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

MINOR MODIFICATION #1 To

OPERATING PERMIT (TITLE V) Issued Pursuant to Tennessee Air Quality Act

This permit fulfills the requirements of Title V of the Federal Clean Air Act (42 U.S.C. 7661a-7661e) and the federal regulations promulgated thereunder at 40 CFR Part 70. (FR Vol. 57, No. 140, Tuesday, July 21, 1992 p.32295-32312). This permit is issued in accordance with the provisions of paragraph 1200-3-9-.02(11) of the TAPCR. The permittee has been granted permission to operate an air contaminant source in accordance with emissions limitations and monitoring requirements set forth herein.

Issue Date: **November 26, 2018**

Permit Number: **572833**

Date of Minor Modification #1: **draft**

Expiration Date: **November 25, 2023**

Issued To:
Tennessee Valley Authority
Johnsonville Fossil Plant

Installation Address:
535 Steam Plant Road
New Johnsonville

Installation Description:
Combustion Turbine Electric Generating Plant:

11 – 20: Combustion Turbine Plant – 10 Units (no. 2 fuel oil or natural gas fired)
29: Coal Handling Operation
30: Ash Handling System
32: Combustion Turbine Plant – Three Units (no. 2 fuel oil or natural gas fired)
33: Two Gas Fired Heaters
35: Natural Gas-Fired Combustion Turbine with Heat Recovery Steam Generator (EU-26)
36: Natural Gas-Fired Auxiliary Boiler (EU-37)
37: Natural Gas-Fired Auxiliary Boiler (EU-38)

Facility ID: 43-0011

Renewal Application Due Date:
Between February 28, 2023 **and** May 29, 2023

Primary SIC: 49

Information Relied Upon:
May 20, 2014, Consent Decree and Federal Facilities Compliance Agreement; Renewal application dated July 2, 2017; Minor Modification Application dated March 23, 2018, and revision dated June 4, 2018; Significant Modification application dated February 13, 2020; Minor Modification application dated December 4, 2024

(continued on the next page)

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

CONTENTS

SECTION A
GENERAL PERMIT CONDITIONS

SECTION B
GENERAL CONDITIONS for MONITORING, REPORTING, and ENFORCEMENT

SECTION C
PERMIT CHANGES

SECTION D
GENERAL APPLICABLE REQUIREMENTS

SECTION E

SOURCE SPECIFIC EMISSION STANDARDS, OPERATING LIMITATIONS, and MONITORING, RECORDKEEPING and REPORTING REQUIREMENTS

ATTACHMENTS

SECTION A

GENERAL PERMIT CONDITIONS

A permit issued under the provisions of Tennessee Air Pollution Control Regulations (TAPCR) paragraph 1200-03-09-.02(11) is a permit issued pursuant to the requirements of Title V of the Federal Act and its implementing Federal regulations promulgated at 40 CFR, Part 70.

A1. **__Definitions.__** Terms not otherwise defined in the permit shall have the meaning assigned to such terms in the referenced regulations.

TAPCR 1200-03 and 0400-30

A2. **__Compliance requirement.__** All terms and conditions in a permit issued pursuant to TAPCR paragraph 1200-03-09-.02(11), including any provisions designed to limit a source's potential to emit, are enforceable by the Administrator and citizens under the Federal Act. The permittee shall comply with all conditions of its permit. Except for requirements specifically designated herein as not being federally enforceable (State Only), non-compliance with the permit requirements is a violation of the Federal Act and the Tennessee Air Quality Act and is grounds for enforcement action; for a permit termination, revocation and reissuance, or modification; or for denial of a permit renewal application. Non-compliance with permit conditions specifically designated herein as not being federally enforceable (State Only) is a violation of the Tennessee Air Quality Act and may be grounds for these actions.

TAPCR 1200-03-09-.02(11)(e)2(i) and 1200-03-09-.02(11)(e)1(vi)(I)

A3. **__Need to halt or reduce activity__.** The need to halt or reduce activity is not a defense for noncompliance. It shall not be a defense for a permittee in an enforcement action that it would have been necessary to halt or reduce the permitted activity in order to maintain compliance with the conditions of the permit. However, nothing in this item shall be construed as precluding consideration of a need to halt or reduce activity as a mitigating factor in assessing penalties for noncompliance if the health, safety, or environmental impacts of halting or reducing operations would be more serious than the impacts of continuing operations.

TAPCR 1200-03-09-.02(11)(e)1(vi)(II)

A4. **__The permit.__** The permit may be modified, revoked, reopened, and reissued, or terminated for cause. The filing of a request by the permittee for a permit modification, revocation and reissuance, or termination, or of a notification of planned changes or anticipated noncompliance, does not stay any permit condition.

TAPCR 1200-03-09-.02(11)(e)1(vi)(III)

A5. **__Property rights.__** The permit does not convey any property rights of any sort, or any exclusive privilege.

TAPCR 1200-03-09-.02(11)(e)1(vi)(IV)

A6. **__Submittal of requested information.__** The permittee shall furnish to the Technical Secretary, within a reasonable time, any information that the Technical Secretary may request in writing to determine whether cause exists for modifying, revoking and reissuing, or termination of the permit or to determine compliance with the permit. Upon request, the permittee shall also furnish to the Technical Secretary copies of records required to be kept by the permit. If the permittee claims that such information is confidential, the Technical Secretary may review that claim and hold the information in protected status until such time that the Board can hear any contested proceedings regarding confidentiality disputes. If the information is desired by EPA, the permittee may mail the information directly to EPA. Any claims of confidentiality for federal purposes will be determined by EPA.

TAPCR 1200-03-09-.02(11)(e)1(vi)(V)

A7. **Severability clause.** The requirements of this permit are severable. A dispute regarding one or more requirements of this permit does not invalidate or otherwise excuse the permittee from their duty to comply with the remaining portion of the permit.

TAPCR 1200-03-09.02(11)(e)1(v)

A8. **Fee payment.**

(a) The permittee shall pay an annual Title V fee in accordance with TAPCR 1200-03-26-.02(9) based upon the applicable base fee; the applicable permit modification fee(s); the responsible official's choice of actual emissions, allowable emissions, or a combination of actual and allowable emissions; and on the responsible official's choice of annual accounting period. An emission cap of 4,000 tons per year per regulated pollutant per major source SIC Code shall apply to actual or allowable based emission fees. A Title V annual emission fee will not be charged for emissions in excess of the cap. Title V annual emission fees will not be charged for carbon monoxide or for greenhouse gas pollutants solely because they are greenhouse gases.

(b) Title V sources shall pay allowable based emission fees until the beginning of the next annual accounting period following receipt of their initial Title V operating permit. At that time, the permittee shall begin paying their Title V fee based upon the applicable base fee; the applicable permit modification fee(s); and their choice of actual or allowable based fees, or mixed actual and allowable based fees. Once permitted, the Responsible Official may revise their existing fee choice by submitting a written request to the Division no later than December 31 of the annual accounting period for which the fee is due.

(c) When paying annual Title V emission fees, the permittee shall comply with all provisions of TAPCR Rule 1200-03-26-.02 and paragraph 1200-03-09-.02(11) applicable to such fees.

(d) Where more than one allowable emission limit is applicable to a regulated pollutant, the allowable emissions for the regulated pollutants shall not be double counted. Major sources subject to the provisions of TAPCR paragraph 1200-03-26-.02(9) shall apportion their emissions as follows to ensure that their fees are not double counted.

1. Emissions of hazardous air pollutants (HAP) that are included in the particulate matter (including PM_{10}) category or the volatile organic compound category shall be included in those categories.

2. HAP that are not included in either the particulate matter category or volatile organic compound category shall be included in the category of Hazardous Air Pollutants Not Included Above.

3. Each individual HAP is subject to the 4,000 ton cap provisions of TAPCR subparagraph 1200-03-26-.02(2)(i).

4. Major sources that wish to pay annual emission fees for PM_{10} on an allowable emission basis may do so if they have a specific PM_{10} allowable emission standard. If a major source has a total particulate emission standard, but wishes to pay annual emission fees on an actual PM_{10} emission basis, it may do so if the PM_{10} actual emission levels are proven to the satisfaction of the Technical Secretary. The method to demonstrate the actual PM_{10} emission levels must be made as part of the source's major source operating permit in advance in order to exercise this option. The PM_{10} emissions reported under these options shall not be subject to fees under the family of particulate emissions. The 4,000 ton cap provisions of TAPCR subparagraph 1200-03-26-.02(2)(i) shall also apply to PM_{10} emissions.

(e) Emissions of pollutants that do not fall in one of the listed categories shall be included in the category of Miscellaneous Pollutants Not Listed Above. Each miscellaneous pollutant is subject to the 4,000-ton cap provisions.

TAPCR 1200-03-26-.02 and 1200-03-09-.02(11)(e)1(vii)

A9. **Permit revision not required.** A permit revision will not be required under any approved economic incentives, marketable permits, emissions trading and other similar programs or process for changes that are provided for in the permit.

TAPCR 1200-03-09-.02(11)(e)1(viii)

A10. **Inspection and entry.** Upon presentation of credentials and other documents as may be required by law, the permittee shall allow the Technical Secretary or an authorized representative to perform the following for the purposes of determining compliance with the permit applicable requirements:

(a) Enter upon, at reasonable times, the permittee's premises where a source is located or emissions-related activity is conducted, or where records must be kept under the conditions of the permit;

(b) Have access to and copy, at reasonable times, any records that must be kept under the conditions of the permit;

(c) Inspect at reasonable times any facilities, equipment (including monitoring and air pollution control equipment), practices, or operations regulated or required under the permit; and

(d) As authorized by the Clean Air Act and Chapter 1200-03-10 of the TAPCR, sample or monitor at reasonable times substances or parameters for the purpose of assuring compliance with the permit or applicable requirements.

(e) "Reasonable times" shall be considered to be customary business hours unless reasonable cause exists to suspect noncompliance with the Act, TAPCR Division 1200-03 or any permit issued pursuant thereto and the Technical Secretary specifically authorizes an inspector to inspect a facility at any other time.

TAPCR 1200-03-09-.02(11)(e)3(ii)

A11. **Permit shield.**

(a) Compliance with the conditions of this permit shall be deemed compliance with all applicable requirements as of the date of permit issuance, provided that:

1. Such applicable requirements are included and are specifically identified in the permit; or

2. The Technical Secretary, in acting on the permit application or revision, determines in writing that other requirements specifically identified are not applicable to the source, and the permit includes the determination or a concise summary thereof.

(b) Nothing in this permit shall alter or affect the following:

1. The provisions of section 303 of the Federal Act (emergency orders), including the authority of the Administrator under that section. Similarly, the provisions of T.C.A. §68-201-109 (emergency orders) including the authority of the Governor under the section;

2. The liability of an owner or operator of a source for any violation of applicable requirements prior to or at the time of permit issuance;

3. The applicable requirements of the acid rain program, consistent with section 408(a) of the Federal Act; or

4. The ability of EPA to obtain information from a source pursuant to section 114 of the Federal Act.

(c) Permit shield is granted to the permittee.

(d) The permit shield does not apply to permit changes made under the minor permit modification procedures of TAPCR subpart 1200-03-09-.02(11)(f)5(ii) nor the administrative permit amendment procedures of TAPCR part 1200-03-09-.02(11)(f)4, except that the permit shield may be extended for administrative permit amendments that meet the relevant requirements of TAPCR subparagraph 1200-03-09-.02(11)(e), subparagraph 1200-03-09-.02(11)(f) and subparagraph 1200-03-09-.02(11)(g) for significant permit modifications.

(e) The permit shield does not apply to off-permit changes made under the operational flexibility provisions of TAPCR part 1200-03-09-.02(11)(a)4.

TAPCR 1200-03-09-.02(11)(e)6 and 1200-03-09-.02(11)(f)4(iv)

A12. **Permit renewal and expiration.**

(a) An application for permit renewal must be submitted at least 180 days, but no more than 270 days, prior to the expiration of this permit. Permit expiration terminates the source's right to operate unless a timely and complete renewal application has been submitted.

(b) If the permittee submits a timely and complete application for permit renewal the source will not be considered to be operating without a permit until the Technical Secretary takes final action on the permit application, except as otherwise noted in TAPCR paragraph 1200-03-09-.02(11).

(c) This permit, its shield provided in Condition A11, and its conditions will be extended and effective after its expiration date provided that the source has submitted a timely, complete renewal application to the Technical Secretary.

TAPCR 1200-03-09-.02(11)(f)2 and 3, 1200-03-09-.02(11)(d)1(i)(III), and 1200-03-09-.02(11)(a)2

A13. **Reopening for cause.**

(a) A permit shall be reopened and revised prior to the expiration of the permit under any of the circumstances listed below:

1. Additional applicable requirements under the Federal Act become applicable to the sources contained in this permit provided the permit has a remaining term of 3 or more years. Such a reopening shall be completed not later than 18 months after promulgation of the applicable requirement. No such reopening is required if the effective date of the requirement is later than the permit expiration date of this permit, unless the original has been extended pursuant to TAPCR part 1200-03-09-.02(11)(a)2.

2. Additional requirements become applicable to an affected source under the acid rain program.

3. The Technical Secretary or EPA determines that the permit contains a material mistake or that inaccurate statements were made in establishing the emissions standards or other terms or conditions of the permit.

4. The Technical Secretary or EPA determines that the permit must be revised or revoked to assure compliance with the applicable requirements.

(b) Proceedings to reopen and issue a permit shall follow the same proceedings as apply to initial permit issuance and shall affect only those parts of the permit for which cause to reopen exists, and not the entire permit. Such reopening shall be made as expeditiously as practicable.

(c) Reopenings for cause shall not be initiated before a notice of such intent is provided to the permittee by the Technical Secretary at least 30 days in advance of the date that the permit is to be reopened except that the Technical Secretary may provide a shorter time period in the case of an emergency. An emergency shall be established by the criteria of T.C.A. 68-201-109 or other compelling reasons that public welfare is being adversely affected by the operation of a source that is in compliance with its permit requirements.

(d) If the Administrator finds that cause exists to terminate, modify, or revoke and reissue a permit as identified in A13, he is required under federal rules to notify the Technical Secretary and the permittee of such findings in writing. Upon receipt of such notification, the Technical Secretary shall investigate the matter in order to determine if he agrees or disagrees with the Administrator's findings. If he agrees with the Administrator's findings, the Technical Secretary shall conduct the reopening in the following manner:

1. The Technical Secretary shall, within 90 days after receipt of such notification, forward to EPA a proposed determination of termination, modification, or revocation and reissuance, as appropriate. If the Administrator grants additional time to secure permit applications or additional information from the permittee, the Technical Secretary shall have the additional time period added to the standard 90-day time period.

2. EPA will evaluate the Technical Secretary's proposed revisions and respond as to their evaluation.

3. If EPA agrees with the proposed revisions, the Technical Secretary shall proceed with the reopening in the same manner prescribed under Condition A13(b) and Condition A13(c).

4. If the Technical Secretary disagrees with either the findings or the Administrator that a permit should be reopened or an objection of the Administrator to a proposed revision to a permit submitted pursuant to Condition A13(d), he shall bring the matter to the Board at its next regularly scheduled meeting for instructions as to how he should proceed. The permittee shall be required to file a written brief expressing their position relative to the Administrator's objection and have a responsible official present at the meeting to answer questions for the Board. If the Board agrees that EPA is wrong in their demand for a permit revision, they shall instruct the Technical Secretary to conform to EPA's demand, but to issue the permit under protest preserving all rights available for litigation against EPA.

TAPCR 1200-03-09-.02(11)(f)6 and 7

A14. **Permit transference.** An administrative permit amendment allows for a change of ownership or operational control of a source where the Technical Secretary determines that no other change in the permit is necessary, provided that the following requirements are met:

(a) Transfer of ownership permit application is filed consistent with the provisions of TAPCR paragraph 1200-03-09-.03(6), and

(b) written agreement containing a specific date for transfer of permit responsibility, coverage, and liability between the current and new permittee has been submitted to the Technical Secretary.

TAPCR 1200-03-09-.02(11)(f)4(i)(IV) and 1200-03-09-.03(6)

A15. **Air pollution alert.** When the Technical Secretary has declared that an air pollution alert, an air pollution warning, or an air pollution emergency exists, the permittee must follow the requirements for that episode level as outlined in TAPCR paragraph 1200-03-09-.03(1) and TAPCR Rule 1200-03-15-.03.

A16. **Construction permit required.** Except as exempted in TAPCR Rule 1200-03-09-.04, or excluded in TAPCR subparagraph 1200-03-02-.01(1)(aa) or TAPCR subparagraph 1200-03-02-.01(1)(cc), this facility shall not begin the construction of a new air contaminant source or the modification of an air contaminant source which may result in the discharge of air contaminants without first having applied for and received from the Technical Secretary a construction permit for the construction or modification of such air contaminant source.

TAPCR 1200-03-09-.01(1)(a)

A17. **Notification of changes.** The permittee shall notify the Technical Secretary 30 days prior to commencement of any of the following changes to an air contaminant source which would not be a modification requiring a construction permit.

(a) change in air pollution control equipment

(b) change in stack height or diameter

(c) change in exit velocity of more than 25 percent or exit temperature of more than 15 percent based on absolute temperature.

TAPCR 1200-03-09-.02(7)

A18. **Schedule of compliance.** The permittee will comply with any applicable requirement that becomes effective during the permit term on a timely basis and no later than required by the provisions of the new applicable requirement. If the permittee is not in compliance the permittee must submit a schedule for coming into compliance which must include a schedule of remedial measure(s), including an enforceable set of deadlines for specific actions.

TAPCR 1200-03-09-.02(11)(d)3, 1200-03-09-.03(8), 0400-30-38, 0400-30-39, and 40 CFR Part 70.5(c)

A19. **Title VI.**

(a) The permittee shall comply with the standards for recycling and emissions reduction pursuant to 40 CFR, Part 82, Subpart F, except as provided for motor vehicle air conditioners (MVACs) in Subpart B:

1. Persons opening appliances for maintenance, service, repair, or disposal must comply with the required practices pursuant to Section 82.156.

2. Equipment used during the maintenance, service, repair, or disposal of appliances must comply with the standards for recycling and recovery equipment pursuant to Section 82.158.

3. Persons performing maintenance, service, repair, or disposal of appliances must be certified by an approved technician certification program pursuant to Section 82.161.

(b) If the permittee performs a service on motor (fleet) vehicles when this service involves ozone depleting substance refrigerant in the motor vehicle air conditioner (MVAC), the permittee is subject to all the applicable requirements as specified in 40 CFR, Part 82, Subpart B, Servicing of Motor Vehicle Air Conditioners.

(c) The permittee shall be allowed to switch from any ozone-depleting substance to any alternative that is listed in the Significant New Alternatives Program (SNAP) promulgated pursuant to 40 CFR, Part 82, Subpart G, Significant New Alternatives Policy Program.

TAPCR 1200-03-09-.03(8)

A20. **112 (r).** Sources which are subject to the provisions of Section 112(r) of the federal Clean Air Act or any federal regulations promulgated thereunder, shall annually certify in writing to the Technical Secretary that they are properly following their accidental release plan. The annual certification is due in the office of the Technical Secretary no later than January 31 of each year. Said certification will be for the preceding calendar year.

TAPCR 1200-03-32-.03(3)

SECTION B

GENERAL CONDITIONS for MONITORING, REPORTING, and ENFORCEMENT

B1. **<u>Recordkeeping.</u>** Monitoring and related record keeping shall be performed in accordance with the requirements specified in the permit conditions for each individual permit unit. In no case shall reports of any required monitoring and record keeping be submitted less frequently than every six months.

(a) Where applicable, records of required monitoring information include the following:

1. The date, place as defined in the permit, and time of sampling or measurements;
2. The date(s) analyses were performed;
3. The company or entity that performed the analysis;
4. The analytical techniques or methods used;
5. The results of such analyses; and
6. The operating conditions as existing at the time of sampling or measurement.

(b) Digital data accumulation which utilizes valid data compression techniques shall be acceptable for compliance determination as long as such compression does not violate an applicable requirement and its use has been approved in advance by the Technical Secretary.

TAPCR 1200-03-09-.02(11)(e)1(iii)

B2. **<u>Retention of monitoring data.</u>** The permittee shall retain records of all required monitoring data and support information for a period of at least 5 years from the date of the monitoring sample, measurement, report, or application. Support information includes all calibration and maintenance records and all original strip chart recordings for continuous monitoring instrumentation, and copies of all reports required by the permit.

TAPCR 1200-03-09-.02(11)(e)1(iii)(II)II

B3. **<u>Reporting.</u>** Reports of any required monitoring and record keeping shall be submitted to the Technical Secretary in accordance with the frequencies specified in the permit conditions for each individual permit unit. Reports shall be submitted within 60 days of the close of the reporting period unless otherwise noted. All instances of deviations from permit requirements must be clearly identified in such reports. All required reports must be certified by a responsible official. Reports required under "State only requirements" are not required to be certified by a responsible official.

TAPCR 1200-03-09-.02(11)(e)1(iii)

B4. **<u>Certification.</u>** Except for reports required under “State Only” requirements, any application form, report or compliance certification submitted pursuant to the requirements of this permit shall contain certification by a responsible official of truth, accuracy and completeness. This certification shall state that, based on information and belief formed after reasonable inquiry, the statements and information in the document are true, accurate and complete.

TAPCR 1200-03-09-.02(11)(d)4

B5. **<u>Annual compliance certification.</u>** The permittee shall submit annually compliance certifications with terms and conditions contained in Sections A, B, D and E of this permit, including emission limitations, standards, or work practices. This compliance certification shall include all of the following (provided that the identification of applicable information may cross-reference the permit or previous reports, as applicable):

(a) The identification of each term or condition of the permit that is the basis of the certification;

(b) The identification of the method(s) or other means used by the owner or operator for determining the compliance status with each term and condition during the certification period; such methods and other means shall include, at a minimum, the methods and means required by this permit. If necessary, the owner or operator also shall identify any other material information that must be included in the certification to comply with section 113(c)(2) of the Federal Act, which prohibits knowingly making a false certification or omitting material information;

(c) The status of compliance with the terms and conditions of the permit for the period covered by the certification, including whether <u>compliance during the period was continuous or intermittent</u>. The certification shall be based on the method or means designated in B5(b) above. The certification shall identify each deviation and take it into account in the compliance certification. The certification shall also identify as possible exceptions to compliance any periods during which compliance is required and in which an excursion* or exceedance** as defined below occurred; and

(d) Such other facts as the Technical Secretary may require to determine the compliance status of the source.

* "Excursion" shall mean a departure from an indicator range established for monitoring under this paragraph, consistent with any averaging period specified for averaging the results of the monitoring.

** "Exceedance" shall mean a condition that is detected by monitoring that provides data in terms of an emission limitation or standard and that indicates that emissions (or opacity) are greater than the applicable emission limitation or standard (or less than the applicable standard in the case of a percent reduction requirement) consistent with any averaging period specified for averaging the results of the monitoring.

40 CFR Part 70.6(c)(5)(iii) as amended in the Federal Register Vol. 79, No.144, July 28, 2014, pages 43661 through 43667

B6. **<u>Submission of compliance certification.</u>** The compliance certification shall be submitted to:

The Tennessee Department of Environment and Conservation Environmental Field Office specified in Section E of this permit	and	Air Enforcement Branch US EPA Region IV 61 Forsyth Street, SW Atlanta, Georgia 30303

TAPCR 1200-03-09-.02(11)(e)3(v)(IV)

B7. **<u>Reserved</u>**

B8. **<u>Excess emissions reporting.</u>**

(a) The permittee shall promptly notify the Technical Secretary when any emission source, air pollution control equipment, or related facility breaks down in such a manner to cause the emission of air contaminants in excess of the applicable emission standards contained in TAPCR Division 1200-03 or any permit issued thereto, or of sufficient duration to cause damage to property or public health. The permittee must provide the Technical Secretary with a statement giving all pertinent facts, including the estimated duration of the breakdown, the probable cause of the deviation, and any corrective actions or preventative measures taken. Violations of the visible emission standard which occur for less than 20 minutes in one day (midnight to midnight) need not be reported. Prompt notification will be within 24 hours of the malfunction and shall be provided by telephone to the Division's Nashville office. The Technical Secretary shall be notified when the condition causing the failure or breakdown has been corrected. In attainment and unclassified areas if emissions other than from sources designated as significantly impacting on a nonattainment area in excess of the standards will not and do not occur over more than a 24-hour period (or will not recur over more than a 24-hour period) and no damage to property and or public health is anticipated, notification is not required.

(b) Any malfunction that creates an imminent hazard to health must be reported by telephone immediately to the Division's Nashville office at (615) 532-0554 and to the State Civil Defense.

(c) A log of all malfunctions, startups, and shutdowns resulting in emissions in excess of the standards in TAPCR Division 1200-03 or any permit issued thereto must be kept at the plant. All information shall be entered in the log no later than twenty-four (24) hours after the startup or shutdown is complete, or the malfunction has ceased or has been corrected. Any later discovered corrections can be added in the log as footnotes with the reason given for the change. This log must record at least the following:

1. Stack or emission point involved
2. Time malfunction, startup, or shutdown began and/or when first noticed
3. Type of malfunction and/or reason for shutdown
4. Time startup or shutdown was complete or time the air contaminant source returned to normal operation
5. The company employee making entry on the log must sign, date, and indicate the time of each log entry

The information under items 1. and 2. must be entered into the log by the end of the shift during which the malfunction or startup began. For any source utilizing continuous emission(s) monitoring, continuous emission(s) monitoring collection satisfies the above log keeping requirement.

TAPCR 1200-03-20-.03 and .04

B9. **<u>Malfunctions, startups and shutdowns - reasonable measures required.</u>** The permittee must take all reasonable measures to keep emissions to a minimum during startups, shutdowns, and malfunctions. These measures may include installation and use of alternate control systems, changes in operating methods or procedures, cessation of operation until the process equipment and/or air pollution control equipment is repaired, maintaining sufficient spare parts, use of overtime labor, use of outside consultants and contractors, and other appropriate means. Failures that are caused by poor maintenance, careless operation or any other preventable upset condition or preventable equipment breakdown shall not be considered malfunctions. This provision does not apply to standards found in 40 CFR, Parts 60(Standards of performance for new stationary sources), 61(National emission standards for hazardous air pollutants) and 63(National emission standards for hazardous air pollutants for source categories).

TAPCR 1200-03-20-.02

B10. Reserved.

B11. **<u>Report required upon the issuance of a notice of violation for excess emissions.</u>** The permittee must submit, within twenty days after receipt of the notice of violation, the data required below. If this data has been made available to the Technical Secretary prior to the issuance of the notice of violation no further action is required of the violating source. However, if the source desires to submit additional information, then this must be submitted within the same 20-day time period. The minimum data requirements are:

(a) The identity of the stack and/or other emission point where the excess emission(s) occurred;

(b) The magnitude of the excess emissions expressed in pounds per hour and the units of the applicable emission limitation(s) and the operating data and calculations used in determining the magnitude of the excess emissions;

(c) The time and duration of the emissions;

(d) The nature and cause of such emissions;

(e) For malfunctions, the steps taken to correct the situation and the action taken or planned to prevent the recurrence of such malfunctions;

(f) The steps taken to limit the excess emissions during the occurrence reported, and

(g) If applicable, documentation that the air pollution control equipment, process equipment, or processes were at all times maintained and operated in a manner consistent with good operating practices for minimizing emissions.

Failure to submit the required report within the 20-day period specified shall preclude the admissibility of the data for determination of potential enforcement action.

TAPCR 1200-03-20-.06(2), (3) and (4)

SECTION C

PERMIT CHANGES

C1. **Operational flexibility changes.** The source may make operational flexibility changes that are not addressed or prohibited by the permit without a permit revision subject to the following requirements:

(a) The change cannot be subject to a requirement of Title IV of the Federal Act or TAPCR Chapter 1200-03-30.

(b) The change cannot be a modification under any provision of Title I of the federal Act or TAPCR Division 1200-03.

(c) Each change shall meet all applicable requirements and shall not violate any existing permit term or condition.

(d) The source must provide contemporaneous written notice to the Technical Secretary and EPA of each such change, except for changes that are below the threshold of levels that are specified in TAPCR Rule 1200-03-09-.04.

(e) Each change shall be described in the notice including the date, any change in emissions, pollutants emitted, and any applicable requirements that would apply as a result of the change.

(f) The change shall not qualify for a permit shield under the provisions of TAPCR part 1200-03-09-.02(11)(e)6.

(g) The permittee shall keep a record describing the changes made at the source that result in emissions of a regulated air pollutant subject to an applicable requirement, but not otherwise regulated under the permit, and the emissions resulting from those changes. The records shall be retained until the changes are incorporated into subsequently issued permits.

TAPCR 1200-03-09-.02(11)(a)4(ii)

C2. **Section 502(b)(10) changes.**

(a) The permittee can make certain changes without requiring a permit revision, if the changes are not modifications under Title I of the Federal Act or TAPCR Division 1200-03 and the changes do not exceed the emissions allowable under the permit. The permittee must, however, provide the Administrator and Technical Secretary with written notification within a minimum of 7 days in advance of the proposed changes. The Technical Secretary may waive the 7-day advance notice in instances where the source demonstrates in writing that an emergency necessitates the change. Emergency shall be demonstrated by the criteria of TAPCR part 1200-03-09-.02(11)(e)7 and in no way shall it include changes solely to take advantages of an unforeseen business opportunity. The Technical Secretary and EPA shall attach each such notice to their copy of the relevant permit.

(b) The written notification must be signed by a facility Title V responsible official and include the following:

1. a brief description of the change within the permitted facility;

2. the date on which the change will occur;

3. a declaration and quantification of any change in emissions;

4. a declaration of any permit term or condition that is no longer applicable as a result of the change; and

5. a declaration that the requested change is not a Title I modification and will not exceed allowable emissions under the permit.

(c) The permit shield provisions of TAPCR part 1200-03-09-.02(11)(e)6 shall not apply to Section 502(b)(10) changes.

TAPCR 1200-03-09-.02(11)(a)4(i)

C3. **Administrative amendment.**

(a) Administrative permit amendments to this permit shall be in accordance with TAPCR part 1200-03-09-.02(11)(f)4. The source may implement the changes addressed in the request for an administrative amendment immediately upon submittal of the request.

(b) The permit shield shall be extended as part of an administrative permit amendment revision consistent with the provisions of TAPCR part 1200-03-09-.02(11)(e)6 for such revisions made pursuant to item (c) of this condition which meet the relevant requirements of TAPCR subparagraph 1200-03-09-.02(11)(e), TAPCR subparagraph 1200-03-09-.02(11)(f) and TAPCR subparagraph 1200-03-09-.02(11)(g) for significant permit modifications.

(c) Proceedings to review and grant administrative permit amendments shall be limited to only those parts of the permit for which cause to amend exists, and not the entire permit.

TAPCR 1200-03-09-.02(11)(f)4

C4. **Minor permit modifications.**

(a) The permittee may submit an application for a minor permit modification in accordance with TAPCR subpart 1200-03-09-.02(11)(f)5(ii).

(b) The permittee may make the change proposed in its minor permit modification immediately after an application is filed with the Technical Secretary.

(c) Proceedings to review and modify permits shall be limited to only those parts of the permit for which cause to modify exists, and not the entire permit.
(d) Minor permit modifications do not qualify for a permit shield.

TAPCR 1200-03-09-.02(11)(f)5(ii)

C5. **Significant permit modifications.**
(a) The permittee may submit an application for a significant modification in accordance with TAPCR subpart 1200-03-09-.02(11)(f)5(iv).
(b) Proceedings to review and modify permits shall be limited to only those parts of the permit for which cause to modify exists, and not the entire permit.

TAPCR 1200-03-09-.02(11)(f)5(iv)

C6. **New construction or modifications.**
Future construction at this facility that is subject to the provisions of TAPCR Rule 1200-03-09-.01 shall be governed by the following:
(a) The permittee shall designate in their construction permit application the route that they desire to follow for the purposes of incorporating the newly constructed or modified sources into their existing operating permit. The Technical Secretary shall use that information to prepare the operating permit application submittal deadlines in their construction permit.
(b) Sources desiring the permit shield shall choose the administrative amendment route of TAPCR part 1200-03-09-.02(11)(f)4 or the significant modification route of TAPCR subpart 1200-03-09-.02(11)(f)5(iv).
(c) Sources desiring expediency instead of the permit shield shall choose the minor permit modification procedure route of TAPCR subpart 1200-03-09-.02(11)(f)5(ii) or group processing of minor modifications under the provisions of TAPCR subpart 1200-03-09-.02(11)(f)5(iii) as applicable to the magnitude of their construction.

TAPCR 1200-03-09-.02(11)(d)1(i)(V)

SECTION D

GENERAL APPLICABLE REQUIREMENTS

D1. **Visible emissions.**

(a) With the exception of air emission sources exempt from the requirements of TAPCR Chapter 1200-03-05 and air emission sources for which a different opacity standard is specifically provided elsewhere in this permit, the permittee shall not cause, suffer, allow or permit discharge of a visible emission from any air contaminant source with an opacity in excess of twenty (20) percent for an aggregate of more than five (5) minutes in any one (1)hour or more than 20 minutes in any twenty-four (24) hour period; provided, however, that for fuel burning installations with fuel burning equipment of input capacity greater than 600 million btu per hour, the permittee shall not cause, suffer, allow, or permit discharge of a visible emission from any fuel burning installation with an opacity in excess of 20 percent (6-minute average) except for one six minute period per one hour of not more than 40 percent opacity. Sources constructed or modified after July 7, 1992, shall utilize 6-minute averaging.

(b) Consistent with the requirements of TAPCR Chapter 1200-03-20, due allowance may be made for visible emissions in excess of that permitted under TAPCR Chapter 1200-03-05 which are necessary or unavoidable due to routine startup and shutdown conditions. The facility shall maintain a continuous, current log of all excess visible emissions showing the time at which such conditions began and ended and that such record shall be available to the Technical Secretary or an authorized representative upon request.

TAPCR 1200-03-05-.01(1), TAPCR 1200-03-05-.03(6) and TAPCR 1200-03-05-.02(1)

D2. **General provisions and applicability for non-process gaseous emissions.** Any person constructing or otherwise establishing a non-portable air contaminant source emitting gaseous air contaminants after April 3, 1972, or relocating an air contaminant source more than 1.0 km from the previous position after November 6, 1988, shall install and utilize the best equipment and technology currently available for controlling such gaseous emissions.

TAPCR 1200-03-06-.03(2)

D3. **Non-process emission standards.** The permittee shall not cause, suffer, allow, or permit particulate emissions from non-process sources in excess of the standards in TAPCR Chapter 1200-03-06.

D4. **General provisions and applicability for process gaseous emissions.** Any person constructing or otherwise establishing an air contaminant source emitting gaseous air contaminants after April 3, 1972, or relocating an air contaminant source more than 1.0 km from the previous position after November 6, 1988, shall install and utilize equipment and technology which is deemed reasonable and proper by the Technical Secretary.

TAPCR 1200-03-07-.07(2)

D5. **Particulate emissions from process emission sources.** The permittee shall not cause, suffer, allow, or permit particulate emissions from process sources in excess of the standards in TAPCR part 1200-03-07.

D6. **Sulfur dioxide emission standards.** The permittee shall not cause, suffer, allow, or permit sulfur dioxide emissions from process and non-process sources in excess of the standards in TAPCR Chapter 1200-03-14. Regardless of the specific emission standard, new process sources shall utilize the best available control technology as deemed appropriate by the Technical Secretary of the Tennessee Air Pollution Control Board.

D7. **Fugitive Dust.**

(a) The permittee shall not cause, suffer, allow, or permit any materials to be handled, transported, or stored; or a building, its appurtenances, or a road to be used, constructed, altered, repaired, or demolished without taking reasonable precautions to prevent particulate matter from becoming airborne. Such reasonable precautions shall include, but not be limited to, the following:

1. Use, where possible, of water or chemicals for control of dust in demolition of existing buildings or structures, construction operations, grading of roads, or the clearing of land;

2. Application of asphalt, water, or suitable chemicals on dirt roads, material stockpiles, and other surfaces which can create airborne dusts;

3. Installation and use of hoods, fans, and fabric filters to enclose and vent the handling of dusty materials. Adequate containment methods shall be employed during sandblasting or other similar operations.

(b) The permittee shall not cause, suffer, allow, or permit fugitive dust to be emitted in such manner to exceed five (5) minutes per hour or 20 minutes per day as to produce a visible emission beyond the property line of the property on which the emission originates, excluding malfunction of equipment as provided in TAPCR Chapter 1200-03-20.

TAPCR 1200-03-08

D8. **Open burning.** The permittee shall comply with the TAPCR Chapter 1200-03-04 for all open burning activities at the facility.

TAPCR 1200-03-04

D9. **Asbestos.** Where applicable, the permittee shall comply with the requirements of 40 CFR Part 61 when conducting any renovation or demolition activities at the facility.

TAPCR 0400-30-38-.01(2) and 40 CFR, Part 61

D10. **Annual certification of compliance.** The generally applicable requirements set forth in Section D of this permit are intended to apply to activities and sources that are insignificant emission units or activities. By annual certification of compliance with the conditions in this Section the permittee shall be considered to meet the monitoring and related record keeping and reporting requirements of TAPCR subpart 1200-03-09-.02(11)(e)1(iii) and part 1200-03-10-.04(2)(b)1 and the compliance requirements of TAPCR subpart 1200-03-09-.02(11)(e)3(i). The permittee shall submit compliance certification for these conditions annually.

D11. **Emission Standards for Hazardous Air Pollutants.** The permittee shall comply with all applicable requirements of TAPCR Chapter 0400-30-38 for all emission sources subject to a requirement contained therein.

D12. **Standards of Performance for New Stationary Sources.** The permittee shall comply with all applicable requirements of TAPCR chapters 0400-30-39 and 1200-03-16 for all emission sources subject to a requirement contained therein.

D13. **Gasoline Dispensing Facilities.** The permittee shall comply with all applicable requirements of TAPCR Rule 1200-03-18-.24 for all emission sources subject to a requirement contained therein.

D14. **Internal Combustion Engines.**

(a) All stationary reciprocating internal combustion engines, including engines deemed insignificant activities and insignificant emission units, shall comply with the applicable provisions of TAPCR Rule 0400-30-38-.01.

(b) All stationary compression ignition internal combustion engines, including engines deemed insignificant activities and insignificant emission units, shall comply with the applicable provisions of TAPCR Chapter 0400-30-39.

(c) All stationary spark ignition internal combustion engines, including engines deemed insignificant activities and insignificant emission units, shall comply with the applicable provisions of TAPCR Chapter 0400-30-39.

TAPCR 0400-30-38 and 39

SECTION E

SOURCE SPECIFIC EMISSION STANDARDS, OPERATING LIMITATIONS, and MONITORING, RECORDKEEPING and REPORTING REQUIREMENTS

43-0011	**Facility Description:**	TVA Johnsonville is a Combustion Turbine powered electric generating facility with ash handling operations for Coal Combustion Residuals.

Conditions E1 and E2 apply to all sources in Section E of this permit unless otherwise noted.

E1(MM1). **Fee payment**

FEE EMISSIONS SUMMARY TABLE FOR MAJOR SOURCE 43-0011

REGULATED POLLUTANTS	ALLOWABLE EMISSIONS (tons per AAP)	ACTUAL EMISSIONS (tons per AAP)	COMMENTS
PARTICULATE MATTER (PM)	**1,296**	**AEAR**	
SO_2	**9,773**	**AEAR**	
VOC	**158**	**AEAR**	
NO_X	**7,619**	**AEAR**	
Facility-Wide Total HAP Limit		**AEAR**	
Facility-Wide Individual HAP Limit		**AEAR**	
HAZARDOUS AIR POLLUTANTS (HAPs) NOT INCLUDED ABOVE*			
Non-VOC Gaseous HAP	**4.60**	**AEAR**	Fee emissions not included above.
		AEAR	
		AEAR	
MISCELLANEOUS POLLUTANTS NOT LISTED ABOVE**			
EACH MISC POLLUTANT NOT LISTED ABOVE			
		AEAR	
		AEAR	
		AEAR	
		AEAR	

NOTES

AAP The **Annual Accounting Period** (**AAP**) is a 12 consecutive month period that **either (a) begins each July 1st and ends June 30th of the following year when fees are paid on a fiscal year basis, or (b) begins January 1st and ends December 31st of the same year when paying on a calendar year basis.** The **AAP** at the time of Minor Modification #1 issuance **began January 1, 2025, and ends December 31, 2025.** The next AAP begins **January 1, 2026**, and ends **December 31, 2026,** unless a request to change the annual accounting period is submitted by the responsible official as required by subparagraph 1200-03-26-.02(9)(b) of the TAPCR and approved by the Technical Secretary**.** If the permittee wishes to revise their annual accounting period or their annual emission fee basis as allowed by subparagraph 1200-03-26-.02(9)(b) of the TAPCR, the responsible official must submit the request to the Division in writing on or before December 31 of the annual accounting period for which the fee is due. If a change in fee basis from allowable emissions to actual emissions for any pollutant is requested, the request from the responsible official must include the methods that will be used to determine actual emissions. **Changes in fee bases must be made using the Title V Fee Selection form, form number APC 36 (CN-1583), included as an attachment to this permit and available on the Division of Air Pollution Control's website**.

N/A **N/A** indicates that no emissions are specified for fee computation.

AEAR If the permittee is paying annual emission fees on an actual emissions basis, **AEAR** indicates that an **A**ctual **E**missions **A**nalysis is **R**equired to determine the actual emissions of:

- **(1)** **each regulated pollutant** (Particulate matter [PM], SO_2, VOC, NO_X and so forth. See TAPCR 1200-03-26-.02(2)(i) for the definition of a regulated pollutant.),
- **(2)** the "**HAP Not Included Above" Category (non-VOC and non-PM HAP not included in a facility-wide limit)**, and
- **(3)** the **Miscellaneous Category**

under consideration during the **Annual Accounting Period**.

* **Hazardous Air Pollutants Not Included Above:** This category is made-up of hazardous air pollutants that are not included in the VOC or PM category, such as HCl and HF, and are not included in a facility-wide HAP emission limitation. **For fee computation**, each individual hazardous air pollutant is subject to the 4,000-ton cap provisions of subparagraph 1200-03-26-.02(2)(i) of the TAPCR.

** **Miscellaneous Pollutants Not Listed Above:** This category is for pollutants that are not included in one of the other categories but for which an emission limitation has been established in this permit (including NSPS pollutants). **For fee computation**, each pollutant in this category is subject to the 4,000-ton cap provisions of subparagraph 1200-03-26-.02(2)(i).

END NOTES

The permittee shall:

(1) Pay Title V **annual fees** (including the emissions fee, base fee, significant modification fee, & minor modification fee), on the emissions and year bases requested by the responsible official and approved by the Technical Secretary, for each annual accounting period (AAP) by the payment deadline(s) established in TAPCR 1200-03-26-.02(9)(a). Fees may be paid on an **actual**, **allowable**, or **mixed** emissions basis, and on either a **state fiscal year** or a **calendar year**, provided the requirements of TAPCR 1200-03-26-.02(9)(b) are met. If any part of any fee imposed under TAPCR 1200-03-26-.02 is not paid within 15 days of the due date, penalties shall at once accrue as specified in TAPCR 1200-03-26-.02(8).

(2) Sources paying annual fees on an allowable emissions basis: pay annual fees for each AAP no later than April 1 of each year pursuant to TAPCR 1200-03-26-.02(9)(d). TAPCR 1200-03-26-.02(9)(a)2(i)

(3) Sources paying annual fees on a calendar year basis and an actual or mixed emissions basis: pay annual allowable based emission fees for each AAP no later than April 1 of each year pursuant to TAPCR 1200-03-26-.02(9)(d), except as allowed by TAPCR 1200-03-26-.02(9)(g)3.
TAPCR 1200-03-26-.02(9)(a)2(ii)

(4) Sources paying annual fees on a fiscal year basis and an actual or mixed emissions basis: for each AAP, pay an estimated 65% of the fee due no later than April 1 of the current fiscal year. The remainder of the fee for each annual accounting period is due no later than August 1 of each year pursuant to TAPCR 1200-03-26-.02(9)(d), except as allowed by TAPCR 1200-03-26-.02(9)(g)3.
TAPCR 1200-03-26-.02(9)(a)2(iii)

(5) Sources paying annual fees on an actual emissions basis: prepare an **actual emissions analysis** for each AAP and pay **actual based emission fees** pursuant to TAPCR 1200-03-26-.02(9)(d). The **actual emissions analysis** shall include:
(a) the completed **Fee Emissions Summary Table**,
(b) each **actual emissions analysis** required**,** and
(c) the actual emission records for each pollutant and each source as required for actual emission fee determination, or a summary of the actual emission records required for fee determination, as specified by the Technical Secretary or the Technical Secretary's representative. The summary must include sufficient information for the Technical Secretary to determine the accuracy of the calculations. These calculations must be based on the Fee Year basis approved by the Technical Secretary (a state fiscal year [July 1 through June 30] or a calendar year [January 1 through December 31]). These

records shall be used to complete the **actual emissions analyses** required by the above **Fee Emissions Summary Table**.

TAPCR 1200-03-26-.02(9)(g)2

(6) Sources paying annual fees on a Fee Choice of a mixed emissions basis: for all pollutants and all sources for which the permittee has chosen an actual emissions basis, prepare an **actual emissions analysis** for each AAP and pay **actual based emission fees** pursuant to TAPCR 1200-03-26-.02(9)(d). The **actual emissions analysis** shall include:

(a) the completed **Fee Emissions Summary Table**,

(b) each **actual emissions analysis** required**,** and

(c) the actual emission records for each pollutant and each source as required for actual emission fee determination, or a summary of the actual emission records required for fee determination, as specified by the Technical Secretary or the Technical Secretary's representative. The summary must include sufficient information for the Technical Secretary to determine the accuracy of the calculations. These calculations must be based on the Fee Year basis approved by the Technical Secretary (a state fiscal year [July 1 through June 30] or a calendar year [January 1 through December 31]). These records shall be used to complete the **actual emissions analysis**.

For all pollutants and all sources for which the permittee has chosen an allowable emissions basis, pay allowable based emission fees pursuant to TAPCR 1200-03-26-.02(9)(d).

TAPCR 1200-03-26-.02(9)(g)2

(7) When paying on an actual or mixed emissions basis, submit the **actual emissions analyses** at the time the fees are paid in full or earlier.

TAPCR 1200-03-26-.02(9)(g)2

(8) Include with each required AEAR report the following statement signed by the Responsible Official: *"I have reviewed this document in its entirety, and to the best of my knowledge, based on information and belief formed after reasonable inquiry, the statements and information contained in this document are true, accurate, and complete."*

TAPCR 1200-03-09-.02(11)(d)4

The annual fee due dates are specified in TAPCR 1200-03-26-.02(9)(a) and are dependent on the Responsible Official's choice of fee bases as described above. If any part of any fee imposed under TAPCR 1200-03-26-.02 is not paid within 15 days of the due date, penalties shall at once accrue as specified in TAPCR 1200-03-26-.02(8). Emissions for regulated pollutants shall not be double counted as specified in Condition A8(d) of this permit.

Payment of the fee due and the actual emissions analysis (if required) shall be submitted to the Technical Secretary a the following address:

Payment of Fee to:		**Actual Emissions Analyses to:**
Tennessee Department of Environment and Conservation Division of Fiscal Services Consolidated Fee Section – APC Davy Crockett Tower, 6th Floor 500 James Robertson Parkway Nashville, Tennessee 37243	and	A "Title V Emissions Summary Form" and the AEAR must b submitted electronically as directed by the Division. Addition information can be found at https://www.tn.gov/environment/air/inventory.html

TAPCR 1200-03-26-.02(3), (8), and (9), and TAPCR 1200-03-09-.02(11)(e)1(vii)

<u>Actual Emissions Analyses for 43-0011 are required as follows when paying on an actual emissions basis:</u>

Actual particulate emissions for fuel burning installation 43-0011-11-20 shall be calculated as follows:

TPY per combustion turbine = (btu/yr) * (lb particulate/ 10^6 btu) * (ton/ 2,000 lb)

where: btu/yr = actual annual heat input to the CT for the AAP.

lb particulate / 10^6 btu = emission factors of 0.029 lb per 10^6 Btu for fuel oil and 0.007 lb per 10^6 Btu for natural gas from manufacturer's data, emission factors for fuel oil and natural gas combustion - permit application revisions dated May 2001 pages 4-50 and 4-55 – **(Attachment 6 of this permit)**

Actual particulate emissions for source 43-0011-29 shall be calculated as described on pages 5-22 through 5-30 of the November 18, 1996 permit application (Attachment 5 of this permit).

Actual particulate emissions for source 43-0011-30 shall be calculated as described on pages 6-17 through 6-22 of the November 18, 1996 permit application (attachment 4 of this permit).

Actual particulate emissions for fuel burning installations 43-0011-32 and 35 shall be calculated as follows:

TPY per combustion turbine = (btu/yr) * (lb particulate/ 10^6 btu) * (ton/ 2000 lb)

where: btu/yr = actual annual heat input to the CT for the AAP.
lb particulate / 10^6 btu = emission factors of 0.012 lb per 10^6 Btu for fuel oil and 0.0066 lb per 10^6 Btu for natural gas from AP-42, emission factors for fuel oil and natural gas combustion – Table 3.1-2a. – **(Attachment 6 of this permit**)

Actual particulate emissions for fuel burning installations 43-0011-33, 36, and 37 shall be calculated as follows:

TPY per heater = (btu/yr) * (lb particulate/ 10^6 scf) * (scf/ 1020 btu) * (ton/ 2000 lb)

where: btu/yr = actual annual heat input to the heater/boiler for the AAP.
lb particulate / 10^6 scf = emission factor of 7.6 lb per 10^6 scf derived from AP-42, Table 1.4-2, emission factors for natural gas combustion **(Attachment 2 of this permit**)

Actual Non-VOC gaseous group (HAP without a standard) shall be calculated for the previous Annual Accounting Period (AAP) and as reported for the National Emissions Inventory.

Actual oxides of nitrogen and volatile organic compound emissions for all emission sources shall be calculated based on the methods outlined in Attachment 8(SM1).

For all other emission sources, if the responsible official chooses to base the annual emission fee on actual emissions, then the responsible official must prove the magnitude of the source's emissions to the satisfaction of the Technical Secretary (TAPCR 1200-03-26-.02(9)(g)2.(ii)).

E2(MM1). **<u>Reporting requirements</u>**

(a) Reserved

(b) **<u>Semiannual reports.</u>** Reporting periods shall be **<u>January 1 to June 30</u>** and **<u>July 1 to December 31</u>** of each calendar year. The Semiannual reports shall be submitted within 60 days after the end of each reporting period. Semiannual reports of this facility (43-0011) shall include:

(1) Any recordkeeping and monitoring required by **Conditions E4-7, E8-12, E8-13, E8-16, E10-7, and E10-9** of this permit. However, a summary report of this data is acceptable provided there is sufficient information to enable the Technical Secretary to evaluate compliance.

(2) The visible emission evaluation readings from **Conditions E2-2(b), E4-3, E6-1, E7-1(b), E8-11, and E9-3** of this permit if required. However, a summary report of this data is acceptable provided there is sufficient information to enable the Technical Secretary to evaluate compliance.

(3) Identification of all instances of deviations from **<u>ALL PERMIT REQUIRMENTS</u>**.

These reports must be certified by a responsible official consistent with Condition B4 of this permit and shall be submitted to The Technical Secretary at the address in Condition E2(c) of this permit.

TAPCR 1200-03-09-.02(11)(e)1(iii)

(c) **Annual compliance certification.** The permittee shall submit annually compliance certifications with terms and conditions contained in Sections **A**, **B**, **D**, and **E** of this permit, including emission limitations, standards, or work practices. This compliance certification shall include all of the following (provided that the identification of applicable information may cross-reference the permit or previous reports, as applicable):

(1) The identification of each term or condition of the permit that is the basis of the certification;

(2) The identification of the method(s) or other means used by the owner or operator for determining the compliance status with each term and condition during the certification period. Such methods and other means shall include, at a minimum, the methods and means required by this permit. If necessary, the owner or operator also shall identify any other material information that must be included in the certification to comply with section 113(c)(2) of the Federal Act, which prohibits knowingly making a false certification or omitting material information.

(3) Reserved.

(4) The status of compliance with the terms and conditions of the permit for the period covered by the certification, including whether compliance during the period was continuous or intermittent. The certification shall be based on the method or means designated in E2(b)(1) above. The certification shall identify each deviation and take it into account in the compliance certification. The certification shall also identify as possible exceptions to compliance any periods during which compliance is required and in which an *excursion or **exceedance as defined below occurred; and

(5) Such other facts as the Technical Secretary may require to determine the compliance status of the source.

*"Excursion" shall mean a departure from an indicator range established for monitoring under this paragraph, consistent with any averaging period specified for averaging the results of the monitoring.

**"Exceedance" shall mean a condition that is detected by monitoring that provides data in terms of an emission limitation or standard and that indicates that emissions (or opacity) are greater than the applicable emission limitation or standard (or less than the applicable standard in the case of a percent reduction requirement) consistent with any averaging period specified for averaging the results of the monitoring.

Annual compliance certifications shall cover the 12-month periods from January 1 to December 31 of each calendar year and shall be submitted within 60 days after the 12-month reporting period.

These certifications shall be submitted to: TN APCD and EPA

Division of Air Pollution Control **Nashville Environmental Field Office** **711 R.S. Gass Blvd.** **Nashville, Tennessee 37216** **or** **APC.NashEFO@tn.gov**	**and**	**Air Enforcement Branch** **US EPA Region IV** **61 Forsyth Street, SW Street** **Atlanta, GA 30303** **or** **Through the EPA CDX** **(https://cdx.epa.gov)**

40 CFR Part 70.6(c)(5)(iii) as amended in the Federal Register Vol. 79, No. 144, July 28, 2014, pages 43661 through 43667
TAPCR 1200-03-09-.02(11)(e)3(v)

(d) The NSPS reports required by 40 CFR 60 Subpart KKKK (**Condition E10-6**) and 40 CFR 60 Subpart Db (**Condition E11-6**).

These reports shall be submitted to:

Tennessee Division of Air Pollution Control Davy Crockett Tower, 7th Floor 500 James Robertson Parkway	OR	Air.Pollution.Control@tn.gov

Nashville, TN 37243		

(e) **<u>NESHAP Reporting Requirements</u>** The permittee must submit NESHAP reports as follows:
40 CFR Part 63, Subpart DDDDD Annual Reports: The permittee must submit Annual Compliance Reports required in **Condition E11-7.** Each 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) (*www.epa.gov/cdx*). 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 Technical Secretary at one of the addresses listed in **Condition E2(d)**.

(f) **<u>Retention of Records</u>** All records required by any condition in Section E of this permit must be retained for a period of not less than five years. Additionally, these records shall be kept available for inspection by the Technical Secretary or the authorized representative.

TAPCR1200-03-09-.02(11)(e)1(iii)(II)II

(g) The CEM quality assurance checks specified at **Conditions E8-15 and E10-8** shall be submitted to the Technical Secretary electronically to <u>air.pollution.control@tn.gov.</u>

TAPCR 1200-03-10-.02(1)(a)

E2-1. Recordkeeping: Data Entry Requirements

(a) For monthly recordkeeping, all data, including the results of all calculations, must be entered into the log no later than 30 days from the end of the month for which the data is required.

(b) For weekly recordkeeping, all data, including the results of all calculations, must be entered into the log no later than seven days from the end of the week for which the data is required.

(c) For daily recordkeeping, all data, including the results of all calculations, must be entered into the log no later than seven days from the end of the day for which the data is required.

TAPCR 1200-03-10-.02(2)(a)

E2-2. Visible Emissions Evaluation: General Requirements

(a) For all emission sources that use the opacity matrix decision trees (Attachment 1) to comply with any visible emissions requirement, including emission sources for which visible emissions are not required by the opacity matrix, if the magnitude and frequency of excursions reported by the permittee in the periodic monitoring for emissions is unsatisfactory to the Technical Secretary, this permit may be reopened to impose additional opacity monitoring requirements.

(b) Compliance with the fugitive emission requirements of **Condition D7(b)** shall be determined by compliance with **Condition D7(a)** and by Tennessee Visible Emissions Evaluation Method 4 as adopted by the Tennessee Air Pollution Control Board on April 16, 1986. These evaluations shall be made semiannually.

TAPCR 1200-03-08, TAPCR 1200-03-09-.02(11)(e)1.(iii), and TAPCR 1200-03-10-.02(1)(a)

E2-3. Ambient Monitoring for SO_2

Consistent with the provisions of TAPCR 1200-03-14-.01(6), each owner or operator of a fuel burning installation having a total rated capacity greater than 1,000 MMBtu/hr or of a process emission source emitting more than 1,000 tons per year of sulfur dioxide during calendar year 1972 or any other calendar year thereafter must comply with the following requirements:

(a) Demonstrate to the satisfaction of the Technical Secretary, that the sulfur dioxide emitted either alone or in contribution to other sources will not interfere with attainment and maintenance of any primary or secondary air quality standard.

(b) Install and maintain air quality sensors to monitor attainment and maintenance of ambient air quality standards in the areas influenced by the emissions from such installation. Such shall be done in the manner prescribed by the Technical Secretary. Results of such monitoring shall be provided to the Technical Secretary in the manner and form as he shall direct. Owners or operators may petition and be granted permission by the Technical Secretary to terminate ambient air quality monitoring provided two calendar years air quality data has been generated in the area under the influence of the source's emissions to verify compliance with the Tennessee Ambient Air Quality Standards. Petitions may be granted if the following conditions are met:

(1) The source must be located in an attainment area and must not significantly impact a sulfur dioxide nonattainment area.

(2) Measurements of air quality in the vicinity of the source demonstrate that ambient sulfur dioxide levels do not exceed 75 percent of the Tennessee Ambient Air Quality Standards.

(c) All calculations performed pursuant to demonstration required by rule .01(6) shall assume that the process emission source and fuel burning installation is operating at a maximum rated capacity.

Pursuant to the approval letter from the Technical Secretary dated February 1, 2008, this facility has met the requirements of paragraphs (b)(1) and (b)(2) of this condition, and ambient SO_2 monitoring is not required.

TAPCR 1200-03-14-.01(6)

E2-4. **<u>Acid rain program</u>**

(**a**) The permittee shall not produce emissions in excess of allowances held under Title IV of the Federal Clean Air Act and the regulations promulgated thereunder and TAPCR 1200-03-30.

(**b**) The permittee shall not be subject to the permit revision requirements of TAPCR 1200-03-09-.02(11)(f) for increases in emissions that are authorized by allowances acquired pursuant to the acid rain program, provided that such increases do not require a permit revision under any other applicable requirement.

(**c**) Where an applicable requirement of the Federal Act is more stringent than the Federal regulations promulgated under Title IV of the Federal Act, both provisions shall be incorporated into the permit and shall be enforceable by the administrator.

(**d**) No limit shall be placed on the number of allowances held by this source under the acid rain program. The permittee may not use allowances as a defense for noncompliance with any other applicable requirement.

(**e**) Any allowance shall be accounted for according to the regulations promulgated under Title IV of the Federal Clean Air Act and the provisions of TAPCR 1200-03-30.

(f) This facility is subject to the provisions of Acid Rain Permit **No. 877422** as specified in **Attachment 3** of this permit.

TAPCR 1200-03-09-.02(11)(e)1(iv)

E2-5. Identification of Responsible Official, Technical Contact, and Billing Contact

(a) The application that was utilized in the preparation of this renewal permit is dated June 2, 2017, and is signed by Steve L Holland, Assistant Plant Manager. The letter dated May 24, 2018 identifies Michael W. Parker as the Responsible Official for the permitted facility. If this person terminates their employment or is assigned different duties such that they are no longer a Responsible Official for this facility as defined in part 1200-03-09-.02(11)(b)21 of the TAPCR, the owner or operator of this air contaminant source shall notify the Technical Secretary of the change. Said notification must be in writing and must be submitted within 30 days of the change. The notification shall include the name and title of the new Responsible Official and certification of truth and accuracy. All representations, agreement to terms and conditions, and covenants made by the former Responsible Official that were used in the establishment of the permit terms and conditions will continue to be binding on the facility until such time that a revision to this permit is obtained that would change said representations, agreements, and/or covenants.

(b) The application that was utilized in the preparation of this renewal permit is dated June 2, 2017, and identifies Rebecca J. Seaton as the Principal Technical Contact for the permitted facility. If this person terminates their employment or is assigned different duties such that they are no longer the Principal Technical Contact for this facility, the owner or operator of this air contaminant source shall notify the Technical Secretary of the change. Said notification must be in writing and must be submitted within 30 days of the change. The notification shall include the name and title of the new Principal Technical Contact and certification of truth and accuracy.

(c) The application that was utilized in the preparation of this renewal permit is dated June 2, 2017. A letter dated July 9, 2018, identifies Michael G. Tritapoe, as the Billing Contact for the permitted facility. If this person terminates their employment or is assigned different duties such that they are no longer the Billing Contact for this facility, the owner or operator of this air contaminant source shall notify the Technical Secretary of the change. Said notification must be in writing and must be submitted within 30 days of the change. The notification shall include the name and title of the new Billing Contact and certification of truth and accuracy.

E2-6. Cross-State Air Pollution Rule (CSAPR) Requirements

The permittee shall comply with the applicable provisions of 40 CFR 97 Subparts AAAAA (CSAPR NO_X Annual Trading Program), CCCCC (CSAPR SO_2 Group 1 Trading Program), and EEEEE (CSAPR NO_X Ozone Season Group 2 Trading Program). The permittee shall comply with paragraphs 74 through 78 of the Consent Decree regarding the use and surrender of NO_X allowances, and with paragraphs 90 through 93 of the Consent Decree regarding the use and surrender of SO_2 allowances. The permittee may sell, bank, use, trade, or transfer any allowances in accordance with paragraphs 82 and 94 of the Consent Decree (Super-Compliance Allowances). For surrender of allowances, the permittee shall comply with paragraphs 79, 80, 95, and 96 of the Consent Decree. Specific trading program requirements are included in Attachment 9.

TAPCR 1200-03-09-.03(8) and 40 CFR §52.2240 and §52.2241, 40 CFR §§97.401 – 97.435, §§97.501 – 97.535, §§97.601 – 97.635, Consent Decree

E2-7. Unless otherwise specified in this permit, the averaging time for an emission standard shall be the same time period as that of the compliance test method approved by the Technical Secretary.

SOURCE SPECIFIC CONDITIONS

43-0011-11 through 20 (MM1)	**Source Description**	**Combustion Turbine Electric Generating Plant:** Ten (10) simple cycle turbines; CT Units JCT1-10 9,280 million Btu/hour nominal heat input capacity at 0 degrees F (928 million Btu/hour each unit); 787 megawatt total electrical output; No. 2 Fuel oil or natural gas fired. Evaporative inlet fogging for NO_X control. TVA designated emission units 2-11 Two (2) natural gas fired heaters; Heater Units NGH3 and NGH4: Heating of heat exchanger water used to vaporize condensate in natural gas feed to the combustion turbines. 22 million Btu/hour nominal heat input capacity (11 million Btu/hour each unit). TVA designated emission units 29- 32 (heaters 3&4)

Conditions E4-1 through E4-7 apply to fuel burning installation 43-0011-11-20

E4-1. Particulate emissions from this fuel burning installation shall not exceed **0.100** pounds per million Btu of heat input as specified in subparagraph 1200-03-06-.02(2)(a) of the TAPCR. Testing methodology shall be EPA Method 5, as published in the current 40 CFR 60, Appendix A.

Compliance Method: Compliance assurance for the particulate standard stated in this condition is based upon the following emission factors for combustion of No. 2 fuel oil and natural gas:

Pollutant	**Emission Factor (pounds per million Btu)**
Particulate matter	0.029 (fuel oil)
	0.0070 (natural gas)

Data from manufacturer's data and sample calculation on page 4-55 of the permit application revisions dated May 2001 (enclosed as Attachment 6)

TAPCR 1200-03-09-.02(11)(e)1(iii)

E4-2. Sulfur dioxide emitted from this fuel burning installation while burning No. 2 fuel oil shall not exceed **0.8** pounds per million Btu of heat input utilizing a one hour averaging basis as specified in Subparagraphs 1200-03-14-.02(2)(b) and 1200-03-19-.14(1)(b) of the TAPCR. Testing methodology shall be EPA Method 6, as published in the current 40 CFR 60, Appendix A.

Compliance Method: Compliance assurance for the sulfur dioxide emission standard stated in this condition is based upon the following emission factors for combustion of No. 2 fuel oil and natural gas:

Pollutant	**Emission Factor (pounds per million Btu)**
Sulfur dioxide	0.48 (fuel oil)
	0.0034 (natural gas)

Data from AP-42, Table 3.1-2a and sample calculation on page 4-59 of the permit application revisions dated May 2001 (enclosed as Attachment 6)

TAPCR 1200-03-09-.02(11)(e)1(iii)

E4-3. Visible emissions from this fuel burning installation shall not exceed 20 percent opacity except for one six-minute period per one hour of not more than 40% opacity as specified in Paragraph 1200-03-05-.01(1) of the TAPCR. Opacity data reduction shall be accomplished utilizing the procedures outlined in the current 40 CFR 60, Appendix A, Method 9. (6-minute average).

TAPCR 1200-03-05-.01(1)

Compliance Method: Compliance with this standard shall be determined by the procedures of the Division's Opacity Matrix amended September 11, 2013 enclosed as **Attachment 1**.

E4-4. Only grade No. 2 fuel oil or natural gas shall be burned in the combustion turbines to ensure compliance with the applicable sulfur dioxide, particulates, and opacity limitations. The sulfur content of the no. 2 fuel oil shall not exceed 0.5 percent by weight.

TAPCR 1200-03-09-.02(11)(e)1(iii)

Compliance Method: Compliance with this condition shall be assured by the recordkeeping of **Condition E4-7**.

E4-5. Reserved

E4-6(MM1). Consistent with the provisions of Section 2.12.2.F.2 Reasonable Further Progress (New Johnsonville Additional Control Area) of the Air Quality Implementation Plan of the State of Tennessee as of July 1, 1982, the operating capacity of this fuel burning installation shall not exceed 35% of its total theoretical design capacity (2,100.21 gigawatt-hours per year). This limitation is established pursuant to Rules 1200-03-06-.01(7) and 1200-03-14-.01(3) of the TAPCR and the information contained in the agreement letter dated March 12, 2025 (Attachment 11), from the permittee.

Compliance Method: Compliance with this condition shall be assured by the recordkeeping of **Condition E4-7**.

E4-7. A monthly log of the following information must be maintained at the source location and kept available for inspection by the Technical Secretary or the authorized representative:

(a) Sulfur analysis for each shipment of #2 fuel oil or certification statement by the vendor that the fuel oil sulfur content shall not exceed 0.5 percent by weight

(b) Megawatt hour output

TAPCR 1200-03-19-.14(1)(b) and TAPCR 1200-03-09-.02(11)(e)1(iii)

43-0011-29	**Source Description**	**<u>Coal Handling Facility:</u>** TVA designated emission units 18 and 19. (Note- as of March 23, 2018, the coal storage pile (stockout/reclaim) will remain on-site until a method for closure has been approved by state and federal agencies)

Condition E6-1 applies to source 43-0011-29

E6-1. Fugitive emissions from this facility shall be controlled as specified in Chapter 1200-03-08 of the TAPCR. Specifically, fugitive emissions shall be controlled such that there are no visible emissions beyond the property line of the property on which the emission originates, excluding legitimate malfunctions of the equipment, for more than five minutes per hour or 20 minutes per day.

TAPCR 1200-03-08

Compliance Method: Compliance with this standard shall be determined by TVEE Method 4, as adopted by the Tennessee Air Pollution Control Board on April 16, 1986. These evaluations shall be made semiannually and the results of the evaluations shall be maintained at the facility and kept available for inspection by the Technical Secretary or the authorized representative.

Fugitive emissions associated with the remaining coal storage pile will be controlled with wet suppression measures. The wet suppression and TVEE inspection requirements will be allowed to cease following closure." Within 90 days of closure the permittee shall apply for a minor permit modification to remove this source from the permit.

43-0011-30	**Source Description**	**<u>Ash Disposal Area for Ash Settling Pond:</u>** Ash stacking and disposal area with haul road; Wet Suppression Control TVA designated emission units 20 and 21.

Condition E7-1 applies to source 43-0011-30

E7-1. Fugitive emissions from this facility shall be controlled as specified in Chapter 1200-03-08 of the TAPCR. Specifically, fugitive emissions shall be controlled such that there are no visible emissions beyond the property line of the property on which the emission originates, excluding legitimate malfunctions of the equipment, for more than five minutes per hour or 20 minutes per day.

TAPCR 1200-03-08

Compliance Method:

(a) The application of water to the ash disposal operations (hauling/bulldozing) shall be employed as needed to control fugitive emissions.

(b) Compliance with this standard shall be determined by TVEE Method 4, as adopted by the Tennessee Air Pollution Control Board on April 16, 1986. These evaluations shall be made semiannually and the results of the evaluations shall be maintained at the facility and kept available for inspection by the Technical Secretary or the authorized representative.

43-0011-32	**Source Description**	**Combustion Turbine Electric Generating Plant:** Three (3) simple cycle turbines; CT Units 17-19 3,296 million Btu/hour nominal heat input capacity at 59 degrees F (1098.7 million Btu/hour each unit) 283.8 megawatt electrical output; No. 2 fuel oil or natural gas fired; Dry low NO_X combustors for natural gas combustion and water injection for NO_X control during fuel oil combustion. Two (2) natural gas fired fuel heaters; Heater Units NGH1 and NGH2: Heating of heat exchanger water used to vaporize condensate in natural gas feed to the combustion turbines. 13.4 million Btu/hour nominal heat input capacity (7.787 million Btu/hour each unit). TVA designated emission units 27 and 28 (heaters 1&2) NSPS, PSD

Conditions E8-1 through E8-16 apply to source 43-0011-32

E8-1. Reserved.

E8-2. Except as provided in **Condition E8-3**, only natural gas and #2 fuel oil shall be used as fuels for the combustion turbines. This operational restriction shall represent BACT for the combustion turbines for emissions of particulate matter, carbon monoxide, and volatile organic compounds.

TAPCR 1200-03-09-.03(8)

E8-3. Alternate fuels that comply with the applicable particulate and sulfur dioxide emission standards may be used.

TAPCR 1200-03-09-.03(8) and Condition 4 of Construction Permit 959329P issued July 12, 2006

Compliance Method: Compliance with this condition shall be assured as follows:

(a) The permittee shall provide written notification to the Technical Secretary at least 30 days prior to initiation of the burning of such fuels. At a minimum, the notification shall include an identification of the fuels to be burned; an estimated start date and (as applicable) completion date; an estimate of the impact on control devices; and an estimate of the impact on emissions;

(b) The permittee shall demonstrate compliance with the applicable particulate matter and sulfur dioxide emission standards; and

(c) The permittee shall perform any additional testing requested by the Technical Secretary.

E8-4. Only natural gas shall be used as fuel for the natural gas heaters. Annual natural gas usage by the heaters shall not exceed **66.6** million standard cubic feet. This operational restriction shall represent BACT for the natural gas heaters for emissions of particulate matter, carbon monoxide, volatile organic compounds, and nitrogen oxides.

TAPCR 1200-03-09-.01(4)

Compliance Method: Compliance shall be assured by the recordkeeping of **Condition E8-12**.

E8-5. The sulfur content of the #2 fuel oil shall not exceed **0.05** percent by weight.

TAPCR 1200-03-09-.01(4)

Compliance Method: Compliance shall be assured by the recordkeeping of **Condition E8-12**.

E8-6. The total production for this fuel-burning installation shall not exceed **955.0** gigawatt-hours per year. No more than **316.7** gigawatt-hours of annual production shall occur during oil-fired operation, with the remainder of annual production to occur during gas-fired operation.

These operational limitations are established pursuant to Rules 1200-03-06-.01(7) and 1200-03-14-.01(3) of the TAPCR and the information contained in the application dated November 24, 1998.

Compliance Method: Compliance shall be assured by the recordkeeping of **Condition E8-12**.

E8-7. Particulate matter (TSP) emitted from each combustion turbine unit of this fuel-burning installation shall not exceed the following limits (in pounds per hour):

Pollutant	Emission Limit (lb/hr) while firing natural gas	Emission Limit (lb/hr) while firing fuel oil
TSP	7.34	15.7

TAPCR 1200-03-09-.01(4)(j)

Compliance Method: Compliance assurance for the particulate standards stated in this condition is based upon compliance with **Conditions E8-2** and **E8-12** and the following AP-42 emission factors for natural gas and fuel oil combustion:

Pollutant	Emission Factor (pounds per million Btu)
Particulate matter	0.0120 (fuel oil)
	0.00660 (natural gas)

Data from AP-42, Table 3.1-2a, (enclosed as Attachment 6)

E8-8. Sulfur dioxide (SO_2), carbon monoxide (CO), and volatile organic compounds (VOC) emitted from each combustion turbine unit of this fuel-burning installation shall not exceed the following limits (in pounds per million British Thermal Units of heat input), based on operation at full capacity:

Pollutant	Emission Limits (lb/MMBtu of heat input) while firing natural gas	Emission Limits (lb/MMBtu of heat input) while firing fuel oil
SO_2	0.0006	0.048
CO	0.062	0.05
VOC	0.01	0.01

TAPCR 1200-03-09-.01(4)(j)

Compliance Method: Compliance assurance for the sulfur dioxide (SO_2), carbon monoxide (CO), and volatile organic compounds (VOC) emission standards stated in this condition is based upon compliance with **Conditions E8-2, E8-5**, and **E8-12**.

E8-9. Total nitrogen oxides (NO_X) emitted from this fuel-burning installation shall not exceed **556.0** tons per calendar year.

TAPCR 1200-03-09-.01(4)

Compliance Method: Compliance shall be assured by the monitoring of **Condition E8-13**.

E8-10. Exhaust nitrogen oxides concentrations shall not exceed 15 parts per million (corrected to 15% oxygen) when burning natural gas and 42 parts per million (corrected to 15% oxygen) when burning #2 fuel oil, based on a 30-operating-day rolling average. These limitations shall represent BACT for emissions of nitrogen oxides. Nitrogen oxides concentrations during start-up and shut-down and periods of fuel switching shall not be included in determining compliance with the 30-operating -day rolling averages. Start-up is defined as the period beginning with initial ignition of fuel in the unit and ending 21 minutes after synchronization of the unit to the grid. Shut-down is defined the 25 minute period immediately prior to cessation of fuel ignition in the unit. Fuel Switching is defined as the period commencing when a turbine decreases load to accommodate the fuel switch and ends 15 minutes after the commencement of this action. The commencement and ending of this action shall be noted by the permittee on the nitrogen oxides emissions report required by **Condition E8-13** of this permit. There shall be no more than three Fuel Switching periods per calendar day. The permittee shall keep documentation of the commencement and end of each Fuel Switching period. The exclusion of Fuel Switching periods only applies to the determination of compliance with the above-specified 30-operating-day rolling average nitrogen oxides concentration limits. This exclusion does not affect the nitrogen oxides emission limits found in **Condition E8-9**.

TAPCR 1200-03-09-.01(4)

Compliance Method: Compliance shall be assured by the monitoring of **Conditions E8-13 and E8-16.**

E8-11. Visible emissions from this fuel-burning installation shall not exhibit greater than ten percent (10%) opacity. Opacity data reduction shall be accomplished utilizing procedures outlined in the current 40 CFR 60, Appendix A, Method 9 (six-minute average).

TAPCR 1200-03-09-.01(4)

Compliance Method: Compliance with this standard shall be determined by the procedures of the Division's Opacity Matrix amended September 11, 2013 enclosed as **Attachment 1**.

E8-12. A monthly log of the following information must be maintained at the source location and kept available for inspection by the Technical Secretary or the authorized representative:

(a) No. 2 fuel oil usage
(b) Natural gas usage for the combustion turbines - units 17-19
(c) Natural gas usage for the natural gas heaters NGH1 and NGH2
(d) Sulfur analyses for each shipment of #2 fuel oil or certification statement by the vendor that the fuel oil sulfur content shall not exceed 0.05 percent by weight
(e) Electric generation output
(f) Hours of operation for each fuel/mode combination
(g) Maintenance inspections and repairs

The above recordkeeping requirements for combustion turbines at this source shall apply to JCT units 17-19. This log must be retained for a period of not less than five years.

TAPCR 1200-03-09-.02(11)(e)1.(iii)

E8-13. Nitrogen oxides (NO_X) emissions from the combustion turbines shall be monitored using continuous emission monitoring systems (CEMS). These devices shall be installed and maintained in accordance with the requirements of 40 CFR Part 75.

TAPCR 1200-03-10-.02(1)(a) and 1200-03-30-.01

E8-14. This source shall comply with all applicable requirements of 40 CFR Part 60, Subpart GG - Standards of Performance for Stationary Gas Turbines, with the following exception(s):

The alternative compliance methods approved in the EPA letter dated April 6, 2000 (**Attachment 7**).

E8-15. Quality assurance checks shall be performed on each CEM in accordance with the requirements of 40 CFR Part 75. Reports of each quality assurance check shall be submitted to the Technical Secretary electronically to air.pollution.control@tn.gov. Reports shall be submitted no later than sixty days after the completion of each test. This requirement only applies to the Relative Accuracy Testing Audits (RATA's) and does not apply to other Part 75-required Quality Assurance Checks.

TAPCR 1200-03-10-.02(1)(a)

E8-16. The following information shall be submitted to the Technical Secretary in the semiannual report required by **Condition E2(b)(1):**

(a) For NO_X, the report shall include emission averages, in the units of the applicable standard (ppmvd corrected to 15% O_2 on a 30 -operating-day rolling average).

(b) The report shall include the date and time identifying each period during which the system was inoperative (except for zero and span checks) and the nature of system repairs or adjustments. The Technical Secretary may require proof of system performance whenever system repairs or adjustments have been made.

(c) When the system has not been inoperative, repaired, or adjusted, such information shall be included in the report.

TAPCR 1200-03-10-.02(2)

43-0011-33	**Source Description**	**Two Natural Gas-fired Heaters:** Heater Units NGH3 and NGH4: Heating of heat exchanger water used to vaporize condensate in natural gas feed to the combustion turbines 1-16. 22 million Btu/hour nominal heat input capacity (11 million Btu/hour each unit). TVA designated emission units 29 and 32.

Conditions E9-1 through E9-4 apply to source 43-0011-33

E9-1. Particulate matter emitted from this source shall not exceed **0.387** pounds per million Btu of heat input and shall not exceed one (1) ton per year.

TAPCR 1200-03-06-.02(1)

Compliance Method: Compliance assurance for the particulate standard stated in this condition is based upon the following EPA AP-42 emission factor for combustion of natural gas.

Pollutant	Emission Factor (pounds per million cubic feet)
Particulate matter	7.6

Data from AP-42, Table 1.4-2 (enclosed as Attachment 2)

E9-2. Sulfur dioxide (SO_2) emitted from this source shall not exceed **5.0** pounds per million Btu of heat input (one-hour average).

TAPCR 1200-03-14-.02(2)(a)

Compliance Method: Compliance assurance for the sulfur dioxide emission standard stated in this condition is based upon the following EPA AP-42 emission factor for combustion of natural gas.

Pollutant	Emission Factor (pounds per million cubic feet)
Sulfur dioxide	0.6

Data from AP-42, Table 1.4-2 (enclosed as Attachment 2)

E9-3. Visible emissions from this fuel-burning installation shall not exhibit greater than 20% opacity. Opacity data reduction shall be accomplished utilizing procedures outlined in the current 40 CFR 60, Appendix A, Method 9 (six-minute average).

TAPCR 1200-03-05-.03(6)

Compliance Method: Compliance with this standard shall be determined by the procedures of the Division's Opacity Matrix amended September 11, 2013 enclosed as **Attachment 1**.

If the magnitude and frequency of excursions reported by the permittee in the periodic monitoring for emissions is unsatisfactory to the Technical Secretary, this permit may be reopened to impose additional opacity monitoring requirements.

E9-4. Only natural gas shall be burned in the heaters.

TAPCR 1200-03-09-.03(8)

43-0011-34	**Source Description**	**Three Emergency Fire Pump Engines # 1, 2, and 3:** Cummins Model N-855P250 diesel engines rated at 220 hp each. TVA designated stacks 33, 34, and 35

This source was removed from the permit through Significant Modification #1. These emission units have been designated insignificant activities.

43-0011-35 (SM1)	**Source Description**	**Combustion Turbine with Heat Recovery Steam Generator (HRSG):** This emission source consists of one existing dual-fuel combustion turbine (CT) generator (GE Model PG 7121EA) and one new heat recovery steam generator (HRSG) with duct burner. The HRSG will recover waste heat from the CT exhaust and generate steam, which will be piped to an offsite customer. A natural gas-fired duct burner will be used to augment steam production. Catalytic oxidation will be used for control of CO and VOC emissions, and selective catalytic reduction will be used for control of NO_X emissions. 40 CFR 60 Subpart KKKK applies. TVA designated emission unit EU-26.

Conditions E10-1 through E10-11 apply to Source 43-0011-35

E10-1 Only natural gas and No. 2 fuel oil, with a sulfur content not to exceed 15 parts per million by weight, shall be used as fuels for this source.

TAPCR 1200-03-09-.01(1)(d), TAPCR 1200-03-09-.01(4), and the PSD application dated September 17, 2015

Compliance Method: Compliance with this condition shall be assured by compliance with **Condition E10-3** of this permit.

E10-2. The rated heat input capacity for this source shall not exceed the following limits (Table 10-1).

Table 10-1: Heat Input Limits	
Unit	**Rated Input Capacity (MMBtu/hr)**
Combustion Turbine	1,019.7 when firing natural gas 1,083.7 when firing No. 2 fuel oil
HRSG Duct Burner	319.3
Heat-input capacity (MMBtu/hr, higher heating value) is for maximum load at 59°F ambient temperature.	

TAPCR 1200-03-09-.01(1)(d), 1200-03-09-.01(4), and the PSD application dated September 17, 2015

Compliance Method: Compliance with this condition is based on the information provided with the PSD application dated September 17, 2015. The permittee shall not modify the source to increase the rated heat input capacity without first having applied for and received from the Technical Secretary a construction permit in accordance with TAPCR 1200-03-09-.01(1).

E10-3. A daily log of the heat input and fuel usage shall be maintained at the source location and kept available for inspection by the Technical Secretary or a Division representative. This log shall be retained for a period of not less than five years.

TAPCR 1200-03-10-.02(2)(a)

Compliance Method: The permittee shall assure compliance with this condition by maintaining the required records in accordance with **Condition E2-1.**

E10-4. Particulate matter, carbon monoxide, nitrogen oxides, and carbon dioxide equivalent emitted from this source shall not exceed the limits shown in Table 10-2. These limits shall represent Best Available Control Technology (BACT) for this emission source.

Table 10-2: BACT Emission Limits			
Pollutant	**Emission Limit (Note 1)**	**Control Technology**	**Compliance Method**
Particulate Matter	0.005 lb/MMBtu		

Table 10-2: BACT Emission Limits			
Pollutant	**Emission Limit (Note 1)**	**Control Technology**	**Compliance Method**
(PM, PM_{10}, and $PM_{2.5}$)	when firing natural gas	Good combustion design and practices	Comply with **Conditions E10-1, E10-2, E10-3, and E10-5**
	0.015 lb/MMBtu when firing No. 2 fuel oil		
Carbon Monoxide (CO), normal operation	2 ppmvd corrected to 15% O_2 when firing natural gas 30 unit-operating-day moving average	Good combustion design and practices, oxidation catalyst	Comply with **Conditions E10-1, E10-2, E10-3, E10-5, E10-7, E10-8, and E10-9**
	10 ppmvd corrected to 15% O_2 when firing No. 2 fuel oil 15 unit-operating-day moving average		
Carbon Monoxide (CO), startup and shutdown (Note 2)	Startup: 1,760 lb/event Shutdown: 22 lb/event when firing natural gas	Good combustion design and practices	Comply with **Conditions E10-1, E10-2, E10-3, E10-5, E10-7, E10-8, and E10-9**
	Startup: 3,000 lb/event Shutdown: 12.8 lb/event when firing No. 2 fuel oil		
Nitrogen Oxides (NO_X), as NO_2, normal operation	2 ppmvd corrected to 15% O_2 when firing natural gas, 30 unit-operating-day moving average, excluding startup and shutdown	Good combustion design and practices, selective catalytic reduction (SCR)	Comply with **Conditions E10-1, E10-2, E10-3, E10-5, E10-6, E10-7, E10-8, and E10-9**
	8 ppmvd corrected to 15% O_2 when firing No. 2 fuel oil, 15 unit-operating-day moving average, excluding startup and shutdown		
Nitrogen Oxides (NO_X), as NO_2, startup and shutdown (Note 2)	15 ppmvd corrected to 15% O_2 when firing natural gas 30 unit-operating-day moving average, applies at all times	Good combustion design and practices	Comply with **Condition E10-6**
	42 ppmvd corrected to 15% O_2 when firing No. 2 fuel oil 30 unit-operating-day moving average, applies at all times		
Carbon Dioxide Equivalent (CO_2e)	1,800 lb/MWh 12-month moving average	Good combustion design and practices	Comply with **Conditions E10-1, E10-2, E10-3, and E10-5**

Notes:
1. All heat input-based emission limits are based on the high heating value (HHV). The output-based limit for CO_2e is based on gross generation.
2. Startup will be defined as the period beginning with initial ignition of fuel in the unit and ending 15 minutes after ammonia starts to flow in the SCR system, not to exceed six hours per event. Shutdown will be defined as the period from cessation of ammonia flow until cessation of fuel ignition, not to exceed one hour per event.

TAPCR 1200-03-09-.01(4)(j)3.

E10-5. The permittee shall continuously operate any pollution control technology (SCR for NO_X control, oxidation catalyst for CO control) or combustion control (good combustion practice for particulate matter and CO_2e control) at all times when this source is in operation. "Continuously operate" means that a pollution control technology or combustion control shall be operated at all times this source is in operation (except during a malfunction that is determined to be a Force Majeure Event), so as to minimize emissions to the greatest extent technically practicable consistent with the technological limitations, manufacturers' specifications, fire prevention codes, and good engineering and maintenance practices for such pollution control technology or combustion control and the source.

TAPCR 1200-03-09-.01(4)(j)3.

E10-6(MM1). The source shall comply with the applicable requirements of 40 CFR Part 60 Subpart KKKK (Table 10-3).

Table 10-3: NSPS Requirements (40 CFR 60 Subpart KKKK)

Rule Citation	Requirement
§60.4305(a)	This subpart applies to each stationary combustion turbine with a heat input at peak load equal to or greater than 10 MMBtu/hr per hour, based on the higher heating value of the fuel, which commenced construction, modification, or reconstruction after February 18, 2005. Any additional heat input to associated heat recovery steam generators (HRSG) or duct burners should not be included when determining the peak heat input. However, this subpart does apply to emissions from any associated HRSG and duct burners.
§60.4320, §60.4325, Table 1 to Subpart KKKK	The applicable NO_X emission limits in Table 1 to Subpart KKKK apply at all times, including startup and shutdown. Comply with §60.4325 when burning mixtures of natural gas and distillate oil.
§60.4330	Comply with SO_2 emission limit of 0.90 lb/MWh gross output or do not burn any fuel which contains total potential sulfur emissions in excess of 0.060 lb SO_2 per MMBtu of heat input. If the turbine simultaneously fires multiple fuels, each fuel must meet this requirement.
§60.4333(a)	Operate and maintain the stationary combustion turbine, air pollution control equipment, and monitoring equipment in a manner consistent with good air pollution control practices for minimizing emissions at all times including during startup, shutdown, and malfunction.
§60.4335(b), §60.4340(b), §60.4345	Install, certify, maintain, and operate a continuous emission monitoring system (CEMS) consisting of a NO_X monitor and a diluent gas (O_2 or CO_2) monitor, to determine the hourly NO_X emission rate in ppm. NO_X CEMS must comply with the specifications of §60.4345.
§60.4350, §60.4380	Use CEMS data as specified in §60.4350 and §60.4380 to identify excess emissions and monitor downtime.
§60.4365	You may elect not to monitor the total sulfur content of the fuel combusted in the turbine, if the fuel is demonstrated not to exceed potential sulfur emissions of 0.060 lb SO_2/MMBtu heat input for units located in continental areas.
§60.4370	Determine the sulfur content of the fuel in accordance with §60.4370
§60.4375(a), §60.4395	Submit reports of excess emissions and monitor downtime, in accordance with §60.7(c). Excess emissions must be reported for all periods of unit operation, including startup, shutdown, and malfunction. All reports required under §60.7(c) must be postmarked by the 60th day following the end of each six-month period. Reports shall be submitted to: Division of Air Pollution Control Compliance Validation Program Davy Crockett Tower, 7th Floor 500 James Robertson Parkway Nashville, TN 37243 or Adobe Portable Document Format (PDF) Copy to: Air.Pollution.Control@tn.gov

TAPCR 1200-03-09-.03(8) and 40 CFR 60 Subpart KKKK

E10-7. NO_X and CO emissions from this source shall be measured with continuous emissions monitoring systems (CEMS). CO CEMS shall be installed and maintained in accordance with the requirements of 40 CFR 60 Appendix B, Performance Specification 4 or 4A. NO_X CEMS shall be installed and maintained in accordance with 40 CFR 75.

The CO and NO_X CEMS shall be fully operational for at least 95% of the operating time of the monitored unit during each semiannual period (January 1 through June 30 and July 1 through December 31 of each calendar year). An operational availability of less than this amount may be the basis for declaring a unit in noncompliance with the applicable monitoring requirement, unless the reasons for the failure to maintain this level of availability are accepted by the Division as legitimate malfunctions of the instruments. If any CEMS is inoperative for more than seven consecutive days, the use of a backup monitor may be required.

TAPCR 1200-03-10-.04

E10-8. Quality assurance checks shall be performed on each CEMS in accordance with the requirements of 40 CFR Part 75. The quality assurance checks shall consist of a repetition of the relative accuracy portion of the Performance Specification Test.

Within 90 days of each major modification or major repair of any emissions monitor, diluent monitor, or electronic signal combining system, a repeat of the performance specification test shall be conducted, and a written report of it submitted to the Technical Secretary as proof of the continuous operation of the emissions monitoring system within acceptable limits.

TAPCR 1200-03-10-.02(1)(a)

E10-9(MM1). The following information shall be submitted to the Technical Secretary in a semiannual report. Semiannual reports shall cover the 6-month periods from January 1 through June 30 and July 1 to December 31 of each calendar year and shall be submitted within 60 days after the end of each six-month period.

(a) For NO_X, the report shall include emission averages, in the units of the applicable standard (ppmvd corrected to 15% O_2), for each averaging period during operation of the source (30 operating day average when firing natural gas and 15 operating day average when firing No. 2 fuel oil). For each averaging period, the report shall indicate the type of fuel combusted and any periods of startup or shutdown.

(b) For CO, the report shall include emission averages, in the units of the applicable standard(s) (ppmvd corrected to 15% O_2 and pounds per startup/shutdown event), for each averaging period. For each averaging period, the report shall indicate the type of fuel combusted and any periods of startup or shutdown.

(c) The report shall include the date and time identifying each period during which the system was inoperative (except for zero and span checks) and the nature of system repairs or adjustments. The Technical Secretary may require proof of system performance whenever system repairs or adjustments have been made.

(d) The report shall include written reports of the quality assurance checks required by **Condition E10-8**.

(e) When the system has been inoperative, repaired, or adjusted, such information shall be included in the report.

The report shall be submitted to the following address:

Division of Air Pollution Control
Permit Program
Davy Crockett Tower, 7th Floor
500 James Robertson Parkway
Nashville, TN 37243

or

Adobe Portable Document Format (PDF)
Copy to: Air.Pollution.Control@tn.gov

TAPCR 1200-03-10-.02(2)

E10-10. Pursuant to §63.6090(b)(4), existing stationary combustion turbines in all subcategories do not have to meet the requirements of 40 CFR 63 Subparts A and YYYY. No initial notification is necessary for any existing stationary combustion turbine, even if a new or reconstructed turbine in the same category would require an initial notification.

TAPCR 1200-03-09-.03(8) and 40 CFR 63 Subpart YYYY

E10-11. The exhaust gases from this source shall be discharged unobstructed vertically upwards to the ambient air from a stack with an exit diameter of 15.5 feet and not less than 150 feet above ground level.

TAPCR 1200-03-09-.01(1)(d) and the application dated January 26, 2016

43-0011-36 (SM1) 43-0011-37 (SM1)	Source Description	Natural Gas-Fired Auxiliary Boiler (EU-37) and Natural Gas-Fired Auxiliary Boiler (EU-38): Two 450 MMBtu/hr natural gas-fired auxiliary boilers used to generate steam during threshold transitional periods and during malfunction events when the CT and HRSG are not able to operate. Each auxiliary boiler will have emissions controlled by low-NO_X burners, flue gas recirculation, and SCR. 40 CFR 60 Subpart Db and 40 CFR 63 Subpart DDDDD apply.

E11-1. Only natural gas shall be used as fuel for emission sources 43-0011-36 and 43-0011-37.

TAPCR 1200-03-09-.01(1)(d), the PSD application dated September 17, 2015, and TAPCR 1200-03-09-.01(4)

Compliance Method: Compliance with this condition shall be assured by compliance with **Condition 11-3** of this permit.

E11-2. The total maximum heat input capacity for emission sources 43-0011-36 and 43-0011-37 shall not exceed the following limits, on a daily average basis (Table 11-1).

Table 11-1: Heat Input Limits	
Unit	**Rated Input Capacity (MMBtu/hr)**
Natural Gas-Fired Auxiliary Boiler (EU-37)	450
Natural Gas-Fired Auxiliary Boiler (EU-38)	450

TAPCR 1200-03-09-.01(1)(d), the PSD application dated September 17, 2015, and TAPCR 1200-03-09-.01(4)

Compliance Method: Compliance with this condition shall be assured by compliance with **Condition E11-3** of this permit.

E11-3. For each auxiliary boiler, a daily log of the heat input, fuel usage, and operating hours, which readily shows compliance with **Conditions E11-1 and E11-2**, shall be maintained at the source location and kept available for inspection by the Technical Secretary or his representative. This log must be retained for a period of not less than five years.

TAPCR 1200-03-10-.02(2)(a)

E11-4. Particulate matter, carbon monoxide, nitrogen oxides, and carbon dioxide equivalent emitted from each auxiliary boiler shall not exceed the limits shown in Table 11-2. These limits shall represent Best Available Control Technology (BACT) for emission sources 43-0011-36 and 43-0011-37.

Table 11-2: BACT Emission Limits			
Pollutant	**Emission Limit (Notes 1 and 2)**	**Control Technology**	**Compliance Method**
Total Particulate Matter (PM, PM_{10}, and $PM_{2.5}$)	0.008 lb/MMBtu	Good combustion design and practices	Comply with **Conditions E11-1, E11-2, E11-3, and 11-5**
Carbon Monoxide (CO)	0.084 lb/MMBtu	Good combustion design and practices	Comply with **Conditions E11-1, E11-2, E11-3, and 11-5**
Nitrogen Oxides (NO_X), normal operation	0.013 lb/MMBtu 30 unit-operating day moving average excluding startup and shutdown	Good combustion design and practices, selective catalytic reduction (SCR), low-NO_X burners with flue gas recirculation	Comply with **Conditions E11-1, E11-2, E11-3, and 11-5**
Nitrogen Oxides (NO_X), startup and shutdown (Note 3)	0.20 lb/MMBtu 30 unit-operating day moving average, applies at all times	Good combustion design and practices,	Comply with **Condition E11-6**

Table 11-2: BACT Emission Limits			
Pollutant	**Emission Limit (Notes 1 and 2)**	**Control Technology**	**Compliance Method**
Carbon Dioxide Equivalent (CO_2e)	117 lb/MMBtu 12-month moving average	Efficient design (including insulation to reduce ambient heat loss), good combustion practices, good operating and maintenance practices.	Comply with **Conditions E11-1, E11-2, E11-3, and 11-5**

Notes:
1. All heat input-based emission limits are based on the high heating value (HHV).
2. All emission limits are based on a daily average unless otherwise noted.
3. Startup will be defined as the period beginning with initial ignition of fuel in the unit and ending 15 minutes after ammonia starts to flow in the SCR system, not to exceed six hours per event. Shutdown will be defined as the period from cessation of ammonia flow until cessation of fuel ignition, not to exceed one hour per event.

TAPCR 1200-03-09-.01(4)(j)3.

E11-5. The permittee shall continuously operate any pollution control technology (SCR, low-NO_X burners, and flue gas recirculation for NO_X control) or combustion control (good combustion practice for particulate matter, CO, and CO_2e control) at all times when either auxiliary boiler is in operation. "Continuously operate" means that a pollution control technology or combustion control shall be operated at all times this source is in operation (except during a malfunction that is determined to be a Force Majeure Event), so as to minimize emissions to the greatest extent technically practicable consistent with the technological limitations, manufacturers' specifications, fire prevention codes, and good engineering and maintenance practices for such pollution control technology or combustion control and the source.

TAPCR 1200-03-09-.01(4)(j)3.

E11-6. This source shall comply with all applicable requirements of 40 CFR Part 60, Subpart Db – Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units (Table 11-3). All required reporting and recordkeeping for the subject unit shall be accomplished in accordance with section §60.49b.

Table 11-3: Summary of 40 CFR 60 Subpart Db Requirements	
Rule Citation	**Requirement**
§60.44b(l)	No owner or operator of an affected facility that commenced construction after July 9, 1997 shall cause to be discharged into the atmosphere from that affected facility any gases that contain NO_X (expressed as NO_2) in excess of 86 ng/J (0.20 lb/MMBtu) heat input if the affected facility combusts natural gas. Units where more than 10% of total annual output is electrical or mechanical may comply with an optional limit of 270 ng/J (2.1 lb/MWh) gross energy output, based on a 30-day rolling average. Units complying with this limit must demonstrate compliance according to §60.48Da(i) and §§60.49Da(c), (k), through (n).
§60.46b(c)	Compliance with the NO_X emission standards shall be determined through performance testing under §60.46b(e) or (h), as applicable.
§60.48b	Comply with the requirements of §60.48b for NO_X emissions monitoring.
§60.49b(a)	Submit notification of the date of initial startup, as provided by §60.7.
§60.49b(b)	Submit data from the initial performance test and the performance evaluation of the CEMS
§60.49b(c)	The owner or operator of each affected facility who seeks to demonstrate compliance with the NO_X standard through monitoring of steam generating unit operating conditions shall submit a plan that identifies the operating conditions to be monitored and the records to be maintained. This plan shall be submitted to the Administrator for approval within 360 days of the initial startup of the affected facility. If the plan is approved, the owner or operator shall maintain records of predicted NO_X emission rates and the monitored operating conditions identified in the plan.
§60.49b(d)	Maintain records of the amounts of each fuel combusted during each day and calculate the annual capacity factor (12-month rolling average) for the reporting period.

Table 11-3: Summary of 40 CFR 60 Subpart Db Requirements	
Rule Citation	**Requirement**
§60.49b(g)	Maintain the following records for each steam generating unit operating day: (1) Calendar date; (2) Average hourly NO_X emission rates (expressed as NO_2) measured or predicted; (3) 30-day average NO_X emission rates calculated at the end of each steam generating unit operating day; (4) Identification of the steam generating unit operating days when the calculated 30-day average NO_X emission rates are in excess of the NO_X emissions standards, the reasons for such excess emissions, and a description of corrective actions taken; (5) Identification of the steam generating unit operating days for which pollutant data have not been obtained, the reasons for not obtaining sufficient data, and a description of corrective actions taken; (6) Identification of the times when emission data have been excluded from the calculation of average emission rates and the reasons for excluding data; (7) Identification of "F" factor used for calculations, method of determination, and type of fuel combusted; (8) Identification of the times when the pollutant concentration exceeded full span of the CEMS; (9) Description of any modifications to the CEMS that could affect the ability of the CEMS to comply with Performance Specification 2 or 3; and (10) Results of daily CEMS drift tests and quarterly accuracy assessments.
§60.49b(i)	The owner or operator of any affected facility subject to the continuous monitoring requirements for NO_X under §60.48(b) shall submit reports containing the information recorded under §60.49(g).
§60.49b(o)	Maintain all records required under this subpart for 2 years following the date of such record.
§60.49b(v)	The owner or operator of an affected facility may submit electronic reports in lieu of written reports. The format of each quarterly electronic report shall be coordinated with the permitting authority. The electronic report(s) shall be submitted no later than 30 days after the end of the calendar quarter and shall be accompanied by a certification statement from the owner or operator, indicating whether compliance with the applicable emission standards and minimum data requirements of this subpart was achieved during the reporting period. Before submitting reports in the electronic format, the owner or operator shall coordinate with the permitting authority to obtain their agreement to submit reports in this alternative format.
§60.49b(w)	The reporting period for the reports required under this subpart is each six-month period. All reports shall be postmarked by the 30th day following the end of the reporting period.

TAPCR 1200-03-09-.03(8) and 40 CFR 60 Subpart Db

E11-7. Each auxiliary boiler shall comply with the applicable requirements of 40 CFR Part 63, Subpart DDDDD – National Emission Standards for Hazardous Air Pollutants for Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters (Table 11-4).

Table 11-4: Summary of 40 CFR 63 Subpart DDDDD Requirements	
Rule Citation	**Description**
§63.7490(b)	A boiler or process heater is new if you commence construction of the boiler or process heater after June 4, 2010, and you meet the applicability criteria at the time you commence construction.
§63.7495(a)	New sources must comply with Subpart DDDDD by January 31, 2013, or upon startup, whichever is later.
§63.7499(l)	Subcategories of boilers and process heaters: Units designed to burn gas 1 fuels
§63.7500(a)(3)	Operate and maintain any affected source at all times in a manner consistent with safety and good air pollution control practices for minimizing emissions.

Table 11-4: Summary of 40 CFR 63 Subpart DDDDD Requirements	
Rule Citation	**Description**
§63.7500(e)	Boilers and process heaters in the units designed to burn gas 1 fuels subcategory are not subject to the emission limits in Tables 1 and 2 or 11 through 13 to Subpart DDDDD, or the operating limits in Table 4 to Subpart DDDDD.
§63.7500(f), §63.7505 (a)	Comply with the emission limits, work practice standards, and operating limits in Subpart DDDDD. These limits apply at all times the affected unit is operating, except during periods of startup and shutdown.
§63.7530(f)	Submit the Notification of Compliance Status containing the results of the initial compliance demonstration according to the requirements in § 63.7545(e).
§63.7510(g), §63.7515(d), §63.7540(a)(10)	If your boiler or process heater has a heat input capacity of 10 MMBtu/hr or greater, conduct an annual tune-up of the boiler or process heater to demonstrate continuous compliance. For a new or reconstructed affected source, the first annual tune-up must be no later than 13 months after initial startup of the source. Each subsequent annual tune-up must be no more than 13 months after the previous tune-up. Affected sources must maintain onsite and submit, if requested by the Administrator, an annual report containing the information in §§63.7540(a)(10)(vi)(A) through (C).
§63.7545(a)	Submit to the Administrator all of the notifications in §§ 63.7(b) and (c), 63.8(e), (f)(4) and (6), and 63.9(b) through (h) that apply by the dates specified.
§63.7545(e)	Submit a Notification of Compliance Status according to §63.9(h)(2)(ii).
§63.7550(a), §63.7550(b)	Submit each report in Table 9 to Subpart DDDDD that applies. Unless the Administrator has approved a different schedule for submission of reports, submit each report according to the requirements in §§63.7550(b)(1) through (4). For units that are subject only to a requirement to conduct an annual, biennial, or 5-year tune-up and not subject to emission limits or operating limits, affected sources may submit only an annual, biennial, or 5-year compliance report, as applicable.
§63.7550(c)	If the facility is subject to tune-up requirements, submit a compliance report with the following information: • Company and Facility name and address. • Process unit information, emissions limitations, and operating parameter limitations. • Date of report and beginning and ending dates of the reporting period. • The total operating time during the reporting period. • Include the date of the most recent tune-up for each unit subject to only the requirement to conduct an annual, biennial, or 5-year tune-up. Include the date of the most recent burner inspection if it was not done annually, biennially, or on a 5-year period and was delayed until the next scheduled or unscheduled unit shutdown. • Statement by a responsible official with that official's name, title, and signature, certifying the truth, accuracy, and completeness of the content of the report.
§63.7550(h)	Submit reports according to the procedures specified in §§63.7550(h)(1) through (3).
§§63.7555(a)(1) and (2), §63.7560	Keep the following records: • A copy of each notification and report that you submitted to comply with Subpart DDDDD, including all documentation supporting any Initial Notification or Notification of Compliance Status or semiannual compliance report. • Records of performance tests, fuel analyses, or other compliance demonstrations and performance evaluations as required in §63.10(b)(2)(viii). Records must be in a form suitable and readily available for expeditious review, according to §63.10(b)(1). As specified in § 63.10(b)(1), keep each record for 5 years following the date of each occurrence, measurement, maintenance, corrective action, report, or record. Records must be kept onsite or accessible from onsite for at least 2 years after the date of each occurrence, measurement, maintenance, corrective action, report, or record. Records may be kept offsite for the remaining 3 years.
§63.7565	Part 63 General Provisions apply as indicated in Table 10 to Subpart DDDDD.

TAPCR 1200-03-09-.03(8) and 40 CFR 63 Subpart DDDDD

E11-8. The exhaust gases from each boiler shall be discharged unobstructed vertically upwards to the ambient air from a stack with an exit diameter of 6.5 feet, a stack height of not less than 199 feet above ground level, and a stack height of no more than 213 feet above ground level.

TAPCR 1200-03-09-.01(1)(d) and the application dated January 26, 2016

43-0011-39	**Source Description**	**Emergency Telecom Diesel Engine:** Cummins Model 4BT3.9-G4 diesel engine rated at 90 hp. TVA designated stack 36

This source was removed from the permit through Significant Modification #1. This emission unit has been designated an insignificant activity.

END OF MINOR MODIFICATION #1 TO PERMIT NUMBER: 572833

ATTACHMENT 1

OPACITY MATRIX DECISION TREE FOR VISIBLE EMISSION EVALUATION BY TVEE METHOD 1 AND EPA METHOD 9

AMENDED SEPTEMBER 11, 2013

Decision Tree PM for Opacity from
Nontraditional Sources (Roads and Parking Areas)
<u>Utilizing TVEE Method 1</u>

Notes:

The use of Tennessee Visible Emission Evaluation (TVEE) Method 1 is only applicable where the use of the method is specified as a permit condition.

PM = Periodic Monitoring required by 1200-03-09-.02(11)(e)(1)(iii).

This Decision Tree outlines the criteria by which major sources can meet the PM requirements of Title V for demonstrating compliance with the visible emissions standard for nontraditional sources (roads and parking areas). It is not intended to determine compliance requirements for EPA's Compliance Assurance Monitoring (CAM) Rule (formerly referred to as Enhanced Monitoring – Proposed 40 CFR 64).

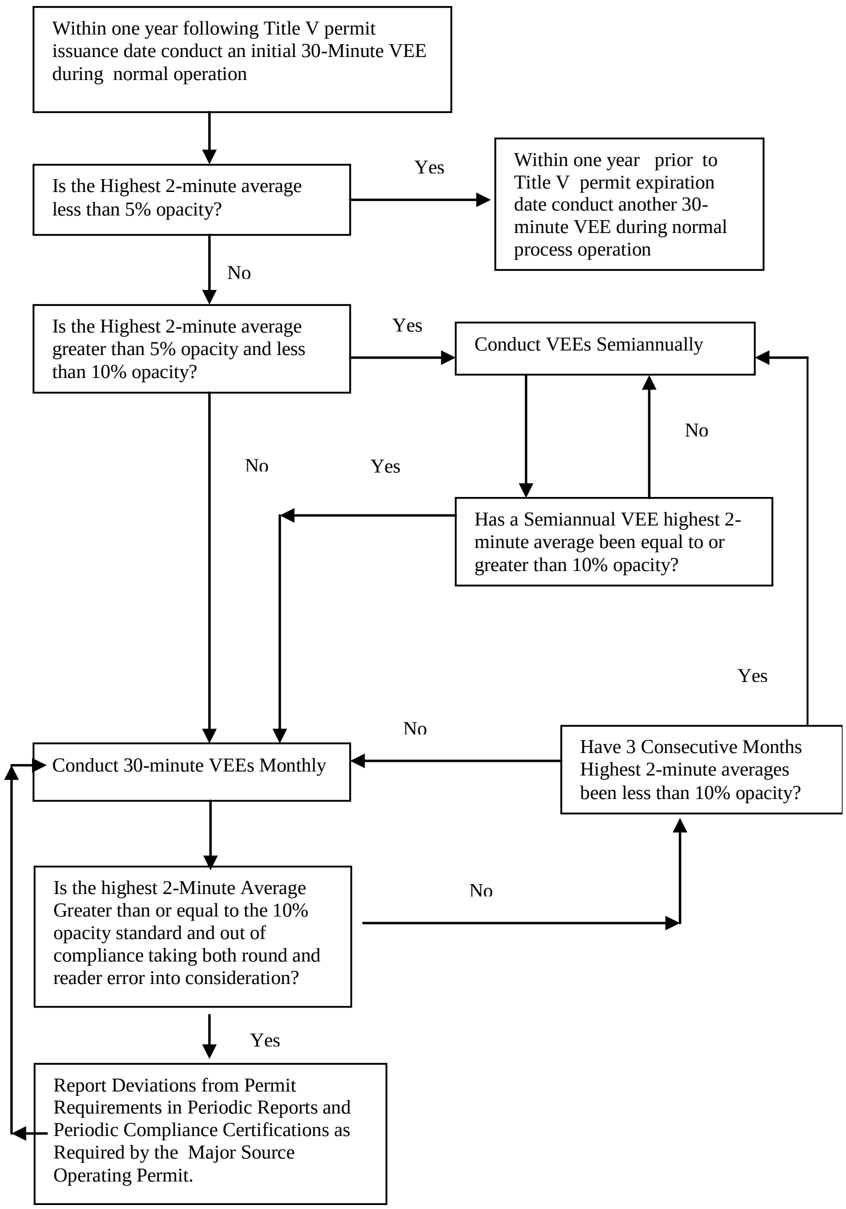
Visible Emissions Evaluations (VEEs) are to be conducted utilizing TVEE Method 1. The observer must be properly certified according to criteria specified in TVEE Method 1 to conduct Method 1 evaluations.

Initial observations are to be repeated within 90 days of startup of a modified source if a new construction permit is issued for modification of the source.

A VEE conducted by TDAPC personnel after the Title V permit is issued will also constitute an initial reading.

Reader Error
For TVEE Method 1, the TDAPC declares non-compliance when the highest two-minute average exceeds the standard plus 10% opacity for sources having this standard applied prior to August 24, 1984 or 8.8% for sources having this standard applied on or after August 24, 1984.

Dated June 18, 1996
Amended September 11, 2013



Decision Tree PM for Opacity for
<u>Sources Utilizing EPA Method 9*</u>

Notes:

PM = Periodic Monitoring required by 1200-03-09-.02(11)(e)(iii).

This Decision Tree outlines the criteria by which major sources can meet the periodic monitoring and testing requirements of Title V for demonstrating compliance with the visible emission standards set forth in the permit. It is not intended to determine compliance requirements for EPA's Compliance Assurance Monitoring (CAM) Rule (formerly referred to as Enhanced Monitoring – Proposed 40 CFR 64).

Examine each emission unit using this Decision Tree to determine the PM required.*

Use of continuous emission monitoring systems eliminates the need to do any additional periodic monitoring.

Visible Emission Evaluations (VEEs) are to be conducted utilizing EPA Method 9. The observer must be properly certified to conduct valid evaluations.

Typical Pollutants
Particulates, VOC, CO, SO_2, NO_x, HCl, HF, HBr, Ammonia, and Methane.

Initial observations are to be repeated within 90 days of startup of a modified source, if a new construction permit is issued for modification of the source.

A VEE conducted by TAPCD personnel after the Title V permit is issued will also constitute an initial reading.

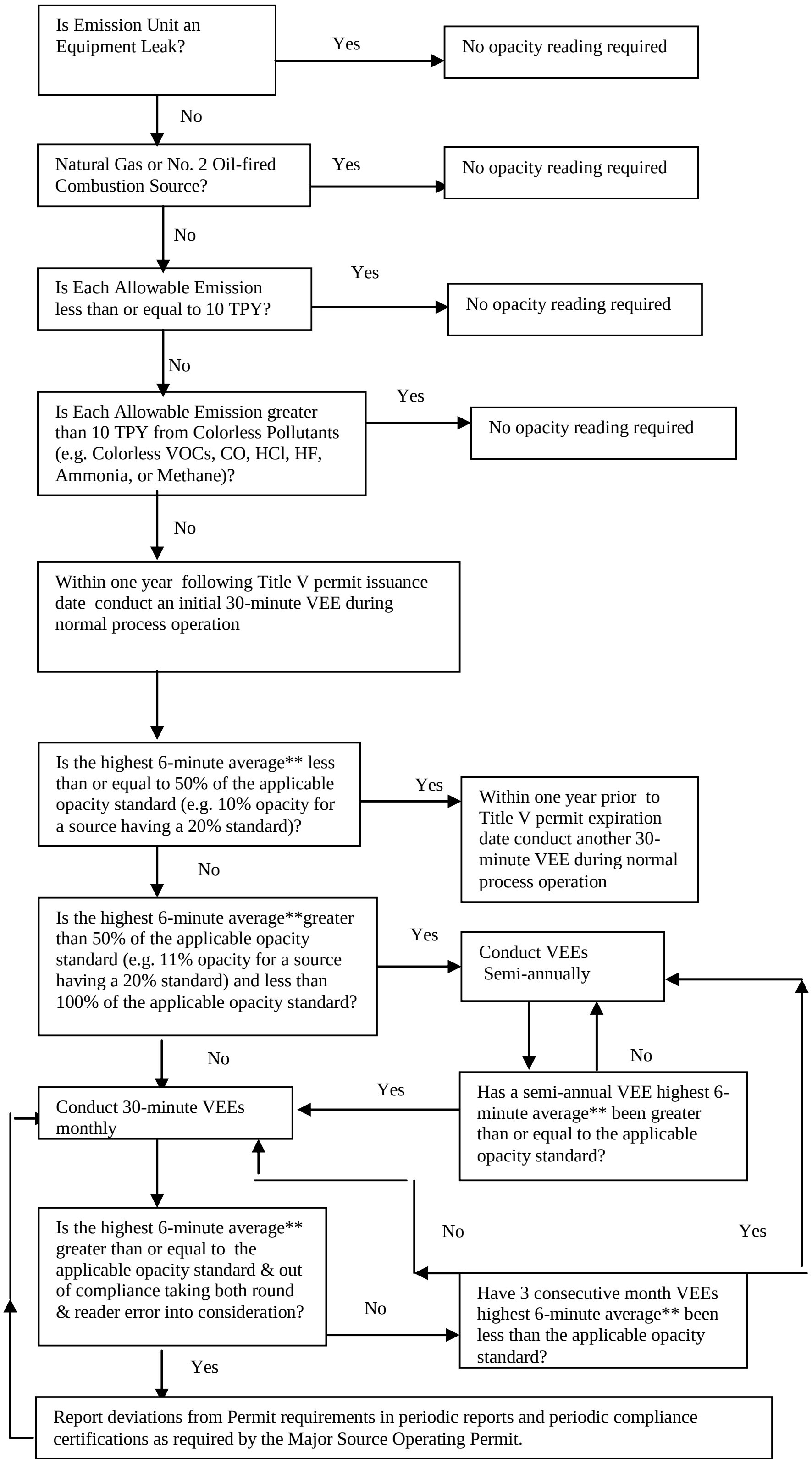
Reader Error
EPA Method 9, Non-NSPS or NESHAPS stipulated opacity standards:
The TAPCD guidance is to declares non-compliance when the highest six-minute average** exceeds the standard plus 6.8% opacity (e.g. 26.8% for a 20% standard).

EPA Method 9, NSPS or NESHAPS stipulate opacity standards:
EPA guidance is to allow only engineering round. No allowance for reader error is given.

*Not applicable to Asbestos manufacturing subject to 40 CFR 61.142

**Or second highest six-minute average, if the source has an exemption period stipulated in either the regulations or in the permit.

Dated June 18, 1996
Amended September 11, 2013



ATTACHMENT 2

AP-42 Emission Factors for Fuel Oil and Natural Gas Combustion
Tables 1.3-1, 1.3-2, 1.3-3, 1.4-1, and 1.4-2

Table 1.3-1. CRITERIA POLLUTANT EMISSION FACTORS FOR FUEL OIL COMBUSTION[a]

Firing Configuration (SCC)[a]	SO_2[b]		SO_3[c]		NO_x[d]		CO[e]		Filterable PM[f]	
	Emission Factor (lb/10^3 gal)	EMISSION FACTOR RATING	Emission Factor (lb/10^3 gal)	EMISSION FACTOR RATING	Emission Factor (lb/10^3 gal)	EMISSION FACTOR RATING	Emission Factor (lb/10^3 gal)	EMISSION FACTOR RATING	Emission Factor (lb/10^3 gal)	EMISSION FACTOR RATING
Boilers > 100 Million Btu/hr										
No. 6 oil fired, normal firing (1-01-004-01), (1-02-004-01), (1-03-004-01)	157S	A	5.7S	C	47	A	5	A	9.19(S)+3.22	A
No. 6 oil fired, normal firing, low NO_x burner (1-01-004-01), (1-02-004-01)	157S	A	5.7S	C	40	B	5	A	9.19(S)+3.22	A
No. 6 oil fired, tangential firing, (1-01-004-04)	157S	A	5.7S	C	32	A	5	A	9.19(S)+3.22	A
No. 6 oil fired, tangential firing, low NO_x burner (1-01-004-04)	157S	A	5.7S	C	26	E	5	A	9.19(S)+3.22	A
No. 5 oil fired, normal firing (1-01-004-05), (1-02-004-04)	157S	A	5.7S	C	47	B	5	A	10	B
No. 5 oil fired, tangential firing (1-01-004-06)	157S	A	5.7S	C	32	B	5	A	10	B
No. 4 oil fired, normal firing (1-01-005-04), (1-02-005-04)	150S	A	5.7S	C	47	B	5	A	7	B
No. 4 oil fired, tangential firing (1-01-005-05)	150S	A	5.7S	C	32	B	5	A	7	B
No. 2 oil fired (1-01-005-01), (1-02-005-01), (1-03-005-01)	142S[h]	A	5.7S	C	24	D	5	A	2	A
No.2 oil fired, LNB/FGR, (1-01-005-01), (1-02-005-01), (1-03-005-01)	142S[h]	A	5.7S	A	10	D	5	A	2	A

Table 1.3-1. (cont.)

Firing Configuration (SCC)[a]	SO_2[b]		SO_3[c]		NO_x[d]		CO[e]		Filterable PM[f]	
	Emission Factor ($lb/10^3$ gal)	EMISSION FACTOR RATING	Emission Factor ($lb/10^3$ gal)	EMISSION FACTOR RATING	Emission Factor ($lb/10^3$ gal)	EMISSION FACTOR RATING	Emission Factor ($lb/10^3$ gal)	EMISSION FACTOR RATING	Emission Factor ($lb/10^3$ gal)	EMISSION FACTOR RATING
Boilers < 100 Million Btu/hr										
No. 6 oil fired (1-02-004-02/03) (1-03-004-02/03)	157S	A	2S	A	55	A	5	A	9.19(S)+3.22[i]	B
No. 5 oil fired (1-03-004-04)	157S	A	2S	A	55	A	5	A	10[i]	A
No. 4 oil fired (1-03-005-04)	150S	A	2S	A	20	A	5	A	7	B
Distillate oil fired (1-02-005-02/03) (1-03-005-02/03)	142S	A	2S	A	20	A	5	A	2	A
Residential furnace (A2104004/A2104011)	142S	A	2S	A	18	A	5	A	0.4[g]	B

a To convert from lb/103 gal to kg/103 L, multiply by 0.120. SCC = Source Classification Code.
b References 1-2,6-9,14,56-60. S indicates that the weight % of sulfur in the oil should be multiplied by the value given. For example, if the fuel is 1% sulfur, then S = 1.
c References 1-2,6-8,16,57-60. S indicates that the weight % of sulfur in the oil should be multiplied by the value given. For example, if the fuel is 1% sulfur, then S = 1.
d References 6-7,15,19,22,56-62. Expressed as NO2. Test results indicate that at least 95% by weight of NOx is NO for all boiler types except residential furnaces, where about 75% is NO. For utility vertical fired boilers use 105 lb/103 gal at full load and normal (>15%) excess air. Nitrogen oxides emissions from residual oil combustion in industrial and commercial boilers are related to fuel nitrogen content, estimated by the following empirical relationship: lb NO2 /103 gal = 20.54 + 104.39(N), where N is the weight % of nitrogen in the oil. For example, if the fuel is 1% nitrogen, then N = 1.
e References 6-8,14,17-19,56-61. CO emissions may increase by factors of 10 to 100 if the unit is improperly operated or not well maintained.
f References 6-8,10,13-15,56-60,62-63. Filterable PM is that particulate collected on or prior to the filter of an EPA Method 5 (or equivalent) sampling train. Particulate emission factors for residual oil combustion are, on average, a function of fuel oil sulfur content where S is the weight % of sulfur in oil. For example, if fuel oil is 1% sulfur, then S = 1.
g Based on data from new burner designs. Pre-1970's burner designs may emit filterable PM as high as 3.0 1b/103 gal.
h The SO2 emission factor for both no. 2 oil fired and for no. 2 oil fired with LNB/FGR, is 142S, not 157S. Errata dated April 28, 2000. Section corrected May 2010.
i The PM factors for No.6 and No. 5 fuel were reversed. Errata dated April 28, 2000. Section corrected May 2010.

Table 1.3-2. CONDENSABLE PARTICULATE MATTER EMISSION FACTORS FOR OIL COMBUSTION[a]

Firing Configuration[b] (SCC)	Controls	CPM - TOT[c, d]		CPM - IOR[c, d]		CPM - ORG[c, d]	
		Emission Factor ($lb/10^3$ gal)	EMISSION FACTOR RATING	Emission Factor ($lb/10^3$ gal)	EMISSION FACTOR RATING	Emission Factor ($lb/10^3$ gal)	EMISSION FACTOR RATING
No. 2 oil fired (1-01-005-01, 1-02-005-01, 1-03-005-01)	All controls, or uncontrolled	1.3[d, e]	D	65% of CPM-TOT emission factor[c]	D	35% of CPM-TOT emission factor[c]	D
No. 6 oil fired (1-01-004-01/04, 1-02-004-01, 1-03-004-01)	All controls, or uncontrolled	1.5[f]	D	85% of CPM-TOT emission factor[d]	E	15% of CPM-TOT emission factor[d]	E

[a] All condensable PM is assumed to be less than 1.0 micron in diameter.
[b] No data are available for numbers 3, 4, and 5 oil. For number 3 oil, use the factors provided for number 2 oil. For numbers 4 and 5 oil, use the factors provided for number 6 oil.
[c] CPM-TOT = total condensable particulate matter.
CPM-IOR = inorganic condensable particulate matter.
CPM-ORG = organic condensable particulate matter.
[d] To convert to lb/MMBtu of No. 2 oil, divide by 140 MMBtu/10^3 gal. To convert to lb/MMBtu of No. 6 oil, divide by 150 MMBtu/10^3 gal.
[e] References: 76-78.
[f] References: 79-82.

Table 1.3-3. EMISSION FACTORS FOR TOTAL ORGANIC COMPOUNDS (TOC), METHANE, AND NONMETHANE TOC (NMTOC) FROM UNCONTROLLED FUEL OIL COMBUSTION[a]

EMISSION FACTOR RATING: A

Firing Configuration (SCC)	TOC[b] Emission Factor ($lb/10^3$ gal)	Methane[b] Emission Factor ($lb/10^3$ gal)	NMTOC[b] Emission Factor ($lb/10^3$ gal)
Utility boilers			
No. 6 oil fired, normal firing (1-01-004-01)	1.04	0.28	0.76
No. 6 oil fired, tangential firing (1-01-004-04)	1.04	0.28	0.76
No. 5 oil fired, normal firing (1-01-004-05)	1.04	0.28	0.76
No. 5 oil fired, tangential firing (1-01-004-06)	1.04	0.28	0.76
No. 4 oil fired, normal firing (1-01-005-04)	1.04	0.28	0.76
No. 4 oil fired, tangential firing (1-01-005-05)	1.04	0.28	0.76
Industrial boilers			
No. 6 oil fired (1-02-004-01/02/03)	1.28	1.00	0.28
No. 5 oil fired (1-02-004-04)	1.28	1.00	0.28
Distillate oil fired (1-02-005-01/02/03)	0.252	0.052	0.2
No. 4 oil fired (1-02-005-04)	0.252	0.052	0.2
Commercial/institutional/residential combustors			
No. 6 oil fired (1-03-004-01/02/03)	1.605	0.475	1.13
No. 5 oil fired (1-03-004-04)	1.605	0.475	1.13
Distillate oil fired (1-03-005-01/02/03)	0.556	0.216	0.34
No. 4 oil fired (1-03-005-04)	0.556	0.216	0.34
Residential furnace (A2104004/A2104011)	2.493	1.78	0.713

a To convert from lb/103 gal to kg/103 L, multiply by 0.12. SCC = Source Classification Code.

b References 29-32. Volatile organic compound emissions can increase by several orders of magnitude if the boiler is improperly operated or is not well maintained.

Table 1.4-1. EMISSION FACTORS FOR NITROGEN OXIDES (NO_x) AND CARBON MONOXIDE (CO) FROM NATURAL GAS COMBUSTION[a]

Combustor Type (MMBtu/hr Heat Input) [SCC]	NO_x[b]		CO	
	Emission Factor ($lb/10^6$ scf)	Emission Factor Rating	Emission Factor ($lb/10^6$ scf)	Emission Factor Rating
Large Wall-Fired Boilers (>100) [1-01-006-01, 1-02-006-01, 1-03-006-01]				
Uncontrolled (Pre-NSPS)[c]	280	A	84	B
Uncontrolled (Post-NSPS)[c]	190	A	84	B
Controlled - Low NO_x burners	140	A	84	B
Controlled - Flue gas recirculation	100	D	84	B
Small Boilers (<100) [1-01-006-02, 1-02-006-02, 1-03-006-02, 1-03-006-03]				
Uncontrolled	100	B	84	B
Controlled - Low NO_x burners	50	D	84	B
Controlled - Low NO_x burners/Flue gas recirculation	32	C	84	B
Tangential-Fired Boilers (All Sizes) [1-01-006-04]				
Uncontrolled	170	A	24	C
Controlled - Flue gas recirculation	76	D	98	D
Residential Furnaces (<0.3) [No SCC]				
Uncontrolled	94	B	40	B

[a] Reference 11. Units are in pounds of pollutant per million standard cubic feet of natural gas fired. To convert from $lb/10^6$ scf to $kg/10^6$ m^3, multiply by 16. Emission factors are based on an average natural gas higher heating value of 1,020 Btu/scf. To convert from $lb/10^6$ scf to lb/MMBtu, divide by 1,020. The emission factors in this table may be converted to other natural gas heating values by multiplying the given emission factor by the ratio of the specified heating value to this average heating value. SCC = Source Classification Code. ND = no data. NA = not applicable.

[b] Expressed as NO_2. For large and small wall fired boilers with SNCR control, apply a 24 percent reduction to the appropriate NO_x emission factor. For tangential-fired boilers with SNCR control, apply a 13 percent reduction to the appropriate NO_x emission factor.

[c] NSPS=New Source Performance Standard as defined in 40 CFR 60 Subparts D and Db. Post-NSPS units are boilers with greater than 250 MMBtu/hr of heat input that commenced construction modification, or reconstruction after August 17, 1971, and units with heat input capacities between 100 and 250 MMBtu/hr that commenced construction modification, or reconstruction after June 19, 1984.

TABLE 1.4-2. EMISSION FACTORS FOR CRITERIA POLLUTANTS AND GREENHOUSE GASES FROM NATURAL GAS COMBUSTION[a]

Pollutant	Emission Factor ($lb/10^6$ scf)	Emission Factor Rating
CO_2[b]	120,000	A
Lead	0.0005	D
N_2O (Uncontrolled)	2.2	E
N_2O (Controlled-low-NO_X burner)	0.64	E
PM (Total)[c]	7.6	D
PM (Condensable)[c]	5.7	D
PM (Filterable)[c]	1.9	B
SO_2[d]	0.6	A
TOC	11	B
Methane	2.3	B
VOC	5.5	C

[a] Reference 11. Units are in pounds of pollutant per million standard cubic feet of natural gas fired. Data are for all natural gas combustion sources. To convert from $lb/10^6$ scf to $kg/10^6$ m^3, multiply by 16. To convert from $lb/10^6$ scf to 1b/MMBtu, divide by 1,020. The emission factors in this table may be converted to other natural gas heating values by multiplying the given emission factor by the ratio of the specified heating value to this average heating value. TOC = Total Organic Compounds. VOC = Volatile Organic Compounds.

[b] Based on approximately 100% conversion of fuel carbon to CO_2. $CO_2[lb/10^6 \text{ scf}] = (3.67)$ (CON) (C)(D), where CON = fractional conversion of fuel carbon to CO_2, C = carbon content of fuel by weight (0.76), and D = density of fuel, 4.2×10^4 $lb/10^6$ scf.

[c] All PM (total, condensible, and filterable) is assumed to be less than 1.0 micrometer in diameter. Therefore, the PM emission factors presented here may be used to estimate PM_{10}, $PM_{2.5}$ or PM_1 emissions. Total PM is the sum of the filterable PM and condensible PM. Condensible PM is the particulate matter collected using EPA Method 202 (or equivalent). Filterable PM is the particulate matter collected on, or prior to, the filter of an EPA Method 5 (or equivalent) sampling train.

[d] Based on 100% conversion of fuel sulfur to SO_2.
Assumes sulfur content is natural gas of 2,000 grains/10^6 scf. The SO_2 emission factor in this table can be converted to other natural gas sulfur contents by multiplying the SO_2 emission factor by the ratio of the site-specific sulfur content (grains/10^6 scf) to 2,000 grains/10^6 scf.

ATTACHMENT 3

Acid Rain Permit for TVA - Johnsonville Fossil Plant

(SM1)

TENNESSEE AIR POLLUTION CONTROL BOARD
DEPARTMENT OF ENVIRONMENT AND CONSERVATION
NASHVILLE, TENNESSEE 37243-1531

PHASE II ACID RAIN PERMIT

This permit fulfills the requirements of the federal regulations promulgated at 40 CFR Parts 72, 73, 75, 77, and 78. This permit is issued in accordance with the applicable provisions of Tennessee Air Pollution Control Regulations (TAPCR) 1200-03-30. The permittee has been granted permission to operate an air contaminant source in accordance with emissions limitations and monitoring requirements set forth herein.

Date Issued:	**April 28, 2021**	**Permit Number:**	877422
Effective Dates:	**April 27, 2026**		

Issued By:
Tennessee Air Pollution Control Board
Tennessee Department of Environment and Conservation

Issued To:	**Installation Address:**
Tennessee Valley Authority	Highway 70
Johnsonville Fossil Plant	New Johnsonville

Emission Source Reference Number: 43-0011 **ORIS/Facility Code:** 3406

Acid Rain Permit Contents:

1. Statement of Basis.
2. SO_2 allowances allocated under this permit and NO_x requirements for each affected unit.
3. Standard Requirements (40 CFR §72.9 and TAPCR 1200-03-30-.01(6))
4. Comments, notes, and justifications regarding permit decisions and changes made to the permit application forms during the review process, and any additional requirements or conditions.
5. The permit application and NO_X compliance plan submitted for this source, as corrected by the Tennessee Department of Environment and Conservation. The owners and operators of the source must comply with the standard requirements and special provisions set forth in the application.
6. Summary of previous actions and present action.

Michelle W. Owenby
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>

1. Statement of Basis

Statutory and Regulatory Authorities: In accordance with Tennessee Code Annotated 68-201-105 and 4-5-202 and Titles IV and V of the Clean Air Act, the Tennessee Air Pollution Control Board and Tennessee Department of Environment and Conservation issue this permit pursuant to TAPCR 1200-03-30 and 1200-03-09-.02(11) and 40 CFR Part 76.

2. SO_2 Allowance Allocations and NO_x Requirements for each affected unit

		2021	2022	2023	2024	2025
Unit JCT17	SO_2 allowances	*	*	*	*	*
	NO_x limit	40 CFR Part 76 is not applicable to unit. Natural gas / fuel oil fired unit.				

		2021	2022	2023	2024	2025
Unit JCT18	SO_2 allowances	*	*	*	*	*
	NO_x limit	40 CFR Part 76 is not applicable to unit. Natural gas / fuel oil fired unit.				

		2021	2022	2023	2024	2025
Unit JCT19	SO_2 allowances	*	*	*	*	*
	NO_x limit	40 CFR Part 76 is not applicable to unit. Natural gas / fuel oil fired unit.				

		2021	2022	2023	2024	2025
Unit JCT20	SO_2 allowances	*	*	*	*	*
	NO_x limit	40 CFR Part 76 is not applicable to unit. Natural gas / fuel oil fired unit.				

* These new units are not eligible for an SO_2 allowance allocation under 40 CFR Part 73, but the source must comply with all of the standard requirements and special provisions stated in the Phase II permit application. The source must hold sufficient allowances to cover SO_2 emissions.

3. **Standard Requirements (40 CFR 72.9 and TAPCR 1200-03-30-.01(6)):** Included with permit application.

4. **Comments, Notes, and Justifications:** Affected units are four new natural gas / fuel oil fired combustion turbines. The facility's phase II permit application lists a commence operation date of March 15, 2000 for the combustion turbine (CT) units. Sixteen existing natural gas / no. 2 fuel oil fired simple cycle combustion turbines are not affected units.

5. **Permit Application and NO_X Compliance Plan:** Attached.

6. **Summary of Previous Actions and Present Action:**

Previous Actions:

1.	Draft permit, including SO_2 compliance plan, issued for public comment:	**August 5, 1997**
2.	SO_2 portion of permit finalized and issued:	**November 10, 1997**
3.	Permit revised to include a draft nitrogen oxides Emissions Averaging Plan for Units 1, 2, 3, 4, 5, 6, 7, 8, 9, and 10, issued for public comment on the NO_X portion only:	**October 8, 1998**
4.	NO_X portion of permit finalized and issued:	**April 1, 1999**
5.	Permit revised (1) to include a revised draft nitrogen oxides Averaging Plan for Units 1, 2, 3, 4, 5, 6, 7, 8, 9, and 10, and (2) add SO_2 compliance plan for new CT Units JCT17-20, issued for public comment (NO_X portion only for Units 1-10):	**February 20, 2001**
6.	Permit, including revised NO_X Averaging Plan for Units 1-10 and SO_2 Compliance Plan for new CT Units, Finalized and issued:	**May 14, 2001**

7.	Renewal Permit 861324P finalized and issued:	**June 30, 2008**
8.	Draft permit, including SO_2 compliance plan, issued for public comment:	**March 2, 2012**
9.	Renewal Permit 863259P finalized and issued:	**December 5, 2012**
10.	Closure of Coal-fired Boilers 1-10	**December 31, 2017**
11.	Renewal Permit 869160 finalized and issued:	**November 26, 2018**

Present Action:

12.	Draft renewal 877422 issued for public comment:	**March 11, 2021**
13.	Renewal Permit 877422 finalized and issued:	**April 28, 2021**

Acid Rain Permit Application and NOx Compliance Plan

United States
Environmental Protection Agency
Acid Rain Program

OMB No. 2060-0258
Approval expires 11/30/2018

Acid Rain Permit Application

For more information, see instructions and 40 CFR 72.30 and 72.31.

This submission is: ☐ new ☐ revised ☑ for ARP permit renewal

STEP 1

Identify the facility name, State, and plant (ORIS) code.

Facility (Source) Name	State	Plant Code
Johnsonville	TN	3406

STEP 2

Enter the unit ID# for every affected unit at the affected source in column "a."

a	b
Unit ID#	Unit Will Hold Allowances in Accordance with 40 CFR 72.9(c)(1)
JCT17	Yes
JCT18	Yes
JCT19	Yes
JCT20	Yes

Facility (Source) Name (from STEP 1) Johnsonville

STEP 3

Read the standard requirements.

Permit Requirements

(1) The designated representative of each affected source and each affected unit at the source shall:
- (i) Submit a complete Acid Rain permit application (including a compliance plan) under 40 CFR part 72 in accordance with the deadlines specified in 40 CFR 72.30; and
- (ii) Submit in a timely manner any supplemental information that the permitting authority determines is necessary in order to review an Acid Rain permit application and issue or deny an Acid Rain permit;

(2) The owners and operators of each affected source and each affected unit at the source shall:
- (i) Operate the unit in compliance with a complete Acid Rain permit application or a superseding Acid Rain permit issued by the permitting authority; and
- (ii) Have an Acid Rain Permit.

Monitoring Requirements

(1) The owners and operators and, to the extent applicable, designated representative of each affected source and each affected unit at the source shall comply with the monitoring requirements as provided in 40 CFR part 75.

(2) The emissions measurements recorded and reported in accordance with 40 CFR part 75 shall be used to determine compliance by the source or unit, as appropriate, with the Acid Rain emissions limitations and emissions reduction requirements for sulfur dioxide and nitrogen oxides under the Acid Rain Program.

(3) The requirements of 40 CFR part 75 shall not affect the responsibility of the owners and operators to monitor emissions of other pollutants or other emissions characteristics at the unit under other applicable requirements of the Act and other provisions of the operating permit for the source.

Sulfur Dioxide Requirements

(1) The owners and operators of each source and each affected unit at the source shall:
- (i) Hold allowances, as of the allowance transfer deadline, in the source's compliance account (after deductions under 40 CFR 73.34(c)), not less than the total annual emissions of sulfur dioxide for the previous calendar year from the affected units at the source; and
- (ii) Comply with the applicable Acid Rain emissions limitations for sulfur dioxide.

(2) Each ton of sulfur dioxide emitted in excess of the Acid Rain emissions limitations for sulfur dioxide shall constitute a separate violation of the Act.

(3) An affected unit shall be subject to the requirements under paragraph (1) of the sulfur dioxide requirements as follows:
- (i) Starting January 1, 2000, an affected unit under 40 CFR 72.6(a)(2); or
- (ii) Starting on the later of January 1, 2000 or the deadline for monitor certification under 40 CFR part 75, an affected unit under 40 CFR 72.6(a)(3).

(4) Allowances shall be held in, deducted from, or transferred among Allowance Tracking System accounts in accordance with the Acid Rain Program.

(5) An allowance shall not be deducted in order to comply with the requirements under paragraph (1) of the sulfur dioxide requirements prior to the calendar year for which the allowance was allocated.

(6) An allowance allocated by the Administrator under the Acid Rain Program is a limited authorization to emit sulfur dioxide in accordance with the Acid Rain Program. No provision of the Acid Rain Program, the Acid Rain permit application, the Acid Rain permit, or an exemption under 40 CFR 72.7 or 72.8 and no provision of law shall be construed to limit the authority of the United States to terminate or limit such authorization.

(7) An allowance allocated by the Administrator under the Acid Rain Program does not constitute a property right.

Nitrogen Oxides Requirements

The owners and operators of the source and each affected unit at the source shall comply with the applicable Acid Rain emissions limitation for nitrogen oxides.

Facility (Source) Name (from STEP 1) Johnsonville

STEP 3, Cont'd.

Excess Emissions Requirements

(1) The designated representative of an affected source that has excess emissions in any calendar year shall submit a proposed offset plan, as required under 40 CFR part 77.
(2) The owners and operators of an affected source that has excess emissions in any calendar year shall:
  (i) Pay without demand the penalty required, and pay upon demand the interest on that penalty, as required by 40 CFR part 77; and
  (ii) Comply with the terms of an approved offset plan, as required by 40 CFR part 77.

Recordkeeping and Reporting Requirements

(1) Unless otherwise provided, the owners and operators of the source and each affected unit at the source shall keep on site at the source each of the following documents for a period of 5 years from the date the document is created. This period may be extended for cause, at any time prior to the end of 5 years, in writing by the Administrator or permitting authority:
  (i) The certificate of representation for the designated representative for the source and each affected unit at the source and all documents that demonstrate the truth of the statements in the certificate of representation, in accordance with 40 CFR 72.24; provided that the certificate and documents shall be retained on site at the source beyond such 5-year period until such documents are superseded because of the submission of a new certificate of representation changing the designated representative;
  (ii) All emissions monitoring information, in accordance with 40 CFR part 75, provided that to the extent that 40 CFR part 75 provides for a 3-year period for recordkeeping, the 3-year period shall apply.
  (iii) Copies of all reports, compliance certifications, and other submissions and all records made or required under the Acid Rain Program; and,
  (iv) Copies of all documents used to complete an Acid Rain permit application and any other submission under the Acid Rain Program or to demonstrate compliance with the requirements of the Acid Rain Program.
(2) The designated representative of an affected source and each affected unit at the source shall submit the reports and compliance certifications required under the Acid Rain Program, including those under 40 CFR part 72 subpart I and 40 CFR part 75.

Liability

(1) Any person who knowingly violates any requirement or prohibition of the Acid Rain Program, a complete Acid Rain permit application, an Acid Rain permit, or an exemption under 40 CFR 72.7 or 72.8, including any requirement for the payment of any penalty owed to the United States, shall be subject to enforcement pursuant to section 113(c) of the Act.
(2) Any person who knowingly makes a false, material statement in any record, submission, or report under the Acid Rain Program shall be subject to criminal enforcement pursuant to section 113(c) of the Act and 18 U.S.C. 1001.
(3) No permit revision shall excuse any violation of the requirements of the Acid Rain Program that occurs prior to the date that the revision takes effect.
(4) Each affected source and each affected unit shall meet the requirements of the Acid Rain Program.
(5) Any provision of the Acid Rain Program that applies to an affected source (including a provision applicable to the designated representative of an affected source) shall also apply to the owners and operators of such source and of the affected units at the source.
(6) Any provision of the Acid Rain Program that applies to an affected unit (including a provision applicable to the designated representative of an affected unit) shall also apply to the owners and operators of such unit.
(7) Each violation of a provision of 40 CFR parts 72, 73, 74, 75, 76, 77, and 78 by an affected source or affected unit, or by an owner or operator or designated representative of such source or unit, shall be a separate violation of the Act.

Facility (Source) Name (from STEP 1) Johnsonville

STEP 3, Cont'd.

Effect on Other Authorities

No provision of the Acid Rain Program, an Acid Rain permit application, an Acid Rain permit, or an exemption under 40 CFR 72.7 or 72.8 shall be construed as:

(1) Except as expressly provided in title IV of the Act, exempting or excluding the owners and operators and, to the extent applicable, the designated representative of an affected source or affected unit from compliance with any other provision of the Act, including the provisions of title I of the Act relating to applicable National Ambient Air Quality Standards or State Implementation Plans;

(2) Limiting the number of allowances a source can hold; provided, that the number of allowances held by the source shall not affect the source's obligation to comply with any other provisions of the Act;

(3) Requiring a change of any kind in any State law regulating electric utility rates and charges, affecting any State law regarding such State regulation, or limiting such State regulation, including any prudence review requirements under such State law;

(4) Modifying the Federal Power Act or affecting the authority of the Federal Energy Regulatory Commission under the Federal Power Act; or,

(5) Interfering with or impairing any program for competitive bidding for power supply in a State in which such program is established.

STEP 4

Read the certification statement, sign, and date.

Certification

I am authorized to make this submission on behalf of the owners and operators of the affected source or affected units for which the submission is made. I certify under penalty of law that I have personally examined, and am familiar with, the statements and information submitted in this document and all its attachments. Based on my inquiry of those individuals with primary responsibility for obtaining the information, I certify that the statements and information are to the best of my knowledge and belief true, accurate, and complete. I am aware that there are significant penalties for submitting false statements and information or omitting required statements and information, including the possibility of fine or imprisonment.

Name Jacinda B. Woodward	
Signature [signature]	Date 8/21/2019

ATTACHMENT 4

Emission Factors (Table 6-2 of Application) and Calculation of Particulate Emissions from Ash Handling Process (43-0011-30)

Pages 6-15 through 6-22 from 11-18-96 Permit Application

E 6-2

JOHNSONVILLE FOSSIL PLANT: ASH HANDLING PROCESS - ACTUAL PARTICULATE EMISSIONS FROM SIGNIFICANT SOURCES

JULY 1993 - JUNE 1994

EMISSION UNIT NUMBER	DESCRIPTION	EMISSION UNIT COMPONENT	APPLICABLE EMISSION EQUATION (1)	INPUT PARAMETERS (2) PARAMETER	VALUE	EMISSION FACTOR	SCALING FACTOR (PROCESS MEASURE)	UNCONTROLLED TSP EMISSIONS T/YR	LB/HR	CONTROLS	% CONTROL EFFICIENCY (3)	CONTROLLED TSP EMISSIONS T/YR	LB/HR
20A	HAUL ROAD TO ASH DISPOSAL AREA	HAUL ASH IN DUMP TRUCK TO THE ASH DISPOSAL AREA FOR STACKING (ONE-WAY FULL; GRAVEL ROAD)	UNPAVED ROAD FUGITIVE DUST (AP-42, SEC. 11.2.1.2)	SILT CONTENT, % VEHICLE SPEED, MPH VEHICLE WEIGHT, TONS NO. OF WHEELS WET DAYS/YR	28.5 15 23 10 119	24.85 LB/VMT	150 T/HR 3.50E+05 T/YR 12 T/TRIP 0.4 MILES/TRIP	1.45E+02	1.24E+02	WET SUPPRESSION	90	1.45E+01	1.24E+01
20B		HAUL ASH IN DUMP TRUCK TO THE ASH DISPOSAL AREA FOR STACKING (ONE-WAY FULL; DIRT ROAD)	UNPAVED ROAD FUGITIVE DUST (AP-42, SEC. 11.2.1.2)	SILT CONTENT, % VEHICLE SPEED, MPH VEHICLE WEIGHT, TONS NO. OF WHEELS WET DAYS/YR	28.5 15 23 10 119	24.85 LB/VMT	150 T/HR 3.50E+05 T/YR 12 T/TRIP 0.25 MILES/TRIP	9.06E+01	7.77E+01	WET SUPPRESSION	90	9.06E+00	7.77E+00
20C		HAUL ASH IN DUMP TRUCK TO THE ASH DISPOSAL AREA FOR STACKING (ONE-WAY EMPTY; DIRT ROAD)	UNPAVED ROAD FUGITIVE DUST (AP-42, SEC. 11.2.1.2)	SILT CONTENT, % VEHICLE SPEED, MPH VEHICLE WEIGHT, TONS NO. OF WHEELS WET DAYS/YR	28.5 15 11 10 119	14.83 LB/VMT	150 T/HR 3.50E+05 T/YR 12 T/TRIP 0.25 MILES/TRIP	5.41E+01	4.63E+01	WET SUPPRESSION	90	5.41E+00	4.63E+00
20D		HAUL ASH IN DUMP TRUCK TO THE ASH DISPOSAL AREA FOR STACKING (ONE-WAY EMPTY; GRAVEL ROAD)	UNPAVED ROAD FUGITIVE DUST (AP-42, SEC. 11.2.1.2)	SILT CONTENT, % VEHICLE SPEED, MPH VEHICLE WEIGHT, TONS NO. OF WHEELS WET DAYS/YR	28.5 15 11 10 119	14.83 LB/VMT	150 T/HR 3.50E+05 T/YR 12 T/TRIP 0.4 MILES/TRIP	8.65E+01	7.42E+01	WET SUPPRESSION	90	8.65E+00	7.42E+00
20E		HAUL DIRT IN DUMP TRUCK TO THE ASH DISPOSAL AREA FOR COVER (ONE-WAY FULL; DIRT ROAD)	UNPAVED ROAD FUGITIVE DUST (AP-42, SEC. 11.2.1.2)	SILT CONTENT, % VEHICLE SPEED, MPH VEHICLE WEIGHT, TONS NO. OF WHEELS WET DAYS/YR	28.5 15 27.5 10 119	28.17 LB/VMT	120 T/HR 4.65E+04 T/YR 15 T/TRIP 0.25 MILES/TRIP	1.09E+01	5.63E+01	WET SUPPRESSION	90	1.09E+00	5.63E+00
20F		HAUL DIRT IN DUMP TRUCK TO THE ASH DISPOSAL AREA FOR COVER (ONE-WAY EMPTY; DIRT ROAD)	UNPAVED ROAD FUGITIVE DUST (AP-42, SEC. 11.2.1.2)	SILT CONTENT, % VEHICLE SPEED, MPH VEHICLE WEIGHT, TONS NO. OF WHEELS WET DAYS/YR	28.5 15 12.5 10 119	16.22 LB/VMT	120 T/HR 4.65E+04 T/YR 15 T/TRIP 0.25 MILES/TRIP	6.29E+00	3.24E+01	WET SUPPRESSION	90	6.29E-01	3.24E+00
20G		HAUL ROAD AND PILE WATERING WITH WATER TRUCK FOR DUST SUPPRESSION	UNPAVED ROAD FUGITIVE DUST (AP-42, SEC. 11.2.1.2)	SILT CONTENT, % VEHICLE SPEED, MPH AVG HAUL WEIGHT, TONS EMPTY WEIGHT, TONS TRUCK CAPACITY, TONS NO. OF WHEELS WET DAYS/YR	28.5 10 47.5 40 15 4 119	17.41 LB/VMT	52 DAYS/YR 8 HR/DAY 10 MILES/HR	3.62E+01	1.74E+02	WET SUPPRESSION	90	3.62E+00	1.74E+01

TABLE 6-2 (Continued)
JOHNSONVILLE FOSSIL PLANT: ASH HANDLING PROCESS - ACTUAL PARTICULATE EMISSIONS FROM SIGNIFICANT SOURCES

EMISSION UNIT NUMBER	DESCRIPTION	EMISSION UNIT COMPONENT	APPLICABLE EMISSION EQUATION (1)	INPUT PARAMETERS (2)		EMISSION FACTOR	SCALING FACTOR (PROCESS MEASURE)	UNCONTROLLED TSP EMISSIONS		CONTROLS	% CONTROL EFFICIENCY (3)	CONTROLLED TSP EMISSIONS	
				PARAMETER	VALUE			T/YR	LB/HR			T/YR	LB/HR
21A	ASH DISPOSAL AREA	DUMP TRUCK DISCHARGE ASH TO DISPOSAL AREA FOR STACKING	BATCH/CONTINUOUS DROP OPERATIONS (AP-42, SECTION 11.2.3.3)	H_2O CONTENT, % AVG WIND SPEED, MPH	15 5	1.41E-04 LB/T	150 T/HR 3.50E+05 T/YR	2.47E-02	2.12E-02	NONE	0	2.47E-02	2.12E-02
21B		DUMP TRUCK DISCHARGE DIRT TO DISPOSAL AREA FOR STACK COVER	BATCH/CONTINUOUS DROP OPERATIONS (AP-42, SECTION 11.2.3.3)	H_2O CONTENT, % AVG WIND SPEED, MPH	7.9 5	3.46E-04 LB/T	150 T/HR 3.50E+05 T/YR	6.06E-02	5.19E-02	NONE	0	6.06E-02	5.19E-02
21C		OPEN STORAGE PILE WIND EROSION	WIND EROSION FROM ACTIVE STORAGE PILE (EPA-450/2-92-004, SECTION 2.3.1.3)	SILT CONTENT, % WET DAYS/YR WIND FREQ > 12 MPH, %	100 119 3	23.73 LB/(ACRE-DAY)	15.0 ACRES	6.50E+01	1.48E+01	WET SUPPRESSION, COMPACTION, AND CRUSTOVER	90	6.50E+00	1.48E+00
21D		BULLDOZER GRADING/ ROLLER COMPACTING OF ASH STACK	UNPAVED ROAD FUGITIVE DUST (AP-42, SEC. 11.2.1.2)	SILT CONTENT, % VEHICLE SPEED, MPH VEHICLE WEIGHT, TONS NO. OF WHEELS WET DAYS/YR	100 5 41 4 119	27.56 LB/VMT	260 DAYS/YR 4 HR/DAY 5 MILES/HR	7.16E+01	1.38E+02	WET SUPPRESSION	75	1.79E+01	3.44E+01
21E		BULLDOZER GRADING/ ROLLER COMPACTING DIRT COVER	UNPAVED ROAD FUGITIVE DUST (AP-42, SEC. 11.2.1.2)	SILT CONTENT, % VEHICLE SPEED, MPH VEHICLE WEIGHT, TONS NO. OF WHEELS WET DAYS/YR	28.5 5 41 4 119	7.85 LB/VMT	260 DAYS/YR 4 HR/DAY 5 MILES/HR	2.04E+01	3.93E+01	WET SUPPRESSION	75	5.10E+00	9.82E+00

ASH HANDLING PROCESS PARTICULATE EMISSION TOTALS FOR SIGNIFICANT SOURCES:

	Uncontrolled T/YR	Uncontrolled LB/HR	Controlled T/YR	Controlled LB/HR
POINT- SOURCE	0.00E+00	0.00E+00	0.00E+00	0.00E+00
FUGITIVE				
EMISSION UNIT 20	4.30E+02	5.85E+02	4.30E+01	5.85E+01
EMISSION UNIT 21	1.57E+02	1.92E+02	2.96E+01	4.58E+01
TOTAL	5.87E+02	7.77E+02	7.26E+01	1.04E+02

NOTES:	REFERENCES:
(1) The sources of emission equations/factors are:	
(a) Wind erosion from active (frequently disturbed) piles	EPA-450/2-92-004, Fugitive Dust Background Document and Technical Information Document for Best Available Control Measures, p. 2-25, Sept.,1992.
(b) Batch and continuous drop operations	EPA. AP-42, 4th Edition, Supplement B, Section 11.2.3.3., September, 1988.
(c) Unpaved roads; grading and compacting of ash pile and dirt cover	EPA, AP-42, 4th Edition, Supplement B, Section 11.2.1.2, September, 1988
(2) The sources for meteorological input parameters are:	
(a) Average wind speed (5.0 mph) and frequency of winds greater than 12 mph (3.0 %)	Johnsonville Fossil Plant Meteorological Tower, 1985-87 data base
(b) Number of wet days per year (119)	NOAA, 1993 Local Climatological Data, Annual Summary with Comparative Data, Nashville, Tennessee, 1942-1993 Average
(3) The sources of control efficiencies are:	
(a) Wet suppression (for haul roads)	90 % (AWMA, Air Pollution Engineering Manual, pp. 143-144, 1992)
(b) Wet suppression (for ash pile maintenance)	75% (AWMA, Air Pollution Engineering Manual, pp. 143-144, 1992)
(c) Wet suppression, compaction, and crustover (for ash open-storage pile)	90% (DOE/RG/10312-1 (Vol.2), Technical guide for Estimating Fugitive Dust Impacts from Coal Handling Operations, p. 4-7, 1984)

SAMPLE CALCULATIONS FOR THE ASH HANDLING PROCESS
JOHNSONVILLE FOSSIL PLANT

All the bottom ash, pyrites, economizer ash, and the fly ash from the mechanical collectors and ESPs at Johnsonville Fossil Plant are collected and pumped as a wet slurry to the active ash pond. The only air emissions that occur in this phase of the wet disposal process are at the vents from the air separator tanks (one for each of the ten boiler units) on the vacuum-producing systems (e.g. HYDROVEYORS), and they are defined as categorically exempt insignificant activities by TAPCR 1200-3-9-.04(5)(f)62 and 1200-3-9-.04(5)(f)109(iv).

After the ash is sluiced to the active ash pond, some of the bottom ash is excavated from the pond inlet, moved to another portion of the pond, and stacked. In addition, some of the remaining ash from the active ash pond is dredged and transferred to an ash disposal area to gain additional sluicing capacity in the active ash pond. Calculations for estimates of fugitive emissions that occur during the excavating operations in the active ash pond are shown in Appendix B. These estimates show this is an insignificant activity because uncontrolled emissions are less than 5 tons per year [TAPCR 1200-3-9-.04(5)(a)4(i)]. These calculations assumed that the only frequently disturbed portion of the active ash pond subject to wind erosions was the portion where bottom ash was excavated and stacked; the remainder of the active ash pond is either submerged under a layer of water or remains wet at all times.

The two significant sources for the ash handling process are (1) the haul roads from the active ash pond to the ash disposal area and (2) the ash disposal area. Current operations dredge ash from the active ash pond and pump to the ash disposal area so the haul roads for hauling ash would not be a source; however, a worst-case scenario is assumed, so haul roads for ash hauling are used to estimate particulate emissions. Haul roads for hauling dirt for stack cover prior to seeding are currently used and are also included in the worst-case scenario to estimate particulate emissions.

MAXIMUM ALLOWABLE EMISSIONS

There is no air permit that limits emission from the ash handling system so no maximum allowable emission calculations were performed. There are no point sources of emission except the air separator vents noted above, and all ash is collected and transferred using a wet process.

ACTUAL EMISSIONS

The preceding table summarizes the estimated actual particulate emissions from the two significant sources in the ash handling process at Johnsonville. All emissions are from fugitive dust sources. The following discussion reviews the assumptions and equations used to estimate the particulate emissions from a representative sample of fugitive dust sources in the process.

(1) Wind Erosion from Active (Frequently Disturbed) Storage Piles

Source: EPA-450/2-92-004, Fugitive Dust Background Document And Technical Information Document For Best Available Control Measures, Section 2.3.1.3, page 2-25, September 1992.

$$E(TSP) = 1.7\left(\frac{s}{1.5}\right)\left(\frac{d}{235}\right)\left(\frac{f}{15}\right)$$

Where: E = *TSP* (<30μ) *emission factor, lb/(acre·day) of pile area*
s = *Silt content of material, weight %*
d = *Number of dry days per year* (<0.01 *inches of precipitation per day*)
f = *Frequency of wind speeds* >12 *mph at the mean pile height, %*

Sample Calculation - Ash Disposal Area (Emission Unit 21C):Open Storage Pile Wind Erosion

For a worst-case scenario, the silt content of fly ash (100%) was used in this calculation. It is realized that the ash at this point is a mixture of fly ash, bottom ash, pyrites, and economizer ash, so the silt content would actually be somewhere intermediate to the silt content of fly ash (100%) and bottom ash (2.5%).

$$E = 1.7\ \left(\frac{100}{1.5}\right)\ \left(\frac{365-119}{235}\right)\ \left(\frac{3.0}{15}\right) = 23.73\ lb/(acre \cdot day)$$

The total area to be used for ash stacking is estimated to be 15 acres for each disposal area, and the area exposed as stacked ash will be limited to one disposal area of 15 acres at any one time prior to being covered with a dirt cap and seeded.

Uncontrolled Emissions:

$$ANNUAL = \frac{23.73\ lb}{acre \cdot day} \times 15.0\ acres \times \frac{365\ day}{year} \times \frac{ton}{2{,}000\ lb} = 65.0\ tpy$$

$$HOURLY = \frac{23.73\ lb}{acre \cdot day} \times 15.0\ acres \times \frac{day}{24\ hour} = 14.8\ lb/hr$$

Controlled Emissions:

Controlled Emissions = (Uncontrolled emissions) (1-e/100)

Where: e = Control Efficiency (%) = 90%

$$ANNUAL = 65.0\ tpy \times (1 - \frac{90}{100}) = 6.50\ tpy$$

$$HOURLY = 14.8\ lb/hr \times (1 - \frac{90}{100}) = 1.48\ lb/hr$$

(2) Unpaved Road

Source: EPA, AP-42, 4th Edition, Supplement B, Section 11.2.1.2, September 1988

$$E = k\ (5.9)\ (\frac{s}{12})\ (\frac{S}{30})\ (\frac{W}{3})^{0.7}\ (\frac{w}{4})^{0.5}\ \frac{(365\ -\ p)}{365}$$

Where: E = *Emission factor, lb/VMT (VMT = Vehicle Miles Traveled)*
k = *Particle size multiplier* (0.80 *for TSP*)
s = *Silt content of road surface material, weight %*
S = *Mean vehicle speed, mph*
W = *Mean vehicle weight, tons*
w = *Mean number of wheels*
p = *Number of days per year with at least* 0.01″ *of precipitation*

Sample Calculation - Haul Road to Ash Disposal Area (Emission Unit 20A): Haul Ash in Dump Truck to Ash Disposal Area for Stacking, (One-way, Full Load, Gravel Road)

$$E = 0.8(5.9) \times \frac{28.5}{12} \times \frac{15}{30} \times (\frac{23}{3})^{0.7}(\frac{10}{4})^{0.5}\ \frac{(365-119)}{365} = 24.85\ lb/VMT$$

VMT = (Total weight hauled/weight hauled per trip) (length of each trip)

It is assumed that a total of 350,000 tons per year of ash is transferred from the active ash pond to the ash disposal area and it is hauled in dump trucks at a rate of 150 tons per hour.

Uncontrolled Emissions:

$$ANNUAL = \frac{24.85\ lb}{VMT} \times \frac{350{,}000\ tons}{year} \times \frac{1\ trip}{12\ tons} \times \frac{0.4\ miles}{trip} \times \frac{ton}{2{,}000\ lb} = 145\ tpy$$

$$HOURLY = \frac{24.85\ lb}{VMT} \times \frac{150\ tons}{hour} \times \frac{1\ trip}{12\ tons} \times \frac{0.4\ miles}{trip} = 124\ lb/hr$$

Controlled Emissions:

Controlled emission = (Uncontrolled emission) (1-e/100)

Where: e = Control Efficiency (%)

The AWMA Air Pollution Engineering Manual, citing field-test data at a coal-fired power plant, indicates that wet suppression methods can effectively control unpaved-road fugitive emissions. TVA believes that an effective watering program will achieve 90 percent control efficiency for ash hauling and open storage pile fugitive emissions.

$$ANNUAL = 145\ tpy \times (1 - \frac{90}{100}) = 14.5\ tpy$$

$$HOURLY = 124\ lb/hr \times (1 - \frac{90}{100}) = 12.4\ lb/hr$$

(3) <u>Batch Drop Operations</u>

Source: EPA, AP-42, 4th Edition, Supplement B, Section 11.2.3.3, September 1988.

$$E = k(0.0032)\frac{(\frac{u}{5})^{1.3}}{(\frac{M}{2})^{1.4}}$$

Where: E = *Particulate emission factor, lb/ton*
k = *Particle size multiplier*, 0.74 *for TSP* (<30µm)
u = *Mean wind speed, mph*
M = *Material moisture content, weight %*

Sample Calculation - Ash Disposal Area (Emission Unit 21A): Dump Truck Discharge Ash to Disposal Area for Stacking

$$E = 0.74(0.0032) \times \frac{(\frac{5.0}{5})^{1.3}}{(\frac{15}{2})^{1.4}} = 1.41 \times 10^{-4} lb/ton$$

Uncontrolled Emissions:

$$ANNUAL = 1.41\times10^{-4}\ lb/ton \times 350{,}000\ tons/yr \times \frac{ton}{2{,}000\ lb} = 2.47\times10^{-2}\ tpy$$

$$HOURLY = 1.41\times10^{-4}\ lb/ton \times 150\ tons/hr = 2.12\times10^{-2}\ lb/hr$$

Controlled Emissions:

Controlled emissions = (Uncontrolled emissions) (1-e/100)

Where: e = Control Efficiency (%) = 0%

$$ANNUAL = 2.47\times10^{-2}\ tpy \times (1-\frac{0}{100}) = 2.47\times10^{-2}\ tpy$$

$$HOURLY = 2.12\times10^{-2}\ lb/hr \times (1-\frac{0}{100}) = 2.12\times10^{-2}\ lb/hr$$

(4) <u>Grading and Compacting with Bulldozer</u>

Source: EPA, AP-42, 4th Edition, Supplement B, Section 11.2.1.2, September 1992

$$E = k(5.9)(\frac{s}{12})(\frac{S}{30})(\frac{W}{3})^{0.7}(\frac{w}{4})^{0.5}\frac{(365-p)}{365}$$

Where: E = *Emission factor, lb/VMT (VMT = Vehicle Miles Traveled)*
k = *Particle size multiplier* (0.80 *for TSP*)
s = *Silt content of road surface material, weight %*
S = *Mean vehicle speed, mph*
W = *Mean vehicle weight, tons*
w = *Mean number of wheels*
p = *Number of days per year with at least* 0.01″ *of precipitation*

Sample Calculation - Ash Disposal Area (Emission Unit 21D): Bulldozer Grading and Roller Compacting Of Ash Stack

$$E = 0.8(5.9) \times \frac{100}{12} \times \frac{5}{30} \times (\frac{41}{3})^{0.7} (\frac{4}{4})^{0.5} \frac{(365-119)}{365} = 27.56\ lb/VMT$$

It is assumed that one bulldozer operated 4 hours per day, 260 days per year at a speed of 5 mph for ash pile maintenance activities. The bulldozer was assumed to have a mean vehicle weight of 41 tons and have an equivalent of 4 wheels.

Uncontrolled Emissions:

$$ANNUAL = 27.56\ lb/VMT \times \frac{260\ days}{yr} \times \frac{4\ hr}{day} \times \frac{5\ miles}{hr} \times \frac{ton}{2{,}000\ lb} = 71.6\ tpy$$

$$HOURLY = 27.56\ lb/VMT \times \frac{5\ miles}{hr} = 138\ lb/hr$$

Controlled Emissions:

Controlled emissions = (Uncontrolled emissions) (1-e/100)

Where: e = Control Efficiency (%)

TVA believes that an effective watering program will achieve 75 percent control efficiency for ash pile maintenance fugitive emissions, taking into account realistic limitations in the area that the water truck can cover as compared to the bulldozers.

$$ANNUAL = 71.6\ tpy \times (1-\frac{75}{100}) = 17.9\ tpy$$

$$HOURLY = 138\ lb/hr \times (1-\frac{75}{100}) = 34.4\ lb/hr$$

ATTACHMENT 5

Emission Factors (Table 5-2 of Application) and Calculation of Particulate Emissions from Coal Handling Facility (43-0011-29)

Pages 5-20 through 5-30 from 11-18-96 Permit Application

TABLE 5-2
JOHNSONVILLE FOSSIL PLANT: SOLID-FUEL HANDLING PROCESS - ACTUAL PARTICULATE EMISSIONS FROM SIGNIFICANT SOURCES
JULY 1993-JUNE 1994

EMISSION UNIT NUMBER	DESCRIPTION	EMISSION UNIT COMPONENT	APPLICABLE EMISSION EQUATION (1)	INPUT PARAMETERS (2) PARAMETER	VALUE	EMISSION FACTOR	SCALING FACTOR (PROCESS MEASURE)	UNCONTROLLED TSP EMISSIONS T/YR	LB/HR	CONTROLS	% CONTROL EFFICIENCY(3)	CONTROLLED TSP EMISSIONS T/YR	LB/HR
18A	COAL STORAGE YARD	OPEN STORAGE PILE WIND EROSION	WIND EROSION FROM ACTIVE STORAGE PILE (EPA-450/2-92-004, SECTION 2.3.1.3)	SILT CONTENT, % WET DAYS/YR WIND FREQ > 12 MPH, %	4 119 3	0.95 LB/(ACRE-DAY)	13.5 ACRES	2.34E+00	5.34E-01	NONE	0	2.34E+00	5.34E-01
18B		PAN SCRAPERS STOCKOUT HAULING, (ONE-WAY FULL)	UNPAVED ROAD FUGITIVE DUST (AP-42, SEC. 11.2.1.2)	SILT CONTENT, % VEHICLE SPEED, MPH VEHICLE WEIGHT, TONS NO. OF WHEELS WET DAYS/YR	4 15 75 4 119	5.05 LB/VMT	2,000 T/HR 9.22E+05 T/YR 22.5 T/TRIP 500 FT/TRIP	9.79E+00	4.25E+01	WET SUPPRESSION	75	2.45E+00	1.06E+01
18C		PAN SCRAPERS STOCKOUT HAULING, (ONE-WAY EMPTY)	UNPAVED ROAD FUGITIVE DUST (AP-42, SEC. 11.2.1.2)	SILT CONTENT, % VEHICLE SPEED, MPH VEHICLE WEIGHT, TONS NO. OF WHEELS WET DAYS/YR	4 15 52.5 4 119	3.93 LB/VMT	2,000 T/HR 9.22E+05 T/YR 22.5 T/TRIP 500 FT/TRIP	7.63E+00	3.31E+01	WET SUPPRESSION	75	1.91E+00	8.27E+00
18D		PAN SCRAPERS DISCHARGE COAL TO STORAGE PILE	BATCH/CONTINUOUS DROP OPERATIONS (AP-42, SECTION 11.2.3.3)	H_2O CONTENT, % AVG WIND SPEED, MPH	10 5	2.49E-04 LB/T	2,000 T/HR 9.22E+05 T/YR	1.15E-01	4.98E-01	NONE	0	1.15E-01	4.98E-01
18E		PAN SCRAPERS RECLAIM HAULING, (ONE-WAY FULL)	UNPAVED ROAD FUGITIVE DUST (AP-42, SEC. 11.2.1.2)	SILT CONTENT, % VEHICLE SPEED, MPH VEHICLE WEIGHT, TONS NO. OF WHEELS WET DAYS/YR	4 15 75 4 119	5.05 LB/VMT	2,000 T/HR 9.22E+05 T/YR 22.5 T/TRIP 500 FT/TRIP	9.79E+00	4.25E+01	WET SUPPRESSION	75	2.45E+00	1.06E+01
18F		PAN SCRAPERS RECLAIM HAULING, (ONE-WAY EMPTY)	UNPAVED ROAD FUGITIVE DUST (AP-42, SEC. 11.2.1.2)	SILT CONTENT, % VEHICLE SPEED, MPH VEHICLE WEIGHT, TONS NO. OF WHEELS WET DAYS/YR	4 15 52.5 4 119	3.93 LB/VMT	2,000 T/HR 9.22E+05 T/YR 22.5 T/TRIP 500 FT/TRIP	7.63E+00	3.31E+01	WET SUPPRESSION	75	1.91E+00	8.27E+00
18G		BULLDOZER GRADING AND COMPACTING COAL PILE FOR PILE MAINTENANCE	UNPAVED ROAD FUGITIVE DUST (AP-42, SEC. 11.2.1.2)	SILT CONTENT, % VEHICLE SPEED, MPH VEHICLE WEIGHT, TONS NO. OF WHEELS WET DAYS/YR	4 5 66 4 119	1.54 LB/VMT	260 DAYS/YR 4 HR/DAY 5 MILES/HR	4.00E+00	7.69E+00	NONE	0	4.00E+00	7.69E+00
18H		HAUL ROAD WATERING WITH WATERING TRUCK FOR DUST SUPPRESSION	UNPAVED ROAD FUGITIVE DUST (AP-42, SEC. 11.2.1.2)	SILT CONTENT, % VEHICLE SPEED, MPH AVG HAUL WEIGHT, TONS EMPTY WEIGHT, TONS TRUCK CAPACITY, TONS NO. OF WHEELS WET DAYS/YR	4 10 47.5 40 15 4 119	2.44 LB/VMT	52 DAYS/YR 8 HR/DAY 10 MILES/HR	5.08E+00	2.44E+01	WET SUPPRESSION	75	1.27E+00	6.11E+00
19A	SCREENING AND CRUSHING STATION #1 AND #2	COAL DISCHARGE FROM CONVEYOR BC-3 TO SCREENS/CRUSHER	BATCH/CONTINUOUS DROP OPERATIONS (AP-42, SECTION 11.2.3.3)	H_2O CONTENT, % AVG WIND SPEED, MPH	10 5	2.49E-04 LB/T	1,000 T/HR 1.84E+06 T/YR	2.29E-01	2.49E-01	ENCLOSURE	70	6.88E-02	7.46E-02
19B		COAL DISCHARGE FROM CONVEYOR BC-13 TO SCREENS/CRUSHER	BATCH/CONTINUOUS DROP OPERATIONS (AP-42, SECTION 11.2.3.3)	H_2O CONTENT, % AVG WIND SPEED, MPH	10 5	2.49E-04 LB/T	1,000 T/HR 1.84E+06 T/YR	2.29E-01	2.49E-01	ENCLOSURE	70	6.88E-02	7.46E-02
19C		COAL DISCHARGE FROM CONVEYOR BC-15 TO SCREENS/CRUSHER	BATCH/CONTINUOUS DROP OPERATIONS (AP-42, SECTION 11.2.3.3)	H_2O CONTENT, % AVG WIND SPEED, MPH	10 5	2.49E-04 LB/T	1,000 T/HR 1.84E+06 T/YR	2.29E-01	2.49E-01	ENCLOSURE	70	6.88E-02	7.46E-02

TABL (Continued)
JOHNSONVILLE FOSSIL PLANT: SOLID-FUEL HANDLING PROCESS - ACTUAL PARTICULATE EMISSIONS FROM SIGNIFICANT SOURCES
JULY 1993-JUNE 1994

EMISSION UNIT NUMBER	DESCRIPTION	EMISSION UNIT COMPONENT	APPLICABLE EMISSION EQUATION (1)	INPUT PARAMETERS (2)		EMISSION FACTOR	SCALING FACTOR (PROCESS MEASURE)	UNCONTROLLED TSP EMISSIONS		CONTROLS	% CONTROL EFFICIENCY(3)	CONTROLLED TSP EMISSIONS	
				PARAMETER	VALUE			T/YR	LB/HR			T/YR	LB/HR
19D	SCREENING AND CRUSHING STATION #1 AND #2 (CONTINUED)	SCREENED/CRUSHED COAL DISCHARGE FROM CONVEYORS BC-3, BC-13, AND BC-15 (25% OF FEED TO CRUSHERS)	PRIMARY CRUSHER W/HIGH MOISTURE ORE (AP-42, SECTION 8.23.2)	—	—	0.02 LB/T	500 T/HR 9.22E+05 T/YR	9.22E+00	1.00E+01	ENCLOSURE	70	2.77E+00	3.00E+00
19E		COAL DISCHARGE FROM SCREENS/CRUSHERS TO CONVEYOR BC-4 AND CONVEYOR BC-20	BATCH/CONTINUOUS DROP OPERATIONS (AP-42, SECTION 11.2.3.3)	H_2O CONTENT, % AVG WIND SPEED, MPH	10 5	2.49E-04 LB/T	2,000 T/HR 3.69E+06 T/YR	4.59E-01	4.98E-01	ENCLOSURE	70	1.38E-01	1.49E-01

SOLID-FUEL HANDLING PROCESS PARTICULATE EMISSION TOTALS FOR SIGNIFICANT SOURCES:

	UNCONTROLLED T/YR	UNCONTROLLED LB/HR	CONTROLLED T/YR	CONTROLLED LB/HR
POINT-SOURCE	0.00E+00	0.00E+00	0.00E+00	0.00E+00
FUGITIVE				
EMISSION UNIT 18	4.64E+01	1.84E+02	1.64E+01	5.26E+01
EMISSION UNIT 19	1.01E+01	1.10E+01	3.04E+00	3.30E+00
TOTAL	5.65E+01	1.95E+02	1.95E+01	5.59E+01

THE TOTALS ABOVE DO NOT INCLUDE EMISSION UNIT NUMBER 19B; THIS CONVEYOR TRANSFER FROM THE RAILCAR AND TRUCK UNLOADING STATION IS OUT OF SERVICE AND NOT EXPECTED TO BE USED. UNIT 19B CALCULATIONS ARE BASED ON 50% OF TOTAL PLANT COAL FEED TO SHOW POTENTIAL EMISSIONS FOR ILLUSTRATIVE PURPOSES; HOWEVER, INCLUDING THIS NUMBER IN THE TOTAL WOULD OVERSTATE THE EMISSIONS.

NOTES:	REFERENCES:
(1) The sources of emission equations/factors are:	
(a) Wind erosion from active (frequently disturbed) piles	EPA-450/2-92-004, Fugitive Dust Background Document and Technical Information Document for Best Available Control Measures, p 2-25, Sept.,1992.
(b) Batch and continuous drop operations	EPA. AP-42, 4th Edition, Supplement B, Section 11.2.3.3., September, 1988.
(c) Unpaved roads; grading and compacting of coal pile	EPA, AP-42, 4th Edition, Supplement B, Section 11.2.1.2, September, 1988
(d) Coal crushers, primary and secondary	EPA, AP-42, Supplement A, Section 8.23.2, Table 8.23-1, August, 1982
(2) The sources for meteorological input parameters are:	
(a) Average wind speed (5.0 mph) and frequency of winds greater than 12 mph (3.0 %)	Johnsonville Fossil Plant Meteorological Tower, 1985-87 data base
(b) Number of wet days per year (119)	NOAA, 1993 Local Climatological Data, Annual Summary with Comparative Data, Nashville, Tennessee, 1942-1993 Average
(3) The sources of control efficiencies are:	
(a) Enclosures of conveyors and transfer points	70 % (AWMA, Air Pollution Engineering Manual, p. 794, 1992)
(b) Wet suppression (for haul roads)	75 % (AWMA, Air Pollution Engineering Manual, pp. 143-144, 1992)

SAMPLE CALCULATIONS FOR THE SOLID-FUEL HANDLING PROCESS
JOHNSONVILLE FOSSIL PLANT

MAXIMUM ALLOWABLE EMISSIONS

The only quantitative emission limit applying to the solid-fuel handling process is the particulate matter (PM) emissions standard of 82 pounds per hour based on the process weight rate. In the existing air permit, this limit applies only to the point sources (cyclone collectors). The existing point sources in the solid-fuel handling process are the dust collectors for the powerhouse bunkers and coal scales. Calculations in Appendix B show the powerhouse bunkers dust collectors are not a significant source and the coal scales dust collectors are an exempt source [TAPCR 1200-3-9-.04(5)(f)109(ii)]. Therefore, there are no significant point sources shown in the solid-fuel handling process. At one point in time, a Rotoclone dust collector was in operation at the Screening and Crushing Stations #1 and #2 (Emission Unit 19), however a January 9, 1984, letter transmitting permit application information for the solid-fuel handling facility indicated that equipment was no longer operational. Therefore, the fugitive dust equations shown in the sample calculations and the attached summary table were used to calculate the uncontrolled emissions generated at that emission unit and an estimated 70% control efficiency based on an enclosure was applied to predict the controlled emissions from that unit and this value is used to estimate potential annual emissions.

ACTUAL EMISSIONS

Currently coal is the only solid fuel burned at Johnsonville Fossil Plant. The following discussion reviews the assumptions and equations used to generate particulate emissions estimates for a representative sample of fugitive dust sources in the solid-fuel handling process.

Johnsonville Fossil Plant has two parallel lines of barge unloaders and conveyors feeding the powerhouse. Each has a current capacity of 700 tons per hour, 1,400 tons per hour total. The calculations for actual fugitive emissions are based on a total capacity of 2,000 tons per hour to allow for potential future upgrades of each conveyor line to 1,000 tons per hour.

A rail car thawer has been installed as part of this process, but is no longer in service. It is electrically heated, so there are no combustion emissions from this unit and it is not included in the sample calculations and emissions summary for the solid-fuel handling process.

(1) Wind Erosion from Active (Frequently Disturbed) Storage Piles

Source: EPA-450/2-92-004, Fugitive Dust Background Document And Technical Information Document For Best Available Control Measures, Section 2.3.1.3, page 2-25, September 1992.

$$E\,(TSP) = 1.7\left(\frac{s}{1.5}\right)\left(\frac{d}{235}\right)\left(\frac{f}{15}\right)$$

Where: E = *TSP* ($<30\mu$) *emission factor, lb/(acre·day) of pile area*
s = *Silt content of material, weight %*
d = *Number of dry days per year* (<0.01 *inches of precipitation per day*)
f = *Frequency of wind speeds greater than* 12 *mph at the mean pile height, %*

Sample Calculation - Coal Storage Yard (Emission Unit 18A): Open Storage Pile Wind Erosion

$$E = 1.7\left(\frac{4.0}{1.5}\right)\left(\frac{365-119}{235}\right)\left(\frac{3.0}{15}\right) = 0.95\ lb/(acre\cdot day)$$

The footprint for the coal storage pile under extreme operations (45-day supply assumed at full coal burn) is approximately 13.5 acres according to recently redesigned stockpile.

Uncontrolled Emissions:

$$ANNUAL = \frac{0.95\ lb}{acre\cdot day} \times 13.5\ acres \times \frac{365\ day}{year} \times \frac{ton}{2{,}000\ lb} = 2.34\ tpy$$

$$HOURLY = \frac{0.95\ lb}{acre\cdot day} \times 13.5\ acres \times \frac{day}{24\ hour} = 0.534\ lb/hr$$

Controlled Emissions:

Controlled Emissions = (Uncontrolled emissions) (1-e/100)

Where: e = Control Efficiency (%) = 0%

$$ANNUAL = 2.34\ tpy \times (1 - \frac{0}{100}) = 2.34\ tpy$$

$$HOURLY = 0.534\ lb/hr \times (1 - \frac{0}{100}) = 0.534\ lb/hr$$

(2) <u>Unpaved Road</u>

Source: EPA, AP-42, 4th Edition, Supplement B, Section 11.2.1.2, September 1988

$$E = k\ (5.9)\ (\frac{s}{12})\ (\frac{S}{30})\ (\frac{W}{3})^{0.7}\ (\frac{w}{4})^{0.5}\ \frac{(365 - p)}{365}$$

Where: E = *Emission factor, lb/VMT (VMT = Vehicle Miles Traveled)*
k = *Particle size multiplier* (0.80 *for TSP*)
s = *Silt content of road surface material, weight %*
S = *Mean vehicle speed, mph*
W = *Mean vehicle weight, tons*
w = *Mean number of wheels*
p = *Number of days per year with at least* 0.01″ *of precipitation*

<u>Sample Calculation</u> - Coal Storage Yard (Emission Unit 18B): Pan Scrapers Stockout Hauling, One-way, Full Load

$$E = 0.8(5.9) \times \frac{4.0}{12} \times \frac{15}{30} \times (\frac{75}{3})^{0.7}(\frac{4}{4})^{0.5}\ \frac{(365-119)}{365} = 5.05\ lb/VMT$$

VMT =(Total weight hauled/weight hauled per trip) (length of each trip)

For calculation of estimated emissions, 25% of total coal unloaded through the barge unloading stations is stocked out to the coal storage yard. The remaining 75% of the coal unloaded is fed directly to the powerhouse. The coal stocked out and reclaimed (sum of both operations) averaged 36% of coal receipts for 1988-1994, so the values used in the calculations (25% stockout and 25% reclaim) should be conservative ones.

Uncontrolled Emissions:

$$ANNUAL = \frac{5.05\ lb}{VMT} \times 0.25 \times \frac{3.69 \times 10^6\ tons}{year} \times \frac{1\ trip}{22.5\ tons} \times \frac{500\ feet}{trip} \times \frac{mile}{5{,}280\ feet} \times \frac{ton}{2{,}000\ lb} = 9.79\ tpy$$

$$HOURLY = \frac{5.05\ lb}{VMT} \times \frac{2{,}000\ tons}{hour} \times \frac{1\ trip}{22.5\ tons} \times \frac{500\ feet}{trip} \times \frac{mile}{5{,}280\ feet} = 42.5\ lb/hr$$

Controlled Emissions:

Controlled emission = (Uncontrolled emission) (1-e/100)

Where: e = Control Efficiency (%)

The AWMA Air Pollution Engineering Manual, citing field-test data at a coal-fired power plant, indicates that wet suppression methods can effectively control unpaved-road fugitive emissions. TVA believes that an effective watering program will achieve 75 percent control efficiency for coal storage yard stockout/reclaim fugitive emissions, taking into account realistic limitations in the area that the water truck can cover as compared to the pan scrapers.

$$ANNUAL = 9.79\ tpy \times (1 - \frac{75}{100}) = 2.45\ tpy$$

$$HOURLY = 42.5\ lb/hr \times (1 - \frac{75}{100}) = 10.6\ lb/hr$$

(3) **Batch Drop Operations**

Source: EPA, AP-42, 4th Edition, Supplement B, Section 11.2.3.3, September 1988.

$$E = k(0.0032)\frac{(\frac{u}{5})^{1.3}}{(\frac{M}{2})^{1.4}}$$

Where: E = *Particulate emission factor, lb/ton*
k = *Particle size multiplier,* 0.74 *for TSP* (<30μm)
u = *Mean wind speed, mph*
M = *Material moisture content, weight %*

Sample Calculation - Coal Storage Yard (Emission Unit 18D): Pan Scraper Discharge Coal to Storage Pile

The average coal moisture for the previous 5-year period (fiscal years 1990-1994) was 10.0%, so this value is used for the material moisture content.

$$E = 0.74(0.0032) \times \frac{(\frac{5.0 mph}{5})^{1.3}}{(\frac{10}{2})^{1.4}} = 2.49 \times 10^{-4} lb/ton$$

It is assumed that for worst-case, 25% of total coal unloaded through the barge unloading station is stocked out and then hauled and dumped to the coal storage pile by pan scrapers.

Uncontrolled Emissions:

$$ANNUAL = 2.49 \times 10^{-4}\ lb/ton \times 0.25 \times 3.69 \times 10^{6}\ tons/yr \times \frac{ton}{2{,}000\ lb} = 1.15 \times 10^{-1}\ tpy$$

$$HOURLY = 2.49 \times 10^{-4}\ lb/ton \times 2{,}000\ tons/hr = 4.98 \times 10^{-1}\ lb/hr$$

Controlled Emissions:

Controlled emissions = (Uncontrolled emissions) (1-e/100)

Where: e = Control Efficiency (%) = 0%

$$ANNUAL = 1.15 \times 10^{-1}\ tpy \times (1 - \frac{0}{100}) = 1.15 \times 10^{-1}\ tpy$$

$$HOURLY = 4.98 \times 10^{-1}\ lb/hr \times (1 - \frac{0}{100}) = 4.98 \times 10^{-1}\ lb/hr$$

The same equations and procedures are used to calculate coal dust emissions from the clamshell operation at the Barge Unloading Station (Insignificant Activities in Appendix B).

(4) <u>Grading and Compacting with Bulldozer</u>

Source: EPA, AP-42, 4th Edition, Supplement B, Section 11.2.1.2, September, 1992

$$E = k(5.9)(\frac{s}{12})(\frac{S}{30})(\frac{W}{3})^{0.7}(\frac{w}{4})^{0.5}\frac{(365-p)}{365}$$

Where: E = *Emission factor, lb/VMT (VMT = Vehicle Miles Traveled)*
k = *Particle size multiplier* (0.80 *for TSP*)
s = *Silt content of road surface material, weight %*
S = *Mean vehicle speed, mph*
W = *Mean vehicle weight, tons*
w = *Mean number of wheels*
p = *Number of days per year with at least* $0.01''$ *of precipitation*

<u>Sample Calculation</u> - Coal Storage Yard (Emission Unit 18G): Bulldozer Grading and Compacting Coal Pile

$$E = 0.8(5.9) \times \frac{4.0}{12} \times \frac{5}{30} \times (\frac{61}{3})^{0.7} (\frac{4}{4})^{0.5} \frac{(365-119)}{365} = 1.54\ lb/VMT$$

It is assumed that one bulldozer operated 4 hours per day, 260 days per year at a speed of 5 mph for coal pile maintenance activities. The bulldozer currently used has a vehicle weight of 61 tons and is assumed to have an equivalent of 4 wheels.

Uncontrolled Emissions:

$$ANNUAL = 1.54\ lb/VMT \times \frac{260\ days}{yr} \times \frac{4\ hr}{day} \times \frac{5\ miles}{hr} \times \frac{ton}{2{,}000\ lb} = 4.00\ tpy$$

$$HOURLY = 1.54\ lb/VMT \times \frac{5\ miles}{hr} = 7.69\ lb/hr$$

Controlled Emissions:

Controlled emissions = (Uncontrolled emissions) (1-e/100)

Where: e = Control Efficiency (%) = 0%

$$ANNUAL = 4.00\ tpy \times (1 - \frac{0}{100}) = 4.00\ tpy$$

$$HOURLY = 7.69\ lb/hr \times (1 - \frac{0}{100}) = 7.69\ lb/hr$$

(5) Continuous Drop Operations

Source: EPA, AP-42, 4th Edition, Supplement B, Section 11.2.3.3, September 1988

$$E = k(0.0032)\ \frac{(\frac{u}{5})^{1.3}}{(\frac{M}{2})^{1.4}}$$

Where: E = *Uncontrolled particulate emission factor, lb/ton*
k = *Particle size multiplier,* 0.74 *for TSP* (<30μm)
u = *Mean wind speed, mph*
M = *Material moisture content, weight %*

Sample Calculation - Screening and Crushing Station #1 and #2 (Emission Unit 19A): Coal Discharge from Conveyor BC-3 to Screens/Crusher

$$E = 0.74(0.0032)\frac{(\frac{5.0}{5})^{1.3}}{(\frac{10}{2})^{1.4}} = 2.49\times10^{-4}\ lb/ton$$

It is assumed that one-half of the coal burned at Johnsonville Boiler Units 1 - 10 during July 1993 - June 1994 was handled through this conveyor. The conveyor has a current maximum capacity of 700 tons/hr, but an anticipated upgrade to 1,000 tons/hr is expected in the future. The higher number is used for these hourly calculations.

Uncontrolled Emissions:

$$ANNUAL = 2.49\times10^{-4}\ lb/ton \times 0.5 \times 3.69\times10^{6}\ tons/yr \times \frac{ton}{2,000\ lb} = 2.29\times10^{-1}\ tpy$$

$$HOURLY = 2.49\times10^{-4}\ lb/ton \times 1,000\ tons/hr = 2.49\times10^{-1}\ lb/hr$$

Controlled Emissions:

Controlled emissions = (Uncontrolled emissions) (1-e/100)

Where: e = Control Efficiency (%)

The discharge from conveyor BC-3 occurs inside the screening and crushing station, and the coal falls within an enclosed chute to screens and crushers, which are enclosed. Enclosure control efficiencies for conveyor transfer emissions are listed in the 70 - 90% range. Emissions are conservatively estimated using the lower value given in the AWMA, Air Pollution Manual, Page 794, Table 3, 1992.

$$ANNUAL = 2.29\times10^{-1}\ tpy \times (1-\frac{70}{100}) = 6.88\times10^{-2}\ tpy$$

$$HOURLY = 2.49\times10^{-1}\ lb/hr \times (1-\frac{70}{100}) = 7.46\times10^{-2}\ lb/hr$$

(6) Screening and Crushing

Source: EPA, AP-42, Section 8.23.2, August 1982

Coal is either directly transferred from the barge unloading stations to the powerhouse or it is stocked out in the coal storage yard and reclaimed to feed to the powerhouse. All this coal is fed through the Screening and Crushing Station #1 and #2 where it is screened and approximately 25% of the coal feed is screened oversize material that is fed to the crusher; the remaining 75% bypasses the crushers. Each of these two hammermill crushers has a capacity of 700 tons per hour. The crushers are assumed to be primary crushers therefore an emission factor of 0.02 pounds per ton is used. This factor for high-moisture ore is assumed for the process since the definition of high-moisture ore is a moisture content of 4% by weight or greater. Coal moisture at Johnsonville Fossil Plant averaged 10% moisture for the five previous fiscal years (1990-1994), so the coal would be a high-moisture ore.

Sample Calculation - Screening and Crushing Stations #1 and #2 (Emission Unit 19D): Screen/Crush Coal Discharged from BC-3 and BC-13 Conveyors.

Uncontrolled Emissions:

$$ANNUAL = 0.02\ lb/ton \times 0.25 \times 3.69 \times 10^6\ tons/yr \times \frac{ton}{2{,}000\ lb} = 9.22\ tpy$$

$$HOURLY = 0.02\ lb/ton \times 0.25 \times 2{,}000\ tons/hr = 10.0\ lb/hr$$

Controlled Emissions:

Controlled emissions = (Uncontrolled emissions) (1-e/100)

Where: e = Control Efficiency (%) = 70%

Using 70% as control efficiency for an enclosure, the controlled emissions are:

$$ANNUAL = 9.22\ tpy \times (1 - \frac{70}{100}) = 2.77\ tpy$$

$$HOURLY = 10.0\ lb/hr \times (1 - \frac{70}{100}) = 3.00\ lb/hr$$

ATTACHMENT 6

AP-42 Emission Factors for Natural Gas and Fuel Oil Combustion in Turbines (Tables 3.1-1 and 3.1-2a) And Manufacturer's Emissions Data and Emissions Calculations for Combustion Turbines of Source 11-26 Pages 4-50, 4-54, 4-55, and 4-59 of May 2001 Permit Application Revisions

Table 3.1-1. EMISSION FACTORS FOR NITROGEN OXIDES (NO_X) AND CARBON MONOXIDE (CO) FROM STATIONARY GAS TURBINES

Emission Factors[a]				
Turbine Type	Nitrogen Oxides		Carbon Monoxide	
Natural Gas-Fired Turbines[b]	(lb/MMBtu)[c] (Fuel Input)	Emission Factor Rating	(lb/MMBtu)[c] (Fuel Input)	Emission Factor Rating
Uncontrolled	3.2 E-01	A	8.2 E-02[d]	A
Water-Steam Injection	1.3 E-01	A	3.0 E-02	A
Lean-Premix	9.9 E-02	D	1.5 E-02	D
Distillate Oil-Fired Turbines[e]	(lb/MMBtu)[f] (Fuel Input)	Emission Factor Rating	(lb/MMBtu)[f] (Fuel Input)	Emission Factor Rating
Uncontrolled	8.8 E-01	C	3.3 E-03	C
Water-Steam Injection	2.4 E-01	B	7.6 E-02	C
Landfill Gas-Fired Turbines[g]	(lb/MMBtu)[h] (Fuel Input)	Emission Factor Rating	(lb/MMBtu)[h] (Fuel Input)	Emission Factor Rating
Uncontrolled	1.4 E-01	A	4.4 E-01	A
Digester Gas-Fired Turbines[j]	(lb/MMBtu)[k] (Fuel Input)	Emission Factor Rating	(lb/MMBtu)[k] (Fuel Input)	Emission Factor Rating
Uncontrolled	1.6 E-01	D	1.7 E-02	D

[a] Factors are derived from units operating at high loads (≥80 percent load) only. For information on units operating at other loads, consult the background report for this chapter (Reference 16), available at "www.epa.gov/ttn/chief".

[b] Source Classification Codes (SCCs) for natural gas-fired turbines include 2-01-002-01, 2-02-002-01, 2-02-002-03, 2-03-002-02, and 2-03-002-03. The emission factors in this table may be converted to other natural gas heating values by multiplying the given emission factor by the ratio of the specified heating value to this average heating value.

[c] Emission factors based on an average natural gas heating value (HHV) of 1020 Btu/scf at 60°F. To convert from (lb/MMBtu) to (lb/10^6 scf), multiply by 1020.

[d] It is recognized that the uncontrolled emission factor for CO is higher than the water-steam injection and lean-premix emission factors, which is contrary to expectation. The EPA could not identify the reason for this behavior, except that the data sets used for developing these factors are different.

[e] SCCs for distillate oil-fired turbines include 2-01-001-01, 2-02-001-01, 2-02-001-03, and 2-03-001-02.

[f] Emission factors based on an average distillate oil heating value of 139 MMBtu/10^3 gallons. To convert from (lb/MMBtu) to (lb/10^3 gallons), multiply by 139.

[g] SCC for landfill gas-fired turbines is 2-03-008-01.

[h] Emission factors based on an average landfill gas heating value of 400 Btu/scf at 60°F. To convert from (lb/MMBtu), to (lb/10^6 scf) multiply by 400.

[j] SCC for digester gas-fired turbine is 2-03-007-01.

[k] Emission factors based on an average digester gas heating value of 600 Btu/scf at 60°F. To convert from (lb/MMBtu) to (lb/10^6 scf) multiply by 600.

Table 3.1-2a. EMISSION FACTORS FOR CRITERIA POLLUTANTS AND GREENHOUSE GASES FROM STATIONARY GAS TURBINES

Emission Factors[a] - Uncontrolled				
Pollutant	Natural Gas-Fired Turbines[b]		Distillate Oil-Fired Turbines[d]	
	(lb/MMBtu)[c] (Fuel Input)	Emission Factor Rating	(lb/MMBtu)[e] (Fuel Input)	Emission Factor Rating
CO_2[f]	110	A	157	A
N_2O	0.003[g]	E	ND	NA
Lead	ND	NA	1.4 E-05	C
SO_2	0.94S[h]	B	1.01S[h]	B
Methane	8.6 E-03	C	ND	NA
VOC	2.1 E-03	D	4.1 E-04[j]	E
TOC[k]	1.1 E-02	B	4.0 E-03[l]	C
PM (condensible)	4.7 E-03[l]	C	7.2 E-03[l]	C
PM (filterable)	1.9 E-03[l]	C	4.3 E-03[l]	C
PM (total)	6.6 E-03[l]	C	1.2 E-02[l]	C

[a] Factors are derived from units operating at high loads (≥80 percent load) only. For information on units operating at other loads, consult the background report for this chapter (Reference 16), available at "www.epa.gov/ttn/chief". ND = No Data, NA = Not Applicable.

[b] SCCs for natural gas-fired turbines include 2-01-002-01, 2-02-002-01 & 03, and 2-03-002-02 & 03.

[c] Emission factors based on an average natural gas heating value (HHV) of 1020 Btu/scf at 60°F. To convert from (lb/MMBtu) to (lb/10^6 scf), multiply by 1020. Similarly, these emission factors can be converted to other natural gas heating values.

[d] SCCs for distillate oil-fired turbines are 2-01-001-01, 2-02-001-01, 2-02-001-03, and 2-03-001-02.

[e] Emission factors based on an average distillate oil heating value of 139 MMBtu/10^3 gallons. To convert from (lb/MMBtu) to (lb/10^3 gallons), multiply by 139.

[f] Based on 99.5% conversion of fuel carbon to CO_2 for natural gas and 99% conversion of fuel carbon to CO_2 for distillate oil. CO_2 (Natural Gas) [lb/MMBtu] = (0.0036 scf/Btu)(%CON)(C)(D), where %CON = weight percent conversion of fuel carbon to CO_2, C = carbon content of fuel by weight, and D = density of fuel. For natural gas, C is assumed at 75%, and D is assumed at 4.1 E+04 lb/10^6scf. For distillate oil, CO_2 (Distillate Oil) [lb/MMBtu] = (26.4 gal/MMBtu) (%CON)(C)(D), where C is assumed at 87%, and the D is assumed at 6.9 lb/gallon.

[g] Emission factor is carried over from the previous revision to AP-42 (Supplement B, October 1996) and is based on limited source tests on a single turbine with water-steam injection (Reference 5).

[h] All sulfur in the fuel is assumed to be converted to SO_2. S = percent sulfur in fuel. Example, if sulfur content in the fuel is 3.4 percent, then S = 3.4. If S is not available, use 3.4 E-03 lb/MMBtu for natural gas turbines, and 3.3 E-02 lb/MMBtu for distillate oil turbines (the equations are more accurate).

[j] VOC emissions are assumed equal to the sum of organic emissions.

[k] Pollutant referenced as THC in the gathered emission tests. It is assumed as TOC, because it is based on EPA Test Method 25A.

[l] Emission factors are based on combustion turbines using water-steam injection.

TABLE 4-8
SUMMARY OF EMISSION FACTORS FOR DETERMINING ACTUAL EMISSIONS FROM COMBUSTION TURBINES 1-16
JOHNSONVILLE FOSSIL PLANT

Pollutant	Emission Factor, lb/10^6 Btu [HHV]		Reference No.	
	Natural Gas	Fuel Oil	Natural Gas	Fuel Oil
Particulate Matter (PM)	7.00E-03	2.90E-02	manufacturer's data	manufacturer's data
Sulfur Dioxide (SO_2)-Avg	0.0034	0.259	5, see sample calcs	5, see sample calcs
Sulfur Dioxide (SO_2)-Max	0.0034	0.480	5, see sample calcs	5, see sample calcs
Nitrogen Oxides (NO_x)	0.361	0.604	manufacturer's data	manufacturer's data
Carbon Monoxide (CO)	0.0266	0.0266	manufacturer's data	manufacturer's data
Volatile Organic Compounds (VOC)	2.13E-03	5.32E-03	manufacturer's data	manufacturer's data
Sulfuric Acid Mist (H_2SO_4)-Avg	0	0.0209	5, see sample calcs	5, see sample calcs
Sulfuric Acid Mist (H_2SO_4)-Max	0	0.0387	5, see sample calcs	5, see sample calcs
Particulate HAPs				
Antimony (Sb)	1.80E-07	2.20E-05	1	2
Arsenic (As)	2.30E-07	1.10E-05	3	5
Beryllium (Be)	1.00E-08	3.10E-07	3	5
Cadmium (Cd)	4.00E-08	4.80E-06	3	5
Chromium (Cr)	1.10E-06	1.10E-05	3	5
Cobalt (Co)	8.00E-08	9.10E-06	3	2
Lead (Pb)	4.00E-07	1.40E-05	3	5
Manganese (Mn)	4.00E-07	7.90E-04	3	5
Nickel (Ni)	2.40E-06	4.60E-06	3	5
Particulate HAPs Total[a]	4.84E-06	8.67E-04		
Gaseous HAPs				
Hydrogen Chloride (HCl)		3.06E-03		4
Mercury (Hg)	8.00E-10	1.20E-06	3	5
Selenium (Se)	2.00E-08	2.50E-05	3	5
Organic HAPs (CAS Number)				
1,3-Butadiene (106990)	4.30E-07	1.60E-05	5	5
Acetaldehyde (75070)	4.00E-05		5	
Acrolein (107028)	6.40E-06		5	
Benzene (71432)	1.20E-05	5.50E-05	5	5
Ethyl benzene (100414)	3.20E-05		5	
Formaldehyde (50000)	7.10E-04	2.80E-04	5	5
Naphthalene (91203)	1.30E-06	3.50E-05	5	5
Propylene Oxide (75569)	2.90E-05		5	
Toluene (108883)	1.30E-04		5	
Xylenes (1330207)	6.40E-05		5	
Polycyclic Organic Matter (POM)	2.20E-06	4.00E-05	5	5
Organic HAPs Total	1.03E-03	4.26E-04		
Gaseous HAP Total[b]	1.03E-03	3.51E-03		

[a]Particulate HAPs total includes antimony, arsenic, beryllium, cadmium, chromium, cobalt, manganese, and nickel.
[b]Gaseous HAPs total includes HCl, mercury, selenium and Organic HAPs total.

TABLE 4-11
MANUFACTURER'S EMISSION ESTIMATES FOR GE 7001B COMBUSTION TURBINES, PERTINENT OPERATING PARAMETERS AND RELATED DATA

Johnsonville Fossil Plant	Natural Gas	Fuel Oil
Manufacturer's Emission Estimates at 100% Load, 59°F[a]		
NO_x, ppmv (15% O2)	100	155
CO, ppmv	10	10
VOC, ppmv	1.4	3.5
PM, lb/CT-hr	5	20
Heat Input at Peak-Load and Electrical Generation at 0°F Ambient Temperature[b]		
Peak-Load Output, MW/CT	79.8	78.9
Heat Rate, Btu (HHV)/kW-hr	11,065	11,065
Peak-Load Heat Input, 10^6 Btu (HHV)/CT-hr	883	873
Heat Rate, Btu (LHV)/kW-hr	9,968	10,438
Peak-Load Heat Input, 10^6 Btu (LHV)/CT-hr	796	824
Peak-Load Stack Flow, 10^3 ft^3/min	541	535
Design Heat Input at 59°F Ambient Temperature[c]		
Heat Input, 10^6 Btu/hr		749.6
Stack Flow, 10^3 dscfm		459.25
Stack Temperature, °F		1034
Stack H_20, %		3.3
Stack Flow, acfm		1338
Maximum Dependable Capacity (MDC) at 60°F[d]		
Net MDC Output, MW/CT	59.1	57.8
Max Heat Rate, Btu (HHV)/kw-hr	12,154	11,766
MDC Heat Input, 10^6 Btu/CT-hr	718	680
K-value[e]	12.1	13.2
LHV, Btu/lb[e]	20,610	18,330
Ratio of HHV Heat Rate to LHV Heat Rate	1.11	1.06

[a]Fax from S.C. Strunk to J.D. Lokey, 2/23/98
[b]Johnsonville Fossil Plant Title V Application, 11/18/96
[c]Permit Application for Johnsonville Fossil Plant GE 7001B CT units , 5/9/83
[d]Excel file "CT98 Gen Plan copy.xls" in email from S.C. Strunk to J.D. Lokey, 1/14/98
[e]Alternative Control Techniques Document-NO_x Emissions from Stationary Gas Turbines, EPA, January 1993

Determination of Emission Factors (lb/10^6 Btu heat input) from Manufacturer's data.

Manufacturer's data for criteria pollutants is used to estimate emissions. Table 4-11 is a listing of manufacturer's data, pertinent operating parameters and related data that are used to determine emission factors.

PM

From Table 4-11.

1. Manufacturer's emission estimate for TVA's GE MS700 1B at 100% load, 59°F.
   Natural gas: 5 lb/CT-hr
   Fuel oil: 20 lb/CT-hr
2. Maximum Dependable Capacity Heat Input, 60°F
   Natural gas: 718 x 10^6 Btu/CT-hr
   Fuel Oil: 680 x 10^6 Btu/CT-hr

Calculation of Emission factor

Natural gas:

$$\frac{5\ lb}{CT-hr} x \frac{CT-hr}{718\ x\ 10^6\ Btu} = \frac{0.0070\ lb}{10^6\ Btu}$$

Fuel oil:

$$\frac{20\ lb}{CT-hr} x \frac{CT-hr}{680\ x\ 10^6\ Btu} = \frac{0.029\ lb}{10^6\ Btu}$$

NO_x

From Table 4-11.

1. Manufacturer's emission estimate for TVA's GE MS700 1B at 100% load, 59°F.
   Natural gas: 100 ppmvd
   Fuel oil: 155 ppmvd
2. Maximum Dependable Capacity Heat Input, 60°F
   Natural gas: 718 x 10^6 Btu/CT-hr
   Fuel Oil: 680 x 10^6 Btu/CT-hr
3. Generation Output, 60°F
   Natural gas: 59.1 MW/CT
   Fuel oil: 57.8 MW/CT
4. K-value relating ppmvd NO_x to mass of NO_x emissions per mass of fuel input, a constant that depends on the fuel's stoichiometry.
   Natural gas: 12.1 ppmvd/(lb NO_x/10^3 lb fuel)
   Fuel oil: 13.2 ppmvd/(lb NO_x/10^3 lb fuel)

ATTACHMENT 7

EPA LETTER DATED APRIL 6, 2000
ALTERNATIVE MONITORING AND TESTING PROPOSALS FOR COMBUSTION TURBINES
NSPS – 40 CFR 60, SUBPART GG

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
REGION 4
ATLANTA FEDERAL CENTER
61 FORSYTH STREET
ATLANTA, GEORGIA 30303-8960

RECEIVED

APR 0 6 2000

4APT-ARB

Mr. Jeryl W. Stewart
Compliance Validation Program
Department of Environment and Conservation
Division of Air Pollution Control
9th Floor, L&C Annex
401 Church Street
Nashville, Tennessee 37243-1531

SUBJ: Alternative Monitoring and Testing Proposals for Combustion Turbines Located at the Tennessee Valley Authority Gallatin and Johnsonville Facilities

Dear Mr. Stewart:

Thank you for your March 13, 2000, letter requesting a determination regarding several alternative monitoring and testing proposals that the Tennessee Valley Authority (TVA) submitted for four new combustion turbines (CTs) that will be installed at the Gallatin Facility and for eight new CTs that will be installed at the Johnsonville Facility. These CTs will be subject to sulfur dioxide (SO_2) and nitrogen oxides (NO_x) emission limits under 40 C.F.R. Part 60, Subpart GG (Standards of Performance for Stationary Gas Turbines). In addition, they will be subject to NO_x emission limits under the terms of a Prevention of Significant Deterioration (PSD) permit issued by your agency and acid rain monitoring requirements for SO_2 and NO_x pursuant to 40 C.F.R. Part 75. The alternative monitoring and testing proposals from TVA are summarized along with our comments in the remainder of this letter.

SO_2 custom fuel monitoring

Since TVA will not have intermediate bulk storage for the natural gas burned in the CTs at the Gallatin and Johnsonville Facilities, 40 C.F.R. §60.334(b)(2) would require that the company collect gas samples on a daily basis and analyze them for sulfur content. Under the terms of a custom fuel monitoring policy issued by the U.S. Environmental Protection Agency (EPA) Headquarters on August 14, 1987, the sulfur monitoring frequency for pipeline quality natural gas can be reduced from a daily to a semiannual basis. In order to qualify for this reduction, companies must conduct sampling twice a month for six months followed by quarterly sampling for six quarters and demonstrate that the sulfur content of the samples is well below the applicable standard with low variability. TVA asked that it be allowed to use a semiannual sampling frequency immediately upon the startup of the CTs at the Gallatin and Johnsonville Facilities, and in a July 8, 1999, letter to you we indicated that TVA would have to provide historical data on the sulfur content of the natural gas from its fuel supplier(s) in order to justify an immediate reduction the sulfur monitoring frequency for natural gas burned in the CTs at the Gallatin and Johnsonville Facilities.

Based upon data provided by TVA in a February 22, 2000, letter that was enclosed with your request, it will be acceptable for the company to use a semiannual sulfur monitoring frequency for natural gas immediately upon startup at the Gallatin and Johnsonville Facilities. The data for Gallatin were for 35 samples collected between January 1998 and January 1999, and the data for Johnsonville were for 22 samples collected between January 1995 and September 1999. In all cases, the sulfur content of the samples analyzed was either at or below the method detection limit of 0.0001 weight percent. This concentration is three order of magnitude below the applicable standard of 0.8 weight percent in 40 C.F.R. §60.333(b), and the results confirm low variability in the sulfur concentration of the gas supplied to TVA. On this basis, semiannual monitoring for sulfur content in the gas used to fire the CTs at the Gallatin and Johnsonville Facilities will be adequate.

Use of NO_x monitor data for initial performance test

TVA made two different proposals involving NO_x emission testing that must be conducted in order to demonstrate compliance with both Subpart GG and PSD limits. One proposal is to drop the requirement to sample at four different load points across the CTs' operating ranges, and the other one is to demonstrate compliance using data from certified continuous emission monitoring systems (CEMS) that will be installed on the units. Based upon the fact that NO_x CEMS will be installed and certified on the CTs at Gallatin and Johnsonville, conducting the initial performance test at four different operating rates will not be necessary, and using the CEMS to conduct the initial performance test would be acceptable under certain conditions.

TVA cited the fact that NO_x emissions at the Gallatin and Johnsonville Facilities will not be controlled using water injection as the basis for dropping the requirement to test at four operation loads, but this fact does not by itself constitute a basis for allowing the company to conduct the initial performance test at fewer than four loads. The basis for this position is that, in addition to providing data to develop a water-to-fuel injection ratio curve for excess emission monitoring purposes, conducting a four-load test also provides assurance that a turbine is capable of complying with the applicable NO_x limit across the unit's entire operating range. This assurance is important because EPA generally requires that performance testing be conducted under "worst case" conditions, and Region 4 experience has been that predicting the operating load that represents worst case conditions for stationary gas turbines is difficult. In TVA's case, however, the CEMS installed and certified on its CTs will provide credible evidence of compliance even after the initial performance test has been completed. Therefore, conducting the initial performance test at multiple loads will not be necessary.

Using the certified NO_x CEMS to conduct the initial performance test would be acceptable provided that TVA completes certification testing which verifies that its CEMS sampling probes are located in representative locations and conducts pre- and post-test calibration checks of the CEMS in accordance with the provisions in EPA Method 20. If the CEMS are calibrated properly before and after each test run, using the CEMS to conduct the NO_x performance test would constitute a Method 20 alternative only to the extent that sampling would be conducted at a single point, rather than at eight points selected based upon the results of a pre-test traverse. In order to be certified under the acid rain rule, the CEMS must pass a relative accuracy test audit (RATA), and passing the RATA provides justification for single point sampling by demonstrating that the CEMS probe is located at points where the pollutant and diluent gas concentrations are representative of the average concentrations in the stack.

One issue that was not addressed in the TVA proposal was the number and duration of test runs that would be conducted with the CEMS. In order to ensure that representative results are obtained, we recommend that compliance be determined on the basis of at least three hours of CEMS data for each of the CTs at the Gallatin and Johnsonville Facilities. These data could be collected over three one-periods or they could be collected using shorter test periods similar to the 21-minute test runs conducted during a RATA. Regardless of the number of test runs conducted, however, a calibration check conducted in accordance with Section 6.2.3 of Method 20 must be performed on the CEMS following each run.

Fuel oil nitrogen content monitoring

TVA asked that the requirement in 40 C.F.R. §60.334(b) to monitor the nitrogen content of the fuel oil burned in its CTs be waived. Under Subpart GG, the two operating parameters used to track NO_x excess are water-to-fuel injection rates and fuel nitrogen content. Baseline values for both parameters are established during an initial performance test, and 40 C.F.R. §60.334(c)(1) defines how excess emissions are identified in terms of these parameters. TVA will be installing, certifying, operating, and maintaining NO_x CEMS on its CTs in order to comply with requirements under 40 C.F.R. Part 75 and will also be using these CEMS to track excess emissions under Subpart GG. Since TVA will be monitoring NO_x excess emissions directly using its CEMS, monitoring the nitrogen content of the oil burned in the CTs is unnecessary, and the waiver requested by the company is acceptable.

Correcting NOx data to International Standard Organization (ISO) conditions

The enclosed March 12, 1993, EPA determination summarizes requirements for CEMS that are used for NO_x excess emission monitoring under Subpart GG, and one of these requirements is that the CEMS be capable of calculating emissions corrected to 15 percent oxygen and ISO standard day conditions (288 Kelvin, 60 percent relative humidity, and 101.3 kilopascals pressure). In several recent determinations, Region 4 has indicated that making the ISO correction on a continuous basis is not necessary for turbines that are subject to PSD NO_x limits that are substantially more stringent than those under Subpart GG. In these determinations, Region 4 has indicated, however, that records of the ambient temperature and humidity data used to correct the results to ISO conditions must be maintained so that results can be calculated in terms of the standard in Subpart GG whenever requested by the EPA or a state or local air pollution control agency.

In addition to requesting that a correction to ISO day conditions not be required for its CTs, TVA requested that the requirement to maintain records of the ambient data used to make the ISO correction also be waived. The justification provided for this proposal was that the PSD NO_x limits for its CTs (15 parts per million for gas and 42 parts per million for oil) are so far below the standard in Subpart GG (75 parts per million) that NSPS compliance will be assured even if the ISO correction is not made. Although we have determined that it will not be necessary for TVA's CEMS to correct results to ISO conditions on a continuous basis, there is not enough information at this time to justify waiving the requirement to keep records of the ambient data used to make the ISO correction.

One basis for our conclusion that there is not enough information to justify waiving the requirement to keep records of the data used to make the ISO correction is that, even though TVA's PSD limits are tighter than the corresponding NSPS limit, this assures compliance with Subpart GG only to the extent that the company remains in compliance with the PSD limits. If the company does ever violate either of its PSD limits, there would be a point at which it would be necessary to correct results to ISO conditions in order to verify NSPS compliance. A second basis for our conclusion that there is not enough information to justify waiving the requirement to keep records of the data used to make the ISO correction is that the averaging time for the PSD limit (30 days) is substantially longer than the averaging time of the NSPS limit (one hour). Because of this difference in averaging times, meeting the long-term PSD limit does not necessarily assure compliance with the short-term ISO-corrected NSPS limit. Therefore, a waiver of the requirement to maintain records of the data used to make the ISO correction cannot be granted at this time. We would, however, be willing to reconsider this issue at a later date if TVA collects at least one year of operating data verifying that emissions from its CTs are always well below the applicable ISO-corrected NSPS limits based upon a one-hour average.

Fuel oil sulfur monitoring

According to 40 C.F.R. §60.334(b)(1) the sulfur content of fuel held in a bulk storage tank must be determined each time fuel is transferred to the tank from any other source. At the Gallatin and Johnsonville Facilities, the amount of sampling that would have to be conducted in order to comply with this requirement would be limited since oil is transferred into the storage tanks at both facilities from barges. At another facility where TVA plans to install CTs, oil will be delivered in tanker trucks, and using the procedures in 40 C.F.R. §60.334(b)(1) to monitor the sulfur content of the oil at this facility would be burdensome because TVA would have to collect and analyze a sample after each tanker truck delivery. Therefore, TVA has proposed to use vendor analyses, rather than onsite sampling to monitor the sulfur content of the oil burned at the facility.

Provided that all of the oil delivered to the facility in question meets the sulfur content limit of 0.8 weight percent promulgated at 40 C.F.R. §60.333(b), TVA's proposal for monitoring the sulfur content of the oil used to fire the CTs at this facility will be acceptable. The basis for this determination is that if all of the oil delivered to the facility has a sulfur content of less than 0.8 weight percent, the oil contained in the storage tank and used to fire the CTs will meet the applicable standard by default. If the sulfur content of any oil delivered to the facility exceeds the applicable standard, it would be necessary to collect and analyze samples from the storage tank to ensure that the average sulfur content of the oil burned is less than 0.8 weight percent. This issue is not expected to be a concern at the facility in question, however, because the American Society for Testing and Materials limit on the sulfur content of distillate oil (0.5 weight percent) is well below the standard in Subpart GG.

If you have any questions about the issues addressed in this letter, please contact Mr. David McNeal of the EPA Region 4 staff at (404) 562-9102.

Sincerely,

Douglas Neeley

R. Douglas Neeley
Chief
Air and Radiation Technology Branch
Air, Pesticides and Toxics
Management Division

Enclosure

(1) March 12, 1993, EPA policy on the use of CEMS for excess emission monitoring under Subpart GG

ATTACHMENT 8

AEAR Fee Related Recordkeeping Requirements

SM1

43-0011 Recordkeeping for NO_X Emissions for fee purposes - JOF

Source 43-0011	Emission Determination method	Notes
01-10 Boilers	NO_X emissions monitoring data as specified by the Part 75 requirements of condition E3-1.	
11-26 Combustion Turbine Plant – 16 Units	NO_X emissions monitoring data as specified by Part 75.	
28 Two Auxiliary Heating Boilers (No. 2 fuel oil fired)	The following NO_X emission factor shall be used in combination with records of heat input and fuel usage for determination of emissions Emission Factor: 24 lb/thousand gallons No. 2 fuel oil	AP-42 Table 1.3-1.
32 Combustion Turbine Plant – 4 Units	NO_X emissions monitoring data as specified by the Part 75 requirements of condition E8-13.	
33 Gas Fired Heaters	The following NO_X emission factor shall be used in combination with records of heat input and fuel usage for all units. Emission Factor: 100 pounds NO_X/million cubic feet of Gas combusted	AP-42 Table 1.4-1.
35 Natural Gas-Fired Combustion Turbine with Heat Recovery Steam Generator (SM1)	NO_X emissions monitoring data as specified by the Part 75 requirements of condition E10-7.	
36-37 Two natural gas-fired auxiliary boilers (SM1)	NO_X emissions monitoring data as specified by the requirements of condition E11-6.	

43-0011 Record-keeping for VOC Emissions for fee purposes - JOF

Source 43-0011	Emission Determination method	Notes
01-10 Boilers	The following VOC emission factor shall be used in combination with records of heat input and fuel usage for determination of emissions Emission Factors: 0.06 lb/ton coal burned 0.2 lb/thousand gallons No. 2 fuel oil	Application, Table 3-7
11-26 Combustion Turbine Plant – 16 Units	The following VOC emission factor shall be used in combination with records of heat input and fuel usage for determination of emissions Emission Factor: 5.5 lb VOC/million cubic feet of Gas combusted	AP-42 Table 1.4-2.
28 Two Auxiliary Heating Boilers (No. 2 fuel oil fired)	The following VOC emission factor shall be used in combination with records of heat input and fuel usage for determination of emissions Emission Factor: 0.2 lb/thousand gallons No. 2 fuel oil	AP-42 Table 1.3-3; Industrial distillate-fired boilers, NMTOC.
32 Combustion Turbine Plant – 4 Units	The following VOC emission factor shall be used in combination with records of heat input and fuel usage for determination of emissions Emission Factor: 5.5 lb VOC/million cubic feet of Gas combusted	AP-42 Table 1.4-2.
33 Gas Fired Heaters	The following VOC emission factor shall be used in combination with records of heat input and fuel usage for determination of emissions Emission Factor: 5.5 lb VOC/million cubic feet of Gas combusted	AP-42 Table 1.4-2.
35 Natural Gas-Fired Combustion Turbine with Heat Recovery Steam Generator (SM1)	The following VOC emission factor shall be used in combination with records of heat input and fuel usage for determination of emissions Emission Factor: 5.5 lb VOC/million cubic feet of Gas combusted	AP-42 Table 1.4-2.
36-37 Two natural gas-fired auxiliary boilers (SM1)	The following VOC emission factor shall be used in combination with records of heat input and fuel usage for determination of emissions Emission Factor: 5.5 lb VOC/million cubic feet of Gas combusted	AP-42 Table 1.4-2.

ATTACHMENT 9

CROSS-STATE AIR POLLUTION RULE REQUIREMENTS

Cross-State Air Pollution Rule (CSAPR) Trading Program Title V Requirements

Description of CSAPR Monitoring Provisions

The CSAPR subject unit(s), and the unit-specific monitoring provisions at this source, are identified in the following table(s). These unit(s) are subject to the requirements for the CSAPR NO_X Annual Trading Program, CSAPR NO_X Ozone Season Trading Programs (Group 1 and Group 2), and CSAPR SO_2 Group 1 Trading Program.

Unit ID:					
Parameter	**CEMS requirements pursuant to 40 CFR part 75, Subparts B (SO_2 monitoring) and H (NO_X monitoring)**	**Excepted monitoring system requirements for gas- and oil-fired units pursuant to 40 CFR 75, Appendix D**	**Excepted monitoring system requirements for gas- and oil-fired peaking units pursuant to 40 CFR 75, Appendix E**	**Low Mass Emissions excepted monitoring (LME) requirements for gas- and oil-fired units pursuant to §75.19**	**EPA-approved alternative monitoring system requirements pursuant to 40 CFR 75 Subpart E**
SO_2	X		----------------		
NO_X	X	-------------			
Heat Input	X		----------------		

1. The above description of the monitoring used by a unit does not change, create an exemption from, or otherwise affect the monitoring, recordkeeping, and reporting requirements applicable to the unit under 40 CFR §§97.430 through 97.435" *CSAPR NO_X Annual Trading Program),* §§97.530 through 97.535 *(CSAPR NO_X Ozone Season Group 1 Trading Program),* and §§97.630 through 97.635 *(CSAPR SO_2 Group 1 Trading Program)*. The monitoring, recordkeeping and reporting requirements applicable to each unit are included below in the standard conditions for the applicable CSAPR trading programs.

2. Owners and operators must submit to the Administrator a monitoring plan for each unit in accordance with §§75.53, 75.62 and 75.73, as applicable. The monitoring plan for each unit is available at the EPA's website at http://www.epa.gov/airmarkets/emissions/monitoringplans.html.

3. Owners and operators that want to use an alternative monitoring system must submit to the Administrator a petition requesting approval of the alternative monitoring system in accordance with 40 CFR 75 Subpart E and §75.66 and §97.435, §97.535, and §97.635, as applicable. The Administrator's response approving or disapproving any petition for an alternative monitoring system is available on the EPA's website at http://www.epa.gov/airmarkets/emissions/petitions.html.

4. Owners and operators that want to use an alternative to any monitoring, recordkeeping, or reporting requirement under 40 CFR §§97.430 through 97.434, §§97.530 through 97.534, or §§97.630 through 97.634 must submit to the Administrator a petition requesting approval of the alternative in accordance with §75.66 and §97.435, §97.535, and §97.635, as applicable. The Administrator's response approving or disapproving any petition for an alternative to a monitoring, recordkeeping, or reporting requirement is available on EPA's website at http://www.epa.gov/airmarkets/emissions/petitions.html.

5. The descriptions of monitoring applicable to the unit included above meet the requirements of §§97.430 through 97.434, §§97.530 through 97.534, and §§97.630 through 97.634, as applicable, and minor permit modification procedures, in accordance with §70.7(e)(2)(i)(B) or §71.7(e)(1)(i)(B), may be used to add to or change this unit's monitoring system description.

CSAPR NO_X Annual Trading Program requirements (40 CFR 97.406)

(a) Designated representative requirements. The owners and operators shall comply with the requirement to have a designated representative, and may have an alternate designated representative, in accordance with 40 CFR 97.413 through 97.418.

(b) Emissions monitoring, reporting, and recordkeeping requirements.

(1) The owners and operators, and the designated representative, of each CSAPR NO_X Annual source and each CSAPR NO_X Annual unit at the source shall comply with the monitoring, reporting, and recordkeeping requirements of 40 CFR 97.430 (general requirements, including installation, certification, and data accounting, compliance deadlines, reporting data, prohibitions, and long-term cold storage), 97.431 (initial monitoring system certification and recertification procedures), 97.432 (monitoring system out-of-control periods), 97.433 (notifications concerning monitoring), 97.434 (recordkeeping and reporting, including monitoring plans, certification applications, quarterly reports, and compliance certification), and 97.435 (petitions for alternatives to monitoring, recordkeeping, or reporting requirements).

(2) The emissions data determined in accordance with 40 CFR 97.430 through 97.435 shall be used to calculate allocations of CSAPR NO_X Annual allowances under 40 CFR 97.411(a)(2) and (b) and 97.412 and to determine compliance with the CSAPR NO_X Annual emissions limitation and assurance provisions under paragraph (c) below, provided that, for each monitoring location from which mass emissions are reported, the mass emissions amount used in calculating such allocations and determining such compliance shall be the mass emissions amount for the monitoring location determined in accordance with 40 CFR 97.430 through 97.435 and rounded to the nearest ton, with any fraction of a ton less than 0.50 being deemed to be zero.

(c) NO_X emissions requirements.

(1) CSAPR NO_X Annual emissions limitation.

(i) As of the allowance transfer deadline for a control period in a given year, the owners and operators of each CSAPR NO_X Annual source and each CSAPR NO_X Annual unit at the source shall hold, in the source's compliance account, CSAPR NO_X Annual allowances available for deduction for such control period under 40 CFR 97.424(a) in an amount not less than the tons of total NO_X emissions for such control period from all CSAPR NO_X Annual units at the source.

(ii) If total NO_X emissions during a control period in a given year from the CSAPR NO_X Annual units at a CSAPR NO_X Annual source are in excess of the CSAPR NO_X Annual emissions limitation set forth in paragraph (c)(1)(i) above, then:

(A) The owners and operators of the source and each CSAPR NO_X Annual unit at the source shall hold the CSAPR NO_X Annual allowances required for deduction under 40 CFR 97.424(d); and

(B) The owners and operators of the source and each CSAPR NO_X Annual unit at the source shall pay any fine, penalty, or assessment or comply with any other remedy imposed, for the same violations, under the Clean Air Act, and each ton of such excess emissions and each day of such control period shall constitute a separate violation of 40 CFR part 97, subpart AAAAA and the Clean Air Act.

(2) CSAPR NO_X Annual assurance provisions.

(i) If total NO_X emissions during a control period in a given year from all CSAPR NO_X Annual units at CSAPR NO_X Annual sources in the state exceed the state assurance level, then the owners and operators of such sources and units in each group of one or more sources and units having a common designated representative for such control period, where the common designated representative's share of such NO_X emissions during such control period exceeds the common designated representative's assurance level for the state and such control period, shall hold (in the assurance account established for the owners and operators of such group) CSAPR NO_X Annual allowances available for deduction for such control period under 40 CFR 97.425(a) in an amount equal to two times the product (rounded to the nearest whole number), as determined by the Administrator in accordance with 40 CFR 97.425(b), of multiplying— (A) The quotient of the amount by which the common designated representative's share of such NO_X emissions exceeds the common designated representative's assurance level divided by the sum of the amounts, determined for all common designated representatives for such sources and units in the state for such control period, by which each common designated representative's share of such NO_X emissions exceeds the respective common designated representative's assurance level; and (B) The amount by which total NO_X emissions from all CSAPR NO_X Annual units at CSAPR NO_X Annual sources in the state for such control period exceed the state assurance level.

(ii) The owners and operators shall hold the CSAPR NO_X Annual allowances required under paragraph (c)(2)(i) above, as of midnight of November 1 (if it is a business day), or midnight of the first business day thereafter (if November 1 is not a business day), immediately after such control period.

(iii) Total NO_X emissions from all CSAPR NO_X Annual units at CSAPR NO_X Annual sources in the State during a control period in a given year exceed the state assurance level if such total NO_X emissions exceed the sum, for such control period, of the state NO_X Annual trading budget under 40 CFR 97.410(a) and the state's variability limit under 40 CFR 97.410(b).

(iv) It shall not be a violation of 40 CFR part 97, subpart AAAAA or of the Clean Air Act if total NO_X emissions from all CSAPR NO_X Annual units at CSAPR NO_X Annual sources in the State during a control period exceed the state assurance level or if a common designated representative's share of total NO_X emissions from the CSAPR NO_X Annual units at CSAPR NO_X Annual sources in the state during a control period exceeds the common designated representative's assurance level.

(v) To the extent the owners and operators fail to hold CSAPR NO_X Annual allowances for a control period in a given year in accordance with paragraphs (c)(2)(i) through (iii) above,

(A) The owners and operators shall pay any fine, penalty, or assessment or comply with any other remedy imposed under the Clean Air Act; and

(B) Each CSAPR NO_X Annual allowance that the owners and operators fail to hold for such control period in accordance with paragraphs (c)(2)(i) through (iii) above and each day of such control period shall constitute a separate violation of 40 CFR part 97, subpart AAAAA and the Clean Air Act.

(3) Compliance periods.

(i) A CSAPR NO_X Annual unit shall be subject to the requirements under paragraph (c)(1) above for the control period starting on the later of January 1, 2015, or the deadline for meeting the unit's monitor certification requirements under 40 CFR 97.430(b) and for each control period thereafter.

(ii) A CSAPR NO_X Annual unit shall be subject to the requirements under paragraph (c)(2) above for the control period starting on the later of January 1, 2017 or the deadline for meeting the unit's monitor certification requirements under 40 CFR 97.430(b) and for each control period thereafter.

(4) Vintage of allowances held for compliance.

(i) A CSAPR NO_X Annual allowance held for compliance with the requirements under paragraph (c)(1)(i) above for a control period in a given year must be a CSAPR NO_X Annual allowance that was allocated for such control period or a control period in a prior year.

(ii) A CSAPR NO_X Annual allowance held for compliance with the requirements under paragraphs (c)(1)(ii)(A) and (2)(i) through (iii) above for a control period in a given year must be a CSAPR NO_X Annual allowance that was allocated for a control period in a prior year or the control period in the given year or in the immediately following year.

(5) Allowance Management System requirements. Each CSAPR NO_X Annual allowance shall be held in, deducted from, or transferred into, out of, or between Allowance Management System accounts in accordance with 40 CFR part 97, subpart AAAAA.

(6) Limited authorization. A CSAPR NO_X Annual allowance is a limited authorization to emit one ton of NO_X during the control period in one year. Such authorization is limited in its use and duration as follows:

(i) Such authorization shall only be used in accordance with the CSAPR NO_X Annual Trading Program; and

(ii) Notwithstanding any other provision of 40 CFR part 97, the Administrator has the authority to terminate or limit the use and duration of such authorization to the extent the Administrator determines is necessary or appropriate to implement any provision of the Clean Air Act.

(7) Property right. A CSAPR NO_X Annual allowance does not constitute a property right.

(d) Title V permit revision requirements.

(1) No title V permit revision shall be required for any allocation, holding, deduction, or transfer of CSAPR NO_X Annual allowances in accordance with 40 CFR part 97, subpart AAAAA.

(2) This permit incorporates the CSAPR emissions monitoring, recordkeeping and reporting requirements pursuant to 40 CFR 97.430 through 97.435, and the requirements for a continuous emission monitoring system (pursuant to 40 CFR part 75, subparts B and H), an excepted monitoring system (pursuant to 40 CFR part 75, appendices D and E), a low mass emissions excepted monitoring methodology (pursuant to 40 CFR 75.19), and an alternative monitoring system (pursuant to 40 CFR part 75, subpart E). Therefore, the Description of CSAPR Monitoring Provisions table for units identified in this permit may be added to, or changed, in this title V permit using minor permit modification procedures in accordance with 40 CFR 97.406(d)(2) and 70.7(e)(2)(i)(B) or 71.7(e)(1)(i)(B).

(e) Additional recordkeeping and reporting requirements.

(1) Unless otherwise provided, the owners and operators of each CSAPR NO_X Annual source and each CSAPR NO_X Annual unit at the source shall keep on site at the source each of the following documents (in hardcopy or electronic format) for a period of 5 years from the date the document is created. This period may be extended for cause, at any time before the end of 5 years, in writing by the Administrator.

(i). The certificate of representation under 40 CFR 97.416 for the designated representative for the source and each CSAPR NO_X Annual unit at the source and all documents that demonstrate the truth of the statements in the certificate of representation; provided that the certificate and documents shall be retained on site at the source beyond such 5-year period until such certificate of representation and documents are superseded because of the submission of a new certificate of representation under 40 CFR 97.416 changing the designated representative.

(ii). All emissions monitoring information, in accordance with 40 CFR part 97, subpart AAAAA.

(iii). Copies of all reports, compliance certifications, and other submissions and all records made or required under, or to demonstrate compliance with the requirements of, the CSAPR NO_X Annual Trading Program.

(2) The designated representative of a CSAPR NO_X Annual source and each CSAPR NO_X Annual unit at the source shall make all submissions required under the CSAPR NO_X Annual Trading Program, except as provided in 40 CFR 97.418. This requirement does not change, create an exemption from, or otherwise affect the responsible official submission requirements under a title V operating permit program in 40 CFR parts 70 and 71.

(f) Liability.

(1) Any provision of the CSAPR NO_X Annual Trading Program that applies to a CSAPR NO_X Annual source or the designated representative of a CSAPR NO_X Annual source shall also apply to the owners and operators of such source and of the CSAPR NO_X Annual units at the source.

(2) Any provision of the CSAPR NO_X Annual Trading Program that applies to a CSAPR NO_X Annual unit or the designated representative of a CSAPR NO_X Annual unit shall also apply to the owners and operators of such unit.

(g) Effect on other authorities. No provision of the CSAPR NO_X Annual Trading Program or exemption under 40 CFR 97.405 shall be construed as exempting or excluding the owners and operators, and the designated representative, of a CSAPR NO_X Annual source or CSAPR NO_X Annual unit from compliance with any other provision of the applicable, approved state implementation plan, a federally enforceable permit, or the Clean Air Act.

CSAPR NO_X Ozone Season Group 1 Trading Program Requirements (40 CFR §97.506)

(a) Designated representative requirements. The owners and operators shall comply with the requirement to have a designated representative, and may have an alternate designated representative, in accordance with 40 CFR 97.513 through 97.518.

(b) Emissions monitoring, reporting, and recordkeeping requirements.

(1) The owners and operators, and the designated representative, of each CSAPR NO_X Ozone Season Group 1 source and each CSAPR NO_X Ozone Season Group 1 unit at the source shall comply with the monitoring, reporting, and recordkeeping requirements of 40 CFR 97.530 (general requirements, including installation, certification, and data accounting, compliance deadlines, reporting data, prohibitions, and long-term cold storage), 97.531 (initial monitoring system certification and recertification procedures), 97.532 (monitoring system out-of-control periods), 97.533 (notifications concerning monitoring), 97.534 (recordkeeping and reporting, including monitoring plans, certification applications, quarterly reports, and compliance certification), and 97.535 (petitions for alternatives to monitoring, recordkeeping, or reporting requirements).

(2) The emissions data determined in accordance with 40 CFR 97.530 through 97.535 shall be used to calculate allocations of CSAPR NO_X Ozone Season Group 1 allowances under 40 CFR 97.511(a)(2) and (b) and 97.512 and to determine compliance with the CSAPR NO_X Ozone Season Group 1 emissions limitation and assurance provisions under paragraph (c) below, provided that, for each monitoring location from which mass emissions are reported, the mass emissions amount used in calculating such allocations and determining such compliance shall be the mass emissions amount for the monitoring location determined in accordance with 40 CFR 97.530 through 97.535 and rounded to the nearest ton, with any fraction of a ton less than 0.50 being deemed to be zero.

(c) NO_X emissions requirements.

(1) CSAPR NO_X Ozone Season Group 1 emissions limitation.

(i) As of the allowance transfer deadline for a control period in a given year, the owners and operators of each CSAPR NO_X Ozone Season Group 1 source and each CSAPR NO_X Ozone Season Group 1 unit at the source shall hold, in the source's compliance account, CSAPR NO_X Ozone Season Group 1 allowances available for deduction for such control period under 40 CFR 97.524(a) in an amount not less than the tons of total NO_X emissions for such control period from all CSAPR NO_X Ozone Season Group 1 units at the source.

(ii) If total NO_X emissions during a control period in a given year from the CSAPR NO_X Ozone Season Group 1 units at a CSAPR NO_X Ozone Season Group 1 source are in excess of the CSAPR NO_X Ozone Season Group 1 emissions limitation set forth in paragraph (c)(1)(i) above, then:

(A) The owners and operators of the source and each CSAPR NO_X Ozone Season Group 1 unit at the source shall hold the CSAPR NO_X Ozone Season Group 1 allowances required for deduction under 40 CFR 97.524(d); and

(B) The owners and operators of the source and each CSAPR NO_X Ozone Season Group 1 unit at the source shall pay any fine, penalty, or assessment or comply with any other remedy imposed, for the same violations, under the Clean Air Act, and each ton of such excess emissions and each day of such control period shall constitute a separate violation of 40 CFR part 97, subpart BBBBB and the Clean Air Act.

(2) CSAPR NO_X Ozone Season Group 1 assurance provisions.

(i) If total NO_X emissions during a control period in a given year from all CSAPR NO_X Ozone Season Group 1 units at CSAPR NO_X Ozone Season Group 1 sources in the state exceed the state assurance level, then the owners and operators of such sources and units in each group of one or more sources and units having a common designated representative for such control period, where the common designated representative's share of such NO_X emissions during such control period exceeds the common designated representative's assurance level for the state and such control period, shall hold (in the assurance account established for the owners and operators of such group) CSAPR NO_X Ozone Season Group 1 allowances available for deduction for such control period under 40 CFR 97.525(a) in an amount equal to two times the product (rounded to the nearest whole number), as determined by the Administrator in accordance with 40 CFR 97.525(b), of multiplying—

(A) The quotient of the amount by which the common designated representative's share of such NO_X emissions exceeds the common designated representative's assurance level divided by the sum of the amounts, determined for all common designated representatives for such sources and units in the state for such control period, by which each common designated representative's share of such NO_X emissions exceeds the respective common designated representative's assurance level; and

(B) The amount by which total NO_X emissions from all CSAPR NO_X Ozone Season Group 1 units at CSAPR NO_X Ozone Season Group 1 sources in the state for such control period exceed the state assurance level.

(ii) The owners and operators shall hold the CSAPR NO_X Ozone Season Group 1 allowances required under paragraph (c)(2)(i) above, as of midnight of November 1 (if it is a business day), or midnight of the first business day thereafter (if November 1 is not a business day), immediately after such control period.

(iii) Total NO_X emissions from all CSAPR NO_X Ozone Season Group 1 units at CSAPR NO_X Ozone Season Group 1 sources in the state during a control period in a given year exceed the state assurance level if such total NO_X emissions exceed the sum, for such control period, of the State NO_X Ozone Season Group 1 trading budget under 40 CFR 97.510(a) and the state's variability limit under 40 CFR 97.510(b).

(iv) It shall not be a violation of 40 CFR part 97, subpart BBBBB or of the Clean Air Act if total NO_X emissions from all CSAPR NO_X Ozone Season Group 1 units at CSAPR NO_X Ozone Season Group 1 sources in the state during a control period exceed the state assurance level or if a common designated representative's share of total NO_X emissions from the CSAPR NO_X Ozone Season Group 1 units at CSAPR NO_X Ozone Season Group 1 sources in the state during a control period exceeds the common designated representative's assurance level.

(v) To the extent the owners and operators fail to hold CSAPR NO_X Ozone Season Group 1 allowances for a control period in a given year in accordance with paragraphs (c)(2)(i) through (iii) above,

(A) The owners and operators shall pay any fine, penalty, or assessment or comply with any other remedy imposed under the Clean Air Act; and

(B) Each CSAPR NO_X Ozone Season Group 1 allowance that the owners and operators fail to hold for such control period in accordance with paragraphs (c)(2)(i) through (iii) above and each day of such control period shall constitute a separate violation of 40 CFR part 97, subpart BBBBB and the Clean Air Act.

(3) Compliance periods.

(i) A CSAPR NO_X Ozone Season Group 1 unit shall be subject to the requirements under paragraph (c)(1) above for the control period starting on the later of May 1, 2015 or the deadline for meeting the unit's monitor certification requirements under 40 CFR 97.530(b) and for each control period thereafter.

(ii) A CSAPR NO_X Ozone Season Group 1 unit shall be subject to the requirements under paragraph (c)(2) above for the control period starting on the later of May 1, 2017 or the deadline for meeting the unit's monitor certification requirements under 40 CFR 97.530(b) and for each control period thereafter.

(4) Vintage of allowances held for compliance.

(i) A CSAPR NO_X Ozone Season Group 1 allowance held for compliance with the requirements under paragraph (c)(1)(i) above for a control period in a given year must be a CSAPR NO_X Ozone Season Group 1 allowance that was allocated for such control period or a control period in a prior year.

(ii) A CSAPR NO_X Ozone Season Group 1 allowance held for compliance with the requirements under paragraphs (c)(1)(ii)(A) and (2)(i) through (iii) above for a control period in a given year must be a CSAPR NO_X Ozone Season Group 1 allowance that was allocated for a control period in a prior year or the control period in the given year or in the immediately following year.

(5) Allowance Management System requirements. Each CSAPR NO_X Ozone Season Group 1 allowance shall be held in, deducted from, or transferred into, out of, or between Allowance Management System accounts in accordance with 40 CFR part 97, subpart BBBBB.

(6) Limited authorization. A CSAPR NO_X Ozone Season Group 1 allowance is a limited authorization to emit one ton of NO_X during the control period in one year. Such authorization is limited in its use and duration as follows:

(i) Such authorization shall only be used in accordance with the CSAPR NO_X Ozone Season Group 1 Trading Program; and

(ii) Notwithstanding any other provision of 40 CFR part 97, subpart BBBBB, the Administrator has the authority to terminate or limit the use and duration of such authorization to the extent the Administrator determines is necessary or appropriate to implement any provision of the Clean Air Act.

(7) Property right. A CSAPR NO_X Ozone Season Group 1 allowance does not constitute a property right.

(d) Title V permit revision requirements.

(1) No title V permit revision shall be required for any allocation, holding, deduction, or transfer of CSAPR NO_X Ozone Season Group 1 allowances in accordance with 40 CFR part 97, subpart BBBBB.

(2) This permit incorporates the CSAPR emissions monitoring, recordkeeping and reporting requirements pursuant to 40 CFR 97.530 through 97.535, and the requirements for a continuous emission monitoring system (pursuant to 40 CFR part 75, subparts B and H), an excepted monitoring system (pursuant to 40 CFR part 75, appendices D and E), a low mass emissions excepted monitoring methodology (pursuant to 40 CFR 75.19), and an alternative monitoring system (pursuant to 40 CFR part 75, subpart E). Therefore, the Description of CSAPR Monitoring Provisions table for units identified in this permit may be added to, or changed, in this title V permit using minor permit modification procedures in accordance with 40 CFR 97.506(d)(2) and 70.7(e)(2)(i)(B) or 71.7(e)(1)(i)(B).

(e) Additional recordkeeping and reporting requirements.

(1) Unless otherwise provided, the owners and operators of each CSAPR NO_X Ozone Season Group 1 source and each CSAPR NO_X Ozone Season Group 1 unit at the source shall keep on site at the source each of the following documents (in hardcopy or electronic format) for a period of 5 years from the date the document is created. This period may be extended for cause, at any time before the end of 5 years, in writing by the Administrator.

(i). The certificate of representation under 40 CFR 97.516 for the designated representative for the source and each CSAPR NO_X Ozone Season Group 1 unit at the source and all documents that demonstrate the truth of the statements in the certificate of representation; provided that the certificate and documents shall be retained on site at the source beyond such 5-year period until such certificate of representation and documents are superseded because of the submission of a new certificate of representation under 40 CFR 97.516 changing the designated representative.

(ii). All emissions monitoring information, in accordance with 40 CFR part 97, subpart BBBBB.

(iii). Copies of all reports, compliance certifications, and other submissions and all records made or required under, or to demonstrate compliance with the requirements of, the CSAPR NO_X Ozone Season Group 1 Trading Program.

(2) The designated representative of a CSAPR NO_X Ozone Season Group 1 source and each CSAPR NO_X Ozone Season Group 1 unit at the source shall make all submissions required under the CSAPR NO_X Ozone Season Group 1 Trading Program, except as provided in 40 CFR 97.518. This requirement does not change, create an exemption from, or otherwise affect the responsible official submission requirements under a title V operating permit program in 40 CFR parts 70 and 71.

(f) Liability.

(1) Any provision of the CSAPR NO_X Ozone Season Group 1 Trading Program that applies to a CSAPR NO_X Ozone Season Group 1 source or the designated representative of a CSAPR NO_X Ozone Season Group 1 source shall also apply to the owners and operators of such source and of the CSAPR NO_X Ozone Season Group 1 units at the source.

(2) Any provision of the CSAPR NO_X Ozone Season Group 1 Trading Program that applies to a CSAPR NO_X Ozone Season Group 1 unit or the designated representative of a CSAPR NO_X Ozone Season Group 1 unit shall also apply to the owners and operators of such unit.

(g) Effect on other authorities. No provision of the CSAPR NO_X Ozone Season Group 1 Trading Program or exemption under 40 CFR 97.505 shall be construed as exempting or excluding the owners and operators, and the designated representative, of a CSAPR NO_X Ozone Season Group 1 source or CSAPR NO_X Ozone Season Group 1 unit from compliance with any other provision of the applicable, approved state implementation plan, a federally enforceable permit, or the Clean Air Act.

CSAPR SO_2 Group 1 Trading Program requirements (40 CFR 97.606)

(a) Designated representative requirements. The owners and operators shall comply with the requirement to have a designated representative, and may have an alternate designated representative, in accordance with 40 CFR 97.613 through 97.618.

(b) Emissions monitoring, reporting, and recordkeeping requirements.

(1) The owners and operators, and the designated representative, of each CSAPR SO_2 Group 1 source and each CSAPR SO_2 Group 1 unit at the source shall comply with the monitoring, reporting, and recordkeeping requirements of 40 CFR 97.630 (general requirements, including installation, certification, and data accounting, compliance deadlines, reporting data, prohibitions, and long-term cold storage), 97.631 (initial monitoring system certification and recertification procedures), 97.632 (monitoring system out-of-control periods), 97.633 (notifications concerning monitoring), 97.634 (recordkeeping and reporting, including monitoring plans, certification applications, quarterly reports, and compliance certification), and 97.635 (petitions for alternatives to monitoring, recordkeeping, or reporting requirements).

(2) The emissions data determined in accordance with 40 CFR 97.630 through 97.635 shall be used to calculate allocations of CSAPR SO_2 Group 1 allowances under 40 CFR 97.611(a)(2) and (b) and 97.612 and to determine compliance with the CSAPR SO_2 Group 1 emissions limitation and assurance provisions under paragraph (c) below, provided that, for each monitoring location from which mass emissions are reported, the mass emissions amount used in calculating

such allocations and determining such compliance shall be the mass emissions amount for the monitoring location determined in accordance with 40 CFR 97.630 through 97.635 and rounded to the nearest ton, with any fraction of a ton less than 0.50 being deemed to be zero.

(c) SO_2 emissions requirements.

(1) CSAPR SO_2 Group 1 emissions limitation.

(i) As of the allowance transfer deadline for a control period in a given year, the owners and operators of each CSAPR SO_2 Group 1 source and each CSAPR SO_2 Group 1 unit at the source shall hold, in the source's compliance account, CSAPR SO_2 Group 1 allowances available for deduction for such control period under 40 CFR 97.624(a) in an amount not less than the tons of total SO_2 emissions for such control period from all CSAPR SO_2 Group 1 units at the source.

(ii) If total SO_2 emissions during a control period in a given year from the CSAPR SO_2 Group 1 units at a CSAPR SO_2 Group 1 source are in excess of the CSAPR SO_2 Group 1 emissions limitation set forth in paragraph (c)(1)(i) above, then:

(A) The owners and operators of the source and each CSAPR SO_2 Group 1 unit at the source shall hold the CSAPR SO_2 Group 1 allowances required for deduction under 40 CFR 97.624(d); and

(B) The owners and operators of the source and each CSAPR SO_2 Group 1 unit at the source shall pay any fine, penalty, or assessment or comply with any other remedy imposed, for the same violations, under the Clean Air Act, and each ton of such excess emissions and each day of such control period shall constitute a separate violation 40 CFR part 97, subpart CCCCC and the Clean Air Act.

(2) CSAPR SO_2 Group 1 assurance provisions.

(i) If total SO_2 emissions during a control period in a given year from all CSAPR SO_2 Group 1 units at CSAPR SO_2 Group 1 sources in the state exceed the state assurance level, then the owners and operators of such sources and units in each group of one or more sources and units having a common designated representative for such control period, where the common designated representative's share of such SO_2 emissions during such control period exceeds the common designated representative's assurance level for the state and such control period, shall hold (in the assurance account established for the owners and operators of such group) CSAPR SO_2 Group 1 allowances available for deduction for such control period under 40 CFR 97.625(a) in an amount equal to two times the product (rounded to the nearest whole number), as determined by the Administrator in accordance with 40 CFR 97.625(b), of multiplying—

(A) The quotient of the amount by which the common designated representative's share of such SO_2 emissions exceeds the common designated representative's assurance level divided by the sum of the amounts, determined for all common designated representatives for such sources and units in the state for such control period, by which each common designated representative's share of such SO_2 emissions exceeds the respective common designated representative's assurance level; and

(B) The amount by which total SO_2 emissions from all CSAPR SO_2 Group 1 units at CSAPR SO_2 Group 1 sources in the state for such control period exceed the state assurance level.

(ii) The owners and operators shall hold the CSAPR SO_2 Group 1 allowances required under paragraph (c)(2)(i) above, as of midnight of November 1 (if it is a business day), or midnight of the first business day thereafter (if November 1 is not a business day), immediately after such control period.

(iii) Total SO_2 emissions from all CSAPR SO_2 Group 1 units at CSAPR SO_2 Group 1 sources in the state during a control period in a given year exceed the state assurance level if such total SO_2 emissions exceed the sum, for such control period, of the state SO_2 Group 1 trading budget under 40 CFR 97.610(a) and the state's variability limit under 40 CFR 97.610(b).

(iv) It shall not be a violation of 40 CFR part 97, subpart CCCCC or of the Clean Air Act if total SO_2 emissions from all CSAPR SO_2 Group 1 units at CSAPR SO_2 Group 1 sources in the state during a control period exceed the state assurance level or if a common designated representative's share of total SO_2 emissions from the CSAPR SO_2 Group 1 units at CSAPR SO_2 Group 1 sources in the state during a control period exceeds the common designated representative's assurance level.

(v) To the extent the owners and operators fail to hold CSAPR SO_2 Group 1 allowances for a control period in a given year in accordance with paragraphs (c)(2)(i) through (iii) above,

(A) The owners and operators shall pay any fine, penalty, or assessment or comply with any other remedy imposed under the Clean Air Act; and

(B) Each CSAPR SO_2 Group 1 allowance that the owners and operators fail to hold for such control period in accordance with paragraphs (c)(2)(i) through (iii) above and each day of such control period shall constitute a separate violation of 40 CFR part 97, subpart CCCCC and the Clean Air Act.

(3) Compliance periods.

(i) A CSAPR SO_2 Group 1 unit shall be subject to the requirements under paragraph (c)(1) above for the control period starting on the later of January 1, 2015 or the deadline for meeting the unit's monitor certification requirements under 40 CFR 97.630(b) and for each control period thereafter.

(ii) A CSAPR SO_2 Group 1 unit shall be subject to the requirements under paragraph (c)(2) above for the control period starting on the later of January 1, 2017 or the deadline for meeting the unit's monitor certification requirements under 40 CFR 97.630(b) and for each control period thereafter.

(4) Vintage of allowances held for compliance.

(i) A CSAPR SO_2 Group 1 allowance held for compliance with the requirements under paragraph (c)(1)(i) above for a control period in a given year must be a CSAPR SO_2 Group 1 allowance that was allocated for such control period or a control period in a prior year.

(ii) A CSAPR SO_2 Group 1 allowance held for compliance with the requirements under paragraphs (c)(1)(ii)(A) and (2)(i) through (iii) above for a control period in a given year must be a CSAPR SO_2 Group 1 allowance that was allocated for a control period in a prior year or the control period in the given year or in the immediately following year.

(5) Allowance Management System requirements. Each CSAPR SO_2 Group 1 allowance shall be held in, deducted from, or transferred into, out of, or between Allowance Management System accounts in accordance with 40 CFR part 97, subpart CCCCC.

(6) Limited authorization. A CSAPR SO_2 Group 1 allowance is a limited authorization to emit one ton of SO_2 during the control period in one year. Such authorization is limited in its use and duration as follows:

(i) Such authorization shall only be used in accordance with the CSAPR SO_2 Group 1 Trading Program; and

(ii) Notwithstanding any other provision of 40 CFR part 97, subpart CCCCC, the Administrator has the authority to terminate or limit the use and duration of such authorization to the extent the Administrator determines is necessary or appropriate to implement any provision of the Clean Air Act.

(7) Property right. A CSAPR SO_2 Group 1 allowance does not constitute a property right.

(d) Title V permit revision requirements.

(1) No title V permit revision shall be required for any allocation, holding, deduction, or transfer of CSAPR SO_2 Group 1 allowances in accordance with 40 CFR part 97, subpart CCCCC.

(2) This permit incorporates the CSAPR emissions monitoring, recordkeeping and reporting requirements pursuant to 40 CFR 97.630 through 97.635, and the requirements for a continuous emission monitoring system (pursuant to 40 CFR part 75, subparts B and H), an excepted monitoring system (pursuant to 40 CFR part 75, appendices D and E), a low mass emissions excepted monitoring methodology (pursuant to 40 CFR part 75.19), and an alternative monitoring system (pursuant to 40 CFR part 75, subpart E), Therefore, the Description of CSAPR Monitoring Provisions table for units identified in this permit may be added to, or changed, in this title V permit using minor permit modification procedures in accordance with 40 CFR 97.606(d)(2) and 70.7(e)(2)(i)(B) or 71.7(e)(1)(i)(B).

(e) Additional recordkeeping and reporting requirements.

(1) Unless otherwise provided, the owners and operators of each CSAPR SO_2 Group 1 source and each CSAPR SO_2 Group 1 unit at the source shall keep on site at the source each of the following documents (in hardcopy or electronic format) for a period of 5 years from the date the document is created. This period may be extended for cause, at any time before the end of 5 years, in writing by the Administrator.

(i) The certificate of representation under 40 CFR 97.616 for the designated representative for the source and each CSAPR SO_2 Group 1 unit at the source and all documents that demonstrate the truth of the statements in the certificate of representation; provided that the certificate and documents shall be retained on site at the source beyond such 5-year period until such certificate of representation and documents are superseded because of the submission of a new certificate of representation under 40 CFR 97.616 changing the designated representative.

(ii) All emissions monitoring information, in accordance with 40 CFR part 97, subpart CCCCC.

(iii) Copies of all reports, compliance certifications, and other submissions and all records made or required under, or to demonstrate compliance with the requirements of, the CSAPR SO_2 Group 1 Trading Program.

(2) The designated representative of a CSAPR SO_2 Group 1 source and each CSAPR SO_2 Group 1 unit at the source shall make all submissions required under the CSAPR SO_2 Group 1 Trading Program, except as provided in 40 CFR 97.618. This requirement does not change, create an exemption from, or otherwise affect the responsible official submission requirements under a title V operating permit program in 40 CFR parts 70 and 71.

(f) Liability.

(1) Any provision of the CSAPR SO_2 Group 1 Trading Program that applies to a CSAPR SO_2 Group 1 source or the designated representative of a CSAPR SO_2 Group 1 source shall also apply to the owners and operators of such source and of the CSAPR SO_2 Group 1 units at the source.

(2) Any provision of the CSAPR SO_2 Group 1 Trading Program that applies to a CSAPR SO_2 Group 1 unit or the designated representative of a CSAPR SO_2 Group 1 unit shall also apply to the owners and operators of such unit.

(g) **Effect on other authorities.** No provision of the CSAPR SO_2 Group 1 Trading Program or exemption under 40 CFR 97.605 shall be construed as exempting or excluding the owners and operators, and the designated representative, of a CSAPR SO_2 Group 1 source or CSAPR SO_2 Group 1 unit from compliance with any other provision of the applicable, approved state implementation plan, a federally enforceable permit, or the Clean Air Act.

CSAPR NO_X Ozone Season Group 2 Trading Program Requirements (40 CFR §97.806)

(a) Designated representative requirements. The owners and operators shall comply with the requirement to have a designated representative, and may have an alternate designated representative, in accordance with §§97.813 through 97.818.

(b) Emissions monitoring, reporting, and recordkeeping requirements.

(1) The owners and operators, and the designated representative, of each CSAPR NO_X Ozone Season Group 2 source and each CSAPR NO_X Ozone Season Group 2 unit at the source shall comply with the monitoring, reporting, and recordkeeping requirements of §§97.830 through 97.835.

(2) The emissions data determined in accordance with §§97.830 through 97.835 shall be used to calculate allocations of CSAPR NO_X Ozone Season Group 2 allowances under §§97.811(a)(2) and (b) and 97.812 and to determine compliance with the CSAPR NO_X Ozone Season Group 2 emissions limitation and assurance provisions under paragraph (c) of this section, provided that, for each monitoring location from which mass emissions are reported, the mass emissions amount used in calculating such allocations and determining such compliance shall be the mass emissions amount for the monitoring location determined in accordance with §§97.830 through 97.835 and rounded to the nearest ton, with any fraction of a ton less than 0.50 being deemed to be zero.

(c) NO_X emissions requirements—

(1) CSAPR NO_X Ozone Season Group 2 emissions limitation.

(i) As of the allowance transfer deadline for a control period in a given year, the owners and operators of each CSAPR NO_X Ozone Season Group 2 source and each CSAPR NO_X Ozone Season Group 2 unit at the source shall hold, in the source's compliance account, CSAPR NO_X Ozone Season Group 2 allowances available for deduction for such control period under §97.824(a) in an amount not less than the tons of total NO_X emissions for such control period from all CSAPR NO_X Ozone Season Group 2 units at the source.

(ii) If total NO_X emissions during a control period in a given year from the CSAPR NO_X Ozone Season Group 2 units at a CSAPR NO_X Ozone Season Group 2 source are in excess of the CSAPR NO_X Ozone Season Group 2 emissions limitation set forth in paragraph (c)(1)(i) of this section, then:

(A) The owners and operators of the source and each CSAPR NO_X Ozone Season Group 2 unit at the source shall hold the CSAPR NO_X Ozone Season Group 2 allowances required for deduction under §97.824(d); and

(B) The owners and operators of the source and each CSAPR NO_X Ozone Season Group 2 unit at the source shall pay any fine, penalty, or assessment or comply with any other remedy imposed, for the same violations, under the Clean Air Act, and each ton of such excess emissions and each day of such control period shall constitute a separate violation of this subpart and the Clean Air Act.

(2) CSAPR NO_X Ozone Season Group 2 assurance provisions.

(i) If total NO_X emissions during a control period in a given year from all base CSAPR NO_X Ozone Season Group 2 units at base CSAPR NO_X Ozone Season Group 2 sources in a State (and Indian country within the borders of such State) exceed the State assurance level, then the owners and operators of such sources and units in each group of one or more sources and units having a common designated representative for such control period, where the common designated representative's share of such NO_X emissions during such control period exceeds the common designated representative's assurance level for the State and such control period, shall hold (in the assurance account established for the owners and operators of such group) CSAPR NO_X Ozone Season Group 2 allowances available for deduction for such control period under §97.825(a) in an amount equal to two times the product (rounded to the nearest whole number), as determined by the Administrator in accordance with §97.825(b), of multiplying—

(A) The quotient of the amount by which the common designated representative's share of such NO_X emissions exceeds the common designated representative's assurance level divided by the sum of the amounts, determined for all common designated representatives for such sources and units in the State (and Indian country within the borders of such State) for such control period, by which each common designated representative's share of such NO_X emissions exceeds the respective common designated representative's assurance level; and

(B) The amount by which total NO_X emissions from all base CSAPR NO_X Ozone Season Group 2 units at base CSAPR NO_X Ozone Season Group 2 sources in the State (and Indian country within the borders of such State) for such control period exceed the State assurance level.

(ii) The owners and operators shall hold the CSAPR NO_X Ozone Season Group 2 allowances required under paragraph (c)(2)(i) of this section, as of midnight of November 1 (if it is a business day), or midnight of the first business day thereafter (if November 1 is not a business day), immediately after the year of such control period.

(iii) Total NO_X emissions from all base CSAPR NO_X Ozone Season Group 2 units at base CSAPR NO_X Ozone Season Group 2 sources in a State (and Indian country within the borders of such State) during a control period in a given year exceed the State assurance level if such total NO_X emissions exceed the sum, for such control period, of the State NO_X Ozone Season Group 2 trading budget under §97.810(a) and the State's variability limit under §97.810(b).

(iv) It shall not be a violation of this subpart or of the Clean Air Act if total NO_X emissions from all base CSAPR NO_X Ozone Season Group 2 units at base CSAPR NO_X Ozone Season Group 2 sources in a State (and Indian country within the borders of such State) during a control period exceed the State assurance level or if a common designated representative's share of total NO_X emissions from the base CSAPR NO_X Ozone Season Group 2 units at base CSAPR NO_X Ozone Season Group 2 sources in a State (and Indian country within the borders of such State) during a control period exceeds the common designated representative's assurance level.

(v) To the extent the owners and operators fail to hold CSAPR NO_X Ozone Season Group 2 allowances for a control period in a given year in accordance with paragraphs (c)(2)(i) through (iii) of this section,

(A) The owners and operators shall pay any fine, penalty, or assessment or comply with any other remedy imposed under the Clean Air Act; and

(B) Each CSAPR NO_X Ozone Season Group 2 allowance that the owners and operators fail to hold for such control period in accordance with paragraphs (c)(2)(i) through (iii) of this section and each day of such control period shall constitute a separate violation of this subpart and the Clean Air Act.

(3) Compliance periods.

(i) A CSAPR NO_X Ozone Season Group 2 unit shall be subject to the requirements under paragraph (c)(1) of this section for the control period starting on the later of May 1, 2017 or the deadline for meeting the unit's monitor certification requirements under §97.830(b) and for each control period thereafter.

(ii) A base CSAPR NO_X Ozone Season Group 2 unit shall be subject to the requirements under paragraph (c)(2) of this section for the control period starting on the later of May 1, 2017 or the deadline for meeting the unit's monitor certification requirements under §97.830(b) and for each control period thereafter.

(4) Vintage of CSAPR NO_X Ozone Season Group 2 allowances held for compliance.

(i) A CSAPR NO_X Ozone Season Group 2 allowance held for compliance with the requirements under paragraph (c)(1)(i) of this section for a control period in a given year must be a CSAPR NO_X Ozone Season Group 2 allowance that was allocated or auctioned for such control period or a control period in a prior year.

(ii) A CSAPR NO_X Ozone Season Group 2 allowance held for compliance with the requirements under paragraphs (c)(1)(ii)(A) and (c)(2)(i) through (iii) of this section for a control period in a given year must be a CSAPR NO_X Ozone Season Group 2 allowance that was allocated or auctioned for a control period in a prior year or the control period in the given year or in the immediately following year.

(5) Allowance Management System requirements. Each CSAPR NO_X Ozone Season Group 2 allowance shall be held in, deducted from, or transferred into, out of, or between Allowance Management System accounts in accordance with this subpart.

(6) Limited authorization. A CSAPR NO_X Ozone Season Group 2 allowance is a limited authorization to emit one ton of NO_X during the control period in one year. Such authorization is limited in its use and duration as follows:

(i) Such authorization shall only be used in accordance with the CSAPR NO_X Ozone Season Group 2 Trading Program; and

(ii) Notwithstanding any other provision of this subpart, the Administrator has the authority to terminate or limit the use and duration of such authorization to the extent the Administrator determines is necessary or appropriate to implement any provision of the Clean Air Act.

(7) Property right. A CSAPR NO_X Ozone Season Group 2 allowance does not constitute a property right.

(d) Title V permit requirements.

(1) No title V permit revision shall be required for any allocation, holding, deduction, or transfer of CSAPR NO_X Ozone Season Group 2 allowances in accordance with this subpart.

(2) A description of whether a unit is required to monitor and report NO_X emissions using a continuous emission monitoring system (under subpart H of part 75 of this chapter), an excepted monitoring system (under appendices D and E to part 75 of this chapter), a low mass emissions excepted monitoring methodology (under §75.19 of this chapter), or an alternative monitoring system (under subpart E of part 75 of this chapter) in accordance with §§97.830 through 97.835 may be added to, or changed in, a title V permit using minor permit modification procedures in accordance with §§70.7(e)(2) and 71.7(e)(1) of this chapter, provided that the requirements applicable to the described monitoring and reporting (as added or changed, respectively) are already incorporated in such permit. This paragraph explicitly provides that the addition of, or change to, a unit's description as described in the prior sentence is eligible for minor permit modification procedures in accordance with §§70.7(e)(2)(i)(B) and 71.7(e)(1)(i)(B) of this chapter.

(e) Additional recordkeeping and reporting requirements.

(1) Unless otherwise provided, the owners and operators of each CSAPR NO_X Ozone Season Group 2 source and each CSAPR NO_X Ozone Season Group 2 unit at the source shall keep on site at the source each of the following documents (in hardcopy or electronic format) for a period of 5 years from the date the document is created. This period may be extended for cause, at any time before the end of 5 years, in writing by the Administrator.

(i) The certificate of representation under §97.816 for the designated representative for the source and each CSAPR NO_X Ozone Season Group 2 unit at the source and all documents that demonstrate the truth of the statements in the certificate of representation; provided that the certificate and documents shall be retained on site at the source beyond such 5-year period until such certificate of representation and documents are superseded because of the submission of a new certificate of representation under §97.816 changing the designated representative.

(ii) All emissions monitoring information, in accordance with this subpart.

(iii) Copies of all reports, compliance certifications, and other submissions and all records made or required under, or to demonstrate compliance with the requirements of, the CSAPR NO_X Ozone Season Group 2 Trading Program.

(2) The designated representative of a CSAPR NO_X Ozone Season Group 2 source and each CSAPR NO_X Ozone Season Group 2 unit at the source shall make all submissions required under the CSAPR NO_X Ozone Season Group 2 Trading Program, except as provided in §97.818. This requirement does not change, create an exemption from, or otherwise affect the responsible official submission requirements under a title V operating permit program in parts 70 and 71 of this chapter.

(f) Liability.

(1) Any provision of the CSAPR NO_X Ozone Season Group 2 Trading Program that applies to a CSAPR NO_X Ozone Season Group 2 source or the designated representative of a CSAPR NO_X Ozone Season Group 2 source shall also apply to the owners and operators of such source and of the CSAPR NO_X Ozone Season Group 2 units at the source.

(2) Any provision of the CSAPR NO_X Ozone Season Group 2 Trading Program that applies to a CSAPR NO_X Ozone Season Group 2 unit or the designated representative of a CSAPR NO_X Ozone Season Group 2 unit shall also apply to the owners and operators of such unit.

(h) Effect on other authorities. No provision of the CSAPR NO_X Ozone Season Group 2 Trading Program or exemption under §97.805 shall be construed as exempting or excluding the owners and operators, and the designated representative, of a CSAPR NO_X Ozone Season Group 2 source or CSAPR NO_X Ozone Season Group 2 unit from compliance with any other provision of the applicable, approved State implementation plan, a federally enforceable permit, or the Clean Air Act

ATTACHMENT 10

Title V Fee Selection Form

APC 36 (CN-1583)

DEPARTMENT OF ENVIRONMENT AND CONSERVATION
DIVISION OF AIR POLLUTION CONTROL
Davy Crockett Tower, 7th Floor
500 James Robertson Parkway, Nashville, TN 37243
Telephone: (615) 532-0554, Email: Air.Pollution.Control@TN.gov

TITLE V FEE SELECTION

Type or print and submit to the email address above.

FACILITY INFORMATION

1. Organization's legal name and SOS control number [as registered with the TN Secretary of State (SOS)]	
2. Site name (if different from legal name)	
3. Site address (St./Rd./Hwy.)	County name
City	Zip code
4. Emission source reference number	**5.** Title V permit number

FEE SELECTION

This fee selection is effective beginning January 1, _______. When approved, this selection will be effective until a new Fee Selection form is submitted. Fee Selection forms must be submitted on or before December 31 of the annual accounting period.

6. Payment Schedule (choose one):

Calendar Year Basis (January 1 – December 31) ☐ Fiscal Year Basis (July 1 – June 30) ☐

7. Payment Basis (choose one):

Actual Emissions Basis ☐ Allowable Emissions Basis ☐ Combination of Actual and Allowable Emissions Basis ☐

8. If Payment Basis is "Actual Emissions" or "Combination of Actual and Allowable Emissions", complete the following table for each permitted source and each pollutant for which fees are due for that source. See instructions for further details.

Source ID	Pollutant	Allowable or Actual Emissions	If allowable emissions: Specify condition number and limit. If actual emissions: Describe calculation method and provide example. Provide condition number that specifies method, if applicable.

8. (Continued)

Source ID	Pollutant	Allowable or Actual Emissions	If allowable emissions: Specify condition number and limit. If actual emissions: Describe calculation method and provide example. Provide condition number that specifies method, if applicable.

CONTACT INFORMATION (BILLING)

9. Billing contact			Phone number with area code
Mailing address (St./Rd./Hwy.)			Fax number with area code
City	State	Zip code	**Email address**

SIGNATURE BY RESPONSIBLE OFFICIAL

Based upon information and belief formed after reasonable inquiry, I, as the responsible person of the above mentioned facility, certify that the information contained in the submittal is accurate and true to the best of my knowledge. As specified in TCA Section 39-16-702(a)(4), this declaration is made under penalty of perjury.

10. Signature		Date
Signer's name (type or print)	**Title**	Phone number with area code

ATTACHMENT 11

Agreement Letter

TVA TENNESSEE VALLEY AUTHORITY

Johnsonville Combustion Turbines, 535 Steam Plant Road, New Johnsonville, Tennessee 37134

Sent Via Electronic Transmittal

March 12, 2025

Ms. Michelle Owenby, Director (Air.Pollution.Control@tn.gov)
Division of Air Pollution Control
Tennessee Department of Environment
and Conservation (TDEC)
Davey Crockett Tower, 7th Floor
500 James Robertson Parkway
Nashville, Tennessee 37243

Dear Ms. Owenby:

TENNESSEE VALLEY AUTHORITY (TVA) – JOHNSONVILLE COMBUSTION TURBINE PLANT (JCT) – FACILITY ID: 43-0011 – MINOR MODIFICATION #1 TO TITLE V PERMIT NUMBER 572833 – AGREEMENT LETTER WITH REQUEST FOR OPERATING CAPACITY LIMIT

TVA requests operations for the ten (10) existing simple cycle combustion turbine units, JCT1-10 (Source No. 43-0011-11-20), be limited to 2,100.21 gigawatt-hours per year, which represents a 35 percent capacity factor. This aligns with the January 20, 1999, agreement letter by Ms. Janet K Watts (TVA) and is consistent with the provisions of Section 2.12.2.F.2 Reasonable Further Progress (New Johnsonville Additional Control Area) of the Air Quality Implementation Plan of the State of Tennessee as of July 1, 1982.

If you have any questions or need additional information, please contact Jack Byars via email at jgbyars@tva.gov.

I, the undersigned, am the responsible official as defined in TAPCR 1200-03-09-.02 (11)(b)21 for TVA JCT, for which this document is being submitted. I hereby certify, based on the information and belief formed after reasonable inquiry, that the statements and information contained in this document are true, accurate, and complete

Sincerely,

Steven G. Trull
Site Manager
Johnsonville Combustion Turbines