, the following: 1. The identity of the stack and/or emission point where the excess emissions occurred; 2. The magnitude of excess emissions expressed in the units of the applicable emission limitation and the operating data and calculations used in determining the excess emissions; 3. The time and duration of excess emissions; 4. The identity of the equipment causing the excess emissions; 5. The nature and cause of such excess emissions; 6. The steps taken to remedy the malfunction and the steps taken or planned to prevent the recurrence of such malfunction; 7. The steps taken to limit the excess emissions; and, 8. Documentation that the air pollution control equipment, process equipment, or processes were at all times maintained and operated, to the maximum extent practicable, in a manner consistent with good practice for minimizing emissions. The initial twenty-four (24) hour notification should be made to the Department's local Regional Office. The written report should be sent to the Department.
F.5	(S.C. Regulation 61-62.1, Section II(J)(2)) Where submittals, requests, or documents are required by this permit or regulation, they shall be submitted through the Department's ePermitting system. Where the term postmarked is used in this permit or regulation, the ePermitting submittal date shall be applied.
F.6	(S.C. Regulation 61-62.1, Section II(A)(3)) The owner or operator shall submit written notification to the Department of the date construction is commenced, postmarked within thirty (30) days after such date.

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G. PERMIT EXPIRATION AND EXTENSION	
Condition Number	**Conditions**
G.1	(S.C. Regulation 61-62.1, Section II(A)(4) and (5) and S.C. Regulation 61-62.1, Section II(J)(1)(f)) Approval to construct shall become invalid if construction: a. Is not commenced within eighteen (18) months after receipt of such approval; b. Is discontinued for a period of eighteen (18) months or more; or c. Is not completed within a reasonable time as deemed by the Department. The Department may extend the construction permit for an additional eighteen (18) month period upon a satisfactory showing that an extension is justified. This request must be made prior to the permit expiration. This provision does not apply to the time period between construction of the approved phases of a phased construction project; each phase must commence construction within eighteen (18) months of the projected and approved commencement date.

H. PERMIT TO OPERATE	
Condition Number	**Conditions**
H.1	(S.C. Regulation 61-62.1, Section II(F)(3)) When a Department issued construction permit includes engineering and/or construction specifications, the owner or operator or professional engineer in charge of the project shall certify that, to the best of his/her knowledge and belief and as a result of periodic observation during construction, the construction under application has been completed in accordance with the specifications agreed upon in the construction permit issued by the Department. If construction is certified as provided above, the owner or operator may operate the source in compliance with the terms and conditions of the construction permit until the operating permit is issued by the Department. If construction is not built as specified in the permit application and associated construction permit(s), the owner or operator must submit to the Department a complete description of modifications that are at variance with the documentation of the construction permitting determination prior to commencing operation. Construction variances that would trigger additional requirements that have not been addressed prior to start of operation shall be considered construction without a permit.
H.2	(S.C. Regulation 61-62.1, Section II(F)(1)) The owner or operator shall submit written notification to the Department of the actual date of initial startup of each new or altered source, postmarked within fifteen (15) days after such date. Any source that is required to obtain an air quality construction permit issued by the Department must obtain an operating permit when the new or altered source is placed into operation and shall comply with the requirements of this section.
H.3	(S.C. Regulation 61-62.1, Section II(F)(4)(b)) For sources not subject to S.C. Regulation 61-62.70, or not yet covered by an effective Title V operating permit, the owner or operator shall submit a written request to the Department for a new or revised operating permit to cover any new or altered source

H. PERMIT TO OPERATE	
Condition Number	**Conditions**
	postmarked within fifteen (15) days after the actual date of initial startup of each new or altered source. (S.C. Regulation 61-62.1, Section II(F)(4)(c)) The written request for a new or revised operating permit must include, at a minimum, the following information: i. A list of sources that were placed into operation; and ii. The actual date of initial startup of each new or altered source. (S.C. Regulation 61-62.70.5(a)) The owner or operator shall submit a timely and complete Part 70 permit application within twelve (12) months of startup. This Title V application submittal requirement applies to facilities unless they obtain an effective Conditional Major Operating Permit within twelve (12) months of startup of this permit activity. A request for a Conditional Major Operating Permit shall address the requirements specified in S.C. Regulation 61-62.1.

I. AMBIENT AIR STANDARDS	
Condition Number	**Conditions**
I.1	Air dispersion modeling (or other method) has previously demonstrated that this facility's operation will not interfere with the attainment and maintenance of any state or federal ambient air standard. Any changes in the parameters used in this demonstration may require a review by the facility to determine continuing compliance with these standards. These potential changes include any decrease in stack height, decrease in stack velocity, increase in stack diameter, decrease in stack exit temperature, increase in building height or building additions, increase in emission rates, decrease in distance between stack and property line, changes in vertical stack orientation, and installation of a rain cap that impedes vertical flow. Parameters that are not required in the determination will not invalidate the demonstration if they are modified. Variations from the input parameters in the demonstration shall not constitute a violation unless the maximum allowable ambient concentrations identified in the standard are exceeded. The owner or operator shall maintain this facility at or below the emission rates used in the most recent air dispersion modeling (or other method) demonstration submitted to and approved by the Department, not to exceed the pollutant limitations of this permit. Should the facility wish to increase the emission rates used in the demonstration, not to exceed the pollutant limitations in the body of this permit, it may do so by submitting a new demonstration for approval. This condition along with the referenced modeling demonstration will also serve to meet the intent of S.C. Regulation 61-62.5, Standard No. 8, Section II(D). This is a State Only enforceable requirement.

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