PUBLIC NOTICE

Teknor Apex Tennessee Company (Teknor Apex) has applied to the Tennessee Department of Environment and Conservation, Division of Air Pollution Control for a significant modification to an existing major source (Title V) operating permit subject to the provisions of Tennessee Air Pollution Control Regulations 1200-03-09-.02(11). A major source operating permit is required by both the Federal Clean Air Act and the Tennessee Air Pollution Control Regulations.

Teknor Apex has applied for a significant modification to add emission source 38-0039-101 (Natural gas-fired Sigma thermal heater). The Title V operating permit subject to the modification is identified as follows: Division identification number 38-0039/570726. The specific permit conditions affected by this modification are identified as follows: Condition A8 (fee payment); Condition A20 (112(r)); Condition B3 (reporting); Condition B6 (submission of compliance certification); Condition B8 (excess emissions reporting); Condition B11 (report required upon the issuance of a Notice of Violation); Condition C6 (new construction or modifications); Condition D7 (fugitive dust); Condition D8 (open burning); Condition D9 (asbestos); Condition D11 (Emission Standards for Hazardous Air Pollutants); Condition D12 (Standards of Performance for New Stationary Sources); Condition D13 (gasoline dispensing facilities); Condition D14 (internal combustion engines); Condition E1 (fee payment); Condition E2 (reporting requirements); Condition E4-8 (Compliance Assurance Monitoring); Conditions E4-12 and E6-8, (Boiler MACT); Condition E4-15 (identification of Responsible Official, technical contact, and billing contact); Condition E7-3 (Standards of Performance for Stationary Compression Ignition Internal Combustion Engines); Condition E10-3 (fuel oil sulfur content limit for 38-0039-70); Conditions E12-1 through E12-9 (emission limits and other requirements for 38-0039-101); Attachment 11 (manufacturer's specifications for 38-0039-101); and Attachment 12 (Title V fee selection form). Only the portions of the Title V permit affected by the significant modifications are open to comment during the notice period.

EPA has agreed to treat this draft Part 70 permit as a proposed Part 70 permit and to perform its 45-day review provided by the law concurrently with the public notice period. If any substantive comments are received, EPA's 45-day review period will cease to be performed concurrently with the public notice period. EPA's 45-day review period will start once the public notice period has been completed and EPA receives notification from the Tennessee Air Pollution Control Division that comments have been received and resolved. Whether EPA's 45-day review period is performed concurrently with the public comment period or after the public comment period has ended, the deadline for citizen's petitions to the EPA Administrator will be determined as if EPA's 45-day review period is performed after the public comment period has ended (*i.e.*, sequentially). The status regarding EPA's 45-day review of these permits and the deadline for submitting a citizen's petition can be found at the following website address:

http://www2.epa.gov/caa-permitting/caa-permitting-epas-southeastern-region

Copies of the application materials and draft permits are available for public inspection during normal business hours at the following locations:

Tennessee Department of Environment and Conservation
Division of Air Pollution Control
Jackson Environmental Field Office
1625 Hollywood Drive
Jackson, TN 38305

and

Tennessee Department of Environment and Conservation
Division of Air Pollution Control
William R. Snodgrass Tennessee Tower
312 Rosa L. Parks Avenue, 15th Floor
Nashville, TN 37243

An electronic copy of the draft permit is available by accessing the TDEC internet site located at:

http://www.tn.gov/environment/topic/ppo-air

Questions concerning the source(s) may be addressed to Mr. Travis Blake at (615) 532-0617 or by e-mail at travis.blake@tn.gov.

Interested parties are invited to review these materials and comment. In addition, a public hearing may be requested at which written or oral presentations may be made. To be considered, written comments or requests for a public hearing must be received no later than 4:30 PM on **October 5, 2020.** To assure that written comments are received and addressed in a timely manner, written comments must be submitted using one of the following methods:

1. **Mail, private carrier, or hand delivery:** Address written comments to Travis Blake, Division of Air Pollution Control, William R. Snodgrass Tennessee Tower, 312 Rosa L. Parks Avenue 15th Floor, Nashville, Tennessee 37243.

2. **E-mail**: Submit electronic comments to air.pollution.control@tn.gov.

A final determination will be made after weighing all relevant comments.

Individuals with disabilities who wish to review information maintained at the above-mentioned depositories should contact the Tennessee Department of Environment and Conservation to discuss any auxiliary aids or services needed to facilitate such review. Such contact may be in person, by writing, telephone, or other means, and should be made no less than ten days prior to the end of the public comment period to allow time to provide such aid or services. Contact the Tennessee Department of Environment and Conservation ADA Coordinator, William R. Snodgrass Tennessee Tower, 312 Rosa L. Parks Avenue 2nd Floor, Nashville, TN 37243, 1-(866)-253-5827. Hearing impaired callers may use the Tennessee Relay Service, 1-(800)-848-0298.

For the *Brownsville Press* – publish once during the time period of August 31, 2020 through September 4, 2020.

Air Pollution Control DATE: AUGUST 13, 2020
Assigned to –Travis Blake

No alterations to the above are allowed:
Teknor Apex must pay to place this advertisement in the newspaper
Air Pollution Control must be furnished with an affidavit from the newspaper stating that the ad was run and the date of the ad or one complete sheet from the newspaper showing this advertisement, the name of the newspaper and the date of publication. Mail to Travis Blake, Division of Air Pollution Control, William R. Snodgrass Tennessee Tower, 312 Rosa L. Parks Avenue 15th Floor, Nashville, Tennessee 37243.

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

SIGNIFICANT 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 Tennessee Air Pollution Control Regulations (TAPCR) 1200-03-09-.02(11). 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: **January 13, 2017**

Modification Date: ********DRAFT********

Expiration Date: **January 12, 2022**

Permit Number: **570726**

Issued To:
Teknor Apex Tennessee Company

Installation Address:
751 Dupree Street
Brownsville

Installation Description:
Specialty Chemicals Plant:
01-Boiler #3 **(MACT)**
04-Boiler #6 **(NSPS & MACT)**
08-Emergency Engines **(NSPS & MACT)**
16-Boiler #4 **(MACT)**
66-Bucket Elevators (2) with Baghouses (2)
70-Boiler #5 **(NSPS & MACT)**
92-Specialty Chemicals Plant **(NSPS & MACT)**
101-Natural Gas-Fired Sigma Thermal Heater **(NSPS & MACT)**

Emission Source Reference No.: **38-0039 – Specialty Chemicals Plant**

Renewal Application Due Date: **Between April 17, 2021 through July 16, 2021**

Primary SIC: **28**

Information Relied Upon: **Renewal application dated August 13, 2015. Significant Modification #1 application dated November 27, 2019.**

(Continued on the next page)

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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>

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SECTION A
GENERAL PERMIT CONDITIONS

A permit issued under the provisions of 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 regulation.

TAPCR 1200-03

A2. **Compliance requirement.** All terms and conditions in a permit issued pursuant to 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 (SM1). **Fee payment.**

(a) The permittee shall pay an annual Title V emission fee based upon 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 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 1200-03-26-.02 and 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 paragraph 1200-03-26-.02(9) shall apportion their emissions as follows to ensure that their fees are not double counted.

1. Sources that are subject to federally promulgated hazardous air pollutant under 40 CFR 60, 61, or 63 will place such regulated emissions in the regulated hazardous air pollutant (HAP) category.

2. A category of miscellaneous HAPs shall be used for hazardous air pollutants listed at part 1200-03-26-.02(2)(i)12 that are not subject to federally promulgated hazardous air pollutant standards under 40 CFR 60, 61, or 63.

3. HAPs that are also in the family of volatile organic compounds, particulate matter, or PM_{10} shall not be placed in either the regulated HAP category or miscellaneous HAP category.

4. Sources that are subject to a provision of chapter 1200-03-16 New Source Performance Standards (NSPS) or chapter 0400-30-39 Standards of Performance for New Stationary Sources for pollutants that are neither particulate matter, PM_{10}, sulfur dioxide (SO_2), volatile organic compounds (VOC), nitrogen oxides (NO_x), or hazardous air pollutants (HAPs) will place such regulated emissions in an NSPS pollutant category.

5. The regulated HAP category, the miscellaneous HAP category, and the NSPS pollutant category are each subject to the 4,000 ton cap provisions of subparagraph 1200-03-26-.02(2)(i).

6. 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 subparagraph 1200-03-26-.02(2)(i) shall also apply to PM_{10} emissions.

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 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, 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. **<u>Permit shield.</u>**

(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.

TAPCR 1200-03-09-.02(11)(e)6

A12. **<u>Permit renewal and expiration.</u>**

(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 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 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 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 1200-03-09-.03(1) and TAPCR 1200-03-15-.03.

A16. **Construction permit required.** Except as exempted in TAPCR 1200-03-09-.04, or excluded in subparagraph TAPCR 1200-03-02-.01(1)(aa) or subparagraph TAPCR 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. 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 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.

A20 (SM1). **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. **Recordkeeping.** 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. **Retention of monitoring data.** The permittee shall retain records of all required monitoring data and support information for a period of at least five 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 (SM1). **Reporting.** 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. **Certification.** 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. **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):

(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 compliance during the period was continuous or intermittent. 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 (SM1). **Submission of compliance certification.** The compliance certification shall be submitted to:

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

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

B7. **Emergency provisions.** An emergency constitutes an affirmative defense to an enforcement action brought against this source for noncompliance with a technology-based emission limitation due to unavoidable increases in emissions attributable to the emergency. An emergency shall not include noncompliance to the extent caused by improperly designed equipment, lack of preventative maintenance, careless or improper operation, or operator error.

(a) The affirmative defense of the emergency shall be demonstrated through properly signed, contemporaneous operating logs, or other relevant evidence that:

1. An emergency occurred and that the permittee can identify the probable cause(s) of the emergency. "Probable" must be supported by a credible investigation into the incident that seeks to identify the causes and results in an explanation supported by generally accepted engineering or scientific principles.

2. The permitted source was at the time being properly operated. In determining whether or not a source was being properly operated, the Technical Secretary shall examine the source's written standard operating procedures which were in effect at the time of the noncompliance and any other code as detailed below that would be relevant to preventing the noncompliance. Adherence to the source's standard operating procedures will be the test of adequate preventative maintenance, careless operation, improper operation or operator error to the extent that such adherence would prevent noncompliance. The source's failure to follow recognized standards of practice to the extent that adherence to such a standard would have prevented noncompliance will disqualify the source from any claim of an emergency and an affirmative defense.

3. During the period of the emergency, the permittee took all reasonable steps to minimize levels of emissions that exceeded the emission standards, or other requirements in the permit.

4. The permittee submitted notice of the emergency to the Technical Secretary according to the notification criteria for malfunctions in rule 1200-03-20-.03. For the purposes of this condition, "emergency" shall be substituted for "malfunction(s)" in rule 1200-03-20-.03 to determine the relevant notification threshold. The notice shall include a description of the emergency, any steps taken to mitigate emissions, and corrective actions taken.

(b) In any enforcement proceeding, the permittee seeking to establish the occurrence of an emergency has the burden of proof.

(c) The provisions of this condition are in addition to any emergency, malfunction or upset requirement contained in Division 1200-03 or other applicable requirement.

TAPCR 1200-03-09-.02(11)(e)7

B8 (SM1). **Excess emissions reporting.**

(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 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. 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 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 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. **Malfunctions, startups and shutdowns - reasonable measures required.** 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 (SM1). **Report required upon the issuance of a notice of violation for excess emissions.** The permittee must submit within 20 days after receipt of the notice of violation, the data required below. If this data has previously been 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 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 Chapter 1200-03-30.

(b) The change cannot be a modification under any provision of Title I of the federal Act or 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 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 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 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 seven days in advance of the proposed changes. The Technical Secretary may waive the seven-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 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 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 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 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 1200-03-09-.02(11)(e), TAPCR 1200-03-09-.02(11)(f) and TAPCR 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 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 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 (SM1). **New construction or modifications.** Future construction at this facility that is subject to the provisions of TAPCR 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 1200-03-09-.02(11)(f)4 or the significant modification route of TAPCR 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 1200-03-09-.02(11)(f)5(ii) or group processing of minor modifications under the provisions of TAPCR 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.** 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 20% for an aggregate of more than five minutes in any one hour or more than 20 minutes in any 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% (six-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 six-minute averaging. 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 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 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 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 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 (SM1). **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 stock piles, 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 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 Chapter 1200-03-20.

TAPCR 1200-03-08

D8 (SM1). **Open burning.** The permittee shall comply with TAPCR 1200-03-04 for all open burning activities at the facility.

TAPCR 1200-03-04

D9 (SM1). **Asbestos.** Where applicable, the permittee shall comply with the requirements of 1200-03-11-.02(2)(d) when conducting any renovation or demolition activities at the facility.

TAPCR 1200-03-11-.02(2)(d) 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 not subject to source-specific applicable requirements contained in State of Tennessee and U.S. EPA regulations. By annual certification of compliance, the permittee shall be considered to meet the monitoring and related record keeping and reporting requirements of TAPCR 1200-03-09-.02(11)(e)1.(iii) and 1200-03-10-.04(2)(b)1 and compliance requirements of TAPCR 1200-03-09-.02(11)(e)3.(i). The permittee shall submit compliance certification for these conditions annually.

D11 (SM1). **Emission Standards for Hazardous Air Pollutants.** When applicable, the permittee shall comply with TAPCR 0400-30-38 for all emission sources subject to a requirement contained therein.

TAPCR 0400-30-38

D12 (SM1). **Standards of Performance for New Stationary Sources.** When applicable, the permittee shall comply with TAPCR 0400-30-39 for all emission sources subject to a requirement contained therein.

TAPCR 0400-30-39

D13 (SM1). **Gasoline Dispensing Facilities.** When applicable, the permittee shall comply with TAPCR 1200-03-18-.24 for all emission sources subject to a requirement contained therein.

D14 (SM1). **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 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 0400-30-39-.01.

(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 0400-30-39-.02.

TAPCR 0400-30-38 and 39

SECTION E

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

38-0039	Facility Description:	Specialty Chemicals Plant - See Source Specific Emission Standards

E1 (SM1). **Fee payment**

FEE EMISSIONS SUMMARY TABLE FOR MAJOR SOURCE 38-0069			
REGULATED POLLUTANTS	ALLOWABLE EMISSIONS (tons per AAP)	ACTUAL EMISSIONS (tons per AAP)	COMMENTS
PARTICULATE MATTER (PM)	7.88 SM1	AEAR	Includes all fee emissions.
PM_{10}	N/A	N/A	
SO_2	0.65 SM1	AEAR	Includes all fee emissions.
VOC	68.37 SM1	AEAR	Does not include VOC HAP with a standard.
NO_X	56.17 SM1	AEAR	Includes all fee emissions.
CATEGORY OF MISCELLANEOUS HAZARDOUS AIR POLLUTANTS (HAPs WITHOUT A STANDARD)*			
VOC FAMILY GROUP	N/A	N/A	
NON-VOC GASEOUS GROUP	N/A	N/A	
PM FAMILY GROUP	N/A	N/A	
CATEGORY OF SPECIFIC HAZARDOUS AIR POLLUTANTS (HAPs WITH A STANDARD)**			
VOC FAMILY GROUP			40 CFR 63 Subpart FFFF. Fee emissions are not included in VOC above.
Bis (2-ethylhexyl) Phthalate	1	AEAR	
Ethylene Glycol	2.8	AEAR	
Phthalic Anhydride	1.5	AEAR	
NON-VOC GASEOUS GROUP	N/A	N/A	
PM FAMILY GROUP	N/A	N/A	
CATEGORY OF NSPS POLLUTANTS NOT LISTED ABOVE***			
EACH NSPS POLLUTANT NOT LISTED ABOVE	N/A	N/A	

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 **Annual Accounting Period** at the time of modification issuance began **July 1, 2020** and ends **June 30, 2021.** The next Annual Accounting Period begins **July 1, 2021** and ends **June 30, 2022** 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 Attachment 12 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, SO_2, VOC, NO_X and so forth. See TAPCR 1200-03-26-.02(2)(i) for the definition of a regulated pollutant.),
(2) **each pollutant group** (VOC Family, Non-VOC Gaseous, and Particulate Family),
(3) the **Miscellaneous HAP Category,**
(4) the **Specific HAP Category**, and

(5) the **NSPS Category**

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

* **Category of Miscellaneous HAP (HAP Without A Standard):** This category is made-up of hazardous air pollutants that do not have a federal or state standard. Each HAP is classified into one of three groups, the **VOC Family** group**, the Non-VOC Gaseous** group**,** or the **Particulate (PM) Family** group**. For fee computation**, the **Miscellaneous HAP Category** is subject to the 4,000 ton cap provisions of subparagraph 1200-03-26-.02(2)(i) of the TAPCR.

** **Category of Specific HAP (HAP with A Standard):** This category is made-up of hazardous air pollutants (HAP) that are subject to Federally promulgated Hazardous Air Pollutant Standards that can be imposed under Chapter 1200-03-11 or Chapter 1200-03-31. Each individual hazardous air pollutant is classified into one of three groups, the **VOC Family** group**, the Non-VOC Gaseous** group**,** or the **Particulate (PM) Family** group**. For fee computation**, each individual hazardous air pollutant of the **Specific HAP Category** is subject to the 4,000 ton cap provisions of subparagraph 1200-03-26-.02(2)(i) of the TAPCR.

*** **Category of NSPS Pollutants Not Listed Above:** This category is made-up of each **N**ew **S**ource **P**erformance **S**tandard (**NSPS**) pollutant whose emissions are not included in the **PM**, **SO_2, VOC** or **NO_X** emissions from each source in this permit. **For fee computation**, each **NSPS pollutant not listed above** is subject to the 4,000 ton cap provisions of subparagraph 1200-03-26-.02(2)(i) of the TAPCR.

END NOTES

The permittee shall:

(1) Pay Title V **annual emission fees**, 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)(g). 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 emissions fees on an allowable emissions basis: pay annual allowable based emission fees for each annual accounting period no later than April 1 of each year pursuant to TAPCR 1200-03-26-.02(9)(d).

(3) Sources paying annual emissions 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 annual fee 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**.

(4) Sources paying annual emissions fees on 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 bases approved by the Technical Secretary (payment on an actual or mixed emissions basis) and payment on 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).

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

The annual emission fee due dates are specified in TAPCR 1200-03-26-.02(9)(g) 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 at the following address:

Payment of Fee to:		Actual Emissions Analyses to:
The Tennessee Department of Environment and Conservation	and	The Tennessee Department of Environment and Conservation
Division of Fiscal Services		Division of Air Pollution Control
Consolidated Fee Section – APC		Emission Inventory Program
William R. Snodgrass Tennessee Tower		William R. Snodgrass Tennessee Tower
312 Rosa L. Parks Avenue, 10th Floor		312 Rosa L. Parks Avenue, 15th Floor
Nashville, Tennessee 37243		Nashville, Tennessee 37243
		or
		An electronic copy (PDF) of actual emissions analysis can also be submitted to: apc.inventory@tn.gov

E2 (SM1). **Reporting requirements**.

(a) **Title V Semiannual reports.** The first report shall cover the period from **April 1** through **September 30** of each calendar year and from **October 1** of each calendar year through **March 31** of the following calendar year. Reports shall be submitted within 60 days after the end of each six-month period. The semiannual reports for Title V permit #570726 shall include:

(1) Any monitoring and recordkeeping required by Conditions ***E5-2, E5-3, E5-4, E7-4, E8-2, E8-3, E8-4, E9-2, E10-1, E10-2, E10-3, E10-4, E10-5, E11-1, and E12-8*** of this permit. 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 ***E4-1, E9-3, E10-1, and E12-7*** of this permit if required. 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 **ALL PERMIT REQUIREMENTS**.

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(b) of this permit.

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

(b) **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) 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)(2) 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

(4) 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.

The certification covering the full 12-month period shall be submitted within 60 days after each 12-month period ending **September 30.**

These certifications shall be submitted to:

Jackson Environmental Field Office
Division of Air Pollution Control
1625 Hollywood Drive
Jackson, Tennessee 38305
Or via email: APC.JackEFO@tn.gov

and

Air and EPCRA Enforcement Branch
US EPA Region IV
61 Forsyth Street, SW
Atlanta, Georgia 30303

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

(c) **Retention of Records** 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 his representative.

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

E3. MACT and NSPS Reporting Requirements.

E3-1. MACT and NSPS semiannual and annual reporting periods shall be synchronized with the semiannual and annual reporting periods for this Title V permit. The semiannual reporting periods of April-September and October-March and the annual reporting period of October-September have been established and are stipulated in **Conditions E2(a) and E2(b)**. The MACT and NSPS reports shall be submitted within 60 days after each six-month period ends. Unless otherwise noted, the MACT and NSPS reports shall be submitted within 60 days after each 6-month period ends or as outlined in Attachment 10.

All MACT and NSPS reports must be certified by a responsible official consistent with condition B4 of this permit and shall be submitted to: The Technical Secretary, Tennessee Division of Air Pollution Control, 312 Rosa L. Parks Avenue, 15TH Floor, Nashville, TN 37243 or electronic copy via email: Air.Pollution.Control@tn.gov

E3-2. Pursuant to 40 CFR § 63.2520(e), the permittee's semiannual compliance report for 40 CFR 63, Subpart FFFF must contain the following information:

(a) Company name and address.

(b) Statement by a responsible official with that official's name, title, and signature, certifying the accuracy of the content of the report.

(c) Date of report and beginning and ending dates of the reporting period.

(d) For each SSM during which excess emissions occur, the compliance report must include records that the procedures specified in the startup, shutdown, and malfunction plan (SSMP) were followed or documentation of actions taken that are not consistent with the SSMP, and include a brief description of each malfunction.

(e) The compliance report must contain the information on deviations, as defined below:

(1) If there are no deviations from any emission limit, operating limit or work practice standards specified in 40 CFR 63, Subpart FFFF, include a statement that there were no deviations from the emission limits, operating limits, or work practice standards during the reporting period.

(2) For each deviation from an emission limit, operating limit, and work practice standard that occurs at an affected source where a continuous monitoring system (CMS) is not used to comply with the emission limit or work practice standard in this subpart, the permittee must include the information below. This includes periods of SSM.

(i) The total operating time of the affected source during the reporting period.

(ii) Information on the number, duration, and cause of deviations (including unknown cause, if applicable), as applicable, and the corrective action taken.

(iii) Operating logs of processes with batch vents from batch operations for the day(s) during which the deviation occurred, except operating logs are not required for deviations of the work practice standards for equipment leaks.

(3) If documented in the notification of compliance status report that an MCPU has Group 2 batch process vents because the non-reactive HAP is the only HAP and usage is less than 10,000 lb/yr, the total uncontrolled organic HAP emissions from the batch process vents in an MCPU will be less than 1,000 lb/yr for the anticipated number of standard batches, or total uncontrolled hydrogen halide and halogen HAP emissions from all batch process vents and continuous process vents in a process are less than 1,000 lb/yr, include the records associated with each calculation required by **Condition E3-3(e)** that exceeds an applicable HAP usage or emissions threshold.

(f) Include each new operating scenario which has been operated since the time period covered by the last compliance report and has not been submitted in the notification of compliance status report or a previous compliance report. For each new operating scenario, the permittee must provide verification that the operating conditions for any associated control or treatment device have not been exceeded and that any required calculations and engineering analyses have been performed. For the purposes of this paragraph, a revised operating scenario for an existing process is considered to be a new operating scenario.

(g) Records of process units added to a PUG as specified in **Condition E3-3(i)(4)** and records of primary product redeterminations as specified in **Condition E3-3(i)(5)**.

(h) Applicable records and information for periodic reports as specified in **Condition E11-17(e)**.

(i) Notification of process change.

(1) Except as specified in (2) below, whenever the permittee makes a process change, or change any of the information submitted in the notification of compliance status report or a previous compliance report, that is not within the scope of an existing operating scenario, the permittee must document the change in the compliance report. A process change does not include moving within a range of conditions identified in the standard batch, and a nonstandard batch does not constitute a process change. The notification must include all of the following information.

(i) A description of the process change.

(ii) Revisions to any of the information reported in the original notification of compliance status report.

(iii) Information required by the notification of compliance status report for changes involving the addition of processes or equipment at the affected source.

(2) The permittee must submit a report 60 days before the scheduled implementation date of any of the following changes:

(i) Any change to the information contained in the precompliance report.

(ii) A change in the status of a control device from small to large.

(iii) A change from Group 2 to Group 1 for any emission point except for batch process vents that meet the conditions specified in **Condition E11-15(f)**.

E3-3. Pursuant to 40 CFR § 63.2525, the permittee must keep the following records for 40 CFR 63, Subpart FFFF:

(a) Each applicable record required by subpart A of 40 CFR part 63 and in referenced subparts F, G, SS, UU, WW, and GGG of 40 CFR part 63 and in referenced subpart F of 40 CFR part 65.

(b) Records of each operating scenario as specified in (b)(1) through (8) below:

(1) A description of the process and the type of process equipment used.

(2) An identification of related process vents, including their associated emissions episodes if not complying with the alternative standard in 40 CFR §63.2505; wastewater point of determination (POD); storage tanks; and transfer racks.

(3) The applicable control requirements of this subpart, including the level of required control, and for vents, the level of control for each vent.

(4) The control device or treatment process used, as applicable, including a description of operating and/or testing conditions for any associated control device.

(5) The process vents, wastewater POD, transfer racks, and storage tanks (including those from other processes) that are simultaneously routed to the control device or treatment process(s).

(6) The applicable monitoring requirements of this subpart and any parametric level that assures compliance for all emissions routed to the control device or treatment process.

(7) Calculations and engineering analyses required to demonstrate compliance.

(8) For reporting purposes, a change to any of these elements not previously reported, except for paragraph (b)(5) of this section, constitutes a new operating scenario.

(c) A schedule or log of operating scenarios for processes with batch vents from batch operations updated each time a different operating scenario is put into effect.

(d) The information specified in (d)(1) and (2) below for Group 1 batch process vents in compliance with a percent reduction emission limit in Table 2 to 40 CFR 63, Subpart FFFF if some of the vents are controlled to less the percent reduction requirement.

(1) Records of whether each batch operated was considered a standard batch.

(2) The estimated uncontrolled and controlled emissions for each batch that is considered to be a nonstandard batch.

(e) The information specified in (e)(2), (3), or (4) below, as applicable, for each process with Group 2 batch process vents or uncontrolled hydrogen halide and halogen HAP emissions from the sum of all batch and continuous process vents less than 1,000 lb/yr. No records are required for situations described in (e)(1) below.

(1) No records are required if the notification of compliance status report documented that the MCPU meets any of the situations described in (e)(1)(i), (ii), or (iii) below.

(i) The MCPU does not process, use, or generate HAP.

(ii) The Group 2 batch process vents are controlled using a flare that meets the requirements of 40 CFR §63.987.

(iii) The Group 2 batch process vents are controlled using a control device for which the determination of worst case for initial compliance includes the contribution of all Group 2 batch process vents.

(2) If the notification of compliance status report documented that an MCPU has Group 2 batch process vents because the non-reactive organic HAP is the only HAP and usage is less than 10,000 lb/yr, as specified in **Condition E11-15(g)**, the permittee must keep records of the amount of HAP material used, and calculate the daily rolling annual sum of the amount used no less frequently than monthly. If a record indicates usage exceeds 10,000 lb/yr, the permittee must estimate emissions for the preceding 12 months based on the number of batches operated and the estimated emissions for a standard batch, and the permittee must begin recordkeeping as specified in (e)(4) below. After 1 year, the permittee may revert to recording only usage if the usage during the year is less than 10,000 lb.

(3) If the notification of compliance status report documented that total uncontrolled organic HAP emissions from the batch process vents in an MCPU will be less than 1,000 lb/yr for the anticipated number of standard batches, then the permittee must keep records of the number of batches operated and calculate a daily rolling annual sum of batches operated no less frequently than monthly. If the number of batches operated results in organic HAP emissions that exceed 1,000 lb/yr, the permittee must estimate emissions for the preceding 12 months based on the number of batches operated and the estimated emissions for a standard batch, and the permittee must begin recordkeeping as specified in (e)(4) below. After 1 year, the permittee may revert to recording only the number of batches if the number of batches operated during the year results in less than 1,000 lb of organic HAP emissions.

(4) If none of the conditions specified in (e)(1) through (3) above are met, the permittee must keep records of the information specified in (e)(4)(i) through (iv) below.

(i) A record of the day each batch was completed and/or the operating hours per day for continuous operations with hydrogen halide and halogen emissions.

(ii) A record of whether each batch operated was considered a standard batch.

(iii) The estimated uncontrolled and controlled emissions for each batch that is considered to be a nonstandard batch.

(iv) Records of the daily 365-day rolling summations of emissions, or alternative records that correlate to the emissions (e.g., number of batches), calculated no less frequently than monthly.

(f) A record of each time a safety device is opened to avoid unsafe conditions in accordance with 40 CFR §63.2450(s).

(g) In the SSMP required by 40 CFR §63.6(e)(3), the permittee is not required to include Group 2 emission points, unless those emission points are used in an emissions average. For equipment leaks, the SSMP requirement is limited to control devices and is optional for other equipment.

E3-4. Pursuant to 40 CFR §63.7550, the permittee must submit annual, or five-year, 40 CFR 63, Subpart DDDDD compliance reports, whichever is applicable. In order to synchronize the reporting period with the Title V reporting period, the first 40 CFR 63, Subpart DDDDD compliance report must cover the period beginning January 31, 2013 and ending on either September 30, 2013 if reporting annually, or September 30, 2018 if reporting every five years, whichever is applicable. Reports must be postmarked or delivered no later than 60 days after the report period ends. Subsequent compliance reports shall be submitted within 60 days after the end of each annual or five-year period following the first report. The compliance reports must contain the information required in (a) through (e) below:

(a) Company and Facility name and address.

(b) Process unit information, emissions limitations, and operating parameter limitations.

(c) Date of report and beginning and ending dates of the reporting period.

(d) The total operating time during the reporting period.

(e) Include the date of the most recent tune-up for each unit subject to only the requirement to conduct an annual or five-year tune-up according to **Condition E6-8(c) or (d)**, respectively. Include the date of the most recent burner inspection if it was not done annually or on a five-year period and was delayed until the next scheduled or unscheduled unit shutdown.

E3-5. Pursuant to 40 CFR §63.7555 and §63.7560, the permittee must keep the following records pertaining to 40 CFR 63, Subpart DDDDD in a form suitable and readily available for expeditious review, according to §63.10(b)(1). The permittee must keep each record for five years following the date of each occurrence, measurement, maintenance, corrective action, report, or record. Each record must be kept on site, or they must be accessible from on site (for example, through a computer network), for at least two years after the date of each occurrence, measurement, maintenance, corrective action, report, or record, according to § 63.10(b)(1). Records may be kept off site for the remaining three years.

(a) A copy of each notification and report submitted to comply with subpart DDDDD, including all documentation supporting any Initial Notification or Notification of Compliance Status or compliance report submitted, according to the requirements in § 63.10(b)(2)(xiv).

(b) Records of performance tests, fuel analyses, or other compliance demonstrations and performance evaluations as required in § 63.10(b)(2)(viii).

(c) If the permittee operates a unit in the unit designed to burn gas 1 subcategory, and an alternative fuel other than natural gas, refinery gas, gaseous fuel subject to another subpart under part 63, other gas 1 fuel, or gaseous fuel subject to another subpart of part 63 or part 60, 61, or 65, is used, the permittee must keep records of the total hours per calendar year that alternative fuel is burned and the total hours per calendar year that the unit operated during periods of gas curtailment or gas supply emergencies.

(d) Records of the calendar date, time, occurrence and duration of each startup and shutdown.

(e) Records of the type(s) and amount(s) of fuels used during each startup and shutdown.

E3-6. Pursuant to 40 CFR §60.4214(d), if the permittee's emergency stationary ICE is contractually obligated to be available for operation or is operated for the purposes specified in §§60.4211(f)(3)(i), the permittee shall prepare and submit an annual report under 40 CFR 60, Subpart IIII. In order to synchronize the reporting period with the Title V reporting period, the first 40 CFR 60, Subpart IIII report must cover the period beginning January 1, 2015 and ending on September 30, 2015. Reports must be postmarked or delivered no later than 60 days after the report period ends. Subsequent compliance reports shall be submitted within 60 days after the end of each 12-month period following the first report. The reports must contain the information required in (a) through (g) below:

(a) Company name and address where the engine is located.

(b) Date of the report and beginning and ending dates of the reporting period.

(c) Engine site rating and model year.

(d) Latitude and longitude of the engine in decimal degrees reported to the fifth decimal place.

(e) Reserved

(f) Reserved

(g) Hours spent for operation for the purposes specified in § 60.4211(f)(3)(i), including the date, start time, and end time for engine operation for the purposes specified in § 60.4211(f)(3)(i). The report must also identify the entity that dispatched the engine and the situation that necessitated the dispatch of the engine.

E4. General Permit Requirements.

E4-1. Unless otherwise specified, visible emissions from any stack at this facility shall not exhibit greater than 20% opacity, except for one six-minute period in any one hour period, and for no more than four six-minute periods in any 24-hour period. Visible emissions shall be determined by EPA Method 9, as published in the current 40 CFR 60, Appendix A (six-minute average). TAPCR 1200-03-05-.01(1) and 1200-03-05-.03(6)

Compliance Method: The permittee shall assure compliance with the opacity standard by utilizing the opacity matrix dated June 18, 1996 (amended on September 11, 2013) that is enclosed as Attachment 1. Reports and certifications shall be submitted in accordance with **Condition E2** of this permit.

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.

E4-2. Reasonable precautions must be taken to prevent the generation of fugitive dust as these precautions are defined in Rule 1200-03-08-.01 of the Tennessee Air Pollution Control Regulations.

E4-3. Documentation for all VOC and HAP containing materials used along with material safety data sheets must be maintained and kept available for inspection by the Technical Secretary or his representative. These records must be retained for a period of not less than five years. TAPCR 1200-03-09

E4-4. The associated air pollution control equipment shall be in place and operational during all times of source operation.

TAPCR 1200-03-09

E4-5. Upon the malfunction/failure of any emission control device(s) serving this source, the operation of the process(es) served by the device(s) shall be regulated by Chapter 1200-03-20 of the Tennessee Air Pollution Control Regulations.

E4-6. Title V Operating Permit No. 570726 represents the second renewal of the original Title V Operating Permit No. 546546 issued June 3, 2002, and all subsequent revisions to the original Title V permit.

E4-7. **Accidental release plan.** The permittee is not required to file an accidental release plan pursuant to Section 112(r) of the Clean Air Act and 1200-03-32 of TAPCR.

E4-8 (SM1). Reserved – SM1 deletes this condition.

E4-9. Recordkeeping, data collection, monitoring and reporting for any new requirements not previously specified in the original Title V permit or any of its revisions, shall commence on the first day of the calendar month that occurs no later than 60 days after the issuance date of this Title V permit renewal unless stipulated otherwise. TAPCR 1200-03-09

E4-10. Regarding recordkeeping of logs, the following is applicable. TAPCR 1200-03-09

(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 7 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 7 days from the end of the day for which the data is required.

E4-11. Logs and records specified in this permit shall be made available upon request by the Technical Secretary or his representative and shall be retained for a period of not less than five years unless otherwise noted. Logs and records contained in this permit may be based on a recommended format. Any logs that have an alternative format may be utilized provided such logs contain the same information that is required. Computer-generated logs are also acceptable. Logs and records are not required to be submitted semiannually unless specified in **Condition E2(a)(1)**. TAPCR 1200-03-09

E4-12 (SM1). The boilers (Boiler #3, Boiler #4, Boiler #5 and Boiler #6) at this facility are subject to the requirements of the National Emission Standard for Hazardous Air Pollutants for Industrial, Commercial and Institutional Boilers and Process

Heaters (40 CFR 63 Subpart DDDDD), as referenced below. The permittee shall comply with the requirements of (a) through (i) below:

(a) Pursuant to 40 CFR §63.7500, the permittee must comply with the following requirements at all times:

(1) The permittee must meet the work practice standard in Table 3 to subpart DDDDD as follows:

If the unit is . . .	The permittee must. . .
A new boiler with a continuous oxygen trim system that maintains an optimum air to fuel ratio	Conduct a tune-up of the boiler every 5 years as specified in **E4-12(d)**.
A new or existing boiler without a continuous oxygen trim system and with heat input capacity of 10 million Btu per hour or greater.	Conduct a tune-up of the boiler annually as specified in **E4-12(c)**.

(2) At all times, the permittee must operate and maintain any affected source, including associated air pollution control equipment and monitoring equipment, in a manner consistent with safety and good air pollution control practices for minimizing emissions. Determination of whether such operation and maintenance procedures are being used will be based on information available to the Technical Secretary that may include, but is not limited to, monitoring results, review of operation and maintenance procedures, review of operation and maintenance records, and inspection of the source.

(b) Pursuant to 40 CFR §§63.7510(g) and 63.7515(d), the permittee must demonstrate initial compliance with the applicable work practice standard in Table 3 within the applicable annual or five-year schedule following January 31, 2013 as specified in **Condition E4-12(c) or (d)**. The first annual or five-year tune-up must be no later than 13 months or 61 months, respectively, after the initial startup of the new affected source which was reported to have occurred on August 24, 2012. Thereafter, the permittee is required to complete the applicable annual or five-year tune-up no more than 13 months or 61 months, respectively, after the previous tune-up.

(c) Pursuant to 40 CFR §63.7540(a)(10), the permittee must conduct a tune-up of the boiler or process heater annually to demonstrate continuous compliance as specified in (1) through (6) below.

(1) As applicable, inspect the burner, and clean or replace any components of the burner as necessary (the permittee may delay the burner inspection until the next scheduled unit shutdown). At units where entry into a piece of process equipment or into a storage vessel is required to complete the tune-up inspections, inspections are required only during planned entries into the storage vessel or process equipment;

(2) Inspect the flame pattern, as applicable, and adjust the burner as necessary to optimize the flame pattern. The adjustment should be consistent with the manufacturer's specifications, if available;

(3) Inspect the system controlling the air-to-fuel ratio, as applicable, and ensure that it is correctly calibrated and functioning properly (the permittee may delay the inspection until the next scheduled unit shutdown).

(4) Optimize total emissions of CO. This optimization should be consistent with the manufacturer's specifications, if available, and with any NO_X requirement to which the unit is subject;

(5) Measure the concentrations in the effluent stream of CO in parts per million, by volume, and oxygen in volume percent, before and after the adjustments are made (measurements may be either on a dry or wet basis, as long as it is the same basis before and after the adjustments are made). Measurements may be taken using a portable CO analyzer; and

(6) Maintain on-site and submit, if requested by the Technical Secretary, an annual report containing the information in (i) through (iii) below:

(i) The concentrations of CO in the effluent stream in parts per million by volume, and oxygen in volume percent, measured at high fire or typical operating load, before and after the tune-up of the boiler;

(ii) A description of any corrective actions taken as a part of the tune-up; and

(iii) The type and amount of fuel used over the 12 months prior to the tune-up, but only if the unit was physically and legally capable of using more than one type of fuel during that period. Units sharing a fuel meter may estimate the fuel used by each unit.

(d) Pursuant to 40 CFR §63.7540(a)(12), if the affected boiler or process heater has a continuous oxygen trim system that maintains an optimum air to fuel ratio, the permittee must conduct a tune-up of the boiler or process heater every 5 years as specified in **Condition E4-12(c)** to demonstrate continuous compliance. The permittee may delay the burner inspection specified **Condition E4-12(c)(1)** until the next scheduled or unscheduled unit shutdown but must be inspected at least once every 72 months.

(e) Pursuant to 40 CFR §63.7540(a)(13), if the unit is not operating on the required date for a tune-up, the tune-up must be conducted within 30 calendar days of startup.

(f) Pursuant to 40 CFR §63.7540(b), the permittee must report each instance in which the work practice standard in Table 3 to subpart DDDDD was not met. These instances are deviations from the emission limits in this subpart. These deviations must be reported according to the requirements in **Condition E4-12**.

(g) Reserved

(h) Pursuant to 40 CFR §63.7545(f), if the permittee intends to use a fuel other than natural gas, refinery gas, gaseous fuel subject to another subpart of part 63, part 60, 61, or 65, or other gas 1 fuel to fire the affected unit during a period of natural gas curtailment or supply interruption, as defined in § 63.7575, the permittee must submit a notification of alternative fuel use within 48 hours of the declaration of each period of natural gas curtailment or supply interruption, as defined in §63.7575. The notification must include the information specified in (1) through (5) below:

(1) Company name and address.

(2) Identification of the affected unit.

(3) Reason for inability to use natural gas or equivalent fuel, including the date when the natural gas curtailment was declared or the natural gas supply interruption began.

(4) Type of alternative fuel that is intended to be used.

(5) Dates when the alternative fuel use is expected to begin and end.

(i) Pursuant to 40 CFR §63.7565, the permittee must comply with the applicable General Provisions according to Table 10 to 40 CFR 63 Subpart DDDDD (Attachment 7).

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

E4-13. Natural gas, fuel oil and spent alcohol only shall be used as fuel for Boilers #3, #4, #5 and #6. Fuel oil (Up to No. 6 fuel oil) and spent alcohol shall only be used during periods of gas curtailment, gas supply emergencies, or periodic testing on liquid fuel (less than 48 hours of testing during any calendar year). This condition is established pursuant to Rule 1200-03-06-.01(7) of TAPCR and the agreement contained in the letter dated November 17, 2016 from the permittee.

E4-14. The following storage tanks are no longer subject to the Federal New Source Performance Standards as specified in 40 CFR Part 60, Subpart Kb, Standards of Performance Volatile Organic Liquid Storage Vessels (Including Petroleum Liquid Storage Vessels) for which Construction, Reconstruction, or Modification Commenced After July 23, 1984; and therefore, they have been deemed insignificant activities per TAPCR 1200-03-09-.04(5)(a)4.

Tank I.D.	Capacity*
5	15,220
6	15,220
10	24,943
11	15,220
29	100,593
30	100,593
31	15,220

Tank I.D.	Capacity*
53	204,738
54	50,497
55	204,738
56	100,593
57	204,738
58	204,738
61	29,770

Tank I.D.	Capacity*
74	204,620
76	100,593
RA Tank 3	12,078
RA Tank 4	12,078
RA Tank 11	12,078
RA Tank 12	12,078
Hold Tank 5	11,013

Tank I.D.	Capacity*
33	11,013
34	11,013
37	20,293
41	25,366
42	25,366
43	13,892
44	13,892
45	24,849
46	24,849
51	50,497
52	50,497

Tank I.D.	Capacity*
62	29,770
63	29,770
64	29,770
65	29,770
66	29,770
67	29,770
68	29,770
69	29,770
71	50,497
72	50,497
73	50,497

Tank I.D.	Capacity*
Hold Tank 6	11,013
Hold Tank 7	29,770
Hold Tank 8	29,770
Hold Tank 9	29,770
Hold Tank 10	29,770
Hold Tank 11	29,770
Hold Tank 12	29,770
Hold Tank 13	29,770
FP Tank 3	10,683
FP Tank 4	10,683

* For the above listed storage tanks, the true vapor pressure of the actual material stored is less than the NSPS threshold that corresponds to the maximum storage capacity, i.e. maximum tank capacity ≥ 39,890 gallons, the vapor pressure of the material stored is less than 3.5 kPa, and maximum tank capacity > 19,813 gallons, but < 39,890 gallons, the vapor pressure of the material stored is less than 15.0 kPa. Tanks with maximum capacity < 19,813 gallons and process tanks are no longer subject to the requirements of 40 CFR 60, Subpart Kb.

E4-15 (SM1). Identification of Responsible Official, Technical Contact, and Billing Contact:

(a) The applications that were utilized in the preparation of this permit are dated August 13, 2015 and November 27, 2019 and are signed by Responsible Official Robert Lincer, General Manager of the permitted facility. If this person terminates employment or is assigned different duties and is no longer a Responsible Official for this facility as defined in part 1200-03-09-.02(11)(b)21 of the Tennessee Air Pollution Control Regulations, 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 applications that were utilized in the preparation of this permit are dated July 24, 2015 and November 27, 2019 and identify Susan Paris as the Principal Technical Contact for the permitted facility. If this person terminates employment or is assigned different duties and is 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 applications that were utilized in the preparation of this permit are dated July 24, 2015 and November 27, 2019. The application dated November 27, 2019 identifies Robert Lincer as the Billing Contact for the permitted facility. If this person terminates employment or is assigned different duties and is 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.

TAPCR 1200-03-09

Source Specific Emission Standards:

38-0039-01	**Source Identification**	**Boiler #3 (31.7 MMBtu/hr)** Fueled by Natural Gas, up to and including #6 Fuel Oil, or a Mixture of #6 Fuel Oil and Spent Alcohol **(MACT, Subpart DDDDD)**

Conditions E5-1 through E5-6 apply to source 38-0039-01

E5-1. The total stated design heat input capacity of this source is 31.7 million British thermal units per hour (MMBtu/hr), on a daily average basis. This is the capacity of the boiler as stated in the application dated December 23, 1996.

TAPCR 1200-03-09

Compliance Method: This condition is a statement of design input capacity for this source. If the permittee wishes to increase the design or maximum capacity of this source, the permittee shall pursue the appropriate Title V procedure in accordance with 1200-03-09-.02(11) of TAPCR. If a construction permit is applied for, this shall be done in accordance with 1200-03-09-.01(1) of TAPCR.

E5-2. Particulate matter (PM) emitted from this source shall not exceed 4.5 pounds per hour and 16.9 tons during any 12-consecutive month period. These emission limitations are established pursuant to Rule 1200-03-06-.01(7) of the Tennessee Air Pollution Control regulations and the information contained in the agreement letters dated June 11, 1992 and January 25, 2002, respectively, from the permittee.

Compliance Method: Compliance with the hourly emission limit is assured by compliance with **Condition E5-5** at maximum #6 fuel oil usage rate of 211 gallons per hour at 150,000 Btu per gallon. To show compliance with the 12-consecutive month emission limit, the permittee shall maintain records of fuel usage in boiler #3 and calculate the monthly PM emission rate and record the results in a format (see example below) that readily shows compliance with annual PM emission limit**.** These records must be maintained at the source location and kept available for inspection by the Technical Secretary or his representative. These logs must also be reported in accordance with **Condition E2** of this permit and be retained for a period of not less than five years.

MONTHLY FUEL USAGE LOG and PM emissions for boiler 03 (38-0039-01)

Month/Year	Fuel Type, ie. NG, #2 Fuel Oil, #3 Fuel oil, etc…	Fuel usage (ft^3 or gallon/month)	Emission Factor	PM emissions (Tons per Month)	PM emissions (Tons per 12-Consecutive Months)

E5-3. Sulfur dioxide (SO_2) emitted from this source shall not exceed 59.7 pounds per hour and 240.0 tons during any 12-consecutive month period. These emission limitations are established pursuant to Rule 1200-03-14-.01(3) of the Tennessee Air Pollution Control regulations and the information contained in the agreement letters dated June 11, 1992 and July 18, 1995 from the permittee.

Compliance Method: Compliance with the hourly emission limit is assured by compliance with **Conditions E5-4 and E5-5** at maximum #6 fuel oil usage rate of 211 gallons per hour at 150,000 Btu per gallon. To show compliance with the 12-consecutive month emission limit, the permittee shall maintain records of fuel usage in boiler #3 and calculate the monthly SO_2 emission rate and record the results in a format (see example below) that readily shows compliance with annual SO_2 emission limit**.** For purposes of simplifying calculations required by this permit, the sulfur content of the fuel oil shall be used when calculating SO_2 emissions from any mixture of fuel oil and spent alcohol. These records must be maintained at the source location and kept available for inspection by the Technical Secretary or his representative. These logs must also be reported in accordance with **Condition E2** of this permit and be retained for a period of not less than five years.

MONTHLY FUEL USAGE LOG and SO_2 emissions for boiler 03 (38-0039-01)

Month/Year	Fuel Type, ie. NG, #2 Fuel Oil, #3 Fuel oil, etc…	Fuel usage (ft^3 or gallon/month)	Emission Factor	SO_2 emissions (Tons per Month)	SO_2 emissions (Tons per 12-Consecutive Months)

E5-4. The sulfur content of the fuel oil shall not exceed 1.8 percent by weight. This limitation is established pursuant to TAPCR 1200-03-26-.02(9)(g) and the information contained in the agreement letter dated June 11, 1992 from the permittee.

Compliance Method: The permittee shall obtain certification from the fuel supplier of the fuel sulfur content (by weight) for each shipment of fuel oil. Records must be retained for a period of not less than five years. Certifications shall be submitted in accordance with **Condition E2** of this permit.

E5-5. Natural gas, fuel oil (up to and including #6), and fuel oil (up to and including #6) commingled with spent alcohol shall be the only fuels used for this source. TAPCR 1200-03-09

E5-6. For fee purposes, the permittee shall calculate its actual oxides of nitrogen (NO_x) emissions, particulate matter (PM) emissions, sulfur dioxide (SO_2) emissions, and volatile organic compound (VOC) emissions for each fiscal year from this fuel-burning source using EPA, AP-42 emission factors (Attachments 5 and 6), in conjunction with fuel usage records (natural gas and fuel oil) and the sulfur content of the fuel. The results of these calculations shall be recorded and maintained in tabular form (see example below) and shall be retained for a period of not less than five years. These logs must also be reported in accordance with **Condition E1** of this permit. TAPCR 1200-03-09

Fiscal Year log of emissions for 38-0039-01 July 1, ______ to June 30, _______

Pollutant	Emissions from NG (tons)	Emissions from liquid fuels (tons)	Total Emissions (tons)
NO_x			
SO_2			
PM			
VOC			

38-0039-04	**Boiler #6 (43.27 MMBTU/Hour)** Fueled by Natural Gas	**(NSPS, Subpart Dc & MACT, Subpart DDDDD)**

Conditions E6-1 through E6-8 apply to source 38-0039-04

E6-1. The total stated design heat input capacity for this source is 43.27 million British thermal units per hour (MMBtu/hr), on a daily average basis. This is the capacity of the boiler as stated in the application dated September 24, 2012. TAPCR 1200-03-09

Compliance Method: This condition is a statement of design input capacity for this fuel burning source. If the permittee wishes to increase the design capacity of this source, the permittee shall pursue the appropriate Title V procedure in accordance with 1200-03-09-.02(11) of TAPCR. If a construction permit is applied for, this shall be done in accordance with 1200-03-09-.01(1) of TAPCR.

E6-2. Only natural gas shall be used as fuel for this source. TAPCR 1200-03-09

E6-3. The NO_x emissions from this source shall not exceed 50 pounds NO_x per million cubic feet of natural gas combusted (AP-42 Table 1.4-1 Controlled low-NOx burners). TAPCR 1200-03-06-.03(2)

Compliance Method: The permittee has specified that this unit is equipped with low-NO_x burners with flue gas recirculation. This source shall not operate unless the low-NO_x burners with flue gas recirculation are fully operational. Documentation from the manufacturer for this unit which specifies that these features are present and which also provides NO_x emission factors shall be maintained onsite and shall be made available to the Technical Secretary or his representative.

E6-4. Particulate matter (PM) emitted from this source shall not exceed 0.33 pounds per hour, nor 1.44 tons per year. This condition is established pursuant to Rule 1200-03-06-.01(7) of TAPCR and the agreements contained in the letters dated September 21, 2011 and September 24, 2012 from the permittee.

Compliance Method: Compliance shall be assured by firing only natural gas at the rated capacity listed in **Condition E6-1**, and the emission factor for particulate matter from AP-42, Chapter 1.4**,** Natural Gas Combustion**.**

E6-5. Sulfur dioxide (SO_2) emitted from this source shall not exceed 0.03 pounds per hour, nor 0.11 tons per year. This condition is established pursuant to Rule 1200-03-14-.01(3) of TAPCR and the agreement contained in the letter dated September 21, 2011 from the permittee.

Compliance Method: Compliance shall be assured by firing only natural gas at the rated capacity listed in **Condition E6-1**, and the emission factor for sulfur dioxide from AP-42, Chapter 1.4**,** Natural Gas Combustion**.**

E6-6. Pursuant to 40 CFR §60.48c(g)(1) and (2), a log of the actual quantity of fuel used per month at this source must be maintained at the source location (see example below) and kept available for inspection by the Technical Secretary or his representative. These logs must be retained for a period of not less than five years.

Monthly Fuel Usage Log for 38-0039-04 Year__________

Month	NG Usage (ft^3)	Month	NG Usage (ft^3)
January		July	
February		August	
March		September	
April		October	
May		November	
June		December	

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

E6-7. For fee purposes, the permittee shall calculate its actual oxides of nitrogen (NO_x) emissions, particulate matter (PM) emissions, sulfur dioxide (SO_2) emissions, and volatile organic compound (VOC) emissions for each fiscal year from this fuel-burning source using EPA, AP-42 emission factors (Attachments 5 and 6), in conjunction with fuel usage records. The results of these calculations shall be recorded and maintained in tabular form (see example below) and shall be retained for a period of not less than five years. These logs must also be reported in accordance with **Condition E1** of this permit. TAPCR 1200-03-26-.02(9)

Fiscal Year log of emissions for 38-0039-04 July 1, ______ to June 30, _______

Pollutant	Emissions from NG (tons)	Total Emissions (tons)
NO_x		
SO_2		
PM		
VOC		

E6-8 (SM1). This new (construction commenced after June 4, 2010) industrial boiler located at a major source of hazardous air pollutants is subject to 40 CFR 63 Subpart DDDDD (National Emission Standards for Hazardous Air Pollutants for Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters), as referenced below. The permittee shall comply with the following requirements of (a) through (i) below:

(a) Pursuant to 40 CFR §63.7500, the permittee must meet the following requirements at all times:

(1) The permittee must meet the work practice standard in Table 3 to subpart DDDDD as follows:

If the unit is . . .	The permittee must. . .
A new boiler with a continuous oxygen trim system that maintains an optimum air to fuel ratio	Conduct a tune-up of the boiler every five years as specified in **E6-8(d)**.
A new boiler without a continuous oxygen trim system and with heat input capacity of 10 million Btu per hour or greater.	Conduct a tune-up of the boiler annually as specified in **E6-8(c)**.

(2) At all times, the permittee must operate and maintain any affected source, including associated air pollution control equipment and monitoring equipment, in a manner consistent with safety and good air pollution control practices for minimizing emissions. Determination of whether such operation and maintenance procedures are being used will be based on information available to the Technical Secretary that may include, but is not limited to, monitoring results, review of operation and maintenance procedures, review of operation and maintenance records, and inspection of the source.

(b) Pursuant to 40 CFR § 63.7510(g) and 63.7515(d), the permittee must demonstrate initial compliance with the applicable work practice standard in Table 3 within the applicable annual or five-year schedule following January 31, 2013 as specified in **Condition E6-8(c) or (d)**. The first annual or five-year tune-up must be no later than 13 months or 61 months, respectively, after the initial startup of the new affected source which was reported to have occurred on August 24, 2012. Thereafter, the permittee is required to complete the applicable annual or five-year tune-up no more than 13 months or 61 months, respectively, after the previous tune-up.

(c) Pursuant to 40 CFR §63.7540(a)(10), the permittee must conduct a tune-up of the boiler or process heater annually to demonstrate continuous compliance as specified in (1) through (6) below.

(1) As applicable, inspect the burner, and clean or replace any components of the burner as necessary (the permittee may delay the burner inspection until the next scheduled unit shutdown). At units where entry into a piece of process equipment or into a storage vessel is required to complete the tune-up inspections, inspections are required only during planned entries into the storage vessel or process equipment;

(2) Inspect the flame pattern, as applicable, and adjust the burner as necessary to optimize the flame pattern. The adjustment should be consistent with the manufacturer's specifications, if available;

(3) Inspect the system controlling the air-to-fuel ratio, as applicable, and ensure that it is correctly calibrated and functioning properly (the permittee may delay the inspection until the next scheduled unit shutdown).

(4) Optimize total emissions of CO. This optimization should be consistent with the manufacturer's specifications, if available, and with any NO_X requirement to which the unit is subject;

(5) Measure the concentrations in the effluent stream of CO in parts per million, by volume, and oxygen in volume percent, before and after the adjustments are made (measurements may be either on a dry or wet

basis, as long as it is the same basis before and after the adjustments are made). Measurements may be taken using a portable CO analyzer; and

(6) Maintain on-site and submit, if requested by the Technical Secretary, an annual report containing the information in (i) through (iii) below:

(i) The concentrations of CO in the effluent stream in parts per million by volume, and oxygen in volume percent, measured at high fire or typical operating load, before and after the tune-up of the boiler;

(ii) A description of any corrective actions taken as a part of the tune-up; and

(iii) The type and amount of fuel used over the 12 months prior to the tune-up, but only if the unit was physically and legally capable of using more than one type of fuel during that period. Units sharing a fuel meter may estimate the fuel used by each unit.

(d) Pursuant to 40 CFR §63.7540(a)(12), if the affected boiler or process heater has a continuous oxygen trim system that maintains an optimum air to fuel ratio, the permittee must conduct a tune-up of the boiler or process heater every 5 years as specified in **Condition E6-8(c)** to demonstrate continuous compliance. The permittee may delay the burner inspection specified **Condition E6-8(c)(1)** until the next scheduled or unscheduled unit shutdown, but each burner must be inspected at least once every 72 months.

(e) Pursuant to 40 CFR §63.7540(a)(13), if the unit is not operating on the required date for a tune-up, the tune-up must be conducted within 30 calendar days of startup.

(f) Pursuant to 40 CFR §63.7540(b), the permittee must report each instance in which you the work practice standard in Table 3 to subpart DDDDD was not met. These instances are deviations from the emission limits in this subpart. These deviations must be reported according to the requirements in **Condition E3-4**.

(g) Reserved

(h) Pursuant to 40 CFR §63.7545(f), if the permittee intends to use a fuel other than natural gas, refinery gas, gaseous fuel subject to another subpart of part 63, part 60, 61, or 65, or other gas 1 fuel to fire the affected unit during a period of natural gas curtailment or supply interruption, as defined in § 63.7575, the permittee must submit a notification of alternative fuel use within 48 hours of the declaration of each period of natural gas curtailment or supply interruption, as defined in §63.7575. The notification must include the information specified in (1) through (5) below:

(1) Company name and address.

(2) Identification of the affected unit.

(3) Reason for inability to use natural gas or equivalent fuel, including the date when the natural gas curtailment was declared or the natural gas supply interruption began.

(4) Type of alternative fuel that is intended to be used.

(5) Dates when the alternative fuel use is expected to begin and end.

(i) Pursuant to 40 CFR §63.7565, the permittee must comply with the applicable General Provisions according to Table 10 to 40 CFR 63 Subpart DDDDD (Attachment 7).

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

38-0039-08	**Source Identification**	**Emergency Diesel IC Engines:** Two 305 HP engines for emergency water pumps. (NSPS, Subpart IIII, and MACT, Subpart ZZZZ)

Conditions E7-1 through E7-6 apply to source 38-0039-08

E7-1. The total rated heat input capacity of this source is 4,000,000 British Thermal Units per hour. This is the combined capacity of the engines as stated in the application dated August 15, 2012. TAPCR 1200-03-09

Compliance method: This condition is a statement of design input capacity for this source. If the permittee wishes to increase the design or maximum capacity of this source, the permittee shall pursue the appropriate Title V procedure in accordance with 1200-03-09-.02(11) of TAPCR. If a construction permit is applied for, this shall be done in accordance with 1200-03-09-.01(1) of TAPCR.

E7-2. Sulfur dioxide (SO_2) emitted from each engine shall not exceed 0.63 pounds per hour. TAPCR 1200-03-14-.03(5).

Compliance method: Compliance shall be assured by firing only diesel fuel within the specifications of **Condition E7-3(b)** at the rated capacities listed in **Condition E7-1**, and the emission factor for sulfur dioxide from AP-42, Chapter 3.3**,** Diesel Industrial Engines**.**

E7-3 (SM1). The new (manufactured after July 1, 2006) NFPA certified fire pump engines are subject to regulations under 40 CFR 60 Subpart IIII (Standards of Performance for Stationary Compression Ignition Internal Combustion Engines), as referenced below. The permittee's engines identified below shall comply with the requirements of (a) through (g) below:

Engine Make/Model	Engine Model YR	Engine Power (br-hp)
Clarke JU6H-UFADX8	2012	305
Clarke JU6H-UFADX8	2012	305

(a) Pursuant to 40 CFR §60.4205(c) and §60.4206, the fire pump engines with a displacement of less than 30 liters per cylinder must comply with the emission standards in table 4 to subpart IIII as shown below. The permittee must operate and maintain the engines to achieve these emission standards over the entire life of the engines.

Maximum engine power	**Model year(s)**	**NMHC + NOx** g/KW-hr (g/HP-hr)	**CO** g/KW-hr (g/HP-hr)	**PM** g/KW-hr (g/HP-hr)
225≤KW<450 (300≤HP<600)	2009+	4.0 (3.0)	3.5 (2.6)	0.20 (0.15)

(b) Pursuant to 40 CFR §60.4207, the permittee must use diesel fuel that meets the requirements of 40 CFR §80.510(b) for nonroad diesel fuel, except that any existing diesel fuel purchased (or otherwise obtained) prior to October 1, 2010, may be used until depleted.

(c) Monitoring for the emergency engine shall meet all applicable monitoring requirements specified in 40 CFR §60.4209, including the installation of a non-resettable hour meter and/or backpressure monitor, if required.

(d) Pursuant to 40 CFR §60.4211(a), the permittee shall:

(1) Operate and maintain the stationary CI internal combustion engine and control device according to the manufacturer's emission-related written instructions; and

(2) Change only those emission-related settings that are permitted by the manufacturer.

(e) Pursuant to 40 CFR §60.4211(c), the permittee has complied by purchasing an engine certified to the emission standards in **Condition E7-3(a)**. The engine must be installed and configured according to the manufacturer's emission-related specifications.

(f) Pursuant to 40 CFR §60.4211(f), emergency stationary ICE may be operated for the purpose of maintenance checks and readiness testing, provided that the tests are recommended by federal, state or local government, the manufacturer, the vendor, the regional transmission organization or equivalent balancing organization and transmission operator, or the insurance company associated with the engine. Any combination of maintenance checks and readiness testing, by such units is limited to 100 hours per calendar year. There is no time limit on the use of emergency stationary ICE in emergency situations. The permittee may petition the Technical Secretary for approval of additional hours to be used for maintenance checks and readiness testing, but a petition is not required if the permittee maintains records indicating that federal, state, or local standards require maintenance and testing of emergency ICE beyond 100 hours per calendar year. Emergency stationary ICE may be operated up to 50 hours per calendar year in non-emergency situations, but those 50 hours are counted as part of the 100 hours per calendar year provided for maintenance and testing and emergency demand response. The 50 hours per calendar year for non-emergency situations cannot be used for peak shaving or non-emergency demand response, or to generate income for a facility to supply power to an electric grid or otherwise supply non-emergency power as part of a financial arrangement with another entity, except as provided in §§60.4211(f)(3)(i). In order for the engine to be considered an emergency stationary ICE, any operation other than emergency operation, maintenance and testing, emergency demand response, and operation in non-emergency situations for 50 hours per year, as required in this condition, is prohibited. If the engine is not operated according to these requirements, it will not be considered an emergency engine and must meet all the requirements for non-emergency engines.

(g) Pursuant to 40 CFR §60.4218, the permittee must comply with the applicable General Provisions according to Table 8 to 40 CFR 60 Subpart IIII (Attachment 8).

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

E7-4. The permittee shall keep a log of the number of operating hours for each month and each 12-consecutive month interval at this source, in a form that readily shows compliance with this **Condition E7-3(f)** (see example below). All data, including all required calculations, must be entered in the log no later than 30 days from the end of the month for which the data is required. These logs must be maintained at the source location and kept available for inspection by the Technical Secretary or his representative. These logs must also be reported in accordance with Condition **E2** of this permit and be retained for a period of not less than five years. TAPCR 1200-03-09

MONTHLY/YEARLY LOG: Source 38-0039-08

Year:					
Month	Hours Per Month	Hours Per 12 Consecutive Months*	Month	Hours Per Month	Hours Per 12 Consecutive Months*
January			July		
February			August		
March			September		
April			October		
May			November		
June			December		

(*) The "Hours per 12 consecutive months" values are the sum of the hours in the 11 months preceding the month just completed + the hours in the month just completed. If data is not available for the 11 months preceding the initial use of this table, this value will be equal to the hours per month. For the second month it will be the sum of the first month and the second month. Indicate in parentheses the number of months summed [i.e., 3 (2) represents 3 hours operated in 2 months].

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

E7-5. The emergency engines driving the fire pumps are subject to regulations under 40 CFR Part 63, Subpart ZZZZ (National Emission Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines). Pursuant to 40 CFR 63.6590(c)(7), the permittee shall meet the requirements of 40 CFR Part 63, Subpart ZZZZ, by meeting the requirements of 40 CFR Part 60, Subpart IIII. No further requirements apply for these emergency engines under 40 CFR Part 63, Subpart ZZZZ.

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

E7-6. For fee purposes, the permittee shall calculate its annual actual oxides of nitrogen (NO_x) emissions, particulate matter (PM) emissions, sulfur dioxide (SO_2) emissions, and volatile organic compound (VOC) emissions from this fuel-burning source using appropriate AP42 or vendor supplied emission factors, in conjunction with hours of operation of each engine. The results of these calculations shall be recorded and maintained in tabular form (see example below) and shall be retained for a period of not less than five years. These records shall be reported in accordance with condition **E1** of this permit.

Fiscal Year log of total emissions from fire pump engines (38-0039-08)

Engine________________ July 1, ______ to June 30, _______

Emissions from fire pump engines

Pollutant	Operating time (hr)	Emission Factor (gm/hp-hr)	Emissions (tons)
NO_x			
SO_2			
PM			
VOC			

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

38-0039-16	Source Identification	**Boiler #4 (20.9 MMBTU/Hour)** Fueled by Natural Gas, up to and including #6 Fuel Oil, or a Mixture of #6 Fuel Oil and Spent Alcohol

Conditions E8-1 through E8-6 apply to source 38-0039-16

E8-1. The total stated design heat input capacity of this source is 20.9 million British thermal units per hour (MMBtu/hr), on a daily average basis. This is the capacity of the boiler as stated in the application dated December 23, 1996.

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

Compliance Method: This condition is a statement of design input capacity for this source. If the permittee wishes to increase the design or maximum capacity of this source, the permittee shall pursue the appropriate Title V procedure in accordance with 1200-03-09-.02(11) of TAPCR. If a construction permit is applied for, this shall be done in accordance with 1200-03-09-.01(1) of TAPCR.

E8-2. Particulate matter (PM) emitted from this source shall not exceed 2.9 pounds per hour and 4.2 tons during any 12-consecutive month period. These emission limitations are established pursuant to Rule 1200-03-06-.01(7) of the Tennessee Air Pollution Control regulations and the information contained in the agreement letters dated June 11, 1992 and January 25, 2002, respectively, from the permittee.

Compliance Method: Compliance with the hourly emission limit is assured by compliance with **Condition E8-5** at maximum #6 fuel oil usage rate of 139 gallons per hour at 150,000 Btu per gallon. To show compliance with the 12-consecutive month emission limit, the permittee shall maintain records of fuel usage in boiler #4, calculate the monthly PM emission rate, and record the results in a format (see example below) that readily shows compliance with annual PM emission limit**.** These records must be maintained at the source location and kept available for inspection by the Technical Secretary or his representative. These logs must also be reported in accordance with Condition **E2** of this permit and be retained for a period of not less than five years.

MONTHLY FUEL USAGE LOG and PM emissions for boiler 04 (38-0039-16)

Month/Year	Fuel Type, ie. NG, #2 Fuel Oil, #3 Fuel oil, etc…	Fuel usage (ft^3 or gallon/month)	Emission Factor	PM emissions (Tons per Month)	PM emissions (Tons per 12-Consecutive Months)

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

E8-3. Sulfur dioxide (SO_2) emitted from this source shall not exceed **39.4** pounds per hour and **48** tons during any 12-consecutive month period. These emission limitations are established pursuant to Rule 1200-03-14-.01(3) of the Tennessee Air Pollution Control regulations and the information contained in the agreement letters dated June 11, 1992 and July 18, 1995 from the permittee.

Compliance Method: Compliance with the hourly emission limit is assured by compliance with **Conditions E8-4 and E8-5** at maximum #6 fuel oil usage rate of 139 gallons per hour at 150,000 Btu per gallon. To show compliance with the 12-consecutive month emission limit, the permittee shall maintain records of fuel usage in boiler #4, calculate the monthly SO_2 emission rate, and record the results in a format (see example below) that readily shows compliance with annual SO_2 emission limit**.** For purposes of simplifying calculations required by this permit, the sulfur content of the fuel oil shall be used when calculating SO_2 emissions from any mixture of fuel oil and spent alcohol. These records must be maintained at the source location and kept available for inspection by the Technical Secretary or his representative. These logs must also be reported in accordance with Condition **E2** of this permit and be retained for a period of not less than five years.

MONTHLY FUEL USAGE LOG and SO_2 emissions for boiler 04 (38-0039-16)

Month/Year	Fuel Type, ie. NG, #2 Fuel Oil, #3 Fuel oil, etc…	Fuel usage (ft^3 or gallon/month)	Emission Factor	SO_2 emissions (Tons per Month)	SO_2 emissions (Tons per 12-Consecutive Months)

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

E8-4. The sulfur content of the fuel oil shall not exceed 1.8 percent by weight. This limitation is established pursuant to TAPCR 1200-03-26-.02(9)(g) and the information contained in the agreement letter dated June 11, 1992 from the permittee.

Compliance Method: The permittee shall obtain certification from the fuel supplier of the fuel sulfur content (by weight) for each shipment of fuel oil. Records must be retained for a period of not less than five years. Certifications shall be submitted in accordance with **Condition E2** of this permit.

E8-5. Natural gas, fuel oil (up to and including #6), and fuel oil (up to and including #6) commingled with spent alcohol shall be the only fuels used for this source. TAPCR 1200-03-09-.01(d)

E8-6. For fee purposes, the permittee shall calculate its actual oxides of nitrogen (NO_x) emissions, particulate matter (PM) emissions, sulfur dioxide (SO_2) emissions, and volatile organic compound (VOC) emissions for each fiscal year from this fuel-burning source using EPA, AP-42 emission factors (Attachments 5 and 6), in conjunction with fuel usage records (natural gas and fuel oil) and the sulfur content of the fuel. The results of these calculations shall be recorded and maintained in tabular form (see example below) and shall be retained for a period of not less than five years. These records shall be reported in accordance with **Condition E1** of this permit. TAPCR 1200-03-26-.02(9)

Fiscal Year log of emissions for 38-0039-16 July 1, ______ to June 30, _______

Pollutant	Emissions from NG (tons)	Emissions from liquid fuels (tons)	Total Emissions (tons)
NO_x			
SO_2			
PM			
VOC			

38-0039-66	Source Identification	Material Handling Operation Consisting of two (2) bucket elevators with two (2) dust collectors and a HEPA filter, and a pre-charge reactant mixing tank.

Conditions E9-1 through E9-4 apply to source 38-0039-66

E9-1. The total stated design input capacity of this source is 75,000 pounds per hour on a monthly average basis. This is the capacity of the source as stated in the application dated December 11, 2003. TAPCR 1200-03-09-.01(1)(d)

Compliance Method: None. This condition is a statement of design input capacity for this source. If the permittee wishes to increase the design or maximum capacity of this source, the permittee shall pursue the appropriate Title V procedure in accordance with 1200-03-09-.02(11) of TAPCR. If a construction permit is applied for, this shall be done in accordance with 1200-03-09-.01(1) of TAPCR.

E9-2. Particulate matter emitted from this source shall not exceed 0.01 grains per dry standard cubic foot of exhaust gas. This emission limitation is established pursuant to Rule 1200-03-07-.01(5) of the Tennessee Air Pollution Control regulations and the information contained in the agreement letter dated May 10, 2012 from the permittee. At the reported combined exhaust flow rate of 7,498 dry standard cubic foot of exhaust gas per minute in the application, a concentration of 0.01 gr/dscf yields an actual emission rate of 0.65 pound per hour. This value multiplied by 8,760 hours per year, yields an actual emission rate of 2.9 tons per year.

Compliance Method: The dust collectors and filters will be maintained, kept in good operating condition, and inspected semiannually to ensure compliance with the applicable particulate matter limits. Documentation of the semiannual inspections and any maintenance performed will be kept on site for a period of not less than five years. A monthly summary of these logs shall be kept and reported in accordance with **Condition E2.**

E9-3. Visible emissions from the baghouses serving this source shall not exhibit greater than 10% opacity as determined by EPA Method 9, as published in 40 CFR 60, Appendix A (six-minute average). This condition is established pursuant to Rule 1200-03-05-.01(3) of the Tennessee Air Pollution Control Regulations and the agreement letter dated May 10, 2012 from the permittee.

Compliance Method: The permittee shall assure compliance with the opacity standard by utilizing the opacity matrix dated June 18, 1996 (amended on September 13, 2011) that is enclosed as Attachment 1. Reports and certifications shall be submitted in accordance with **Condition E2** of this permit.

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. For fee purposes, actual emissions from this source will be estimated at 0.01 grains per dry standard cubic foot of exhaust gas during the time the process is in operation. The permittee shall record the operating time of the source, and shall once yearly, measure and/or calculate the exhaust flow rate of each dust collector. This data will be used to calculate the actual emissions, in tons, from the operation of this source assuming an outlet concentration of 0.01 grains of PM per dry standard cubic foot of exhaust gas during the fiscal year. These records shall be maintained on site and retained for a period of not less than five years. These records shall be reported in accordance with **Condition E1** of this permit.

TAPCR 1200-03-09

E9-5. This source is subject to the provisions of 40 CFR 64 Compliance Assurance Monitoring (CAM). The provisions of CAM are specified in Attachment 9 of this permit. The following dust collectors are included in this requirement:

Control Unit Identification	Approximate Dry Standard Cubic Feet per Minute of Exhaust gas flow
AAC-1 dust collector Adipic Acid collector	4463
AAC-2 dust collector Adipic Charge Receiver	632
BE-2 Bucket Elevator dust Collector #2	1973

Control Unit Identification	Approximate Dry Standard Cubic Feet per Minute of Exhaust gas flow
HEPA TMA Charge Guard Filter	395
R3CHG R-3 Charge Bin Vent Filter	35

38-0039-70	Source Identification	**Boiler #5 Cleaver Brooks Watertube Model DL-52, Gas Recirculating** Natural gas, #6 fuel oil and spent alcohol fuels **(NSPS, Subpart Dc)**

Conditions E10-1 through E10-7 apply to source 38-0039-70

E10-1. This boiler is subject to 40 CFR 60 Subpart Dc (Standards of Performance for Small Industrial-Commercial- Institutional Steam Generating Units). The boiler has a heat input capacity of 43,146,000 Btu per hour. The primary fuel is natural gas with #6 fuel oil / #6 fuel oil and spent alcohol blend as back up fuels. Under Subpart Dc, owners and operators of units in which #6 fuel oil is burned are required to install, certify and operate a Continuous Opacity Monitor (COM) if the heat input capacity of the unit is 30 million Btu per hour or greater. Under the provisions of 40 CFR part 60.13(i)(2), EPA has the authority to allow the use of alternative monitoring for sources which infrequently burn #6 fuel oil. EPA concluded that for #6 fuel oil an annual capacity factor of 5% or less constitutes infrequent use (Annual Capacity Factor means the ratio of the actual heat input to a steam generating unit from an individual fuel or combination of fuels during a period of 12-consecutive calendar months to the potential heat input to the steam generating unit from all fuels had the steam generating unit been operated for 8,760 hours during that 12-month period at the maximum design heat input capacity). The permittee has agreed to a limit of 5% annual capacity factor limit for #6 fuel oil. The permittee shall institute opacity monitoring alternative subject to the following conditions:

(a) At least once every four hours during daylight shifts when #6 fuel oil / alcohol mixture is combusted, an observer certified in accordance with EPA Method 9 shall perform a six-minute visible emission observation.

(b) If the average opacity for a six-minute set of readings made in accordance with **Condition E10-1(a)** exceeds 10 percent, the observer must collect two additional six-minute sets of visible emission readings for a total of three data sets.

(c) Records of the date and time of visible emission observations, along with the results of each observation, must be maintained.

(d) Thirty days after the end of each calendar quarter in which there are opacity excess emissions during combustion of #6 fuel oil or the oil / spent alcohol mixture, the permittee must submit an excess emission report (EER) to the Division of Air Pollution Control. If there are no opacity excess emissions during a calendar quarter, EERs may be submitted on a semiannual basis. For reporting purposes, excess emissions are defined as any six-minute periods during which the average opacity exceeds 20 percent and EERs must indicate the total time of the visible emission observations during a calendar quarter and identify the duration of any excess emissions.

(e) The permittee must record the quantity of #6 fuel oil burned each calendar quarter and include this information in the reports required under Condition **E2**. If, based upon this information, the #6 fuel oil annual capacity factor as defined in 40 CFR subpart 60.41c ever exceeds 10 percent, the permittee would no longer qualify to use an opacity monitoring alternative, and this source must be put on a schedule for installing and certifying a continuous opacity monitor. The permittee must notify the Division in writing within 30 days of the discovery of such an exceedance.

(f) The permittee must maintain the boiler by following procedures and schedules recommended by the boiler manufacturer and must keep records verifying that the necessary maintenance activities have been performed.

(g) This alternative opacity monitoring approval is valid only during operation while combusting #6 fuel oil / spent alcohol and the alternative opacity monitoring may not be used if any other liquid or solid fuels are burned in the boiler.

(h) All records required under terms of this approval must be maintained by the permittee for a period of no less than five years.

(i) The EPA confirmation letter in regard to "**alternative opacity monitoring**" is attached to this permit (see attachment #2)

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

E10-2. The following operational limits apply:

(a) Natural gas, Number 6 (#6) fuel oil, Number 6 (#6) fuel oil and spent alcohol blend, or natural gas and spent alcohol fired simultaneously, only shall be used as fuels for this source.

(b) When burning Number 6 (#6) fuel oil, or Number 6 (#6) fuel oil and spent alcohol blend:

(1) The heat input shall not exceed 43,146,000 Btu per hour, and

(2) Fuel usage rates shall not exceed the following:

Fuels\ Fuels Usage Rates	#6 Fuel Oil (gallons/hour)	#6 Fuel Oil* (gallons/year)	Spent Alcohol (gallons/hour)	Spent Alcohol (gallons/year)
#6 Fuel Oil	288.8	1,024,530	0	0
#6 Fuel oil and Spent Alcohol blend	275.93	979,553	15.4	54,660

***provided that total sulfur dioxide emissions from this source do not exceed 39.9 tons per year.**

(c) When burning natural gas, or natural gas and spent alcohol fired simultaneously:

(1) The heat input shall not exceed **41,280,000 Btu** per hour.

(2) Fuel usage rates shall not exceed the following:

Fuels\ Fuels Usage Rates	Natural Gas (ft^3/hour)	Natural Gas (ft^3/year)	Spent Alcohol (gallons/hour)	Spent Alcohol (gallons/year)
Natural Gas	41,280	361,612,800	0	0
Natural Gas and Spent Alcohol fired simultaneously	39,468	345,739,680	14.73	129,035

Compliance Method: Adequate records in a form that readily assure compliance with these rates shall be maintained. These records shall be maintained for a period of not less than five years. A summary report and certifications shall be submitted in accordance with **Condition E2** of this permit.

TAPCR 1200-03-07-.01(5) and 1200-03-14-.01(3) and Agreement Letters dated April 27, 1994 and August 8, 1995

E10-3 (SM1). Pursuant to 40 CFR 60.42c(d) and (g), the sulfur content of the fuel oil used at this source shall not exceed 0.5 percent by weight, on a 30-day rolling average basis.

Compliance Method: When combusting residual fuel oil (#6 fuel oil), the permittee shall collect oil samples from the fuel tank immediately after the fuel tank is filled and before any oil is combusted. The fuel oil sample shall be analyzed to determine the sulfur content of the oil. If a partially empty fuel tank is refilled, a new sample and analysis of the fuel in the tank would be required upon filling. Results of the fuel analysis taken after each new shipment of oil is received, shall be used as the daily value when calculating the 30-day rolling average until the next shipment is received. If the fuel analysis shows that the sulfur content in the fuel tank is greater than 0.5 weight percent sulfur, the owner or operator shall ensure that the sulfur content of subsequent oil shipments is low enough to cause the 30-day rolling average sulfur content to be 0.5 weight percent sulfur or less. These records shall be kept available for inspection by the Technical Secretary or an authorized representative and be retained for a period of not less than five years. Summary reports and certifications shall be submitted in accordance with **Condition E2** of this permit.

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

E10-4. Particulate matter emitted from this source shall not exceed:

(a) 0.56 pounds per hour when burning natural gas, or natural gas and spent alcohol fired simultaneously, or

(b) 8.0 pounds per hour when burning Number 6 (#6) fuel oil, or Number 6 (#6) fuel oil and spent alcohol blend.

Also, particulate matter emitted from this source shall not exceed 5.5 tons per year. The hourly and yearly emission limitations are established pursuant to Rule 1200-03-06-.01(7) of the Tennessee Air Pollution Control Regulations and the information contained in the agreement letter dated January 29, 1997 and January 25, 2002, respectively, from the permittee.

Compliance Method (hourly limits): This source is deemed to be in compliance with the hourly particulate emission limit when natural gas is being burned exclusively, based upon EPA, AP-42, Fifth Edition emission factors. When burning fuel oil exclusively, or fuel oil in any combination with natural gas and/or spent alcohol, this source is in compliance with the particulate emission limit if it is in compliance with **Conditions E10-2 and E10-3** of this permit, based on EPA, AP-42, Fifth Edition emission factors (attachments 5 & 6). Reports and certifications shall be submitted in accordance with **Condition E2** of this permit.

Compliance Method (annual limit): To show compliance with the 12-consecutive month emission limit, the permittee shall maintain records of fuel usage in boiler #4, and calculate the monthly PM emission rate and record the results in a format (see example below) that readily shows compliance with annual PM emission limit**.** These records must be maintained at the source location and kept available for inspection by the Technical Secretary or his representative. These logs must also be reported in accordance with **Condition E2** of this permit and be retained for a period of not less than five years.

MONTHLY FUEL USAGE LOG and PM emissions for boiler 05 (38-0039-70)

Month/Year	Fuel Type, ie. NG, #2 Fuel Oil, #3 Fuel oil, etc…	Fuel usage (ft^3 or gallon/month)	Emission Factor	PM emissions (Tons per Month)	PM emissions (Tons per 12-Consecutive Months)

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

E10-5. Sulfur dioxide emitted from this source shall not exceed:

(a) 0.1 pound per hour when burning natural gas, or natural gas and spent alcohol fired simultaneously, or

(b) 22.7 pounds per hour when burning Number 6 (#6) fuel oil, or Number 6 (#6) fuel oil and spent alcohol blend.

These emission limitations are established pursuant to Rule 1200-03-14-.01(3) of the Tennessee Air Pollution Control Regulations and the information contained in the agreement letter dated August 8, 1995 from the permittee.

Compliance Method: Use of natural gas and/or #6 fuel oil at no more than 0.5 weight percent sulfur is considered to assure compliance with the hourly SO_2 limit using EPA, AP-42, Fifth Edition emission factors (attachments 5 & 6). Reports and certifications shall be submitted in accordance with **Condition E2** of this permit.

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

E10-6. No waste which, at the point of generation, exhibits the characteristics of hazardous waste as set forth by the Tennessee Department of Environment and Conservation, Division of Solid Waste Management's Rule 1200-01-11-.02(3), shall be blended or used with the fuel input to this boiler; nor shall any waste listed in the Tennessee Division of Solid Waste Management's Rule 1200-01-11-.02(4) be blended or used with the fuel input to this boiler. TAPCR 1200-03-09

E10-7. For fee purposes, the permittee shall calculate its actual oxides of nitrogen (NO_x) emissions, particulate matter (PM) emissions, sulfur dioxide (SO_2) emissions, and volatile organic compound (VOC) emissions for each fiscal year from this fuel-burning source using EPA, AP-42 emission factors (attachments 5 & 6), in conjunction with fuel usage records (natural gas and fuel oil) and the sulfur content of the fuel. The results of these calculations shall be recorded and maintained in tabular form (see example below) and shall be retained for a period of not less than five years. These records shall be reported in accordance with **Condition E1** of this permit.

Fiscal Year log of emissions for 38-0039-70 July 1, ______ to June 30, _______

Pollutant	Emissions from NG (tons)	Emissions from liquid fuels (tons)	Total Emissions (tons)
NO_x			
SO_2			
PM			
VOC			

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

38-0039-92	**Source Identification**	**Synthetic Organic Specialty Chemicals Batch Manufacturing Processes (NSPS/MACT):** Four Reactor Systems: Three Batch & One Semi-Continuous, Five Vent Receivers, Six Hotwells, Four Filter Press Tanks, Four Filter Presses, Two Inert Gas Generators, Three Wash Tanks, One Stripper Feed Tank, One Stripping Column, and Associated Equipment

Conditions E11-1 through E11-17 apply to source 38-0039-92

E11-1. The permittee shall not cause, allow, or discharge into the atmosphere, Volatile Organic Compounds (VOC) emissions from this source greater than:

(a) 70.0 tons during any period of 12 consecutive months, and
(b) 12.0 tons during any month

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

Compliance Method: The permittee shall maintain a monthly log of the actual amount of Volatile Organic Compounds (VOC) emitted by this source (see example below), using emission factors provided to the Division by the permittee in the letter dated July 31 2003, as shown in the tables below. These records shall be retained for a period of not less than five years. **Reports and certifications shall be submitted in accordance with Condition E2 of this permit.**

VOC Emission Log for month of ____________ Year_____

Process	# of Batches	Emission Factor (lb/batch)	VOC emissions (tons)
R-1		38.1	
R-2		38.1	
R-3		33.4	
R-4		38.1	

Consecutive 12-Month VOC Emission Log

12-Month Period		VOC Emissions (tons)
Begin	End	

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

E11-2. For fee purposes, the permittee shall calculate its annual actual volatile organic compound (VOC) emissions from this source using the records required by **Condition E11-1**. The results of these calculations shall be recorded and maintained in tabular form and shall be retained for a period of not less than five years. These records shall be reported in accordance with **Condition E1** of this permit. TAPCR 1200-03-26-.02(9)

E11-3. The stated maximum design production capacity for the two inert gas generators combined is 6,000 standard cubic feet of inert gas per hour (6,000 SCFH). TAPCR 1200-03-09 Minor Modification #5 to Permit #546546 issued April 25, 2005 TAPCR 1200-03-09-.02(6)

Compliance Method: This condition is a statement of design input capacity for this equipment. If the permittee wishes to increase the design or maximum capacity of this equipment, the permittee shall pursue the appropriate Title V procedure in accordance with 1200-03-09-.02(11) of TAPCR. If a construction permit is applied for, this shall be done in accordance with TAPCR 1200-03-09-.01(1).

E11-4. Carbon Monoxide emitted from the inert gas generators shall not exceed 17.6 tons per year, combined. TAPCR 1200-03-07-.07(2) Minor Modification #5 to Permit #546546 issued April 25, 2005 TAPCR 1200-03-09-.02(6)

Compliance Method: Compliance with this emission limit is assured by compliance with the design production capacity specified in **Condition E11-3**.

E11-5. This source is subject to Federal NSPS Standards as specified in paragraph 60.660 of 40 CFR 60 Subpart NNN (Standards of Performance for Volatile Organic Compound Emissions from Synthetic Organic Chemical Manufacturing Industry). The permittee has chosen to comply with this Federal NSPS Standard through the Consolidated Air Rule (CAR), 40 CFR part 65, Subpart D "Process Vent" in lieu of specified parts of Subpart NNN.

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

E11-6. This process vent is considered to be Group 2B. For Group 2B process vents, the permittee shall maintain a Total Resources Effectiveness (TRE) index greater than 4.0, a flow rate less than 0.011 standard cubic meters per minute, or a concentration less than 300 ppmv of TOC.

40 CFR 65.63(e)

E11-7. Whenever process changes are made that could reasonably be expected to change a 2B process vent to a Group 1 vent, the permittee shall recalculate the TRE index value, flow, or TOC or organic hazardous air pollutant (HAP) concentration for each process vent as necessary to determine whether the process vent is Group 1, Group 2A, or Group 2B. The permittee shall perform the group status determination as soon as practical after the process change and within 180 days after the process change.

Examples of process changes include, but are not limited to, changes in production capacity, production rate, feedstock type, or catalyst type, or whenever there is replacement, removal, or addition of recovery equipment. If the process changes cause the group status change to Group 1, the permittee shall comply with the following procedures to establish a compliance date:

(a) The permittee shall submit to the Technical Secretary for approval a compliance schedule, along with a justification for the schedule.

(b) The compliance schedule shall be submitted with the operating permit application or amendment or by other appropriate means.

(c) The Technical Secretary shall approve the compliance schedule or request changes within 120 calendar days of receipt of the compliance schedule and justification.

40 CFR 65.63(f)

E11-8. The permittee shall calculate the TRE index value of the process vent using the following equation:

$$TRE = A * \left[B + C + D + E + F\right]$$

Where:
TRE = TRE index value.
A, B, C, D, E, and F = Parameters presented in Tables 2 and 3 of 40 CFR 65.60 that include the following variables:

Q = Process vent flow rate, standard cubic meters per minute, at a standard temperature of 20 °C, as calculated according to the following:

(1) Use Method 2, 2A, 2C, or 2D of appendix A of 40 CFR part 60, as appropriate. If the process vent tested passes through a final steam jet ejector and is not condensed, the stream volumetric flow shall be corrected to 2.3 percent moisture; or

(2) Engineering assessment procedures in paragraph (i) of 40 CFR 60

H = Process vent net heating value, megajoules per standard cubic meter, as calculated according to following equation:

$$H_T = K_1 \left(\sum_{j-1}^{n} D_j H_j \right)$$

Where:
H_T = Net heating value of the sample, megajoule per standard cubic meter, where the net enthalpy per mole of process vent is based on combustion at 25 °C and 760 millimeters of mercury, but the standard temperature for determining the volume corresponding to 1 mole is 20 °C as in the definition of Q_S (process vent volumetric flow rate).
K_1 = Constant, 1.740×10^{-7} (parts per million)$^{-1}$ (gram-mole per standard cubic meter) (megajoule per kilocalorie), where standard temperature for (gram-mole per standard cubic meter) is 20 °C.
n = Number of components in the sample.
D_j = Concentration on a wet basis of compound j in parts per million. For process vents that pass through a final steam jet and are not condensed, the moisture is assumed to be 2.3 percent by volume.
H_j = Net heat of combustion of compound j, kilocalorie per gram-mole, based on combustion at 25 °C and 760 millimeters of mercury. The heat of combustion of process vent components shall be determined using American Society for Testing and Materials (ASTM) D2382-76 if published values are not available or cannot be calculated.

E_{TOC} = Emission rate of TOC (minus methane and ethane), kilograms per hour.
E_{HAP} = Emission rate of total organic HAP, kilograms per hour.

$$E = K_2\left(\sum_{j-1}^{n} C_j M_j\right)Q_s$$

Where:
E = Emission rate of TOC (minus methane and ethane) (E_{TOC}) or emission rate of total organic HAP (E_{HAP}) in the sample, kilograms per hour.
K_2 = Constant, 2.494×10^{-6} (parts per million) (gram-mole per standard cubic meter) (kilogram per gram) (minutes per hour), where standard temperature for (gram-mole per standard cubic meter) is 20 °C.
n = Number of components in the sample.
C_j = Concentration on a dry basis of organic compound j in parts per million as measured by Method 18 of appendix A of 40 CFR part 60 as indicated in paragraph (c) of 40 CFR 60. If the TOC emission rate is being calculated, C_j includes all organic compounds measured minus methane and ethane; if the total organic HAP emission rate is being calculated, only organic HAP compounds are included.
M_j = Molecular weight of organic compound j, gram/gram-mole.
Q_s = Process vent flow rate, dry standard cubic meter per minute, at a temperature of 20 °C; or engineering assessment procedures in paragraph (i) of 40 CFR 60.

40 CFR 65.64(h)

E11-9. The permittee shall maintain records of measurements, and calculations performed to determine the TRE index value upon the process changes. These records must be retained for a period of not less than 5 years.

40 CFR 65.66(a)

E11-10. Whenever a process change that causes a Group 2B process vent to become a Group 1 process vent or a Group 2A, the permittee shall either submit a report within 60 days after the performance test or group determination or submit a report included as part of the next periodic report. The report shall include the following information:

(a) A description of the process change;

(b) The results of the recalculation of the flow rate, organic HAP or TOC concentration, and/or TRE index value; and

(c) A statement that the owner or operator will comply with the provisions of §65.63 by the schedules specified in §65.63(f)(4) through (6).

40 CFR 65.67(b)

E11-11. This source shall comply with all applicable requirements of 40 CFR 63, Subpart FFFF (National Emission Standards for Hazardous Air Pollutants: Miscellaneous Organic Chemical Manufacturing). Based upon the current plant operations, at this time all the vents for each affected miscellaneous organic chemical manufacturing process unit (MCPU) are considered to be Group 2B or have a TRE > 5.0.

E11-12. The permittee must be in compliance with the emission limits and work practice standards in tables 1 through 7 in 40 CFR 63, Subpart FFFF at all times, except during periods of startup, shutdown, and malfunction (SSM), and must meet the requirements specified in 40 CFR §§63.2455 through 63.2490 (or the alternative means of compliance in 40 CFR §63.2495, §63.2500, or §63.2505), except as specified in 40 CFR 63.2450(b) through (s). The permittee must meet the notification, reporting, and recordkeeping requirements specified in **Conditions E3-3 and E3-4**.

Based upon the current plant operations at this time, only 40 CFR §§63.2455 and §§63.2460 are applicable to the affected miscellaneous organic chemical manufacturing process units (MCPU).

40 CFR 63.2450(a)

E11-13. For each continuous process vent, the permittee must either designate the vent as a Group 1 continuous process vent or determine the total resource effectiveness (TRE) index value as specified in 40 CFR §63.115(d) (**Attachment 3**), except as specified in (a) through (c) below.

(a) The permittee is not required to determine the Group status or the TRE index value for any continuous process vent that is combined with Group 1 batch process vents before a control device or recovery device because the requirements of §63.2450(c)(2)(i) apply to the combined stream.

(b) When a TRE index value of 4.0 is referred to in 40 CFR §63.115(d), TRE index values of 5.0 for existing affected sources and 8.0 for new and reconstructed affected sources apply for the purposes of this subpart.

(c) When 40 CFR §63.115(d) refers to "emission reductions specified in §63.113(a)," the reductions specified in Table 1 to 40 CFR 63, Subpart FFFF apply for the purposes of this subpart.

40 CFR 63.2455(b)

E11-14. If a recovery device is used to maintain the TRE above a specified threshold, the permittee must meet the requirements of 40 CFR §63.982(e) and the requirements referenced therein, except as specified in 40 CFR §63.2450 and (a) below.

(a) When 40 CFR §63.993 uses the phrase "the TRE index value is between the level specified in a referencing subpart and 4.0," the phrase "the TRE index value is >1.9 but ≤5.0" applies for an existing affected source, and the phrase "the TRE index value is >5.0 but ≤8.0" applies for a new and reconstructed affected source, for the purposes of 40 CFR 63, Subpart FFFF.

40 CFR 63.2455(c)

E11-15. The permittee must determine the group status of the batch process vents by determining and summing the uncontrolled organic HAP emissions from each of the batch process vents within the process using the procedures specified in §63.1257(d)(2)(i) and (ii) (**Attachment 4**), except as specified in (a) through (g) below.

(a) To calculate emissions caused by the heating of a vessel without a process condenser to a temperature lower than the boiling point, the permittee must use the procedures in §63.1257(d)(2)(i)(C)(*3*).

(b) To calculate emissions from depressurization of a vessel without a process condenser, the permittee must use the procedures in §63.1257(d)(2)(i)(D)(*10*).

(c) To calculate emissions from vacuum systems for the purposes of this subpart, the receiving vessel is part of the vacuum system, and terms used in Equation 33 to 40 CFR part 63, subpart GGG, are defined as follows:

P_{system}= absolute pressure of the receiving vessel;
P_i= partial pressure of the HAP determined at the exit temperature and exit pressure conditions of the condenser or at the conditions of the dedicated receiver;
P_j= partial pressure of condensables (including HAP) determined at the exit temperature and exit pressure conditions of the condenser or at the conditions of the dedicated receiver;
MW_{HAP}= molecular weight of the HAP determined at the exit temperature and exit pressure conditions of the condenser or at the conditions of the dedicated receiver.

(d) To calculate uncontrolled emissions when a vessel is equipped with a process condenser, the permittee must use the procedures in §63.1257(d)(3)(i)(B) (**Attachment 4**), except as specified in (1) through (7) below.

(1) The permittee must determine the flowrate of gas (or volume of gas), partial pressures of condensables, temperature (T), and HAP molecular weight (MW_{HAP}) at the exit temperature and exit pressure conditions of the condenser or at the conditions of the dedicated receiver.

(2) The permittee must assume that all of the components contained in the condenser exit vent stream are in equilibrium with the same components in the exit condensate stream (except for noncondensables).

(3) The permittee must perform a material balance for each component.

(4) For the emissions from gas evolution, the term for time, t, must be used in Equation 12 to 40 CFR part 63, subpart GGG.

(5) Emissions from empty vessel purging shall be calculated using Equation 36 to 40 CFR part 63, subpart GGG and the exit temperature and exit pressure conditions of the condenser or the conditions of the dedicated receiver.

(6) The permittee must conduct an engineering assessment as specified in §63.1257(d)(2)(ii) for each emission episode that is not due to vapor displacement, purging, heating, depressurization, vacuum operations, gas evolution, air drying, or empty vessel purging. The requirements of (c) and (d) of this Condition shall apply.

(7) The permittee may elect to conduct an engineering assessment if it can be demonstrated to the Technical Secretary that the methods in §63.1257(d)(3)(i)(B) are not appropriate.

(e) The permittee may elect to designate the batch process vents within a process as Group 1 and not calculate uncontrolled emissions under either of the situations in (e)(1), (2), or (3) below.

(1) Comply with the alternative standard specified in 40 CFR §63.2505.

(2) If all Group 1 batch process vents within a process are controlled; conduct the performance test under hypothetical worst case conditions, as defined in 40 CFR §63.1257(b)(8)(i)(B); and the emission profile is based on capture and control system limitations as specified in 40 CFR §63.1257(b)(8)(ii)(C).

(3) Comply with an emission limit using a flare that meets the requirements specified in 40 CFR §63.987.

(f) The permittee may change from Group 2 to Group 1 in accordance with either (i) or (ii) below. The permittee must comply with the requirements of this condition and submit the test report in the next compliance report.

(1) The permittee may switch at any time after operating as Group 2 for at least 1 year so that the permittee can show compliance with the 10,000 pounds per year (lb/yr) threshold for Group 2 batch process vents for at least 365 days before the switch. The permittee may elect to start keeping records of emissions from Group 2 batch process vents before the compliance date. Report a switch based on this provision in the next compliance report in accordance with **Condition E3-2(i)(1).**

(2) If the requirements of (i) above are not applicable, the permittee must provide a 60-day advance notice in accordance with **Condition E3-2(i)(2)** before switching.

(g) As an alternative to determining the uncontrolled organic HAP emissions as specified in §63.1257(d)(2)(i) and (ii) (Attachment 4), the permittee may elect to demonstrate that non-reactive organic HAP are the only HAP used in the process and non-reactive HAP usage in the process is less than 10,000 lb/yr. The permittee must provide data and supporting rationale in the notification of compliance status report explaining why the non-reactive organic HAP usage will be less than 10,000 lb/yr. The permittee must keep records of the non-reactive organic HAP usage as specified in **Condition E3-3(e)(2)** and include information in compliance reports as specified in **Condition E3-2(e)(3)**.

40 CFR 63.2460(b)

E11-16. The permittee shall meet the following requirements for equipment leaks:

(a) The permittee must meet each requirement in table 6 to subpart FFFF that applies to equipment leaks, except as specified in (b) and (c) below. The permittee has elected to comply with Subpart UU to meet the requirements of 40 CFR 63.2480.

(b) The permittee may elect to comply with the provisions in paragraphs (b)(1) through (3) below as an alternative to the referenced provisions in Subpart UU.

(1) The requirements for pressure testing in 40 CFR §63.1036(b) may be applied to all processes, not just batch processes.

(2) For the purposes of subpart FFFF, pressure testing for leaks in accordance with §63.1036(b) is not required after reconfiguration of an equipment train if flexible hose connections are the only disturbed equipment.

(3) For an existing source, the permittee is not required to develop an initial list of identification numbers for connectors as would otherwise be required under §63.1022(b)(1) or §63.181(b)(1)(i).

(c) The provisions of this condition do not apply to bench-scale processes, regardless of whether the processes are located at the same plant site as a process subject to the provisions of this subpart.

40 CFR 63.2480

E11-17. Pursuant to 40 CFR 63, Subpart FFFF, the following provisions of Subpart UU—National Emission Standards for Equipment Leaks—Control Level 2 Standards apply to this source.

Alternative means of emission limitation: Batch processes.

(a) General requirement. As an alternative to complying with the requirements of 40 CFR §§63.1025 through 63.1033 and §63.1035, the permittee has elected to comply with the standards specified in (b) of this condition. The alternative standards of this condition provide the option of pressure testing the equipment for leaks.

(b) Pressure testing of the batch equipment. The following requirements shall be met if the permittee elects to use pressure testing of batch product-process equipment to demonstrate compliance with Subpart UU.

(1) Reconfiguration. Each time equipment is reconfigured for production of a different product or intermediate, the batch product-process equipment train shall be pressure-tested for leaks before regulated material is first fed to the equipment and the equipment is placed in regulated material service.

(i) When the batch product-process equipment train is reconfigured to produce a different product, pressure testing is required only for the new or disturbed equipment.

(ii) Each batch product process that operates in regulated material service during a calendar year shall be pressure-tested at least once during that calendar year.

(iii) Pressure testing is not required for routine seal breaks, such as changing hoses or filters, that are not part of the reconfiguration to produce a different product or intermediate.

(2) Testing procedures. The batch product process equipment shall be tested either using the procedures specified in (b)(5) of this condition for pressure vacuum loss or with a liquid using the procedures specified in (b)(6) of this condition.

(3) Leak detection.

(i) For pressure or vacuum tests using a gas, a leak is detected if the rate of change in pressure is greater than 6.9 kilopascals (1 pound per square inch gauge) in 1 hour or if there is visible, audible, or olfactory evidence of fluid loss.

(ii) For pressure tests using a liquid, a leak is detected if there are indications of liquids dripping or if there is other evidence of fluid loss.

(4) Leak repair.

(i) If a leak is detected, it shall be repaired and the batch product-process equipment shall be retested before start-up of the process.

(ii) If a batch product-process fails the retest (the second of two consecutive pressure tests), it shall be repaired as soon as practical, but not later than 30 calendar days after the second pressure test except as specified in (d) of this condition.

(5) Gas pressure test procedure for pressure or vacuum loss. The procedures specified in (b)(5)(i) through (b)(5)(v) below shall be used to pressure test batch product-process equipment for pressure or vacuum loss to demonstrate compliance with the requirements of (b)(3)(i) of this condition.

(i) The batch product-process equipment train shall be pressurized with a gas to a pressure less than the set pressure of any safety relief devices or valves or to a pressure slightly above the operating pressure of the equipment, or alternatively the equipment shall be placed under a vacuum.

(ii) Once the test pressure is obtained, the gas source or vacuum source shall be shut off.

(iii) The test shall continue for not less than 15 minutes unless it can be determined in a shorter period of time that the allowable rate of pressure drop or of pressure rise was exceeded. The pressure in the batch product-process equipment shall be measured after the gas or vacuum source is shut off and at the end of the test period. The rate of change in pressure in the batch product-process equipment shall be calculated using the following equation:

$$\Delta(P/t) = \left(\left|P_f - P_i\right|\right) / \left(t_f - t_i\right) \qquad \text{[Eq. 5]}$$

Where:

Δ (P/t) = Change in pressure, pounds per square inch gauge per hour.

Pf= Final pressure, pounds per square inch gauge.

Pi= Initial pressure, pounds per square inch gauge.

tf− ti= Elapsed time, hours.

(iv) The pressure shall be measured using a pressure measurement device (gauge, manometer, or equivalent) that has a precision of ±2.5 millimeter mercury (0.10 inch of mercury) in the range of test pressure and is capable of measuring pressures up to the relief set pressure of the pressure relief device. If such a pressure measurement device is not reasonably available, the permittee shall use a pressure measurement device with a precision of at least ±10 percent of the test pressure of the equipment and shall extend the duration of the test for the time necessary to detect a pressure loss or rise that equals a rate of 1 pound per square inch gauge per hour (7 kilopascals per hour).

(v) An alternative procedure may be used for leak testing the equipment if the permittee demonstrates the alternative procedure is capable of detecting a pressure loss or rise.

(6) Pressure test procedure using test liquid. The procedures specified in (b)(6)(i) through (b)(6)(iv) of this condition shall be used to pressure-test batch product-process equipment using a liquid to demonstrate compliance with the requirements of (b)(3)(ii) of this condition.

(i) The batch product-process equipment train, or section of the equipment train, shall be filled with the test liquid (e.g., water, alcohol) until normal operating pressure is obtained. Once the equipment is filled, the liquid source shall be shut off.

(ii) The test shall be conducted for a period of at least 60 minutes, unless it can be determined in a shorter period of time that the test is a failure.

(iii) Each seal in the equipment being tested shall be inspected for indications of liquid dripping or other indications of fluid loss. If there are any indications of liquids dripping or of fluid loss, a leak is detected.

(iv) An alternative procedure may be used for leak testing the equipment, if the permittee demonstrates the alternative procedure is capable of detecting losses of fluid.

(7) Pressure testing recordkeeping. The owner or operator of a batch product process who elects to pressure test the batch product process equipment train to demonstrate compliance with this subpart shall maintain records of the information specified in (b)(7)(i) through (b)(7)(v) of this condition.

(i) The identification of each product, or product code, produced during the calendar year. It is not necessary to identify individual items of equipment in a batch product process equipment train.

(ii) Physical tagging of the equipment to identify that it is in regulated material service and subject to the provisions of subpart UU is not required. Equipment in a batch product process subject to the provisions of subpart UU may be identified on a plant site plan, in log entries, or by other appropriate methods.

(iii) The dates of each pressure test required in this condition, the test pressure, and the pressure drop observed during the test.

(iv) Records of any visible, audible, or olfactory evidence of fluid loss.

(v) When a batch product process equipment train does not pass two consecutive pressure tests, the information specified in (b)(7)(v)(A) through (b)(7)(v)(E) of this condition shall be recorded in a log and kept for 2 years:

(A) The date of each pressure test and the date of each leak repair attempt.

(B) Repair methods applied in each attempt to repair the leak.

(C) The reason for the delay of repair.

(D) The expected date for delivery of the replacement equipment and the actual date of delivery of the replacement equipment; and

(E) The date of successful repair.

(d) Delay of repair. Delay of repair of equipment for which leaks have been detected is allowed if the replacement equipment is not available providing the provisions specified (d)(1) and (d)(2) of this condition are met.

(1) Equipment supplies have been depleted and supplies had been sufficiently stocked before the supplies were depleted.

(2) The repair is made no later than 10 calendar days after delivery of the replacement equipment.

(e) Periodic report contents. The Periodic Report to be filed pursuant to **Condition E3-2(h)** shall include the information listed below in (e)(1) through (e)(4) of this condition for each process unit.

(1) Batch product process equipment train identification;
(2) The number of pressure tests conducted;
(3) The number of pressure tests where the equipment train failed the pressure test; and
(4) The facts that explain any delay of repairs.

40 CFR 63.1036

38-0039-101	Source Identification:	Natural gas-fired Sigma thermal heater, model HC2-10.0-H-SF, 15.0 MMBtu/hr. 40 CFR 60 Subpart Dc and 40 CFR 63 Subpart DDDDD.

Conditions E12-1 through E12-9 apply to source 38-0039-101

E12-1 (SM1). The total stated design heat input capacity for this fuel-burning installation is 15.0 million British thermal units per hour (MMBtu/hr).

TAPCR 1200-03-09-.03(8), Condition 2 of construction permit 972591

Compliance Method: This condition is a statement of design input capacity for this fuel burning source. If the permittee wishes to increase the design capacity of this source, the permittee shall apply for a construction permit in accordance with TAPCR 1200-03-09-.01(1) or a Title V Modification in accordance with TAPCR 1200-03-09-.02(11).

E12-2 (SM1). Only natural gas shall be used as fuel for this source.

TAPCR 1200-03-09-.031(8), Condition 3 of construction permit 972591

Compliance Method: Compliance with this condition shall be demonstrated by compliance with **Condition E12-8**.

E12-3 (SM1). The natural gas fuel rate for this source shall not exceed 83.0 million standard cubic feet per calendar year.

TAPCR 1200-03-09-.03(8), Condition 4 of construction permit 972591**,** agreement letter dated May 4, 2017.

Compliance Method: Compliance with this condition shall be demonstrated by compliance with **Condition E12-8**.

E12-4 (SM1). Nitrogen oxides (NO_X) emissions from this source shall not exceed 4.99 tons per calendar year.

TAPCR 1200-03-06-.03(2)**,** TAPCR 1200-03-27-.02(2)**,** agreement letter dated May 4, 2017. Condition 5 of construction permit 972591.

Compliance Method: Compliance with this requirement is assured based on information provided by the heater manufacturer for the NOx emission factor of 120 pounds per million standard cubic feet natural gas combustion (**Attachment 11**). The manufacturer information shall be kept for reference permanently. Compliance with this condition shall be assured by compliance with **Condition E12-8**.

E12-5 (SM1). Particulate matter (PM) emitted from this source shall not exceed 0.112 pounds per hour and 0.31 tons per calendar year.

TAPCR 1200-03-06-.01(7), agreement letter dated May 4, 2017. Condition 6 of construction permit 972591.

Compliance Method: Compliance shall be assured by firing only natural gas at the rated capacity listed in **Condition E12-1** and the appropriate uncontrolled emission factor from AP-42, Chapter 1.4, Natural Gas Combustion.

E12-6 (SM1). Sulfur dioxide (SO_2) emitted from this source shall not exceed 0.01 pounds per hour and 0.03 tons per calendar year.

TAPCR 1200-03-14-.01(3), agreement letter dated May 4, 2017. Condition 7 of construction permit 972591.

Compliance Method: Compliance shall be assured by firing only natural gas at the rated capacity listed in **Condition E12-1** and the appropriate uncontrolled emission factor from AP-42, Chapter 1.4, Natural Gas Combustion.

E12-7 (SM1). Visible emissions from this source shall not exhibit greater than 20% opacity, except for one six-minute period in any one-hour period and for no more than four six-minute periods in any 24-hour period. Visible emissions from this source shall be determined by EPA Method 9, as published in the current 40 CFR 60, Appendix A (six-minute average). TAPCR 1200-03-05-.01(1) and 1200-03-05-.03(6)

Compliance Method: The permittee shall assure compliance with the opacity standard by utilizing the opacity matrix dated June 18, 1996 (amended on September 11, 2013) that is 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.

E12-8 (SM1). A log of the actual fuel usage, type of fuel used per month, and NO_X emissions at this source must be maintained at the source location and kept available for inspection by the Technical Secretary or a Division representative (see **Table E12-8** – an alternative format that provides the same information shall also be acceptable). All data, including any required calculations, must be entered into the log no later than 30 days from the end of the day for which the data is required. This log must be reported in accordance with **Condition E2** of this permit and be retained for a period of not less than five years.

TAPCR 1200-03-09-03(8), 40 CFR §§60.48c(g)(1) and (2)

Table E12-8: Monthly Fuel Usage Log				
Calendar Year	**Month**	**Fuel type**	**Usage (std. ft^3)**	**NOx Emissions[1] (tons)**
	January			
	February			
	March			
	April			
	May			
	June			
	July			
	August			
	September			
	October			
	November			
	December			
Calendar Year Totals				

E12-9 (SM1). This new (construction commenced after June 4, 2010) industrial boiler is located at a major source of hazardous air pollutants and is subject to 40 CFR 63 Subpart DDDDD (National Emission Standards for Hazardous Air Pollutants for Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters). The permittee shall comply with the following requirements:

(a) Pursuant to 40 CFR §63.7500, the permittee must meet the following requirements at all times:

(1) The permittee must comply with the following work practice standards, as required by Table 3 to subpart DDDDD:

If the unit is . . .	The permittee must. . .
A new boiler without a continuous oxygen trim system and with heat input capacity of 10 million Btu per hour or greater.	Conduct a tune-up of the boiler annually as specified in **Condition E12-9(c)**.

(2) At all times, the permittee must operate and maintain any affected source, including associated air pollution control equipment and monitoring equipment, in a manner consistent with safety and good air pollution control practices for minimizing emissions. Determination of whether such operation and maintenance procedures are being used will be based on information available to the Technical Secretary that may include, but is not limited to, monitoring results, review of operation and maintenance procedures, review of operation and maintenance records, and inspection of the source.

(b) Pursuant to 40 CFR § 63.7510(g) and 63.7515(d), the permittee must demonstrate initial compliance with the applicable work practice standard in Table 3 within the applicable annual or five-year schedule as specified in **Condition E12-9(c)**. The first annual or five -year tune-up must be no later than 13 months or 61 months, respectively, after the initial startup of the new affected source. Thereafter, the permittee is required to complete the applicable annual or five-year tune-up no more than 13 months or 61 months, respectively, after the previous tune-up.

(c) Pursuant to 40 CFR §63.7540(a)(10), the permittee must conduct a tune-up of the boiler or process heater annually to demonstrate continuous compliance as specified in (1) through (6) below.

(1) As applicable, inspect the burner, and clean or replace any components of the burner as necessary (the permittee may delay the burner inspection until the next scheduled unit shutdown). At units where entry into a piece of process equipment or into a storage vessel is required to complete the tune-up inspections, inspections are required only during planned entries into the storage vessel or process equipment;

(2) Inspect the flame pattern, as applicable, and adjust the burner as necessary to optimize the flame pattern. The adjustment should be consistent with the manufacturer's specifications, if available;

(3) Inspect the system controlling the air-to-fuel ratio, as applicable, and ensure that it is correctly calibrated and functioning properly (the permittee may delay the inspection until the next scheduled unit shutdown).

(4) Optimize total emissions of CO. This optimization should be consistent with the manufacturer's specifications, if available, and with any NO_X requirement to which the unit is subject;

(5) Measure the concentrations in the effluent stream of CO in parts per million, by volume, and oxygen in volume percent, before and after the adjustments are made (measurements may be either on a dry or wet basis, as long as it is the same basis before and after the adjustments are made). Measurements may be taken using a portable CO analyzer; and

(6) Maintain on-site and submit, if requested by the Technical Secretary, an annual report containing the information in (i) through (iii) below:

(i) The concentrations of CO in the effluent stream in parts per million by volume, and oxygen in volume percent, measured at high fire or typical operating load, before and after the tune-up of the boiler;

(ii) A description of any corrective actions taken as a part of the tune-up; and

(iii) The type and amount of fuel used over the 12 months prior to the tune-up, but only if the unit was physically and legally capable of using more than one type of fuel during that period. Units sharing a fuel meter may estimate the fuel used by each unit.

(d) Pursuant to 40 CFR §63.7540(a)(13), if the unit is not operating on the required date for a tune-up, the tune-up must be conducted within 30 calendar days of startup.

(e) Pursuant to 40 CFR §63.7540(b), the permittee must report each instance in which you the work practice standard in Table 3 to subpart DDDDD was not met. These instances are deviations from the emission limits in this subpart. These deviations must be reported according to the requirements in **Condition E3-4**.

(f) Reserved

(g) Pursuant to 40 CFR §63.7545(f), if the permittee intends to use a fuel other than natural gas, refinery gas, gaseous fuel subject to another subpart of part 63, part 60, 61, or 65, or other gas 1 fuel to fire the affected unit during a period of natural gas curtailment or supply interruption, as defined in §63.7575, the permittee must submit a notification of alternative fuel use within 48 hours of the declaration of each period of natural gas curtailment or supply interruption, as defined in §63.7575. The notification must include the information specified in (1) through (5) below:

(1) Company name and address.

(2) Identification of the affected unit.

(3) Reason for inability to use natural gas or equivalent fuel, including the date when the natural gas curtailment was declared or the natural gas supply interruption began.

(4) Type of alternative fuel that is intended to be used.

(5) Dates when the alternative fuel use is expected to begin and end.

(h) Pursuant to 40 CFR §63.7565, the permittee must comply with the applicable General Provisions according to Table 10 to 40 CFR 63 Subpart DDDDD (Attachment 7).

TAPCR 1200-03-09-03(8)

END OF SIGNIFICANT MODIFICATION #1 TO TITLE V PERMIT #570726

ATTACHMENT 1

OPACITY MATRIX DECISION TREE FOR VISIBLE EMISSION EVALUATION METHOD 9
dated June 18, 1996 and amended September 11, 2013

Decision Tree PM for Opacity for Sources Utilizing EPA Method 9*

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.

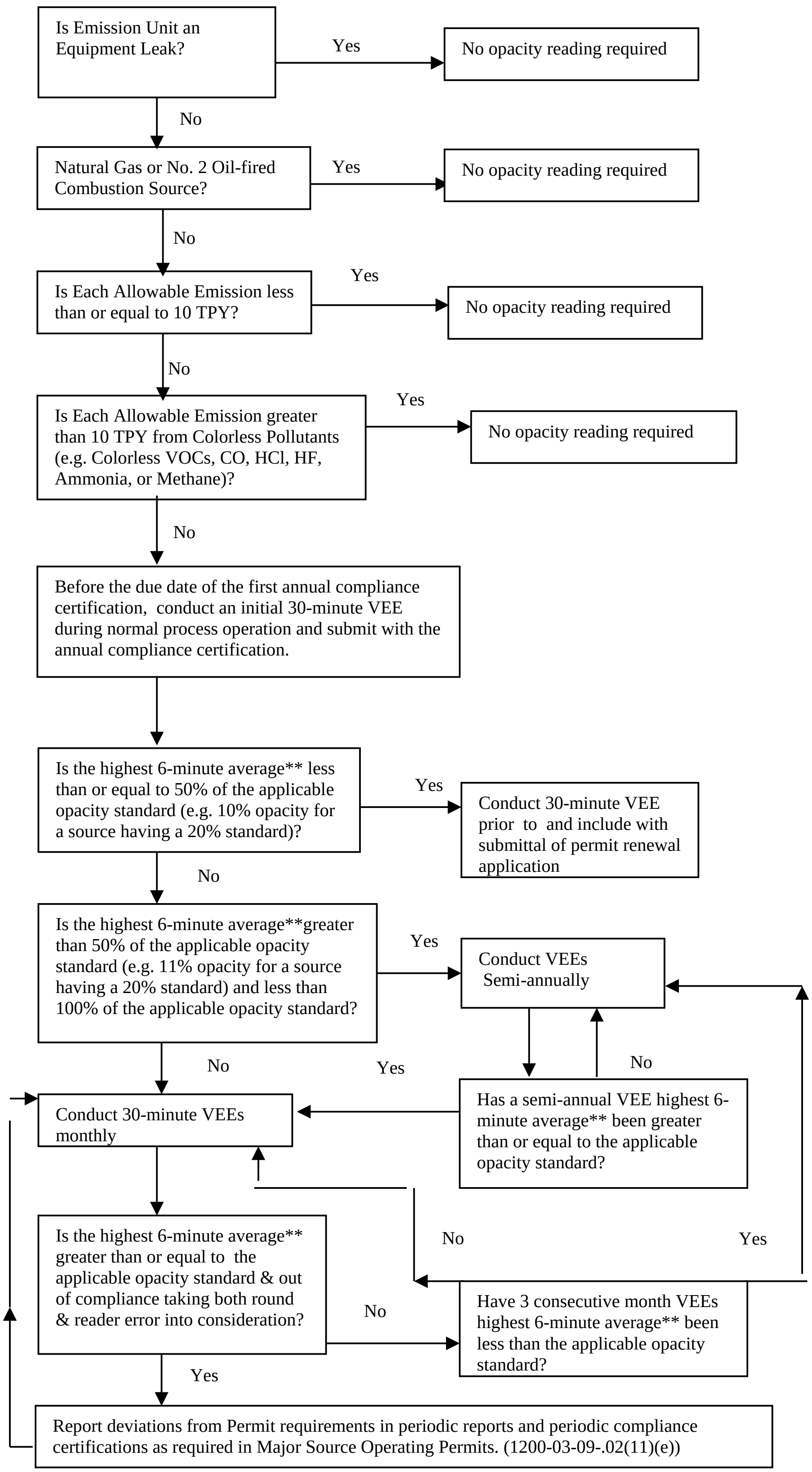
Reader Error
EPA Method 9, Non-NSPS or NESHAPS stipulated opacity standards:
The TAPCD guidance is to declares non-compliance when the highest six-minute average** exceeds the standard plus 6.8% opacity (e.g. 26.8% for a 20% standard).

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

EPA CONFIRMATION LETTER (ALTERNATIVE OPACITY MONITORING FOR SOURCE 38-0039-70)

Determination Detail

Control Number: 9800092

Category: NSPS
EPA Office: Region 4
Date: 04/16/1998
Title: Alternative Opactiy Monitoring
Recipient: Walton, John
Author: Neeley, R. Douglas
Comments:

Subparts:	Part 60, A	General Provisions
	Part 60, Dc	Small Indust.-Comm.-Inst. Steam Gen. Units

References: 60.13

Abstract:
Q: A Boiler primarily burns natural gas with #6 fuel oil or #6 fuel oil mixed with spent alcohol during periods of natural gas curtailment. The annual capacity factor for the fuels other than natural gas is less than 10%. Is a continuous opacity monitoring (COM) alternative permitted due to the low annual capacity factor for #6 fuel oil or oil/alcohol mixture?
A: Yes, under 60.13(i)(2), if #6 fuel oil is used less than 10% of the time or has an annual capacity factor of less that 10%, then an alternative monitoring plan can be approved as outlined in the letter.

Letter:
April 16, 1998
4APT-ARB
John W. Walton, P.E.
Technical Secretary
Tennessee Air Pollution Control Board
9th Floor, L & C Annex
401 Church Street
Nashville, Tennessee 37243-1531
SUBJECT: Alternative Opacity Monitoring Proposal for a Boiler at The Haywood Company
Thank you for your letter of March 5, 1998, to Mr. Brian Beals regarding Haywood's request for an alternative opacity monitoring approach. The referenced boiler is subject to 40 C.F.R. Part 60, Subpart Dc - Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units. This boiler burns natural gas as its primary fuel, but it is capable of operating on #6 fuel oil and #6 fuel oil mixed with spent alcohol as back up fuels. According to Subpart Dc, owners and operators of units in which oil is burned are required to install, certify, and operate continuous opacity monitors (COMs) if the heat input capacity of the unit is 30 million BTU/hour or greater. Haywood has requested an alternative to the use of a COM, however, because the company plans to burn #6 fuel oil or spent alcohol mixture less than 10 percent of the operating time (capacity factor of less than 10 percent).
We have concluded that an opacity monitoring alternative can be approved for Haywood if certain conditions are met. The conditions for the approval of the alternative are based upon several previously approved alternatives granted under the provisions of 40 C.F.R. 60.13(i)(2) which give the U.S. Environmental Protection Agency (EPA) the authority to allow the use of alternative monitoring for infrequently operated sources. Haywood has indicated that the capacity factor for oil combusted in their boiler will not exceed 10 percent. This is comparable to EPA's previous definitions of infrequent usage and a prerequisite for approval

of this opacity monitoring alternative is that this federally enforceable permit condition limiting the annual capacity factor for oil be included in Haywood's Title V permit. EPA concludes that Haywood Company may institute an opacity monitoring alternative subject to the following conditions:
1. At least once every four hours during daylight shifts when #6 fuel oil or the oil/alcohol mixture is combusted, an observer certified in accordance with EPA Method 9 shall perform a 6-minute visible emission observation.
2. If the average opacity for a 6-minute set of readings made in accordance with Condition 1 exceeds 10 percent, the observer must collect two additional 6-minute sets of visible emission readings for a total of three data sets.
3. Records of the date and time of visible emission observations, along with the results of each observation, must be maintained.
4. Thirty days after the end of each calendar quarter in which there are opacity excess emissions during the combustion of #6 fuel oil or the oil/alcohol mixture, Haywood must submit an excess emission report (EER) to the Tennessee Department of Environment and Conservation. If there are no opacity excess emissions during a calendar quarter, EERs may be submitted on a semiannual basis. For reporting purposes, excess emissions are defined as any six minute period during which the average opacity exceeds 20 percent, and EERs must indicate the total time of the visible emission observations during a calendar quarter and identify the duration of any excess emissions.
5. Haywood must record the quantity of #6 fuel oil burned each calendar quarter and include this information in the reports required under Condition 4. If, based upon this information, the #6 fuel oil annual capacity factor ever exceeds 10 percent, Haywood would no longer qualify to use an opacity monitoring alternative, and the company must be put on a schedule for installing and certifying a continuous opacity monitor.
6. Haywood must maintain the boiler following procedures and schedules recommended by the boiler manufacturer. The permit for the boiler must identify necessary maintenance activities, and Haywood must keep records verifying that the necessary maintenance activities have been performed.
7. This alternative opacity monitoring approval is valid only during operation on #6 fuel oil or the oil/alcohol mixture, and the alternative may not be used if any other liquid or solid fuels are burned in the boiler.
8. All records required under terms of this approval must be maintained by Haywood for a period of at least five years.
If you have any questions about the determination
provided in this letter, please contact Mr. David McNeal of my staff at 404/562-9102.
Sincerely,
R. Douglas Neeley, Chief
Air and Radiation Technology
Branch
Air, Pesticides and Toxics
Management Division

ATTACHMENT 3

TRE INDEX CALCULATION METHOD FROM 40 CFR §63.115(d)

§ 63.115 Process vent provisions—methods and procedures for process vent group determination.

(d) To determine the TRE index value, the owner or operator shall conduct a TRE determination and calculate the TRE index value according to the procedures in paragraph (d)(1) or (d)(2) of this section and the TRE equation in paragraph (d)(3) of this section.

(1) Engineering assessment may be used to determine vent stream flow rate, net heating value, TOC emission rate, and total organic HAP emission rate for the representative operating condition expected to yield the lowest TRE index value.

(i) If the TRE value calculated using such engineering assessment and the TRE equation in paragraph (d)(3) of this section is greater than 4.0, then the owner or operator is not required to perform the measurements specified in paragraph (d)(2) of this section.

(ii) If the TRE value calculated using such engineering assessment and the TRE equation in paragraph (d)(3) of this section is less than or equal to 4.0, then the owner or operator is required to perform the measurements specified in paragraph (d)(2) of this section for group determination or consider the process vent a Group 1 vent and comply with the emission reduction specified in §63.113(a) of this subpart.

(iii) Engineering assessment includes, but is not limited to, the following:

(A) Previous test results provided the tests are representative of current operating practices at the process unit.

(B) Bench-scale or pilot-scale test data representative of the process under representative operating conditions.

(C) Maximum flow rate, TOC emission rate, organic HAP emission rate, or net heating value limit specified or implied within a permit limit applicable to the process vent.

(D) Design analysis based on accepted chemical engineering principles, measurable process parameters, or physical or chemical laws or properties. Examples of analytical methods include, but are not limited to:

(*1*) Use of material balances based on process stoichiometry to estimate maximum organic HAP concentrations,

(*2*) Estimation of maximum flow rate based on physical equipment design such as pump or blower capacities,

(*3*) Estimation of TOC or organic HAP concentrations based on saturation conditions,

(*4*) Estimation of maximum expected net heating value based on the vent stream concentration of each organic compound or, alternatively, as if all TOC in the vent stream were the compound with the highest heating value.

(E) All data, assumptions, and procedures used in the engineering assessment shall be documented.

(2) Except as provided in paragraph (d)(1) of this section, vent stream flow rate, net heating value, TOC emission rate, and total organic HAP emission rate shall be measured and calculated according to the procedures in paragraphs (d)(2)(i) through (v) of this section and used as input to the TRE index value calculation in paragraph (d)(3) of this section.

(i) The vent stream volumetric flow rate (Q_s), in standard cubic meters per minute at 20 degrees Celcius, shall be determined using Method 2, 2A, 2C, or 2D of 40 CFR part 60, appendix A, as appropriate. If the vent stream tested passes through a final steam jet ejector and is not condensed, the vent stream volumetric flow shall be corrected to 2.3 percent moisture.

(ii) The molar composition of the vent stream, which is used to calculate net heating value, shall be determined using the following methods:

(A) Method 18 of 40 CFR part 60, appendix A to measure the concentration of each organic compound.

(B) American Society for Testing and Materials D1946–77 to measure the concentration of carbon monoxide and hydrogen.

(C) Method 4 of 40 CFR part 60, appendix A, to measure the moisture content of the vent stream.

(iii) The net heating value of the vent stream shall be calculated using the following equation:

$$H_T = K_1\left(\sum_{j=1}^{n} C_j H_j\right)(1 - B_{ws})$$

where:

H_T=Net heating value of the sample, megaJoule per standard cubic meter, where the net enthalpy per mole of vent stream is based on combustion at 25 °C and 760 millimeters of mercury, but the standard temperature for determining the volume corresponding to one mole is 20 °C, as in the definition of Q_s(vent stream flow rate).

K_1=Constant, 1.740×10^{-7}(parts per million)$^{-1}$(gram-mole per standard cubic meter) (megaJoule per kilocalorie), where standard temperature for (gram-mole per standard cubic meter) is 20 °C.

B_{ws}=Water vapor content of the vent stream, proportion by volume; except that if the vent stream passes through a final steam jet and is not condensed, it shall be assumed that B_{ws}=0.023 in order to correct to 2.3 percent moisture.

C_j=Concentration on a dry basis of compound j in parts per million, as measured for all organic compounds by Method 18 of 40 CFR part 60, appendix A and measured for hydrogen and carbon monoxide by American Society for Testing and Materials D1946–77 as indicated in paragraph (d)(2)(ii) of this section.

H_j=Net heat of combustion of compound j, kilocalorie per gram-mole, based on combustion at 25 °C and 760 millimeters mercury. The heats of combustion of vent stream components shall be determined using American Society for Testing and Materials D2382–76 if published values are not available or cannot be calculated.

(iv) The emission rate of TOC (minus methane and ethane) (E_{TOC}) and the emission rate of total organic HAP (E_{HAP}) in the vent stream shall both be calculated using the following equation:

$$E = K_2\left[\sum_{j=1}^{n} C_j M_j\right] Q_s$$

where:

E=Emission rate of TOC (minus methane and ethane) or emission rate of total organic HAP in the sample, kilograms per hour.

K_2=Constant, 2.494×10^{-6}(parts per million)$^{-1}$(gram-mole per standard cubic meter) (kilogram/gram) (minutes/hour), where standard temperature for (gram-mole per standard cubic meter) is 20°C.

C_j=Concentration on a dry basis of organic compound j in parts per million as measured by Method 18 of 40 CFR part 60, appendix A as indicated in paragraph (d)(2)(ii) of this section. If the TOC emission rate is being calculated, $C_j$includes all organic compounds measured minus methane and ethane; if the total organic HAP emission rate is being calculated, only organic HAP compounds listed in table 2 in subpart F of this part are included.

M_j=Molecular weight of organic compound j, gram/gram-mole.

Q_s=Vent stream flow rate, dry standard cubic meter per minute, at a temperature of 20°C.

(v) In order to determine whether a vent stream is halogenated, the mass emission rate of halogen atoms contained in organic compounds shall be calculated.

(A) The vent stream concentration of each organic compound containing halogen atoms (parts per million by volume, by compound) shall be determined based on the following procedures:

(*1*) Process knowledge that no halogen or hydrogen halides are present in the process, or

(*2*) Applicable engineering assessment as discussed in paragraph (d)(1)(iii) of this section, or

(*3*) Concentration of organic compounds containing halogens measured by Method 18 of 40 CFR part 60, appendix A, or

(*4*) Any other method or data that has been validated according to the applicable procedures in Method 301 of appendix A of this part.

(B) The following equation shall be used to calculate the mass emission rate of halogen atoms:

$$E = K_2 Q \left(\sum_{j=1}^{n} \sum_{i=1}^{m} C_j * L_{ji} * M_{ji} \right)$$

where:

E=mass of halogen atoms, dry basis, kilogram per hour.

K_2=Constant, 2.494×10^{-6}(parts per million)$^{-1}$(kilogram-mole per standard cubic meter) (minute/hour), where standard temperature is 20°C.

C_j=Concentration of halogenated compound j in the gas stream, dry basis, parts per million by volume.

M_{ji}=Molecular weight of halogen atom i in compound j of the gas stream, kilogram per kilogram-mole.

L_{ji}=Number of atoms of halogen i in compound j of the gas stream.

Q=Flow rate of gas stream, dry standard cubic meters per minute, determined according to paragraph (d)(1) or (d)(2)(i) of this section.

j=Halogenated compound j in the gas stream.

i=Halogen atom i in compound j of the gas stream.

n=Number of halogenated compounds j in the gas stream.

m=Number of different halogens i in each compound j of the gas stream.

(3) The owner or operator shall calculate the TRE index value of the vent stream using the equations and procedures in this paragraph.

(i) The equation for calculating the TRE index for a vent stream controlled by a flare or incinerator is as follows:

$$TRE = \frac{1}{E_{HAP}} \left[a + b(Q_s) + c(H_T) + d(E_{TOC}) \right]$$

where:

TRE=TRE index value.

E_{HAP}=Hourly emission rate of total organic HAP, kilograms per hour, as calculated in paragraph (d)(1) or (d)(2)(iv) of this section.

Q_s=Vent stream flow rate, standard cubic meters per minute, at a standard temperature of 20 °C, as calculated in paragraph (d)(1) or (d)(2)(i) of this section.

H_T=Vent stream net heating value, megaJoules per standard cubic meter, as calculated in paragraph (d)(1) or (d)(2)(iii) of this section.

E_{TOC}=Emission rate of TOC (minus methane and ethane), kilograms per hour, as calculated in paragraph (d)(1) or (d)(2)(iv) of this section.

a,b,c,d=Coefficients presented in table 1 of this subpart, selected in accordance with paragraphs (d)(3)(ii) and (iii) of this section.

(ii) The owner or operator of a nonhalogenated vent stream shall calculate the TRE index value based on the use of a flare, a thermal incinerator with 0 percent heat recovery, and a thermal incinerator with 70 percent heat recovery and shall select the lowest TRE index value. The owner or operator shall use the applicable coefficients in table 1 of this subpart for nonhalogenated vent streams located within existing sources and the applicable coefficients in table 2 of this subpart for nonhalogenated vent streams located within new sources.

(iii) The owner or operator of a halogenated vent stream shall calculate the TRE index value based on the use of a thermal incinerator with 0 percent heat recovery, and a scrubber. The owner or operator shall use the applicable coefficients in table 1 of this subpart for halogenated vent streams located within existing sources and the applicable coefficients in table 2 of this subpart for halogenated vent streams located within new sources.

ATTACHMENT 4

EMISSION ESTIMATION PROCEDURES FROM 40 CFR 63.1257(d)(2) TO DETERMINE GROUP STATUS OF BATCH PROCESS VENTS

§ 63.1257 Test methods and compliance procedures.

(d) (2) (i) *Emission estimation procedures.* Owners or operators shall determine uncontrolled emissions of HAP using measurements and/or calculations for each batch emission episode within each unit operation according to the engineering evaluation methodology in paragraphs (d)(2)(i)(A) through (H) of this section. Except where variations are noted, individual HAP partial pressures in multicomponent systems shall be determined by the following methods: If the components are miscible in one another, use Raoult's law to calculate the partial pressures; if the solution is a dilute aqueous mixture, use Henry's law to calculate partial pressures; if Raoult's law or Henry's law are not appropriate or available, use experimentally obtained activity coefficients or models such as the group-contribution models, to predict activity coefficients, or assume the components of the system behave independently and use the summation of all vapor pressures from the HAP as the total HAP partial pressure. Chemical property data can be obtained from standard reference texts.

(A) *Vapor displacement.* Emissions from vapor displacement due to transfer of material shall be calculated using Equation 11 of this subpart. The individual HAP partial pressures may be calculated using Raoult's law.

$$E = \frac{(V)}{(R)(T)} \times \sum_{i=1}^{n} (P_i)(MW_i) \qquad (Eq.\ 11)$$

where:

E = mass of HAP emitted

V = volume of gas displaced from the vessel

R = ideal gas law constant

T = temperature of the vessel vapor space; absolute

P_i= partial pressure of the individual HAP

MW_i= molecular weight of the individual HAP

n = number of HAP compounds in the emission stream

i = identifier for a HAP compound

(B) *Purging.* Emissions from purging shall be calculated using Equation 12 of this subpart. The partial pressures of individual condensable compounds may be calculated using Raoult's law, the pressure of the vessel vapor space may be set equal to 760 mmHg, and the partial pressure of HAP shall be assumed to be 25 percent of the saturated value if the purge flow rate is greater than 100 standard cubic feet per minute (scfm).

$$E = \sum_{i=1}^{n} P_i MW_i \times \frac{(V)(t)}{(R)(T)} \times \frac{P_T}{P_T - \sum_{j=1}^{m} (P_j)} \qquad (Eq.\ 12)$$

Where:

E = mass of HAP emitted

V = purge flow rate at the temperature and pressure of the vessel vapor space

R = ideal gas law constant

T = temperature of the vessel vapor space; absolute

P_i= partial pressure of the individual HAP

P_j= partial pressure of individual condensable VOC compounds (including HAP)

P_T= pressure of the vessel vapor space

MW_i = molecular weight of the individual HAP

t = time of purge

n = number of HAP compounds in the emission stream

i = identifier for a HAP compound

j = identifier for a condensable compound

m = number of condensable compounds (including HAP) in the emission stream

(C) *Heating.* Emissions caused by the heating of a vessel to a temperature equal to or lower than 10 K below the boiling point shall be calculated using the procedures in either paragraph (d)(2)(i)(C)(*1*) or (*3*) of this section. Emissions caused by heating a vessel to a temperature that is higher than 10 K below the boiling point and less than the boiling point, must be calculated using the procedures in either paragraph (d)(2)(i)(C) (*2*) or (*3*) of this section. If the contents of a vessel are heated to the boiling point, emissions must be calculated using the procedures in paragraph (d)(2)(i)(C)(*4*) of this section.

(*1*) This paragraph describes procedures to calculate emissions if the final temperature to which the vessel contents are heated is 10 K below the boiling point of the HAP in the vessel, or lower. The owner or operator shall calculate the mass of HAP emitted per episode using either Equation 13 or 14 of this subpart. The moles of noncondensable gas displaced are calculated using Equation 15 of this subpart. The initial and final pressure of the noncondensable gas in the vessel shall be calculated using Equation 16 of this subpart. The average molecular weight of HAP in the displaced gas shall be calculated using Equation 17 of this subpart.

$$E = \frac{\sum_{i=1}^{n}\left((P_i*)(x_i)(MW_i)\right)}{760 - \sum_{j=1}^{m}\left((P_j*)(x_j)\right)} \times \Delta\eta \qquad \text{(Eq. 13)}$$

$$E = \frac{\dfrac{\sum_{i=1}^{n}(P_i)_{T1}}{Pa_1} + \dfrac{\sum_{i=1}^{n}(P_i)_{T2}}{Pa_2}}{2} \times \Delta\eta \times MW_{HAP} \qquad (Eq.14)$$

$$\Delta\eta = \frac{V}{R}\left[\left(\frac{Pa_1}{T_1}\right) - \left(\frac{Pa_2}{T_2}\right)\right] \qquad (Eq.15)$$

$$Pa_n = P_{atm} - \sum_{j=1}^{m}(P_j)_{Tn} \qquad (Eq.16)$$

$$MW_{HAP} = \sum_{i=1}^{n}\frac{\left((P_i)_{T_1} + (P_i)_{T_2}\right)MW_i}{\sum_{i=1}^{n}\left((P_i)_{T_1} + (P_i)_{T_2}\right)} \qquad (Eq.17)$$

Where:

E = mass of HAP vapor displaced from the vessel being heated

x_i= mole fraction of each HAP in the liquid phase

x_j= mole fraction of each condensable VOC (including HAP) in the liquid phase

P_i* = vapor pressure of each HAP in the vessel headspace at any temperature between the initial and final heatup temperatures, mmHg.

P_j* = vapor pressure of each condensable VOC (including HAP) in the vessel headspace at any temperature between the initial and final heatup temperatures, mmHg.

760 = atmospheric pressure, mmHg

MW_{HAP}= the average molecular weight of HAP present in the displaced gas

$\Delta\eta$ = number of moles of noncondensable gas displaced

V = volume of free space in the vessel

R = ideal gas law constant

T_1= initial temperature of vessel contents, absolute

T_2= final temperature of vessel contents, absolute

Pa_n= partial pressure of noncondensable gas in the vessel headspace at initial (n=1) and final (n=2) temperature

P_{atm}= atmospheric pressure (when $\Delta\eta$ is used in Equation 13 of this subpart, P_{atm} may be set equal to 760 mmHg for any vessel)

$(P_j)_{Tn}$= partial pressure of each condensable compound (including HAP) in the vessel headspace at the initial temperature (n=1) and final (n=2) temperature

m = number of condensable compounds (including HAP) in the displaced vapor

j = identifier for a condensable compound

$(P_i)_{Tn}$= partial pressure of each HAP in the vessel headspace at initial (T_1) and final (T_2) temperature

MW_i= molecular weight of the individual HAP

n = number of HAP compounds in the emission stream

i = identifier for a HAP compound

(*2*) If the vessel contents are heated to a temperature that is higher than 10 K below the boiling point and less than the boiling point, emissions must be calculated using the procedures in paragraph (d)(2)(i)(C)(*2*)(*i*), or (*ii*), or (*iii*) of this section.

(*i*) Use Equation 13 of this subpart. In Equation 13 of this subpart, the HAP vapor pressures must be determined at the temperature 10 K below the boiling point. In the calculation of $\Delta\eta$ for Equation 13 of this subpart, T_2 must be the temperature 10 K below the boiling point, and Pa_2 must be determined at the temperature 10 K below the boiling point.

(*ii*) Use Equation 14 of this subpart. In Equation 14 of this subpart, the HAP partial pressures must be deter mined at the temperature 10 K below the boiling point. In the calculation of $\Delta\eta$ for Equation 14 of this subpart, T_2 must be the temperature 10 K below the boiling point, and Pa_2 must be determined at the temperature 10 K below the boiling point. In the calculation of MW_{HAP}, the HAP partial pressures must be determined at the temperature 10 K below the boiling point.

(*iii*) Use Equation 14 of this subpart over specific temperature increments. If the initial temperature is lower than 10 K below the boiling point, emissions must be calculated as the sum over two increments; one increment is from the initial temperature to 10 K below the boiling point, and the second is from 10 K below the boiling point to the lower of either the final temperature or the temperature 5 K below the boiling point. If the initial temperature is higher than 10 K below the boiling point, emissions are calculated over one increment from the initial temperature to the lower of either the final temperature or the temperature 5 K below the boiling point.

(*3*) (*i*) Emissions caused by heating a vessel are calculated using Equation 18 of this subpart.

$$E = MW_{HAP} \times \left(N_{avg} \times \ln \left(\frac{P_T - \sum_{i=1}^{n} (P_{i,1})}{P_T - \sum_{i=1}^{n} (P_{i,2})} \right) - (n_{i,2} - n_{i,1}) \right) \qquad (Eq.18)$$

Where:

E = mass of HAP vapor displaced from the vessel being heated

N_{avg}= average gas space molar volume during the heating process

P_T= total pressure in the vessel

$P_{i,1}$= partial pressure of the individual HAP compounds at T_1

$P_{i,2}$= partial pressure of the individual HAP compounds at T_2

MW_{HAP}= average molecular weight of the HAP compounds

$n_{i,1}$= number of moles of condensable in the vessel headspace at T_1

$n_{i,2}$= number of moles of condensable in the vessel headspace at T_2

n = number of HAP compounds in the emission stream

(*ii*) The average gas space molar volume during the heating process is calculated using Equation 19 of this subpart.

$$N_{avg} = \frac{VP_T}{2R} \left(\frac{1}{T_1} + \frac{1}{T_2} \right) \qquad (Eq.19)$$

Where:

N_{avg}= average gas space molar volume during the heating process

V = volume of free space in vessel

P_T= total pressure in the vessel

R = ideal gas law constant

T_1= initial temperature of the vessel

T_2= final temperature of the vessel

(*iii*) The difference in the number of moles of condensable in the vessel headspace between the initial and final temperatures is calculated using Equation 20 of this subpart.

$$(n_{i,2} - n_{i,1}) = \frac{V}{(R)(T_2)} \sum_{i=1}^{n} P_{i,2} - \frac{V}{(R)(T_1)} \sum_{i=1}^{n} P_{i,1} \qquad (Eq.20)$$

Where:

V = volume of free space in vessel

R = ideal gas law constant

T_1= initial temperature in the vessel

T_2= final temperature in the vessel

$P_{i,1}$= partial pressure of the individual HAP compounds at T_1

$P_{i,2}$= partial pressure of the individual HAP compounds at T_2

n = number of HAP compounds in the emission stream

(*4*) If the vessel contents are heated to the boiling point, emissions must be calculated using the procedure in paragraphs (d)(2)(i)(C)(*4*)(*i*) and (*ii*) of this section.

(*i*) Use either of the procedures in paragraph (d)(3)(i)(B)(*3*) of this section to calculate the emissions from heating to the boiling point (note that Pa_2=0 in the calculation of $\Delta\eta$); and

(*ii*) While boiling, the vessel must be operated with a properly operated process condenser. An initial demonstration that a process condenser is properly operated is required for some process condensers, as described in paragraph (d)(3)(iii) of this section.

(D) *Depressurization.* Emissions from depressurization shall be calculated using the procedures in either paragraphs (d)(2)(i)(D)(*1*) through (*4*), paragraphs (d)(2)(i)(D)(*5*) through (*9*), or paragraph (d)(2)(i)(D)(*10*) of this section.

(*1*) Equations 21 and 22 of this subpart are used to calculate the initial and final volumes of noncondensable gas present in the vessel, adjusted to atmospheric pressure. The HAP partial pressures may be calculated using Raoult's law.

$$V_{nc1} = \frac{VP_{nc_1}}{760} \qquad (Eq. 21)$$

$$V_{nc2} = \frac{VP_{nc_2}}{760} \qquad (Eq. 22)$$

Where:

V_{nc1}= initial volume of noncondensable gas in the vessel

V_{nc2}= final volume of noncondensable gas in the vessel

V = free volume in the vessel being depressurized

P_{nc1}= initial partial pressure of the noncondensable gas, as calculated using Equation 23 of this subpart, mmHg

P_{nc2}= final partial pressure of the noncondensable gas, as calculated using Equation 24 of this subpart, mmHg

760 = atmospheric pressure, mmHg

(*2*) The initial and final partial pressures of the noncondensable gas in the vessel are determined using Equations 23 and 24 of this subpart:

$$P_{nc1} = P_1 - \sum_{j=1}^{m} (P_j *)(x_j) \qquad (Eq. 23)$$

$$P_{nc2} = P_2 - \sum_{j=1}^{m} (P_j *)(x_j) \qquad (Eq. 24)$$

Where:

P_{nc1}= initial partial pressure of the noncondensable gas

P_{nc2}= final partial pressure of the noncondensable gas

P_1= initial vessel pressure

P_2= final vessel pressure

P_j* = vapor pressure of each condensable (including HAP) in the emission stream

x_j= mole fraction of each condensable (including HAP) in the liquid phase

m = number of condensable compounds (including HAP) in the emission stream

j = identifier for a condensable compound

(*3*) The average ratio of moles of noncondensable to moles of an individual HAP in the emission stream is calculated using Equation 25 of this subpart; this calculation must be repeated for each HAP in the emission stream:

$$n_{Ri} = \frac{\left(\frac{P_{nc1}}{(P_i*)(x_i)} + \frac{P_{nc2}}{(P_i*)(x_i)}\right)}{2} \qquad \text{(Eq. 25)}$$

Where:

n_{Ri}= average ratio of moles of noncondensable to moles of individual HAP

P_{nc1}= initial partial pressure of the noncondensable gas, as calculated using Equation 23 of this subpart

P_{nc2}= final partial pressure of the noncondensable gas, as calculated using Equation 24 of this subpart

P_i* = vapor pressure of each individual HAP

x_i= mole fraction of each individual HAP in the liquid phase.

n = number of HAP compounds

i = identifier for a HAP compound

(*4*) The mass of HAP emitted shall be calculated using Equation 26 of this subpart:

$$E = (V_{nc1} - V_{nc2}) \times \frac{P_{atm}}{RT} \times \sum_{i=1}^{n} \frac{MW_i}{n_{Ri}} \qquad \text{(Eq. 26)}$$

Where:

E = mass of HAP emitted

V_{nc1}= initial volume of noncondensable gas in the vessel, as calculated using Equation 21 of this subpart

V_{nc2}= final volume of noncondensable gas in the vessel, as calculated using Equation 22 of this subpart

n_{Ri}= average ratio of moles of noncondensable to moles of individual HAP, as calculated using Equation 25 of this subpart

P_{atm}= atmospheric pressure, standard

R = ideal gas law constant

T = temperature of the vessel, absolute

MW_i= molecular weight of each HAP

(*5*) The moles of HAP vapor initially in the vessel are calculated using the ideal gas law using Equation 27 of this subpart:

$$n_{HAP} = \frac{(Y_{HAP})(V)(P_1)}{RT} \qquad \textit{(Eq. 27)}$$

Where:

Y_{HAP}= mole fraction of HAP (the sum of the individual HAP fractions, ΣY_i)

V = free volume in the vessel being depressurized

P_1= initial vessel pressure

R = ideal gas law constant

T = vessel temperature, absolute

(*6*) The initial and final moles of noncondensable gas present in the vessel are calculated using Equations 28 and 29 of this subpart:

$$n_1 = \frac{VP_{nc_1}}{RT} \qquad (Eq. 28)$$

$$n_2 = \frac{VP_{nc_2}}{RT} \qquad (Eq. 29)$$

Where:

n_1= initial number of moles of noncondensable gas in the vessel

n_2= final number of moles of noncondensable gas in the vessel

V = free volume in the vessel being depressurized

P_{nc1}= initial partial pressure of the noncondensable gas, as calculated using Equation 23 of this subpart

P_{nc2}= final partial pressure of the noncondensable gas, as calculated using Equation 24 of this subpart

R = ideal gas law constant

T = temperature, absolute

(*7*) The initial and final partial pressures of the noncondensable gas in the vessel are determined using Equations 23 and 24 of this subpart.

(*8*) The moles of HAP emitted during the depressurization are calculated by taking an approximation of the average ratio of moles of HAP to moles of noncondensable and multiplying by the total moles of noncondensables released during the depressurization, using Equation 30 of this subpart:

$$n_{HAP} = \frac{\left(\frac{n_{HAP,1}}{n_1} + \frac{n_{HAP,2}}{n_2}\right)}{2}\left[n_1 - n_2\right] \qquad (Eq. 30)$$

where:

n_{HAP}= moles of HAP emitted

n_1= initial number of moles of noncondensable gas in the vessel, as calculated using Equation 28 of this subpart

n_2= final number of moles of noncondensable gas in the vessel, as calculated using Equation 29 of this subpart

(*9*) The mass of HAP emitted can be calculated using Equation 31 of this subpart:

$E=\eta_{HAP} * MW_{HAP}$ (Eq. 31)

where:

E = mass of HAP emitted

η_{HAP}= moles of HAP emitted, as calculated using Equation 30 of this subpart

MW_{HAP}= average molecular weight of the HAP as calculated using Equation 17 of this subpart

(*10*) Emissions from depressurization may be calculated using equation 32 of this subpart:

$$E = \frac{V}{(R)(T)} \times \ln\left(\frac{P_1 - \sum_{j=1}^{m}(P_j)}{P_2 - \sum_{j=1}^{m}(P_j)}\right) \times \sum_{i=1}^{n}(P_i)(\mathrm{MW}_i) \qquad (Eq.\ 32)$$

Where:

V = free volume in vessel being depressurized

R = ideal gas law constant

T = temperature of the vessel, absolute

P_1= initial pressure in the vessel

P_2= final pressure in the vessel

P_j= partial pressure of the individual condensable compounds (including HAP)

MW_i= molecular weight of the individual HAP compounds

n = number of HAP compounds in the emission stream

m = number of condensable compounds (including HAP) in the emission stream

i = identifier for a HAP compound

j = identifier for a condensable compound.

(E) *Vacuum systems.* Emissions from vacuum systems may be calculated using Equation 33 of this subpart if the air leakage rate is known or can be approximated. The individual HAP partial pressures may be calculated using Raoult's Law.

$$E = \frac{(La)(t)}{MW_{nc}}\left(\frac{\sum_{i=1}^{n} P_i MW_i}{P_{system} - \sum_{j=1}^{m} P_j}\right) \qquad (\mathrm{Eq.}\ 33)$$

Where:

E = mass of HAP emitted

P_{system}= absolute pressure of receiving vessel or ejector outlet conditions, if there is no receiver

P_i= partial pressure of the HAP at the receiver temperature or the ejector outlet conditions

P_j= partial pressure of condensable (including HAP) at the receiver temperature or the ejector outlet conditions

La = total air leak rate in the system, mass/time

MW_{nc}= molecular weight of noncondensable gas

t = time of vacuum operation

MW_i= molecular weight of the individual HAP in the emission stream, with HAP partial pressures calculated at the temperature of the receiver or ejector outlet, as appropriate

(F) *Gas evolution.* Emissions from gas evolution shall be calculated using Equation 12 of this subpart with V calculated using Equation 34 of this subpart:

$$V = \frac{(W_g)(R)(T)}{(P_T)(MW_g)} \qquad (Eq.\,34)$$

Where:

V = volumetric flow rate of gas evolution

W_g= mass flow rate of gas evolution

R = ideal gas law constant

T = temperature at the exit, absolute

P_T= vessel pressure

MW_g= molecular weight of the evolved gas

(G) *Air drying.* Emissions from air drying shall be calculated using Equation 35 of this subpart:

$$E = B \times \left(\frac{PS_1}{100 - PS_1} - \frac{PS_2}{100 - PS_2} \right) \qquad (Eq.\,35)$$

Where:

E = mass of HAP emitted

B = mass of dry solids

PS_1= HAP in material entering dryer, weight percent

PS_2= HAP in material exiting dryer, weight percent

(H) *Empty vessel purging.* Emissions from empty vessel purging shall be calculated using Equation 36 of this subpart (Note: The term $e^{-Ft/v}$ can be assumed to be 0):

$$E = \left(\frac{V}{RT} \times \left(\sum_{i=1}^{n} (P_i)(MW_i) \right) \left(1 - e^{-Ft/v}\right) \right) \qquad (Eq.\,36)$$

Where:

V = volume of empty vessel

R = ideal gas law constant

T = temperature of the vessel vapor space; absolute

P_i= partial pressure of the individual HAP at the beginning of the purge

(MW_i) = molecular weight of the individual HAP

F = flowrate of the purge gas

t = duration of the purge

n = number of HAP compounds in the emission stream

i = identifier for a HAP compound

(ii) *Engineering assessments.* The owner or operator shall conduct an engineering assessment to calculate uncontrolled HAP emissions for each emission episode that is not due to vapor displacement, purging, heating, depressurization, vacuum operations, gas evolution, or air drying. For emission episodes caused by any of these types of activities, the owner or operator also may calculate uncontrolled HAP emissions based on an engineering assessment if the owner or operator can demonstrate to the Administrator that the methods in paragraph (d)(2)(i) of this section are not appropriate. Modified versions of the engineering evaluation methods in paragraphs (d)(2)(i)(A) through (H) may be used if the owner or operator demonstrates that they have been used to meet other regulatory obligations, and they do not affect applicability assessments or compliance determinations under this subpart GGG. One criterion the owner or operator could use to demonstrate that the methods in paragraph (d)(2)(i) of this section are not appropriate is if previous test data are available that show a greater than 20 percent discrepancy between the test value and the estimated value. An engineering assessment includes, but is not limited to, the following:

(A) Previous test results, provided the tests are representative of current operating practices at the process unit.

(B) Bench-scale or pilot-scale test data representative of the process under representative operating conditions.

(C) Maximum flow rate, HAP emission rate, concentration, or other relevant parameter specified or implied within a permit limit applicable to the process vent.

(D) Design analysis based on accepted chemical engineering principles, measurable process parameters, or physical or chemical laws or properties. Examples of analytical methods include, but are not limited to:

(*1*) Use of material balances based on process stoichiometry to estimate maximum organic HAP concentrations.

(*2*) Estimation of maximum flow rate based on physical equipment design such as pump or blower capacities.

(*3*) Estimation of HAP concentrations based on saturation conditions.

(E) All data, assumptions, and procedures used in the engineering assessment shall be documented in accordance with §63.1260(e). Data or other information supporting a finding that the emissions estimation equations are inappropriate shall be reported in the Precompliance report.

(3) (i) (B) *Emission estimation equations.* An owner or operator using a condenser as a control device shall determine controlled emissions using exhaust gas temperature measurements and calculations for each batch emission episode within each unit operation according to the engineering methodology in paragraphs (d)(3)(i)(B)(*1*) through (*8*) of this section. Individual HAP partial pressures shall be calculated as specified in paragraph (d)(2)(i) of this section.

(*1*) Emissions from vapor displacement shall be calculated using Equation 11 of this subpart with T set equal to the temperature of the receiver and the HAP partial pressures determined at the temperature of the receiver.

(*2*) Emissions from purging shall be calculated using Equation 12 of this subpart with T set equal to the temperature of the receiver and the HAP partial pressures determined at the temperature of the receiver.

(*3*) Emissions from heating shall be calculated using either Equation 13 of this subpart or Equation 37 of this subpart. In Equation 13, the HAP vapor pressures shall be determined at the temperature of the receiver. In Equations 13 and 37 of this subpart, Δη is equal to the number of moles of noncondensable displaced from the vessel, as calculated using Equation 15 of this subpart. In Equations 13 and 37 of this subpart, the HAP average molecular weight shall be calculated using Equation 17 with the HAP partial pressures determined at the temperature of the receiver.

$$E = \Delta\eta \times \frac{\sum_{i=1}^{n} P_i}{P_T - \sum_{j=1}^{m} P_j} \times MW_{HAP} \quad (Eq. 37)$$

Where:

E = mass of HAP emitted

Δη = moles of noncondensable gas displaced

P_T= pressure in the receiver

P_i= partial pressure of the individual HAP at the receiver temperature

P_j= partial pressure of the individual condensable (including HAP) at the receiver temperature

n = number of HAP compounds in the emission stream

i = identifier for a HAP compound

MW_{HAP}= the average molecular weight of HAP in vapor exiting the receiver, as calculated using Equation 17 of this subpart

m = number of condensable compounds (including HAP) in the emission stream

(*4*) (*i*) Emissions from depressurization shall be calculated using Equation 38 of this subpart.

$$E = (V_{nc1} - V_{nc2}) \times \frac{\sum_{i=1}^{n}(P_i)}{P_T - \sum_{j=1}^{m}(P_j)} \times \frac{P_T}{RT} \times MW_{HAP} \qquad (Eq. 38)$$

Where:

E = mass of HAP vapor emitted

V_{nc1}= initial volume of noncondensable in the vessel, corrected to the final pressure, as calculated using Equation 39 of this subpart

V_{nc2}= final volume of noncondensable in the vessel, as calculated using Equation 40 of this subpart

P_i= partial pressure of each individual HAP at the receiver temperature

P_j= partial pressure of each condensable (including HAP) at the receiver temperature

P_T= receiver pressure

T = temperature of the receiver

R = ideal gas law constant

MW_{HAP}= the average molecular weight of HAP calculated using Equation 17 of this subpart with partial pressures determined at the receiver temperature

i = identifier for a HAP compound

n = number of HAP compounds in the emission stream

m = number of condensable compounds (including HAP) in the emission stream

j = identifier for a condensable compound

(*ii*) The initial and final volumes of noncondensable gas present in the vessel, adjusted to the pressure of the receiver, are calculated using Equations 39 and 40 of this subpart.

$$V_{nc1} = \frac{VP_{nc_1}}{P_T} \qquad (Eq. 39)$$

$$V_{nc2} = \frac{VP_{nc_2}}{P_T} \qquad (Eq.\ 40)$$

Where:

V_{nc1}= initial volume of noncondensable gas in the vessel

V_{nc2}= final volume of noncondensable gas in the vessel

V = free volume in the vessel being depressurized

P_{nc1}= initial partial pressure of the noncondensable gas, as calculated using Equation 41 of this subpart

P_{nc2}= final partial pressure of the noncondensable gas, as calculated using Equation 42 of this subpart

P_T= pressure of the receiver

(*iii*) Initial and final partial pressures of the noncondensable gas in the vessel are determined using Equations 41 and 42 of this subpart.

$$P_{nc1} = P_1 - \sum_{j=1}^{m} P_j \qquad (Eq.\ 41)$$

$$P_{nc2} = P_2 - \sum_{j=1}^{m} P_j \qquad (Eq.\ 42)$$

Where:

P_{nc1}= initial partial pressure of the noncondensable gas in the vessel

P_{nc2}= final partial pressure of the noncondensable gas in the vessel

P_1= initial vessel pressure

P_2= final vessel pressure

P_j= partial pressure of each condensable compound (including HAP) in the vessel

m = number of condensable compounds (including HAP) in the emission stream

j = identifier for a condensable compound

(*5*) Emissions from vacuum systems shall be calculated using Equation 33 of this subpart.

(*6*) Emissions from gas evolution shall be calculated using Equation 12 with V calculated using Equation 34 of this subpart, T set equal to the receiver temperature, and the HAP partial pressures determined at the receiver temperature. The term for time, t, in Equation 12 of this subpart is not needed for the purposes of this calculation.

(*7*) Emissions from air drying shall be calculated using Equation 11 of this subpart with V equal to the air flow rate and P_i determined at the receiver temperature.

(*8*) Emissions from empty vessel purging shall be calculated using equation 43 of this subpart:

$$E = \frac{V}{R}\left[\left(\sum_{i=1}^{n}\frac{(P_i)_{T_1}(MW_i)}{T_1}\right)\left(-e^{-Ft/V}\right) - \left(\sum_{i=1}^{n}\frac{(P_i)_{T_2}(MW_i)}{T_2}\right)\left(\ln\left(\frac{\sum_{i=1}^{n}(P_i)_{T_2}}{\sum_{i=1}^{n}(P_i)_{T_1}}\right)+1\right)\right] \qquad (Eq.\ 43)$$

Where:

V = volume of empty vessel

R = ideal gas law constant

T_1= temperature of the vessel vapor space at beginning of purge

T_2= temperature of the receiver, absolute

$(P_i)_{T1}$= partial pressure of the individual HAP at the beginning of the purge

$(P_i)_{T2}$= partial pressure of the individual HAP at the receiver temperature

MW_i= molecular weight of the individual HAP

F = flowrate of the purge gas

t = duration of the purge

n = number of HAP compounds in the emission stream

i = identifier for a HAP compound

ATTACHMENT 5

AP-42 FIFTH EDITION EMISSION FACTORS for NATURAL GAS COMBUSTION

Table 1.4-1. EMISSION FACTORS FOR SULFUR DIOXIDE (SO_2), 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 NOx 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 NOx burners	50	D	84	B
Controlled - Low NOx 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 $1b/10^6$ 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 D_b. 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
CO2 [b]	120,000	A
Lead	0.0005	D
N2O (Uncontrolled)	2.2	E
N2O (Controlled-low-NOX burner)	0.64	E
PM (Total)[c]	7.6	D
PM (Condensable)[c]	5.7	D
PM (Filterable)[c]	1.9	B
SO2 [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 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. TOC = Total Organic Compounds. VOC = Volatile Organic Compounds.

b Based on approximately 100% conversion of fuel carbon to CO_2. CO_2 [$lb/10^6$ 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, $4.2x10^4$ $lb/10^6$ 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 6

AP-42 FIFTH EDITION EMISSION FACTORS for FUEL OIL COMBUSTION

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 NOx 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 NOx 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 $lb/10^3$ gal to $kg/10^3$ 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 NO_2. 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 $lb/10^3$ 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 NO_2 $/10^3$ 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 $lb/10^3$ gal.
h The SO_2 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 1.3-3. 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/10^3 gal to kg/10^3 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.

ATTACHMENT 7

Table 10 to Subpart DDDDD of Part 63—Applicability of General Provisions to Subpart DDDDD

Table 10 to Subpart DDDDD of Part 63—Applicability of General Provisions to Subpart DDDDD

As stated in § 63.7565, the permittee must comply with the applicable General Provisions according to the following:

Citation	Subject	Applies to subpart DDDDD
§ 63.1	Applicability	Yes.
§ 63.2	Definitions	Yes. Additional terms defined in § 63.7575
§ 63.3	Units and Abbreviations	Yes.
§ 63.4	Prohibited Activities and Circumvention	Yes.
§ 63.5	Preconstruction Review and Notification Requirements	Yes.
§ 63.6(a), (b)(1)-(b)(5), (b)(7), (c)	Compliance with Standards and Maintenance Requirements	Yes.
§ 63.6(e)(1)(i)	General duty to minimize emissions.	No. See § 63.7500(a)(3) for the general duty requirement.
§ 63.6(e)(1)(ii)	Requirement to correct malfunctions as soon as practicable.	No.
§ 63.6(e)(3)	Startup, shutdown, and malfunction plan requirements.	No.
§ 63.6(f)(1)	Startup, shutdown, and malfunction exemptions for compliance with non-opacity emission standards.	No.
§ 63.6(f)(2) and (3)	Compliance with non-opacity emission standards.	Yes.
§ 63.6(g)	Use of alternative standards	Yes.
§ 63.6(h)(1)	Startup, shutdown, and malfunction exemptions to opacity standards.	No. See § 63.7500(a).
§ 63.6(h)(2) to (h)(9)	Determining compliance with opacity emission standards	Yes.
§ 63.6(i)	Extension of compliance.	Yes. Note: Facilities may also request extensions of compliance for the installation of combined heat and power, waste heat recovery, or gas pipeline or fuel feeding infrastructure as a means of complying with this subpart.
§ 63.6(j)	Presidential exemption.	Yes.
§ 63.7(a), (b), (c), and (d)	Performance Testing Requirements	Yes.
§ 63.7(e)(1)	Conditions for conducting performance tests.	No. Subpart DDDDD specifies conditions for conducting performance tests at § 63.7520(a) to (c).
§ 63.7(e)(2)-(e)(9), (f), (g), and (h)	Performance Testing Requirements	Yes.
§ 63.8(a) and (b)	Applicability and Conduct of Monitoring	Yes.
§ 63.8(c)(1)	Operation and maintenance of CMS	Yes.
§ 63.8(c)(1)(i)	General duty to minimize emissions and CMS operation	No. See § 63.7500(a)(3).
§ 63.8(c)(1)(ii)	Operation and maintenance of CMS	Yes.
§ 63.8(c)(1)(iii)	Startup, shutdown, and malfunction plans for CMS	No.
§ 63.8(c)(2) to (c)(9)	Operation and maintenance of CMS	Yes.
§ 63.8(d)(1) and (2)	Monitoring Requirements, Quality Control Program	Yes.
§ 63.8(d)(3)	Written procedures for CMS	Yes, except for the last sentence, which refers to a startup, shutdown, and malfunction plan. Startup, shutdown, and malfunction plans are not required.
§ 63.8(e)	Performance evaluation of a CMS	Yes.

Citation	Subject	Applies to subpart DDDDD
§ 63.8(f)	Use of an alternative monitoring method.	Yes.
§ 63.8(g)	Reduction of monitoring data.	Yes.
§ 63.9	Notification Requirements	Yes.
§ 63.10(a), (b)(1)	Recordkeeping and Reporting Requirements	Yes.
§ 63.10(b)(2)(i)	Recordkeeping of occurrence and duration of startups or shutdowns	Yes.
§ 63.10(b)(2)(ii)	Recordkeeping of malfunctions	No. See § 63.7555(d)(7) for recordkeeping of occurrence and duration and § 63.7555(d)(8) for actions taken during malfunctions.
§ 63.10(b)(2)(iii)	Maintenance records	Yes.
§ 63.10(b)(2)(iv) and (v)	Actions taken to minimize emissions during startup, shutdown, or malfunction	No.
§ 63.10(b)(2)(vi)	Recordkeeping for CMS malfunctions	Yes.
§ 63.10(b)(2)(vii) to (xiv)	Other CMS requirements	Yes.
§ 63.10(b)(3)	Recordkeeping requirements for applicability determinations	No.
§ 63.10(c)(1) to (9)	Recordkeeping for sources with CMS	Yes.
§ 63.10(c)(10) and (11)	Recording nature and cause of malfunctions, and corrective actions	No. See § 63.7555(d)(7) for recordkeeping of occurrence and duration and § 63.7555(d)(8) for actions taken during malfunctions.
§ 63.10(c)(12) and (13)	Recordkeeping for sources with CMS	Yes.
§ 63.10(c)(15)	Use of startup, shutdown, and malfunction plan	No.
§ 63.10(d)(1) and (2)	General reporting requirements	Yes.
§ 63.10(d)(3)	Reporting opacity or visible emission observation results	No.
§ 63.10(d)(4)	Progress reports under an extension of compliance	Yes.
§ 63.10(d)(5)	Startup, shutdown, and malfunction reports	No. See § 63.7550(c)(11) for malfunction reporting requirements.
§ 63.10(e)	Additional reporting requirements for sources with CMS.	Yes.
§ 63.10(f)	Waiver of recordkeeping or reporting requirements.	Yes.
§ 63.11	Control Device Requirements	No.
§ 63.12	State Authority and Delegation	Yes.
§ 63.13-63.16	Addresses, Incorporation by Reference, Availability of Information, Performance Track Provisions	Yes.
§ 63.1(a)(5),(a)(7)-(a)(9), (b)(2), (c)(3)-(4), (d), 63.6(b)(6), (c)(3), (c)(4), (d), (e)(2), (e)(3)(ii), (h)(3), (h)(5)(iv), 63.8(a)(3), 63.9(b)(3), (h)(4), 63.10(c)(2)-(4), (c)(9).	Reserved	No.

ATTACHMENT 8

Table 8 to Subpart IIII of Part 60—Applicability of General Provisions to Subpart IIII

Table 8 to Subpart IIII of Part 60—Applicability of General Provisions to Subpart IIII
[As stated in § 60.4218, the permittee must comply with the following applicable General Provisions:]

General Provisions citation	Subject of citation	Applies to subpart	Explanation
§ 60.1	General applicability of the General Provisions	Yes	
§ 60.2	Definitions	Yes	Additional terms defined in § 60.4219.
§ 60.3	Units and abbreviations	Yes	
§ 60.4	Address	Yes	
§ 60.5	Determination of construction or modification	Yes	
§ 60.6	Review of plans	Yes	
§ 60.7	Notification and Recordkeeping	Yes	Except that § 60.7 only applies as specified in § 60.4214(a).
§ 60.8	Performance tests	Yes	Except that § 60.8 only applies to stationary CI ICE with a displacement of (≥30 liters per cylinder and engines that are not certified.
§ 60.9	Availability of information	Yes	
§ 60.10	State Authority	Yes	
§ 60.11	Compliance with standards and maintenance requirements	No	Requirements are specified in subpart IIII.
§ 60.12	Circumvention	Yes	
§ 60.13	Monitoring requirements	Yes	Except that § 60.13 only applies to stationary CI ICE with a displacement of (≥30 liters per cylinder.
§ 60.14	Modification	Yes	
§ 60.15	Reconstruction	Yes	
§ 60.16	Priority list	Yes	
§ 60.17	Incorporations by reference	Yes	
§ 60.18	General control device requirements	No	
§ 60.19	General notification and reporting requirements	Yes	

ATTACHMENT 9

Compliance Assurance Monitoring (CAM) Plan

TEKNOR APEX TENNESSEE COMPANY

Compliance Assurance Monitoring (CAM) Plan

A: **Permit ID #**
This plan is for permit # 560518 and # 560513

Source # 38-0039-02	PVC Production Lines #1 - #5 with Baghouse Control, (Stack ID # C124, C114, C116, C117, C118, and C119)
Source # 38-0039-05	PVC Production Line #10 with Baghouse Control, (Stack ID # C122)
Source # 38-0039-07	3 - Nylon Compounding Lines (1, 2, and 3), 1 - PIR Line , 1- Nylon Grinder and 1- Nylon Shredder (Stack ID # N112 , # N113, #N114, #N117 and #N118))
Source # 38-0039-15	Reclaiming Operation – Three (3) Baghouses (Stack ID # H196, RE46 and RE47)
Source # 38-0039-18	PVC Production Lines #8 & #9 with Baghouse Control (Stack ID # C423, C430, and C208)
Source # 38-0039-66	Material Handling Operation Consisting of Two (2) Bucket Elevators with two (2) baghouses
Source # 38-0039-74	PVC Production Lines #6 & #7 with Baghouse Control (Stack ID# C126 and C121)
Source # 38-0039-90	Mixing and Weighing Operation with Baghouse Control (Stack ID # 207)
Source # 38-0039-94	(Stack ID # ElSilo #1, ElSilo #2, ElSilo #3, ElSilo #4, ElSilo #5, ElSilo #6, ElSilo #7, ElSilo #8)

B: **Regulations:**
Per 40 CFR Part 64, facilities must submit a CAM plan for all control devices that are part of a major emissions unit which utilizes the control device to achieve compliance with any such emission limitation or standard.

C. **Control Device Technology:**
To control the particulate matter (PM) and HAP's as PM, Teknor Apex Tennessee Company installed filter bag and cartridge filter dust collectors.

D. **Specified Monitoring Parameters**

Dust collectors having 2,000 CFM or greater

To assure proper control equipment operation, all dust collectors are equipped with pressure drop gauges. The pressure drop gauges should read 0.5 inches or greater of water while the equipment is in operation. These gauges will be observed each day of operation while the equipment is operating. At the same time, the control equipment and monitoring equipment will be visually inspected for operational problems. Any problems will be corrected immediately or the processing equipment will be shut down as soon as practicable until the dust collector is repaired.

Alternate Monitoring Parameters
Pressure drop will be our key indicator. In case of pressure drop gauge failure, opacity will be monitored. We have an opacity limit of 10%. The opacity will be read every 30 seconds for fifteen minutes once per day during operating times, until the pressure drop gauge is functioning correctly. Method 9 will be used in evaluating the visible emissions.

If the opacity is over 10%, the processing equipment will be shut down as soon as practicable until the dust collector is repaired. If visible emissions less than 10% are detected, the dust collector will be shut down as soon as practicable, until the filter media is visually checked for leakage. If the filter media has maintained its integrity, operations will resume and opacity will continue to be monitored and logged by the EHS Manager or a designee as described above. The log will be maintained in the EHS Manager's office and retained for five years.

Dust collectors less than 2,000 CFM
The dust collector will be maintained, kept in good operating condition and inspected semiannually.

E: **Performance Range Criteria & Indicator Rationale**
Observation of on-site dust collectors' performance have shown that pressure drops of 0.5 - 7 inches of water is ideal.

Documentation from Micro-Pulsaire states that normal dust collector performance will be achieved when the pressure drop is between 1 to 6". Micro-Pulsaire Technical Support Manager stated that, while normal ranges are 1 to 6", an acceptable range would be from 0.5 to 7" and the dust collector could operate at an optimum performance at a pressure drop of 0.5". The collector could have a low reading approaching 0.5" if the bags were recently changed, if particle size is too large to cake on the bags, and if cleaning frequency or pulsing of air keeps the bags from accumulating material.

Upon discussion with the manufacturer of some of our dust collection equipment, the dust collector efficiency is expected to be 99.9% when pressure drop is between 0.5" and 7", although Teknor Apex certifies only that raw material dust collector efficiencies are greater than 97.8%, and product dust collector efficiencies are greater than 99%.

For the past several years, Teknor Apex Company has utilized the pressure drop as a major indicator for dust collector efficiency and maintenance. A minimum pressure drop of 0.5 has been used. Pressure drops have been observed at 0.5" after a bag change and after cleaning the filter media. When an observed pressure drop is below 0.5, the dust collector is shut down and a visual inspection of the collector is made. In the past, readings below 0.5" have been a result of a malfunctioning magnahelic gauge.

F: **Recordkeeping and Reporting**

For each day of operation, Teknor Apex Tennessee Company will record the pressure drop for each dust collector listed above (having CFM grater than 2,000), while the process is operating. Records will be filed in the EHS Managers' office and retained for five years.

Reports will be sent to TDEC - APC Section twice per year as part of the semi-annual compliance certification as they are now.

Documentation of the semiannual inspection and any maintenance performed will be kept on file and will be retained for five years.

Revision Date: April 10, 2014

ATTACHMENT 10

MACT Reporting Periods

Federal Regulation	Frequency and Submittal Schedule of Report	Submit Report to:	
40 CFR 63 Subpart FFFF—National Emission Standards for Hazardous Air Pollutants: Miscellaneous Organic Chemical Manufacturing (Ref. No. 38-0039-92)	Semiannual with reporting periods of April-September and October-March Reports are to be submitted within 60 days of the end of the reporting period §63.2520	The Technical Secretary Division of Air Pollution Control ATTN: Permit Program William R. Snodgrass Tennessee Tower 312 Rosa L. Parks Avenue, 15th Floor Nashville, Tennessee 37243 or Air.Pollution.Control@tn.gov	Air and EPCRA Enforcement Branch U. S. EPA Region IV 61 Forsyth Street, SW Atlanta, Georgia 30303
40 CFR 65 Subpart D—Process Vents (this is a compliance option under NSPS Subpart NNN Synthetic Organic Chemical Mfg. 40 CFR 60.660- see condition E11-5) (Ref. No. 38-0039-92)	As required at §65.67 (Reporting provisions)	The Technical Secretary Division of Air Pollution Control ATTN: Permit Program William R. Snodgrass Tennessee Tower 312 Rosa L. Parks Avenue, 15th Floor Nashville, Tennessee 37243 or Air.Pollution.Control@tn.gov	Air and EPCRA Enforcement Branch U. S. EPA Region IV 61 Forsyth Street, SW Atlanta, Georgia 30303
40 CFR 63 Subpart DDDDD—National Emission Standards for Hazardous Air Pollutants for Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters (Ref. Nos. 38-0039-01, 04,16 and 70)	For Tune-ups (only) submit reports on Annual, or Five-year as required, with reporting period ending September 30 of reporting year See condition E3-4 Reports are to be submitted within 60 days of the end of the reporting period	The Technical Secretary Division of Air Pollution Control ATTN: Permit Program William R. Snodgrass Tennessee Tower 312 Rosa L. Parks Avenue, 15th Floor Nashville, Tennessee 37243 or Air.Pollution.Control@tn.gov	EPA via the Compliance and Emissions Data Reporting Interface (CEDRI). (CEDRI can be accessed through the EPA's Central Data Exchange (CDX) (*https://cdx.epa.gov/*).) Performance test data must be submitted in a file format generated through use of the EPA's ERT or an electronic file format consistent with the extensible markup language (XML) schema listed on the EPA's ERT Web site
40 CFR 60 Subpart Dc—Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units (Ref. No. 38-0039-70)	As required by 40 CFR 60 Subpart Dc-See Attachment #2 for Reporting requirements	The Technical Secretary Division of Air Pollution Control ATTN: Permit Program William R. Snodgrass Tennessee Tower 312 Rosa L. Parks Avenue, 15th Floor Nashville, Tennessee 37243 or Air.Pollution.Control@tn.gov	

ATTACHMENT 11

MANUFACTURER'S SPECIFICATIONS, 38-0039-101

SIGMA THERMAL

PROCESS HEATING SYSTEMS DESIGN,
ENGINEERING, & SERVICE

4875 Deen Road
Marietta, GA 30066
Phone: 770-427-5770
Fax: 678-254-1762
www.sigmathermal.com

April 27, 2017

To Whom It May Concern:

This letter is to confirm that the maximum NOx emissions will not exceed 100 ppm (120 lb NOx / MMSCF) for Sigma Thermal project J16249 for the TeknorApex facility in Brownsville, TN. This guarantee is based on the following assumptions:

- Natural gas used for combustion is standard clean natural gas with an approximate HHV value of 1000 BTU/ft^3.
- The burner is commissioned and tuned by a Sigma Thermal service technician.
- All operating conditions match those listed on the approved design documentation submitted by Sigma Thermal.

Best Regards,

William Gardiner

William Gardiner
Inside Sales Engineer
Sigma Thermal, Inc.

ATTACHMENT 12

TITLE V FEE SELECTION FORM APC 36 (CN-1583)

DEPARTMENT OF ENVIRONMENT AND CONSERVATION
DIVISION OF AIR POLLUTION CONTROL
William R. Snodgrass Tennessee Tower
312 Rosa L. Parks Avenue, 15th Floor, 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

TITLE V PERMIT STATEMENT (RENEWAL)

Facility Name: Teknor Apex Tennessee Company	
City: Brownsville	
County: Haywood	

Date Application Received: July 24, 2015	
Date Application Deemed Complete: September 21, 2015	

Emission Source Reference No.: 38-0039	
Permit No.: 570726	

INTRODUCTION

This narrative is being provided to assist the reader in understanding the content of the attached Title V operating permit. This Title V Permit Statement is written pursuant to Tennessee Air Pollution Control Rule 1200-03-09-.02(11)(f)1.(v). The primary purpose of the Title V operating permit is to consolidate and identify existing state and federal air requirements applicable to Teknor Apex Tennessee Company and to provide practical methods for assuring compliance with these requirements. The following narrative is designed to accompany the Title V Operating Permit. It initially describes the facility receiving the permit, then the applicable requirements and their significance, and finally the compliance status with those applicable requirements. This narrative is intended only as an adjunct for the reviewer and has no legal standing. Any revisions made to the permit in response to comments received during the public participation process will be described in an addendum to this narrative.

Acronyms

PSD - Prevention of Significant Deterioration
NESHAP - National Emission Standards for Hazardous Air Pollutants
NSPS - New Source Performance Standards
MACT - Maximum Achievable Control Technology
NSR - New Source Review

I. Identification Information

A. Source Description

Teknor Apex Tennessee Company produces plasticizers which primarily include phthalate, adipate, and trimellitate for intermediate uses. These specialty chemicals are produced in an acid-alcohol esterification process in any one of four reactor systems at the facility: three batch systems, and one semi-continuous system. Other emission sources at this facility include three boilers for process heating, and a bucket elevator system to supply the dry reactants to the reactors.

B. Facility Classification

1. Attainment or Non-Attainment Area Location

Area is designated as an attainment area for all criteria pollutants.

2. Company is located in a Class II area.

C. Regulatory Status

1. PSD/NSR

This facility is a major source under PSD.

2. Title V Major Source Status by Pollutant

Pollutant	Is the pollutant emitted?	If emitted, what is the facility's status? Major Source Status	Non-Major Source Status
PM	Yes	No	
PM_{10}	Yes	N/A	
SO_2	Yes	Yes	
VOC	Yes	No	
NO_X	Yes	Yes	
CO	Yes	No	
Individual HAP	Yes	No	
Total HAPs	Yes	No	
CO_2(e)	Yes	No	

3. MACT Standards

The specialty chemicals plant is not a major source for HAPs by itself; however, the specialty chemicals plant is subject to three final MACT Standards: 40 CFR 63, Subpart FFFF – National Emission Standards for Hazardous Air Pollutants: Miscellaneous Organic Chemical Manufacturing, and 40 CRF 63, Subpart DDDDD - National Emission Standards for Hazardous Air Pollutants: Industrial, Commercial, and Institutional Boilers and Process Heaters, and Subpart ZZZZ - National Emission Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines.

The specialty chemicals plant is subject to 40 CFR 63 because its sister plant (Plastics Compounding) is a major source of HAPs. These facilities share common ownership and are co-located. Although, the two facilities have different SIC codes, the two plants share a factor of interdependence; therefore, they are technically considered one Title V source, and accordingly are treated as one facility with respect to their HAPs emissions.

4. Program Applicability

Are the following programs applicable to the facility?

PSD *Yes*

NESHAP *Yes – Subparts FFFF, DDDDD, and ZZZZ*

NSPS *Yes – Subparts Dc and IIII*

II. Compliance Information

A. Compliance Status

Is the facility currently in compliance with all applicable requirements? *Yes*

Are there any applicable requirements that will become effective during the permit term? *Yes – 40 CFR 63 Subpart DDDDD*

III. Other Requirements

A. Emissions Trading

The facility is not involved in an emission trading program.

B. Acid Rain Requirements

This facility is not subject to any requirements in Title IV of the Clean Air Act.

C. Prevention of Accidental Releases

Not applicable

D. Greenhouse Gas (GHG) Emissions

This facility is not a major source of greenhouse gas emissions.

IV. Public Participation Procedures

Notification of this draft permit was mailed to the following environmental agencies:

1. EPA Region IV
2. State of Mississippi, State of Arkansas, State of Missouri, Shelby County Health Department

V. Permit History

Title V Operating Permit No. 570726 represents the second renewal of the original Title V Permit No. 546546 issued June 3, 2002. The following changes have occurred under the Title V permit renewal 560513 and with this renewal:

- Company name change (Administrative Amendment November 17, 2011)
- Added new receiver with dust collector; removed existing dust collector; added mix tank (Minor Modification #1, July 6, 2012)
- Two new emergency fire pump engines to be installed (Minor Modification #2 request dated September 27, 2012, processed with Significant Modification #1)
- New #6 boiler installed under construction permit number 964912F is added to the operating permit (Significant Modification #1, April 1, 2013)
- The following standard conditions have been updated and modified on the Title V permit renewal 570726:

  Condition E2(b) of the Title V permit issued February 22, 2011 required a statement concerning "whether such method(s) used to determine compliance status provided continuous or intermittent data." This requirement is no longer in effect, and the compliance reporting requirement for this condition has been modified accordingly. Condition B5 of Section B also concerns this same requirement, and is also modified in accordance with the March 3, 2016 "shell" update.

  Conditions A12, B6, and C2 also had minor changes and are also modified in accordance with the March 3, 2016 "shell" update. The Title V "shell" conditions are sections A, B, C and D.

Changes to Title V Permit 570726 Since Renewal Issuance			
Permit Modification	**Issue Date**	**Condition or Section**	**Modification**
Significant Modification #1 (SM1)	Pending	**General Information:**	Significant Modification #1 adds emission source 38-0039-101 (Natural Gas-Fired Sigma Thermal Heater).
		All	Updated numbering conventions to match current practice (e. g., changed “five (5) years” to “five years” and “twelve (12) months” to “12 months”).
		A8	Updated to use standard language for fee payment.
		A20	Updated to use standard language for 112(r) certification. The permittee is not required to file an accidental release plan.
		B3	Removed language requiring reporting periods to be dated from the end of the first complete calendar quarter following permit issuance.
		B6	Updated address for submittal of ACC to U. S. EPA.
		B8	Updated to add APC telephone number for excess emissions reporting.
		B11	Updated language to match current regulations (revised Condition B11 to be consistent with revised 1200-03-30-.06(2), (3), and (4)).
		C6	Changed “future construction at this source” to “future construction at this facility.”
		D7	Updated to remove oil from the list of acceptable dust suppression measures.
		D8, D9	Minor updates to rule citations.
		D11, D12, D13, D14	Added standard requirements for NSPS, MACT, gasoline dispensing, and internal combustion engines.
		E1, Attachment 12	Updated fee emissions, annual accounting period dates, and standard requirements. Added Title V fee selection form.
		E2(a)	Updated semiannual reporting requirements.
		E4-8	This condition was deleted (conflicts with Condition E9-5).
		E4-12, E6-8, E7-3	Deleted the language “including any and/or all applicable emission limitations, notifications, compliance options, records, reports, etc.”
		E4-15	Updated billing contact.
		E10-3	Changed records retention from two years to five years.
		E12-1 through E12-9, Attachment 11	Added emission limits and other compliance requirements for 38-0039-101. Updated the Boiler MACT requirements by removing the five-year tune-up option for sources using a continuous oxygen trim system. Per the e-mail from Susan Paris dated July 27, 2020, the process heater associated with source 101 does not use a continuous oxygen trim system. Updated the limits in E12-4, E12-5, E12-6 to base allowable emissions on a calendar year basis. A calendar year basis, rather than a 12-month rolling total, was used because the agreed limit on fuel usage was based on a calendar year.
		Public Participation	The public notice for this modification will be published in the *Jackson Sun*. Any comments received during the public comment period will be noted here.