NOTICE OF HEARING

TENNESSEE DEPARTMENT OF ENVIRONMENT AND CONSERVATION
DIVISION OF AIR POLLUTION CONTROL
WILLIAM R. SNODGRASS TENNESSEE TOWER
312 ROSA L. PARKS AVENUE, 15th FLOOR
NASHVILLE, TENNESSEE 37243
PHONE: (615) 532-0554 FAX: (615) 532-0614

NOTICE IS HEREBY GIVEN, the Division of Air Pollution Control will hold a public hearing pursuant to Tennessee Code Annotated, Section 68-201-105

Location: Conference Room 15A
William R. Snodgrass Tennessee Tower
312 Rosa L. Parks Avenue, 15th Floor
Nashville, Tennessee

Alternate Hearing Option (Electronic Participation):

Method 1:	Join electronically by going to this link: https://urldefense.com/v3/__https://tn.webex.com/tn/j.php?MTID=m8fc0022a6f6c6fc145fb884f06dbe124__;!!PRtDf9A!-RtjlvRmiilYGqlA375Xhr8S0E-DOEEo9vdxasWec6NbsQSZrURWZLxo9_vEUxMF-w$ Meeting number (access code): 160 620 1611 Meeting password: TPNJsvrvBwi
Method 2:	Join by phone 1-415-655-0001 Access code: 160 620 1611 Global call-in numbers are available online at: Link for Global call-in numbers

Date: June 7, 2021

Public Hearing: 9:30 AM Central Time

There will be a public hearing before the Technical Secretary of the Tennessee Air Pollution Control Board to consider proposed State Implementation Plan (SIP) revisions under the authority of Tennessee Code Annotated, Section 68-201-105.

FIRST ITEM:

Tennessee is proposing a SIP revision to approve alternative monitoring, recordkeeping, and reporting requirements for five boilers subject to the NO_X SIP Call (Boilers 25, 26, 27, 28, and 29) at the B-253 powerhouse owned and operated by Eastman Chemical Company – Tennessee Operations in Kingsport, Tennessee. The specific monitoring requirements will be implemented via operating permit 077509. The Division proposes to issue this permit after appropriate notice and comment and to submit the final permit to U. S. EPA for adoption into Tennessee's State Implementation Plan.

SECOND ITEM

Tennessee is proposing a SIP revision to approve alternative monitoring, recordkeeping, and reporting requirements for one boiler subject to the NO_X SIP Call (Combination Boiler #1) at Packaging Corporation of America's pulp and paper mill in Counce, Tennessee. The specific monitoring requirements will be implemented via operating permit 078563. The Division proposes to issue this permit after appropriate notice and comment and to submit the final permit to U. S. EPA for adoption into Tennessee's State Implementation Plan.

HEARING INFORMATION

The hearing will take place at the location, date, and time indicated above. All persons interested in the air quality of the State of Tennessee are urged to attend and will be afforded the opportunity to present testimony to the hearing officer regarding the proposed State Implementation Plan revision. Anyone desiring to make oral comments at this public hearing is requested to prepare a written copy of their comments to be submitted to the hearing officer at the public hearing. The hearing officer may limit the length of oral comments in order to allow all parties an opportunity to speak and will require that all comments be relevant to the proposed State Implementation Plan revision. Written statements not presented at the hearing will only be considered part of the record if received by close of business on June 7, 2021 at the office of the Technical Secretary, Tennessee Division of Air Pollution Control, 312 Rosa L. Parks Avenue, 15th Floor, William R. Snodgrass Tennessee Tower, Nashville, TN 37243

Individuals with disabilities who wish to participate in these proceedings (or review the file record) should contact TDEC to discuss any auxiliary aids or services needed to facilitate such participation. Contact may be in person, by writing, telephone, or other means, and should be made no less than ten working days prior to June 7, 2021, to allow time to provide such aid or services. Contact the ADA Coordinator (1-866-253-5827) for further information. Hearing impaired callers may use the Tennessee Relay Service (1-800-848-0298).

If you have any questions about the proposed State Implementation Plan revision, you may contact Mr. Travis Blake by phone at (615) 532-0617 or by email at travis.blake@tn.gov. Materials concerning the proposed action are available at http://www.tn.gov/environment/topic/ppo-air.

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Method 2:	Join by phone 1-415-655-0001 Access code: 160 620 1611 Global call-in numbers are available online at: Link for Global call-in numbers

Date: June 9, 2021

Public Hearing: 9:30 AM Central Time

There will be a public hearing before the Technical Secretary of the Tennessee Air Pollution Control Board to consider proposed State Implementation Plan (SIP) revisions under the authority of Tennessee Code Annotated, Section 68-201-105.

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First Item

Eastman Chemical Company – Tennessee Operations
NO_X SIP Call Permit 077509 and 110(l) Demonstration
B-253 Powerhouse (Boilers 25, 26, 27, 28, and 29)

STATE OF TENNESSEE
AIR POLLUTION CONTROL BOARD
DEPARTMENT OF ENVIRONMENT AND CONSERVATION
NASHVILLE, TENNESSEE 37243

OPERATING PERMIT Issued Pursuant to Tennessee Air Quality Act

Issue Date: ******DRAFT******	Permit Number: 077509 Facility ID: 82-0003
Issued To: Eastman Chemical Company	Installation Address 200 South Wilcox Drive Kingsport
Installation Description Natural Gas-Fired Boilers 25-29 (PES B-253-1)	Emission Source Reference No. 82-0003-01 SIP

The holder of this permit shall comply with the conditions contained in this permit as well as all applicable provisions of the Tennessee Air Pollution Control Regulations (TAPCR).

CONDITIONS:

1. Pursuant to 40 CFR §51.121(i)(1), upon issuance of this permit and approval of this permit into Tennessee's State Implementation Plan by U. S. EPA, the permittee may demonstrate compliance with TAPCR 1200-03-27-.11 by monitoring nitrogen oxides (NO_X) emissions from PES B-253-1, Boilers 25 through 29, using the alternative NO_X monitoring provisions contained in **Conditions 2 through 18** of this permit.

   Tennessee Air Pollution Control Regulations (TAPCR) 1200-03-09-.03(8), 40 CFR §51.121(i)(1)

TECHNICAL SECRETARY

No Authority is Granted by this Permit to Operate, Construct, or Maintain any Installation in Violation of any Law, Statute, Code, Ordinance, Rule, or Regulation of the State of Tennessee or any of its Political Subdivisions.

POST AT INSTALLATION ADDRESS

40 CFR Part 75 Appendix E Requirements: Optional NO_X Emissions Estimation Protocol (Conditions 2 through 14)

2. **Certification:** Complete all testing requirements to certify use of this protocol in lieu of a NO_X continuous emission monitoring system and apply to the Technical Secretary for certification to use this method no later than 60 days prior to May 1 of the first control period in which the alternative method will be used. Whenever the monitoring method is to be changed, reapply to the Technical Secretary for certification of the new monitoring method.

3. **Initial Performance Testing:** Use the following procedures for: measuring NO_X emission rates at heat input rate levels corresponding to different load levels; measuring heat input rate; and plotting the correlation between heat input rate and NO_X emission rate, in order to determine the emission rate of the unit(s). The requirements of 40 CFR 75 Appendix A, section 6.1.2, shall apply to any stack testing performed to obtain oxygen (O_2) and NO_X concentration measurements under this condition.

4. **Load Selection:** Establish at least four approximately equally spaced operating load points, ranging from the maximum operating load to the minimum operating load. Select the maximum and minimum operating load from the operating history of the unit during the most recent two years. If projections indicate that the unit's maximum or minimum operating load during the next five years will be significantly different from the most recent two years, select the maximum and minimum operating load based on the projected dispatched load of the unit.

5. **NO_X and O_2 Concentration Measurements:** Use the following procedures to measure NO_X and O_2 concentration in order to determine NO_X emission rate.

   (a) Select an excess O_2 level to be combusted that is representative for each load level.

   (b) Operate the boiler at a normal or conservatively high excess oxygen level in conjunction with these tests. Measure the NO_X and O_2 at each load point for each fuel or consistent fuel combination (and, optionally, for each combination of fuels) to be combusted.

   (c) Measure the NO_X and O_2 concentrations according to methods 7E and 3A in 40 CFR 60 Appendix A. Use a minimum of 12 sample points, located according to Method 1 in 40 CFR 60 Appendix A-1.

   (d) Allow the unit to stabilize for a minimum of 15 minutes (or longer, if needed for the NO_X and O_2 readings to stabilize) prior to commencing NO_X, O_2, and heat input measurements. Determine the measurement system response time according to sections 8.2.5 and 8.2.6 of method 7E in 40 CFR 60 Appendix A-4. When inserting the probe into the flue gas for the first sampling point in each traverse, sample for at least one minute plus twice the measurement system response time (or longer, if necessary, to obtain a stable reading). For all other sampling points in each traverse, sample for at least one minute plus the measurement system response time (or longer, if necessary, to obtain a stable reading). Perform three test runs at each load condition and obtain an arithmetic average of the runs for each load condition. During each test run on a boiler, record the boiler excess oxygen level at five-minute intervals.

6. **Heat Input:** Measure the total heat input (MMBtu) and heat input rate during testing (MMBtu/hr) as follows: When the unit is combusting fuel, measure and record the flow of fuel consumed. Measure the flow of fuel with in-line flow meters and automatically record the data. If a portion of the flow is diverted from the unit without being burned, and that diversion occurs downstream of the fuel flow meter, an in-line flow meter is required to account for the unburned fuel. Install and calibrate in-line flow meters using the procedures and specifications contained in 40 CFR 75 Appendix D (see **Conditions 15 and 16**). Correct any gaseous fuel flow rate measured at actual temperature and pressure to standard conditions of 68 °F and 29.92 inches of mercury.

7. **Tabulation of Results:** Tabulate the results of each baseline correlation test for each fuel or, as applicable, combination of fuels, listing: time of test, duration, operating loads, heat input rate (MMBtu/hr), F-factors, excess oxygen levels, and NO_X concentrations (ppm) on a dry basis (at actual excess oxygen level). Convert the NO_X concentrations (ppm) to NO_X emission rates (to the nearest 0.001 lb/MMBtu) according to equation F-5 of 40 CFR 75 Appendix F or equation 19-3 in method 19 of 40 CFR 60 Appendix A, as appropriate. Calculate the NO_X emission rate in lb/MMBtu for each sampling point and determine the arithmetic average NO_X emission rate of each test run. Calculate the arithmetic average of the boiler excess oxygen readings for each test run. Record the arithmetic average of the three test runs as the NO_X emission rate and the boiler excess oxygen level for the heat input/load condition.

8. **Plotting of Results:** Plot the tabulated results as an x-y graph for each fuel and (as applicable) combination of fuels combusted according to the following procedures: Plot the heat input rate (MMBtu/hr) as the independent (or x) variable and the NO_X

emission rates (lb/MMBtu) as the dependent (or y) variable for each load point. Construct the graph by drawing straight line segments between each load point. Draw a horizontal line to the y-axis from the minimum heat input (load) point.

9. **Periodic NO_X Emission Rate Testing:** Retest the NO_X emission rate at least once every 20 calendar quarters. If a required retest is not completed by the end of the 20th calendar quarter following the quarter of the last test, use the missing data substitution procedures in **Condition 12**, beginning with the first unit operating hour after the end of the 20th calendar quarter. Continue using the missing data procedures until the required retest has been passed. Each time that a new fuel-specific correlation curve is derived from retesting, the new curve shall be used to report NO_X emission rate, beginning with the first operating hour in which the fuel is combusted, following the completion of the retest, or, if the NO_X emission rate testing is performed outside the ozone season, the new correlation curve may be used beginning with the first unit operating hour in the ozone season immediately following the testing.

10. **Other Quality Assurance/Quality Control-Related NOx Emission Rate Testing:** When the operating levels of certain parameters exceed the limits specified below, or where the Technical Secretary issues a notice requesting retesting because the NO_X emission rate data availability is less than 90.0 percent, complete retesting of the NO_X emission rate by the earlier of:

(a) 30 unit operating days (as defined in 40 CFR §72.2); or

(b) 180 calendar days after exceeding the limits or after the date of issuance of a notice from the Technical Secretary to re-verify the unit's NO_X emission rate. Submit test results in accordance with 40 CFR §75.60 within 45 days of completing the retesting.

For boilers using the procedures in this permit, the NO_X emission rate and heat input correlation shall be redetermined if the excess oxygen level at any heat input rate (or unit operating load) continuously exceeds by more than two percentage points O_2 from the boiler excess oxygen level recorded at the same operating heat input rate during the previous NO_X emission rate test for one or more successive operating periods totaling more than 16 unit operating hours.

11. **Procedures for Determining Hourly NO_X Emission Rate:**

(a) Record the time (hr. and min.), load (MWge or steam load in 1,000 lb/hr, or MMBtu/hr thermal output), fuel flow rate and heat input rate (using the procedures in **Condition 6**) for each hour during which the unit combusts fuel. Calculate the total hourly heat input using equation E-1 of **Condition 13(a)**. Record the heat input rate for each fuel to the nearest 0.1 MMBtu/hr. During partial unit operating hours or during hours where more than one fuel is combusted, heat input must be represented as an hourly rate in MMBtu/hr, as if the fuel were combusted for the entire hour at that rate (and not as the actual, total heat input during that partial hour or hour) in order to ensure proper correlation with the NO_X emission rate graph.

(b) Use the graph of the baseline correlation results (appropriate for the fuel or fuel combination) to determine the NO_X emissions rate (lb/MMBtu) corresponding to the heat input rate (MMBtu/hr). Input this correlation into the data acquisition and handling system for the unit. Linearly interpolate to 0.1 MMBtu/hr heat input rate and 0.001 lb/MMBtu NO_X. Calculate NO_X emission rate using the baseline correlation results from the most recent test with that fuel, beginning with the date and hour of the completion of the most recent test.

(c) For each hour, record the critical quality assurance parameters, as identified in the monitoring plan, and as required by **Condition 10** from the date and hour of the completion of the most recent test for each type of fuel.

12. **Missing Data Procedures:** Provide substitute data for each unit electing to use this alternative procedure whenever a valid quality-assured hour of NO_X emission rate data has not been obtained according to the procedures and specifications of this appendix. For the purpose of providing substitute data, calculate the maximum potential NO_X emission rate, as defined in 40 CFR §72.2.

(a) Use the procedures of this condition whenever any of the quality assurance/quality control parameters exceeds the limits in **Condition 10** or whenever any of the quality assurance/quality control parameters are not available.

(b) Substitute missing NO_X emission rate data using the highest NO_X emission rate tabulated during the most recent set of baseline correlation tests, except as provided in **Conditions 12(c), 12(d), and 12(f)**.

(c) If the measured heat input rate during any unit operating hour is higher than the highest heat input rate from the baseline correlation tests, the NO_X emission rate for the hour is considered to be missing. Provide substitute data for each such hour, according to the following procedures, as applicable. Either:

(i) Substitute the higher of: the NO_X emission rate obtained by linear extrapolation of the correlation curve, or the maximum potential NO_X emission rate (MER) (as defined in §72.2), specific to the type of fuel being combusted; or

(ii) Substitute 1.25 times the highest NO_X emission rate from the baseline correlation tests for the fuel (or fuel mixture) being combusted in the unit, not to exceed the MER for that fuel (or mixture).

(d) Whenever 20 full calendar quarters have elapsed following the quarter of the last baseline correlation test for a particular type of fuel (or fuel mixture), without a subsequent baseline correlation test being done, substitute the fuel-specific NO_X MER (as defined in 40 CFR §72.2) for each hour in which that fuel is combusted until a new baseline correlation test for that fuel has been successfully completed.

(e) Maintain a record indicating which data are substitute data and the reasons for the failure to provide a valid quality-assured hour of NO_X emission rate data according to the procedures and specifications of this permit.

(f) Substitute missing data from a fuel flow meter using the procedures in **Condition 18**.

(g) Substitute missing data for gross calorific value of fuel using the procedures in **Condition 17**.

13. **Calculations**.

(a) Calculate the total heat input by summing the product of heat input rate and fuel usage time of each fuel, as in the following equation:

$$H_T = HI_{fuel1} t_1 + HI_{fuel2} t_2 + HI_{fuel3} t_3 + \ldots + HI_{lastfuel} t_{last} \qquad \text{(Eq. E-1)}$$

Where:

H_T = Total heat input of fuel flow or a combination of fuel flows to a unit, MMBtu.

$HI_{fuel\ 1,2,3,\ldots last}$ = Heat input rate from each fuel, in MMBtu/hr as determined using Equation F-19 or F-20 in section 5.5 of 40 CFR 75 Appendix F.

$t_{1,2,3\ldots.last}$ = Fuel usage time for each fuel (rounded up to the nearest fraction of an hour (in equal increments that can range from one hundredth to one quarter of an hour, at the option of the owner or operator)).

(b) Use the F-factors in Table 13-1 as applicable.

Table 13-1: F- and F_c-Factors[1]

Fuel	**F-factor (dscf/MMBtu)**	**F_C-factor (scf CO_2/MMBtu)**
Natural Gas	8,710	1,040

[1]Determined at standard conditions: 20 °C (68 °F) and 29.92 inches of mercury.

(c) Convert the NO_X concentrations (ppm) and O_2 concentrations to NO_X emission rates to the nearest 0.001 lb/MMBtu, according to the appropriate one of the following equations: F-5 in 40 CFR 75 Appendix F for dry basis concentration measurements or 19-3 in Method 19 of 40 CFR 60 Appendix A for wet basis concentration measurements.

(d) Report the quarterly average emission rate (lb/MMBtu) as required in 40 CFR 75 Subpart G. Calculate the quarterly average NO_X emission rate according to equation F-9 in 40 CFR 75 Appendix F.

(e) Report the average emission rate (lb/MMBtu) for the calendar year as required in 40 CFR 75 Subpart G. Calculate the average NO_X emission rate according to equation F-10 in 40 CFR 75 Appendix F.

14. **Quality assurance/quality control:**

(a) Include a section on the NO_X emission rate determination as part of the monitoring quality assurance/quality control plan required under §75.21 and 40 CFR 75 Appendix B for each unit, including: (1) a copy of all data and results from the initial NO_X emission rate testing, including the values of quality assurance parameters specified in **Condition 10**; (2) a copy of all data and results from the most recent NO_X emission rate load correlation testing; (3) a copy of the recommended range of quality assurance- and quality control-related operating parameters.

(b) Submit a copy of the recommended range of operating parameter values, and the range of operating parameter values recorded during the previous NO_X emission rate test that determined the unit's NO_X emission rate, along with the unit's revised monitoring plan submitted with the certification application.

(c) Keep records of these operating parameters for each hour of operation in order to demonstrate that a unit is remaining within the recommended operating range.

40 CFR Part 75 Appendix D Requirements: Optional NO_X Emissions Estimation Protocol (Conditions 15 through 18)

15. For each hour when the unit is combusting fuel, measure and record the flow rate of fuel combusted by the unit, measure the flow rate of fuel with an in-line fuel flow meter, and automatically record the data with a data acquisition and handling system. Install and use fuel flow meters in a pipe going to each unit or install and use a fuel flow meter in a common pipe header (as defined in 40 CFR §72.2). When a fuel flow meter is installed in a common pipe header, proceed as follows:

(a) Apportion the heat input rate measured at the common pipe to the individual units, using Equation F-21a, F-21b, or F-21d in 40 CFR 75 Appendix F.

(b) For a gas-fired unit or an oil-fired unit that continuously or frequently combusts a supplemental fuel for flame stabilization or safety purposes, measure the flow rate of the supplemental fuel with a fuel flow meter meeting the requirements of this permit.

16. **Initial Certification Requirement for all Fuel Flow Meters:** For the purposes of initial certification, each fuel flow meter shall meet a flow meter accuracy of 2.0 percent of the upper range value (i.e. maximum fuel flow rate measurable by the flow meter) across the range of fuel flow rate to be measured at the unit. Flow meter accuracy may be determined under **Condition 16(a)** for initial certification in any of the following ways (as applicable): by design (orifice, nozzle, and venturi-type flow meters, only) or by measurement under laboratory conditions; by the manufacturer; by an independent laboratory; or by the owner or operator. Flow meter accuracy may also be determined under **Condition 16(b)** by in-line comparison against a reference flow meter.

(a) Use the procedures in the following standards to verify flow meter accuracy or design, as appropriate to the type of flow meter: ASME MFC-3M-2004, Measurement of Fluid Flow in Pipes Using Orifice, Nozzle, and Venturi; ASME MFC-4M-1986 (Reaffirmed 1997), Measurement of Gas Flow by Turbine Meters; American Gas Association Report No. 3, Orifice Metering of Natural Gas and Other Related Hydrocarbon Fluids Part 1: General Equations and Uncertainty Guidelines (October 1990 Edition), Part 2: Specification and Installation Requirements (February 1991 Edition), and Part 3: Natural Gas Applications (August 1992 edition) (excluding the modified flow-calculation method in part 3); Section 8, Calibration from American Gas Association Transmission Measurement Committee Report No. 7: Measurement of Gas by Turbine Meters (Second Revision, April 1996); ASME-MFC-5M-1985 (Reaffirmed 1994), Measurement of Liquid Flow in Closed Conduits Using Transit-Time Ultrasonic Flow meters; ASME MFC-6M-1998, Measurement of Fluid Flow in Pipes Using Vortex Flow meters; ASME MFC-7M-1987 (Reaffirmed 1992), Measurement of Gas Flow by Means of Critical Flow Venturi Nozzles; ISO 8316: 1987(E) Measurement of Liquid Flow in Closed Conduits—Method by Collection of the Liquid in a Volumetric Tank; American Petroleum Institute (API) Manual of Petroleum Measurement Standards, Chapter 4—Proving Systems, Section 2—Pipe Provers (Provers Accumulating at Least 10,000 Pulses), Second Edition, March 2001, Section 3—Small Volume Provers, First Edition, July 1988, Reaffirmed October 1993, and Section 5—Master-Meter Provers, Second Edition, May 2000; American Petroleum Institute (API) Manual of Petroleum Measurement Standards, Chapter 22—Testing Protocol, Section 2—Differential Pressure Flow Measurement Devices, First Edition, August 2005; or ASME MFC-9M-1988 (Reaffirmed 2001), Measurement of Liquid Flow in Closed Conduits by Weighing Method, for all other flow meter types (all incorporated by reference under §75.6 of this part). The Administrator may also approve other procedures that use equipment traceable to National Institute of Standards and Technology standards. Document such procedures, the equipment used, and the accuracy of the procedures in the monitoring plan for the unit, and submit a petition signed by the designated representative under §75.66(c). If the flow meter accuracy exceeds 2.0 percent of the upper range value, the flow meter does not qualify for use under this part.

(b) Determine the flow meter accuracy of a fuel flow meter used for the purposes of this part by comparing it to the measured flow from a reference flow meter

(i) The reference flow meter must be designed according to the specifications of American Gas Association Report No. 3 or ASME MFC-3M-1989 or tested for accuracy using a standard listed in **Condition 16(a)** during the previous 365 days. Any secondary elements, such as pressure and temperature transmitters, must be calibrated immediately prior to the comparison. Perform the comparison over a period of no more than seven consecutive unit operating days. Compare the average of three fuel flow rate readings over 20 minutes or longer for each meter at each of three different flow rate levels. The three flow rate levels shall correspond to:

(A) Normal full unit operating load,

(B) Normal minimum unit operating load,

(C) A load point approximately equally spaced between the full and minimum unit operating loads, and

(ii) Calculate the flow meter accuracy at each of the three flow levels using the following equation:

$$ACC = \frac{|R - A|}{URV} \times 100 \qquad \text{(Eq. D-1)}$$

Where:

ACC = Flow meter accuracy at a particular load level, as a percentage of the upper range value.

R = Average of the three flow measurements of the reference flow meter.

A = Average of the three measurements of the flow meter being tested.

URV = Upper range value of fuel flow meter being tested (i.e. maximum measurable flow).

(iii) When an in-place reference meter or prover is used for quality assurance under **Condition 16(b)**, the reference meter calibration requirement (calibrate within 365 days prior to an accuracy test) may be waived if, during the previous in-place accuracy test with that reference meter, the reference flow meter and the flow meter being tested agreed to within ±1.0 percent of each other at all levels tested. This exception shall apply for periods of no longer than 20 consecutive calendar quarters.

(c) If the flow meter accuracy exceeds 2.0%, the flow meter does not qualify for use for this appendix. Either recalibrate the flow meter until the flow meter accuracy is within the performance specification or replace the flow meter with another one that is demonstrated to meet the performance specification. Substitute for fuel flow rate using the missing data procedures in **Condition 18** until quality-assured fuel flow data become available.

(d) For purposes of initial certification, when a flow meter is tested against a reference fuel flow rate (i.e., fuel flow rate from another fuel flow meter under **Condition 16(b)** or flow rate from a procedure performed according to a standard incorporated by reference under **Condition 16(a)**), report the results of flow meter accuracy tests in a manner consistent with **Table 16-1**.

Table 16-1—Table of Flow meter Accuracy Results					
Test number:________ Test completion date[1]:____________________ Test completion time[1]:____________					
Reinstallation date[2] (for testing under 2.1.5.1 only):____________________ Reinstallation time[2]:____________					
Unit or pipe ID: Component/System ID:					
Flow meter serial number: Upper range value:					
Units of measure for flow meter and reference flow readings:					
Measurement level (percent of URV)	**Run No.**	**Time of run (HHMM)**	**Candidate flow meter reading**	**Reference flow reading**	**Percent accuracy (percent of URV)**
Low (Minimum) level ____ percent[3] of URV	1				
	2				
	3				
	Average				
Mid-level ____ percent[3] of URV	1				
	2				
	3				
	Average				
High (Maximum) level ____ percent[3] of URV	1				
	2				
	3				
	Average				

[1]Report the date, hour, and minute that all test runs were completed.

[2]For laboratory tests not performed inline, report the date and hour that the fuel flow meter was reinstalled following the test.

[3]It is required to test at least at three different levels: (1) normal full unit operating load, (2) normal minimum unit operating load, and (3) a load point approximately equally spaced between the full and minimum unit operating loads.

17. When gross calorific value data are missing or invalid for a gas sample, substitute the maximum potential gross calorific value of that fuel (110,000 Btu per 100 standard cubic feet for pipeline natural gas). This value shall be reported whenever the results of a required GCV is missing or invalid.

18. Whenever data are missing from any primary fuel flow meter system (as defined in §72.2) and there is no backup system available to record the fuel flow rate, then substitute for each hour of missing data using the maximum potential fuel flow rate. The maximum potential fuel flow rate is the lesser of the following:

    (a) The maximum fuel flow rate the unit is capable of combusting; or

    (b) The maximum flow rate that the fuel flow meter can measure (i.e., the upper range value of the flow meter).

19. **Reporting**: The permittee shall submit reports in accordance with 40 CFR 75 Subpart G, as applicable.

Proposed Approval of Alternative Monitoring and Clean Air Act §110(l) Demonstration

Eastman Chemical Company, B-253 Powerhouse, Boilers 25-29
Tennessee Air Pollution Control Regulations 1200-03-27-.12(11)

On September 17, 2019, Eastman Chemical Company submitted a petition to request approval of alternative monitoring, recordkeeping, and reporting requirements for five boilers subject to the NO_X SIP Call (Boilers 25, 26, 27, 28, and 29) at Eastman's B-253 powerhouse. The Tennessee Department of Environment and Conservation, Division of Air Pollution Control, is proposing to approve Eastman's petition, subject to the limitations and exceptions identified herein.

The specific monitoring requirements for the B-253 powerhouse will be implemented via operating permit 077509. The Division proposes to issue this permit after appropriate notice and comment and to submit the final permit to U. S. EPA for adoption into Tennessee's State Implementation Plan.

I. Background

On October 27, 1998 (63 FR 57356), EPA adopted the *Finding of Significant Contribution and Rulemaking for Certain States in the Ozone Transport Assessment Group Region for Purposes of Reducing Regional Transport of Ozone* (NO_X SIP Call), which required 22 States and the District of Columbia to submit State Implementation Plan (SIP) revisions to prohibit specified amounts of NO_X emissions for the purpose of reducing NO_X and ozone transport across State boundaries in the eastern half of the United States. This rule also established the NO_X Budget Trading Program, which allowed States to comply with the required emissions reductions via an interstate cap-and-trade program for electric generating units (EGUs) and for large industrial boilers and combustion turbines (i. e., non-EGUs). Tennessee implemented the NO_X Budget Trading Program between 2003 and 2008, when the program was superseded by the Clean Air Interstate Rule (CAIR) Ozone Season NO_X Trading Program.

EPA replaced CAIR with the Cross-State Air Pollution Rule (CSAPR) NO_X trading programs on January 1, 2015. The applicability provisions of the CSAPR ozone season trading programs cover EGUs only, and non-EGU boilers are not covered under CSAPR. To preserve the NO_X reductions established by the NOX SIP Call, the Tennessee Air Pollution Control Board approved Tennessee Air Pollution Control Regulations (TAPCR) 1200-03-27-.12 (NO_X SIP Call Requirements for Stationary Boilers and Combustion Turbines). Tennessee submitted the rule to EPA' s Region 4 office on February 27, 2017 and requested that EPA approve the rule into Tennessee's SIP.

TAPCR 1200-03-27-.12(11)(a) requires the owners and operators of an affected unit to comply with the applicable monitoring, recordkeeping, and reporting requirements provided in 40 CFR part 75 for each control period. On March 8, 2019, EPA published a final rule revising the emissions monitoring provisions required under the NO_X SIP Call (84 FR 8422). This rule allows States to amend their SIPs to establish emissions monitoring alternatives to Part 75 for units subject to the NO_X SIP Call[1]. In approving this rule, EPA stated that the Part 75 monitoring requirements were applied to non-EGU sources in the context of regional emission trading programs, including the NO_X Budget Trading Program and the CAIR NO_X Ozone Season Trading

[1] This revision does not include EGUs or other units subject to the Acid Rain Program or the CSAPR emission trading programs.

Program, which have been discontinued[2]. EPA also noted the substantial margins by which NO_X SIP Call States are complying with their emissions budgets – overall seasonal NO_X emissions from NO_X SIP Call States are less than 40% of the States' NO_X budgets, and no State reported NO_X emissions exceeding 71% of its budget[3].

SIPs that approve alternatives to Part 75 must continue to include some form of emissions monitoring requirements for these types of sources, consistent with the NO_X SIP Call's general enforceability and monitoring requirements at § 51.121(f)(1) and (i)(1).

II. Current Monitoring Requirements

§ 75.10 requires affected sources to install, certify, operate, and maintain, in accordance with all the requirements of Part 75, a NO_X-diluent continuous emission monitoring system (CEMS), consisting of a NO_X pollutant concentration monitor and an O_2 or CO_2 diluent gas monitor, with an automated data acquisition and handling system for measuring and recording NO_X concentration (in ppm), O_2 or CO_2 concentration (in percent O_2 or CO_2) and NO_X emission rate (in lb/MMBtu) discharged to the atmosphere, except as provided in §§75.12 and 75.17 and Subpart E of Part 75. Pursuant to §75.12(c), hourly, quarterly, and annual NO_X emission rates must be calculated from the NO_X concentration, diluent concentration, and percent moisture (if applicable) measurements using the procedures established in Appendix F to Part 75.

III. Requested Alternative Monitoring

The petition requests approval to use 40 CFR Part 75 Appendix E (Optional NO_X Emissions Estimation Protocol for Gas-Fired Peaking Units and Oil-Fired Peaking Units) as an alternative to the CEMS requirements of Part 75. Appendix E establishes the following methodology:

1. Establish at least four approximately equally spaced operating load points, ranging from the maximum operating load to the minimum operating load based on the operating history of the unit during the most recent two years or on the projected dispatched load of the unit.

2. Select an excess O_2 level for each fuel that is representative of each load level. Operate the boiler at a normal or conservatively high excess oxygen level in conjunction with these tests. Measure the NO_X and O_2 concentrations at each load point using the test methods specified in Section 2.1.2 of Appendix E.

3. Measure the total heat input (MMBtu) and heat input rate (MMBtu/hr) using the test methods specified in Section 2.1.3 of Appendix E.

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[2] EPA notes that Part 75 monitoring is necessary for emission trading programs, because these programs can function only with timely reporting of consistent, quality-assured mass emissions data by all participating units.

[3] For Tennessee, EPA reported the following numbers for 2019:

2019 Ozone Season non-EGU NO_X Emissions (tons)		
NO_X Emissions (tons)	**NO_X Budget**	**Total Emissions (% of Budget)**
1,870	5,666 (3,928*)	34% (48%*)
* The non-EGU portion of Tennessee's NO_X budget is 5,666 tons. Of this total, 1,738 tons are set aside for new source growth, leaving 3,928 tons of NO_X emissions allocated to existing units. The 2018 non-EGU NO_X emissions, as a percentage of Tennessee's NO_X budget, were calculated using both numbers.		

4. Calculate the NO_X emission rate in lb/MMBtu for each sampling point and determine the arithmetic average NO_X emission rates and boiler excess oxygen readings for each test run. Tabulate the results of each baseline correlation test, listing: time of test, duration, operating loads, heat input rate (MMBtu/hr), F-factors, excess oxygen levels, and NO_X concentrations (ppm, dry basis at actual excess oxygen level).

5. Plot the heat input rate (MMBtu/hr) as the independent variable and the NO_X emission rates (lb/MMBtu) as the dependent variable for each load point. Construct the graph by drawing straight line segments between each load point. Draw a horizontal line to the y-axis from the minimum heat input (load) point.

6. Record the time, load, fuel flow rate, and heat input rate for each hour during which the unit combusts fuel. Use the graph of the baseline correlation results (appropriate for the fuel or fuel combination) to determine the NO_X emissions rate (lb/MMBtu) corresponding to the heat input rate (MMBtu/hr). Use the data substitution procedures required by Section 2.5 of Appendix E whenever a valid quality-assured hour of NO_X emission rate data is not obtained.

7. Develop and implement a quality assurance/quality control (QA/QC) plan for the monitoring systems as specified in Appendix B to Part 75. Make all procedures, maintenance records, and ancillary supporting documentation available for review upon request from the permitting authority.

8. Retest the NO_X emission rate of the gas-fired peaking unit or the oil-fired peaking unit while combusting each type of fuel (or fuel mixture) for which a NO_X emission rate versus heat input rate correlation curve was derived, at least once every 20 calendar quarters. If a required retest is not completed by the end of the 20th calendar quarter following the quarter of the last test, use the missing data substitution procedures in Section 2.5 of Appendix E.

   Earlier retesting is required as specified in Section 2.3, under the circumstances indicated below. Test results must be submitted in accordance with §75.60 within 45 days of completing the retesting.

   (a) The NO_X emission rate heat input correlation must be redetermined if the excess oxygen level at any heat input rate (or unit operating load) continuously exceeds by more than 2 percentage points O_2 from the boiler excess oxygen level recorded at the same operating heat input rate during the previous NO_X emission rate test for one or more successive operating periods totaling more than 16 unit operating hours.

   (b) Retesting is required if the NO_X emission rate data availability since the last test is less than 90.0% and the Administrator issues a notice requesting retesting.

IV. Justification for Alternative Monitoring

The petition states that NO_X emission rates from Eastman's B-253 boilers, which were converted from coal to natural gas operation between 2013 and 2018, are approximately 20% of the pre-conversion emission rates. As a result, Eastman operates with a substantial margin of compliance relative to the facility's NO_X allocation.

Eastman's allocation is 3,047 tons, and the petition states that Eastman emitted 70% of its allocation during the 2018 ozone season. The petition also notes that if Boiler 26 had been converted to gas for the 2018 control period, Eastman would have emitted approximately 60% of its allocation. The petition indicates that these boilers burn only pipeline quality natural gas and that the units have similar average NO_X emission rates over the history to-date (Table 1).

Table 1: Comparison of B-253 Boiler Ozone Season NO_X Emission Rates

Boiler	Average NO_X Emission Rate (lb/MMBtu)		
	2016	2017	2018
253-25	0.086	0.086	0.085
253-26	N/A*	N/A	N/A
253-27	0.089	0.097	0.093
253-28	N/A	0.083	0.077
253-29	N/A	N/A	0.087

* NO_X emission rates are listed as N/A for boilers that combusted coal during a specific ozone season.

V. Review of Eastman's Alternative Monitoring Request, Clean Air Act §110(l) Requirements

The Division of Air Pollution Control reviewed Eastman's alternative monitoring request, giving consideration to emissions from the affected unit and the adequacy of the proposed monitoring method.

Attainment and maintenance plans in Tennessee rely upon control of NO_X emissions. Section 110(l) of the Clean Air Act (CAA)[4] prohibits revision of a SIP that would interfere with attainment or maintenance of a NAAQS, reasonable further progress toward attainment of a NAAQS, or any other applicable requirement of the CAA. Because this rule is part of Tennessee's SIP, the requirements of CAA §110(l) must be satisfied before changing the existing monitoring requirements.

The Division proposes to approve Eastman's request. The proposed revision would not interfere with any applicable requirement concerning attainment or maintenance of a NAAQS or reasonable further progress toward attainment of a NAAQS.

- NO_X emissions from Eastman's affected units, including B-253 Boilers 25 through 29, are substantially below the facility's NO_X budget established pursuant to 1200-03-27-.12, and the change would not result in an increase in NO_X emissions. The proposed monitoring alternative would not alter the NO_X SIP Call budget that limits emissions from the affected unit.

- The alternate monitoring requirements are permanent, enforceable and sufficient to determine whether the source is in compliance with the NO_X SIP Call emissions requirements.

- The work practice requirements of 40 CFR 63 Subpart DDDDD (periodic tune-ups) will provide additional assurance of proper boiler operation

[4] "Each revision to an implementation plan submitted by a State under this chapter shall be adopted by such State after reasonable notice and public hearing. The Administrator shall not approve a revision of a plan if the revision would interfere with any applicable requirement concerning attainment and reasonable further progress (as defined in section 7501 of this title), or any other applicable requirement of this chapter."

V.1. Emissions

EPA's proposed approval of NO_X SIP Call monitoring alternatives (83 FR 48751) notes the substantial margin by which NO_X SIP Call states are complying with the portions of their statewide emissions budgets assigned to large EGUs and large non-EGU boilers and turbines, averaging less than 40% of the statewide NO_X budgets in 2017.

Eastman's B-253 boilers were converted from coal to natural gas operations between 2014 and 2018, as indicated in Table 2. Eastman's NO_X SIP Call allowance allocation is 3,047 tons, and EPA's Clean Air Markets database (Table 3)[5] indicates that Eastman emitted 54% of its allocation during the 2019 ozone season. EPA's data demonstrate a substantial decline in Eastman's ozone season NO_X emissions since 2017, which was driven primarily by repowering of Eastman's B-253 Boilers (Table 4).

Table 2: B-253 Startup Dates Following Conversion to Natural Gas

Boiler	Startup Date Burning Natural Gas
253-25	4/23/2014
253-26	10/4/2018
253-27	4/23/2016
253-28	10/2/2016
253-29	3/30/2018

Table 3: Eastman NO_X Emissions (All NO_X SIP Call Sources), 2003 – 2019

Year	Program	NO_X Emissions (tons)	Heat Input (MMBtu)	NO_X Emission Rate (lb/MMBtu)
2003	NBP	2,931	16,546,038	0.354
2004	NBP	2,488	13,627,131	0.365
2005	NBP	2,730	17,031,695	0.321
2006	NBP	2,833	16,943,526	0.334
2007	NBP	2,623	15,755,547	0.333
2008	CAIROS	2,639	16,086,750	0.328
2009	CAIROS	2,634	14,817,086	0.356
2010	CAIROS	2,961	16,921,905	0.350
2011	CAIROS	2,978	17,021,743	0.350
2012	CAIROS	2,950	16,902,058	0.349
2013	CAIROS	2,930	17,481,472	0.335
2014	CAIROS	2,949	17,106,922	0.345
2015	SIPNOX	3,012	17,350,946	0.347
2016	SIPNOX	2,796	17,279,303	0.324
2017	SIPNOX	2,224	17,593,154	0.253
2018	SIPNOX	2,145	18,346,901	0.234
2019	SIPNOX	1,656	17,585,764	0.188

[5] https://ampd.epa.gov/ampd/

Table 3: Clean Air Markets Emissions Data, 2003-2019 Eastman Chemical Company, B-253 Powerhouse											
		NO_X Emissions (tons)					NO_X Emission Rate (MMBtu)				
Year	**Program(s)**	**253-25**	**253-26**	**253-27**	**253-28**	**253-29**	**253-25**	**253-26**	**253-27**	**253-28**	**253-29**
2003	NBP	385.1	324.1	330.6	348.1	182.0	0.376	0.324	0.329	0.321	0.327
2004	NBP	286.2	294.4	349.2	282.5	268.5	0.335	0.369	0.362	0.342	0.340
2005	NBP	304.3	297.8	340.2	304.6	314.0	0.327	0.311	0.319	0.312	0.299
2006	NBP	330.8	316.9	342.7	241.6	329.1	0.330	0.322	0.321	0.306	0.320
2007	NBP	306.9	304.2	313.2	314.7	259.5	0.341	0.327	0.338	0.335	0.307
2008	CAIROS	330.1	327.1	283.8	283.0	274.0	0.332	0.339	0.303	0.317	0.307
2009	CAIROS	283.4	314.1	372.0	292.7	299.2	0.367	0.371	0.398	0.383	0.347
2010	CAIROS	352.6	309.1	356.2	282.6	417.8	0.351	0.320	0.353	0.345	0.452
2011	CAIROS	380.6	381.2	381.7	363.5	364.7	0.387	0.354	0.360	0.371	0.476
2012	CAIROS	329.6	342.1	354.3	368.9	378.8	0.345	0.350	0.350	0.434	0.393
2013	CAIROS	411.0	329.0	309.4	303.2	284.9	0.434	0.318	0.309	0.301	0.315
2014	CAIROS	91.1	266.9	467.7	511.5	342.3	0.086	0.374	0.461	0.521	0.326
2015	SIPNOX	86.6	355.6	427.5	504.3	294.5	0.082	0.332	0.455	0.537	0.343
2016	SIPNOX	79.4	453.2	108.4	424.8	408.7	0.086	0.497	0.089	0.502	0.453
2017	SIPNOX	97.4	410.6	119.9	100.7	247.0	0.086	0.461	0.097	0.083	0.338
2018	SIPNOX	94.4	403.3	96.6	90.0	103.9	0.084	0.553	0.093	0.077	0.087
2019	SIPNOX	92.7	99.7	93.5	74.6	86.8	0.086	0.085	0.085	0.076	0.086

Table 5 shows Tennessee's NO_X emissions for all affected non-EGU sources subject to the NO_X Budget Trading Program (2003 – 2008), CAIR NO_X Ozone Season Trading Program (2009 – 2014), and State NO_X SIP Call regulation (2015 – 2019). Since the implementation of the NO_X Budget Trading Program in 2004, Tennessee's ozone season NO_X emissions from these affected sources have decreased from 59.8% of Tennessee's non-EGU NO_X Budget in 2004 to 33.0% of Tennessee's non-EGU NO_X Budget in 2019.

Table 5: Statewide Non-EGU NO_X Emissions, 2003 – 2019

Year	Total NO_X Emissions (tons)	Non-EGU NO_X Budget (tons)	% of NO_X Budget
2003	5,804	5,666	102.4%
2004	3,389	5,666	59.8%
2005	3,879	5,666	68.5%
2006	3,833	5,666	67.6%
2007	3,737	5,666	66.0%
2008	3,661	5,666	64.6%
2009	3,524	5,666	62.2%
2010	3,454	5,666	61.0%
2011	3,476	5,666	61.4%
2012	3,305	5,666	58.3%
2013	3,222	5,666	56.9%
2014	3,241	5,666	57.2%
2015	3,298	5,666	58.2%
2016	3,134	5,666	55.3%
2017	2,350	5,666	41.5%
2018	2,286	5,666	40.4%
2019	1,870	5,666	33.0%

Data source: U. S. EPA Air Markets Program Database (https://ampd.epa.gov/ampd/)

Table 6 shows the emissions from specific facilities subject to the NOX SIP Call since 2003. Of the twelve facilities identified in Table 3, four facilities (Cargill, DOE Oak Ridge, DuPont Old Hickory, and Liberty Fibers) shut down their NO_X SIP Call units and three facilities (TVA Cumberland[6], TVA Johnsonville[7], and Valero) added NO_X SIP Call units. One facility (Domtar) is identified in EPA's Clean Air Markets database but has never been granted an allowance allocation or otherwise subjected to the NO_X SIP Call[8]. Of the remaining facilities,

[6] TVA's Cumberland Fossil Plant includes one non-EGU auxiliary boiler. This boiler was operating prior to 2015 but appears to have been counted with TVA's EGU emissions.

[7] TVA's Johnsonville cogeneration facility includes two non-EGU boilers that began operation in 2018.

[8] Domtar's Kingsport facility includes a biomass boiler with a design heat input of 544 MMBtu/hr, but Condition E6-10 of Title Operating Permit 573622 limits the annual capacity factor for other fuels (natural gas and fuel oils) to 10%. The biomass boiler does not meet the definition of an "affected unit" pursuant to TAPCR 1200-03-27-.12(1)(c)1 (a unit with a maximum design heat input greater than 250

Eastman Chemical, Resolute Forest Products, and Tate & Lyle had significant decreases in NO_X emissions due to full or partial conversions from coal to natural gas operation.

Table 6: Change in NO_X Emissions by Facility						
	Years Subject to the NO_X SIP Call		NO_X Emissions (tons)		NO_X Emission Rate (lb/MMBtu)	
Facility Name	**First Year**	**Last Year**	**First Year**	**Last Year**	**First Year**	**Last Year**
Cargill Corn Milling	2003	2014	5	5	0.039	0.049
TVA Cumberland (non-EGU Boiler)	2015	2019	2	8	0.055	0.058
DOE Oak Ridge Y-12	2003	2009	126	126	0.653	0.582
Domtar Paper Co., LLC	2003	2003	177	177	0.667	0.667
DuPont Old Hickory	2003	2011	366	3	0.586	0.197
Eastman Chemical Company	2003	2019	2,931	1,656	0.354	0.188
TVA Johnsonville (non-EGU Boiler)	2018	2019	1	1	0.005	0.006
Liberty Fibers Corporation	2004	2005	250	206	0.800	0.784
Packaging Corporation of America	2003	2019	14	55	0.172	0.195
Resolute Forest Products	2003	2019	1,304	74	0.886	0.297
Tate & Lyle-Loudon	2003	2019	881	67	0.509	0.054
Valero Refining Company	2013	2019	18	9	0.033	0.038

V.2. Adequacy of Eastman's Proposed Monitoring Method

Eastman's request for approval of alternative monitoring is determined to be acceptable, as follows:

- Appendix E to 40 CFR Part 75[9] establishes sufficient periodic testing requirements to establish the NO_X emission rate for each boiler.

- The monitoring and calculation procedures specified by Appendix E are sufficient to measure NO_X emissions across the range of operating conditions. Continuous monitoring of the oxygen concentration in the boiler duct will assure that the boilers are operated in a manner that is representative of the performance test. The requested alternative includes provisions for additional performance testing if the boiler does not meet the quality assurance requirements established by Appendix E.

- The work practice requirements of 40 CFR 63 Subpart DDDDD (periodic tune-ups) will provide additional assurance of proper boiler operation

MMBtu/hr that combusts, or will combust during any year, fossil fuel alone or in combination with any other fuel, where fossil fuel is projected to comprise more than 50% of the annual heat input on a Btu basis).

[9] Eastman's request to require periodic testing for a single boiler is discussed in Section VI.

V.2.1. Periodic Testing

Section 2.1 of Appendix E requires periodic testing to establish the NO_X emission rate at varying load levels (minimum of four load levels) and at an excess oxygen concentration that is representative of each load level. The source must measure the fuel flow rate during the performance test to demonstrate that the boiler is operating in accordance with the selected load levels during each performance test. The NO_X performance test must be repeated at least every 20 calendar quarters, or whenever the quality assurance requirements are not met (see Section V.2.2).

V.2.2. Continuous Monitoring and Quality Assurance

Continuous emissions monitoring systems (CEMS) provide the most reliable and timely information for determining compliance, but other methods, including periodic stack testing combined with continuous parametric monitoring, are adequate under many circumstances. When periodic testing and continuous parameter monitoring are used in lieu of CEMS, monitoring must be sufficient to ensure that that performance does not degrade after the initial performance test.

For natural gas-fired boilers, Appendix E specifies excess oxygen level as a critical quality assurance parameter and requires monitoring of the excess oxygen level during each hour of boiler operation. The NO_X emission rate and heat input correlation must be redetermined if the excess oxygen level at any heat input rate (or unit operating load) is more than 2 percentage points above the excess oxygen level recorded at the same heat input rate during the performance test "for one or more successive operating periods totaling more than 16 consecutive[10] unit operating hours".

The Division considered whether additional parametric monitoring is required for quality assurance and determined that the monitoring specified by Appendix E is sufficient to assure that boiler performance remains consistent with the performance test.

NO_X emissions are dependent upon fuel nitrogen content, burner temperature, and excess air. The fuel nitrogen content of pipeline natural gas is low and is not expected to vary. Excess air is measured via the oxygen concentration, and the burner temperature is directly proportional to the excess air flow at a given heat input. No other parameters were identified that could affect NO_X emissions.

V.2.3. Periodic Tune-Up Requirements

These boilers are also subject to 40 CFR 63 Subpart DDDDD (National Emission Standards for Hazardous Air Pollutants for Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters).

For boilers that use a continuous oxygen trim system to maintain an optimum air-to-fuel ratio, §§63.7540(a)(10) and (12) require a tune-up of the boiler or process heater every 5 years. The tune-up must include, as applicable, inspection, cleaning, and replacement of burner components; inspection and optimization of the flame pattern; inspection and calibration of the system controlling the air-to-fuel ratio; and optimizing total CO emissions, consistent with any NO_X requirement to which the unit is subject.

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[10] See U. S. EPA, *Part 75 Emissions Monitoring Policy Manual* (2013), Question 24.8. "Consecutive" can include periods of non-operation, but the clock resets if the parameter returns to normal for even one hour prior to the 16th hour.

VI. Conclusion

The proposed change would not increase NO_X emissions from Eastman's B-253 boilers and would not alter the NO_X SIP Call budget that limits emissions from the affected units because: (1) Eastman's NO_X emissions remain substantially below the facility's NO_X budget established pursuant to 1200-03-27-.12; (2) Tennessee's review of all non-EGUs subject to the NO_X SIP Call demonstrates that NO_X emissions for the collection of affected facilities are operating well below the state's NO_X budget; (3) the alternative monitoring requirements would be permanent, enforceable and sufficient to determine whether the source is in compliance with the NO_X SIP Call emissions requirements; and (4) the work practice requirements of 40 CFR 63 Subpart DDDDD (periodic tune-ups) will provide additional assurance that the boilers are operating properly.

Tennessee requests that EPA adopt the specific monitoring, recordkeeping and reporting requirements/conditions associated with B-253 Boilers 25 through 29 as identified in Conditions 1 through 19 of operating permit 077509. In a separate action, Tennessee is proposing to amend the monitoring requirements TAPCR 1200-03-27-.12(11) by allowing affected units to monitor NO_X emissions in accordance with 40 CFR 60 Subpart D, 40 CFR 60 Subpart Db, or an alternative method approved by the Technical Secretary in a revision to the State Implementation Plan in lieu of the existing requirement to monitor NO_X emissions in accordance with 40 CFR Part 75. Therefore, Tennessee requests conditional approval of the source-specific SIP revision and commits to completion of the amendments to TAPCR 1200-03-27-.12(11) not later than one year after the date of approval of the plan revision. Tennessee understands that any such conditional approval shall be treated as a disapproval if the State fails to comply with such commitment.

Second Item

Packaging Corporation of America
NO_X SIP Call Permit 078563 and 110(l) Demonstration
Combination Boiler #1

STATE OF TENNESSEE
AIR POLLUTION CONTROL BOARD
DEPARTMENT OF ENVIRONMENT AND CONSERVATION
NASHVILLE, TENNESSEE 37243

OPERATING PERMIT Issued Pursuant to Tennessee Air Quality Act

Issue Date: ******DRAFT******	Permit Number: 078563 Facility ID: 36-0002
Issued To: Packaging Corporation of America	Installation Address Highway 57 Counce
Installation Description Combination Boiler #1	Emission Source Reference No. 36-0002-17 SIP

The holder of this permit shall comply with the conditions contained in this permit as well as all applicable provisions of the Tennessee Air Pollution Control Regulations (TAPCR).

CONDITIONS:

1. Pursuant to 40 CFR §51.121(i)(1), upon issuance of this permit, approval of this permit into Tennessee's State Implementation Plan by U. S. EPA, and approval of the monitoring program specified in **Condition 3** of this permit, the permittee may demonstrate compliance with TAPCR 1200-03-27-.12 by monitoring nitrogen oxides (NO_X) emissions from Combination Boiler #1 using the alternative NO_X monitoring provisions contained in **Conditions 2 through 5** of this permit in lieu of the requirements established by TAPCR 1200-03-27-.12(11)(a).

   Tennessee Air Pollution Control Regulations (TAPCR) 1200-03-09-.03(8), 40 CFR §51.121(i)(1)

____
TECHNICAL SECRETARY

No Authority is Granted by this Permit to Operate, Construct, or Maintain any Installation in Violation of any Law, Statute, Code, Ordinance, Rule, or Regulation of the State of Tennessee or any of its Political Subdivisions.

<u>POST AT INSTALLATION ADDRESS</u>

2. Pursuant to 40 CFR §51.121(i)(1), upon issuance of this permit and approval of this permit into Tennessee's State Implementation Plan by U.S. EPA, the permittee may demonstrate compliance with TAPCR 1200-03-27-.12 by monitoring NO_X emissions from Combination Boiler #1 using the monitoring methodologies for NO_X emission rate set forth in 40 CFR Part 60, Appendix B in combination with monitoring of heat input. The permittee must continue to monitor NOx emissions in accordance with TAPCR 1200-03-27-.12(11)(a) and 40 CFR Part 75 until the monitoring plan required by **Condition 3** is approved and all required certification testing is performed and approved by the Technical Secretary.

   TAPCR 1200-03-09-.03(8), 40 CFR §51.121(i)(1)

3. The permittee shall submit a program for conducting continuous in-stack monitoring for NO_X mass emissions for approval. To be approvable the program shall address the following:

   (a) A description of the overall monitoring program;

   (b) Specifications demonstrating that the proposed monitoring instruments will meet the requirements of 40 CFR 60, Appendix B;

   (c) Specifications for the proposed fuel flow meter and a discussion of how the fuel Btu content will be determined;

   (d) Proposed location(s) of the monitoring instruments on the boiler effluent gas stream;

   (e) Proposed procedures for conducting performance specification testing of the monitoring instruments in units of the applicable standard (i.e. NO_X mass emissions);

   (f) Proposed ongoing monitoring instrument quality assurance procedures (40 CFR 60, Appendix F or approved alternative);

   (g) Procedures for addressing missing data (40 CFR 75, Appendix C, Appendix F or approved alternative); and

   (h) Proposed format for the reporting of data.

   The report shall be submitted to the Technical Secretary at the following address:

   Division of Air Pollution Control
   Attn: Compliance Validation Program
   William R. Snodgrass Tennessee Tower
   312 Rosa L. Parks Avenue, 15th Floor
   Nashville, TN 37243
   e-mail (PDF): Air.Pollution.Control@tn.gov

   Note: The permittee has previously submitted documentation for paragraphs (b), (d), and (e) of this condition, and no further action is required for these items as long as the currently certified monitoring system continues to be used as previously approved.

   TAPCR 1200-03-09-.03(8), 40 CFR §51.121(i)(1)

4. The permittee shall calculate NO_X mass emissions (in tons) for each control period and report the total to the Technical Secretary no later than December 31 following the end of the control period. NO_X emissions shall be calculated from continuous emissions monitoring system (CEMS) measurements using Method 19 in Appendix A to 40 CFR Part 60.

(a) For each hour in the control period:

(i) Calculate the NO_X emission rate in lb/MMBtu;

(ii) Measure fuel flow rate and calculate the heat input in MMBtu; and

(iii) Calculate NO_X emissions as the NO_X emission rate in lb/MMBtu multiplied by the heat input in MMBtu.

(b) At the end of the control period, calculate the total NO_X emissions as the sum of the hourly NO_X emissions for each hour. Divide the total NO_X emissions by 2,000 to calculate the total NO_X emissions in tons, and report the total NO_X emissions to the Technical Secretary at the following address:

Division of Air Pollution Control
Attn: Emissions Inventory and Special Projects
William R. Snodgrass Tennessee Tower
312 Rosa L. Parks Avenue, 15th Floor
Nashville, TN 37243
e-mail (PDF): Air.Pollution.Control@tn.gov

TAPCR 1200-03-09-.03(8), 40 CFR §51.121(i)(1)

5. The permittee shall maintain records of all measurements, including continuous monitoring system, monitoring device, and performance testing 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 by this part recorded in a permanent form suitable for inspection. These records shall be retained for at least five years following the end of the control period in which the such measurements, maintenance, reports, and records were collected.

TAPCR 1200-03-09-.03(8), 40 CFR §51.121(i)(1)

Proposed Approval of Alternative Monitoring and Clean Air Act §110(l) Demonstration

Packaging Corporation of America, Combination Boiler #1 Tennessee Air Pollution Control Regulations 1200-03-27-.12(11)

On September 16, 2020, Packaging Corporation of America (PCA) submitted a petition to request approval of alternative monitoring, recordkeeping, and reporting requirements for one boiler subject to the NO_X SIP Call (Combination Boiler #1) at PCA's Counce Mill. The Tennessee Department of Environment and Conservation, Division of Air Pollution Control, is proposing to approve PCA's petition, subject to the limitations and exceptions identified herein.

The specific monitoring requirements for Combination Boiler #1 will be implemented via operating permit 078563. The Division proposes to issue this permit after appropriate notice and comment and to submit the final permit to U. S. EPA for adoption into Tennessee's State Implementation Plan.

I. Background

On October 27, 1998 (63 FR 57356), EPA adopted the *Finding of Significant Contribution and Rulemaking for Certain States in the Ozone Transport Assessment Group Region for Purposes of Reducing Regional Transport of Ozone* (NO_X SIP Call), which required 22 States and the District of Columbia to submit State Implementation Plan (SIP) revisions to prohibit specified amounts of NO_X emissions for the purpose of reducing NO_X and ozone transport across State boundaries in the eastern half of the United States. This rule also established the NO_X Budget Trading Program, which allowed States to comply with the required emissions reductions via an interstate cap-and-trade program for electric generating units (EGUs) and for large industrial boilers and combustion turbines (i. e., non-EGUs). Tennessee implemented the NO_X Budget Trading Program between 2003 and 2008, when the program was superseded by the Clean Air Interstate Rule (CAIR) Ozone Season NO_X Trading Program.

EPA replaced CAIR with the Cross-State Air Pollution Rule (CSAPR) NO_X trading programs on January 1, 2015. The applicability provisions of the CSAPR ozone season trading programs cover EGUs only, and non-EGU boilers are not covered under CSAPR. To preserve the NO_X reductions established by the NOX SIP Call, the Tennessee Air Pollution Control Board approved Tennessee Air Pollution Control Regulations (TAPCR) 1200-03-27-.12 (NO_X SIP Call Requirements for Stationary Boilers and Combustion Turbines). Tennessee submitted the rule to EPA' s Region 4 office on February 27, 2017 and requested that EPA approve the rule into Tennessee's SIP.

TAPCR 1200-03-27-.12(11)(a) requires the owners and operators of an affected unit to comply with the applicable monitoring, recordkeeping, and reporting requirements provided in 40 CFR part 75 for each control period. On March 8, 2019, EPA published a final rule revising the emissions monitoring provisions required under the NO_X SIP Call (84 FR 8422). This rule allows States to amend their SIPs to establish emissions monitoring alternatives to Part 75 for units subject to the NO_X SIP Call[1]. In approving this rule, EPA stated that the Part 75 monitoring requirements were applied to non-EGU sources in the context of regional emission trading programs, including the NO_X Budget Trading Program and the CAIR NO_X Ozone Season Trading

[1] This revision does not include EGUs or other units subject to the Acid Rain Program or the CSAPR emission trading programs.

Program, which have been discontinued[2]. EPA also noted the substantial margins by which NO_X SIP Call States are complying with their emissions budgets – overall seasonal NO_X emissions from NO_X SIP Call States are less than 40% of the States' NO_X budgets, and no State reported NO_X emissions exceeding 71% of its budget[3].

SIPs that approve alternatives to Part 75 must continue to include some form of emissions monitoring requirements for these types of sources, consistent with the NO_X SIP Call's general enforceability and monitoring requirements at § 51.121(f)(1) and (i)(1).

II. Current Monitoring Requirements

§ 75.10 requires affected sources to install, certify, operate, and maintain, in accordance with all the requirements of Part 75, a NO_X-diluent continuous emission monitoring system (CEMS), consisting of a NO_X pollutant concentration monitor and an O_2 or CO_2 diluent gas monitor, with an automated data acquisition and handling system for measuring and recording NO_X concentration (in ppm), O_2 or CO_2 concentration (in percent O_2 or CO_2) and NO_X emission rate (in lb/MMBtu) discharged to the atmosphere, except as provided in §§75.12 and 75.17 and Subpart E of Part 75. Pursuant to §75.12(c), hourly, quarterly, and annual NO_X emission rates must be calculated from the NO_X concentration, diluent concentration, and percent moisture (if applicable) measurements using the procedures established in Appendix F to Part 75.

III. Requested Alternative Monitoring

The petition requests approval to use 40 CFR Part 60 Appendix B (Performance Specification 2—Specifications and Test Procedures for SO2 and NOX Continuous Emission Monitoring Systems in Stationary Sources) as an alternative to the CEMS requirements of Part 75.

IV. Justification for Alternative Monitoring

The petition states that PCA uses NO_X CEMS to demonstrate compliance with the Counce Mill's Plantwide Applicability Limit (PAL) permit. Combination Boiler #1 is the only monitor within the mill that is subject to the requirements of 40 CFR Part 75, and the other NO_X sources at the mill operate CEMS in accordance with 40 CFR Part 60. The petition states that PCA wishes to streamline the monitoring requirements among the sources at the mill.

[2] EPA notes that Part 75 monitoring is necessary for emission trading programs, because these programs can function only with timely reporting of consistent, quality-assured mass emissions data by all participating units.

[3] For Tennessee, EPA reported the following numbers for 2019:

2019 Ozone Season non-EGU NO_X Emissions (tons)		
NO_X Emissions (tons)	**NO_X Budget**	**Total Emissions (% of Budget)**
1,870	5,666 (3,928*)	34% (48%*)
* The non-EGU portion of Tennessee's NO_X budget is 5,666 tons. Of this total, 1,738 tons are set aside for new source growth, leaving 3,928 tons of NO_X emissions allocated to existing units. The 2018 non-EGU NO_X emissions, as a percentage of Tennessee's NO_X budget, were calculated using both numbers.		

V. Review of PCA's Alternative Monitoring Request, Clean Air Act §110(l) Requirements

The Division of Air Pollution Control reviewed PCA's alternative monitoring request, giving consideration to emissions from the affected unit and the adequacy of the proposed monitoring method.

Attainment and maintenance plans in Tennessee rely upon control of NO_X emissions. Section 110(l) of the Clean Air Act (CAA)[4] prohibits revision of a SIP that would interfere with attainment or maintenance of a NAAQS, reasonable further progress toward attainment of a NAAQS, or any other applicable requirement of the CAA. Because this rule is part of Tennessee's SIP, the requirements of CAA §110(l) must be satisfied before changing the existing monitoring requirements.

The Division proposes to approve PCA's request. The proposed revision would not interfere with any applicable requirement concerning attainment or maintenance of a NAAQS or reasonable further progress toward attainment of a NAAQS.

- NO_X emissions from PCA's Combination Boiler #1 are substantially below the facility's NO_X budget established pursuant to 1200-03-27-.12, and the change would not result in an increase in NO_X emissions. The proposed monitoring alternative would not alter the NO_X SIP Call budget that limits emissions from the affected unit.

- The alternate monitoring requirements are permanent, enforceable and sufficient to determine whether the source is in compliance with the NO_X SIP Call emissions requirements.

- The work practice requirements of 40 CFR 63 Subpart DDDDD (periodic tune-ups) will provide additional assurance of proper boiler operation

V.1. Emissions

EPA's proposed approval of NO_X SIP Call monitoring alternatives (83 FR 48751) notes the substantial margin by which NO_X SIP Call states are complying with the portions of their statewide emissions budgets assigned to large EGUs and large non-EGU boilers and turbines, averaging less than 40% of the statewide NO_X budgets in 2017.

PCA's NO_X SIP Call allowance allocation is 85 tons, and EPA's Clean Air Markets database[5] indicates that PCA emitted 65% of its allocation during the 2019 ozone season. PCA's ozone season NO_X emissions are shown in Table 1.

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[4] "Each revision to an implementation plan submitted by a State under this chapter shall be adopted by such State after reasonable notice and public hearing. The Administrator shall not approve a revision of a plan if the revision would interfere with any applicable requirement concerning attainment and reasonable further progress (as defined in section 7501 of this title), or any other applicable requirement of this chapter."

[5] https://ampd.epa.gov/ampd/

Table 1: PCA Emissions, 2003 – 2019				
Year	**Program(s) Selected**	**NO_X Emissions (tons)**	**Heat Input (MMBtu)**	**NO_X Emission Rate (lb/MMBtu)**
2003	NBP	14.0	163,405	0.172
2004	NBP	13.6	204,977	0.133
2005	NBP	8.4	107,977	0.156
2006	NBP	8.9	118,124	0.151
2007	NBP	15.3	159,124	0.192
2008	NBP	10.6	148,577	0.142
2008	CAIROS	10.6	148,577	0.142
2009	CAIROS	2.3	37,142	0.125
2010	CAIROS	3.1	62,548	0.099
2011	CAIROS	13.0	230,968	0.112
2012	CAIROS	2.9	42,189	0.138
2013	CAIROS	4.5	58,403	0.155
2014	CAIROS	1.2	19,604	0.122
2015	SIPNOX	0.8	8,716	0.180
2016	SIPNOX	21.4	393,778	0.109
2017	SIPNOX	37.5	612,969	0.122
2018	SIPNOX	45.5	683,515	0.133
2019	SIPNOX	55.2	565,415	0.195

PCA is also subject to a Plantwide Applicability Limit (PAL) for NO_X of 1,665.5 tons during all intervals of 12 consecutive months. The PAL applies to 18 emission sources at the facility[6], including Combination Boiler #1. PALs are enforceable as a practical matter and are established source-wide in accordance with Tennessee's PSD regulations (TAPCR 1200-03-09-.01(4) (s)1 through 15). Any physical change in or change in the method of operation of the PAL source that causes it to emit the PAL pollutant at a level equal to or greater than the PAL is a major modification, and the Technical Secretary may increase the PAL only if the major stationary source complies with TAPCR 1200-03-09-.01(4)(s)11[7].

[6] The sources covered by the NO_X PAL are Recovery Furnace #3 (36-0002-01); Recovery Furnace #1 (36-0002-02); Recovery Furnace #2 (36-0002-03); Lime Kiln #1 (36-0002-07); Lime Kiln #2 (36-0002-08); Combination Boiler #1 (36-0002-17); Combination Boiler #2 (36-0002-18); #2 and #4Woodyards Diesel Engine (36-0002-22/23); Kiln 1 Auxiliary Drive Diesel-Fired Engine (36-0002-37); Kiln 2 Auxiliary Drive Diesel-Fired Engine (36-0002-38); Compression Ignition Emergency Stationary ICE for Caustic Area Stand-by Generator (36-0002-40); Compression Ignition Emergency Stationary ICE for Emergency Fire Pond Pump (36-0002-41); Spark Ignition Emergency Stationary ICE for TG-2 Lube Oil Pumps Back Up Power (36-0002-42); Spark Ignition Emergency Stationary ICE for Admin Building Stand-By Generator (36-0002-43); Spark Ignition Emergency Stationary ICE for Operations Building PI Computer Stand-By Generator (36-0002-44); Spark Ignition Emergency Stationary ICE for Shipping Computer Room Stand-By Generator (36-0002-45); Spark Ignition Emergency Stationary ICE for TG-1 Lube Oil Pumps Back Up Power (36-0002-46); and Spark Ignition Emergency Stationary ICE for Off-Site Railway Scale Stand-By Generator (36-0002-47).

[7] The owner or operator of the major stationary source must submit a complete application to request an increase in the PAL limit for a PAL major modification. The application requirements are:

- Identify the emissions unit(s) contributing to the increase in emissions so as to cause the major stationary source's emissions to equal or exceed its PAL.
- Demonstrate that the sum of the baseline actual emissions (calculated separately for small emissions units and for significant and major emissions units assuming application of BACT equivalent controls), plus the sum of the allowable emissions of the new or modified emissions unit(s), exceeds the PAL.

Table 2 shows Tennessee's NO_X emissions for all affected non-EGU sources subject to the NO_X Budget Trading Program (2003 – 2008), CAIR NO_X Ozone Season Trading Program (2009 – 2014), and State NO_X SIP Call regulation (2015 – 2019). Since the implementation of the NO_X Budget Trading Program in 2004, Tennessee's ozone season NO_X emissions from these affected sources have decreased from 59.8% of Tennessee's non-EGU NO_X Budget in 2004 to 33.0% of Tennessee's non-EGU NO_X Budget in 2019.

Table 2: Statewide Non-EGU NO_X Emissions, 2003 – 2019

Year	Total NO_X Emissions (tons)	Non-EGU NO_X Budget (tons)	% of NO_X Budget
2003	5,804	5,666	102.4%
2004	3,389	5,666	59.8%
2005	3,879	5,666	68.5%
2006	3,833	5,666	67.6%
2007	3,737	5,666	66.0%
2008	3,661	5,666	64.6%
2009	3,524	5,666	62.2%
2010	3,454	5,666	61.0%
2011	3,476	5,666	61.4%
2012	3,305	5,666	58.3%
2013	3,222	5,666	56.9%
2014	3,241	5,666	57.2%
2015	3,298	5,666	58.2%
2016	3,134	5,666	55.3%
2017	2,350	5,666	41.5%
2018	2,286	5,666	40.4%
2019	1,870	5,666	33.0%
Data source: U. S. EPA Air Markets Program Database (https://ampd.epa.gov/ampd/)			

Table 3 shows the emissions from specific facilities subject to the NOX SIP Call since 2003. Of the twelve facilities identified in Table 3, four facilities (Cargill, DOE Oak Ridge, DuPont Old Hickory, and Liberty Fibers) shut down their NO_X SIP Call units and three facilities (TVA Cumberland[8], TVA Johnsonville[9], and Valero) added

- Conduct a new BACT analysis to determine the required level of control on each significant or major emissions unit, unless the emissions unit is currently required to comply with a BACT or LAER requirement that was established within the preceding 10 years.

The owner or operator must obtain a major NSR permit for all emissions units, regardless of the magnitude of the emissions increase resulting from them (any emissions increase above the PAL is significant). These emissions units must comply with any emissions requirements resulting from the major NSR process (e. g., BACT), even though they have also become (or continue to be) subject to the PAL.

[8] TVA's Cumberland Fossil Plant includes one non-EGU auxiliary boiler. This boiler was operating prior to 2015 but appears to have been counted with TVA's EGU emissions.

[9] TVA's Johnsonville cogeneration facility includes two non-EGU boilers that began operation in 2018.

NO_X SIP Call units. One facility (Domtar) is identified in EPA's Clean Air Markets database but has never been granted an allowance allocation or otherwise subjected to the NO_X SIP Call[10]. Of the remaining facilities, Eastman Chemical, Resolute Forest Products, and Tate & Lyle had significant decreases in NO_X emissions due to full or partial conversions from coal to natural gas operation.

Table 2: Change in NO_X Emissions by Facility						
	Years Subject to the NO_X SIP Call		NO_X Emissions (tons)		NO_X Emission Rate (lb/MMBtu)	
Facility Name	**First Year**	**Last Year**	**First Year**	**Last Year**	**First Year**	**Last Year**
Cargill Corn Milling	2003	2014	5	5	0.039	0.049
TVA Cumberland (non-EGU Boiler)	2015	2019	2	8	0.055	0.058
DOE Oak Ridge Y-12	2003	2009	126	126	0.653	0.582
Domtar Paper Co., LLC	2003	2003	177	177	0.667	0.667
DuPont Old Hickory	2003	2011	366	3	0.586	0.197
Eastman Chemical Company	2003	2019	2,931	1,656	0.354	0.188
TVA Johnsonville (non-EGU Boiler)	2018	2019	1	1	0.005	0.006
Liberty Fibers Corporation	2004	2005	250	206	0.800	0.784
Packaging Corporation of America	2003	2019	14	55	0.172	0.195
Resolute Forest Products	2003	2019	1,304	74	0.886	0.297
Tate & Lyle-Loudon	2003	2019	881	67	0.509	0.054
Valero Refining Company	2013	2019	18	9	0.033	0.038

V.2. Alternative Monitoring Requirements

Upon approval of the requested alternative into the SIP, PCA would be allowed to demonstrate compliance with TAPCR 1200-03-27-.12 by monitoring NO_X emissions from Combination Boiler #1 using the monitoring methodologies set forth in 40 CFR Part 60, Appendix B. PCA would continue to monitor NOx emissions in accordance with 40 CFR Part 75 until all required certification testing is performed and approved by the Technical Secretary.

Tennessee will require PCA to calculate NO_X mass emissions (in tons) for each ozone season using NO_X emission rate data obtained in accordance with the applicable NSPS subpart and to report the total to the Division of Air Pollution Control no later than December 31 following that ozone season. The NO_X emission rate will be calculated from Part 60 CEMS measurements using Method 19 in Appendix A to 40 CFR Part 60.

Following receipt of PCA's report, Tennessee will review PCA's total emissions and the emissions from other affected units in the state, including any emissions from new affected units, to verify that Tennessee's ozone-season NO_X budget has not been exceeded. Should the total emissions from any affected unit (at PCA or any

[10] Domtar's Kingsport facility includes a biomass boiler with a design heat input of 544 MMBtu/hr, but Condition E6-10 of Title Operating Permit 573622 limits the annual capacity factor for other fuels (natural gas and fuel oils) to 10%. The biomass boiler does not meet the definition of an "affected unit" pursuant to TAPCR 1200-03-27-.12(1)(c)1 (a unit with a maximum design heat input greater than 250 MMBtu/hr that combusts, or will combust during any year, fossil fuel alone or in combination with any other fuel, where fossil fuel is projected to comprise more than 50% of the annual heat input on a Btu basis).

other facility) exceed its allowance allocation, Tennessee will pursue appropriate action in accordance with TAPCR 1200-03-27-.12(7)(c), including the deduction of allowances for the following control period and the assessment of civil penalties or other remedies.

V.3. Periodic Tune-Up Requirements

Combination Boiler #1 is also subject to 40 CFR 63 Subpart DDDDD (National Emission Standards for Hazardous Air Pollutants for Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters). Subpart DDDDD requires boilers and process heaters with a heat input capacity of 10 MMBtu/hr or greater that do not use a continuous oxygen trim system to maintain an optimum air-to-fuel ratio to perform an annual tune-up of the boiler or process heater as specified in §63.7540(a)(10)(i) through (vi). Boilers and process heaters that use a continuous oxygen trim system to maintain an optimum air-to-fuel ratio must perform tune-ups every five years.

Tune-ups must be performed while burning the fuel(s) that provided the majority of the heat input to the boiler or process heater over the 12 months prior to the tune-up. The tune-ups must include, as applicable, inspection, cleaning, and replacement of burner components; inspection and optimization of the flame pattern; inspection and calibration of the system controlling the air-to-fuel ratio; and optimizing total CO emissions, consistent with any NO_X requirement to which the unit is subject.

VI. Conclusion

The proposed change would not increase NO_X emissions from PCA's Combination Boiler #1 and would not alter the NO_X SIP Call budget that limits emissions from the affected unit because: (1) PCA's NO_X emissions remain substantially below the facility's NO_X budget established pursuant to 1200-03-27-.12; (2) Tennessee's review of all non-EGUs subject to the NO_X SIP Call demonstrates that NO_X emissions for the collection of affected facilities are operating well below the state's NO_X budget; (3) the alternative monitoring requirements would be permanent, enforceable and sufficient to determine whether the source is in compliance with the NO_X SIP Call emissions requirements; and (4) the work practice requirements of 40 CFR 63 Subpart DDDDD (periodic tune-ups) will provide additional assurance that the boiler is operating properly.

Tennessee requests that EPA adopt the specific monitoring, recordkeeping and reporting requirements/conditions associated with Combination Boiler #1 at PCA as identified in Conditions 1 through 5 of operating permit 078563. In a separate action, Tennessee is proposing to amend the monitoring requirements TAPCR 1200-03-27-.12(11) by allowing affected units to monitor NO_X emissions in accordance with 40 CFR 60 Subpart D, 40 CFR 60 Subpart Db, or an alternative method approved by the Technical Secretary in a revision to the State Implementation Plan in lieu of the existing requirement to monitor NO_X emissions in accordance with 40 CFR Part 75. Therefore, Tennessee requests conditional approval of the source-specific SIP revision and commits to completion of the amendments to TAPCR 1200-03-27-.12(11) not later than one year after the date of approval of the plan revision. Tennessee understands that any such conditional approval shall be treated as a disapproval if the State fails to comply with such commitment.