Maryland
Department of
the Environment

Larry Hogan, Governor
Boyd K. Rutherford, Lt. Governor

Horacio Tablada, Secretary
Suzanne E. Dorsey, Deputy Secretary

Mr. Gregory A. Staggers, General Manager
Chalk Point Power, LLC - Chalk Point Generating Station
25100 Chalk Point Road
Aquasco, MD 20608

DEC 0 1 2022

Dear Mr. Staggers:

Re: Initial Part 70/ Title V Operating Permit 24-033-2920-Chalk Point Generating Station

Enclosed, please find the initial Part 70/Title V Operating Permit and Fact Sheet for the Chalk Point Power, LLC- Chalk Point Generating Station. The Permit will expire on November 30, 2027.

The Code of Maryland Regulations (COMAR) 26.11.03.11 states the following:

> If the Department denies a Part 70 permit or issues it with terms and conditions that are objectionable to the applicant, the applicant may request that a contested case hearing be held regarding the permit. This request shall be made to the Department in writing not later than 15 days after the applicant receives notice that the permit has been denied or of the objectionable terms and conditions. The request shall include the basis for the request and refer to any objectionable terms and conditions.

Please note the following revised condition in the Permit under Section II, General Conditions, Number 5, Permit Renewal:

> The Permittee shall submit to the Department a completed application for renewal of this Part 70 permit 12 months before the expiration of the permit. Upon submitting a complete application, the Permittee may continue to operate this facility pending final action by the Department on the renewal.

If you have any questions, please feel free to contact Ms. Marcie Gurley, Chief, Technical Support Division, at Marcie.gurley@maryland.gov, or at (410) 537-3230.

Sincerely,

Suna Yi Sariscak, Manager
Air Quality Permits Program
Air & Radiation Administration

SYS/jm

Enclosures

cc: EPA Region III (w/encl)

KEEP PERMIT AT SITE

CONTROL NO. B - 07262

Larry Hogan
Governor

State of Maryland

Horacio Tablada
Secretary

DEPARTMENT OF THE ENVIRONMENT

Air and Radiation Administration
1800 Washington Boulevard, Suite 720
Baltimore, MD 21230

[ ] Construction Permit

Part 70
[X] Operating Permit

PERMIT NO. 24-033-2920

DATE ISSUED December 1, 2022

PERMIT FEE To be paid in accordance with COMAR 26.11.02.19B

EXPIRATION DATE November 30, 2027

LEGAL OWNER & ADDRESS

Chalk Point Power, LLC
25100 Chalk Point Road
Aquasco, MD 20608
Attn: Mr. Gregory A. Staggers
General Manager

SITE

Chalk Point, LLC Generating Station
25100 Chalk Point Road
Aquasco, MD 20608
AI # 1919

SOURCE DESCRIPTION

An Electrical Generating Station.

This source is subject to the conditions described on the attached pages.

Program Manager

Director, Air and Radiation Administration

MDE/ARMA/PER.009 (REV. 10-08-03)

(NOT TRANSFERABLE)

CHALK POINT POWER, LLC
CHALK POINT GENERATING STATION
25100 CHALK POINT ROAD
AQUASCO, MD 20608
PART 70 OPERATING PERMIT NO. 24-033-2920

CHALK POINT POWER, LLC
CHALK POINT GENERATING STATION
25100 CHALK POINT ROAD
AQUASCO, MD 20608
PART 70 OPERATING PERMIT NO. 24-033-2920

SECTION I SOURCE IDENTIFICATION

1. DESCRIPTION OF FACILITY

The Chalk Point Generating Station is located on the Patuxent River at Swanson Creek in Prince George's County Maryland. The Chalk Point facility is engaged in the generation of electric energy for sale. The primary SIC code for this facility is 4911.

The major components of the facility consist of two (2) oil/gas-fired steam units (**E-3 & E-4**), seven (7) combustion turbines (**E-CT1 through E-CT6** and **SMECO-CT1**) and four (4) auxiliary boilers (**AUX-4 through AUX-7**).

Steam units 3 and 4 [**E-3 and E-4**] are tangentially fired, sub-critical, cycling boilers, each rated at 640 megawatts. These units fire natural gas and No. 6 fuel oil. No. 2 fuel oil or natural gas may be used for ignition, warm-up, and flame stabilization purposes. Steam units 3 and 4 exhaust through two separate stacks each 712 feet high.

All seven (7) CTs have oil-firing capability. **E-CT3 thru E-CT6** and **SMECO-CT1** can fire natural gas. **E-CT3** through **E-CT6** exhaust through four separate stacks each 213 feet high, while **SMECO-CT** exhausts through a single stack 85 feet high.

Auxiliary boilers 4 through7 [**AUX-4 through AUX-7**] use No. 2 fuel oil as the primary fuel. Each boiler is rated at 186.6 MMBtu/hr. heat input. These boilers are used to start up the steam units.

2. FACILITY INVENTORY LIST

Emissions Unit Number	MDE - ARA Registration Number	Emissions Unit Name and Description	Date of Installation
E-3	4-0998	Unit E-3 is a tangentially fired, sub-critical, cycling boiler rated at 640 megawatts and 6,970 MMBtu/hr. heat input. Unit E-3 fires natural gas and No. 6 fuel oil. No. 2 fuel oil or natural gas may be used for ignition, warm-up, and flame stabilization purposes.	Jun 1975
E-4	4-0999	Unit E-4 is a tangentially fired, sub-critical, cycling boiler rated at 640 megawatts and 6,970 MMBtu/hr. heat input. Unit E-4 fires natural gas and No. 6 fuel oil. No. 2 fuel oil or natural gas may be used for ignition, warm-up, and flame stabilization purposes.	Dec 1981
E-CT1	4-0778	Unit E-CT1 is a Pratt and Whitney FT4A combustion turbine rated capacity of 18 megawatts (250 MMBtu/hr. heat input) used for black start capability and peaking service. This turbine is fired with No. 2 fuel oil.	Apr 1967
E-CT2	4-1145	Unit E-CT2 is a Westinghouse (W-251) combustion turbine rated capacity of 35 megawatts (420 MMBtu/hr. heat input) used for black start capability and peaking service. This turbine is fired with No. 2 fuel oil.	Jun 1974
E-CT3	9-0752	Unit E-CT3 is a General Electric Frame-7EA combustion turbine rated capacity of 99 megawatts used for peaking service. This turbine is fired with natural gas as a primary fuel and No. 2 fuel oil as a secondary fuel and injects water in the combustion zone for NO_x control.	Jun 1991
E-CT4	9-0753	Unit E-CT4 is a General Electric Frame-7EA combustion turbine rated capacity of	Jun 1991

Emissions Unit Number	MDE - ARA Registration Number	Emissions Unit Name and Description	Date of Installation
		99 megawatts used for peaking service. This turbine is fired with natural gas as a primary fuel and No. 2 fuel oil as a secondary fuel and injects water in the combustion zone for NO_x control.	
E-CT5	9-0754	Unit E-CT5 is a Kraftwork Union V84.2 combustion turbine rated capacity of 120 megawatts used for peaking service. This turbine is fired with natural gas as a primary fuel and No. 2 fuel oil as a secondary fuel and injects water in the combustion zone for NO_x control when firing No. 2 fuel oil and dry low NO_x combustors when firing natural gas.	Jun 1991
E-CT6	9-0755	Unit E-CT6 is a Kraftwork Union V84.2 combustion turbine rated capacity of 120 megawatts used for peaking service. This turbine is fired with natural gas as a primary fuel and No. 2 fuel oil as a secondary fuel and injects water in the combustion zone for NO_x control when firing No. 2 fuel oil and dry low NO_x combustors when firing natural gas.	Jun 1991
AUX-4	4-1155	AUX-4 is a Combustion Engineering, Model #30VP-12W, auxiliary boiler rated at 186.6 MMBtu/hr. This boiler is fired with No.2 fuel oil.	1972
AUX-5	4-1156	AUX-5 is a Combustion Engineering, Model #30VP-12W, auxiliary boiler rated at 186.6 MMBtu/hr. This boiler is fired with No.2 fuel oil.	1972
AUX-6	4-1157	AUX-6 is a Combustion Engineering, Model #30VP-12W, auxiliary boiler rated at 186.6 MMBtu/hr. This boiler is fired with No.2 fuel oil.	1981

CHALK POINT POWER, LLC
CHALK POINT GENERATING STATION
25100 CHALK POINT ROAD
AQUASCO, MD 20608
PART 70 OPERATING PERMIT NO. 24-033-2920

Emissions Unit Number	MDE - ARA Registration Number	Emissions Unit Name and Description	Date of Installation
AUX-7	4-1158	AUX-7 is a Combustion Engineering, Model #30VP-12W, auxiliary boiler rated at 186.6 MMBtu/hr. This boiler is fired with No.2 fuel oil.	1981
SMECO-CT1	5-0749	Unit SMECO-CT1 is a General Electric GE-7EA combustion turbine rated capacity of 93 megawatts. This turbine is fired with natural gas as a primary fuel and No. 2 fuel oil as a secondary. This unit was owned by Southern Maryland Electric Cooperative until 2015 when NRG purchased the unit.	Jun 1990
	9-1346	One (1) emergency fire pump and one (1) quench pump; E-CT2 starting engine, CT site fire pump. Main Plant fire pump. MTS building emergency generator - diesel-fired internal combustion engines.	Various

SECTION II GENERAL CONDITIONS

1. DEFINITIONS

[COMAR 26.11.01.01] and [COMAR 26.11.02.01]

The words or terms in this Part 70 permit shall have the meanings established under COMAR 26.11.01 and .02 unless otherwise stated in this permit.

2. ACRONYMS

ARA	Air and Radiation Administration
BACT	Best Available Control Technology
Btu	British thermal unit
CAA	Clean Air Act
CAM	Compliance Assurance Monitoring
CEM	Continuous Emissions Monitor
CFR	Code of Federal Regulations
CO	Carbon Monoxide
COMAR	Code of Maryland Regulations
EPA	United States Environmental Protection Agency
FR	Federal Register
gr	grains
HAP	Hazardous Air Pollutant
MACT	Maximum Achievable Control Technology
MDE	Maryland Department of the Environment
MVAC	Motor Vehicle Air Conditioner
NESHAPS	National Emission Standards for Hazardous Air Pollutants
NO_X	Nitrogen Oxides
NSPS	New Source Performance Standards
NSR	New Source Review
OTR	Ozone Transport Region
PM	Particulate Matter
PM_{10}	Particulate Matter with Nominal Aerodynamic Diameter of 10 micrometers or less
ppm	parts per million
ppb	parts per billion
PSD	Prevention of Significant Deterioration
PTC	Permit to construct
PTO	Permit to operate (State)
SIC	Standard Industrial Classification

SO_2	Sulfur Dioxide
TAP	Toxic Air Pollutant
tpy	tons per year
VE	Visible Emissions
VOC	Volatile Organic Compounds

3. EFFECTIVE DATE

The effective date of the conditions in this Part 70 permit is the date of permit issuance, unless otherwise stated in the permit.

4. PERMIT EXPIRATION

[COMAR 26.11.03.13B(2)]

Upon expiration of this permit, the terms of the permit will automatically continue to remain in effect until a new Part 70 permit is issued for this facility provided that the Permittee has submitted a timely and complete application and has paid applicable fees under COMAR 26.11.02.16.

Otherwise, upon expiration of this permit the right of the Permittee to operate this facility is terminated.

5. PERMIT RENEWAL

[COMAR 26.11.03.02B(3)] and [COMAR 26.11.03.02E]

The Permittee shall submit to the Department a completed application for renewal of this Part 70 permit at least 12 months before the expiration of the permit. Upon submitting a completed application, the Permittee may continue to operate this facility pending final action by the Department on the renewal.

The Permittee, upon becoming aware that any relevant facts were omitted, or incorrect information was submitted in the permit application, shall submit such supplementary facts or corrected information no later than 10 days after becoming aware that this occurred. The Permittee shall also provide additional information as necessary to address any requirements that become applicable to the facility after the date a completed application was submitted, but prior to the release of a draft

permit. This information shall be submitted to the Department no later than 20 days after a new requirement has been adopted.

6. CONFIDENTIAL INFORMATION

[COMAR 26.11.02.02G]

In accordance with the provisions of the State Government Article, Sec. 10-611 et seq., Annotated Code of Maryland, all information submitted in an application shall be considered part of the public record and available for inspection and copying, unless the Permittee claims that the information is confidential when it is submitted to the Department. At the time of the request for inspection or copying, the Department will make a determination with regard to the confidentiality of the information. The Permittee, when requesting confidentiality, shall identify the information in a manner specified by the Department and, when requested by the Department, promptly provide specific reasons supporting the claim of confidentiality. Information submitted to the Department without a request that the information be deemed confidential may be made available to the public. Subject to approval of the Department, the Permittee may provide a summary of confidential information that is suitable for public review. The content of this Part 70 permit is not subject to confidential treatment.

7. PERMIT ACTIONS

[COMAR 26.11.03.06E(3)] and [COMAR 26.11.03.20(A)]

This Part 70 permit may be revoked or reopened and revised for cause. The filing of an application by the Permittee for a permit revision or renewal; or a notification of termination, planned changes or anticipated noncompliance by the facility, does not stay a term or condition of this permit.

The Department shall reopen and revise, or revoke the Permittee's Part 70 permit under the following circumstances:

a. Additional requirements of the Clean Air Act become applicable to this facility and the remaining permit term is 3 years or more;

b. The Department or the EPA determines that this Part 70 permit contains a material mistake, or is based on false or inaccurate information supplied by or on behalf of the Permittee;

c. The Department or the EPA determines that this Part 70 permit must be revised or revoked to assure compliance with applicable requirements of the Clean Air Act; or

d. Additional requirements become applicable to an affected source under the Federal Acid Rain Program.

8. PERMIT AVAILABILITY

[COMAR 26.11.02.13G]

The Permittee shall maintain this Part 70 permit in the vicinity of the facility for which it was issued, unless it is not practical to do so, and make this permit immediately available to officials of the Department upon request.

9. REOPENING THE PART 70 PERMIT FOR CAUSE BY THE EPA

[COMAR 26.11.03.20B]

The EPA may terminate, modify, or revoke and reissue a permit for cause as prescribed in 40 CFR §70.7(g)

10. TRANSFER OF PERMIT

[COMAR 26.11.02.02E]

The Permittee shall not transfer this Part 70 permit except as provided in COMAR 26.11.03.15.

11. REVISION OF PART 70 PERMITS – GENERAL CONDITIONS

[COMAR 26.11.03.14] and [COMAR 26.11.03.06A(8)]

a. The Permittee shall submit an application to the Department to revise this Part 70 permit when required under COMAR 26.11.03.15 -.17.

b. When applying for a revision to a Part 70 permit, the Permittee shall comply with the requirements of COMAR 26.11.03.02 and .03 except that the application for a revision need include only information listed that is related to the proposed change to the source and revision to the permit. This information shall be sufficient to evaluate the proposed change and to determine whether it will comply with all applicable requirements of the Clean Air Act.

c. The Permittee may not change any provision of a compliance plan or schedule in a Part 70 permit as an administrative permit amendment or as a minor permit modification unless the change has been approved by the Department in writing.

d. A permit revision is not required for a change that is provided for in this permit relating to approved economic incentives, marketable permits, emissions trading, and other similar programs.

12. SIGNIFICANT PART 70 OPERATING PERMIT MODIFICATIONS

[COMAR 26.11.03.17]

The Permittee may apply to the Department to make a significant modification to its Part 70 Permit as provided in COMAR 26.11.03.17 and in accordance with the following conditions:

a. A significant modification is a revision to the federally enforceable provisions in the permit that does not qualify as an administrative permit amendment under COMAR 26.11.03.15 or a minor permit modification as defined under COMAR 26.11.03.16.

b. This permit does not preclude the Permittee from making changes, consistent with the provisions of COMAR 26.11.03, that would make the permit or particular terms and conditions of the permit irrelevant, such as by shutting down or reducing the level of operation of a source or of an emissions unit within the source. Air pollution control equipment shall not be shut down or its level of operation reduced if doing so would violate any term of this permit.

c. Significant permit modifications are subject to all requirements of COMAR 26.11.03 as they apply to permit issuance and renewal,

including the requirements for applications, public participation, and review by affected states and EPA, except:

(1) An application need include only information pertaining to the proposed change to the source and modification of this permit, including a description of the change and modification, and any new applicable requirements of the Clean Air Act that will apply if the change occurs;

(2) Public participation, and review by affected states and EPA, is limited to only the application and those federally enforceable terms and conditions of the Part 70 permit that are affected by the significant permit modification.

d. As provided in COMAR 26.11.03.15B(5), an administrative permit amendment may be used to make a change that would otherwise require a significant permit modification if procedures for enhanced preconstruction review of the change are followed that satisfy the requirements of 40 CFR 70.7(d)(1)(v).

e. Before making a change that qualifies as a significant permit modification, the Permittee shall obtain all permits-to-construct and approvals required by COMAR 26.11.02.

f. The Permittee shall not make a significant permit modification that results in a violation of any applicable requirement of the Clean Air Act.

g. The permit shield in COMAR 26.11.03.23 applies to a final significant permit modification that has been issued by the Department, to the extent applicable under COMAR 26.11.03.23.

13. MINOR PERMIT MODIFICATIONS

[COMAR 26.11.03.16]

The Permittee may apply to the Department to make a minor modification to the federally enforceable provisions of this Part 70 permit as provided in COMAR 26.11.03.16 and in accordance with the following conditions:

a. A minor permit modification is a Part 70 permit revision that:

(1) Does not result in a violation of any applicable requirement of the Clean Air Act;

(2) Does not significantly revise existing federally enforceable monitoring, including test methods, reporting, record keeping, or compliance certification requirements except by:

(a) Adding new requirements,

(b) Eliminating the requirements if they are rendered meaningless because the emissions to which the requirements apply will no longer occur, or

(c) Changing from one approved test method for a pollutant and source category to another;

(3) Does not require or modify a:

(a) Case-by-case determination of a federally enforceable emissions standard,

(b) Source specific determination for temporary sources of ambient impacts, or

(c) Visibility or increment analysis;

(4) Does not seek to establish or modify a federally enforceable permit term or condition for which there is no corresponding underlying applicable requirement of the Clean Air Act, but that the Permittee has assumed to avoid an applicable requirement to which the source would otherwise be subject, including:

(a) A federally enforceable emissions standard applied to the source pursuant to COMAR 26.11.02.03 to avoid classification as a Title I modification; and

(b) An alternative emissions standard applied to an emissions unit pursuant to regulations promulgated under Section 112(i)(5) of the Clean Air Act

(5) Is not a Title I modification; and

(6) Is not required under COMAR 26.11.03.17 to be processed as a significant modification to this Part 70 permit.

b. Application for a Minor Permit Modification

The Permittee shall submit to the Department an application for a minor permit modification that satisfies the requirements of COMAR 26.11.03.03 which includes the following:

(1) A description of the proposed change, the emissions resulting from the change, and any new applicable requirements that will apply if the change is made;

(2) The proposed minor permit modification;

(3) Certification by a responsible official, in accordance with COMAR 26.11.02.02F, that:

(a) The proposed change meets the criteria for a minor permit modification, and

(b) The Permittee has obtained or applied for all required permits-to-construct required by COMAR 26.11.03.16 with respect to the proposed change;

(4) Completed forms for the Department to use to notify the EPA and affected states, as required by COMAR 26.11.03.07-.12.

c. Permittee's Ability to Make Change

(1) For changes proposed as minor permit modifications to this permit that will require the applicant to obtain a permit to construct, the permit to construct must be issued prior to the new change.

(2) During the period of time after the Permittee applies for a minor modification but before the Department acts in accordance with COMAR 26.11.03.16F(2):

(a) The Permittee shall comply with applicable requirements of the Clean Air Act related to the change and the permit terms and conditions described in the application for the minor modification.

(b) The Permittee is not required to comply with the terms and conditions in the permit it seeks to modify. If the Permittee fails to comply with the terms and conditions in the application during this time, the terms, and conditions of both this permit and the application for modification may be enforced against it.

d. The Permittee is subject to enforcement action if it is determined at any time that a change made under COMAR 26.11.03.16 is not within the scope of this regulation.

e. Minor permit modification procedures may be used for Part 70 permit modifications involving the use of economic incentives, marketable permits, emissions trading, and other similar approaches, but only to the extent that the minor permit modification procedures are explicitly provided for in regulations approved by the EPA as part of the Maryland SIP or in other applicable requirements of the Clean Air Act.

14. ADMINISTRATIVE PART 70 OPERATING PERMIT AMENDMENTS

[COMAR 26.11.03.15]

The Permittee may apply to the department to make an administrative permit amendment as provided in COMAR 26.11.03.15 and in accordance with the following conditions:

a. An application for an administrative permit amendment shall:

(1) Be in writing;

(2) Include a statement certified by a responsible official that the proposed amendment meets the criteria in COMAR 26.11.03.15 for an administrative permit amendment, and

(3) Identify those provisions of this part 70 permit for which the amendment is requested, including the basis for the request.

b. An administrative permit amendment:

(1) Is a correction of a typographical error;

(2) Identifies a change in the name, address, or phone number of a person identified in this permit, or a similar administrative change involving the Permittee or other matters which are not directly related to the control of air pollution;

(3) requires more frequent monitoring or reporting by the Permittee;

(4) Allows for a change in ownership or operational control of a source for which the Department determines that no other revision to the permit is necessary and is documented as per COMAR 26.11.03.15B(4);

(5) Incorporates into this permit the requirements from preconstruction review permits or approvals issued by the Department in accordance with COMAR 26.11.03.15B(5), but only if it satisfies 40 CFR 70.7(d)(1)(v);

(6) Incorporates any other type of change, as approved by the EPA, which is similar to those in COMAR 26.11.03.15B(1)—(4);

(7) Notwithstanding COMAR 26.11.03.15B(1)—(6), all modifications to acid rain control provisions included in this Part 70 permit are governed by applicable requirements promulgated under Title IV of the Clean Air Act; or

(8) Incorporates any change to a term or condition specified as State-only enforceable if the Permittee has obtained all necessary permits-to-construct and approvals that apply to the change.

c. The Permittee may make the change addressed in the application for an administrative amendment upon receipt by the Department of the application if all permits-to-construct or approvals otherwise required by COMAR 26.11.02 prior to making the change have first been obtained from the Department.

d. The permit shield in COMAR 26.11.03.23 applies to administrative permit amendments made under Section B(5) of COMAR 26.11.03.15 , but only after the Department takes final action to revise the permit.

e. The Permittee is subject to enforcement action if it is determined at any time that a change made under COMAR 26.11.03.15 is not within the scope of this regulation.

15. OFF-PERMIT CHANGES TO THIS SOURCE

[COMAR 26.11.03.19]

The Permittee may make off-permit changes to this facility as provided in COMAR 26.11.03.19 and in accordance with the following conditions:

a. The Permittee may make a change to this permitted facility that is not addressed or prohibited by the federally enforceable conditions of this Part 70 permit without obtaining a Part 70 permit revision if:

(1) The Permittee has obtained all permits and approvals required by COMAR 26.11.02 and .03;

(2) The change is not subject to any requirements under Title IV of the Clean Air Act;

(3) The change is not a Title I modification; and

(4) The change does not violate an applicable requirement of the Clean Air Act or a federally enforceable term or condition of the permit.

b. For a change that qualifies under COMAR 26.11.03.19, the Permittee shall provide contemporaneous written notice to the Department and the EPA, except for a change to an emissions unit or activity that is exempt from the Part 70 permit application, as provided in COMAR 26.11.03.04. This written notice shall describe the change, including the date it was made, any change in emissions, including the pollutants emitted, and any new applicable requirements of the Clean Air Act that apply as a result of the change.

c. Upon satisfying the requirements of COMAR 26.11.03.19, the Permittee may make the proposed change.

d. The Permittee shall keep a record describing:

(1) Changes made at the facility that result in emissions of a regulated air pollutant subject to an applicable requirement of the Clean Air Act, but not otherwise regulated under this permit; and

(2) The emissions resulting from those changes.

e. Changes that qualify under COMAR 26.11.03.19 are not subject to the requirements for Part 70 revisions.

f. The Permittee shall include each off-permit change under COMAR 26.11.03.19 in the application for renewal of the part 70 permit.

g. The permit shield in COMAR 26.11.03.23 does not apply to off-permit changes made under COMAR 26.11.03.19.

h. The Permittee is subject to enforcement action if it is determined that an off-permit change made under COMAR 26.11.03.19 is not within the scope of this regulation.

16. ON-PERMIT CHANGES TO SOURCES

[COMAR 26.11.03.18]

The Permittee may make on-permit changes that are allowed under Section 502(b)(10) of the Clean Air Act as provided in COMAR 26.11.03.18 and in accordance with the following conditions:

a. The Permittee may make a change to this facility without obtaining a revision to this Part 70 permit if:

(1) The change is not a Title I modification;

(2) The change does not result in emissions in excess of those expressly allowed under the federally enforceable provisions of the Part 70 permit for the permitted facility or for an emissions unit within the facility, whether expressed as a rate of emissions or in terms of total emissions;

(3) The Permittee has obtained all permits and approvals required by COMAR 26.11.02 and .03;

(4) The change does not violate an applicable requirement of the Clean Air Act;

(5) The change does not violate a federally enforceable permit term or condition related to monitoring, including test methods, record keeping, reporting, or compliance certification requirements;

(6) The change does not violate a federally enforceable permit term or condition limiting hours of operation, work practices, fuel usage, raw material usage, or production levels if the term or condition has been established to limit emissions allowable under this permit;

(7) If applicable, the change does not modify a federally enforceable provision of a compliance plan or schedule in this Part 70 permit unless the Department has approved the change in writing; and

(8) This permit does not expressly prohibit the change under COMAR 26.11.03.18.

b. The Permittee shall notify the Department and the EPA in writing of a proposed on-permit change under COMAR 26.11.03.18 not later than 7 days before the change is made. The written information shall include the following information:

(1) A description of the proposed change;

(2) The date on which the change is proposed to be made;

(3) Any change in emissions resulting from the change, including the pollutants emitted;

(4) Any new applicable requirement of the Clean Air Act; and

(5) Any permit term or condition that would no longer apply.

c. The responsible official of this facility shall certify in accordance with COMAR 26.11.02.02F that the proposed change meets the criteria for the use of on-permit changes under COMAR 26.11.03.18.

d. The Permittee shall attach a copy of each notice required by condition b. above to this Part 70 permit.

e. On-permit changes that qualify under COMAR 26.11.03.18 are not subject to the requirements for part 70 permit revisions.

f. Upon satisfying the requirements under COMAR 26.11.03.18, the Permittee may make the proposed change.

g. The permit shield in COMAR 26.11.03.23 does not apply to on-permit changes under COMAR 26.11.03.18.

h. The Permittee is subject to enforcement action if it is determined that an on-permit change made under COMAR 26.11.03.18 is not within the scope of the regulation or violates any requirement of the State air pollution control law.

17. FEE PAYMENT

[COMAR 26.11.02.16A(2) & (5)(b)]

a. The fee for this Part 70 permit is as prescribed in Regulation .19 of COMAR 26.11.02.

b. The fee is due on and shall be paid on or before each 12-month anniversary date of the permit.

c. Failure to pay the annual permit fee constitutes cause for revocation of the permit by the Department.

18. REQUIREMENTS FOR PERMITS-TO-CONSTRUCT AND APPROVALS

[COMAR 26.11.02.09.]

The Permittee may not construct or modify or cause to be constructed or modified any of the following sources without first obtaining, and having in current effect, the specified permits-to-construct, and approvals:

a. New Source Review source, as defined in COMAR 26.11.01.01, approval required, except for generating stations constructed by electric companies;

b. Prevention of Significant Deterioration source, as defined in COMAR 26.11.01.01, approval required, except for generating stations constructed by electric companies;

c. New Source Performance Standard source, as defined in COMAR 26.11.01.01, permit to construct required, except for generating stations constructed by electric companies;

d. National Emission Standards for Hazardous Air Pollutants source, as defined in COMAR 26.11.01.01, permit to construct required, except for generating stations constructed by electric companies;

e. A stationary source of lead that discharges one ton per year or more of lead or lead compounds measured as elemental lead, permit to construct required, except for generating stations constructed by electric companies;

f. All stationary sources of air pollution, including installations and air pollution control equipment, except as listed in COMAR 26.11.02.10, permit to construct required;

g. In the event of a conflict between the applicability of (a.— e.) above and an exemption listed in COMAR 26.11.02.10, the provision that requires a permit applies.

h. Approval of a PSD or NSR source by the Department does not relieve the Permittee obtaining an approval from also obtaining all permits-to-construct required b y (c.— g.) above.

19. CONSOLIDATION OF PROCEDURES FOR PUBLIC PARTICIPATION

[COMAR 26.11.02.11C] and [COMAR 26.11.03.01K]

The Permittee may request the Department to authorize special procedures for the Permittee to apply simultaneously, to the extent possible, for a permit to construct and a revision to this permit.

These procedures may provide for combined public notices, informational meetings, and public hearings for both permits but shall not adversely affect the rights of a person, including EPA and affected states, to obtain information about the application for a permit, to comment on an application, or to challenge a permit that is issued.

These procedures shall not alter any existing permit procedures or time frames.

20. PROPERTY RIGHTS

[COMAR 26.11.03.06E(4)]

This Part 70 permit does not convey any property rights of any sort, or any exclusive privileges.

21. SEVERABILITY

[COMAR 26.11.03.06A(5)]

If any portion of this Part 70 permit is challenged, or any term or condition deemed unenforceable, the remainder of the requirements of the permit continues to be valid.

22. INSPECTION AND ENTRY

[COMAR 26.11.03.06G(3)]

The Permittee shall allow employees and authorized representatives of the Department, the EPA, and local environmental health agencies, upon presentation of credentials or other documents as may be required by law, to:

a. Enter at a reasonable time without delay and without prior notification the Permittee's property where a Part 70 source is located, emissions-related activity is conducted, or records required by this permit are kept;

b. Have access to and make copies of records required by the permit;

c. Inspect all emissions units within the facility subject to the permit and all related monitoring systems, air pollution control equipment, and practices or operations regulated or required by the permit; and

d. Sample or monitor any substances or parameters at or related to the emissions units at the facility for the purpose of determining compliance with the permit.

23. DUTY TO PROVIDE INFORMATION

[COMAR 26.11.03.06E(5)]

The Permittee shall furnish to the Department, within a reasonable time specified by the Department, information requested in writing by the Department in order to determine whether the Permittee is in compliance with the federally enforceable conditions of this Part 70 permit, or whether cause exists for revising or revoking the permit. Upon request, the Permittee shall also furnish to the Department records required to be kept under the permit.

For information claimed by the Permittee to be confidential and therefore potentially not disclosable to the public, the Department may require the Permittee to provide a copy of the records directly to the EPA along with a claim of confidentiality.

The Permittee shall also furnish to the Department, within a reasonable time specified by the Department, information or records requested in writing by the Department in order to determine if the Permittee is in compliance with the State-only enforceable conditions of this permit.

24. COMPLIANCE REQUIREMENTS

[COMAR 26.11.03.06E(1)] and [COMAR 26.11.03.06A(11)] and [COMAR 26.11.02.05]

The Permittee shall comply with the conditions of this Part 70 permit. Noncompliance with the permit constitutes a violation of the Clean Air Act, and/or the Environment Article Title 2 of the Annotated Code of Maryland and may subject the Permittee to:

a. Enforcement action,

b. Permit revocation or revision,

c. Denial of the renewal of a Part 70 permit, or

d. Any combination of these actions.

The conditions in this Part 70 permit are enforceable by EPA and citizens under the Clean Air Act except for the State-only enforceable conditions.

Under Environment Article Section 2-609, Annotated Code of Maryland, the Department may seek immediate injunctive relief against a person who violates this permit in such a manner as to cause a threat to human health or the environment.

25. CREDIBLE EVIDENCE

Nothing in this permit shall be interpreted to preclude the use of credible evidence to demonstrate noncompliance with any term of this permit.

26. NEED TO HALT OR REDUCE ACTIVITY NOT A DEFENSE

[COMAR 26.11.03.06E(2)]

The need to halt or reduce activity in order to comply with the conditions of this permit may not be used as a defense in an enforcement action.

27. CIRCUMVENTION

[COMAR 26.11.01.06]

The Permittee may not install or use any article, machine, equipment or other contrivance, the use of which, without resulting in a reduction in the total weight of emissions, conceals or dilutes emissions which would otherwise constitute a violation of any applicable air pollution control regulation.

28. PERMIT SHIELD

[COMAR 26.11.03.23]

A permit shield as described in COMAR 26.11.03.23 shall apply only to terms and conditions in this Part 70 permit that have been specifically

identified as covered by the permit shield. Neither this permit nor COMAR 26.11.03.23 alters the following:

a. The emergency order provisions in Section 303 of the Clean Air Act, including the authority of EPA under that section;

b. The liability of the Permittee for a violation of an applicable requirement of the Clean Air Act before or when this permit is issued or for a violation that continues after issuance;

c. The requirements of the Acid Rain Program, consistent with Section 408(a) of the Clean Air Act;

d. The ability of the Department or EPA to obtain information from a source pursuant to Maryland law and Section 114 of the Clean Air Act; or

e. The authority of the Department to enforce an applicable requirement of the State air pollution control law that is not an applicable requirement of the Clean Air Act.

29. ALTERNATE OPERATING SCENARIOS

[COMAR 26.11.03.06A(9)]

For all alternate operating scenarios approved by the Department and contained within this permit, the Permittee, while changing from one approved scenario to another, shall contemporaneously record in a log maintained at the facility each scenario under which the emissions unit is operating and the date and time the scenario started and ended.

SECTION III PLANT WIDE CONDITIONS

1. PARTICULATE MATTER FROM CONSTRUCTION AND DEMOLITION

[COMAR 26.11.06.03D]

The Permittee shall not cause or permit any 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.

2. OPEN BURNING

[COMAR 26.11.07]

Except as provided in COMAR 26.11.07.04, the Permittee shall not cause or permit an open fire from June 1 through August 31 of any calendar year. Prior to any open burning, the Permittee shall request and receive approval from the Department.

3. AIR POLLUTION EPISODE

[COMAR 26.11.05.04]

When requested by the Department, the Permittee shall prepare in writing standby emissions reduction plans, consistent with good industrial practice and safe operating procedures, for reducing emissions creating air pollution during periods of Alert, Warning, and Emergency of an air pollution episode.

4. REPORT OF EXCESS EMISSIONS AND DEVIATIONS

[COMAR 26.11.01.07] and [COMAR 26.11.03.06C(7)]

The Permittee shall comply with the following conditions for occurrences of excess emissions and deviations from requirements of this permit, including those in Section VI – State-only Enforceable Conditions:

a. Report any deviation from permit requirements that could endanger human health or the environment, by orally notifying the Department immediately upon discovery of the deviation;

b. Promptly report all occurrences of excess emissions that are expected to last for one hour or longer by orally notifying the Department of the onset and termination of the occurrence;

c. When requested by the Department the Permittee shall report all deviations from permit conditions, including those attributed to malfunctions as defined in COMAR 26.11.01.07A, within 5 days of the request by submitting a written description of the deviation to the Department. The written report shall include the cause, dates and times of the onset and termination of the deviation, and an account of all actions planned or taken to reduce, eliminate, and prevent recurrence of the deviation;

d. The Permittee shall submit to the Department semi-annual monitoring reports that confirm that all required monitoring was performed, and that provide accounts of all deviations from permit requirements that occurred during the reporting periods. Reporting periods shall be January 1 through June 30 and July 1 through December 31, and reports shall be submitted within 30 days of the end of each reporting period. Each account of deviation shall include a description of the deviation, the dates and times of onset and termination, identification of the person who observed or discovered the deviation, causes and corrective actions taken, and actions taken to prevent recurrence. If no deviations from permit conditions occurred during a reporting period, the Permittee shall submit a written report that so states.

e. When requested by the Department, the Permittee shall submit a written report to the Department within 10 days of receiving the request concerning an occurrence of excess emissions. The report shall contain the information required in COMAR 26.11.01.07D(2).

5. ACCIDENTAL RELEASE PROVISIONS

[COMAR 26.11.03.03B(23)] and [40 CFR 68]

Should the Permittee become subject to 40 CFR 68 during the term of this permit, the Permittee shall submit risk management plans by the date

specified in 40 CFR 68.150 and shall certify compliance with the requirements of 40 CFR 68 as part of the annual compliance certification as required by 40 CFR 70.

The Permittee shall initiate a permit revision or reopening according to the procedures of 40 CFR 70.7 to incorporate appropriate permit conditions into the Permittee's Part 70 permit.

6. GENERAL TESTING REQUIREMENTS

[COMAR 26.11.01.04]

The Department may require the Permittee to conduct, or have conducted, testing to determine compliance with this Part 70 permit. The Department, at its option, may witness or conduct these tests. This testing shall be done at a reasonable time, and all information gathered during a testing operation shall be provided to the Department.

7. EMISSIONS TEST METHODS

[COMAR 26.11.01.04]

Compliance with the emissions standards and limitations in this Part 70 permit shall be determined by the test methods designated and described below or other test methods submitted to and approved by the Department.

Reference documents of the test methods approved by the Department include the following:

a. 40 CFR 60, appendix A

b. 40 CFR 51, appendix M

c. The Department's Technical Memorandum 91-01 "Test Methods and Equipment Specifications for Stationary Sources", (January 1991), as amended through Supplement 3, (October 1, 1997)

8. EMISSIONS CERTIFICATION REPORT

[COMAR 26.11.01.05-1] and [COMAR 26.11.02.19C] and [COMAR 26.11.02.19D]

The Permittee shall certify actual annual emissions of regulated pollutants from the facility on a calendar year basis.

a. The certification shall be on forms obtained from the Department and submitted to the Department not later than April 1 of the year following the year for which the certification is required;

b. The individual making the certification shall certify that the information is accurate to the individual's best knowledge. The individual shall be:

(1) Familiar with each source for which the certifications forms are submitted, and

(2) Responsible for the accuracy of the emissions information;

c. The Permittee shall maintain records necessary to support the emissions certification including the following information if applicable:

(1) The total amount of actual emissions of each regulated pollutant and the total of all regulated pollutants;

(2) An explanation of the methods used to quantify the emissions and the operating schedules and production data that were used to determine emissions, including significant assumptions made;

(3) Amounts, types, and analyses of all fuels used;

(4) Emissions data from continuous emissions monitors that are required by this permit, including monitor calibration and malfunction information;

(5) Identification, description, and use records of all air pollution control equipment and compliance monitoring equipment including:

(a) Significant maintenance performed,
(b) Malfunctions and downtime, and
(c) Episodes of reduced efficiency of all equipment;

(6) Limitations on source operation or any work practice standards that significantly affect emissions; and

(7) Other relevant information as required by the Department.

9. COMPLIANCE CERTIFICATION REPORT

[COMAR 26.11.03.06G(6) and (7)]

The Permittee shall submit to the Department and EPA Region III a report certifying compliance with each term of this Part 70 permit including each applicable standard, emissions limitation, and work practice for the previous calendar year by April 1 of each year.

a. The compliance certification shall include:

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

(2) The compliance status;

(3) Whether the compliance was continuous or intermittent;

(4) The methods used for determining the compliance status of each source, currently and over the reporting period; and

(5) Any other information required to be reported to the Department that is necessary to determine the compliance status of the Permittee with this permit.

b. The Permittee shall submit the compliance certification reports to the Department and EPA simultaneously.

10. CERTIFICATION BY RESPONSIBLE OFFICIAL

[COMAR 26.11.02.02F]

All application forms, reports, and compliance certifications submitted pursuant to this permit shall be certified by a responsible official as to truth, accuracy, and completeness. The Permittee shall expeditiously notify the Department of an appointment of a new responsible official.

The certification shall be in the following form:

"I certify under penalty of law that this document and all attachments were prepared under my direction or supervision in accordance with a system designed to assure that qualified personnel properly gather and evaluate the information submitted. Based on my inquiry of the person or persons who manage the system, or those persons directly responsible for gathering the information, the information submitted is, to the best of my knowledge and belief, true, accurate, and complete. I am aware that there are significant penalties for submitting false information, including the possibility of fine and imprisonment for knowing violations."

11. SAMPLING AND EMISSIONS TESTING RECORD KEEPING

[COMAR 26.11.03.06C(5)]

The Permittee shall gather and retain the following information when sampling and testing for compliance demonstrations:

a. The location as specified in this permit, and the date and time that samples and measurements are taken;

b. All pertinent operating conditions existing at the time that samples and measurements are taken;

c. The date that each analysis of a sample or emissions test is performed and the name of the person taking the sample or performing the emissions test;

d. The identity of the Permittee, individual, or other entity that performed the analysis;

e. The analytical techniques and methods used; and

f. The results of each analysis.

12. GENERAL RECORDKEEPING

[COMAR 26.11.03.06C(6)]

The Permittee shall retain records of all monitoring data and information that support the compliance certification for a period of five (5) years from the date that the monitoring, sample measurement, application, report, or emissions test was completed or submitted to the Department.

These records and support information shall include:

a. All calibration and maintenance records;

b. All original data collected from continuous monitoring instrumentation;

c. Records which support the annual emissions certification; and

d. Copies of all reports required by this permit.

13. GENERAL CONFORMITY

[COMAR 26.11.26.09]

The Permittee shall comply with the general conformity requirements of 40 CFR 93, Subpart B and COMAR 26.11.26.09.

14. ASBESTOS PROVISIONS

[40 CFR 61, Subpart M]

The Permittee shall comply with 40 CFR 61, Subpart M when conducting any renovation or demolition activities at the facility.

15. OZONE DEPLETING REGULATIONS

[40 CFR 82, Subpart F]

The Permittee shall comply with the standards for recycling and emissions reduction pursuant to 40 CFR 82, Subpart F, except as provided for MVACs in subpart B:

a. Persons opening appliances for maintenance, service, repair, or disposal shall comply with the prohibitions and required practices pursuant to 40 CFR 82.154 and 82.156.

b. Equipment used during the maintenance, service, repair, or disposal of appliances shall comply with the standards for recycling and recovery equipment pursuant to 40 CFR 82.158.

c. Persons performing maintenance, service, repairs, or disposal of appliances shall be certified by an approved technician certification program pursuant to 40 CFR 82.161.

d. Persons disposing of small appliances, MVACS, and MVAC-like appliances as defined in 40 CFR 82.152, shall comply with record keeping requirements pursuant to 40 CFR 82.155.

e. Persons owning commercial or industrial process refrigeration equipment shall comply with the leak repair requirements pursuant to 40 CFR 82.156.

f. Owners/operators of appliances normally containing 50 or more pounds of refrigerant shall keep records of refrigerant purchased and added to such appliances pursuant to 40 CFR 82.166.

16. ACID RAIN PERMIT

The Permittee shall comply with the provisions and all applicable requirements of the renewal Phase II Acid Rain Permit, for the affected units that are being issued in conjunction with this permit. See Attached Appendix A.

SECTION IV PLANT SPECIFIC CONDITIONS

This section provides tables that include the emissions standards, emissions limitations, and work practices applicable to each emissions unit located at this facility. The Permittee shall comply with all applicable emissions standards, emissions limitations and work practices included herein.

The tables also include testing, monitoring, record keeping and reporting requirements specific to each emissions unit. In addition to the requirements included here in **Section IV**, the Permittee is also subject to the general testing, monitoring, record keeping, and reporting requirements included in **Section III – Plant Wide Conditions** of this permit.

Unless otherwise provided in the specific requirements for an emissions unit, the Permittee shall maintain at the facility for at least five (5) years, and shall make available to the Department upon request, all records that the Permittee is required under this section to establish. **[Reference: COMAR 26.11.03.06C(5)(g)]**

Table IV-1	
1.0	**Emissions Unit Number(s): E-3 and E-4: Boilers** **E-3 and E-4:** Two (2) tangentially fired, sub-critical, cycling boilers, each rated at 640 megawatts and 6970 million Btu per hour heat input. They are fired on natural gas and No. 6 fuel oil. No. 2 fuel oil or natural gas may be used for ignition, warm-up, and flame stabilization purposes.
1.1	**Applicable Standards/Limits:** A. Control of Visible Emissions (1) **COMAR 26.11.09.05A(2) & (3)** – Fuel Burning Equipment "Areas III and IV. In Areas III and IV, a person may not cause or permit the discharge of emissions from any fuel burning equipment, other than water in an uncombined form, which is visible to human observers except that, for the purpose of demonstrating compliance using COM data, emissions that are visible to a human observer are those that are equal to or greater than 10 percent opacity". Exceptions. Section A(1) and (2) of this regulation do not apply to emissions during load changing, soot blowing, startup, or adjustments or occasional cleaning of control equipment if: a. The visible emissions are not greater than 40 percent opacity; and

Table IV-1

b. The visible emissions do not occur for more than 6 consecutive minutes in any sixty-minute period."

(2) NSPS Requirement (**E-4** Only)
§60.42-Standard for particulate matter (PM).
"(a) Except as provided under paragraphs (b), (c), (d), and (e) of this section, on and after the date on which the performance test required to be conducted by §60.8 is completed, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any affected facility any gases that:
(2) Exhibit greater than 20 percent opacity except for one six-minute period per hour of not more than 27 percent opacity."

§60.11(c)-Compliance with standards and maintenance requirements.
"The opacity standards set forth in this part shall apply at all times except during periods of startup, shutdown, malfunction, and as otherwise provided in the applicable standard."

B. Control of Particulate Matter Emissions
(1) **COMAR 26.11.09.06** - Control of Particulate Matter.
"B. Areas III and IV. The following apply in Areas III and IV:
(6) Exceptions.
(a) Fuel burning equipment burning gas with an interruptible gas service is exempt from the provisions of §B(1) and (2) of this regulation."

(2) NSPS Requirements-E-4 Only
§60.42-Standard for particulate matter (PM).
"(a) Except as provided under paragraphs (b), (c), (d), and (e) of this section, on and after the date on which the performance test required to be conducted by §60.8 is completed, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any affected facility any gases that:
(1) Contain PM in excess of 43 nanograms per joule (ng/J) heat input (0.10 lb./MMBtu) derived from fossil fuel or fossil fuel and wood residue."

§60.8(f) "Unless otherwise specified in the applicable subpart, each performance test shall consist of three separate runs using the applicable test method. Each run shall be conducted for the time and under the conditions specified in the applicable standard. For the purpose of determining compliance with an applicable standard, the arithmetic means of results of the three runs shall apply. In the event that a sample is accidentally lost, or conditions occur in which one of the three runs

Table IV-1

must be discontinued because of forced shutdown, failure of an irreplaceable portion of the sample train, extreme meteorological conditions, or other circumstances, beyond the owner or operator's control, compliance may, upon the Administrator's approval, be determined using the arithmetic mean of the results of the two other runs."

C. Control of Sulfur Oxides Emissions
(1) **COMAR 26.11.09.07A(2)** – Control of Sulfur Oxides from fuel burning equipment. "A person may not burn, sell, or make available for sale any fuel with a sulfur content by weight in excess of or which otherwise exceeds the following limitations: In Areas III, and IV:
(a) All solid fuels, 1.0 percent;
(b) Distillate fuel oils, 0.3 percent;
(c) Residual fuel oils, 1.0 percent.

(2) NSPS Requirements E-4 Only
§60.43-Standard for sulfur dioxide (SO_2).
"(a) Except as provided under paragraph (d) of this section, on and after the date on which the performance test required to be conducted by §60.8 is completed, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any affected facility any gases that contain SO_2 in excess of:
(1) 340 ng/J heat input (0.80 lb./MMBtu) derived from liquid fossil fuel or liquid fossil fuel and wood residue."

§60.45(g) - Emissions and fuel monitoring.
"(2) *Sulfur dioxide.* Excess emissions for affected facilities are defined as:
(i) For affected facilities electing not to comply with §60.43(d), any three-hour period during which the average emissions (arithmetic average of three contiguous one-hour periods) of SO_2 as measured by a CEMS exceed the applicable standard in §60.43."

(3) Acid Rain Provisions
The Permittee shall comply with the requirements of the Phase II Acid Rain Permit issued for this generating station. Note: A renewal Phase II Acid Rain Permit will be issued in conjunction with this Part 70 permit and is attached to the Part 70 permit as Appendix A.

(4) Cross-State Air Pollution Rule
See Table IV-5: CSAPR for requirements.

Table IV-1	
	D. Control of Nitrogen Oxides Emissions (1) NO_x RACT Requirements **COMAR 26.11.09.08B(5)** - Operator Training. (a) For purposes of this regulation, the equipment operator to be trained may be the person who maintains the equipment and makes the necessary adjustments for efficient operation. (b) The operator training course sponsored by the Department shall include an in-house training course that is approved by the Department." **COMAR 26.11.09.08C.** - Requirements for Fuel-Burning Equipment with a Rated Heat Input Capacity of 250 million Btu Per Hour or Greater. "(1) A person who owns or operates fuel-burning equipment with a rated heat input capacity of 250 million Btu per hour or greater shall equip each installation with combustion modifications or other technologies to meet the NO_x emission rates in §C(2) of this regulation. (2) The maximum NO_x emission rates as pounds of NO_x per Million Btu per hour are: (a) 0.45 for tangentially coal fired units located at an electric generating facility (excluding high heat release units); (b) 0.50 for wall coal fired units located at an electric generating facility (excluding high heat release units); **(c) 0.30 for oil fired or gas/oil fired units located at an electric generating facility;** (d) 0.70 for coal fired cyclone fuel burning equipment located at an electric generating facility from May 1 through September 30 of each year and 1.5 during the period October 1 through April 30 of each year; (e) 0.70 for a tangentially coal fired high heat release unit located at an electric generating facility; (f) 0.80 for a wall coal fired high heat release unit located at an electric generating facility; (g) 0.6 for coal fired cell burners at an electric generating facility; and (h) 0.70 for fuel burning equipment stacks at a non-electric generating facility during the period May 1 through September 30 of each year and 0.99 during the period October 1 through April 30 of each year. (3) A person who owns or operates fuel burning equipment with a rated heat input capacity of 250 Million Btu per hour or greater shall install, operate, calibrate, and maintain a certified NO_x CEM or an alternative NO_x monitoring method approved by the Department and the EPA on each installation. **COMAR 26.11.09.08B(2)(d)** - Demonstration of Compliance. "Except as otherwise established by the Department and approved by the EPA, for a person who establishes compliance with the NO_x emissions standards in

Table IV-1	
	this regulation using a CEM, compliance shall be determined as 30-day rolling averages." (2) NSPS requirement - **E-4** Only **§60.44** - Standard for nitrogen oxides (NO_x). "(a) Except as provided under paragraph (e) of this section, on and after the date on which the performance test required to be conducted by §60.8 is completed, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any affected facility any gases that contain NO_x, expressed as NO_2 in excess of: (1) 86 ng/J heat input (0.20 lb./MMBtu) derived from gaseous fossil fuel. (2) 129 ng/J heat input (0.30 lb./MMBtu) derived from liquid fossil fuel, liquid fossil fuel and wood residue, or gaseous fossil fuel and wood residue." **§60.45(g)** - Emissions and fuel monitoring. "(**3**) *Nitrogen oxides.* Excess emissions for affected facilities using a CEMS for measuring NO_x are defined as: (i) For affected facilities electing not to comply with §60.44(e), any three-hour period during which the average emissions (arithmetic average of three contiguous one-hour periods) exceed the applicable standards in §60.44." (3) Acid Rain Provisions – These units are not subject to a NO_x limitation under the Acid Rain Program because they are not coal-fired. However, the Permittee is required to comply with the continuous NO_x monitoring requirement of 40CFR Part 75 and associated record keeping and reporting requirements. (4) Cross-State Air Pollution Rule **See Table IV-5: CSAPR for requirements.**
1.2	**Testing Requirements:** A. Control of Visible Emissions (1) The Permittee shall perform quality assurance procedures on the continuous opacity monitoring system as established in COMAR 26.11.31. **[Reference: COMAR 26.11.03.06C]**

Table IV-1	
	(2) NSPS Requirement – **E-4** only See Monitoring Requirements. Also, testing that relates to QC/QA procedures on the Continuous Opacity Monitoring System. B. Control of Particulate Matter Emissions (1) See monitoring requirements. Note: The 2011 Consent Decree establishes a PM emissions limit of 0.020 grains/scfd and a stack testing schedule when residual oil is burned. (2) NSPS Requirement – **E-4** only Stack testing will be conducted in conjunction with the schedule for stack testing established in the 2011 Consent Decree. **[Reference: COMAR 26.11.03.06C** C. Control of Sulfur Oxides Emissions (1) The Permittee shall perform quality control/ quality assurance procedures on the continuous emission monitoring system as established in 40 CFR Part 75, Appendix B. **[Reference: COMAR 26.11.01.11C]** (2) NSPS Requirement – **E-4** only The Permittee shall perform quality control/ quality assurance procedures on the continuous emission monitoring system as established in 40 CFR Part 75, Appendix B. **[Reference: COMAR 26.11.01.11C]**. (3) Acid Rain Provisions See Monitoring Requirements. D. Control of Nitrogen Oxides Emissions (1) NOx RACT Requirements The Permittee shall perform quality control/ quality assurance procedures on the continuous emission monitoring system as established in 40 CFR Part 75, Appendix B. **[Reference: COMAR 26.11.09.08B(2)(c)]** (2) NSPS Requirement – **E-4** only The Permittee shall perform quality control/ quality assurance procedures on the continuous emission monitoring system as established in 40 CFR Part 75, Appendix B. **[Reference: COMAR 26.11.09.08B(2)(c)]** (3) Acid Rain Provisions See Monitoring Requirements.

Table IV-1	
1.3	**Monitoring Requirements:** A. Control of Visible Emissions (1) The Permittee, in accordance with **COMAR 26.11.01.10B,** shall continuously monitor opacity of the stack gases using a continuous opacity monitor that is certified in accordance with 40 CFR Part 60, Appendix B and meets the quality assurance criteria of COMAR 26.11.31. **[Reference: COMAR 26.11.01.10C]** (2) NSPS Requirement – **E-4** only **§60.45(g)** - Emissions and fuel monitoring. **"(a)** Each owner or operator shall install, calibrate, maintain, and operate continuous opacity monitoring system (COMS) for measuring opacity and a CEMS for measuring SO_2 emissions, NO_x emissions, and either oxygen (O_2) or carbon dioxide (CO_2) except as provided in paragraph (b) of this section." B. Control of Particulate Matter (1) & (2) – See Monitoring Requirement for Control of Visible Emissions. C. Control of Sulfur Oxides (1) The Permittee shall obtain appropriate demonstration such as fuel supplier certifications to confirm that the fuel oil is in compliance with the sulfur content in fuel limitation. **[Reference: COMAR 26.11.03.06C].** (2) NSPS Requirement – **E-4** only **§60.45** - Emission and fuel monitoring. "(a) Each owner or operator shall install, calibrate, maintain, and operate continuous monitoring systems for measuring the opacity of emissions, **sulfur dioxide emissions**, nitrogen oxides emissions, and either oxygen or carbon dioxide except as provided in paragraph (b) of this section. (b) Certain of the continuous monitoring system requirements under paragraph (a) of this section do not apply to owners or operators under the following conditions: (1) Not applicable (2) For a fossil fuel-fired steam generator that does not use a flue gas desulfurization device, a continuous monitoring system for measuring sulfur dioxide emissions is not required if the owner or operator monitors sulfur dioxide emissions by fuel sampling and analysis." **Note:** The Permittee may use the data collected from the Acid Rain monitoring system to demonstrate compliance with the NSPS standard.

Table IV-1	
	The data acquisition system must be able to generate sulfur dioxide emissions rates in lbs./ per million BTU on a rolling 3-hour average. (3) Acid Rain Provisions The Permittee shall continuously monitor sulfur dioxide emissions that meet the requirements of 40 CFR Part 75, subpart B §75.10A(1). This continuous monitoring system shall be used to collect emissions information to demonstrate compliance with the Acid Rain Program. **[Reference: §75.10(a)(1)].** D. Control of Nitrogen Oxides Emissions (1) NO_x RACT Requirement The Permittee shall operate, calibrate, and maintain a certified NO_x CEM or an alternative NO_x monitoring method approved by the Department and the EPA on each installation. **[Reference: COMAR 26.11.09.08C(3)].** (2) NSPS Requirement – **E-4** only **§60.45** - Emission and fuel monitoring. "(a) Each owner or operator shall install, calibrate, maintain, and operate continuous monitoring systems for measuring the opacity of emissions, sulfur dioxide emissions, **nitrogen oxides emissions,** and either oxygen or carbon dioxide except as provided in paragraph (b) of this section. **Note:** The Permittee is required to monitor NO_x emissions under the Acid Rain Program. The Permittee may use the data collected from the Acid Rain monitoring system to demonstrate compliance with the NSPS standard. The data acquisition system must be able to generate nitrogen oxides emissions rates in lbs./ per million BTU on an average of 3 one-hour periods. (3) Acid Rain Provisions See the requirements for the continuous monitoring for NO_x for 40 CFR Part 75- Acid Rain Program. **[Reference: Acid Rain Permit and 40 CFR 75 subpart B]**
1.4	**Record Keeping Requirements:** **Note:** All records must be maintained for a period of at least 5 years. **[Reference: COMAR 26.11.03.06C(5)(g)]** A. Control of Visible Emissions (1) The Permittee shall maintain all records necessary to comply with the data reporting requirements of COMAR 26.11.01.10D(2). **[Reference: COMAR 26.11.01.10D(2)].**

Table IV-1

(2) NSPS Requirement – **E-4** only
§60.7(f) – Notification and recordkeeping
"Any owner or operator subject to the provisions of this part shall maintain a file of all measurements, including continuous monitoring system, monitoring device, and performance testing measurements; all continuous monitoring system performance evaluations; all continuous monitoring system or monitoring device calibration checks; adjustments and maintenance performed on these systems or devices; and all other information required by this part recorded in a permanent form suitable for inspection."

B. Control of Particulate Matter Emissions
(1) and (2) - The Permittee shall maintain records of the results of all particulate emission compliance tests. **[Reference: COMAR 26.11.03.06C]**.

C. Control of Sulfur Oxides Emissions
(1) The Permittee shall maintain appropriate documentation evidencing the sulfur content in fuel content from every delivery of residual fuel oil. **[Reference: COMAR 26.11.03.06C].**

(2) NSPS Subpart D Requirement – **E-4** only
§60.7(f) –Notification and recordkeeping
"Any owner or operator subject to the provisions of this part shall maintain a file of all measurements, including continuous monitoring system, monitoring device, and performance testing measurements; all continuous monitoring system performance evaluations; all continuous monitoring system or monitoring device calibration checks; adjustments and maintenance performed on these systems or devices; and all other information required by this part recorded in a permanent form suitable for inspection."

(3) Acid Rain Permit
See the recordkeeping requirements for 40 CFR Part 75- Acid Rain Program. **[Reference: Acid Rain Permit, 40 CFR 75 subpart F]**

D. Control of Nitrogen Oxides Emissions
(1) NO_x RACT Requirement
The Permittee shall maintain all records necessary to comply with the data reporting requirements. **[Reference: COMAR 26.11.03.06C].**

Table IV-1	
	(2) NSPS Subpart D Requirement - E-4 only **§60.7** – Notification and recordkeeping: "**(f)**Any owner or operator subject to the provisions of this part shall maintain a file of all measurements, including continuous monitoring system, monitoring device, and performance testing measurements; all continuous monitoring system performance evaluations; all continuous monitoring system or monitoring device calibration checks; adjustments and maintenance performed on these systems or devices; and all other information required by this part recorded in a permanent form suitable for inspection." (3) Acid Rain Permit See the recordkeeping requirements for 40 CFR Part 75- Acid Rain Program. **[Reference: Acid Rain Permit, 40 CFR 75 subpart F]**
1.5	**Reporting Requirements:** A. Control of Visible Emissions (1) The Permittee shall report: All CEM system downtime that lasts or is expected to last more than 24 hours shall be reported to the Department by telephone before 10 a.m. of the first regular business day following the breakdown. The system breakdown report required by Sec. D(1)(a) of this regulation shall include the reason, if known, for the breakdown and the estimated period of time that the CEM will be down. The owner or operator of the CEM shall notify the Department by telephone when an out-of-service CEM is back in operation and producing valid data. **[Reference: COMAR 26.11.01.10D(1)]** The Permittee shall submit: Quarterly summary reports to the Department not later than 30 days following each calendar quarter. The report shall be in a format approved by the Department, and shall include the following: (i) The cause, time periods, and magnitude of all emissions which exceed the applicable quarterly, daily, and hourly emission standards as provided in COMAR 26.11.09.05A(4); (ii) The COM and installation downtimes, including the time and date of the beginning and end of each downtime period and whether the source downtime was scheduled; (iii) The cause of all COM downtime;

Table IV-1	
	(iv) The total operating time for the quarter, and the total time and percent of the operating time during the quarter that excess emissions occurred, and the percentage of COM downtime, during the calendar quarter; (v) Quarterly quality assurance activities; and (vi) Daily calibration activities that include reference values, actual values, absolute or percent of span differences, and drift status; and (vii) Other information required by the Department that is determined to be necessary to evaluate the data, to ensure that compliance is achieved, or to determine the applicability of this regulation." **[Reference: COMAR 26.11.01.10D(2)]** (2) NSPS Subpart D Requirement – **E-4** only **§60.45** – Emission and fuel monitoring "(**g**) Excess emission and monitoring system performance reports shall be submitted to the Administrator semiannually for each six-month period in the calendar year. All semiannual reports shall be postmarked by the 30th day following the end of each six-month period. Each excess emission and MSP report shall include the information required in §60.7(c). Periods of excess emissions and monitoring systems (MS) downtime that shall be reported are defined as follows: (1) *Opacity.* Excess emissions are defined as any six-minute period during which the average opacity of emissions exceeds 20 percent opacity, except that one six-minute average per hour of up to 27 percent opacity need not be reported." **§60.7(c) –** Notification and recordkeeping "(c) Each owner or operator required to install a continuous monitoring device shall submit excess emissions and monitoring systems performance report (excess emissions are defined in applicable subparts) and-or summary report form (see paragraph (d) of this section) to the Administrator semiannually, except when: more frequent reporting is specifically required by an applicable subpart; or the Administrator, on a case-by-case basis, determines that more frequent reporting is necessary to accurately assess the compliance status of the source. All reports shall be postmarked by the 30th day following the end of each six-month period. Written reports of excess emissions shall include the following information: (1) The magnitude of excess emissions computed in accordance with §60.13(h), any conversion factor(s) used, and the date and time of commencement and completion of each time period of excess emissions. The process operating time during the reporting period.

Table IV-1

(2) Specific identification of each period of excess emissions that occurs during startups, shutdowns, and malfunctions of the affected facility. The nature and cause of any malfunction (if known), the corrective action taken, or preventative measures adopted.
(3) The date and time identifying each period during which the continuous monitoring system was inoperative except for zero and span checks and the nature of the system repairs or adjustments.
(4) When no excess emissions have occurred or the continuous monitoring system(s) have not been inoperative, repaired, or adjusted, such information shall be stated in the report."

B. Control of Particulate Matter Emission
(1) and (2): When requested to perform compliance testing, the Permittee shall submit a stack test protocol to the Department at least 30 days prior to test and notification of testing 10 days prior to test date. The Permittee shall submit a final stack test report with results of testing within 45 days from test completion. **[Reference: COMAR 26.11.01.04A].**

C. Control of Sulfur Oxides Emissions
(1) The Permittee shall submit fuel certification reports when requested by the Department. **[Reference: COMAR 26.11.03.06C].**

(2) NSPS Subpart D Requirement – E-4 only
§60.45 – Emission and fuel monitoring
"(g) Excess emission and monitoring system performance reports shall be submitted to the Administrator semiannually for each six-month period in the calendar year. All semiannual reports shall be postmarked by the 30th day following the end of each six-month period. Each excess emission and MSP report shall include the information required in §60.7(c). Periods of excess emissions and monitoring systems (MS) downtime that shall be reported are defined as follows:
(2) *Sulfur dioxide*. Excess emissions for affected facilities are defined as:
(i) For affected facilities electing not to comply with §60.43(d), any three-hour period during which the average emissions (arithmetic average of three contiguous one-hour periods) of SO_2 as measured by a CEMS exceed the applicable standard in §60.43."

§60.7 – Notification and recordkeeping
"(c) Each owner or operator required to install a continuous monitoring device shall submit excess emissions and monitoring systems performance report (excess emissions are defined in applicable subparts) and-or summary report form (see paragraph (d) of this section) to the

Table IV-1	
	Administrator semiannually, except when: more frequent reporting is specifically required by an applicable subpart; or the Administrator, on a case-by-case basis, determines that more frequent reporting is necessary to accurately assess the compliance status of the source. All reports shall be postmarked by the 30th day following the end of each six-month period. Written reports of excess emissions shall include the following information: (1) The magnitude of excess emissions computed in accordance with §60.13(h), any conversion factor(s) used, and the date and time of commencement and completion of each time period of excess emissions. The process operating time during the reporting period. (2) Specific identification of each period of excess emissions that occurs during startups, shutdowns, and malfunctions of the affected facility. The nature and cause of any malfunction (if known), the corrective action taken, or preventative measures adopted. (3) The date and time identifying each period during which the continuous monitoring system was inoperative except for zero and span checks and the nature of the system repairs or adjustments. (4) When no excess emissions have occurred or the continuous monitoring system(s) have not been inoperative, repaired, or adjusted, such information shall be stated in the report." (3) Acid Rain Provisions See the reporting requirements for 40 CFR Part 75- Acid Rain Program. **[Reference: Acid Rain Permit, 40 CFR 75 subpart G]** D. Control of Nitrogen Oxides Emissions (1) NO_x RACT Requirement The Permittee shall submit quarterly emission reports of CEM data to the Department on or before the thirtieth day of the month following the end of each calendar quarter." **[Reference: COMAR 26.11.09.08K(1)].** The report shall be in a format approved by the Department, and shall include the following: (i) The cause, time periods, and magnitude of all emissions which exceed the applicable emission standards; (ii) The source downtime including the time and date of the beginning and end of each downtime period and whether the source downtime was planned or unplanned; (iii) The time periods and cause of all CEM downtime including records of any repairs, adjustments, or maintenance that may affect the validity of emission data;

Table IV-1	
	(iv) Quarterly totals of excess emissions, installation downtime, and CEM downtime during the calendar quarter; (v) Quarterly quality assurance activities; and (vi) Daily calibration activities that include reference values, actual values, absolute or percent of span differences, and drift status; and (vii) Other information required by the Department that is determined to be necessary to evaluate the data, to ensure that compliance is achieved, or to determine the applicability of this regulation." **[Reference: COMAR 26.11.03.06]** (2) NSPS Subpart D Requirement – E-4 only **§60.45** - Emission and fuel monitoring (**g**) Excess emission and monitoring system performance reports shall be submitted to the Administrator semiannually for each six-month period in the calendar year. All semiannual reports shall be postmarked by the 30th day following the end of each six-month period. Each excess emission and MSP report shall include the information required in §60.7(c). Periods of excess emissions and monitoring systems (MS) downtime that shall be reported are defined as follows: (3) *Nitrogen oxides.* Excess emissions for affected facilities using a CEMS for measuring NOx are defined as: (i) For affected facilities electing not to comply with §60.44(e), any three-hour period during which the average emissions (arithmetic average of three contiguous one-hour periods) exceed the applicable standards in §60.44." **§60.7** – Notification and recordkeeping **(c) -** "Each owner or operator required to install a continuous monitoring device shall submit excess emissions and monitoring systems performance report (excess emissions are defined in applicable subparts) and-or summary report form (see paragraph (d) of this section) to the Administrator semiannually, except when: more frequent reporting is specifically required by an applicable subpart; or the Administrator, on a case-by-case basis, determines that more frequent reporting is necessary to accurately assess the compliance status of the source. All reports shall be postmarked by the 30th day following the end of each six-month period. Written reports of excess emissions shall include the following information: (1) The magnitude of excess emissions computed in accordance with §60.13(h), any conversion factor(s) used, and the date and time of commencement and completion of each time period of excess emissions. The process operating time during the reporting period.

Table IV-1	
	(2) Specific identification of each period of excess emissions that occurs during startups, shutdowns, and malfunctions of the affected facility. The nature and cause of any malfunction (if known), the corrective action taken, or preventative measures adopted. (3) The date and time identifying each period during which the continuous monitoring system was inoperative except for zero and span checks and the nature of the system repairs or adjustments. (4) When no excess emissions have occurred or the continuous monitoring system(s) have not been inoperative, repaired, or adjusted, such information shall be stated in the report." (3) Acid Rain Permit See the reporting requirements for 40 CFR Part 75- Acid Rain Program. **[Reference: Acid Rain Permit, 40 CFR 75 subpart G]**

"A permit shield shall cover the applicable requirements identified for the emissions unit(s) listed in the table above."

Table IV – 2	
2.0	**Emissions Unit Number(s): E-CT1 & E-CT2: Combustion Turbines** **E-CT1:** One (1) Pratt and Whitney FT-4A combustion turbine rated at 18 megawatts used for black start capability and peaking service. This turbine is fired with No. 2 fuel oil. **E-CT2:** One (1) Westinghouse (W-251) combustion turbine rated at 35 megawatts used for black start capability and peaking service. This turbine is fired with No. 2 fuel oil.
2.1	**Applicable Standards/Limits:** A. Control of Visible Emissions **COMAR 26.11.09.05A(2)** – Fuel Burning Equipment "Areas III and IV. In Areas III and IV, a person may not cause or permit the discharge of emissions from any fuel burning equipment, other than water in an uncombined form, which is visible to human observers except that, for the purpose of demonstrating compliance using COM data, emissions that are visible to a human observer are those that are equal to or greater than 10 percent opacity."

Table IV – 2	
	COMAR 26.11.09.05A(3) - Exceptions. "Section A(1) and (2) of this regulation do not apply to emissions during load changing, soot blowing, startup, or adjustments or occasional cleaning of control equipment if: (a) The visible emissions are not greater than 40 percent opacity; and (b) The visible emissions do not occur for more than 6 consecutive minutes in any sixty-minute period." B. Control of Sulfur Oxides Emissions (1) **COMAR 26.11.09.07**: Control of Sulfur Oxides from Fuel Burning Equipment. "A. Sulfur Content Limitations for Fuel. A person may not burn, sell, or make available for sale any fuel with a sulfur content by weight in excess of or which otherwise exceeds the following limitations: (2) In Areas III and IV: (a) All solid fuels, 1.0 percent; **(b) Distillate fuel oils, 0.3 percent;** (c) Residual fuel oils, 1.0 percent. (2) Cross State Air Pollution Rule – **(E-CT2** only) **See Table IV-5: CSAPR for requirements.** C. Control of Nitrogen Oxides Emissions (1) NOx RACT Requirements: **COMAR 26.11.09.08G** – Requirements for Fuel-Burning Equipment with a Capacity Factor of 15 percent or less and Combustion Turbines with a Capacity Factor Greater than 15 percent. (1) A person who owns or operates fuel-burning equipment with a capacity factor (as defined in 40 CFR Part 72.2) of 15 percent or less shall: (a) Provide certification of the capacity factor of the equipment to the Department in writing; (b) For fuel-burning equipment that operates more than 500 hours during a calendar year, perform a combustion analysis and optimize combustion at least once annually; (c) Maintain the results of the combustion analysis and any stack tests at the site for at least 2 years and make these results available to the Department and the EPA upon request; (d) *Not Applicable*; and (e) *Not Applicable.* (2) Cross State Air Pollution Rule -**(E-CT2** only) **See Table IV-5: CSAPR for requirements.**

Table IV – 2	
2.2	**Testing Requirements:** A. Control of Visible Emissions See Monitoring Requirement B. Control of Sulfur Oxides Emissions (1) See Monitoring Requirement C. Control of Nitrogen Oxides (1) NO_x RACT Requirements The Permittee shall perform a combustion analysis and optimize combustion at least once annually. [**Reference: COMAR 26.11.09.08G(1)(b)]**
2.3	**Monitoring Requirements:** A. Control of Visible Emissions The Permittee shall verify that there are no visible emissions when operating. An observer shall perform an EPA Reference Method 9 observation of stack emissions for an 18-minute period at least once for every 168 hours of operation or at a minimum once per calendar year. If the turbine operates for less than 100 hours in a calendar year, the visual observation requirement for that calendar year is waived. The Permittee shall perform the following if emissions are visible to human observer: (a) inspect combustion control system and combustion turbine operations, (b) perform all necessary adjustments and/or repairs to the combustion turbine within 48 hours of operation so that visible emissions are eliminated; and (c) document in writing the results of inspections, adjustments and/or repairs to the combustion turbine. The Permittee shall after 48 hours of operation, if the required adjustments and/or repairs had not eliminated the visible emissions, perform another Method 9 observation once daily when the combustion turbine is operating for 18 minutes until corrective actions have eliminated visible emissions. **[Reference: COMAR 26.11.03.06C]**.

Table IV – 2	
	B. Control of Sulfur Oxides Emissions (1) The Permittee shall obtain fuel supplier certifications stating that the fuel oil is in compliance with the sulfur content in the fuel limitation. **[Reference: COMAR 26.11.03.06C]** C. Control of Nitrogen Oxides Emissions (1) NOx RACT Requirements See Record keeping requirements
2.4	**Record Keeping Requirements:** **Note:** All records must be maintained for a period of at least 5 years. **[Reference: COMAR 26.11.03.06C(5)(g)]** A. Control of Visible Emissions The Permittee shall maintain records of the results of visual emissions observations for a period of at least 5 years. **[Reference: COMAR 26.11.03.06C]** B. Control of Sulfur Oxides Emissions (1) The Permittee shall retain fuel supplier certifications stating that the fuel oil is in compliance with the sulfur content in the fuel limitation for at least 5 years. **[Reference: COMAR 26.11.03.06C].** C. Control of Nitrogen Oxides Emissions (1) NOx RACT Requirements The Permittee shall maintain the results of the combustion analysis and any stack tests at the site for at least 5 years and make these results available to the Department and the EPA upon request. **[Reference: COMAR 26.11.09.08G(1)(c) & COMAR 26.11.03.06C]**
2.5	**Reporting Requirements:** A. Control of Visible Emissions The Permittee shall report incidents of visible emissions in accordance with Permit Condition 4, Section III, "Report of Excess Emissions and Deviations." **[Reference: COMAR 26.11.03.06C].** B. Control of Sulfur Oxides Emissions (1) The Permittee shall submit fuel certification report if requested by MDE. **[Reference: COMAR 26.11.03.06C]**

Table IV – 2	
	C. Control of Nitrogen Oxides Emissions (1) NO_x RACT Requirements The Permittee shall provide certification of the capacity factor of the equipment to the Department in the support information provided with the Annual Emissions Certification Report. **[Reference: COMAR 26.11.09.08G(1)(a) and COMAR 26.11.03.06C].**

"A permit shield shall cover the applicable requirements identified for the emissions unit(s) listed in the table above."

Table IV – 3	
3.0	**Emissions Unit Number(s): E-CT3, E-CT4, E-CT5 and E-CT6: Combustion Turbines** **E-CT3 and E-CT4** – Two (2) General Electric, GE-7EA, combustion turbines, each rated at 99 megawatts. These turbines are fired with natural gas as a primary fuel and No. 2 fuel oil as a secondary. **E-CT5 and E-CT6** – Two (2) Kraft Union combustion turbines, each rated at 120 megawatts. These turbines are fired with natural gas as a primary fuel and No. 2 fuel oil as a secondary.
3.1	**Applicable Standards/Limits:** A. Control of Visible Emissions **COMAR 26.11.09.05A(2)** – Fuel Burning Equipment "Areas III and IV. In Areas III and IV, a person may not cause or permit the discharge of emissions from any fuel burning equipment, other than water in an uncombined form, which is visible to human observers except that, for the purpose of demonstrating compliance using COM data, emissions that are visible to a human observer are those that are equal to or greater than 10 percent opacity." **COMAR 26.11.09.05A(3) -** Exceptions. "Section A(1) and (2) of this regulation do not apply to emissions during load changing, soot blowing, startup, or adjustments or occasional cleaning of control equipment if: (a) The visible emissions are not greater than 40 percent opacity; and (b) The visible emissions do not occur for more than 6 consecutive minutes in any sixty-minute period."

Table IV – 3	
	B. Control of Particulate Matter Emissions **PSD Approval** **CPCN Order No. 68841 (Case 8228) condition 5** limits total combined annual emissions under non-emergency conditions of particulate matter (Total and PM_{10}) in any consecutive 12-month period to 90 tons per year for CT-3, 4, 5 & 6. **For E-CT3 and E-CT4 Only** **CPCN Order No. 68841 (Case 8228) condition 8** limits particulate emissions (Total and PM_{10}) to 5 pounds per hour for natural gas and 34 pounds per hour for No. 2 oil. **For E-CT5 and E-CT6 Only** **CPCN Order No. 68841 (Case 8228) condition 9** limits particulate emissions (Total and PM_{10}) to 5 pounds per hour for natural gas and 10 pounds per hour for No. 2 oil. C. Control of Carbon Monoxide Emissions **PSD Approval** **CPCN Order No. 68841 (Case 8228) condition 5** limits total combined annual emissions of CO under non-emergency conditions in any consecutive 12-month period to 148 tons per year for CT-3, 4, 5 & 6. **For E-CT3 and E-CT4 Only** **CPCN Order No. 68841 (Case 8228) condition 8** limits CO emissions to 60 pounds per hour for natural gas and 60 pounds per hour for No. 2 oil. **For E-CT5 and E-CT6 Only** **CPCN Order No. 68841 (Case 8228) condition 9** limits CO emissions to 24 pounds per hour for natural gas and 28 pounds per hour for No. 2 oil. D. Control of Sulfur Oxides Emissions (1) **COMAR 26.11.09.07**: Control of Sulfur Oxides from Fuel Burning Equipment. "A. Sulfur Content Limitations for Fuel. A person may not burn, sell, or make available for sale any fuel with a sulfur content by weight in excess of or which otherwise exceeds the following limitations: (2) In Areas III and IV: (a) All solid fuels, 1.0 percent; **(b) Distillate fuel oils, 0.3 percent;** (c) Residual fuel oils, 1.0 percent.

Table IV – 3

(2) PSD Approval
CPCN Order No. 68841 (Case 8228), condition 13 limits sulfur in fuel content to 0.2%.

CPCN Order No. 68841 (Case 8228), condition 5 limits total combined annual emissions under non-emergency conditions in any consecutive 12-month period for SO_2 are limited to 768 tons per year for CT-3, 4, 5, & 6.

For E-CT3 and E-CT4 Only
CPCN Order No. 68841 (Case 8228), condition 8 limits sulfur emissions from each CT to 2 lbs. per hour for natural gas firing and 249 lbs. per hour for distillate oil firing.

For E-CT5 and E-CT6 Only
CPCN Order No. 68841 (Case 8228), condition 9 limits sulfur emissions from each CT to 2 lbs. per hour for natural gas firing and 292 lbs. per hour for distillate oil firing.

(3). NSPS Subpart GG standard
40 CFR §60.333 which limits sulfur in fuel content to 0.8%.

(4). Acid Rain Provisions
The Permittee shall comply with the requirements of the renewal Phase II Acid Rain Permit issued in conjunction with this Part 70 permit. The Acid Rain Permit is attached to the Part 70 permit as Appendix A.

(5). Cross-State Air Pollution Rule
See Table IV-5: CSAPR for requirements.

E. Control of Nitrogen Oxides Emissions
(1) **PSD Approval**
CPCN Order No. 68841 (Case 8228) condition 3 for CT3 & CT4 and condition 4 for CT5 & CT6 limits NO_x emissions to no more than 25 parts per million dry (ppmvd) at 15% O_2 when firing natural gas.

During emergency conditions (as defined in CPCN condition 6), NO_x emissions from E-CT5 and E-CT6 shall be limited to no more than 42 ppmvd at 15% O_2.

When firing No. 2 fuel oil, NO_x emissions, in ppmd at 15% O_2, will be limited to no more than the following:

Table IV – 3

For E-CT3 and E-CT4 only

38 for $N < 0.015$ and
$38 + 400N$ for $N > 0.015$

For E-CT5 and E-CT6 only

57 for $N < 0.015$
$57 + 400N$ for $N > 0.015$

where N is the nitrogen content of the fuel in percent by weight. Compliance with this condition will be demonstrated using the procedures described in the NSPS, Subpart GG, 40 CFR 60.335.

CPCN Order No. 68841(Case 8228) condition 12 limits the annual average nitrogen content of the fuel oil burned in the combustion turbines not to exceed 0.05% by weight.

CPCN Order No. 68841 (Case 8228) condition 5 which limits total combined annual emissions for NO_x in any consecutive 12-month period to 1071 tons per year for CT-3, 4, 5 & 6.

For E-CT3 and E-CT4 Only
CPCN Order No. 68841 (Case 8228) condition 8 limits NO_x emissions from each CT to 119 pounds per hour for natural gas and 281 pounds per hour for No. 2 oil.

For E-CT5 and E-CT6 Only
CPCN Order No. 68841 (Case 8228) condition 9 limits NO_x emissions from each CT to 121 pounds per hour for natural gas and 421 pounds per hour for No. 2 oil

(2) NSPS Subpart GG Standard
40 CFR §60.332 - Standard for nitrogen oxides.
"No owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere a from any stationary gas turbine, any gases which contain nitrogen oxides in excess of:

$STD = (0.0075 \times (14.4/Y)) + F$

Where:
STD = allowable NO_x emissions (percent by volume at 15 percent oxygen and on a dry basis)

Table IV – 3

Y = manufacturer's rated heat rate at manufacturer's rated load (kilojoules per watt hour) or, actual measured heat rate based on lower heating value of fuel as measured at actual peak load for the facility. The value of Y shall not exceed 14.4 kilojoules per watt hour.
F = NO_x emission allowance for fuel-bound nitrogen as defined in 40 CFR §60.332(a)(3)

Fuel-Bound Nitrogen (percent by weight)	F (NO_x percent by volume)
$N < 0.015$	0
$0.015 < N < 0.1$	$0.04(N)$
$0.1 < N < 0.25$	$0.004 + 0.0067(N - 0.1)$
$N > 0.25$	0.005

(3) NO_x RACT Requirements:
COMAR 26.11.09.08G – Requirements for Fuel-Burning Equipment with a Capacity Factor of 15 percent or less and Combustion Turbines with a Capacity Factor Greater than 15 percent.
(1) A person who owns or operates fuel-burning equipment with a capacity factor (as defined in 40 CFR Part 72.2) of 15 percent or less shall:
(a) Provide certification of the capacity factor of the equipment to the Department in writing;
(b) For fuel-burning equipment that operates more than 500 hours during a calendar year, perform a combustion analysis and optimize combustion at least once annually;
(c) Maintain the results of the combustion analysis and any stack tests at the site for at least 2 years and make these results available to the Department and the EPA upon request;
(d) *Not Applicable*, and
(e) *Not Applicable*.
(2) A person who owns or operates a combustion turbine with a capacity factor greater than 15 percent shall meet an hourly average NO_x emission rate of not more than 42 ppm when burning gas or 65 ppm when burning fuel oil (dry volume at 15 percent oxygen) or meet applicable Prevention of Significant Deterioration limits, whichever is more restrictive."

(4) Acid Rain Provisions
These units are not subject to a NO_x limitation under Acid Rain because they are not coal-fired. However, the Permittee is required to comply with the continuous NO_x monitoring requirement of 40CFR Part 75 and associated record keeping and reporting requirements.

Table IV – 3	
	(5) Cross State Air Pollution Rule **See Table IV-5: CSAPR for requirements.** F. Control of VOC Emissions **Synthetic minor limitation to avoid non-attainment major new source review requirements:** **CPCN Order No. 68841 (Case 8228) condition 5** which limits total combined annual emissions for VOC in any consecutive 12-month period to 27.5 tons per year for CT-3, 4, 5 & 6. **For E-CT3 and E-CT4 Only** **CPCN Order No. 68841 (Case 8228) condition 8** limits VOC emissions to 2.5 pounds per hour for natural gas and 6 pounds per hour for No. 2 oil. **For E-CT5 and E-CT6 Only** **CPCN Order No. 68841 (Case 8228) condition 9** limits VOC emissions to 10 pounds per hour for natural gas and 10 pounds per hour for No. 2 oil. G. Operational Limitations **CPCN Order No. 68841 (Case No. 8228) condition 1** states that "The combustion turbines shall use natural gas only to generate electricity. This requirement shall not apply during those times when the delivered cost per million Btu of natural gas exceeds the delivered cost per million Btu of No. 2 fuel oil by 15 percent or during those times when the natural gas supply to the unit is curtailed or interrupted under the delivery contract. At such times, the unit shall use No. 2 fuel oil only. Natural gas service curtailments or interruptions shall be verified by a letter to PEPCO each year from the unit's natural gas supplier identifying the dates on which the gas service was curtailed or interrupted." (Note: The reference to "PEPCO" is now "The Permittee") **CPCN Order No. 68841 (Case No. 8228) condition 5** states that "the four combustion turbines shall not operate more than 6000 hours in the aggregate in any calendar year during normal conditions and no more than an additional 2000 hours in the aggregate in any calendar year, inclusive of emergency conditions. At no time shall any one combustion turbine operate more than 2500 hours in any calendar year, inclusive of emergency conditions. Emergency conditions shall be defined at any operations during reserve shortages as described in Section 3 of the PJM Interconnection and Operation Instructions, OI 8.13, Alert and Emergency Procedures, dated May 1989. Any change affecting the definition of

Table IV – 3	
	emergency conditions for the purposes of this permit must have approval of the Maryland Air and Radiation Administration" (Note: The PJM reference has been revised to Manual M-13, Emergency Operations, Section 2, Dated May 1, 2003.) See Note in Record Keeping Requirement dated February 2, 2006, from MDE on oil operations.
3.2	**Testing Requirements:** A. Control of Visible Emissions See Monitoring Requirement B. Control of Particulate Matte Emissions See Monitoring Requirement C. Control of Carbon Monoxide Emissions See Monitoring Requirement D. Control of Sulfur Oxides Emissions 1 PSD Approval See Monitoring Requirement. 2. NSPS Subpart GG Standard See Monitoring Requirement. 3 Acid Rain Provisions See quality assurance requirements for the continuous monitoring for sulfur dioxide for 40 CFR Part 75- Acid Rain Program. **[Reference: Acid Rain Permit, 40 CFR part 75, Appendix D]** E. Control of Nitrogen Oxides Emissions (1) PSD Approval The Permittee is required to perform NO_x testing on the four turbines to satisfy the requirements of the Acid Rain Program. The Permittee currently performs testing in accordance with Appendix E of 40 CFR Part 75 once every 5 years. The results of this testing will be used to support the demonstration of compliance with NO_x standards and limits of the PSD Approval and NSPS Subpart GG. See quality assurance requirements for the continuous monitoring for NO_x for 40 CFR Part 75- Acid Rain Program. **[Reference: Acid Rain Permit, 40 CFR 75 Appendix E]**

Table IV – 3	
	(2) NSPS Subpart GG Standard See Monitoring Requirement. (3) NOx RACT Requirements The Permittee shall perform a combustion analysis and optimize combustion at least once annually on each turbine that operates more than 500 hours during a calendar year. **[Reference: COMAR 26.11.09.08G(1)(b)]** (4) Acid Rain Provisions See Monitoring Requirements F. Control of VOC Emissions See Monitoring requirements G. Operational Limitations See Record keeping requirements
3.3	**Monitoring Requirements:** A. Control of Visible Emissions The Permittee shall verify that there are no visible emissions when burning No. 2 fuel oil. An observer shall perform an EPA Reference Method 9 observation of stack emissions for an 18-minute period at least once for every 168 hours of operation on oil or at a minimum once per calendar year. If the turbine operates for less than 100 hours in a calendar year, the visual observation requirement for that calendar year is waived. The Permittee shall perform the following if emissions are visible to human observer: (a) inspect combustion control system and combustion turbine operations, (b) perform all necessary adjustments and/or repairs to the combustion turbine within 48 hours of operation so that visible emissions are eliminated; and (c) document in writing the results of inspections, adjustments and/or repairs to the combustion turbine. After 48 hours of operation if the required adjustments and/or repairs had not eliminated the visible emissions, the Permittee shall perform another Method 9 observation once daily when the combustion turbine is operating on No.2 fuel oil for 18 minutes until corrective actions have eliminated visible emissions. **[Reference: COMAR 26.11.03.06C]**.

Table IV – 3

B. Control of Particulate Matter Emissions
The Permittee shall perform preventative maintenance to maintain the combustion turbines in a manner such that they continue to operate as designed. **[Reference: COMAR 26.11.03.06C]**

C. Control of Carbon Monoxide Emissions
The Permittee shall perform preventative maintenance to maintain the combustion turbines in a manner such that they continue to operate as designed. **[Reference: COMAR 26.11.03.06C]**

D. Control of Sulfur Oxides Emissions
(1) PSD Approval
The Permittee shall comply with the monitoring requirements of New Source Performance Standards (NSPS), Subpart GG, 40, CFR 60.334. **[Reference: CPCN Order No. 68841 (Case 8228) condition 2]**

(2) NSPS Subpart GG Standard:
40 CFR 60.334:
(h)(1)" The owner or operator of any stationary gas turbine subject to the provisions of this subpart shall monitor the total sulfur content of the fuel being fired in the turbine, except as provided in paragraph (h)(3) of this section. The sulfur content of the fuel must be determined using total sulfur methods described in §60.335(b)(10). Alternatively, if the total sulfur content of the gaseous fuel during the most recent performance test was less than 0.4 weight percent (4000 ppmw), ASTM D4084-82, 94, D5504-01, D5504-01, D6228-98, or Gas Processors Association Standard 2377-86 (all of which are incorporated by reference- see §60.17), which measure the major sulfur compounds may be used".

(h)(3) "Notwithstanding the provisions of paragraph (h) (1) of this section, the owner or operator may elect not to monitor the sulfur content of the gaseous fuel combusted in the turbine, if the gaseous fuel is demonstrated to meet the definition of natural gas in §60.331(u), regardless of whether an existing custom schedule approved by the administrator for subpart GG requires such monitoring. The owner or operator shall use one of the following sources of information to make the required demonstration:
(i) The gas quality characteristics in a current, valid purchase contract, tariff sheet or transportation contract for the gaseous fuel, specifying that the maximum total sulfur content of the fuel is 20.0 grains/100 scf or less; or

Table IV – 3

(ii) Representative fuel sampling data which show that the sulfur content of gaseous fuel does not exceed 20 grains/100 scf. At a minimum, the amount of fuel sampling data specified in section 2.3.1.4 or 2.3.2.4 of Appendix D to part 75 of this chapter is required."

(h)(4)" For any turbine that commenced construction, reconstruction or modification after October 3, 1977, but before July 8, 2004, and for which a custom fuel monitoring schedule has previously been approved, the owner or operator may, without submitting a special petition to the Administrator, continue monitoring on this schedule".

(i) "The frequency of determining the sulfur and nitrogen content of the fuel shall be as follows:

(1) Fuel oil. For fuel oil, use one of the total sulfur sampling options and the associated sampling frequency described in sections 2.2.3, 2.2.4.1, 2.2.4.2, and 2.2.4.3 of appendix D to part 75 of this chapter (i.e., flow proportional sampling, daily sampling, sampling from the unit's storage tank after each addition of fuel to the tank, or sampling each delivery prior to combining it with fuel oil already in the intended storage tank). If an emission allowance is being claimed for fuel-bound nitrogen, the nitrogen content of the oil shall be determined and recorded once per unit operating day."

(3) Acid Rain Provision

See the requirements for the continuous monitoring for sulfur dioxide for 40 CFR Part 75- Acid Rain Program. **[Reference: Acid Rain Permit, 40 CFR 75 subpart B]**

E. Control of Nitrogen Oxides Emissions

(1) PSD Approval

Same as NSPS Subpart GG requirements

(2) NSPS Subpart GG Standard

40CFR60.334:

(a) "Except as provided in paragraph (b) of this subpart, the owner or operator of any stationary gas turbine subject to the provisions of this subpart and using water or steam injection to control NO_x emissions shall install, calibrate, maintain and operate a continuous monitoring system to monitor and record the fuel consumption and the ratio of water or steam to fuel being fired in the turbine."

(3) NO_x RACT Requirements

See Record Keeping Requirements

Table IV – 3	
	(4) Acid Rain Provision See the requirements for the continuous monitoring for NOx for 40 CFR Part 75- Acid Rain Program. **[Reference: Acid Rain Permit, 40 CFR 75 subpart B and Appendix E]** F. Control of VOC Emissions The Permittee shall perform preventative maintenance to maintain the combustion turbines in a manner such that they continue to operate as designed. **[Reference: COMAR 26.11.03.06C]** G. Operational Limitations See record keeping requirements.
3.4	**Record Keeping Requirements:** **Note:** All records must be maintained for a period of at least 5 years. **[Reference: COMAR 26.11.03.06C(5)(g)]** A. Control of Visible Emissions The Permittee shall maintain records of the results of visual emissions observations for a period of at least 5 years. **[Reference: COMAR 26.11.03.06C]** B. Control of Particulate Matter Emissions The Permittee shall maintain for at least five years records of the preventive maintenance that relates to combustion performance. **[Reference: COMAR 26.11.03.06C]**. C. Control of Carbon Monoxide Emissions The Permittee shall maintain for at least five years records of the preventive maintenance that relates to combustion performance. **[Reference: COMAR 26.11.03.06C]**. D. Control of Sulfur Oxides Emissions (1) PSD Approval The Permittee shall comply with the record keeping monitoring requirements of New Source Performance Standards (NSPS), Subpart A, 40 CFR 60.7(f). **[Reference: CPCN Order No. 68841 (Case 8228) condition 2]** The Permittee shall obtain fuel supplier certifications stating that the fuel oil is in compliance with the sulfur content in the fuel limitation. The Permittee shall retain the fuel supplier certifications for at least five years. **[Reference: COMAR 26.11.03.06C].**

Table IV – 3
(2) NSPS Subpart GG Standard **40CFR60.7(f):** "(f) Any owner or operator subject to the provisions of this part shall maintain a file of all measurements, including continuous monitoring system, monitoring device, and performance testing measurements; all continuous monitoring system performance evaluations; all continuous monitoring system or monitoring device calibration checks; adjustments and maintenance performed on these systems or devices; and all other information required by this part recorded in a permanent form suitable for inspection." (3) Acid Rain Provision See the recordkeeping requirements for 40 CFR Part 75- Acid Rain Program. **[Reference: Acid Rain Permit, 40 CFR 75 subpart F]** E. Control of Nitrogen Oxides Emissions (1) PSD Approval Same as for NSPS Subpart GG requirements (2) NSPS Subpart GG Standard **40CFR60.7(f):** "(f)Any owner or operator subject to the provisions of this part shall maintain a file of all measurements, including continuous monitoring system, monitoring device, and performance testing measurements; all continuous monitoring system performance evaluations; all continuous monitoring system or monitoring device calibration checks; adjustments and maintenance performed on these systems or devices; and all other information required by this part recorded in a permanent form suitable for inspection." (3) NO_x RACT Requirements The Permittee shall maintain the results of the combustion analysis and any stack tests at the site for at least 5 years and make these results available to the Department and the EPA upon request. **[Reference: COMAR 26.11.09.08G(1)(c) & COMAR 26.11.03.06C]** (4) Acid Rain Provision See the recordkeeping requirements for 40 CFR Part 75- Acid Rain Program. **[Reference: Acid Rain Permit, 40 CFR 75 subpart F]**

Table IV – 3	
	F. Control of VOC Emissions The Permittee shall maintain for at least five years records of the preventive maintenance that relates to combustion performance. **[Reference: COMAR 26.11.03.06C]**. G. Operational Limitations The Permittee shall maintain records to support the basis for burning fuel oil, either those times when the delivered cost per million Btu of natural gas exceeds the delivered cost per million Btu of No. 2 oil by 15 percent or during those times when the natural gas supply to the unit is curtailed or interrupted under the delivery contract. **[Reference: COMAR 26.11.03.06C]** The Permittee shall maintain a record of the hours of operation identified as operations under non-emergency conditions or emergency conditions. **[Reference: COMAR 26.11.03.06C]** Note: The Department, in a February 2, 2006, letter to GenOn, concurred with GenOn's proposal to clarify natural gas curtailments as follows: Gas pipeline is out of service for maintenance or repair. Documentation of these events will be obtained through postings on the gas supplier's web site; Gas supply is interrupted under the delivery contract. Documentation of these events will be obtained through postings on the gas supplier's web site; One or more of the CT Units is called for by PJM to start or extend operation during periods of time when the pipeline operator is not open for business, typically between 6:00 PM and 10:00 AM daily. GenOn will document PJM dispatch notices during these occasions and will purchase gas upon opening of the commercial gas trading market- typically, 10:00 AM, provided the price of delivered gas is not 15% or more of the price of delivered oil. The 15% cost differential between natural gas and #2 fuel oil will be determined on the following basis: Daily publications from the Platts service will be utilized as representative industry benchmarks of natural gas and #2 oil pricing. GenOn will document delivered gas-to-oil cost differential using these benchmarks. The delivered cost of #2 oil for GenOn facilities is calculated by taking the Platts *Oilgram* New York Harbor Barge price and adding $0.0564/gallon in delivery charges. The delivered cost of natural gas for GenOn facilities is calculated by taking the Platts *Gas Daily* Transco Zone 6 Non-New York

Table IV – 3	
	price and adding $0.10/MMBtu for delivery and $0.22/MMBtu in Park and Loan fees. The delivered prices for #2 oil and natural gas are calculated on a daily basis to determine if the 15% cost differential is met for the current day unit dispatch. CTs are allowed to run on oil for test purposes after repairs or maintenance of the fuel oil system and its appurtenances for operability assurance.
3.5	**Reporting Requirements:** A. Control of Visible Emissions The Permittee shall report incidents of visible emissions in accordance with Permit Condition 4, Section III, "Report of Excess Emissions and Deviations." **[Reference: COMAR 26.11.03.06C].** B. Control of Particulate Matter Emissions The Permittee shall submit records of maintenance to the Department upon request. **[Reference: COMAR 26.11.03.06C]** C. Control of Carbon Monoxide Emissions The Permittee shall submit records of maintenance to the Department upon request. **[Reference: COMAR 26.11.03.06C]** D. Control of Sulfur Oxides Emissions (1) PSD Approval The Permittee shall submit quarterly reports to the Department that contain monthly summaries of the hours of operation burning oil, hours of operation burning natural gas, total hours of operation, average and maximum sulfur contents of the fuel oil, average and maximum nitrogen contents of the fuel oil, average sulfur content of the natural gas, total calculated SO_x (expressed as SO_2) emissions and total calculated NO_x emissions. Data used for developing the above summaries shall be maintained on file at the plant for at least 2 years and shall be readily available for inspection by the Department. **[Reference: CPCN Order No. 68841 (Case 8228) condition 15]** **Note:** The Part 70 general record keeping requirements requires records to be maintained for 5 years. (2) NSPS Subpart GG Standard **40CFR 60.334(j)-** For the purpose of reports required under §60.7(c), periods of excess emissions that shall be reported are defined as follows:

Table IV – 3	
	(1) (Nitrogen oxides requirement) **(2)** Sulfur dioxide. (i) "For samples of gaseous fuel and for oil samples obtained using daily sampling, flow proportional sampling, or sampling from the unit's storage tank, an excess emission occurs each unit operating hour included in the period beginning on the date and hour of any sample for which the sulfur content of the fuel being fired in the gas turbine exceeds 0.8 weight percent and ending on the date and hour that a subsequent sample is taken that demonstrates compliance with the sulfur limit." (iii) "A period of monitor downtime begins when a required sample is not taken by its due date. A period of monitor downtime also begins on the date and hour of a required sample, if invalid results are obtained. The period of monitor downtime shall include only unit operating hours and ends on the date and hour of the next valid sample." **§60.7(c) -** "Each owner or operator required to install a continuous monitoring device shall submit excess emissions and monitoring systems performance report (excess emissions are defined in applicable subparts) and-or summary report form (see paragraph (d) of this section) to the Administrator semiannually, except when: more frequent reporting is specifically required by an applicable subpart; or the Administrator, on a case-by-case basis, determines that more frequent reporting is necessary to accurately assess the compliance status of the source. All reports shall be postmarked by the 30th day following the end of each six-month period. Written reports of excess emissions shall include the following information: (1) The magnitude of excess emissions computed in accordance with §60.13(h), any conversion factor(s) used, and the date and time of commencement and completion of each time period of excess emissions. The process operating time during the reporting period. (2) Specific identification of each period of excess emissions that occurs during startups, shutdowns, and malfunctions of the affected facility. The nature and cause of any malfunction (if known), the corrective action taken, or preventative measures adopted. (3) The date and time identifying each period during which the continuous monitoring system was inoperative except for zero and span checks and the nature of the system repairs or adjustments. (4) When no excess emissions have occurred or the continuous monitoring system(s) have not been inoperative, repaired, or adjusted, such information shall be stated in the report."

Table IV – 3

(3) Acid Rain Provision
See the reporting requirements for 40 CFR Part 75- Acid Rain Program.
[Reference: Acid Rain Permit, 40 CFR 75 subpart G]

E. Control of Nitrogen Oxides Emissions
(1) PSD Approval
CPCN Order No. 68841 (Case 8228) condition 7: The Permittee shall submit quarterly to the Department any one-hour period during which the average water-to-fuel ratio fell below the water-to-fuel ratio used to demonstrate compliance with the NOx emission concentration limits given in CPCN conditions 3 and 4.

The Permittee shall submit the calculation of the annual average nitrogen content of the oil burned in the combustion turbines by January 31st of the following calendar year. **[Reference: COMAR 26.11.03.06C]**

(2) NSPS Subpart GG Standard
40CFR60.334:
"(j) For each affected unit required to continuously monitor parameters or emissions, or to periodically determine the fuel sulfur content or fuel nitrogen content under this subpart, the owner or operator shall submit reports of excess emissions and monitor downtime, in accordance with §60.7(c). Excess emissions shall be reported for all periods of unit operation, including startup, shutdown, and malfunction. For the purpose of reports required under §60.7(c), periods of excess emissions and monitor downtime that shall be reported are defined as follows:"
(1) "Nitrogen oxides".
"(i) For turbines using water or steam to fuel ratio monitoring:"
(A) "An excess emissions shall be any unit operating hour for which the average steam or water to fuel ratio, as measured by the continuous monitoring system, falls below the acceptable steam or water to fuel ratio needed to demonstrate compliance with §60.332, as established during the performance test required in §60.8. Any unit operating hour in which no water or steam is injected into the turbine shall also be considered an excess emission."
(B) "A period of monitor downtime shall be any unit operating hour in which water or steam is injected into the turbine, but the essential parametric data needed to determine the steam or water to fuel ratio are unavailable or invalid."
(C) "Each report shall include the average steam or water to fuel ratio, average fuel consumption, ambient conditions (temperature,

Table IV – 3

pressure, and humidity), gas turbine load, and (if applicable) the nitrogen content of the fuel during each excess emission. You do not have to report ambient conditions if you opt to use the worst-case ISO correction factor as specified in §60.334(b)(3)(ii), or if you are not using the ISO correction equation under the provisions of §60.335(b)(1)."

§60.7(c) - "Each owner or operator required to install a continuous monitoring device shall submit excess emissions and monitoring systems performance report (excess emissions are defined in applicable subparts) and-or summary report form (see paragraph (d) of this section) to the Administrator semiannually, except when: more frequent reporting is specifically required by an applicable subpart; or the Administrator, on a case-by-case basis, determines that more frequent reporting is necessary to accurately assess the compliance status of the source. All reports shall be postmarked by the 30th day following the end of each six-month period. Written reports of excess emissions shall include the following information:

(1) The magnitude of excess emissions computed in accordance with §60.13(h), any conversion factor(s) used, and the date and time of commencement and completion of each time period of excess emissions. The process operating time during the reporting period.

(2) Specific identification of each period of excess emissions that occurs during startups, shutdowns, and malfunctions of the affected facility. The nature and cause of any malfunction (if known), the corrective action taken, or preventative measures adopted.

(3) The date and time identifying each period during which the continuous monitoring system was inoperative except for zero and span checks and the nature of the system repairs or adjustments.

(4) When no excess emissions have occurred or the continuous monitoring system(s) have not been inoperative, repaired, or adjusted, such information shall be stated in the report."

(3) NO_x RACT Requirements
The Permittee shall provide certification of the capacity factor of the equipment to the Department in writing by April 1st of the following calendar year. **[Reference: COMAR 26.11.09.08G(1)(a) & COMAR 26.11.03.06C]**

(4) Acid Rain Provision
See the reporting requirements for 40 CFR Part 75- Acid Rain Program. **[Reference: Acid Rain Permit, 40 CFR 75 subpart G]**

Table IV – 3	
	F. Control of VOC Emissions The Permittee shall submit records of maintenance to the Department upon request. **[Reference: COMAR 26.11.03.06C]** G. Operational Limitations- See Record Keeping Requirements

"A permit shield shall cover the applicable requirements identified for the emissions unit(s) listed in the table above."

Table IV – 4	
4.0	**Emissions Unit Number(s): SMECO-CT1: Combustion Turbine** **SMECO-CT1** – One (1) General Electric, GE-7EA combustion turbine rated at 93 megawatts. This turbine is fired with natural gas as a primary fuel and No. 2 fuel oil as a secondary.
4.1	**Applicable Standards/Limits:** A. Control of Visible Emissions **COMAR 26.11.09.05A(2)** – Fuel Burning Equipment "Areas III and IV. In Areas III and IV, a person may not cause or permit the discharge of emissions from any fuel burning equipment, other than water in an uncombined form, which is visible to human observers except that, for the purpose of demonstrating compliance using COM data, emissions that are visible to a human observer are those that are equal to or greater than 10 percent opacity." **COMAR 26.11.09.05A(3) -** Exceptions. "Section A(1) and (2) of this regulation do not apply to emissions during load changing, soot blowing, startup, or adjustments or occasional cleaning of control equipment if: (a) The visible emissions are not greater than 40 percent opacity; and (b) The visible emissions do not occur for more than 6 consecutive minutes in any sixty-minute period." B. Control of Particulate Matter Emissions **CPCN Order No. 68587 (Case 8102) condition 17** limits particulate emissions to 5 pounds per hour when burning natural gas and 10 pounds per hour when burning No. 2 oil.

Table IV – 4

C. Control of Carbon Monoxide Emissions

CPCN Order No. 68587 (Case 8102) condition 17 limits CO emissions to 24 pounds per hour when burning natural gas and 25 pounds per hour when burning No. 2 oil.

D. Control of Sulfur Oxides Emissions

(1) SIP Limitation

COMAR 26.11.09.07A(2) – Control of Sulfur Oxides from fuel burning equipment. "A person may not burn, sell, or make available for sale any fuel with a sulfur content by weight in excess of or which otherwise exceeds the following limitations: In Areas III and IV:

(a) All solid fuels, 1.0 percent;

(b) Distillate fuel oil, 0.3 percent;

(c) Residual fuel oil, 1.0 percent."

(2) PSD Approval - CPCN

CPCN Order No. 68587 (Case 8102) condition 16 limits sulfur in fuel content to 0.3%.

CPCN Order No 68587 (Case No. 8102) condition 17 which limits sulfur oxides (as SO_2) to 20 pounds per hour when burning natural gas and 380 pounds per hour when burning No. 2 oil.

3. NSPS Subpart GG Standard

40 CFR §60.333 which limits sulfur in fuel content to 0.8%.

E. Control of Nitrogen Oxides

(1) PSD Approval - CPCN

CPCN Order No. 68587 (Case 8102) condition 17 limits nitrogen oxides (as NO_2) to 199 pounds per hour when burning natural gas and 400 pounds per hour when burning No. 2 oil.

CPCN Order No. 68587 (Case 8102) condition 13 limits NOx emissions to no more than 42 parts per million dry (ppmvd) at 15% O_2 when firing natural gas. When firing No. 2 fuel oil, NOx emissions, in ppmvd (at 15% O_2), will be limited to no more than

65 for $N \leq 0.015$ and

$58 + 460N$ for $N > 0.015$

where N is the nitrogen content of the fuel (percent by weight).

CPCN Order No. 68587 (Case 8102) condition 14 limits the annual average nitrogen content of the fuel oil not to exceed 0.05%, by weight.

Table IV – 4

2. NSPS Subpart GG Standard

40 CFR §60.332 - Standard for nitrogen oxides.

"No owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere a from any stationary gas turbine, any gases which contain nitrogen oxides in excess of:

$STD = (0.0075 \times (14.4/Y)) + F$

Where:

STD = allowable NO_x emissions (percent by volume at 15 percent oxygen and on a dry basis)

Y = manufacturer's rated heat rate at manufacturer's rated load (kilojoules per watt hour) or, actual measured heat rate based on lower heating value of fuel as measured at actual peak load for the facility. The value of Y shall not exceed 14.4 kilojoules per watt hour.

F = NO_x emission allowance for fuel-bound nitrogen as defined in 40 CFR §60.332(a)(3):

Fuel-Bound Nitrogen (percent by weight)	F (NO_x percent by volume)
$N < 0.015$	0
$0.015 < N < 0.1$	$0.04(N)$
$0.1 < N < 0.25$	$0.004 + 0.0067(N - 0.1)$
$N > 0.25$	0.005

3. NO_x RACT Requirement

COMAR 26.11.09.08G – Requirements for Fuel-Burning Equipment with a Capacity Factor of 15 percent or less and Combustion Turbines with a Capacity Factor Greater than 15 percent. "A person who owns or operates fuel-burning equipment with a capacity factor (as defined in 40 CFR Part 72.2) of 15 percent or less shall:

(a) Provide certification of the capacity factor of the equipment to the Department in writing;

(b) For fuel-burning equipment that operates more than 500 hours during a calendar year, perform a combustion analysis and optimize combustion at least once annually;

(c) Maintain the results of the combustion analysis and any stack tests at the site for at least 2 years and make these results available to the Department and the EPA upon request;

(d) *Not Applicable*; and

(e) *Not Applicable.*

4. Cross State Air Pollution Rule

See Table IV-5: CSAPR for requirements.

Table IV – 4	
	F. Control of VOC Emissions **CPCN Order No. 68587 (Case 8102) condition 17** limits VOC (hydrocarbons) emissions to 11 pounds per hour when burning natural gas and 11 pounds per hour when burning No. 2 oil. G. Operational Limitations **CPCN Order No. 68587 (Case 8102) condition 9** limits the total annual hours of operation to no more than 1000 hours, and **CPCN Order No. 68587 (Case 8102) condition 11** states that the unit shall generate electricity using natural gas only. This requirement shall not apply during times when the delivered cost of natural gas per MMBtu exceeds the delivered cost per MMBtu of No. 2 oil by 15 percent or during those hours when the natural gas supply to the unit is curtailed or interrupted under the delivery contract. At such times, the unit shall use No. 2 oil only. Natural gas service curtailments or interruptions shall be verified by a letter each year from the unit's natural gas supplier identifying the dates on which gas service was restricted. This condition can be reconsidered in the future if relief is requested by SMECO. See Note in Record Keeping Requirement.
4.2	**Testing Requirements:** A. Control of Visible Emissions See Monitoring Requirements B. Control of Particulate Matter Emissions See Monitoring Requirements C. Control of Carbon Monoxide Emissions See Monitoring Requirements D. Control of Sulfur Oxides Emissions See Monitoring Requirements E. Control of Nitrogen Oxides Emissions 1. PSD Approval See Monitoring Requirements 2. NSPS Subpart GG Standard See Monitoring Requirements

Table IV – 4	
	3. NOx RACT Requirement The Permittee shall perform a combustion analysis and optimize combustion at least once annually in any calendar year that the turbine operates more than 500 hours. **[Reference: COMAR 26.11.09.08G(1)(b)]** F. Control of VOC Emissions See Monitoring Requirements G. Operational Limitations See Record Keeping and Reporting Requirements
4.3	**Monitoring Requirements:** A. Control of Visible Emissions The Permittee shall verify that there are no visible emissions when burning No. 2 fuel oil. An observer shall perform an EPA Reference Method 9 observation of stack emissions for 18-minute period once every 168 hours of operation on oil or at a minimum once per calendar year. If the turbine operates for less than 100 hours in a calendar year, this visible observation requirement is waived for that calendar year. The Permittee shall perform the following if emissions are visible to human observer: (a) inspect combustion control system and combustion turbine operations, (b) perform all necessary adjustments and/or repairs to the combustion turbine within 48 hours of operation so that visible emissions are eliminated; and (c) document in writing the results of inspections, adjustments and/or repairs to the combustion turbine. The Permittee shall after 48 hours of operation, if the required adjustments and/or repairs had not eliminated the visible emissions, perform another Method 9 observation once daily when combustion turbine operating on No.2 fuel oil for 18 minutes until corrective action have eliminated visible emissions. **[Reference: COMAR 26.11.03.06C]**. B. Control of Particulate Matter Emissions The Permittee shall perform preventative maintenance to maintain the combustion turbine in a manner such that they continue to operate as designed. **[Reference: COMAR 26.11.03.06C]**

Table IV – 4	
	C. Control of Carbon Monoxide Emissions The Permittee shall perform preventative maintenance to maintain the combustion turbine in a manner such that they continue to operate as designed. **[Reference: COMAR 26.11.03.06C]** D. Control of Sulfur Oxides Emissions 1. SIP Requirement The Permittee shall obtain fuel supplier certifications stating that the fuel oil is in compliance with the sulfur content in the fuel limitation. **[Reference: COMAR 26.11.03.06C]** 2. PSD Approval - CPCN Requirement Same as for NSPS subpart GG 3. NSPS Subpart GG Standard **40CFR60.334**: **(h)(1)** "The owner or operator of any stationary gas turbine subject to the provisions of this subpart shall monitor the total sulfur content of the fuel being fired in the turbine, except as provided in paragraph (h)(3) of this section. The sulfur content of the fuel must be determined using total sulfur methods described in §60.335(b)(10). Alternatively, if the total sulfur content of the gaseous fuel during the most recent performance test was less than 0.4 weight percent (4000 ppmw), ASTM D4084-82, 94, D5504-01, D5504-01, D6228-98, or Gas Processors Association Standard 2377-86 (all of which are incorporated by reference- see §60.17), which measure the major sulfur compounds may be used". **(h)(3)** "Notwithstanding the provisions of paragraph (h) (1) of this section, the owner or operator may elect not to monitor the sulfur content of the gaseous fuel combusted in the turbine, if the gaseous fuel is demonstrated to meet the definition of natural gas in §60.331(u), regardless of whether an existing custom schedule approved by the administrator for subpart GG requires such monitoring. The owner or operator shall use one of the following sources of information to make the required demonstration: (i) The gas quality characteristics in a current, valid purchase contract, tariff sheet or transportation contract for the gaseous fuel, specifying that the maximum total sulfur content of the fuel is 20.0 grains/100 scf or less; or (ii) Representative fuel sampling data which show that the sulfur content of gaseous fuel does not exceed 20 grains/100 scf. At a minimum, the

Table IV – 4

amount of fuel sampling data specified in section 2.3.1.4 or 2.3.2.4 of Appendix D to part 75 of this chapter is required".

(h)(4) "For any turbine that commenced construction, reconstruction or modification after October 3, 1977, but before July 8, 2004, and for which a custom fuel monitoring schedule has previously been approved, the owner or operator may, without submitting a special petition to the Administrator, continue monitoring on this schedule."

(i) "The frequency of determining the sulfur and nitrogen content of the fuel shall be as follows:"
(1) "Fuel oil. For fuel oil, use one of the total sulfur sampling options and the associated sampling frequency described in sections 2.2.3, 2.2.4.1, 2.2.4.2, and 2.2.4.3 of appendix D to part 75 of this chapter (i.e., flow proportional sampling, daily sampling, sampling from the unit's storage tank after each addition of fuel to the tank, or sampling each delivery prior to combining it with fuel oil already in the intended storage tank). If an emission allowance is being claimed for fuel-bound nitrogen, the nitrogen content of the oil shall be determined and recorded once per unit operating day."

E. Control of Nitrogen Oxides Emissions
1. PSD Approval
Same as for NSPS requirement

2. NSPS Subpart GG Standard
40CFR60.334:
(a) "Except as provided in paragraph (b) of this subpart, the owner or operator of any stationary gas turbine subject to the provisions of this subpart and using water or steam injection to control NOx emissions shall install, calibrate, maintain and operate a continuous monitoring system to monitor and record the fuel consumption and the ratio of water or steam to fuel being fired in the turbine."

3. NO_x RACT Requirement
See Record Keeping Requirements

F. Control of VOC Emissions
The Permittee shall perform preventative maintenance to maintain the combustion turbine in a manner such that they continue to operate as designed. **[Reference: COMAR 26.11.03.06C]**

Table IV – 4	
	G. Operational Limitations See Record Keeping and Reporting Requirements
4.4	**Record Keeping Requirements:** **Note:** All records must be maintained for a period of at least 5 years. **[Reference: COMAR 26.11.03.06C(5)(g)]** A. Control of Visible Emissions The Permittee shall maintain records of the results of visual emissions observations for a period of at least 5 years. [**Reference: COMAR 26.11.03.06C]** B. Control of Particulate Matter Emissions The Permittee shall maintain for at least five years records of the preventive maintenance that relates to combustion performance. **[Reference: COMAR 26.11.03.06C]**. C. Control of Carbon Monoxide Emissions The Permittee shall maintain for at least five years records of the preventive maintenance that relates to combustion performance. **[Reference: COMAR 26.11.03.06C]**. D. Control of Sulfur Oxides Emissions 1 SIP Requirement The Permittee shall retain fuel supplier certifications stating that the fuel oil is in compliance with the sulfur content in the fuel limitation for at least 5 years. [**Reference: COMAR 26.11.03.06C].** 2. PSD Approval - CPCN Limitation Same as for NSPS Subpart GG. 3. NSPS Subpart GG Standard **40CFR60.7(f):** **"(f)**Any owner or operator subject to the provisions of this part shall maintain a file of all measurements, including continuous monitoring system, monitoring device, and performance testing measurements; all continuous monitoring system performance evaluations; all continuous monitoring system or monitoring device calibration checks; adjustments and maintenance performed on these systems or devices; and all other information required by this part recorded in a permanent form suitable for inspection."

Table IV – 4	
	E. Control of Nitrogen Oxides Emissions 1. PSD Approval Same as for NSPS requirement 2. NSPS Subpart GG Standard **40CFR60.7(f):** "(f)Any owner or operator subject to the provisions of this part shall maintain a file of all measurements, including continuous monitoring system, monitoring device, and performance testing measurements; all continuous monitoring system performance evaluations; all continuous monitoring system or monitoring device calibration checks; adjustments and maintenance performed on these systems or devices; and all other information required by this part recorded in a permanent form suitable for inspection." 3. NO_x RACT Requirement The Permittee shall maintain the results of the combustion analysis and any stack tests at the site for at least 5 years and make these results available to the Department and the EPA upon request. **[Reference: COMAR 26.11.09.08G(1)(c) & COMAR 26.11.03.06C]** F. Control of VOC Emissions The Permittee shall maintain for at least five years records of the preventive maintenance that relates to combustion performance. **[Reference: COMAR 26.11.03.06C]**. G. Operational Limitations The Permittee shall maintain a record of the hours of operation for each day. **[Reference: COMAR 26.11.03.06C]** Note: The Department, in a February 2, 2006, letter to GenOn, concurred with GenOn's proposal to clarify natural gas curtailments as follows: Gas pipeline is out of service for maintenance or repair. Documentation of these events will be obtained through postings on the gas supplier's web site; Gas supply is interrupted under the delivery contract. Documentation of these events will be obtained through postings on the gas supplier's web site; One or more of the CT Units is called for by PJM to start or extend operation during periods of time when the pipeline operator is not open for business, typically between 6:00 PM and 10:00 AM daily. GenOn will document PJM dispatch notices during these occasions and will purchase

Table IV – 4	
	gas upon opening of the commercial gas trading market- typically, 10:00 AM, provided the price of delivered gas is not 15% or more of the price of delivered oil. The 15% cost differential between natural gas and #2 fuel oil will be determined on the following basis: Daily publications from the Platts service will be utilized as representative industry benchmarks of natural gas and #2 oil pricing. GenOn will document delivered gas-to-oil cost differential using these benchmarks. The delivered cost of #2 oil for GenOn facilities is calculated by taking the Platts *Oilgram* New York Harbor Barge price and adding $0.0564/gallon in delivery charges. The delivered cost of natural gas for GenOn facilities is calculated by taking the Platts *Gas Daily* Transco Zone 6 Non-New York price and adding $0.10/MMBtu for delivery and $0.22/MMBtu in Park and Loan fees. The delivered prices for #2 oil and natural gas are calculated on a daily basis to determine if the 15% cost differential is met for the current day unit dispatch. CTs are allowed to run on oil for test purposes after repairs or maintenance of the fuel oil system and its appurtenances for operability assurance.
4.5	**Reporting Requirements:** A. Control of Visible Emissions The Permittee shall report incidents of visible emissions in accordance with Permit Condition 4, Section III, "Report of Excess Emissions and Deviations." **[Reference: COMAR 26.11.03.06C].** B. Control of Particulate Matter Emissions The Permittee shall submit records of maintenance to the Department upon request. **[Reference: COMAR 26.11.03.06C** C. Control of Carbon Monoxide Emissions The Permittee shall submit records of maintenance to the Department upon request. **[Reference: COMAR 26.11.03.06C** D. Control of Sulfur Oxides Emissions (1) SIP Requirement The Permittee shall submit fuel certification report if requested by MDE. **[Reference: COMAR 26.11.03.06C]**

Table IV – 4

2. PSD Approval -CPCN
CPCN Order No. 68587 (Case 8102) condition 18 The Permittee shall submit quarterly reports to the Department that contain monthly summaries of the hours of operation burning oil, hours of operation burning natural gas, total hours of operation, **average and maximum sulfur contents of the fuel oil**, average and maximum nitrogen contents of the fuel oil, **average sulfur content of the natural gas, total calculated SO_x (expressed as SO_2) emissions** and total calculated NO_x (expressed as NO_2) emissions. Data used for developing the above summaries shall be maintained on file at the plant for at least 2 years and shall be readily available for inspection by the Department personnel.

3. NSPS Subpart GG Standard
40CFR 60.334(j) – "For the purpose of reports required under §60.7(c), periods of excess emissions that shall be reported are defined as follows:"
(1) (Nitrogen oxides requirement)
(2) Sulfur dioxide.
(i) For samples of gaseous fuel and for oil samples obtained using daily sampling, flow proportional sampling, or sampling from the unit's storage tank, an excess emission occurs each unit operating hour included in the period beginning on the date and hour of any sample for which the sulfur content of the fuel being fired in the gas turbine exceeds 0.8 weight percent and ending on the date and hour that a subsequent sample is taken that demonstrates compliance with the sulfur limit.
(iii) A period of monitor downtime begins when a required sample is not taken by its due date. A period of monitor downtime also begins on the date and hour of a required sample, if invalid results are obtained. The period of monitor downtime shall include only unit operating hours and ends on the date and hour of the next valid sample.

§60.7(c) - "Each owner or operator required to install a continuous monitoring device shall submit excess emissions and monitoring systems performance report (excess emissions are defined in applicable subparts) and-or summary report form (see paragraph (d) of this section) to the Administrator semiannually, except when: more frequent reporting is specifically required by an applicable subpart; or the Administrator, on a case-by-case basis, determines that more frequent reporting is necessary to accurately assess the compliance status of the source. All reports shall be postmarked by the 30th day following the end of each six-month period. Written reports of excess emissions shall include the following information:

Table IV – 4	
	(1) The magnitude of excess emissions computed in accordance with §60.13(h), any conversion factor(s) used, and the date and time of commencement and completion of each time period of excess emissions. The process operating time during the reporting period. (2) Specific identification of each period of excess emissions that occurs during startups, shutdowns, and malfunctions of the affected facility. The nature and cause of any malfunction (if known), the corrective action taken, or preventative measures adopted. (3) The date and time identifying each period during which the continuous monitoring system was inoperative except for zero and span checks and the nature of the system repairs or adjustments. (4) When no excess emissions have occurred or the continuous monitoring system(s) have not been inoperative, repaired, or adjusted, such information shall be stated in the report." E. Control of Nitrogen Oxides Emissions 1. PSD Approval The Permittee shall submit quarterly reports of the average and maximum nitrogen content of the fuel oil and total calculated NO_X (expressed as NO_2) emissions. Data used for developing the above summaries shall be maintained on file at the plant and shall be made readily available for inspection by Department personnel. **[Reference: CPCN Order No. 68587 (Case 8102) condition 18]** 2. NSPS Subpart GG Standard **40CFR60.334**: **"(j)** For each affected unit required to continuously monitor parameters or emissions, or to periodically determine the fuel sulfur content or fuel nitrogen content under this subpart, the owner or operator shall submit reports of excess emissions and monitor downtime, in accordance with §60.7(c). Excess emissions shall be reported for all periods of unit operation, including startup, shutdown, and malfunction. For the purpose of reports required under §60.7(c), periods of excess emissions and monitor downtime that shall be reported are defined as follows:" **(1)"** Nitrogen oxides". **(i)** "For turbines using water or steam to fuel ratio monitoring:" **(A)** "An excess emission shall be any unit operating hour for which the average steam or water to fuel ratio, as measured by the continuous monitoring system, falls below the acceptable steam or water to fuel ratio needed to demonstrate compliance with §60.332, as established during the performance test required in §60.8. Any unit operating hour in which

Table IV – 4	
	no water or steam is injected into the turbine shall also be considered an excess emission." **(B)** "A period of monitor downtime shall be any unit operating hour in which water or steam is injected into the turbine, but the essential parametric data needed to determine the steam or water to fuel ratio are unavailable or invalid". **(C)** "Each report shall include the average steam or water to fuel ratio, average fuel consumption, ambient conditions (temperature, pressure, and humidity), gas turbine load, and (if applicable) the nitrogen content of the fuel during each excess emission. You do not have to report ambient conditions if you opt to use the worst-case ISO correction factor as specified in §60.334(b)(3)(ii), or if you are not using the ISO correction equation under the provisions of §60.335(b)(1)." **§60.7(c) -** "Each owner or operator required to install a continuous monitoring device shall submit excess emissions and monitoring systems performance report (excess emissions are defined in applicable subparts) and-or summary report form (see paragraph (d) of this section) to the Administrator semiannually, except when: more frequent reporting is specifically required by an applicable subpart; or the Administrator, on a case-by-case basis, determines that more frequent reporting is necessary to accurately assess the compliance status of the source. All reports shall be postmarked by the 30th day following the end of each six-month period. Written reports of excess emissions shall include the following information: (1) The magnitude of excess emissions computed in accordance with § 60.13(h), any conversion factor(s) used, and the date and time of commencement and completion of each time period of excess emissions. The process operating time during the reporting period. (2) Specific identification of each period of excess emissions that occurs during startups, shutdowns, and malfunctions of the affected facility. The nature and cause of any malfunction (if known), the corrective action taken, or preventative measures adopted. (3) The date and time identifying each period during which the continuous monitoring system was inoperative except for zero and span checks and the nature of the system repairs or adjustments. (4) When no excess emissions have occurred or the continuous monitoring system(s) have not been inoperative, repaired, or adjusted, such information shall be stated in the report."

Table IV – 4	
	3. NOx RACT Requirement The Permittee shall provide certification of the capacity factor of the equipment to the Department in writing by April 1 of the following calendar year. **[Reference: COMAR 26.11.09.08G(1)(a) & COMAR 26.11.03.06C]** F. Control of VOC Emissions The Permittee shall submit records of maintenance to the Department upon request. **[Reference: COMAR 26.11.03.06C** G. Operational Limitations The Permittee shall submit the record of the hours of operation with the support data in the annual emissions certification report due April 1 of each calendar year. **[Reference: COMAR 26.11.02.19C]**

"A permit shield shall cover the applicable requirements identified for the emissions unit(s) listed in the table above."

Table IV–5: Cross State Air Pollution Rule (CSAPR)	
5.0	**Emissions Unit Number(s): E-3 & E-4: Boilers, E-CT2 thru E-CT6 and SMECO-CT1 Cont'd** **E-3 & E-4**: Two (2) tangentially fired, sub-critical, cycling boilers each rated at 640 megawatts and 6,970 MMBtu/hr. heat input. Units fire natural gas and No. 6 fuel oil. No. 2 fuel oil or natural gas may be used for ignition, warm-up, and flame stabilization purposes. **[4-0998 & 4-0999]** **E-CT2**: One (1) Westinghouse (W-251) combustion turbine rated capacity of 35 megawatts (420 MMBtu/hr. heat input) used for black start capability and peaking service. This turbine is fired with No. 2 fuel oil. **[4-1145]** **E-CT3 & E-CT4**: Two (2) General Electric Frame-7EA combustion turbines each rated capacity of 99 megawatts used for peaking service. This turbine is fired with natural gas as a primary fuel and No. 2 fuel oil as a secondary fuel and injects water in the combustion zone for NOx control. **[9-0752 & 9-0753]**

Table IV–5: Cross State Air Pollution Rule (CSAPR)	
	E-CT5 & E-CT6: Two (2) Kraftwork Union V84.2 combustion turbines each rated capacity of 120 megawatts used for peaking service. These turbines fire with natural gas as a primary fuel and No. 2 fuel oil as a secondary fuel and injects water in the combustion zone for NO_x control when firing No. 2 fuel oil and dry low NO_x combustors when firing natural gas. **[9-0754 & 9-0755]** **SMECO-CT1:** One (1) General Electric GE-7EA combustion turbine rated capacity of 93 megawatts. This turbine is fired with natural gas as a primary fuel and No. 2 fuel oil as a secondary. This unit was owned by Southern Maryland Electric Cooperative until 2015 when NRG purchased the unit. **[5-0749]**
5.1	**Applicable Standards/Limits:** **COMAR 26.11.28.02** - Requirements. A. This chapter incorporates by reference the U.S. EPA CSAPR and the CSAPR Update, including the definitions, criteria, and procedures therein. B. Trading Program Requirements. (1) This chapter incorporates by reference provisions of the CSAPR NO_x Annual Trading Program set forth in 40 CFR Part 97, Subpart AAAAA, as published July 1, 2017, and associated reference methods, performance specifications, and other test methods referenced by these standards, as applicable to existing and new units in Maryland, except the provisions at 40 CFR §97.411(b)(2) and (c)(5)(iii), 97.412(b), and 97.421(h) and (j). (2) This chapter incorporates by reference provisions of the CSAPR NO_x Ozone Season Group 2 Trading Program set forth in 40 CFR Part 97, Subpart EEEEE, as published July 1, 2017, and associated reference methods, performance specifications and other test methods referenced by these standards, as applicable to existing and new units in Maryland, except the provisions at 40 CFR §§97.811(b)(2) and (c)(5)(iii), 97.812(b), and 97.821(h) and (j). (***This is superseded by Group 3 Subpart GGGGG published April 30, 2021, effective June 29, 2021***). (3) This chapter incorporates by reference provisions of the CSAPR SO_2 Group 1 Trading Program set forth in 40 CFR Part 97, Subpart CCCCC, as published July 1, 2017, and associated reference methods, performance specifications and other test methods referenced by these standards, as applicable to existing and new units in Maryland, except the provisions at 40 CFR §§97.611(b)(2) and (c)(5)(iii), 97.612(b), and 97.621(h) and (j).

Table IV–5: Cross State Air Pollution Rule (CSAPR)	
	A. 40 CFR Part 97 Subpart AAAAA—CSAPR NO_x Annual Trading Program **§97.406** - Standard requirements. "(a) ***Designated representative requirements***. The owners and operators shall comply with the requirement to have a designated representative, and may have an alternate designated representative, in accordance with §§97.413 through 97.418. (b) ***Emissions monitoring, reporting, and recordkeeping requirements***. (1) The owners and operators, and the designated representative, of each CSAPR NO_x Annual source and each CSAPR NO_x Annual unit at the source shall comply with the monitoring, reporting, and recordkeeping requirements of §§97.430 through 97.435. (2) The emissions data determined in accordance with §§97.430 through 97.435 shall be used to calculate allocations of CSAPR NO_x Annual allowances under §§97.411(a)(2) and (b) and 97.412 and to determine compliance with the CSAPR NO_x Annual emissions limitation and assurance provisions under paragraph (c) of this section, provided that, for each monitoring location from which mass emissions are reported, the mass emissions amount used in calculating such allocations and determining such compliance shall be the mass emissions amount for the monitoring location determined in accordance with §§97.430 through 97.435 and rounded to the nearest ton, with any fraction of a ton less than 0.50 being deemed to be zero. (c) ***NO_x emissions requirements***—(1) *CSAPR NO_x Annual emissions limitation*. (i) As of the allowance transfer deadline for a control period in a given year, the owners, and operators of each CSAPR NO_x Annual source and each CSAPR NO_x Annual unit at the source shall hold, in the source's compliance account, CSAPR NO_x Annual allowances available for deduction for such control period under §97.424(a) in an amount not less than the tons of total NO_x emissions for such control period from all CSAPR NO_x Annual units at the source. (ii) If total NO_x emissions during a control period in a given year from the CSAPR NO_x Annual units at a CSAPR NO_x Annual source are in excess of the CSAPR NO_x Annual emissions limitation set forth in paragraph (c)(1)(i) of this section, then: (A) The owners and operators of the source and each CSAPR NO_x Annual unit at the source shall hold the CSAPR NO_x Annual allowances required for deduction under §97.424(d); and (B) The owners and operators of the source and each CSAPR NO_x Annual unit at the source shall pay any fine, penalty, or assessment or comply with any other remedy imposed, for the same violations, under

Table IV–5: Cross State Air Pollution Rule (CSAPR)	
	the Clean Air Act, and each ton of such excess emissions and each day of such control period shall constitute a separate violation of this subpart and the Clean Air Act. (2) *CSAPR NO_x Annual assurance provisions*. (i) If total NO_x emissions during a control period in a given year from all CSAPR NO_x Annual units at CSAPR NO_x Annual sources in a State (and Indian country within the borders of such State) exceed the State assurance level, then the owners and operators of such sources and units in each group of one or more sources and units having a common designated representative for such control period, where the common designated representative's share of such NO_x emissions during such control period exceeds the common designated representative's assurance level for the State and such control period, shall hold (in the assurance account established for the owners and operators of such group) CSAPR NO_x Annual allowances available for deduction for such control period under §97.425(a) in an amount equal to two times the product (rounded to the nearest whole number), as determined by the Administrator in accordance with §97.425(b), of multiplying— (A) The quotient of the amount by which the common designated representative's share of such NO_x emissions exceeds the common designated representative's assurance level divided by the sum of the amounts, determined for all common designated representatives for such sources and units in the State (and Indian country within the borders of such State) for such control period, by which each common designated representative's share of such NO_x emissions exceeds the respective common designated representative's assurance level; and (B) The amount by which total NO_x emissions from all CSAPR NO_x Annual units at CSAPR NO_x Annual sources in the State (and Indian country within the borders of such State) for such control period exceed the State assurance level. (ii) The owners and operators shall hold the CSAPR NO_x Annual allowances required under paragraph (c)(2)(i) of this section, as of midnight of November 1 (if it is a business day), or midnight of the first business day thereafter (if November 1 is not a business day), immediately after the year of such control period. (iii) Total NO_x emissions from all CSAPR NO_x Annual units at CSAPR NO_x Annual sources in a State (and Indian country within the borders of such State) during a control period in a given year exceed the State assurance level if such total NO_x emissions exceed the sum, for such control period, of the State NO_x Annual trading budget under §97.410(a) and the State's variability limit under §97.410(b).

Table IV–5: Cross State Air Pollution Rule (CSAPR)	
	(iv) It shall not be a violation of this subpart or of the Clean Air Act if total NO_x emissions from all CSAPR NOx Annual units at CSAPR NO_x Annual sources in a State (and Indian country within the borders of such State) during a control period exceed the State assurance level or if a common designated representative's share of total NO_x emissions from the CSAPR NOx Annual units at CSAPR NOx Annual sources in a State (and Indian country within the borders of such State) during a control period exceeds the common designated representative's assurance level. (v) To the extent the owners and operators fail to hold CSAPR NOx Annual allowances for a control period in a given year in accordance with paragraphs (c)(2)(i) through (iii) of this section, (A) The owners and operators shall pay any fine, penalty, or assessment or comply with any other remedy imposed under the Clean Air Act; and (B) Each CSAPR NOx Annual allowance that the owners and operators fail to hold for such control period in accordance with paragraphs (c)(2)(i) through (iii) of this section and each day of such control period shall constitute a separate violation of this subpart and the Clean Air Act. (3) *Compliance periods*. (i) A CSAPR NOx Annual unit shall be subject to the requirements under paragraph (c)(1) of this section for the control period starting on the later of January 1, 2015, or the deadline for meeting the unit's monitor certification requirements under §97.430(b) and for each control period thereafter. (ii) A CSAPR NOx Annual unit shall be subject to the requirements under paragraph (c)(2) of this section for the control period starting on the later of January 1, 2017, or the deadline for meeting the unit's monitor certification requirements under §97.430(b) and for each control period thereafter. (4) *Vintage of CSAPR NOx Annual allowances held for compliance*. (i) A CSAPR NOx Annual allowance held for compliance with the requirements under paragraph (c)(1)(i) of this section for a control period in a given year must be a CSAPR NOx Annual allowance that was allocated or auctioned for such control period or a control period in a prior year. (ii) A CSAPR NOx Annual allowance held for compliance with the requirements under paragraphs (c)(1)(ii)(A) and (2)(i) through (iii) of this section for a control period in a given year must be a CSAPR NOx Annual allowance that was allocated or auctioned for a control period in a prior year or the control period in the given year or in the immediately following year. (5) *Allowance Management System requirements*. Each CSAPR NOx Annual allowance shall be held in, deducted from, or transferred into, out

Table IV–5: Cross State Air Pollution Rule (CSAPR)	
	of, or between Allowance Management System accounts in accordance with this subpart. (6) *Limited authorization*. A CSAPR NO_x Annual allowance is a limited authorization to emit one ton of NO_x during the control period in one year. Such authorization is limited in its use and duration as follows: (i) Such authorization shall only be used in accordance with the CSAPR NO_x Annual Trading Program; and (ii) Notwithstanding any other provision of this subpart, the Administrator has the authority to terminate or limit the use and duration of such authorization to the extent the Administrator determines is necessary or appropriate to implement any provision of the Clean Air Act. (7) *Property right*. A CSAPR NO_x Annual allowance does not constitute a property right. (**d**) ***Title V permit requirements***. (1) No title V permit revision shall be required for any allocation, holding, deduction, or transfer of CSAPR NO_x Annual allowances in accordance with this subpart. (2) A description of whether a unit is required to monitor and report NO_x emissions using a continuous emission monitoring system (under subpart H of part 75 of this chapter), an excepted monitoring system (under appendices D and E to part 75 of this chapter), a low mass emissions excepted monitoring methodology (under §75.19 of this chapter), or an alternative monitoring system (under subpart E of part 75 of this chapter) in accordance with §§97.430 through 97.435 may be added to, or changed in, a title V permit using minor permit modification procedures in accordance with §§70.7(e)(2) and 71.7(e)(1) of this chapter, provided that the requirements applicable to the described monitoring and reporting (as added or changed, respectively) are already incorporated in such permit. This paragraph explicitly provides that the addition of, or change to, a unit's description as described in the prior sentence is eligible for minor permit modification procedures in accordance with §§70.7(e)(2)(i)(B) and 71.7(e)(1)(i)(B) of this chapter. (**e**) ***Additional recordkeeping and reporting requirements***. (1) Unless otherwise provided, the owners and operators of each CSAPR NO_x Annual source and each CSAPR NO_x Annual unit at the source shall keep on site at the source each of the following documents (in hardcopy or electronic format) for a period of 5 years from the date the document is created. This period may be extended for cause, at any time before the end of 5 years, in writing by the Administrator. (i) The certificate of representation under §97.416 for the designated representative for the source and each CSAPR NO_x Annual unit at the source and all documents that demonstrate the truth of the statements in the certificate of representation; provided that the certificate and

Table IV–5: Cross State Air Pollution Rule (CSAPR)	
	documents shall be retained on site at the source beyond such 5-year period until such certificate of representation and documents are superseded because of the submission of a new certificate of representation under §97.416 changing the designated representative. (ii) All emissions monitoring information, in accordance with this subpart. (iii) Copies of all reports, compliance certifications, and other submissions and all records made or required under, or to demonstrate compliance with the requirements of, the CSAPR NO_x Annual Trading Program. (2) The designated representative of a CSAPR NO_x Annual source and each CSAPR NO_x Annual unit at the source shall make all submissions required under the CSAPR NO_x Annual Trading Program, except as provided in §97.418. This requirement does not change, create an exemption from, or otherwise affect the responsible official submission requirements under a title V operating permit program in parts 70 and 71 of this chapter. (**f**) ***Liability***. (1) Any provision of the CSAPR NO_x Annual Trading Program that applies to a CSAPR NO_x Annual source or the designated representative of a CSAPR NO_x Annual source shall also apply to the owners and operators of such source and of the CSAPR NO_x Annual units at the source. (2) Any provision of the CSAPR NO_x Annual Trading Program that applies to a CSAPR NO_x Annual unit or the designated representative of a CSAPR NO_x Annual unit shall also apply to the owners and operators of such unit. (**g**) ***Effect on other authorities***. No provision of the CSAPR NO_x Annual Trading Program or exemption under §97.405 shall be construed as exempting or excluding the owners and operators, and the designated representative, of a CSAPR NO_x Annual source or CSAPR NO_x Annual unit from compliance with any other provision of the applicable, approved State implementation plan, a federally enforceable permit, or the Clean Air Act." **B. 40 CFR Part 97 Subpart CCCCC—CSAPR SO_2 Group 1 Trading Program** **§97.606** - Standard requirements. "(**a**) ***Designated representative requirements***. The owners and operators shall comply with the requirement to have a designated representative, and may have an alternate designated representative, in accordance with §§97.613 through 97.618. (**b**) ***Emissions monitoring, reporting, and recordkeeping requirements***. (1) The owners and operators, and the designated

Table IV–5: Cross State Air Pollution Rule (CSAPR)	
	representative, of each CSAPR SO_2 Group 1 source and each CSAPR SO_2 Group 1 unit at the source shall comply with the monitoring, reporting, and recordkeeping requirements of §§97.630 through 97.635. (2) The emissions data determined in accordance with §§97.630 through 97.635 shall be used to calculate allocations of CSAPR SO_2 Group 1 allowances under §§97.611(a)(2) and (b) and 97.612 and to determine compliance with the CSAPR SO_2 Group 1 emissions limitation and assurance provisions under paragraph (c) of this section, provided that, for each monitoring location from which mass emissions are reported, the mass emissions amount used in calculating such allocations and determining such compliance shall be the mass emissions amount for the monitoring location determined in accordance with §§97.630 through 97.635 and rounded to the nearest ton, with any fraction of a ton less than 0.50 being deemed to be zero. (c) ***SO_2 emissions requirements***—(1) *CSAPR SO_2 Group 1 emissions limitation*. (i) As of the allowance transfer deadline for a control period in a given year, the owners, and operators of each CSAPR SO_2 Group 1 source and each CSAPR SO_2 Group 1 unit at the source shall hold, in the source's compliance account, CSAPR SO_2 Group 1 allowances available for deduction for such control period under §97.624(a) in an amount not less than the tons of total SO_2 emissions for such control period from all CSAPR SO_2 Group 1 units at the source. (ii) If total SO_2 emissions during a control period in a given year from the CSAPR SO_2 Group 1 units at a CSAPR SO_2 Group 1 source are in excess of the CSAPR SO_2 Group 1 emissions limitation set forth in paragraph (c)(1)(i) of this section, then: (A) The owners and operators of the source and each CSAPR SO_2 Group 1 unit at the source shall hold the CSAPR SO_2 Group 1 allowances required for deduction under §97.624(d); and (B) The owners and operators of the source and each CSAPR SO_2 Group 1 unit at the source shall pay any fine, penalty, or assessment or comply with any other remedy imposed, for the same violations, under the Clean Air Act, and each ton of such excess emissions and each day of such control period shall constitute a separate violation of this subpart and the Clean Air Act. (2) *CSAPR SO_2 Group 1 assurance provisions*. (i) If total SO_2 emissions during a control period in a given year from all CSAPR SO_2 Group 1 units at CSAPR SO_2 Group 1 sources in a State (and Indian country within the borders of such State) exceed the State assurance level, then the owners and operators of such sources and units in each group of one or more sources and units having a common designated representative for such control period, where the common designated representative's

Table IV–5: Cross State Air Pollution Rule (CSAPR)	
	share of such SO_2 emissions during such control period exceeds the common designated representative's assurance level for the State and such control period, shall hold (in the assurance account established for the owners and operators of such group) CSAPR SO_2 Group 1 allowances available for deduction for such control period under §97.625(a) in an amount equal to two times the product (rounded to the nearest whole number), as determined by the Administrator in accordance with §97.625(b), of multiplying— (A) The quotient of the amount by which the common designated representative's share of such SO_2 emissions exceeds the common designated representative's assurance level divided by the sum of the amounts, determined for all common designated representatives for such sources and units in the State (and Indian country within the borders of such State) for such control period, by which each common designated representative's share of such SO_2 emissions exceeds the respective common designated representative's assurance level; and (B) The amount by which total SO_2 emissions from all CSAPR SO_2 Group 1 units at CSAPR SO_2 Group 1 sources in the State (and Indian country within the borders of such State) for such control period exceed the State assurance level. (ii) The owners and operators shall hold the CSAPR SO_2 Group 1 allowances required under paragraph (c)(2)(i) of this section, as of midnight of November 1 (if it is a business day), or midnight of the first business day thereafter (if November 1 is not a business day), immediately after the year of such control period. (iii) Total SO_2 emissions from all CSAPR SO_2 Group 1 units at CSAPR SO_2 Group 1 sources in a State (and Indian country within the borders of such State) during a control period in a given year exceed the State assurance level if such total SO_2 emissions exceed the sum, for such control period, of the State SO_2 Group 1 trading budget under §97.610(a) and the State's variability limit under §97.610(b). (iv) It shall not be a violation of this subpart or of the Clean Air Act if total SO_2 emissions from all CSAPR SO_2 Group 1 units at CSAPR SO_2 Group 1 sources in a State (and Indian country within the borders of such State) during a control period exceed the State assurance level or if a common designated representative's share of total SO_2 emissions from the CSAPR SO_2 Group 1 units at CSAPR SO_2 Group 1 sources in a State (and Indian country within the borders of such State) during a control period exceeds the common designated representative's assurance level.

Table IV–5: Cross State Air Pollution Rule (CSAPR)	
	(v) To the extent the owners and operators fail to hold CSAPR SO_2 Group 1 allowances for a control period in a given year in accordance with paragraphs (c)(2)(i) through (iii) of this section, (A) The owners and operators shall pay any fine, penalty, or assessment or comply with any other remedy imposed under the Clean Air Act; and (B) Each CSAPR SO_2 Group 1 allowance that the owners and operators fail to hold for such control period in accordance with paragraphs (c)(2)(i) through (iii) of this section and each day of such control period shall constitute a separate violation of this subpart and the Clean Air Act. (3) *Compliance periods*. (i) A CSAPR SO_2 Group 1 unit shall be subject to the requirements under paragraph (c)(1) of this section for the control period starting on the later of January 1, 2015, or the deadline for meeting the unit's monitor certification requirements under §97.630(b) and for each control period thereafter. (ii) A CSAPR SO_2 Group 1 unit shall be subject to the requirements under paragraph (c)(2) of this section for the control period starting on the later of January 1, 2017, or the deadline for meeting the unit's monitor certification requirements under §97.630(b) and for each control period thereafter. (4) *Vintage of CSAPR SO_2 Group 1 allowances held for compliance*. (i) A CSAPR SO_2 Group 1 allowance held for compliance with the requirements under paragraph (c)(1)(i) of this section for a control period in a given year must be a CSAPR SO_2 Group 1 allowance that was allocated or auctioned for such control period or a control period in a prior year. (ii) A CSAPR SO_2 Group 1 allowance held for compliance with the requirements under paragraphs (c)(1)(ii)(A) and (2)(i) through (iii) of this section for a control period in a given year must be a CSAPR SO_2 Group 1 allowance that was allocated or auctioned for a control period in a prior year or the control period in the given year or in the immediately following year. (5) *Allowance Management System requirements*. Each CSAPR SO_2 Group 1 allowance shall be held in, deducted from, or transferred into, out of, or between Allowance Management System accounts in accordance with this subpart. (6) *Limited authorization*. A CSAPR SO_2 Group 1 allowance is a limited authorization to emit one ton of SO_2 during the control period in one year. Such authorization is limited in its use and duration as follows: (i) Such authorization shall only be used in accordance with the CSAPR SO_2 Group 1 Trading Program; and (ii) Notwithstanding any other provision of this subpart, the Administrator has the authority to terminate or limit the use and duration of such

Table IV–5: Cross State Air Pollution Rule (CSAPR)	
	authorization to the extent the Administrator determines is necessary or appropriate to implement any provision of the Clean Air Act. (7) *Property right*. A CSAPR SO_2 Group 1 allowance does not constitute a property right. (**d**) ***Title V permit requirements***. (1) No title V permit revision shall be required for any allocation, holding, deduction, or transfer of CSAPR SO_2 Group 1 allowances in accordance with this subpart. (2) A description of whether a unit is required to monitor and report SO_2 emissions using a continuous emission monitoring system (under subpart B of part 75 of this chapter), an excepted monitoring system (under appendices D and E to part 75 of this chapter), a low mass emissions excepted monitoring methodology (under §75.19 of this chapter), or an alternative monitoring system (under subpart E of part 75 of this chapter) in accordance with §§97.630 through 97.635 may be added to, or changed in, a title V permit using minor permit modification procedures in accordance with §§70.7(e)(2) and 71.7(e)(1) of this chapter, provided that the requirements applicable to the described monitoring and reporting (as added or changed, respectively) are already incorporated in such permit. This paragraph explicitly provides that the addition of, or change to, a unit's description as described in the prior sentence is eligible for minor permit modification procedures in accordance with §§70.7(e)(2)(i)(B) and 71.7(e)(1)(i)(B) of this chapter. (**e**) ***Additional recordkeeping and reporting requirements***. (1) Unless otherwise provided, the owners and operators of each CSAPR SO_2 Group 1 source and each CSAPR SO_2 Group 1 unit at the source shall keep on site at the source each of the following documents (in hardcopy or electronic format) for a period of 5 years from the date the document is created. This period may be extended for cause, at any time before the end of 5 years, in writing by the Administrator. (i) The certificate of representation under §97.616 for the designated representative for the source and each CSAPR SO_2 Group 1 unit at the source and all documents that demonstrate the truth of the statements in the certificate of representation; provided that the certificate and documents shall be retained on site at the source beyond such 5-year period until such certificate of representation and documents are superseded because of the submission of a new certificate of representation under §97.616 changing the designated representative. (ii) All emissions monitoring information, in accordance with this subpart. (iii) Copies of all reports, compliance certifications, and other submissions and all records made or required under, or to demonstrate compliance with the requirements of, the CSAPR SO_2 Group 1 Trading Program.

Table IV–5: Cross State Air Pollution Rule (CSAPR)	
	(2) The designated representative of a CSAPR SO_2 Group 1 source and each CSAPR SO_2 Group 1 unit at the source shall make all submissions required under the CSAPR SO_2 Group 1 Trading Program, except as provided in §97.618. This requirement does not change, create an exemption from, or otherwise affect the responsible official submission requirements under a title V operating permit program in parts 70 and 71 of this chapter. (f) ***Liability***. (1) Any provision of the CSAPR SO_2 Group 1 Trading Program that applies to a CSAPR SO_2 Group 1 source or the designated representative of a CSAPR SO_2 Group 1 source shall also apply to the owners and operators of such source and of the CSAPR SO_2 Group 1 units at the source. (2) Any provision of the CSAPR SO_2 Group 1 Trading Program that applies to a CSAPR SO_2 Group 1 unit or the designated representative of a CSAPR SO_2 Group 1 unit shall also apply to the owners and operators of such unit. (g) ***Effect on other authorities***. No provision of the CSAPR SO_2 Group 1 Trading Program or exemption under §97.605 shall be construed as exempting or excluding the owners and operators, and the designated representative, of a CSAPR SO_2 Group 1 source or CSAPR SO_2 Group 1 unit from compliance with any other provision of the applicable, approved State implementation plan, a federally enforceable permit, or the Clean Air Act." **C. 40 CFR Part 97 Subpart GGGGG - CSAPR NO_x Ozone Season Group 3 Trading Program** **§97.1006** Standard requirements (a) ***Designated representative requirements.*** The owners and operators shall comply with the requirement to have a designated representative, and may have an alternate designated representative, in accordance with §§97.1013 through 97.1018. (b) ***Emissions monitoring, reporting, and recordkeeping requirements.*** (1) The owners and operators, and the designated representative, of each CSAPR NO_x Ozone Season Group 3 source and each CSAPR NO_x Ozone Season Group 3 unit at the source shall comply with the monitoring, reporting, and recordkeeping requirements of §§97.1030 through 97.1035. (2) The emissions data determined in accordance with §§97.1030 through 97.1035 shall be used to calculate allocations of CSAPR NO_x Ozone Season Group 3 allowances under §§97.1011(a)(2) and (b) and 97.1012 and to determine compliance with the CSAPR NO_x Ozone

Table IV–5: Cross State Air Pollution Rule (CSAPR)	
	Season Group 3 emissions limitation and assurance provisions under paragraph (c) of this section, provided that, for each monitoring location from which mass emissions are reported, the mass emissions amount used in calculating such allocations and determining such compliance shall be the mass emissions amount for the monitoring location determined in accordance with §§97.1030 through 97.1035 and rounded to the nearest ton, with any fraction of a ton less than 0.50 being deemed to be zero. (c) ***NOx emissions requirements*** - (1) *CSAPR NO_X Ozone Season Group 3 emissions limitation.* (i) As of the allowance transfer deadline for a control period in a given year, the owners and operators of each CSAPR NOx Ozone Season Group 3 source and each CSAPR NOx Ozone Season Group 3 unit at the source shall hold, in the source's compliance account, CSAPR NOx Ozone Season Group 3 allowances available for deduction for such control period under §97.1024(a) in an amount not less than the tons of total NOx emissions for such control period from all CSAPR NOx Ozone Season Group 3 units at the source. (ii) If total NOx emissions during a control period in a given year from the CSAPR NOx Ozone Season Group 3 units at a CSAPR NOx Ozone Season Group 3 source are in excess of the CSAPR NOx Ozone Season Group 3 emissions limitation set forth in paragraph (c)(1)(i) of this section, then: (A) The owners and operators of the source and each CSAPR NOx Ozone Season Group 3 unit at the source shall hold the CSAPR NOx Ozone Season Group 3 allowances required for deduction under §97.1024(d); and (B) The owners and operators of the source and each CSAPR NOx Ozone Season Group 3 unit at the source shall pay any fine, penalty, or assessment or comply with any other remedy imposed, for the same violations, under the Clean Air Act, and each ton of such excess emissions and each day of such control period shall constitute a separate violation of this subpart and the Clean Air Act. (2) *CSAPR NO_X Ozone Season Group 3 assurance provisions.* (i) If total NOx emissions during a control period in a given year from all base CSAPR NOx Ozone Season Group 3 units at base CSAPR NOx Ozone Season Group 3 sources in a State (and Indian country within the borders of such State) exceed the State assurance level, then the owners and operators of such sources and units in each group of one or more sources and units having a common designated representative for such control period, where the common designated representative's share of such NOx emissions during such control period exceeds the

Table IV–5: Cross State Air Pollution Rule (CSAPR)	
	common designated representative's assurance level for the State and such control period, shall hold (in the assurance account established for the owners and operators of such group) CSAPR NO_x Ozone Season Group 3 allowances available for deduction for such control period under §97.1025(a) in an amount equal to two times the product (rounded to the nearest whole number), as determined by the Administrator in accordance with §97.1025(b), of multiplying - (A) The quotient of the amount by which the common designated representative's share of such NO_x emissions exceeds the common designated representative's assurance level divided by the sum of the amounts, determined for all common designated representatives for such sources and units in the State (and Indian country within the borders of such State) for such control period, by which each common designated representative's share of such NO_x emissions exceeds the respective common designated representative's assurance level; and (B) The amount by which total NO_x emissions from all base CSAPR NO_x Ozone Season Group 3 units at base CSAPR NO_x Ozone Season Group 3 sources in the State (and Indian country within the borders of such State) for such control period exceed the State assurance level. (ii) The owners and operators shall hold the CSAPR NO_x Ozone Season Group 3 allowances required under paragraph (c)(2)(i) of this section, as of midnight of November 1 (if it is a business day), or midnight of the first business day thereafter (if November 1 is not a business day), immediately after the year of such control period. (iii) Total NO_x emissions from all base CSAPR NO_x Ozone Season Group 3 units at base CSAPR NO_x Ozone Season Group 3 sources in a State (and Indian country within the borders of such State) during a control period in a given year exceed the State assurance level if such total NO_x emissions exceed the sum, for such control period, of the State NO_x Ozone Season Group 3 trading budget under §97.1010(a), the State's variability limit under §97.1010(b), and, for the control period in 2021 only, the product (rounded to the nearest allowance) of 1.21 multiplied by the supplemental amount of CSAPR NO_x Ozone Season Group 3 allowances determined for the State under §97.1010(d). (iv) It shall not be a violation of this subpart or of the Clean Air Act if total NO_x emissions from all base CSAPR NO_x Ozone Season Group 3 units at base CSAPR NO_x Ozone Season Group 3 sources in a State (and Indian country within the borders of such State) during a control period exceed the State assurance level or if a common designated representative's share of total NO_x emissions from the base CSAPR NO_x Ozone Season Group 3 units at base CSAPR NO_x Ozone Season Group 3 sources in a State (and Indian country within the borders of such State)

Table IV–5: Cross State Air Pollution Rule (CSAPR)	
	during a control period exceeds the common designated representative's assurance level. (v) To the extent the owners and operators fail to hold CSAPR NOx Ozone Season Group 3 allowances for a control period in a given year in accordance with paragraphs (c)(2)(i) through (iii) of this section: (A) The owners and operators shall pay any fine, penalty, or assessment or comply with any other remedy imposed under the Clean Air Act; and (B) Each CSAPR NOx Ozone Season Group 3 allowance that the owners and operators fail to hold for such control period in accordance with paragraphs (c)(2)(i) through (iii) of this section and each day of such control period shall constitute a separate violation of this subpart and the Clean Air Act. (3) *Compliance periods*. (i) A CSAPR NOx Ozone Season Group 3 unit shall be subject to the requirements under paragraph (c)(1) of this section for the control period starting on the later of May 1, 2021, or the deadline for meeting the unit's monitor certification requirements under §97.1030(b) and for each control period thereafter. (ii) A base CSAPR NOx Ozone Season Group 3 unit shall be subject to the requirements under paragraph (c)(2) of this section for the control period starting on the later of May 1, 2021, or the deadline for meeting the unit's monitor certification requirements under §97.1030(b) and for each control period thereafter. (4) *Vintage of CSAPR NO_X Ozone Season Group 3 allowances held for compliance*. (i) A CSAPR NOx Ozone Season Group 3 allowance held for compliance with the requirements under paragraph (c)(1)(i) of this section for a control period in a given year must be a CSAPR NOx Ozone Season Group 3 allowance that was allocated or auctioned for such control period or a control period in a prior year. (ii) A CSAPR NOx Ozone Season Group 3 allowance held for compliance with the requirements under paragraphs (c)(1)(ii)(A) and (c)(2)(i) through (iii) of this section for a control period in a given year must be a CSAPR NOx Ozone Season Group 3 allowance that was allocated or auctioned for a control period in a prior year or the control period in the given year or in the immediately following year. (5) *Allowance Management System requirements*. Each CSAPR NOx Ozone Season Group 3 allowance shall be held in, deducted from, or transferred into, out of, or between Allowance Management System accounts in accordance with this subpart. (6) *Limited authorization*. A CSAPR NOx Ozone Season Group 3 allowance is a limited authorization to emit one ton of NOx during the

Table IV–5: Cross State Air Pollution Rule (CSAPR)	
	control period in one year. Such authorization is limited in its use and duration as follows: (i) Such authorization shall only be used in accordance with the CSAPR NO_x Ozone Season Group 3 Trading Program; and (ii) Notwithstanding any other provision of this subpart, the Administrator has the authority to terminate or limit the use and duration of such authorization to the extent the Administrator determines is necessary or appropriate to implement any provision of the Clean Air Act. (7) *Property right.* A CSAPR NO_x Ozone Season Group 3 allowance does not constitute a property right. **(d) *Title V permit requirements.*** (1) No title V permit revision shall be required for any allocation, holding, deduction, or transfer of CSAPR NO_x Ozone Season Group 3 allowances in accordance with this subpart. (2) A description of whether a unit is required to monitor and report NO_x emissions using a continuous emission monitoring system (under subpart H of part 75 of this chapter), an excepted monitoring system (under appendices D and E to part 75 of this chapter), a low mass emissions excepted monitoring methodology (under §75.19 of this chapter), or an alternative monitoring system (under subpart E of part 75 of this chapter) in accordance with §§97.1030 through 97.1035 may be added to, or changed in, a title V permit using minor permit modification procedures in accordance with §§70.7(e)(2) and 71.7(e)(1) of this chapter, provided that the requirements applicable to the described monitoring and reporting (as added or changed, respectively) are already incorporated in such permit. This paragraph explicitly provides that the addition of, or change to, a unit's description as described in the prior sentence is eligible for minor permit modification procedures in accordance with §§70.7(e)(2)(i)(B) and 71.7(e)(1)(i)(B) of this chapter. **(e) *Additional recordkeeping and reporting requirements.*** (1) Unless otherwise provided, the owners and operators of each CSAPR NO_x Ozone Season Group 3 source and each CSAPR NO_x Ozone Season Group 3 unit at the source shall keep on site at the source each of the following documents (in hardcopy or electronic format) for a period of 5 years from the date the document is created. This period may be extended for cause, at any time before the end of 5 years, in writing by the Administrator. (i) The certificate of representation under §97.1016 for the designated representative for the source and each CSAPR NO_x Ozone Season Group 3 unit at the source and all documents that demonstrate the truth of the statements in the certificate of representation; provided that the certificate and documents shall be retained on site at the source beyond

Table IV–5: Cross State Air Pollution Rule (CSAPR)	
	such 5-year period until such certificate of representation and documents are superseded because of the submission of a new certificate of representation under §97.1016 changing the designated representative. (ii) All emissions monitoring information, in accordance with this subpart. (iii) Copies of all reports, compliance certifications, and other submissions and all records made or required under, or to demonstrate compliance with the requirements of, the CSAPR NOx Ozone Season Group 3 Trading Program. (2) The designated representative of a CSAPR NOx Ozone Season Group 3 source and each CSAPR NOx Ozone Season Group 3 unit at the source shall make all submissions required under the CSAPR NOx Ozone Season Group 3 Trading Program, except as provided in §97.1018. This requirement does not change, create an exemption from, or otherwise affect the responsible official submission requirements under a title V operating permit program in parts 70 and 71 of this chapter. (f) ***Liability***. (1) Any provision of the CSAPR NOx Ozone Season Group 3 Trading Program that applies to a CSAPR NOx Ozone Season Group 3 source or the designated representative of a CSAPR NOx Ozone Season Group 3 source shall also apply to the owners and operators of such source and of the CSAPR NOx Ozone Season Group 3 units at the source. (2) Any provision of the CSAPR NOx Ozone Season Group 3 Trading Program that applies to a CSAPR NOx Ozone Season Group 3 unit or the designated representative of a CSAPR NOx Ozone Season Group 3 unit shall also apply to the owners and operators of such unit. (g) ***Effect on other authorities***. No provision of the CSAPR NOx Ozone Season Group 3 Trading Program or exemption under §97.1005 shall be construed as exempting or excluding the owners and operators, and the designated representative, of a CSAPR NOx Ozone Season Group 3 source or CSAPR NOx Ozone Season Group 3 unit from compliance with any other provision of the applicable, approved State implementation plan, a federally enforceable permit, or the Clean Air Act."
5.2	**Testing Requirements:** **A, B, & C**: See Monitoring Requirements.
5.3	**Monitoring Requirements:** **A. 40 CFR Part 97 Subpart AAAAA—CSAPR NOx Annual Trading Program**

Table IV–5: Cross State Air Pollution Rule (CSAPR)	
	The Permittee shall comply with the monitoring requirements found in §97.406, §97.430, and §97.434 for the NO_x Annual Trading Program. **B. 40 CFR Part 97 Subpart CCCCC—CSAPR SO_2 Group 1 Trading Program** The Permittee shall comply with the monitoring requirements found in §97.606, §97.630, §97.631, §97.632, and §97.633. The Permittee operates continuous emission monitoring system (CEMS) pursuant to 40 CFR Part 75, Subpart B (for SO_2 monitoring) and 40 CFR Part 75, Subpart H (for NO_x monitoring). **C. 40 CFR Part 97 Subpart GGGGG - CSAPR NO_x Ozone Season Group 3 Trading Program** The Permittee shall comply with the monitoring requirements found in §97.1006; §97.1030; §97.1031, §97.1032, and §97.1033 for the NO_x Ozone Season Group 3 Trading Program.
5.4	**Record Keeping Requirements:** **Note:** All records must be maintained for a period of at least 5 years. **[Reference: COMAR 26.11.03.06C(5)(g)]** **A. 40 CFR Part 97 Subpart AAAAA—CSAPR NO_x Annual Trading Program** The Permittee shall comply with the recordkeeping requirements found in §97.406, §97.430, and §97.434 for the NO_x Annual Trading Program. **B. 40 CFR Part 97 Subpart CCCCC—CSAPR SO_2 Group 1 Trading Program** The Permittee shall comply with the recordkeeping requirements found in §97.606, §97.630, and §97.634. **C. 40 CFR Part 97 Subpart GGGGG - CSAPR NO_x Ozone Season Group 3 Trading Program** The Permittee shall comply with the recordkeeping requirements found in §97.1006; §97.1030 and §97.1034 for the NO_x Ozone Season Group 3 Trading Program.
5.5	**Reporting Requirements:** **A. 40 CFR Part 97 Subpart AAAAA—CSAPR NO_x Annual Trading Program**

Table IV–5: Cross State Air Pollution Rule (CSAPR)	
	The Permittee shall comply with the reporting requirements found in §97.406, §97.430, §97.433 and §97.434 for the NO_x Annual Trading Program. **B. 40 CFR Part 97 Subpart CCCCC—CSAPR SO_2 Group 1 Trading Program** The Permittee shall comply with the reporting requirements found in §97.606, §97.630, §97.633 and §97.634. **C. 40 CFR Part 97 Subpart GGGGG - CSAPR NO_x Ozone Season Group 3 Trading Program** The Permittee shall comply with the reporting requirements found in §97.1006; §97.1030 and §97.1034 for the NO_x Ozone Season Group 3 Trading Program

"A permit shield shall cover the applicable requirements identified for the emissions unit(s) listed in the table above."

Table IV – 6	
6.0	**Emissions Unit Number(s): AUX-4 thru AUX-7: Auxiliary Boilers** **AUX-4 thru AUX-7:** Four (4) Combustion Engineering, Model #30VP-12W, auxiliary boilers, each rated at 186.6 MMBtu/hr. These boilers are fired with No. 2 fuel oil.
6.1	**Applicable Standards/Limits:** A. Control of Visible Emissions **COMAR 26.11.09.05A(2)** – Fuel Burning Equipment "Areas III and IV. In Areas III and IV, a person may not cause or permit the discharge of emissions from any fuel burning equipment, other than water in an uncombined form, which is visible to human observers except that, for the purpose of demonstrating compliance using COM data, emissions that are visible to a human observer are those that are equal to or greater than 10 percent opacity." **COMAR 26.11.09.05A(3) -** Exceptions. "Section A(1) and (2) of this regulation do not apply to emissions during load changing, soot blowing, startup, or adjustments or occasional cleaning of control equipment if: (c) The visible emissions are not greater than 40 percent opacity; and

Table IV – 6

The visible emissions do not occur for more than 6 consecutive minutes in any sixty-minute period."

B. Control of Sulfur Oxides Emissions
COMAR 26.11.09.07: Control of Sulfur Oxides from Fuel Burning Equipment.
"A. Sulfur Content Limitations for Fuel. A person may not burn, sell, or make available for sale any fuel with a sulfur content by weight in excess of or which otherwise exceeds the following limitations: (2) In Areas III and IV: **(b) Distillate fuel oils, 0.3 percent."**

C. Control of Nitrogen Oxides Emissions
(1) NOx RACT Requirements
COMAR 26.11.09.08B(5) - Operator Training.
(a) For purposes of this regulation, the equipment operator to be trained may be the person who maintains the equipment and makes the necessary adjustments for efficient operation.
(b) The operator training course sponsored by the Department shall include an in-house training course that is approved by the Department."
COMAR 26.11.09.08G – Requirements for Fuel-Burning Equipment with a Capacity Factor of 15 percent or less and Combustion Turbines with a Capacity Factor Greater than 15 percent. "A person who owns or operates fuel-burning equipment with a capacity factor (as defined in 40 CFR Part 72.2) of 15 percent or less shall:
(a) Provide certification of the capacity factor of the equipment to the Department in writing;
(b) For fuel-burning equipment that operates more than 500 hours during a calendar year, perform a combustion analysis and optimize combustion at least once annually;
(c) Maintain the results of the combustion analysis and any stack tests at the site for at least 2 years and make these results available to the Department and the EPA upon request;
(d) Require each operator of an installation, except combustion turbines, to attend operator training programs at least once every 3 years, on combustion optimization that are sponsored by the Department, the EPA, or equipment vendors; and
(e) Maintain a record of training program attendance for each operator at the site and make these records available to the Department upon request."

Control of HAPs Emissions: See Table IV-6a-Boiler MACT

Table IV – 6	
6.2	**Testing Requirements:** A. Control of Visible Emissions See Monitoring Requirements. B. Control of Sulfur Oxides See Monitoring Requirements. C. Control of Nitrogen Oxides The Permittee shall perform a combustion analysis and optimize combustion at least once annually for any of the auxiliary boiler that operates more than 500 hours during a calendar year. [**Reference: COMAR 26.11.09.08G(1)(b)]**
6.3	**Monitoring Requirements:** A. Control of Visible Emissions The Permittee shall verify that there are no visible emissions when operating. An observer shall perform an EPA Reference Method 9 observation of stack emissions for 18-minute period once every 168 hours of operation or at a minimum once per year. If the boiler operates for less than 100 hours in a calendar year, the visual observation requirement for that calendar year is waived. The Permittee shall perform the following if emissions are visible to human observer: (a) inspect combustion control system and boiler operations, (b) perform all necessary adjustments and/or repairs to the boiler within 48 hours of operation so that visible emissions are eliminated; and (c) document in writing the results of inspections, adjustments and/or repairs to the auxiliary boiler. (d) after 48 hours of operation, if the required adjustments and/or repairs had not eliminated the visible emissions, the Permittee shall perform a Method 9 observation once daily for an 18-minute period until corrective actions have eliminated visible emissions. **[Reference: COMAR 26.11.03.06C]** B. Control of Sulfur Oxides The Permittee shall obtain a certification from the fuel supplier indicating that the fuel oil complies with the limitation on sulfur content of the fuel oil. **[Reference: COMAR 26.11.03.06C].**

Table IV – 6	
	C. Control of Nitrogen Oxides See Record Keeping Requirements.
6.4	**Record Keeping Requirements:** **Note:** All records must be maintained for a period of at least 5 years. **[Reference: COMAR 26.11.03.06C(5)(g)]** A. Control of Visible Emissions The Permittee shall maintain records of all visible emissions observations. **[Reference: COMAR 26.11.03.06C]** B. Control of Sulfur Oxides The Permittee shall retain annual fuel supplier certifications stating that the fuel oil is in compliance with this regulation must be maintained for at least 5 years. **[Reference: COMAR 26.11.09.07C].** C. Control of Nitrogen Oxides The Permittee shall maintain records of the results of the combustion analyses on site for at least five years and make them available to the Department and EPA upon request. **[Reference: COMAR 26.11.09.08G(1)(c) & COMAR 26.11.03.06C]**. The Permittee shall maintain record of training program attendance for each operator on site for at least five years and make the records available to the Department upon request. **[Reference: COMAR 26.11.09.08G(e) & COMAR 26.11.03.06C]**.
6.5	**Reporting Requirements:** A. Control of Visible Emissions The Permittee shall report incidents of visible emissions in accordance with Permit Condition 4, Section III, Plant Wide Condition, "Report of Excess Emissions and Deviations" **[Reference: COMAR 26.11.03.06C]** B. Control of Sulfur Oxides The Permittee shall report annual fuel supplier certification to the Department upon request. **[Reference: COMAR 26.11.09.07C].** C. Control of Nitrogen Oxides The Permittee shall provide certification of the annual capacity factor of the equipment to the Department with support documentation in Annual Emissions certification Report. **[Reference: COMAR 26.11.03.06C].**

Table IV – 6	
	The Permittee shall submit a list of trained operators to the Department upon request. **[Reference: COMAR 26.11.09.08G(e) and COMAR 26.11.03.06C].**

"A permit shield shall cover the applicable requirements identified for the emissions unit(s) listed in the table above."

Table IV – 6a – MACT Subpart DDDDD	
6a.0	**Emissions Unit Number(s): AUX-4 thru AUX-7: Auxiliary Boilers** **AUX-4 thru AUX-7:** Four (4) Combustion Engineering, Model #30VP-12W, auxiliary boilers, each rated at 186.6 MMBtu/hr. These boilers are fired with No. 2 fuel oil.
6a.1	**Applicable Standards/Limits:** Control of HAPs Emissions **40 CFR Part 63, Subpart DDDDD—National Emission Standards for Hazardous Air Pollutants for Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters** **§63.7485** - Am I subject to this subpart? You are subject to this subpart if you own or operate an industrial, commercial, or institutional boiler or process heater as defined in §63.7575 that is located at, or is part of, a major source of HAP, except as specified in §63.7491. For purposes of this subpart, a major source of HAP is as defined in §63.2, except that for oil and natural gas production facilities, a major source of HAP is as defined in §63.7575. **§63.7495** - When do I have to comply with this subpart? "(b) If you have an **existing boiler** or process heater, you must comply with this subpart no later than **January 31, 2016**, except as provided in §63.6(i)." "(d) You must meet the notification requirements in §63.7545 according to the schedule in §63.7545 and in subpart A of this part. Some of the notifications must be submitted before you are required to comply with the emission limits and work practice standards in this subpart." **§63.7500** - What emission limitations, work practice standards, and operating limits must I meet?

Table IV – 6a – MACT Subpart DDDDD

"(a) You must meet the requirements in paragraphs (a)(1) through (3) of this section, except as provided in paragraphs (b), through (e) of this section. You must meet these requirements at all times the affected unit is operating, except as provided in paragraph (f) of this section."
"(c) Limited-use boilers and process heaters must complete a tune-up every 5 years as specified in §63.7540. They are not subject to the emission limits in Tables 1 and 2 or 11 through 13 to this subpart, the annual tune-up, or the energy assessment requirements in **Table 3** to this subpart, or the operating limits in Table 4 to this subpart."
"(f) These standards apply at all times the affected unit is operating, except during periods of startup and shutdown during which time you must comply only with Table 3 to this subpart."

Table 3 to Subpart DDDDD of Part 63—Work Practice Standards
As stated in §63.7500, you must comply with the following applicable work practice standards:

If your unit is...	You must meet the following...
1. A new or **existing** boiler or process heater with a continuous oxygen trim system that maintains an optimum air to fuel ratio, or a heat input capacity of less than or equal to 5 million Btu per hour in any of the following subcategories: unit designed to burn gas 1; unit designed to burn gas 2 (other); or unit designed to burn light liquid, or **a limited use boiler** or process heater	Conduct a tune-up of the boiler or process heater every 5 years as specified in §63.7540.

Limited-use boiler *or process heater* means any boiler or process heater that burns any amount of solid, liquid, or gaseous fuels and has a federally enforceable average annual capacity factor of no more than 10 percent. [§63.7575]

Operational Limits
E-Aux4 – E-Aux7: Auxiliary Boilers 4–7 operations shall be limited to an annual capacity factor of 10 percent or less or an annual heat input of not greater than 163,462 million Btu per boiler.
These units shall be defined as limited use boilers as defined in §63.7500(c) & §63.7575.

6a.2 **Testing Requirements:**

Control of HAPs Emissions
§63.7510 - What are my initial compliance requirements and by what date must I conduct them?

Table IV – 6a – MACT Subpart DDDDD	
	"(e) For existing affected sources (as defined in §63.7490), you must complete the initial compliance demonstration, as specified in paragraphs (a) through (d) of this section, no later than 180 days after the compliance date that is specified for your source in §63.7495 and according to the applicable provisions in §63.7(a)(2) as cited in Table 10 to this subpart, except as specified in paragraph (j) of this section. You must complete an initial tune-up by following the procedures described in §63.7540(a)(10)(i) through (vi) no later than the compliance date specified in §63.7495, except as specified in paragraph (j) of this section. You must complete the one-time energy assessment specified in Table 3 to this subpart no later than the compliance date specified in §63.7495, except as specified in paragraph (j) of this section." **§63.7515** - When must I conduct subsequent performance tests, fuel analyses, or tune-ups? "(d) If you are required to meet an applicable tune-up work practice standard, you must conduct an annual, biennial, or 5-year performance tune-up according to §63.7540(a)(10), (11), or (12), respectively. Each annual tune-up specified in §63.7540(a)(10) must be no more than 13 months after the previous tune-up. Each biennial tune-up specified in §63.7540(a)(11) must be conducted no more than 25 months after the previous tune-up. Each 5-year tune-up specified in §63.7540(a)(12) must be conducted no more than 61 months after the previous tune-up. For a new or reconstructed affected source (as defined in §63.7490), the first annual, biennial, or 5-year tune-up must be no later than 13 months, 25 months, or 61 months, respectively, after the initial startup of the new or reconstructed affected source."
6a.3	**Monitoring Requirements:** Control of HAPs Emissions **§63.7530** - How do I demonstrate initial compliance with the emission limitations, fuel specifications and work practice standards? "(f) You must submit the Notification of Compliance Status containing the results of the initial compliance demonstration according to the requirements in §63.7545(e)." **Continuous Compliance Requirements** **§63.7540** - How do I demonstrate continuous compliance with the emission limitations, fuel specifications and work practice standards? "(a) You must demonstrate continuous compliance with each emission limit in Tables 1 and 2 or 11 through 13 to this subpart, the work practice

Table IV – 6a – MACT Subpart DDDDD	
	standards in Table 3 to this subpart, and the operating limits in Table 4 to this subpart that applies to you according to the methods specified in Table 8 to this subpart and paragraphs (a)(1) through (19) of this section." "(10) If your boiler or process heater has a heat input capacity of 10 million Btu per hour or greater, you must conduct an annual tune-up of the boiler or process heater to demonstrate continuous compliance as specified in paragraphs (a)(10)(i) through (vi) of this section. **This frequency does not apply to limited-use boilers and process heaters, as defined in §63.7575**, or units with continuous oxygen trim systems that maintain an optimum air to fuel ratio. (i) As applicable, inspect the burner, and clean or replace any components of the burner as necessary (you may delay the burner inspection until the next scheduled unit shutdown). Units that produce electricity for sale may delay the burner inspection until the first outage, not to exceed 36 months from the previous inspection. 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; (ii) 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; (iii) Inspect the system controlling the air-to-fuel ratio, as applicable, and ensure that it is correctly calibrated and functioning properly (you may delay the inspection until the next scheduled unit shutdown). Units that produce electricity for sale may delay the inspection until the first outage, not to exceed 36 months from the previous inspection; (iv) 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; (v) 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 (vi) Maintain on-site and submit, if requested by the Administrator, an annual report containing the information in paragraphs (a)(10)(vi)(A) through (C) of this section, (A) The concentrations of CO in the effluent stream in parts per million by volume, and oxygen in volume percent, measured at high fire or

Table IV – 6a – MACT Subpart DDDDD	
	typical operating load, before and after the tune-up of the boiler or process heater; (B) A description of any corrective actions taken as a part of the tune-up; and (C) 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." "(12) If your boiler or process heater has a continuous oxygen trim system that maintains an optimum air to fuel ratio, or a heat input capacity of less than or equal to 5 million Btu per hour and the unit is in the units designed to burn gas 1; units designed to burn gas 2 (other); or units designed to burn light liquid subcategories, or **meets the definition of limited-use boiler or process heater in §63.7575**, you must conduct a tune-up of the boiler or process heater every 5 years as specified in paragraphs (a)(10)(i) through (vi) of this section to demonstrate continuous compliance. You may delay the burner inspection specified in paragraph (a)(10)(i) of this section until the next scheduled or unscheduled unit shutdown, but you must inspect each burner at least once every 72 months." "(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."
6a.4	**Record Keeping Requirements:** **Note:** All records must be maintained for a period of 5 years. **[Reference: COMAR 26.11.03.06C(5)(g)]** Control of HAPs Emissions **Notification, Reports, and Records** **§63.7555** - What records must I keep? "(a) You must keep records according to paragraphs (a)(1) and (2) of this section. (1) A copy of each notification and report that you submitted to comply with this subpart, including all documentation supporting any Initial Notification or Notification of Compliance Status or semiannual compliance report that you submitted, according to the requirements in §63.10(b)(2)(xiv). (2) Records of performance tests, fuel analyses, or other compliance demonstrations and performance evaluations as required in §63.10(b)(2)(viii)."

Table IV – 6a – MACT Subpart DDDDD	
	§63.7560 - In what form and how long must I keep my records? "(a) Your records must be in a form suitable and readily available for expeditious review, according to §63.10(b)(1). (b) As specified in §63.10(b)(1), you must keep each record for 5 years following the date of each occurrence, measurement, maintenance, corrective action, report, or record. (c) You must keep each record on site, or they must be accessible from on site (for example, through a computer network), for at least 2 years after the date of each occurrence, measurement, maintenance, corrective action, report, or record, according to §63.10(b)(1). You can keep the records off site for the remaining 3 years."
6a.5	**Reporting Requirements:** Control of HAPs Emissions **Notification, Reports, and Records** **§63.7545** - What notifications must I submit and when? "(a) You must submit to the Administrator all of the notifications in §§63.7(b) and (c), 63.8(e), (f)(4) and (6), and 63.9(b) through (h) that apply to you by the dates specified." "(e) If you are required to conduct an initial compliance demonstration as specified in §63.7530, you must submit a Notification of Compliance Status according to §63.9(h)(2)(ii). For the initial compliance demonstration for each boiler or process heater, you must submit the Notification of Compliance Status, including all performance test results and fuel analyses, before the close of business on the 60th day following the completion of all performance test and/or other initial compliance demonstrations for all boiler or process heaters at the facility according to §63.10(d)(2). The Notification of Compliance Status report must contain all the information specified in paragraphs (e)(1) through (**8**), as applicable. If you are not required to conduct an initial compliance demonstration as specified in §63.7530(a), the Notification of Compliance Status must only contain the information specified in paragraphs (e)(1) and (**8**)." "(8) In addition to the information required in §63.9(h)(2), your notification of compliance status must include the following certification(s) of compliance, as applicable, and signed by a responsible official: (i) "This facility complies with the required initial tune-up according to the procedures in §63.7540(a)(10)(i) through (vi)."

Table IV – 6a – MACT Subpart DDDDD

§63.7550 - What reports must I submit and when?

"(a) You must submit each report in Table 9 to this subpart that applies to you.

Table 9 to Subpart DDDDD of Part 63—Reporting Requirements
As stated in §63.7550, you must comply with the following requirements for reports:

You must submit a(n)	The report must contain	You must submit the report.
1. Compliance report	a. Information required in §63.7550(c)(1) through (5); and	Semiannually, annually, biennially, or **every 5 years according to the requirements in §63.7550(b).**

(b) Unless the EPA Administrator has approved a different schedule for submission of reports under §63.10(a), you must submit each report, according to paragraph (h) of this section, by the date in Table 9 to this subpart and according to the requirements in paragraphs (b)(1) through (4) of this section. **For units that are subject only to a requirement to conduct** an annual, biennial, or **5-year tune-up according to §63.7540(a)(10)**, (11), or (12), respectively, and **not subject to emission limits or operating limits, you may submit only an annual, biennial, or 5-year compliance report, as applicable, as specified in paragraphs (b)(1) through (4) of this section, instead of a semi-annual compliance report.**

(1) The first compliance report must cover the period beginning on the compliance date that is specified for each boiler or process heater in §63.7495 and ending on July 31 or January 31, whichever date is the first date that occurs at least 180 days (or 1, 2, or 5 years, as applicable, if submitting an annual, biennial, or 5-year compliance report) after the compliance date that is specified for your source in §63.7495.

(2) The first compliance report must be postmarked or submitted no later than July 31 or January 31, whichever date is the first date following the end of the first calendar half after the compliance date that is specified for each boiler or process heater in §63.7495. The first annual, biennial, or 5-year compliance report must be postmarked or submitted no later than January 31.

(3) Each subsequent compliance report must cover the semiannual reporting period from January 1 through June 30 or the semiannual reporting period from July 1 through December 31. **Annual, biennial, and 5-year compliance reports must cover the applicable 1-, 2-, or 5-year periods from January 1 to December 31.**

(4) Each subsequent compliance report must be postmarked or submitted no later than July 31 or January 31, whichever date is the first

Table IV – 6a – MACT Subpart DDDDD	
	date following the end of the semiannual reporting period. **Annual, biennial, and 5-year compliance reports must be postmarked or submitted no later than January 31**. "(c) A compliance report must contain the following information depending on how the facility chooses to comply with the limits set in this rule. (1) If the facility is subject to the requirements of a tune up, they must submit a compliance report with the information in paragraphs (c)(5)(i) through (iv) and (xiv) of this section." "(xiv) Include the date of the most recent tune-up for each unit subject to only the requirement to conduct an annual, biennial, or **5-year tune-up** according to §63.7540(a)(10), (11), or (12) respectively. Include the date of the most recent burner inspection if it was not done annually, biennially, or on a 5-year period and was delayed until the next scheduled or unscheduled unit shutdown." "(h) You must submit the reports according to the procedures specified in paragraphs (h)(1) through (3) of this section." "(3) You must submit all reports required by Table 9 of this subpart electronically using CEDRI that is accessed through the EPA's Central Data Exchange (CDX) (*www.epa.gov/cdx*). However, if the reporting form specific to this subpart is not available in CEDRI at the time that the report is due the report you must submit the report to the Administrator at the appropriate address listed in § 63.13. At the discretion of the Administrator, you must also submit these reports, to the Administrator in the format specified by the Administrator."

"A permit shield shall cover the applicable requirements identified for the emissions unit(s) listed in the table above."

Table IV – 7	
7.0	**Emissions Unit Number(s): 9-1346** One (1) Emergency Fire Pump and one (1) Quench Pump: CT2 Starting engine, CT site fire pump. Main plant fire pump, MTS bldg. emergency generator - Diesel-Fired IC engines.
7.1	**Applicable Standards/Limits:** A. Control of Visible Emissions **1. COMAR 26.11.09.05E(2),** Emission During Idle Mode. "A person may not cause or permit the discharge of emissions from any engine,

Table IV – 7

operating at idle, greater than 10 percent opacity." This requirement is not applicable during Preventative Maintenance.
COMAR 26.11.09.05E(3), Emission During Operating Mode. "A person may not cause or permit the discharge of emissions from any engine, operating at other than idle conditions, greater than 40 percent opacity." This requirement is not applicable during Preventative Maintenance.
Exceptions. **COMAR 26.11.09.05E(4)**
"(a) Section E(2) does not apply for a period of 2 consecutive minutes after a period of idling of 15 minutes for the purpose of clearing exhaust system.
(b) Section E(2) does not apply to emissions resulting directly from cold engine start-up and warm-up for the following maximum periods:
(i) Engines that are idled continuously when not in service: 30 minutes;
(ii) All other engines: 15 minutes.
(c) Section E(2) and E(3) does not apply while maintenance, repair, or testing is being performed by qualified mechanics."

2. 40 CFR Part 60 Subpart IIII - Standards of Performance (NSPS) for Stationary Compression Ignition (CI) Internal Combustion Engines (ICE).
§89.113 - Smoke emission standard.
(a) Exhaust opacity from compression- ignition non-road engines for which this subpart is applicable must not exceed:
(1) 20 percent during the acceleration mode;
(2) 15 percent during the lugging mode; and
(3) 50 percent during the peaks in either the acceleration or lugging modes.

B. Control of Particulate Matter Emissions
NSPS Subpart IIII
§60.4205b - What emission standards must I meet for emergency engines if I am an owner or operator of a stationary CI internal combustion engine?
"(b) Owners and operators of 2007 model year and later emergency stationary CI ICE with a displacement of less than 30 liters per cylinder must comply with the emission standards for new non-road CI engines in **§60.4202,** for all pollutants, for the same model year and maximum engine power for their 2007 model year and later emergency stationary CI ICE.".

C. Control of Sulfur Oxides Emissions
COMAR 26.11.09.07A(2) – Control of Sulfur Oxides from fuel burning equipment. "A person may not burn, sell, or make available for sale any

Table IV – 7	
	fuel with a sulfur content by weight in excess of or which otherwise exceeds the following limitations: In Areas III and IV: (a) All solid fuels, 1.0 percent; (b) **Distillate fuel oils, 0.3 percent;** (c) Residual fuel oils, 1.0 percent. " **§60.4207** - <u>What fuel requirements must I meet if I am an owner or operator of a stationary CI internal combustion engine subject to this subpart?"</u> "**(a)** Beginning October 1, 2007, owners and operators of stationary CI ICE subject to this subpart that use diesel fuel must use diesel fuel that meets the requirements of 40 CFR 80.510(a). **(b)** Beginning October 1, 2010, owners and operators of stationary CI ICE subject to this subpart with a displacement of less than 30 liters per cylinder that use diesel fuel must use diesel fuel that meets the requirements of 40 CFR 80.510(b) for non-road diesel fuel." D. <u>Control of Nitrogen Oxides Emissions</u> **COMAR 26.11.09.08G** – <u>Requirements for Fuel-Burning Equipment with a Capacity Factor of 15 percent or less and Combustion Turbines with a Capacity Factor Greater than 15 percent.</u> (1) "A person who owns or operates fuel-burning equipment with a capacity factor (as defined in 40 CFR Part 72.2) of 15 percent or less shall: (a) Provide certification of the capacity factor of the equipment to the Department in writing; (b) For fuel-burning equipment that operates more than 500 hours during a calendar year, perform a combustion analysis and optimize combustion at least once annually; (c) Maintain the results of the combustion analysis and any stack tests at the site for at least 2 years and make these results available to the Department and the EPA upon request; (d) Require each operator of an installation, except combustion turbines, to attend operator training programs at least once every 3 years, on combustion optimization that are sponsored by the Department, the EPA, or equipment vendors; and (e) Maintain a record of training program attendance for each operator at the site and make these records available to the Department upon request." NSPS Subpart IIII

Table IV – 7	
	§60.4205b - What emission standards must I meet for emergency engines if I am an owner or operator of a stationary CI internal combustion engine? "(b) Owners and operators of 2007 model year and later emergency stationary CI ICE with a displacement of less than 30 liters per cylinder must comply with the emission standards for new non-road CI engines in §60.4202, for all pollutants, for the same model year and maximum engine power for their 2007 model year and later emergency stationary CI ICE.". E. Control of Hazardous Air Pollutants (HAPS) Emissions **40CFR 63 Subpart ZZZZ**—National Emissions Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines "**§63.6590** - What parts of my plant does this subpart cover? This subpart applies to each affected source. (c) Stationary RICE subject to Regulations under 40 CFR Part 60. An affected source that meets any of the criteria in paragraphs (c)(1) through (7) of this section must meet the requirements of this part by meeting the requirements of **40 CFR part 60 subpart IIII**, for compression ignition engines or 40 CFR part 60 subpart JJJJ, for spark ignition engines. *No further requirements apply for such engines under this part.* (1) A new or reconstructed stationary RICE located at an area source." F. NSPS subpart IIII Operational limitations **§60.4209(a)** - What are the monitoring requirements if I am an owner or operator of a stationary combustion engine? "(a) If you are an owner or operator of an emergency stationary CI internal combustion engine, you must install a non-resettable hour meter prior to startup of the engine." §60.4206 How long must I meet the emission standards if I am an owner or operator of a stationary CI internal combustion engine? "Owners and operators of stationary CI ICE must operate and maintain stationary CI ICE that achieve the emission standards as required in §§60.4204 and **60.4205** according to the manufacturer's written instructions or procedures developed by the owner or operator that are approved by the engine manufacturer, over the entire life of the engine." **§60.4211(a) and (e)** - What are my compliance requirements if I am an owner or operator of a stationary CI internal combustion engine?

Table IV – 7	
	"(a) If you are an owner or operator and must comply with the emission standards specified in this subpart, you must operate and maintain the stationary CI internal combustion engine and control device according to the manufacturer's written instructions or procedures developed by the owner or operator that are approved by the engine manufacturer. In addition, owners and operators may only change those settings that are permitted by the manufacturer. You must also meet the requirements of 40 CFR parts 89, 94 and/or 1068, as they apply to you." "(e) Owners or operators may operate the stationary CI ICE 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, or the insurance company associated with the engine. Maintenance checks and readiness testing shall be limited to 100 hours per year. There is no time limit on the use of emergency stationary ICE in emergency situations. Anyone may petition the Administrator for approval of additional hours to be used for maintenance checks and readiness testing, but a petition is not required if the owner or operator maintains records indicating that Federal, State, or local government standards require maintenance and testing of emergency ICE beyond 100 hours per year. Any operation other than emergency operation, and maintenance and testing, is prohibited.
7.2	**Testing Requirements:** A. Control of Visible Emissions 1. & 2. See Monitoring Requirements. B. Control of Particulate Matter Emissions **NSPS: 40 CFR 60 – Subpart IIII** See Monitoring Requirements. C. Control of Sulfur Oxides Emissions 1. & 2. See Monitoring Requirements D. Control of Nitrogen Oxides Emissions 1 NO_x RACT The Permittee shall perform a combustion analysis and optimize combustion at least once annually when the hours of operation exceed 500 during the year. **[Reference: COMAR 26.11.09.08G(1)(b)]**

Table IV – 7	
	2 NSPS See Monitoring Requirements. E. Control of Hazardous Air Pollutants (HAPS) Emissions Comply with NSPS Subpart IIII requirements **[Reference: §63.6590(c)]** F. NSPS subpart IIII Operational limitations See Record Keeping Requirements.
7.3	**Monitoring Requirements:** A. Control of Visible Emissions 1 The Permittee shall properly operate and maintain the engines in a manner to minimize visible emissions. **[Reference: COMAR 26.11.03.06C]** 2- The Permittee must operate and maintain the stationary CI internal combustion engine according to the manufacturer's written instructions or procedures developed by the owner or operator that are approved by the engine manufacturer. **[Reference: §60.4211(a)]** B. Control of Particulate Matter Emissions **NSPS: 40 CFR 60 – Subpart IIII** See operational limitations above. C. Control of Sulfur Oxides Emissions 1 SO_2 RACT The Permittee shall obtain a certification from the fuel supplier indicating that the fuel oil is in compliance with the limitation on the sulfur content of the fuel oil or obtain sulfur in fuel analyses of oil that is representative of the oil burned. **[Reference: COMAR 26.11.03.06C]** 2. NSPS: 40 CFR 60 – Subpart IIII Comply with Tier III requirements. D. Control of Nitrogen Oxides Emissions 1 NO_x RACT The Permittee shall calculate the capacity factor of the engines for each calendar year within 30 days after the end of each year. **[Reference: COMAR 26.11.03.06C]**

Table IV – 7	
	2 NSPS The Permittee must operate and maintain the stationary CI internal combustion engine according to the manufacturer's written instructions or procedures developed by the owner or operator that are approved by the engine manufacturer. **[Reference: §60.4211(a)]** E. Control of Hazardous Air Pollutants (HAPS) Emissions Comply with NSPS Subpart IIII requirements **[Reference: §63.6590(c)]** F. NSPS subpart IIII Operational limitations See Record Keeping Requirements.
7.4	**Record Keeping Requirements:** **Note:** All records must be maintained for a period of at least 5 years. **[Reference: COMAR 26.11.03.06C(5)(g)]** A. Control of Visible Emissions 1. The Permittee shall retain records of preventative maintenance that relate to combustion performance on site for at least 5 years and make these records available to the Department upon request. **[Reference: COMAR 26.11.03.06C]** 2. NSPS: 40 CFR 60 – Subpart IIII Comply with Tier III requirements. B. Control of Particulate Matter Emissions **NSPS: 40 CFR 60 – Subpart IIII** See operational limitations above. C. Control of Sulfur Oxides Emissions 1 SO_2 RACT The Permittee shall maintain records of fuel supplier's certification or sulfur in fuel analyses and shall make records available to the Department upon request. **[Reference: COMAR 26.11.09.07C]** 2. NSPS: 40 CFR 60 – Subpart IIII Comply with Tier III requirements. D. Control of Nitrogen Oxides Emissions 1. NO_x RACT

Table IV – 7	
	The Permittee shall maintain: (1) Records of the calculated capacity factors. **[Reference: COMAR 26.11.03.06C]** (2) Records of hour of operation. **[Reference: COMAR 26.11.02.19.C(1)(b)]** (3) Records of combustion analysis performed if the hours of operation exceed 500. **[Reference: COMAR 26.11.09.08G(1)(c)]** (4) Record of training program attendance for each operator. **[Reference: COMAR 26.11.09.08G(1)(e)]** 2. NSPS40 CFR 60 – Subpart IIII Comply with Tier III requirements. E. Control of Hazardous Air Pollutants (HAPS) Emissions Comply with NSPS Subpart IIII requirements **[Reference: §63.6590(c)]** F. NSPS subpart IIII Operational limitations (1) The Permittee shall maintain a log for the emergency generator indicating the amounts of fuel oil combusted or the hours of operation, and reason for generator operation (i.e., maintenance or operational testing, power outage, etc.). (2) The Permittee shall maintain on site for the life of the source the following records for the emergency diesel generator(s): (a) Documentation of the manufacture date of the diesel engine, if manufactured prior to April 1, 2006, and the manufacturer model year of the diesel engine; (b) The installation date of each emergency diesel generator; and (c) The certifications of compliance or manufacturer engine test data required by 40 CFR §60.4211 and §60.4214(b (3) Beginning October 1, 2007, for any NSPS emergency diesel generator the Permittee shall for each fuel delivery obtain from the fuel supplier a fuel supplier certification consisting of the name of the oil supplier, the date of delivery, the amount of fuel delivered, and a statement from the fuel supplier that the diesel fuel oil complies with the specifications of 40 CFR §80.510. The Permittee shall maintain the required records on site for at least five (5) years. **[Reference: COMAR 26.11.03.06C]**
7.5	**Reporting Requirements:** A. Control of Visible Emissions

Table IV – 7	
	1. & 2: The Permittee shall report incidents of visible emissions in accordance with Permit Condition 4, Section III, "Report of Excess Emissions and Deviations." B. Control of Particulate Matter Emissions **NSPS: 40 CFR 60 – Subpart IIII** See operational limitations above. C. Control of Sulfur Oxides Emissions 1 SO_2 RACT The Permittee shall report fuel supplier certification or a copy of the sulfur in fuel analyses to the Department upon request. **[Reference: COMAR 26.11.09.07C]** 2. NSPS: 40 CFR 60 – Subpart IIII Comply with Tier III requirements. D. Control of Nitrogen Oxides Emissions 1. NO_x RACT The Permittee shall provide certification of the capacity factor of the equipment to the Department in writing as part of the April 1 emission certification report. **[Reference: COMAR 26.11.09.08G(1)(a) & COMAR 26.11.03.06C]** The Permittee shall submit a record of training program attendance for each operator to the Department upon request. **[Reference: COMAR 26.11.09.08G(1)(e)]** E. Control of Hazardous Air Pollutants (HAPS) Emissions Comply with NSPS Subpart IIII requirements **[Reference: §63.6590(c)]** F. NSPS subpart IIII Operational limitations The Permittee shall report the amounts of fuel oil combusted or the hours of operation, and reason for generator operation (i.e., maintenance or operational testing, power outage, etc.) to the Department in the annual emission certification report due on April 1 of each year. **[Reference: COMAR 26.11.03.06C]**

"A permit shield shall cover the applicable requirements identified for the emissions unit(s) listed in the table above."

SECTION V INSIGNIFICANT ACTIVITIES

This section provides a list of insignificant emissions units that were reported in the Title V permit application. The applicable Clean Air Act requirements, if any, are listed below the insignificant activity.

(1) No. **10** Fuel burning equipment using gaseous fuels or no. 1 or no. 2 fuel oil, and having a heat input less than 1,000,000 Btu (1.06 gigajoules) per hour;

[For Areas III and IV]

These *affected fuel burning units* are subject to the following requirements:

COMAR 26.11.09.05A(2), which establishes that the Permittee may not cause or permit the discharge of emissions from any fuel burning equipment, other than water in an uncombined form, which is visible to human observers.

Exceptions: COMAR 26.11.09.05A(2) does not apply to emissions during load changing, soot blowing, start-up, or adjustments or occasional cleaning of control equipment if:

(a) The visible emissions are not greater than 40 percent opacity; and

(b) The visible emissions do not occur for more than 6 consecutive minutes in any sixty-minute period.

[For Distillate Fuel Oil]

COMAR 26.11.09.07A(2)(b), which establishes that the Permittee may not burn, sell, or make available for sale any distillate fuel with a sulfur content by weight in excess of 0.3 percent.

(2) No. **2** Stationary internal combustion engines with an output less than 500 brake horsepower (373 kilowatts) and which are not used to generate electricity for sale or for peak or load shaving;

The *affected units* are subject to the following requirements:

(A) COMAR 26.11.09.05E(2), Emissions During Idle Mode: The Permittee may not cause or permit the discharge of

emissions from any engine, operating at idle, greater than 10 percent opacity.

(B) COMAR 26.11.09.05E(3), Emissions During Operating Mode: The Permittee may not cause or permit the discharge of emissions from any engine, operating at other than idle conditions, greater than 40 percent opacity.

(C) Exceptions:

(i) COMAR 26.11.09.05E(2) does not apply for a period of 2 consecutive minutes after a period of idling of 15 consecutive minutes for the purpose of clearing the exhaust system.

(ii) COMAR 26.11.09.05E(2) does not apply to emissions resulting directly from cold engine start-up and warm-up for the following maximum periods:
(a) Engines that are idled continuously when not in service: 30 minutes
(b) all other engines: 15 minutes.

(iii) COMAR 26.11.09.05E(2) & (3) do not apply while maintenance, repair or testing is being performed by qualified mechanics.

(3) ✓ Space heaters utilizing direct heat transfer and used solely for comfort heat; (**25 heaters**)

(4) No. **50** Unheated VOC dispensing containers or unheated VOC rinsing containers of 60 gallons (227 liters) capacity or less;

The *affected units* are subject to COMAR 26.11.19.09D, which requires that the Permittee control emissions of volatile organic compounds (VOC) from cold degreasing operations by meeting the following requirements:

(a) COMAR 26.11.19.09D(2)(b), which establishes that the Permittee shall not use any VOC degreasing material that exceeds a vapor pressure of 1 mm Hg at 20 °C;

(b) COMAR 26.11.19.09D(3)(a—d), which requires that the Permittee implement good operating practices designed to

minimize spills and evaporation of VOC degreasing material. These practices, which shall be established in writing and displayed such that they are clearly visible to operators, shall include covers (including water covers), lids, or other methods of minimizing evaporative losses, and reducing the time and frequency during which parts are cleaned;

(c) COMAR 26.11.19.09D(4), which prohibits the use of any halogenated VOC for cold degreasing.

The Permittee shall maintain on site for at least five (5) years, and shall make available to the Department upon request, the following records of operating data:

(a) Monthly records of the total VOC degreasing materials used; and

(b) Written descriptions of good operating practices designed to minimize spills and evaporation of VOC degreasing materials.

(5) ✓ Equipment for drilling, carving, cutting, routing, turning, sawing, planing, spindle sanding, or disc sanding of wood or wood products; (**5**)

(6) ✓ Brazing, soldering, or welding equipment, and cutting torches related to manufacturing and construction activities that emit HAP metals and not directly related to plant maintenance, upkeep and repair or maintenance shop activities; (**10**)

(7) ✓ Equipment for washing or drying products fabricated from metal or glass, provided that no VOC is used in the process and that no oil or solid fuel is burned; (**2**)

(8) Containers, reservoirs, or tanks used exclusively for:

(a) ✓ Dipping operations for applying coatings of natural or synthetic resins that contain no VOC; (**2**)

(b) ✓ Storage of butane, propane, or liquefied petroleum, or natural gas; **(2)**

(c) No. **9** Storage of lubricating oils;

(d) No. **1** Unheated storage of VOC with an initial boiling point of 300 °F (149 °C) or greater;

(e) No. **10** Storage of Numbers 1, 2, 4, 5, and 6 fuel oil and aviation jet engine fuel;

(f) No. **1** Storage of motor vehicle gasoline and having individual tank capacities of 2,000 gallons (7.6 cubic meters) or less;

(g) No. **50** The storage of VOC normally used as solvents, diluents, thinners, inks, colorants, paints, lacquers, enamels, varnishes, liquid resins, or other surface coatings and having individual capacities of 2,000 gallons (7.6 cubic meters) or less;

(9) ✓ Gaseous fuel-fired or electrically heated furnaces for heat treating glass or metals, the use of which does not involve molten materials; **(2)**

(10) ✓ Charbroilers and pit barbecues as defined in COMAR 26.11.18.01 with a total cooking area of 5 square feet (0.46 square meter) or less; **(2)**

(11) ✓ First aid and emergency medical care provided at the facility, including related activities such as sterilization and medicine preparation used in support of a manufacturing or production process;

(12) ✓ Certain recreational equipment and activities, such as fireplaces, barbecue pits and cookers, fireworks display, and kerosene fuel use;

(13) ✓ Potable water treatment equipment, not including air stripping equipment; **(2)**

(14) ✓ Comfort air conditioning subject to requirements of Title VI of the Clean Air Act;(**5**)

(15) ✓ Natural draft hoods or natural draft ventilators that exhaust air pollutants into the ambient air from manufacturing/industrial or commercial processes; (**5**)

(16) ✓ Laboratory fume hoods and vents;

SECTION VI STATE-ONLY ENFORCEABLE CONDITIONS

The Permittee is subject to the following State-only enforceable requirements:

1. **Applicable Regulations**:

COMAR 26.11.06.08 – Nuisance. "An installation or premises may not be operated or maintained in such a manner that a nuisance or air pollution is created. Nothing in this regulation relating to the control of emissions may in any manner be consumed as authorizing or permitting the creation of, or maintenance of, nuisance or air pollution."

COMAR 26.11.06.09 - Odors. "A person may not cause or permit the discharge into the atmosphere of gases, vapors, or odors beyond the property line in such a manner that a nuisance or air pollution is created."

Emissions Unit Number(s): E-3 and E-4: Boilers Cont'd

E-3 and E-4: Two (2) tangentially fired, sub-critical, cycling boilers, each rated at 640 megawatts and 6970 million Btu per hour heat input. They are fired on natural gas and No. 6 fuel oil. No. 2 fuel oil or natural gas may be used for ignition, warm-up, and flame stabilization purposes.

Applicable Standards/Limits:

Control of Particulate Matter Emissions
(3) 2011 Consent Decree

3. Subject to Paragraph 4, GenOn Chalk Point, LLC ("GenOn") shall comply with the provisions of Subparagraphs (a) through (d) of this Paragraph.

(a) On days that GenOn is dispatched by PJM Interconnection ("PJM"), pursuant to the PJM's tariff, to operate Chalk Point Unit 3 and/or Unit 4, GenOn will request natural gas deliveries in the quantities GenOn anticipates will be needed to meet GenOn's estimate of PJM's hourly dispatch; provided that GenOn shall not be required to contract for natural gas delivery greater than the minimum operating load consistent with the PJM dispatch if doing so might require GenOn to accept delivery of natural gas in excess of the quantity needed to meet demand.

(b) GenOn may burn fuel oil only to the extent necessary to maintain operations, perform stack testing, respond to a PJM dispatch directive, or

meet the required generation need where the natural gas supply company or pipeline operator interrupts natural gas service. Natural gas service is interrupted within the meaning of this Paragraph when:

(i) A natural gas supply company has limited GenOn's consumption of natural gas due to high demand or inadequate supply.

(ii) A pipeline operator will not permit GenOn to draw natural gas in non-ratable quantities sufficient to meet the dispatch profile authorized by PJM.

(iii) GenOn must discontinue or curtail gas consumption to comply with a directive from a pipeline operator.

(iv) GenOn is unable to obtain delivery of natural gas because natural gas scheduling nominations have closed; or

(v) The gas spur and pressure reducing station that connects the Chalk Point Facility and the pipeline is out of service.

(c) GenOn shall utilize its dual-fuel firing capabilities to burn natural gas to the maximum extent consistent with the provisions of Subparagraphs (a) and (b), and safety and engineering constraints where an interruption of natural gas requires load shaping with oil.

(d) When natural gas has been interrupted, GenOn will attempt to obtain natural gas in quantities needed to meet its generation needs consistent with Subparagraph (a) at the next available nomination period.

4. Notwithstanding the provisions of Paragraph 3, GenOn shall contract for interruptible gas transportation to supply natural gas as the primary fuel for operation of Chalk Point Unit 3 and Unit 4 and shall burn natural gas for no less than 75.0 % of the annual heat input of the Units, calculated on a calendar yearly basis. Note: Unit 4 is also subject to New Source Performance Standard ("NSPS") set forth in 40 C.F.R. § 60.42, which establishes a particulate emissions limitation of 0.10 lbs./MMBtu for residual oil burning units (see condition 9).

5. If the Pipeline or the spur to the plant is damaged, destroyed, or is otherwise not available, the requirements of Paragraphs 3 and 4 shall not apply until the Pipeline or spur is repaired, rebuilt, or otherwise made available. Further, if PJM issues a dispatch order for Chalk Point Units 3 and/or 4 to run under Emergency Procedures or Abnormal Bulk Electric System Operations, invoked to maintain system reliability, stability, and/or avoid load shedding events, the

requirements of Paragraphs 3 and 4 shall not apply for the duration of that dispatch order.

6. Notwithstanding Paragraphs 3 and 4 and COMAR 26.11.09.06B(6)(a), particulate emissions from GenOn Chalk Point Unit 3 and Unit 4 shall not exceed an emissions limitation of 0.020 grains per standard cubic foot of dry exhaust gas (gr/scfd). .....

Ozone Season Restrictions

11. (a) Notwithstanding and subject to Paragraph 4 and Subparagraph (b) of this Paragraph, GenOn shall burn natural gas in Units 3 and 4 for 95 % of their heat input during the Ozone Season, which begins on May 1 and ends on September 30 of each year.

(b) In the event GenOn burns natural gas for less than 95 % of the Units' Ozone Season heat input, GenOn shall record such shortfall and:

(i) burn the equivalent amount of natural gas to make up such shortfall outside the Ozone Season; or

(ii) if GenOn is unable to make up the shortfall outside the Ozone Season before the installation of controls described in Paragraph 15, GenOn agrees to burn the equivalent amount of gas to make up such shortfall following installation of the control equipment referenced in Paragraph 15 of this Consent Decree.

(c) In no event shall the shortfall exceed 3.84 million MMBtu derived from No. 6 fuel oil.

Visible Emissions

12. Upon entry of this Consent Decree GenOn shall:

(a) use natural gas for start-up of Units 3 and 4 when gas is available from the Pipeline under GenOn's interruptible gas service contract.

(b) twice per year, optimize the air-to-fuel ratio in the boilers for Units 3 and 4.

(c) continue use of a chemical additive with Number 6 fuel oil in Units 3 and 4 to reduce opacity: and

(d) wash down the boiler tubes in Units 3 and 4 during each PJM planned outage to reduce opacity during soot blowing.

13. GenOn shall continue to maintain and operate a human machine interface (HMI), or other similar technology on Units 3 and 4, which includes proactive alarming and feedback from opacity monitors to controls to manage the duration and frequency of soot blowing.

14. GenOn shall demonstrate that Units 3 and 4 comply with the visible emission standard set forth in COMAR 26.11.09.05A(2) through the submission of continuous opacity monitor system ("COMS") data, in accordance with Paragraph 22.

Pollution Control Equipment

15. Except for the requirements of Paragraph 11(b)(ii), the requirements of Paragraphs 11, 12, and 13 will terminate as to each Unit after GenOn installs and successfully tests, to the satisfaction of the Department, an electrostatic precipitator or other particulate pollution control equipment on such Unit that GenOn demonstrates, and the Department's satisfaction, is comparable to an electrostatic precipitator in its effectiveness. Prior to terminating the requirements of Paragraphs 11, 12, and 13, except for 11(b)(ii), the Department will secure written concurrence of its determination from the United States Environmental Protection Agency ("USEPA").

Fuel Sulfur Content

16. Unit 3 shall operate in compliance with the requirements of COMAR 26.11.09.07A(2), which establishes the standards for sulfur content in residual oil. In order to demonstrate compliance with this Paragraph, GenOn shall maintain appropriate documentation evidencing the fuel sulfur content from each delivery of residual fuel oil.

Testing Requirements:

Control of Particulate Matter Emissions

(3) 2011 Consent Decree

6.... GenOn shall demonstrate compliance with this emissions limitation through the use of stack testing in accordance with the provisions of Subparagraphs (a) through (e) of this Paragraph.

(a) GenOn shall perform an initial stack test on Unit 3 and Unit 4 in the 2011 calendar year.

(b) Beginning January 1, 2012, GenOn shall perform subsequent stack testing when either Unit 3 or Unit 4 exceeds 570,000 MMBtu (approximately 100 hours of operation) derived from residual fuel oil during any calendar year

(the "Trigger"). In the event that GenOn fails a particulate matter stack test under Paragraph 6, the Trigger shall be reduced to 475,000 MMBtu for subsequent stack tests triggered by residual fuel oil usage. When GenOn has performed four (4) consecutive stack tests triggered by residual fuel oil usage which demonstrate compliance with the particulate matter standard in Paragraph 6, the Trigger shall be reset to 570,000 MMBtu.

(c) Stack testing shall be performed on the corresponding stack serving the Unit meeting the Trigger and shall occur within the one-hundred-eighty (180) days from the date the Trigger is met.

(d) A stack test conducted in accordance with Paragraphs 6 or 7 shall be exempt from the requirements of Paragraph 3 and residual fuel oil burned during such test shall not count towards the Trigger.

(e) Stack testing on oil shall be conducted in accordance with EPA Method 5, under conditions representative of normal operation.

(f) GenOn shall submit stack test protocols for each of Units 3 and 4 to the Department for approval and notify the Department of the scheduled test date(s) at least thirty (30) days in advance of the test(s). GenOn shall submit the stack test results to the Department no later than forty-five (45) days following completion of the applicable test.

7. In the event GenOn fails the stack test for compliance under Paragraph 6 for either Unit 3 or Unit 4 (as applicable), GenOn shall perform a second stack test no later than sixty (60) days following receipt of the stack test results. GenOn shall notify the Department of the scheduled test date at least two weeks in advance of the test(s).

8. In the event GenOn fails to pass the second stack test, GenOn shall evaluate the reasons for the failure, and no later than ninety (90) days following receipt of the second stack test results, submit to the Department for approval, a plan to achieve compliance at the applicable unit through the installation of control technology, fuel switching, or other measures.

9. Stack testing on Unit 4 performed in 2010 in accordance with the requirements of EPA National Stack Testing Guidance dated April 27, 2009, satisfies GenOn's obligations to determine compliance with the New Source Performance Standard ("NSPS") set forth in 40 C.F.R. § 60.42, which establishes a particulate emissions limitation of 0.10 lbs./MMBtu for residual oil burning units.

10. The residual oil burned during a stack test required by Paragraphs 6 or 7 shall not count toward the annual heat input of Chalk Point Unit 3 and Unit 4, for purposes of calculating compliance with Paragraph 4, if the residual oil burned during the stack test:

(a) Accounts for 50.0% or more of the residual oil burned at the corresponding Unit during the calendar year in which the stack test was conducted; and
(b) The required stack test causes GenOn to violate the requirements of Paragraph 4.

Monitoring Requirements:

Control of Particulate Matter
(3) 2011 Consent Decree
See Record Keeping and Reporting Requirements.

Record Keeping Requirements:
Note: All records must be maintained for a period of at least 5 years.
[Reference: COMAR 26.11.03.06C(5)(g)]

E. Control of Particulate Matter Emissions
(3) 2011 Consent Decree
17. GenOn shall preserve for a minimum of five (5) years all fuel use data and other information relied upon to establish compliance with Paragraphs 3 and 4 of this Consent Decree for the time period beginning with entry of this Consent Decree through December 31, 2011. Such documentation shall include the documents described in Paragraph 19(a) and (b). GenOn shall provide the data and information to the Department within 30 days of receiving the Department's written request.

24. Except for that information retention governed by Paragraph 17, GenOn shall preserve from the date of lodging of this Consent Decree, and for a minimum of five (5) years following the date of termination of this Consent Decree, all emissions data and other data relied upon to establish compliance with applicable regulatory standards as required by this Consent Decree.

Reporting Requirements:

Control of Particulate Matter Emission
(3) 2011 Consent Decree
18. Beginning January 1, 2012, GenOn shall submit quarterly reports to the Department detailing the status of GenOn's compliance with Paragraphs 3 and

4 of this Consent Decree. Each quarterly report shall be submitted no later than 30 days following the end of the quarter, unless such date falls on a weekend or holiday, in which case the report shall be due on the next business day.

19. Each quarterly report submitted under Paragraph 18 shall document GenOn's attempts to procure and use natural gas to operate Chalk Point Unit 3 and Unit 4, and shall, at a minimum, include:

(a) Documentation of the dates, hours, and the quantity of fuel burned, and for days where residual oil is burned, the reason natural gas was not used;

(b) For days where any residual oil is burned, the nominating documents and burn profiles submitted to the pipeline operator, and purchase orders between GenOn and any natural gas supplier. Equivalent documentation used in normal and ordinary course of industry practice may be substituted for specific documents described above. If the pipeline operator has notified GenOn in advance that GenOn will be required to take gas ratably and GenOn expects that it will not be dispatched for all 24 hours in that day (the "Notification"), GenOn will not submit a nominating document or burn profile to the pipeline operator nor enter into a purchase order with any natural gas supplier. Instead, GenOn will produce a memorandum or email memorializing the pipeline operator's Notification. In addition to providing that memorandum in its quarterly report, GenOn shall submit the memorandum to the Department within 11 business days of the Notification.

(c) A statement certifying the percent of the annual heat input of the Units derived from the burning of natural gas, as calculated from the beginning of the calendar year through the end of the applicable calendar quarter; and

(d) A compliance certification, signed by a responsible official under the penalty of perjury as to truth, accuracy, and completeness of the report, indicating the compliance status with regard to each term of this Consent Order and whether that compliance was continuous or intermittent.

20. Beginning with the quarterly report for the quarter ending September 30 following entry of this Consent Decree, and each third-quarter report thereafter, GenOn shall submit to the Department documentation of its compliance with

the requirements of Paragraph 11. Progress in addressing any shortfall shall be included in subsequent quarterly reports submitted pursuant to Paragraph 18.

21. GenOn shall submit semi-annual NSPS reports that comply with the requirements of 40 CFR § 60.45(g).

22. GenOn shall submit quarterly opacity reports in accordance with COMAR 26.11.01.10D(2)(c). GenOn shall accurately calculate each Unit's operating time in accordance with the procedures in COMAR 26.11.01.10.

23. All reports and submissions required by this Consent Decree shall be mailed to:

Program Manager
Air Quality Compliance Program
Maryland Department of the Environment
1800 Washington Boulevard
Baltimore, Maryland 21230

Emissions Unit Number(s): E3 & E4: Boilers Cont'd

*Alternate Operating Scenario for Emission Units **E3 & E4***

E-3 & E-4: Two (2) tangentially fired, sub-critical, cycling boilers each rated at 640 megawatts and 6,970 MMBtu/hr. heat input. Units fire natural gas and No. 6 fuel oil. No. 2 fuel oil or natural gas may be used for ignition, warm-up, and flame stabilization purposes. **[4-0998 & 4-0999]**

The Permittee shall burn used oil and boiler chemical cleaning waste materials in the utility boilers.

Applicable Regulations:

COMAR 26.11.09.10 - Requirements to Burn Used Oil and Waste Combustible Fluid as Fuel.
A. General Requirements.
"(1) A person who proposes to burn used oil in fuel-burning equipment shall submit the following information to the Department:

(a) A description of any fuel-burning equipment in which used oil is to be burned, including the unit's location and rated heat input capacity;
(b) The type and amount of fuel currently being used in any fuel-burning equipment in which used oil is to be burned and the gallons of used oil expected to be burned annually;
(c) The maximum blend (percent) of used oil to be burned as fuel in any fuel-burning equipment at any time; and
(d) An analysis by an independent laboratory of a representative sample of the used oil, which shall include the concentration of each of the materials listed in §B of this regulation, the sulfur content, the PCB concentration, and the flash point.
(2) A person who burns fuel oil in fuel-burning equipment with a rated heat input capacity less than 50 million Btu per hour in accordance with a permit to construct or a registration pursuant to COMAR 26.11.02.02A may burn on-specification used oil in that equipment after submitting the information in §A(1) of this regulation.
(3) A person who is burning used oil or WCF under a current written approval from the Department may continue to burn the approved material if:
(a) The person demonstrates that any WCF being burned satisfies the definition of that term in Regulation .01B of this chapter;
(b) The used oil or WCF is being burned in an authorized installation;
(c) The conditions of the approval are continuously met; and
(d) The sulfur requirement in §B(1)(g) of this regulation is not exceeded.
(4) A person shall obtain written approval from the Department before burning:
(a) On-specification used oil in any fuel-burning equipment that has not been registered or previously issued a permit to construct pursuant to COMAR 26.11.02.02 to burn fuel oil;
(b) On-specification used oil in any fuel-burning equipment that has a rated heat input capacity of 50 million Btu per hour or greater;
(c) On-specification used oil in any installation other than fuel-burning equipment; or
(d) Waste combustible fluid or off-specification used oil as fuel in any installation.
(5) A person who obtains written approval from the Department to burn used oil or WCF shall burn only those materials for which approval has been obtained.
(6) Except as provided in §A(7) of this regulation and notwithstanding any applicable conditions in permits issued by the Department, a person may burn off-specification used oil only in those installations listed at 40 CFR §279.12(c).
(7) The requirement to burn off-specification used oil only in those installations listed at 40 CFR §279.12(c) does not apply if the used oil is off-specification only because of the sulfur content."

B. Specifications for Used Oil.
"(1) Except as provided in §B(2) of this regulation, used oil specifications are as follows:

Material	Allowable Level
(a) Lead	100 ppm
(b) Total halogens	1,000 ppm
(c) Arsenic	5 ppm
(d) Cadmium	2 ppm
(e) Chromium	10 ppm
(f) Flash point	100°F minimum
(g) Sulphur content	0.5 weight percent

(2) For used oil that satisfies the rebuttable presumption for halogens at 40 CFR §279.10(b)(1)(ii) and 40 CFR §279.63, the maximum allowable level for halogens is 4,000 ppm."

C. Additional Requirements for Burning Used Oil or WCF Containing Polychlorinated Biphenyls (PCBs).
"(1) Used oil or WCF containing quantifiable levels of PCB (i.e. 2 ppm or greater, but less than 50 ppm) may be burned only in those installations listed at 40 CFR §279.12(c) or 40 CFR §761.
(2) Used oil or WCF with a PCB concentration of 50 ppm or greater is hazardous waste and may only be burned in accordance with the requirements in COMAR 26.13.07 and 40 CFR §761."

D. Reporting Requirements. "By April 1of each year, a person subject to this regulation shall submit a report, in accordance with COMAR 26.11.01.05C, that provides information on:
(1) The quantity of used oil or WCF burned during the previous year; and
(2) The equipment in which the used oil or WCF was burned."

Phase II Initial Acid Rain Permit: Chalk Point Generating Station

Maryland Department of the Environment
Air and Radiation Administration

PHASE II ACID RAIN PERMIT

Plant Name:	Chalk Point Generating Station	
Affected Units:	Unit 3 & 4, GT3, GT4, GT5 & GT6	
Owner: Chalk Point Power LLC		ORIS Code 1572
Effective Date From: December 1, 2022	To: November 30, 2027	

Contents:

---

1. Statement of Basis

Statutory and Regulatory Authorities: In accordance with Environmental Article§2-401, Annotated Code of Maryland and Titles IV and V of the Clean Air Act, the Maryland Department of the Environment, Air and Radiation Administration issues this permit pursuant to COMAR 26.11.02 and COMAR 26.11.03.

Phase II Initial Acid Rain Permit: Chalk Point Generating Station

2. SO_2 Requirements for Each Affected Unit

SO_2 Requirements	
SO_2 Allowances for each unit (Units 3, and 4 and GT3, GT4, GT5 and GT6)	Chalk Point Power, LLC will hold allowances for each unit in accordance with 40 CFR 72.9(c)(1)

3. Comments, Notes, and Justifications Regarding Decisions; Changes Made to the Permit Application Forms During the Review Process, Any Additional Requirements or Conditions:

Units 3 and 4 and GT3, GT4, GT5 and GT6 burn fuel oil or natural gas. Because these units are not coal fired, the nitrogen oxide emissions reduction regulations of 40 CFR Part 76 are not applicable.

Renewal Permit Approval

Angela Bianca

Date of Issuance: December 1, 2022

for Christopher R. Hoagland, Director
Air and Radiation Administration

Maryland Department of the Environment
Air and Radiation Administration

CO_2 BUDGET TRADING PROGRAM PERMIT

Plant Name: Chalk Point Generating Station	
Affected Trading Units: 3, 4, GT2, GT3, GT4, GT5, GT6 and SMECO	
Owner: Chalk Point Power LLC	**ORIS Code** 1571
Effective Date: December 1, 2022 To: November 30, 2027	

Contents:

---

1. Statement of Basis

Statutory and Regulatory Authorities: In accordance with Environmental Article §2-401, Annotated Code of Maryland, the Maryland Department of the Environment, Air and Radiation Administration issues this permit pursuant to COMAR 26.09.01 thru COMAR 26.09.04.

Initial Permit Approval

Christopher G. Hoagland., Director
Air and Radiation Administration

DEC 0 1 2022

Date of Issue

2. Affected Units

Unit ID #	ARA ID #	Unit Description
Unit 3	4-0998	640 MWe (approx..) dual fired boiler, natural gas with No. 6 oil backup
Unit 4	4-0999	640 MWe (approx..) dual fired boiler, natural gas with No. 6 oil backup
GT2	4-1145	35 MWe (approx.) No. 2 oil fired combustion turbine.
GT3	9-0752	99 MWe (approx..) dual fuel fired combustion turbine, natural gas or No. 2 fuel oil.
GT4	9-0753	99 MWe (approx..) dual fuel fired combustion turbine, natural gas or No. 2 fuel oil.
GT5	9-0754	120 MWe (approx..) dual fuel fired combustion turbine, natural gas or No. 2 fuel oil.
GT6	9-0755	120 MWe (approx..) dual fuel fired combustion turbine, natural gas or No. 2 fuel oil.
SMECO	5-0759	93 MWe (approx..) dual fuel fired combustion turbine, natural gas or No. 2 fuel oil.

3. Standard Requirements:

A. Selection and Responsibilities of CO_2 Budget Source Compliance Account Authorized Account Representatives.

(1) Each CO_2 budget source shall have a CO_2 authorized account representative and an alternate CO_2 authorized account representative. (COMAR 26.09.01.04B)

(2) Upon receipt of a complete account certificate of representation:

(a) The CO_2 authorized account representative and alternate CO_2 authorized account representative shall represent and, by representations, actions, inactions, or submissions, legally bind each owner or operator of the CO_2 budget source represented and each CO_2 budget unit at the source in all matters pertaining to this subtitle, notwithstanding any agreement between the CO_2

authorized account representative, alternate CO_2 authorized account representative, and the owners or operators; and

(b) The owners or operators shall be bound by any decision or order issued to the CO_2 authorized account representative or alternate CO_2 authorized account representative by the Department or a court regarding the CO_2 budget source or unit.
(COMAR 26.09.01.04E (1) & (2))

(3) A CO_2 budget permit may not be issued, or a compliance account established for a CO_2 budget source until the Department has received a complete account certificate of representation for a CO_2 authorized account representative and alternate CO_2 authorized account representative of the source and the CO_2 budget units at the source. (COMAR 26.09.01.04F)

(4) Each submission shall be signed and certified by the CO_2 authorized account representative or alternate CO_2 authorized account representative on behalf of each CO_2 budget source and shall include the following statement by the CO_2 authorized account representative or alternate CO_2 authorized account representative: "I am authorized to make the submission on behalf of the owners or operators of the CO_2 budget sources or CO_2 budget units for which the submission is made. I certify under penalty of law that I have personally examined, and am familiar with, the statements and information submitted in the document and all its attachments. Based on my inquiry of those individuals with primary responsibility for obtaining the information, I certify that the statements and information are to the best of my knowledge and belief true, accurate, and complete. I am aware that there are significant penalties for submitting false statements and information or omitting required statements and information, including the possibility of fine or imprisonment."
(COMAR 26.09.01.04G)

B. Distribution of CO_2 Allowances and Compliance

(1) Unless otherwise specified in this chapter, a CO_2 budget source shall demonstrate compliance with its CO_2 budget emissions limitation by holding one CO_2 allowance in its compliance account for every ton of CO_2 that it emits in a control period, by the allowance transfer deadline for that control period. (COMAR 26.09.02.03I(1))

(2) As of the CO_2 allowance transfer deadline for an interim control period, the owners and operators of each CO_2 budget source and each CO_2 budget unit at the source shall hold, in the source's compliance account for deduction under §I of this regulation, CO_2 allowances for no less than 50 percent of the total CO_2 emissions for the interim control period from all CO_2 budget units at the source. (COMAR 26.09.02.03I(2))

(3) Allowances Available for Compliance Deduction. The following CO_2 allowances may be deducted from a compliance account for purposes of complying with a budget source's CO_2 budget emissions limitation for a control period or an interim control period:

(a) CO_2 allowances that are not CO_2 offset allowances and are identified as allowances falling within a prior control period, the same control period, or the same interim control period for which the allowances are deducted;

(b) CO_2 allowances that are held or transferred into the CO_2 budget source's compliance account as of the CO_2 allowance transfer deadline for that control period or for the interim control period contained within that control period;

(c) CO_2 offset allowances that are available to be deducted for compliance during a control period or an interim control period where the quantity of allowances is limited to:

(i) 3.3 percent of the CO_2 budget source's CO_2 emissions for that control period; or

(ii) 3.3 percent of the CO_2 budget source's CO_2 emissions for an interim control period multiplied by 0.50.
(COMAR 26.09.02.03I(3)(a)-(c))

(4) Deduction of CO_2 allowances:
(a) The Department shall deduct allowances from the CO_2 budget source's compliance account until:

(i) The number of CO_2 allowances deducted equals 50 percent of the total CO_2 emissions for an interim control period; or

(ii) The number of CO_2 allowances deducted equals the total CO_2 emissions for the control period.

(b) No deduction shall be made for CO_2 emissions attributable to the burning of eligible biomass.
(COMAR 26.09.02.03I(4)(a) & (b))

(5) The identification of available CO_2 allowances for compliance deduction by serial number or by default is as follows:

(a) The CO_2 authorized account representative for a source's compliance account may request that specific CO_2 allowances, identified by serial number for a control period or interim control period, be deducted; and

(b) In the absence of an identification or in the case of a partial identification of available CO_2 allowances by serial number, the Department shall deduct CO_2 allowances for a control period or interim control period in the following descending order:

(i) For the first control period, all CO_2 allowances purchased by direct sale from the Department during years 2009, 2010, and 2011 resulting from the occurrence of the $7 auction clearing price;

(ii) All CO_2 allowances for a control period allocated to a CO_2 budget unit from the Long-Term Contract Set-aside Account or the Clean Generation Set-aside Account;

(iii) Subject to the relevant compliance deduction limitations identified in §I(3)(c) of this regulation, any CO_2 offset allowances transferred and recorded in the compliance account, in

chronological order; and

(iv) Any CO_2 allowances, other than those identified in §I(5)(b)(i)—(iii) of this regulation, that are available for deduction in the order they were recorded.
(COMAR 26.09.02.03I(5)(a)-(b))

(6) Deductions for Excess Emissions.

(a) If a CO_2 budget source has excess emissions, the Department shall deduct, from the CO_2 budget source's compliance account, CO_2 allowances from allocation years that occur after the control period or interim control period in which the excess emissions or excess interim emissions occurred, equal to three times the excess emissions.

(b) If a source's compliance account holds insufficient CO_2 allowances to cover the excess emissions, the source shall immediately transfer sufficient allowances into its compliance account.

(c) CO_2 offset allowances may not be deducted to account for the source's excess emissions.

(d) No CO_2 allowance deduction shall relieve the owners or operators of the CO_2 budget units at the source of liability for any fine, penalty, assessment or obligation to comply with any other remedy, for the same violation, as ordered under applicable State law.
(COMAR 26.09.02.03I(6)(a)-(d))

(7) Guidelines.

(a) The following guidelines apply in assessing fines, penalties, or other obligations:

(i) For purposes of determining the number of days of violation, if a CO_2 budget unit has excess emissions for a control period or interim control period, each day in the control period or interim control period, as applicable, constitutes a separate day of violation unless the owners or operators of the unit can demonstrate to the satisfaction of the Department that a lesser number of days should be considered; and

(ii) The Department shall consider the amount of excess emissions in determining the severity of the violation.

(b) Each ton of excess interim emissions is a separate violation.
(COMAR 26.09.02.03I(7)(a)-(b))

(8) If the CO_2 budget source's compliance account no longer exists, the CO_2 allowances shall be deposited in a general account selected by the owner or operator of the CO_2 budget source.
(COMAR 26.09.02.03I(8))

(9) Adjustments and Errors.

(a) The Department may review and conduct independent audits concerning any submission under this subtitle and make appropriate adjustments to the information, if necessary.

(b) The Department may correct any error in any account and, within 10 business days of making any correction, notify the CO_2 authorized account representative for the account.
(COMAR 26.09.02.03I(9)(a)-(b))

C. Applicability and Administration

(1) The requirements of this permit apply to the owner or operator of a CO_2 budget unit. When this permit establishes a requirement such as the submittal of a permit application, a report, a request for allowances or transfer of allowances, or general information, these actions shall be achieved through the authorized account representative on behalf of the owner or operator of the affected CO_2 budget source or unit.
(COMAR 26.09.02.02A)

(2) The requirements of this subtitle are effective on January 1, 2009 or, for new CO_2 budget units, on the day on which the unit commences operation.
(COMAR 26.09.02.02C).

(3) The provisions of this permit do not exempt or otherwise relieve the owners or operators of a CO_2 budget source from achieving compliance with any other provision of applicable State and federal laws and regulations.
(COMAR 26.09.02.02D).

(4) Unless otherwise stated under this subtitle, any time period scheduled to begin:

(a) On the occurrence of an act or event, begins on the day the act or event occurs; and

(b) Before the occurrence of an act or event, is computed so that the period ends the day before the act or event occurs.
(COMAR 26.09.02.02E)

(5) Unless otherwise stated, if the final day of any time period for performing an act required by this subtitle falls on a weekend or on a State or federal holiday, the time period is extended until or to the next business day.
(COMAR 26.09.02.02F)

D. Permit Requirements

(1) The account representative or designate alternate account representative) of each affected unit at a source, (every fossil fuel fired unit with a nameplate capacity of 25 MW or greater) for that source shall comply with the following:

(a) The CO_2 authorized account representative for the source shall submit an initial CO_2 budget permit application by October 1, 2008, or 12 months before the date on which the CO_2 budget source, or a new unit at the source, commences operation.
(COMAR 26.09.02.04A(2));

(b) The CO_2 budget permit application shall include the following in a format prescribed by the Department: 1) the identification of the CO_2 budget source; 2) plant name and the ORIS (Office of Regulatory Information Systems) or facility code assigned to the source by the Energy Information Administration of the U. S. Department of Energy, if applicable; 3) each CO_2 budget unit at the source; and 4) other information required by the Department.
(COMAR 26.09.02.04A(3))

(c) A CO_2 authorized account representative for the source shall submit a complete application for the renewal of an existing CO_2 budget permit on forms provided by the Department not later than 90 days before the expiration of the current CO_2 budget permit and in accordance with this regulation.
(COMAR 26.09.02.04E)

(2) Each CO_2 budget source shall apply for and have in effect a CO_2 budget permit that contains all applicable requirements.
(COMAR 26.09.02.04A(1)).

(3) The CO_2 budget permit issued by the Department shall be separate but attached to the budget source's Part 70 permit.
(COMAR 26.09.02.04B)

(4) A CO_2 budget permit expires 5 years from the date of issuance by the Department, unless an earlier expiration date is specified in the permit.
(COMAR 26.09.02.04D)

E. Monitoring, Initial Certification and Recertification Requirements

(1) For each control period in which a CO_2 budget source is subject to the CO_2 budget emissions limitation, the CO_2 authorized account representative of the source shall submit a compliance certification report by the March 1 following the relevant control period. A compliance certification report is not required as part of the compliance obligation during an interim control period.
(COMAR 26.09.02.05A(1))

(2) The CO_2 authorized account representative shall include in the compliance certification report the following:

(a) Identification of the source and each CO_2 budget unit at the source;

(b) At the CO_2 authorized account representative's option, the serial numbers of the CO_2 allowances that are to be deducted from the source's compliance account for the control period, including the serial numbers of any CO_2 offset allowances that are to be deducted subject to applicable limitations; and

(c) The compliance certification required by §A(3) of COMAR 26.09.02.05.
(COMAR 26.09.02.05A(2))

(3) In the compliance certification report, the CO_2 authorized account representative shall certify whether the source and each CO_2 budget unit at the source for which the compliance certification is submitted was operated during the control period in compliance with the requirements of this subtitle, including:

(a) Whether each CO_2 budget unit at the source was operated in compliance with the CO_2 budget emissions limitation;

(b) Whether the monitoring plan applicable to each unit at the source: (i) has been maintained to reflect the actual operation and monitoring of the unit; and (ii) contains all information necessary to track CO_2 emissions from the unit;

(c) Whether all CO_2 emissions from each unit at the source were monitored or accounted for through the missing data procedures and reported in the quarterly monitoring reports, including: (i) whether all conditional data was reported in the quarterly reports; or (ii) if conditional data were reported, whether the status of all conditional data has been resolved and all necessary quarterly report resubmissions have been made;

(d) Whether the basis for certification or for using an excepted monitoring method or approved alternative monitoring method has changed; and

(e) If a change is required to be reported, include: (i) the nature and reasons for the change; (ii) when the change occurred; and (iii) how the unit's compliance status was determined after the change, including the method used to determine emissions when a change mandated the need for monitor recertification.
(COMAR 26.09.02.05A (3) (a)-(e))

(4) The Department, at its discretion, may review and conduct independent audits of any compliance certification or other submission required by this permit.
(COMAR 26.09.02.05B(1))

(5) The Department may deduct CO_2 allowances from, or transfer CO_2 allowances to, a compliance account to correct errors in the account or to accurately reflect CO_2 emissions, based on the information in the compliance certification or other submissions.
(COMAR 26.09.02.05B(2))

(6) The owner or operator of a CO_2 budget unit shall:

(a) Install monitoring systems to monitor CO_2 concentration, stack gas flow rate, oxygen concentration, heat input, and fuel flow rate;

(b) Install all monitoring systems in accordance with 40 CFR Part 75, except for equation G-1 in Appendix G (see below); and

$$W_{CO_2} = \frac{\left(MW_C + MW_{O_2}\right) \times W_C}{2,000\, MW_C} \quad (Eq.\ G\text{-}1)$$

Where:
W_{CO_2}=CO_2 emitted from combustion, tons/day.
MW_C=Molecular weight of carbon (12.0).
MW_{O_2}=Molecular weight of oxygen (32.0)
W_C= Carbon burned, lb/day, determined using fuel sampling and analysis and fuel feed rates.

(c) Record, report, and verify the data from the monitoring systems.
(COMAR 26.09.02.10A(1)(a)-(c))

(7) Install and certify the monitoring system on or before the following dates:

(a) For a CO_2 budget unit that commences commercial operation before July 1, 2008, the owner or operator shall comply on or before January 1, 2009; and

(b) For a CO_2 budget unit that commences commercial operation or constructs a new stack or flue on or after July 1, 2008, the owner or operator shall comply by January 1, 2009, or 90 operating days after the date on which the unit commences commercial operation.
(COMAR 26.09.02.10A(1)(d))

(8) The owner or operator of a CO_2 budget unit that does not meet the applicable compliance date shall, in accordance with the provisions in 40 CFR §75.31(b)(2) or (c)(3), or §2.4 of Appendix D, determine, record, and report maximum potential or, as appropriate, minimum potential for the following:

(a) CO_2 concentration;

(b) CO_2 emissions rate;

(c) Stack gas moisture content;

(d) Fuel flow rate; and

(e) Any other parameter required to determine CO_2 mass emissions.
(COMAR 26.09.02.10A(2)(a)-(e))

(9) The owner or operator of a CO_2 budget unit that does not meet the applicable compliance date for any monitoring system shall determine, record, and report substitute data using the applicable missing data procedures in 40 CFR Part 75 Subpart D, or Appendix D, instead of the maximum potential values or, as appropriate, minimum potential values for a parameter, if the owner or operator demonstrates that there is continuity between the data streams for that parameter before and after the construction or installation.
(COMAR 26.09.02.10A(3))

(10) An owner or operator of a CO_2 budget unit or a non-CO_2 budget unit monitored under 40 CFR

§75.72 (b) (2) (ii) may not:

(a) Use any alternative monitoring system, alternative reference method, or any other alternative for the required continuous emissions monitoring system without having obtained prior written approval from the Department;

(b) Operate the unit so as to discharge, or allow to be discharged, CO_2 emissions to the atmosphere without accounting for all emissions in accordance with the applicable provisions of this chapter and 40 CFR Part 75;

(c) Disrupt the operation of the CEMS, any portion of the CEMS, or any other approved emissions monitoring method, and thereby avoid monitoring and recording CO_2 mass emissions discharged into the atmosphere, except for periods of recertification or periods when calibration, quality assurance testing, or maintenance is performed; or

(d) Permanently discontinue use of the approved CEMS unless the owner or operator monitors emissions with a system approved in accordance with this chapter and 40 CFR Part 75.
(COMAR 26.09.02.10A(4)(a)-(d))

(11) For purposes of this subtitle only, the owner or operator of a CO_2 budget unit is exempt from demonstrating compliance with the initial certification requirements of 40 CFR §75.20 for a monitoring system if the following conditions are met:

(a) The monitoring system has been previously certified in accordance with 40 CFR §75.20; and

(b) The applicable quality assurance and quality-control requirements of 40 CFR §75.21 and Appendix B and Appendix D of 40 CFR Part 75 are fully met for the certified monitoring system.
(COMAR 26.09.02.10B(1)(a)-(b))

(12) The recertification provisions of this regulation apply to a monitoring system exempt from the initial certification requirements of this regulation.
(COMAR 26.09.02.10B(2))

(13) If the Department has previously approved a petition under 40 CFR §75.72(b)(2)(ii) or 40 CFR §75.16(b)(2)(ii)(B) pursuant to 40 CFR §75.13 for apportioning the CO_2 emissions rate measured in a common stack or a petition under 40 CFR §75.66 for an alternative requirement in 40 CFR Part 75, the CO_2 authorized account representative shall resubmit the petition to the Department to determine whether the approval applies under this chapter.
(COMAR 26.09.02.10B(3))

(14) The owner or operator of a CO_2 budget unit shall comply with the initial certification and recertification procedures for a CEMS and an excepted monitoring system under 40 CFR Part 75, Appendix D.
(COMAR 26.09.02.10B(4))

(15) The owner or operator of a unit that qualifies to use the low mass emissions excepted monitoring methodology in 40 CFR §75.19 or that qualifies to use an alternative monitoring system under 40 CFR Part 75, Subpart E, shall comply with this regulation.
(COMAR 26.09.02.10 B(5))

(16) When the owner or operator replaces, modifies, or changes a CEMS that the Department determines significantly affects the ability of the system to accurately measure or record CO_2 mass emissions or to meet the quality assurance and quality control requirements of 40 CFR §75.21 or Appendix B, the owner or operator shall recertify the monitoring system according to 40 CFR §75.20(b).
(COMAR 26.09.02.10C(1))

(17) When the owner or operator replaces, modifies, or changes the flue gas handling system or the unit's operation in a manner that the Department determines has significantly changed the flow or concentration profile, the owner or operator shall recertify the CEMS according to 40 CFR §75.20(b).
(COMAR 26.09.02.10C(2))

(18) Approval Process for Initial Certifications and Recertification. The procedures in 40 CFR §75.20(b)(5) and (g)(7) apply for recertification. The CO_2 authorized account representative shall submit to the Department:

(a) A written notice of the dates of certification; and

(b) A recertification application for each monitoring system, including the information specified in 40 CFR §75.63.
(COMAR 26.09.02.10C(3)(a)-(b))

(19) Provisional certification data for a monitor shall be:

(a) Determined in accordance with 40 CFR §75.20(a)(3);

(b) A provisionally certified monitor may be used for a period not to exceed 120 days after receipt of the complete certification application for the monitoring system or component; and

(c) Data measured and recorded by the provisionally certified monitoring system or component is considered valid quality assured data, retroactive to the date and time of provisional certification, if the Department does not issue a notice of disapproval within 120 days of receipt of the complete certification application.
(COMAR 26.09.02.10C(4)(a)-(c))

(20) The Department shall issue a written notice of approval or disapproval of the certification application to the owner or operator within 120 days of receipt of the complete certification application.
(COMAR 26.09.02.10D(1))

(21) If the Department does not issue the notice within the 120-day period, each monitoring system that meets the applicable performance requirements of 40 CFR Part 75 and is included in the certification application shall be deemed certified for use.
(COMAR 26.09.02.10D(2))

(22) If the certification application is complete and shows that each monitoring system meets the applicable performance requirements of 40 CFR Part 75, the Department shall issue a written notice of approval of the certification application within 120 days of receipt.
(COMAR 26.09.02.10D(3))

(23) If the certification application is not complete, the Department shall issue a written notice of incompleteness that sets a reasonable date by which the CO_2 authorized account representative is to submit the additional information required to complete the certification application.
(COMAR 26.09.02.10D(4))

(24) If the CO_2 authorized account representative does not comply with the notice of incompleteness by the specified date, the Department may issue a notice of disapproval.
(COMAR 26.09.02.10D(5))

(25) If the Department issues a notice of disapproval of a certification application or a notice of disapproval of certification status, the owner or operator shall substitute the following values for each disapproved monitoring system, for each hour of unit operation during the period of invalid data beginning with the date and hour of provisional certification and continuing until the time, date, and hour specified under 40 CFR §75.20(a)(5)(i) or 75.20(g)(7):

(a) For units using or intending to monitor for CO_2 mass emissions using heat input or for units using the low mass emissions excepted methodology under 40 CFR §75.19, the maximum potential hourly heat input of the unit; or

(b) For units intending to monitor for CO_2 mass emissions using a CO_2 pollutant concentration monitor and a flow monitor, the maximum potential concentration of CO_2 and the maximum potential flow rate of the unit under 40 CFR Part 75, Appendix A, §2.1.
(COMAR 26.09.02.10 D(6)(a)-(b))

(26) The CO_2 authorized account representative shall submit a notification of certification retest dates and a new certification application. The owner or operator shall repeat all certification tests or other requirements that were failed by the monitoring system, as indicated in the Department's notice of disapproval, not later than 30 operating days after the date of issuance of the notice of disapproval.
(COMAR 26.09.02.10D(7))

(27) The owner or operator of a unit qualified to use the low mass emissions excepted methodology under 40 CFR §75.19 shall meet the applicable certification and recertification requirements of 40 CFR §§75.19(a) (2) and 75.20(h).
(COMAR 26.09.02.10E(1))

(28) If the owner or operator of this unit elects to certify a fuel flow meter system for heat input

determinations, the owner or operator shall also meet the certification and recertification requirements in 40 CFR §75.20(g).
(COMAR 26.09.02.10E(2))

(29) Certification and Recertification Procedures for Alternative Monitoring Systems. For each unit for which the owner or operator intends to use an alternative monitoring system approved by the Department, 40 CFR Part 75, Subpart E, shall be used to comply with the applicable notification and application procedures of 40 CFR §75.20(f).
(COMAR 26.09.02.10F)

(30) When any monitoring system fails to meet the quality assurance and quality control requirements or data validation requirements of 40 CFR Part 75, data shall be substituted using the applicable procedures in 40 CFR Part 75, Subpart D, Appendix D.
(COMAR 26.09.02.10G(1))

(31) Audit Decertification.

(a) Whenever both an audit of a monitoring system and a review of the initial certification or recertification application reveal that any monitoring system should not have been certified or recertified because it did not meet a particular performance specification or the applicable provisions of 40 CFR Part 75, both at the time of the initial certification or recertification application submission and at the time of the audit, the Department shall issue a notice of disapproval of the certification status of the monitoring system.

(b) By issuing the notice of disapproval, the certification status of the monitoring system is prospectively revoked.
(COMAR 26.09.02.10G(2))

(32) The data measured and recorded by the monitoring system may not be considered valid quality-assured data from the date of issuance of the notification of the revoked certification status.
(COMAR 26.09.02.10G(3))

F. Record Keeping and Reporting Requirements

(1) The CO_2 authorized account representative shall comply with all record-keeping and reporting requirements in COMAR 26.09.02.10 and the applicable record-keeping and reporting requirements under 40 CFR §75.73.
(COMAR 26.09.02.11A)

(2) The CO_2 authorized account representative shall submit quarterly reports as described below in this section.
(COMAR 26.09.02.11B(1))

(3) The report shall contain the CO_2 mass emissions data for the CO_2 budget unit in an electronic format, unless otherwise required by the Department, for each calendar quarter beginning with:

(a) The calendar quarter covering January 1, 2009 — March 31, 2009, for a unit that commences commercial operation before July 1, 2008; or

(b) For a unit commencing commercial operation on or after July 1, 2008, the calendar quarter corresponding to the earlier of the: (i) date of provisional certification; or (ii) applicable deadline for initial certification.
(COMAR 26.09.02.11B(2)(a)-(b))

(c) If the quarter is the third or fourth quarter of 2008, reporting shall commence in the quarter covering January 1, 2009 through March 31, 2009.
(COMAR 26.09.02.11B(3))

(4) The CO_2 authorized account representative shall submit each quarterly report within 30 days following the end of the calendar quarter covered by the report and in accordance with 40 CFR Part 75, Subpart H, §75.64 and 40 CFR Part 75, Subpart G except for the opacity, NO_x and SO_2 provisions.
(COMAR 26.09.02.11B(4))

(5) The CO_2 authorized account representative shall submit a compliance certification in support of each quarterly report. The certification shall state that:

(a) The monitoring data submitted were recorded in accordance with the applicable requirements of this chapter and 40 CFR Part 75, including the quality assurance procedures and specifications;

(b) For a unit with add-on CO_2 emissions controls and for all hours where data are substituted in accordance with 40 CFR §75.34(a)(1) , the add-on emissions controls were operating within the range of parameters listed in the quality assurance and quality control program under 40 CFR Part 75, Appendix B, and the substitute values do not systematically underestimate CO_2 emissions; and

(c) The CO_2 concentration values substituted for missing data under 40 CFR Part 75, Subpart D, do not systematically underestimate CO_2 emissions.
(COMAR 26.09.02.11B(5)(a)-(c))

(6) The CO_2 authorized account representative of a CO_2 budget unit may submit a petition to the Department under 40 CFR §75.66 requesting approval to apply an alternative to any requirement of this chapter.
(COMAR 26.09.02.11C)

(7) The CO_2 authorized account representative or alternate CO_2 authorized account representative of a CO_2 budget unit that burns eligible biomass as a compliance mechanism under this chapter shall report the following information for each calendar quarter:

(a) For each shipment of solid eligible biomass fuel fired at the CO_2 budget unit:

(i) Total eligible biomass fuel input, on an as-fired basis, in pounds; and

(ii) The moisture content, on an as-fired basis, as a fraction of weight;

(b) For each distinct type of gaseous eligible biomass fuel fired at the CO_2 budget unit:

(i) The density of the biogas, on an as-fired basis, in pounds per standard cubic foot; and

(ii) The moisture content of the biogas, as a fraction by total weight;

(c) For each distinct type of eligible biomass fuel fired at the CO_2 budget unit:

(i) The dry basis carbon content of the fuel type, as a fraction by dry weight;

(ii) The dry basis higher heating value, in MMBtu per dry pound;

(iii) The total dry basis eligible biomass fuel input, in pounds;

(iv) The total eligible biomass fuel heat input; and

(v) Chemical analysis, including heat value and carbon content;

(d) The total amount of CO_2 emitted from the CO_2 budget unit due to firing eligible biomass fuel, in tons, calculated as in §D(2)(b) of this regulation;

(e) The total heat input to the CO_2 budget unit due to firing eligible biomass fuel, in MMBtu, calculated below; and

(f) Description and documentation of monitoring technology and fuel sampling methodology employed, including sampling frequency.
(COMAR 26.09.02.11 D(1)(a)-(f))

(8) An owner or operator of a CO_2 budget unit shall calculate and submit on a quarterly basis the total dry weight for each distinct type of eligible biomass fired by the CO_2 budget unit during the reporting quarter:

(a) For solid eligible biomass fuel, determined as follows:

$$F_j = \sum_{i=1}^{m} (1 - M_i) x F_i$$

where:
(i) F_j = Total eligible biomass dry basis fuel input (pounds) for fuel type j;
(ii) F_i = Eligible biomass as fired fuel input (pounds) for fired shipment i;
(iii) M_i = Moisture content (fraction) for fired shipment i:
(iv) i = fired fuel shipment;
(v) j = fuel type; and

(vi) m = number of shipments.

(b) For gaseous eligible biomass fuel, as determined as follows:

$$F_j = D_j x V_j x (1 - M_j)$$

where:

(i) F_j = Total eligible biomass dry basis fuel input (pounds) for fuel type j;
(ii) D_j = Density of biogas (pounds/scf) for fuel type j;
(iii) Vj = Total volume (scf) for fuel type j;
(iv) Mj = Moisture content (fraction) for fuel type j; and
(v) j = fuel type
(COMAR 26.09.02.11D(2)(a)-(b))

(9) The amount of CO_2 emissions that is produced from the firing of eligible biomass for any full calendar quarter, during which either no fuel other than eligible biomass is combusted or during which fuels other than eligible biomass are combusted, is determined as follows:

$$CO_2 tons = \sum_{j=1}^{n} F_j x C_j x O_j \left(\frac{44\left(\frac{g}{molCO_2}\right)}{12\left(\frac{g}{molC}\right)} \right) (0.0005)$$

where:

(a) CO_2 tons = CO_2 emissions due to firing of eligible biomass for the reporting quarter;
(b) F_j = Total eligible biomass dry basis fuel input (pounds) for fuel type j, as calculated in §D(2)(a) of this regulation;
(c) C_j = Carbon fraction (dry basis) for fuel type j;
(d) Oj = Oxidation factor for eligible biomass fuel type j, derived for solid fuels based on the ash content of the eligible biomass fired and the carbon content of this ash or for gaseous eligible biomass fuels, a default oxidation factor of 0.995 may be used;

(e) $\dfrac{44\left(\frac{g}{molCO_2}\right)}{12\left(\frac{g}{molC}\right)}$

= The number of tons of carbon dioxide that are created when one ton of carbon is combusted;

(f) 0.0005 = The number of short tons which is equal to one pound;
(g) j = Fuel type; and
(h) n = number of distinct fuel types.
(COMAR 26.09.02.11D(3))

(10) Heat input due to firing of eligible biomass for each quarter shall be determined as follows:

(a) For each distinct fuel type:

$$H_j = F_j x HHV_j$$

where:

(i) H_j = Heat input (MMBtu) for fuel type j;
(ii) F_j = Total eligible biomass dry basis fuel input (pounds) for fuel type j;
(iii) HHV_j = Higher heating value (MMBtu/pound), dry basis, for fuel type j, as determined through chemical analysis;
(iv) j = Fuel type.

(b) For all fuel types:

$$HeatInputMMBtu = \sum_{j=1}^{n} H_j$$

where:

(i) H_j = Heat input (MMBtu) for fuel type j;
(ii) j = fuel type; and
(iii) n = number of distinct fuel types.

Fuel sampling methods and fuel sampling technology shall be consistent with the New York State Renewable Portfolio Standard Biomass Guidebook, September 2011.
(COMAR 26.09.02.11D(4) & D(5))

(11) A CO_2 budget unit shall submit to the Department the megawatt-hour value and a statement certifying that the megawatt-hour of electrical output reported reflects the total actual electrical output for all CO_2 budget units at the facility used by the independent system operator (ISO) to determine settlement resources of energy market participants.
(COMAR 26.09.02.11E(1))

(12) A CO_2 budget unit shall report gross hourly megawatts to the Department in the same electronic data report (EDR) for gross output as submitted to the EPA Administrator, for the operating time in the hour, added for all hours in a year.
(COMAR 26.09.02.11E(2))

(13) A CO_2 budget unit shall submit the net electrical output to the Department in accordance with this regulation. A CO_2 budget source whose electrical output is not used in the independent system operator (ISO) energy market settlement determinations shall propose a method for quantification of net electrical output.
(COMAR 26.09.02.11E(3))

(14) Report of net Steam Output.

(a) CO_2 budget sources selling steam shall use billing meters to determine net steam output or an alternative method to measure net steam output approved by the Department.

(b) If data for steam output is not available, the CO_2 budget source may report heat input, substituting useful steam output for steam output.
(COMAR 26.09.02.11E(4)(a)-(b))

(15) Each CO_2 budget source shall submit an output monitoring plan with a description and diagram that include the following:

(a) If the CO_2 budget unit monitors net electric output, the diagram shall contain all CO_2 budget units and all generators served by each CO_2 budget unit and the relationship between CO_2 budget units and generators;

(b) If a generator served by a CO_2 budget unit is also served by a nonaffected unit, the nonaffected unit and its relationship to each generator shall be indicated on the diagram;

(c) The diagram shall indicate where the net electric output is measured and include all electrical inputs and outputs to and from the plant;

(d) If net electric output is determined using a billing meter, the diagram shall show each billing meter used to determine net sales of electricity and show that all electricity measured at the point of sale is generated by the CO_2 budget units;

(e) If the CO_2 budget unit monitors net thermal output, the diagram shall indicate all steam or hot water coming into the net steam system, including steam from CO_2 budget units and nonaffected units, and all exit points of steam or hot water from the net steam system;

(f) Each input and output stream shall have an estimated temperature, pressure and phase indicator, and an enthalpy in Btu per pound;

(g) The diagram of the net steam system shall identify all useful loads, house loads, parasitic loads, any other steam loads, and all boiler feedwater returns;

(h) The diagram shall represent all energy losses in the system as either usable or unusable losses;

(i) The diagram shall indicate all flow meters, temperature or pressure sensors, or other equipment used to calculate gross thermal output; and

(j) If a sales agreement is used to determine net thermal output, the diagram shall show the monitoring equipment used to determine the sales of steam.
(COMAR 26.09.02.11F(2)(a)-(j))

(16) The description of the output monitoring system shall include:

(a) A written description of the output system and the equations used to calculate output, and, for

net thermal output systems, descriptions and justifications of each useful load;

(b) A detailed description of all quality assurance and quality control activities that will be performed to maintain the output system; and

(c) Documentation supporting any output value to be used as a missing data value if there are periods of invalid output data.

(d) The missing data output value shall be either zero or an output value that is likely to be lower than a measured value and approved as part of the required monitoring plan.
(COMAR 26.09.02.11F(3)(a)-(b))

(17) A certification statement shall be submitted by the CO_2 authorized account representative stating that either:

(a) The output monitoring system consists entirely of billing meters; or

(b) The output monitoring system meets one of the accuracy requirements for nonbilling meters.
(COMAR 26.09.02.11G(1)(a)-(b))

(18) The billing meter shall record the electric or thermal output. Any electric or thermal output values reported shall be the same as the values used in billing for the output.
(COMAR 26.09.02.11G(2))

(19) For nonbilling meters, either the output monitoring system shall meet an accuracy of within 10 percent of the reference value, or each component monitor for the output system shall meet an accuracy of within 3 percent of the full scale value, whichever is less stringent.
(COMAR 26.09.02.11G(3))

(20) The system approach to accuracy shall include:

(a) A determination of how the system accuracy of 10 percent is achieved using the individual components in the system; and

(b) Data loggers and any wattmeters used to calculate the final net electric output data or any flowmeters for steam or condensate, temperature measurement devices, absolute pressure measurement devices, and differential pressure devices used for measuring thermal energy.
(COMAR 26.09.02.11G(4) (a)-(b))

(21) If, upon testing a piece of output measurement equipment, it is determined that the output readings are not accurate to within 3 percent of the full scale value, then the equipment shall be repaired or replaced to meet that requirement.
(COMAR 26.09.02.11G(5))

(22) Data is invalid until the output measurement equipment passes an accuracy test or is replaced with another piece of equipment that passes the accuracy test.

(COMAR 26.09.02.11G(6))

(23) Ongoing quality assurance and quality control activities shall be performed in order to maintain the output system.
(COMAR 26.09.02.11H(1))

(24) If billing meters are used to determine output, quality assurance and quality control activities are not required beyond what are already performed.
(COMAR 26.09.02.11H(2))

(25) Certain types of equipment such as potential transformers, current transformers, nozzle and venture type meters, and the primary element of an orifice plate only require an initial certification of calibration and do not require periodic recalibration unless the equipment is physically changed.

(a) Pressure and temperature transmitters accompanying an orifice plate will require periodic retesting.

(b) For other types of equipment, the meter accuracy shall be recalibrated or verified at least once every 2 years, unless a consensus standard allows for less frequent calibrations or accuracy tests.

(c) For nonbilling meters, either the output monitoring system shall meet an accuracy of within 10 percent of the reference value, or each component monitor for the output system shall meet an accuracy of within 3 percent of the full-scale value, whichever is less stringent.

(d) If, upon testing a piece of output measurement equipment, it is determined that the output readings are not accurate to within 3 percent of the full-scale value, then the equipment shall be repaired or replaced to meet that requirement.
(COMAR 26.09.02.11 H(3)(a)-(e))

(26) Out-of-Control Periods.

(a) If, upon testing a piece of output measurement equipment, it is determined that the output readings are not accurate to the certification value, data is invalid until the output measurement equipment passes an accuracy test or is replaced with another piece of equipment that passes the accuracy test.

(b) All invalid data shall be replaced by either zero or an output value that is likely to be lower than a measured value and that is approved as part of the required monitoring plan.
(COMAR 26.09.02.11 H(4)(a)-(b))

(27) The CO_2 authorized account representative shall submit annual output reports, as follows:

(a) Data shall be sent both electronically and in hardcopy by March 1 for the immediately preceding calendar year; and
(COMAR 26.09.02.11I 1))

(28) The annual report shall include unit level megawatt hours, all useful steam output, and a certification statement from the CO_2 authorized account representative stating the following, "I am authorized to make this submission on behalf of the owners and operators of the CO_2 budget sources or CO_2 budget units for which the submission is made. I certify under penalty of law that I have personally examined, and am familiar with, the statements and information submitted in this document and all its attachments. Based on my inquiry of those individuals with primary responsibility for obtaining the information, I certify that the statements and information are to the best of my knowledge and belief true, accurate, and complete. I am aware that there are significant penalties for submitting false statements and information or omitting required statements and information, including the possibility of fine or imprisonment."
(COMAR 26.09.02.11I(2))

G. CO_2 Emission Offset Projects

(1) In order to qualify for the award of CO_2 offset allowances, the following offset projects shall satisfy all applicable requirements identified in COMAR 26.09.03 and initially commence on or after December 20, 2005:

(a) Landfill methane capture and destruction;

(b) Reduction in emissions of sulfur hexafluoride (SF_6);

(c) Sequestration of carbon due to afforestation;

(d) Reduction or avoidance of CO_2 emissions from natural gas, oil, or propane end-use combustion due to end-use energy efficiency; and

(e) Avoided methane emissions from agricultural manure management operations.
(COMAR 26.09.03.02A(1)-(5))

4. Permit Application (See Attachment)

CHALK POINT POWER, LLC
CHALK POINT GENERATING STATION
25100 CHALK POINT ROAD AQUASCO, MD 20608
PERMIT NO. 24-033-2920
PART 70 OPERATING PERMIT FACT SHEET

BACKGROUND

The Chalk Point Generating Station is located on the Patuxent River at Swanson Creek in Prince Georges' County Maryland. The Chalk Point facility is engaged in the generation of electric energy for sale. The primary SIC code for this facility is 4911.

The major components of the facility consist of two (2) oil/gas-fired steam units (**E-3 & E-4**), seven (7) combustion turbines (**E-CT1 through E-CT6 and SMECO-CT1**) and four (4) auxiliary boilers (**AUX-4 through AUX-7**).

Steam units 3 and 4 [**E-3 and E-4**] are tangentially fired, sub-critical, cycling boilers, each rated at 640 megawatts. These units fire natural gas and No. 6 fuel oil. No. 2 fuel oil or natural gas may be used for ignition, warm-up, and flame stabilization purposes. Steam units E-3 and E-4 exhaust through two separate stacks, each 712 feet high.

All seven (7) CTs have oil-firing capability. **E-CT3 thru E-CT6** and **SMECO-CT1** can fire natural gas. **E-CT3** through **E-CT6** exhausts through four separate stacks each 213 feet high, while **SMECO-CT1** exhaust through a single stack 85 feet high.

Auxiliary boilers [**AUX-4 through AUX-7**] use No. 2 fuel oil as the primary fuel. Each boiler is rated at 186.6 MMBtu/hr. heat input. These boilers are used to start up the steam units.

The following table 1 summarizes the actual emissions from Chalk Point Generating Station based on its Annual Emission Certification Reports:

Table 1: Actual Emissions (all units including coal units)

Year	NO_x (TPY)	SO_x (TPY)	PM_{10} / $PM_{2.5}$ (TPY)	CO (TPY)	VOC (TPY)	Total HAP (TPY)
2021	704.85	605.34	47.16 / 37.12	100.78	13.35	5.64
2020	282.79	229.50	23.71 / 20.57	64.33	10.50	1.68
2019	600.06	412.18	30.83 / 18.91	72.47	9.13	4.01
2018	1,392.54	799.30	90.47 / 73.91	195.55	30.61	7.53
2017	780.03	555.61	65.53 / 49.93	121.37	20.06	3.98
2016	2,326.11	1,578.81	411.12 / 383.05	393.02	63.09	21.81

Coal units retired on June 1, 2021.

Table 1a: Actual Emissions (Gas and oil units only without coal units)

Year	NO_x (TPY)	SO_x (TPY)	PM_{10} / $PM_{2.5}$ (TPY)	CO (TPY)	VOC (TPY)	Total HAP (TPY)
2021	109.25	13.14	7.21 / 7.06	24.82	4.42	0.00
2020	164.09	15.00	11.38 / 11.18	36.81	7.52	0.00
2019	71.17	13.08	5.46 / 5.00	15.55	2.60	0.00
2018	459.97	88.00	27.52 / 27.02	83.31	17.80	0.00
2017	327.13	30.91	21.26 / 20.30	64.31	13.32	0.00
2016	1,002.71	40.34	60.38 / 59.46	197.03	41.49	0.00

The major source threshold for triggering Title V permitting requirements in Prince Georges' County is 25 tons per year for VOC and NO_x, and 100 tons per year for any other criteria pollutants and 10 tons for a single HAP or 25 tons per year for total HAPS. Since the actual NO_x, SO_x, VOC, PM_{10} and CO emissions from the facility are greater than the major source threshold, Chalk Point Generating Station is required to obtain a Title V – Part 70 Operating Permit under COMAR 26.11.03.01.

The Department, on November 27, 2019, received the Chalk Point Generating Station's Part 70-permit initial application, which was submitted by GenOn Mid-Atlantic, LLC. An administrative completeness review was conducted, and the application was deemed complete. A completeness determination letter was sent to GenOn Mid-Atlantic, LLC on December 05, 2019, granting Chalk Point Generating Station an application shield.

A modification to the application was submitted May 8, 2020, via email. The modification includes the separation of the oil/gas-fired units under a new title V permit. The purpose of the separation is to prepare one or both entities for a potential future sale.

On November 13, 2020, GenOn Mid-Atlantic, LLC had its name changed to Lanyard Power Holdings, LLC.

The two (2) coal fired boilers retired from operation on June 1, 2021. The Department received a letter dated June 9, 2021, with the submission of the "Retired Unit Exemption Notices" for Chalk Point Generating Station Units 1 & 2 for the Acid Rain and CSAPR Programs.

A letter dated January 5, 2022, from Lanyard Power Holdings, LLC stating that the company is not seeking renewal permits for the retired coal units, since these units are retired and will remain permanently retired.

MACT and NSPS

Chalk Point Generating Station is a major source of HAPs and is subject to the following MACT standards (40 CFR Part 63):

1. Subpart DDDDD—National Emission Standards for Hazardous Air Pollutants for Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters (**AUX-4 thru AUX-7**). The auxiliary boilers are subject to the National Emissions Standards for Hazardous Air Pollutants for Industrial, Commercial, and Institutional Boilers and Process Heaters, 40 CFR part 63, Subpart DDDDD (Boiler MACT)
2. Subpart ZZZZ—National Emission Standard for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines (Fire Pump and Quench Pump Emergency Diesel Generators)

Chalk Point Generating Station is subject to NSPS (40 CFR Part 60),

1. Subpart GG—Standards of Performance for Stationary Gas Turbines (**E-CT3 thru E-CT6, SMECO-CT1**).
2. Subpart D—Standards of Performance for Fossil-Fuel-Fired Steam Generators (**E-4**)
3. Subpart IIII—Standards of Performance for Stationary Compression Ignition Internal Combustion Engines (Fire Pump and Quench Pump Emergency Diesel Generators)

Chalk Point Generating Station is subject to the NO_x Reasonably Available Control Technology (RACT) requirements, Acid Rain Program, and the Cross-State Air Pollution Rule (CSAPR). Chalk Point Generating Station is also subject to the requirements of the Regional Greenhouse Gas Initiative (RGGI) program which is a State-only enforceable program. Under these regulations, Chalk Point Generating Station is required to submit a RGGI permit application. The renewal RGGI permit upon issuance will be attached to the Part 70 permit.

Cross-State Air Pollution Rule (CSAPR)

The U.S. Environmental Protection Agency (EPA) issued the Cross-State Air Pollution Rule (CSAPR) in July 2011 to address Clean Air Act requirements concerning interstate transport of air pollution and to replace the previous Clean Air Interstate Rule (CAIR) which the D.C. Circuit remanded to the EPA for replacement. Following the original rulemaking, CSAPR was amended by three further rules known as the Supplemental Rule, the First Revisions Rule, and the Second Revisions Rule. As amended, CSAPR requires 28 states to limit their

state-wide emissions of sulfur dioxide (SO_2) and/or nitrogen oxides (NO_x) in order to reduce or eliminate the states' contributions to fine particulate matter and/or ground-level ozone pollution in other states. The emissions limitations are defined in terms of maximum state-wide "budgets" for emissions of annual SO_2, annual NO_x, and/or ozone season NO_x by each state's large electricity generating units (EGUs). The emissions budgets are implemented in two phases of generally increasing stringency. As the mechanism for achieving compliance with the emissions limitations, CSAPR establishes federal implementation plans (FIPs) that require large EGUs in each affected state to participate in one or more new emission trading programs that supersede the existing CAIR emissions trading programs. On December 30, 2011, in response to petitions challenging CSAPR, the D.C. Circuit granted a stay of the rule, ordering the EPA to continue administering CAIR on an interim basis. In a subsequent decision, the Court vacated CSAPR, but on April 29, 2014, the U.S. Supreme Court reversed that decision and remanded the case to the D.C. Circuit Court for further proceedings. In order to allow CSAPR to replace CAIR in an orderly manner, EPA filed a motion asking the D.C. Circuit to lift the stay and to toll, by three years, all CSAPR compliance deadlines that had not yet passed. On October 23, 2014, the Court granted the EPA's motion.

Consistent with the Court's order, compliance with CSAPR's Phase 1 emissions budgets is now required in 2015 and 2016 and compliance with the rule's Phase 2 emissions budgets and assurance provisions is now required in 2017 and beyond.

On September 7, 2016, EPA finalized the CSAPR Update, which further reduced NO_x emissions from EGUs in 22 states during the ozone season, May 1 thru September 30, thereby reducing pollution transport and helping downwind states achieve and maintain the 2008 ozone standard (75 ppb). On October 26, 2016, CSAPR Update was published in the federal register, with an effective date of December 27, 2016.

On March 15, 2021, EPA finalized the Revised Cross-State Air Pollution Rule Update for the 2008 ozone National Ambient Air Quality Standards (NAAQS). Starting in the 2021 ozone season, the rule will require additional emissions reductions of nitrogen oxides (NO_x) from power plants in 12 states, improving air quality for millions of Americans. On April 30, 2021, the Revised CSAPR Update was published in the federal register, with an effective date of June 29, 2021.

This renewal Part 70 permit identifies the applicable regulations of the CSAPR rule as found in 40 CFR Part 97 subparts AAAAA - NO_x Annual Trading Program, subparts GGGGG - NO_x Ozone Season Group 3 Trading Program, and subpart CCCCC SO_2 Group 1 Trading Program.

REGIONAL GREENHOUSE GAS INITIATIVE

The Regional Greenhouse Gas Initiative (RGGI) is a market-based carbon dioxide (CO_2) cap and trade program designed to reduce CO_2 emissions from fossil fuel-fired power plants. It is a Maryland Sate-only enforceable program. The Healthy Air Act (discussed above) required Maryland to join RGGI by July 2007. Maryland joined RGGI by signing RGGI's multi-state Memorandum of Understanding (MOU) on April 20, 2007. The MOU requires Maryland to adopt regulations by December 31, 2008, implementing the RGGI program. The Maryland CO_2 Budget Trading Program, Code of Maryland Regulations (COMAR) 26.09.01 to .03, became effective on July 17, 2008. COMAR 26.09.04 became effective as an emergency action on April 4, 2008, and as a permanent action on August 25, 2008.

The regulations require the following:

1) Implement a cap-and-trade program for CO_2 emissions from fossil fuel-fired electric generating units located in Maryland having a capacity of at least 25 megawatts;
2) Distribute CO_2 allowances to stakeholders through auction, sale and/or allocation;
3) Require each affected source to have a CO_2 budget account representative and a compliance account;
4) Require each budget unit to hold in its source's compliance account at the end of each 3-year control period one allowance for each ton of CO_2 emissions emitted in that period;
5) Require sources to monitor emissions and submit quarterly and annual emission reports;
6) Establish set-aside accounts for voluntary renewable purchase, limited industrial generator exemptions, and long-term contract generators;
7) Establish a consumer benefit or strategic energy purpose fund to support energy efficiency, directly mitigate electricity ratepayer impacts, promote renewable or non-carbon emitting energy technologies, stimulate or reward investment in the development of innovative carbon emissions abatement technologies with significant carbon reduction potential, and fund administration of the program; and
8) Establish procedures to evaluate and award allowances to persons who undertake offset projects that will reduce CO_2 emissions.
9) Require affected sources to submit an application for a CO_2 Budget Permit. A CO_2 Budget Permit when issued will be an attachment to the Part 70 permit.

GREENHOUSE GAS (GHG) EMISSIONS

Chalk Point Generating Station emits the following greenhouse gases (GHGs) related to Clean Air Act requirements: carbon dioxide, methane, and nitrous oxide. These GHGs originate from various processes (i.e., boilers, combustion turbines, and engines) contained within the facility premises applicable to Chalk Point Generating Station. The facility has not triggered Prevention of Significant Deterioration (PSD) requirements for GHG emissions; therefore, there are no applicable GHG Clean Air Act requirements. While there may be no applicable requirements as a result of PSD, emission certification reports for the years 2018, 2019, 2020, and 2021, showed that Chalk Point Generating Station is a major source (threshold: 100,000tpy CO_2e) for GHG's (see Table 3 shown below). The Permittee shall quantify facility wide GHGs emissions and report them in accordance with Section 3 of the Part 70 permit.

The following table summarizes the actual emissions from Chalk Point Generating Station based on its Annual Emission Certification Reports:

Table 3: Greenhouse Gases Emissions Summary (all units including coal units)

GHG	Conversion factor	2018 tpy CO_2e	2019 tpy CO_2e	2020 tpy CO_2e	2021 tpy CO_2e
Carbon dioxide CO_2	1	1,607,253.2	668,110.1	445,265.8	965,451.9
Methane CH_4	25	3,570.2	1,767.7	855.0	2,568.9
Nitrous Oxide N_2O	298	6,118.5	3,060.9	1,446.9	4,437.5
Total GHG CO_{2eq}		**1,616,941.9**	**672,938.7**	**447,567.7**	**972,458.2**

Coal units retired on June 1, 2021.

Table 3a: Greenhouse Gases Emissions Summary (Gas & oil units without coal units)

GHG	Conversion factor	2018 tpy CO_2e	2019 tpy CO_2e	2020 tpy CO_2e	2021 tpy CO_2e
Carbon dioxide CO_2	1	435,934.7	68,916.0	174,844.6	114,613.7
Methane CH_4	25	221.5	40.0	87.1	59.4
Nitrous Oxide N_2O	298	306.0	65.2	116.4	84.3
Total GHG CO_{2eq}		**436,462.3**	**69,021.2**	**175,048.1**	**114,757.4**

EMISSION UNIT IDENTIFICATION

Chalk Point Generating Station has identified the following emission units as being subject to Title V permitting requirements and having applicable requirements.

Table 2: Emission Unit Identification

Emissions Unit Number	MDE - ARA Registration Number	Emissions Unit Name and Description	Date of Installation
E-3	4-0998	Unit E-3 is a tangentially-fired, sub-critical, cycling boiler rated at 640 megawatts and 6,970 MMBtu/hr. heat input. Unit E-3 fires natural gas and No. 6 fuel oil. No. 2 fuel oil or natural gas may be used for ignition, warm-up and flame stabilization purposes.	Jun 1975
E-4	4-0999	Unit E-4 is a tangentially-fired, sub-critical, cycling boiler rated at 640 megawatts and 6,970 MMBtu/hr. heat input. Unit E-4 fires natural gas and No. 6 fuel oil. No. 2 fuel oil or natural gas may be used for ignition, warm-up and flame stabilization purposes.	Dec 1981
E-CT1	4-0778	Unit E-CT1 is a Pratt and Whitney FT4A combustion turbine rated capacity of 18 megawatts (250 MMBtu/hr. heat input) used for black start capability and peaking service. This turbine is fired with No. 2 fuel oil.	Apr 1967
E-CT2	4-1145	Unit E-CT2 is a Westinghouse (W-251) combustion turbine rated capacity of 35 megawatts (420 MMBtu/hr. heat input) used for black start capability and peaking service. This turbine is fired with No. 2 fuel oil.	Jun 1974

Emissions Unit Number	MDE - ARA Registration Number	Emissions Unit Name and Description	Date of Installation
E-CT3	9-0752	Unit E-CT3 is a General Electric Frame-7EA combustion turbine rated capacity of 99 megawatts used for peaking service. This turbine is fired with natural gas as a primary fuel and No. 2 fuel oil as a secondary fuel and injects water in the combustion zone for NOx control.	Jun 1991
E-CT4	9-0753	Unit E-CT4 is a General Electric Frame-7EA combustion turbine rated capacity of 99 megawatts used for peaking service. This turbine is fired with natural gas as a primary fuel and No. 2 fuel oil as a secondary fuel and injects water in the combustion zone for NOx control.	Jun 1991
E-CT5	9-0754	Unit E-CT5 is a Kraftwork Union V84.2 combustion turbine rated capacity of 120 megawatts used for peaking service. This turbine is fired with natural gas as a primary fuel and No. 2 fuel oil as a secondary fuel and injects water in the combustion zone for NOx control when firing No. 2 fuel oil and dry low NOx combustors when firing natural gas.	Jun 1991
E-CT6	9-0755	Unit E-CT6 is a Kraftwork Union V84.2 combustion turbine rated capacity of 120 megawatts used for peaking service. This turbine is fired with natural gas as a primary fuel and No. 2 fuel oil as a secondary fuel and injects water in the combustion zone for NOx control when firing No. 2 fuel oil and dry low NOx combustors when firing natural gas.	Jun 1991
AUX-4	4-1155	AUX-4 is a Combustion Engineering, Model #30VP-12W, auxiliary boiler rated	1972

Emissions Unit Number	MDE - ARA Registration Number	Emissions Unit Name and Description	Date of Installation
		at 186.6 MMBtu/hr. This boiler is fired with No.2 fuel oil.	
AUX-5	4-1156	AUX-5 is a Combustion Engineering, Model #30VP-12W, auxiliary boiler rated at 186.6 MMBtu/hr. This boiler is fired with No.2 fuel oil.	1972
AUX-6	4-1157	AUX-6 is a Combustion Engineering, Model #30VP-12W, auxiliary boiler rated at 186.6 MMBtu/hr. This boiler is fired with No.2 fuel oil.	1981
AUX-7	4-1158	AUX-7 is a Combustion Engineering, Model #30VP-12W, auxiliary boiler rated at 186.6 MMBtu/hr. This boiler is fired with No.2 fuel oil.	1981
SMECO-CT1	5-0749	Unit SMECO-CT1 is a General Electric GE-7EA combustion turbine rated capacity of 93 megawatts. This turbine is fired with natural gas as a primary fuel and No. 2 fuel oil as a secondary. This unit was owned by Southern Maryland Electric Cooperative until 2015 when NRG purchased the unit.	Jun 1990
	9-1346	One (1) emergency fire pump and one (1) quench pump; E-CT2 starting engine, CT site fire pump. Main Plant fire pump. MTS building emergency generator - diesel-fired internal combustion engines.	Various

AN OVERVIEW OF THE PART 70 PERMIT

The Fact Sheet is an informational document. If there are any discrepancies between the Fact Sheet and the Part 70 permit, the Part 70 permit is the enforceable document.

Section I of the Part 70 Permit contains a brief description of the facility and an inventory list of the emissions units for which applicable requirements are identified in Section IV of the permit.

Section II of the Part 70 Permit contains the general requirements that relate to administrative permit actions. This section includes the procedures for renewing, amending, reopening, and transferring permits, the relationship to permits to construct and approvals, and the general duty to provide information and to comply with all applicable requirements.

Section III of the Part 70 Permit contains the general requirements for testing, record keeping and reporting; and requirements that affect the facility as a whole, such as open burning, air pollution episodes, particulate matter from construction and demolition activities, asbestos provisions, ozone depleting substance provisions, general conformity, and acid rain permit. This section includes the requirement to report excess emissions and deviations, to submit an annual emissions certification report and an annual compliance certification report, and results of sampling and testing.

Section IV of the Part 70 Permit identifies the emissions standards, emissions limitations, operational limitations, and work practices applicable to each emissions unit located at the facility. For each standard, limitation, and work practice, the permit identifies the basis upon which the Permittee will demonstrate compliance. The basis will include testing, monitoring, record keeping, and reporting requirements. The demonstration may include one or more of these methods.

Section V of the Part 70 Permit contains a list of insignificant activities. These activities emit very small quantities of regulated air pollutants and do not require a permit to construct or registration with the Department. For insignificant activities that are subject to a requirement under the Clean Air Act, the requirement is listed under the activity.

Section VI of the Part 70 Permit contains State-only enforceable requirements. Upon issuance of the Part 70 Permit, the Part 70 permit supersedes the facility's current State Permit to Operate. Section VI identifies requirements that are not based on the Clean Air Act, but solely on Maryland air pollution regulations.

These requirements generally relate to the prevention of nuisances and implementation of Maryland's Air Toxics Program.

REGULATORY REVIEW/TECHNICAL REVIEW/COMPLIANCE METHODOLOGY

Emission Units: E-3 and E-4: Boilers

E-3 and E-4: Two (2) tangentially fired, sub-critical, cycling boilers, each rated at 640 megawatts and 6970 million Btu per hour heat input. They are fired on natural gas and No. 6 fuel oil. No. 2 fuel oil or natural gas may be used for ignition, warm-up, and flame stabilization purposes.

Compliance Status
For **E-4**: Stack test in July 2011 demonstrated the following: emission rate of 0.02 lb./MMBtu for PM, in compliance with the NSPS emission limit (0.10 lb./MMBtu) & emission rate of 0.011 gr/dscf for PM which is in compliance with the established (2011 Consent Decree) emission limit (0.020 gr/scfd).
For **E-3**: Stack test in July 2011 demonstrated an emission rate of 0.012 gr/dscf for PM which is in compliance with the established (2011 Consent Decree) emission limit (0.020 gr/scfd).
NSPS Report for Unit **E-4** was reviewed for the second half of 2019 (July – Dec). The Unit operated 123 hours in the third quarter of 2019 and 0 hours during the fourth quarter. Unit **E-4** is subject to 40 CFR Part 60 Subpart D, which has a few differences as compared to the state excess emissions reports. The NSPS allows an opacity limit of 20% and has different guidelines for determining the operating time and downtime exclusions. There were no SO_2, NO_X, or Opacity exceedances reported. Downtime reported: Opacity: 0.1%; SO_2: 0%; NO_X: 0%. Unit **E-4** is operating in compliance. [Chalk Point's Air Quality Compliance Semi-Annual Report July – December 2019]
E-4 in 2018 usage was as follows: 3.5×10^6 mcf natural gas and 0 #6 oil.
E-3 in 2018 usage was as follows: 2.9×10^6 mcf natural gas and 0 #6 oil.

Applicable Standards and Limitations:

A. Control of Visible Emissions
(1) **COMAR 26.11.09.05A(2) & (3)** – Fuel Burning Equipment
"Areas III and IV. In Areas III and IV, a person may not cause or permit the discharge of emissions from any fuel burning equipment, other than water in an uncombined form, which is visible to human observers except that, for the purpose of demonstrating compliance using COM data, emissions that are visible to a human observer are those that are equal to or greater than 10 percent opacity".
Exceptions. Section A(1) and (2) of this regulation do not apply to emissions during load changing, soot blowing, startup, or adjustments or occasional cleaning of control equipment if:

a. The visible emissions are not greater than 40 percent opacity; and
b. The visible emissions do not occur for more than 6 consecutive minutes in any sixty minute period."

Compliance Demonstration

(1) The Permittee shall perform quality assurance procedures on the continuous opacity monitoring system as established in COMAR 26.11.31. **[Reference: COMAR 26.11.03.06C]**The Permittee, in accordance with **COMAR 26.11.01.10B,** shall continuously monitor opacity of the stack gases using a continuous opacity monitor that is certified in accordance with 40 CFR Part 60, Appendix B and meets the quality assurance criteria of COMAR 26.11.31. **[Reference: COMAR 26.11.01.10C]**The Permittee shall maintain all records necessary to comply with the data reporting requirements of COMAR 26.11.01.10D(2). **[Reference: COMAR 26.11.01.10D(2)].**

The Permittee shall report:

All CEM system downtime that lasts or is expected to last more than 24 hours shall be reported to the Department by telephone before 10 a.m. of the first regular business day following the breakdown.

The system breakdown report required by Sec. D(1)(a) of this regulation shall include the reason, if known, for the breakdown and the estimated period of time that the CEM will be down. The owner or operator of the CEM shall notify the Department by telephone when an out-of-service CEM is back in operation and producing valid data.

[Reference: COMAR 26.11.01.10D(1)]

The Permittee shall submit:

Quarterly summary reports to the Department not later than 30 days following each calendar quarter. The report shall be in a format approved by the Department, and shall include the following:

(i) The cause, time periods, and magnitude of all emissions which exceed the applicable quarterly, daily, and hourly emission standards as provided in COMAR 26.11.09.05A(4);

(ii) The COM and installation downtimes, including the time and date of the beginning and end of each downtime period and whether the source downtime was scheduled;

(iii) The cause of all COM downtime;

(iv) The total operating time for the quarter, and the total time and percent of the operating time during the quarter that excess emissions occurred, and the percentage of COM downtime, during the calendar quarter;

(v) Quarterly quality assurance activities; and

(vi) Daily calibration activities that include reference values, actual values, absolute or percent of span differences, and drift status; and

(vii) Other information required by the Department that is determined to be necessary to evaluate the data, to ensure that compliance is achieved, or to

determine the applicability of this regulation." **[Reference: COMAR 26.11.01.10D(2)]**

(2) NSPS Requirement (**E-4** Only)
§60.42-Standard for particulate matter (PM).
"(a) Except as provided under paragraphs (b), (c), (d), and (e) of this section, on and after the date on which the performance test required to be conducted by §60.8 is completed, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any affected facility any gases that:
(2) Exhibit greater than 20 percent opacity except for one six-minute period per hour of not more than 27 percent opacity."

§60.11(c)-Compliance with standards and maintenance requirements.
"The opacity standards set forth in this part shall apply at all times except during periods of startup, shutdown, malfunction, and as otherwise provided in the applicable standard."

Compliance Demonstration
§60.45(g) - Emissions and fuel monitoring.
"(a) Each owner or operator shall install, calibrate, maintain, and operate continuous opacity monitoring system (COMS) for measuring opacity and a CEMS for measuring SO_2 emissions, NO_x emissions, and either oxygen (O_2) or carbon dioxide (CO_2) except as provided in paragraph (b) of this section."
§60.7(f) – Notification and recordkeeping
"Any owner or operator subject to the provisions of this part shall maintain a file of all measurements, including continuous monitoring system, monitoring device, and performance testing measurements; all continuous monitoring system performance evaluations; all continuous monitoring system or monitoring device calibration checks; adjustments and maintenance performed on these systems or devices; and all other information required by this part recorded in a permanent form suitable for inspection."
§60.45 – Emission and fuel monitoring
"**(g)** Excess emission and monitoring system performance reports shall be submitted to the Administrator semiannually for each six-month period in the calendar year. All semiannual reports shall be postmarked by the 30th day following the end of each six-month period. Each excess emission and MSP report shall include the information required in §60.7(c). Periods of excess emissions and monitoring systems (MS) downtime that shall be reported are defined as follows:

(1) *Opacity.* Excess emissions are defined as any six-minute period during which the average opacity of emissions exceeds 20 percent opacity, except that one six-minute average per hour of up to 27 percent opacity need not be reported."
§60.7(c) – Notification and recordkeeping
"(c) Each owner or operator required to install a continuous monitoring device shall submit excess emissions and monitoring systems performance report (excess emissions are defined in applicable subparts) and-or summary report form (see paragraph (d) of this section) to the Administrator semiannually, except when: more frequent reporting is specifically required by an applicable subpart; or the Administrator, on a case-by-case basis, determines that more frequent reporting is necessary to accurately assess the compliance status of the source. All reports shall be postmarked by the 30th day following the end of each six-month period. Written reports of excess emissions shall include the following information:
(1) The magnitude of excess emissions computed in accordance with §60.13(h), any conversion factor(s) used, and the date and time of commencement and completion of each time period of excess emissions. The process operating time during the reporting period.
(2) Specific identification of each period of excess emissions that occurs during startups, shutdowns, and malfunctions of the affected facility. The nature and cause of any malfunction (if known), the corrective action taken or preventative measures adopted.
(3) The date and time identifying each period during which the continuous monitoring system was inoperative except for zero and span checks and the nature of the system repairs or adjustments.
(4) When no excess emissions have occurred or the continuous monitoring system(s) have not been inoperative, repaired, or adjusted, such information shall be stated in the report."

B. Control of Particulate Matter Emissions
(1) **COMAR 26.11.09.06** - Control of Particulate Matter.
"B. Areas III and IV. The following apply in Areas III and IV:
(6) Exceptions.
(a) Fuel burning equipment burning gas with an interruptible gas service is exempt from the provisions of §B(1) and (2) of this regulation."

Compliance Demonstration
The Permittee shall maintain records of the results of all particulate emission compliance tests. **[Reference: COMAR 26.11.03.06C]**.
When requested to perform compliance testing, the Permittee shall submit a stack test protocol to the Department at least 30 days prior to test and notification of testing 10 days prior to test date. The Permittee shall submit a final stack test

report with results of testing within 45 days from test completion. **[Reference: COMAR 26.11.01.04A]**

---

(2) NSPS Requirements-**E-4** Only
§60.42-Standard for particulate matter (PM).
"(a) Except as provided under paragraphs (b), (c), (d), and (e) of this section, on and after the date on which the performance test required to be conducted by §60.8 is completed, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any affected facility any gases that:
(1) Contain PM in excess of 43 nanograms per joule (ng/J) heat input (0.10 lb./MMBtu) derived from fossil fuel or fossil fuel and wood residue."

§60.8(f) "Unless otherwise specified in the applicable subpart, each performance test shall consist of three separate runs using the applicable test method. Each run shall be conducted for the time and under the conditions specified in the applicable standard. For the purpose of determining compliance with an applicable standard, the arithmetic means of results of the three runs shall apply. In the event that a sample is accidentally lost or conditions occur in which one of the three runs must be discontinued because of forced shutdown, failure of an irreplaceable portion of the sample train, extreme meteorological conditions, or other circumstances, beyond the owner or operator's control, compliance may, upon the Administrator's approval, be determined using the arithmetic mean of the results of the two other runs."

Compliance Demonstration
Stack testing will be conducted in conjunction with the schedule for stack testing established in the 2011 Consent Decree. The Permittee shall maintain records of the results of all particulate emission compliance tests. **[Reference: COMAR 26.11.03.06C]**.
When requested to perform compliance testing, the Permittee shall submit a stack test protocol to the Department at least 30 days prior to test and notification of testing 10 days prior to test date. The Permittee shall submit a final stack test report with results of testing within 45 days from test completion. **[Reference: COMAR 26.11.01.04A]**

C. Control of Sulfur Oxides Emissions
(1) **COMAR 26.11.09.07A(2)** – Control of Sulfur Oxides from fuel burning equipment. "A person may not burn, sell, or make available for sale any fuel with a sulfur content by weight in excess of or which otherwise exceeds the following limitations: In Areas III, and IV:

(a) All solid fuels, 1.0 percent;
(b) Distillate fuel oils, 0.3 percent;
(c) Residual fuel oils, 1.0 percent.

Compliance Demonstration
1) The Permittee shall perform quality control/ quality assurance procedures on the continuous emission monitoring system as established in 40 CFR Part 75, Appendix B. The Permittee shall obtain appropriate demonstration such as fuel supplier certifications to confirm that the fuel oil is in compliance with the sulfur content in fuel limitation. The Permittee shall maintain appropriate documentation evidencing the sulfur content in fuel content from every delivery of residual fuel oil. The Permittee shall submit fuel certification reports when requested by the Department. **[Reference: COMAR 26.11.03.06C].**

---

(2) NSPS Requirements **E-4** Only
§60.43-Standard for sulfur dioxide (SO_2).
"(a) Except as provided under paragraph (d) of this section, on and after the date on which the performance test required to be conducted by §60.8 is completed, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any affected facility any gases that contain SO_2 in excess of:
(1) 340 ng/J heat input (0.80 lb./MMBtu) derived from liquid fossil fuel or liquid fossil fuel and wood residue."

§60.45(g) - Emissions and fuel monitoring.
"(2) *Sulfur dioxide.* Excess emissions for affected facilities are defined as:
(i) For affected facilities electing not to comply with §60.43(d), any three-hour period during which the average emissions (arithmetic average of three contiguous one-hour periods) of SO_2 as measured by a CEMS exceed the applicable standard in §60.43."

Compliance Demonstration
The Permittee shall perform quality control/ quality assurance procedures on the continuous emission monitoring system as established in 40 CFR Part 75, Appendix B. **[Reference: COMAR 26.11.01.11C]**.
§60.45 - Emission and fuel monitoring.
"(a) Each owner or operator shall install, calibrate, maintain, and operate continuous monitoring systems for measuring the opacity of emissions, **sulfur dioxide emissions**, nitrogen oxides emissions, and either oxygen or carbon dioxide except as provided in paragraph (b) of this section.

(b) Certain of the continuous monitoring system requirements under paragraph (a) of this section do not apply to owners or operators under the following conditions:
(1) *Not applicable*
(2) For a fossil fuel-fired steam generator that does not use a flue gas desulfurization device, a continuous monitoring system for measuring sulfur dioxide emissions is not required if the owner or operator monitors sulfur dioxide emissions by fuel sampling and analysis."

Note: The Permittee may use the data collected from the Acid Rain monitoring system to demonstrate compliance with the NSPS standard. The data acquisition system must be able to generate sulfur dioxide emissions rates in lbs./ per million BTU on a rolling 3-hour average.

§60.7(f) –Notification and recordkeeping
"Any owner or operator subject to the provisions of this part shall maintain a file of all measurements, including continuous monitoring system, monitoring device, and performance testing measurements; all continuous monitoring system performance evaluations; all continuous monitoring system or monitoring device calibration checks; adjustments and maintenance performed on these systems or devices; and all other information required by this part recorded in a permanent form suitable for inspection."
§60.45 – Emission and fuel monitoring
"(g) Excess emission and monitoring system performance reports shall be submitted to the Administrator semiannually for each six-month period in the calendar year. All semiannual reports shall be postmarked by the 30th day following the end of each six-month period. Each excess emission and MSP report shall include the information required in §60.7(c). Periods of excess emissions and monitoring systems (MS) downtime that shall be reported are defined as follows:
(2)*Sulfur dioxide.* Excess emissions for affected facilities are defined as:
(i) For affected facilities electing not to comply with §60.43(d), any three-hour period during which the average emissions (arithmetic average of three contiguous one-hour periods) of SO_2 as measured by a CEMS exceed the applicable standard in §60.43."

§60.7 – Notification and recordkeeping
"(c) Each owner or operator required to install a continuous monitoring device shall submit excess emissions and monitoring systems performance report (excess emissions are defined in applicable subparts) and-or summary report form (see paragraph (d) of this section) to the Administrator semiannually, except when: more frequent reporting is specifically required by an applicable subpart; or the Administrator, on a case-by-case basis, determines that more frequent

reporting is necessary to accurately assess the compliance status of the source. All reports shall be postmarked by the 30th day following the end of each six-month period. Written reports of excess emissions shall include the following information:
(1) The magnitude of excess emissions computed in accordance with §60.13(h), any conversion factor(s) used, and the date and time of commencement and completion of each time period of excess emissions. The process operating time during the reporting period.
(2) Specific identification of each period of excess emissions that occurs during startups, shutdowns, and malfunctions of the affected facility. The nature and cause of any malfunction (if known), the corrective action taken or preventative measures adopted.
(3) The date and time identifying each period during which the continuous monitoring system was inoperative except for zero and span checks and the nature of the system repairs or adjustments.
(4) When no excess emissions have occurred or the continuous monitoring system(s) have not been inoperative, repaired, or adjusted, such information shall be stated in the report."

---

(3) Acid Rain Provisions
The Permittee shall comply with the requirements of the Phase II Acid Rain Permit issued for this generating station. Note: A renewal Phase II Acid Rain Permit will be issued in conjunction with this Part 70 permit and is attached to the Part 70 permit as Appendix A.

(4) Cross-State Air Pollution Rule
See Table IV-5: CSAPR for requirements.

D. Control of Nitrogen Oxides Emissions
(1) NOx RACT Requirements
COMAR 26.11.09.08B(5) - Operator Training.
(a) For purposes of this regulation, the equipment operator to be trained may be the person who maintains the equipment and makes the necessary adjustments for efficient operation.
(b) The operator training course sponsored by the Department shall include an in-house training course that is approved by the Department."
COMAR 26.11.09.08C. - Requirements for Fuel-Burning Equipment with a Rated Heat Input Capacity of 250 Million Btu Per Hour or Greater.
"(1) A person who owns or operates fuel-burning equipment with a rated heat input capacity of 250 Million Btu per hour or greater shall equip each installation

with combustion modifications or other technologies to meet the NOx emission rates in §C(2) of this regulation.
(2) The maximum NOx emission rates as pounds of NOx per Million Btu per hour are:
(a) 0.45 for tangentially coal fired units located at an electric generating facility (excluding high heat release units);
(b) 0.50 for wall coal fired units located at an electric generating facility (excluding high heat release units);
(c) 0.30 for oil fired or gas/oil fired units located at an electric generating facility;
(d) 0.70 for coal fired cyclone fuel burning equipment located at an electric generating facility from May 1 through September 30 of each year and 1.5 during the period October 1 through April 30 of each year;
(e) 0.70 for a tangentially coal fired high heat release unit located at an electric generating facility;
(f) 0.80 for a wall coal fired high heat release unit located at an electric generating facility;
(g) 0.6 for coal fired cell burners at an electric generating facility; and
(h) 0.70 for fuel burning equipment stacks at a non-electric generating facility during the period May 1 through September 30 of each year and 0.99 during the period October 1 through April 30 of each year.
(3) A person who owns or operates fuel burning equipment with a rated heat input capacity of 250 Million Btu per hour or greater shall install, operate, calibrate, and maintain a certified NOx CEM or an alternative NOx monitoring method approved by the Department and the EPA on each installation.
COMAR 26.11.09.08B(2)(d) - Demonstration of Compliance. "Except as otherwise established by the Department and approved by the EPA, for a person who establishes compliance with the NOx emissions standards in this regulation using a CEM, compliance shall be determined as 30-day rolling averages."

Compliance Demonstration
(1) NOx RACT Requirements
The Permittee shall perform quality control/ quality assurance procedures on the continuous emission monitoring system as established in 40 CFR Part 75, Appendix B. **[Reference: COMAR 26.11.09.08B(2)(c)]**
The Permittee shall operate, calibrate, and maintain a certified NOx CEM or an alternative NOx monitoring method approved by the Department and the EPA on each installation. **[Reference: COMAR 26.11.09.08C(3)].**
The Permittee shall maintain all records necessary to comply with the data reporting requirements. **[Reference: COMAR 26.11.03.06C].**
The Permittee shall submit quarterly emission reports of CEM data to the Department on or before the thirtieth day of the month following the end of each calendar quarter." **[Reference: COMAR 26.11.09.08K(1)].**

The report shall be in a format approved by the Department, and shall include the following:
(i) The cause, time periods, and magnitude of all emissions which exceed the applicable emission standards;
(ii) The source downtime including the time and date of the beginning and end of each downtime period and whether the source downtime was planned or unplanned;
(iii) The time periods and cause of all CEM downtime including records of any repairs, adjustments, or maintenance that may affect the validity of emission data;
(iv) Quarterly totals of excess emissions, installation downtime, and CEM downtime during the calendar quarter;
(v) Quarterly quality assurance activities; and
(vi) Daily calibration activities that include reference values, actual values, absolute or percent of span differences, and drift status; and
(vii) Other information required by the Department that is determined to be necessary to evaluate the data, to ensure that compliance is achieved, or to determine the applicability of this regulation."
[Reference: COMAR 26.11.03.06]

---

(2) NSPS requirement - **E-4** Only
§60.44 - Standard for nitrogen oxides (NO_x).
"(a) Except as provided under paragraph (e) of this section, on and after the date on which the performance test required to be conducted by §60.8 is completed, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any affected facility any gases that contain NO_x, expressed as NO_2 in excess of:
(1) 86 ng/J heat input (0.20 lb./MMBtu) derived from gaseous fossil fuel.
(2) 129 ng/J heat input (0.30 lb./MMBtu) derived from liquid fossil fuel, liquid fossil fuel and wood residue, or gaseous fossil fuel and wood residue."

§60.45(g) - Emissions and fuel monitoring.
"(3) *Nitrogen oxides.* Excess emissions for affected facilities using a CEMS for measuring NOx are defined as:
(i) For affected facilities electing not to comply with §60.44(e), any three-hour period during which the average emissions (arithmetic average of three contiguous one-hour periods) exceed the applicable standards in §60.44."

Compliance Demonstration
The Permittee shall perform quality control/ quality assurance procedures on the continuous emission monitoring system as established in 40 CFR Part 75, Appendix B. **[Reference: COMAR 26.11.09.08B(2)(c)]**

§60.45 - Emission and fuel monitoring.
"(a) Each owner or operator shall install, calibrate, maintain, and operate continuous monitoring systems for measuring the opacity of emissions, sulfur dioxide emissions, **nitrogen oxides emissions,** and either oxygen or carbon dioxide except as provided in paragraph (b) of this section.
Note: The Permittee is required to monitor NOx emissions under the Acid Rain Program. The Permittee may use the data collected from the Acid Rain monitoring system to demonstrate compliance with the NSPS standard. The data acquisition system must be able to generate nitrogen oxides emissions rates in lbs./ per million BTU on an average of 3 one-hour periods.
§60.7 – Notification and recordkeeping:
"**(f)**Any owner or operator subject to the provisions of this part shall maintain a file of all measurements, including continuous monitoring system, monitoring device, and performance testing measurements; all continuous monitoring system performance evaluations; all continuous monitoring system or monitoring device calibration checks; adjustments and maintenance performed on these systems or devices; and all other information required by this part recorded in a permanent form suitable for inspection."
§60.45 - Emission and fuel monitoring
(**g**) Excess emission and monitoring system performance reports shall be submitted to the Administrator semiannually for each six-month period in the calendar year. All semiannual reports shall be postmarked by the 30th day following the end of each six-month period. Each excess emission and MSP report shall include the information required in §60.7(c). Periods of excess emissions and monitoring systems (MS) downtime that shall be reported are defined as follows:
(3) *Nitrogen oxides.* Excess emissions for affected facilities using a CEMS for measuring NOx are defined as:
(i) For affected facilities electing not to comply with §60.44(e), any three-hour period during which the average emissions (arithmetic average of three contiguous one-hour periods) exceed the applicable standards in §60.44."

§60.7 – Notification and recordkeeping
(c) - "Each owner or operator required to install a continuous monitoring device shall submit excess emissions and monitoring systems performance report (excess emissions are defined in applicable subparts) and-or summary report form (see paragraph (d) of this section) to the Administrator semiannually, except when: more frequent reporting is specifically required by an applicable subpart; or the Administrator, on a case-by-case basis, determines that more frequent reporting is necessary to accurately assess the compliance status of the source. All reports shall be postmarked by the 30th day following the end of each six-month period. Written reports of excess emissions shall include the following information:

(1) The magnitude of excess emissions computed in accordance with §60.13(h), any conversion factor(s) used, and the date and time of commencement and completion of each time period of excess emissions. The process operating time during the reporting period.
(2) Specific identification of each period of excess emissions that occurs during startups, shutdowns, and malfunctions of the affected facility. The nature and cause of any malfunction (if known), the corrective action taken or preventative measures adopted.
(3) The date and time identifying each period during which the continuous monitoring system was inoperative except for zero and span checks and the nature of the system repairs or adjustments.
(4) When no excess emissions have occurred or the continuous monitoring system(s) have not been inoperative, repaired, or adjusted, such information shall be stated in the report."

---

(3) Acid Rain Provisions – These units are not subject to a NOx limitation under the Acid Rain Program because they are not coal-fired. However, the Permittee is required to comply with the continuous NOx monitoring requirement of 40 CFR Part 75 and associated record keeping and reporting requirements.

(4) Cross-State Air Pollution Rule
See Table IV-5: CSAPR for requirements.

Emission Units: E-CT1 & E-CT2: Combustion Turbines

E-CT1: One (1) Pratt and Whitney FT-4A combustion turbine rated at 18 megawatts used for black start capability and peaking service. This turbine is fired with No. 2 fuel oil.

E-CT2: One (1) Westinghouse (W-251) combustion turbine rated at 35 megawatts used for black start capability and peaking service. This turbine is fired with No. 2 fuel oil.

Compliance Status:
Capacity factors are as follows: **For 2018: E-CT1**= 0.0% operated 4 hrs. (4 days) and **E-CT2** = 0.1% operated 20 hrs. (5 days). **For 2019: E-CT1** = 0.02% and **E-CT2** = 0.01%.

Applicable Standards and Limitations:

A. Control of Visible Emissions

COMAR 26.11.09.05A(2) – Fuel Burning Equipment

"Areas III and IV. In Areas III and IV, a person may not cause or permit the discharge of emissions from any fuel burning equipment, other than water in an uncombined form, which is visible to human observers except that, for the purpose of demonstrating compliance using COM data, emissions that are visible to a human observer are those that are equal to or greater than 10 percent opacity."

COMAR 26.11.09.05A(3) - Exceptions. "Section A(1) and (2) of this regulation do not apply to emissions during load changing, soot blowing, startup, or adjustments or occasional cleaning of control equipment if:

(a) The visible emissions are not greater than 40 percent opacity; and

(b) The visible emissions do not occur for more than 6 consecutive minutes in any sixty minute period."

Compliance Demonstration

The Permittee shall verify that there are no visible emissions when operating. An observer shall perform an EPA Reference Method 9 observation of stack emissions for an 18-minute period at least once for every 168 hours of operation or at a minimum once per calendar year. If the turbine operates for less than 100 hours in a calendar year, the visual observation requirement for that calendar year is waived.

The Permittee shall perform the following, if emissions are visible to human observer:

(a) inspect combustion control system and combustion turbine operations,

(b) perform all necessary adjustments and/or repairs to the combustion turbine within 48 hours of operation so that visible emissions are eliminated; and

(c) document in writing the results of inspections, adjustments and/or repairs to the combustion turbine.

The Permittee shall after 48 hours of operation, if the required adjustments and/or repairs had not eliminated the visible emissions, perform another Method 9 observation once daily when the combustion turbine is operating for 18 minutes until corrective actions have eliminated visible emissions. The Permittee shall maintain records of the results of visual emissions observations for a period of at least 5 years. The Permittee shall report incidents of visible emissions in accordance with Permit Condition 4, Section III, "Report of Excess Emissions and Deviations." **[Reference: COMAR 26.11.03.06C].**

B. Control of Sulfur Oxides Emissions
(1) **COMAR 26.11.09.07**: Control of Sulfur Oxides From Fuel Burning Equipment.
"A. Sulfur Content Limitations for Fuel. A person may not burn, sell, or make available for sale any fuel with a sulfur content by weight in excess of or which otherwise exceeds the following limitations:
(2) In Areas III and IV:
(a) All solid fuels, 1.0 percent;
(b) Distillate fuel oils, 0.3 percent;
(c) Residual fuel oils, 1.0 percent.

Compliance Demonstration
The Permittee shall obtain fuel supplier certifications stating that the fuel oil is in compliance with the sulfur content in the fuel limitation. The Permittee shall retain fuel supplier certifications stating that the fuel oil is in compliance with the sulfur content in the fuel limitation for at least 5 years. The Permittee shall submit fuel certification report if requested by MDE. **[Reference: COMAR 26.11.03.06C]**

---

(2) Cross State Air Pollution Rule – **(E-CT2 only)**
See Table IV-5: CSAPR for requirements.

C. Control of Nitrogen Oxides Emissions
(1) **NO_x RACT Requirements**:
COMAR 26.11.09.08G – Requirements for Fuel-Burning Equipment with a Capacity Factor of 15 percent or less and Combustion Turbines with a Capacity Factor Greater than 15 percent.
(1) A person who owns or operates fuel-burning equipment with a capacity factor (as defined in 40 CFR Part 72.2) of 15 percent or less shall:
(a) Provide certification of the capacity factor of the equipment to the Department in writing;
(b) For fuel-burning equipment that operates more than 500 hours during a calendar year, perform a combustion analysis and optimize combustion at least once annually;
(c) Maintain the results of the combustion analysis and any stack tests at the site for at least 2 years and make these results available to the Department and the EPA upon request;
(d) *Not Applicable*; and
(e) *Not Applicable*.

Compliance Demonstration
The Permittee shall perform a combustion analysis and optimize combustion at least once annually. **[Reference: COMAR 26.11.09.08G(1)(b)]**
The Permittee shall maintain the results of the combustion analysis and any stack tests at the site for at least 5 years and make these results available to the Department and the EPA upon request. **[Reference: COMAR 26.11.09.08G(1)(c) & COMAR 26.11.03.06C]**
The Permittee shall provide certification of the capacity factor of the equipment to the Department in the support information provided with the Annual Emissions Certification Report. **[Reference: COMAR 26.11.09.08G(1)(a) and COMAR 26.11.03.06C].**

(2) Cross State Air Pollution Rule – **(E-CT2 only)**
See Table IV-5: CSAPR for requirements.

Emission Units: E-CT3, E-CT4, E-CT5 and E-CT6: Combustion Turbines

E-CT3 and E-CT4 – Two (2) General Electric, GE-7EA, combustion turbines, each rated at 99 megawatts. These turbines are fired with natural gas as a primary fuel and No. 2 fuel oil as a secondary.

E-CT5 and E-CT6 – Two (2) Kraft Union combustion turbines, each rated at 120 megawatts. These turbines are fired with natural gas as a primary fuel and No. 2 fuel oil as a secondary.

Compliance Status:
Based on 2020 Emissions Certification Report, hours of operation for the CTs during calendar year 2019 are as follows: **E-CT3** – 21; **E-CT4** – 22; **E-CT5** – 19; and **E-CT6** – 19.
Capacity factors reported for 2018 ECR are as follows:
E-CT3 = 0.4% operated 68 hrs. (12 days); **E-CT4** = 0.4% operated 76 hrs. (12 days);
E-CT5 = 0.6% operated 76 hrs. (13 days); **E-CT6** = 0.3% operated 42 hrs. (11 days)
Capacity factors for 2019 ECR are as follows: **E-CT3** = 0.05%; **E-CT4** = 0.01%, **E-CT5** = 0.10%; **E-CT6** = 0.07%.
Periodic NOx Emission Rate Testing of combustion turbine **E-CT4** was conducted on July 28, 2016 while firing fuel oil. **E-CT4** is an LME qualifying unit under requirements under 40 CFR Part 75.19(a)(1) which allows testing at a single load point. (The load point selected corresponds with the operating load which generated the highest NOx rate during previous multi-load tests). Test were conducted at a turbine load of 67.7 MW, 3 runs, 16 minutes per run. The

unit emission rate averaged 0.127 lb./MMBtu or 32.6 ppm @15% O_2 (CPCN limit is 38 ppm @ 15% O_2).
"Periodic NOx Emission Rate Testing" of the combustion turbine units **E-CT5**.
Testing was completed on March 18, 2020, while firing fuel oil.
The purpose of this test program was to measure the NOx emission rate from the Chalk Point Generating Station ECT-05 at a single load point. **E-CT-5** is an LME qualifying unit under the requirements of the 40CFR Part 75.19 (a)(1). The load point selected for the test program corresponded with the operating level which generated the highest NOx emission rate during previous multi-load testing.
Tests were conducted at a turbine load of 65 MW and total of 3 runs. The unit emission rate averaged 0.165 lb./MMBtu or 42.43 ppm @ 15% O_2 (test reports received by the Department April 22, 2020).
Testing was completed on October 27, 2020, while firing on pipeline natural gas.
Tests were conducted at a turbine load on 75 MW and total of 3 runs. The unit emission rate averaged 0.086 lb./MMBtu or 23.24 ppm @ 15% O_2 (test report received by the Department November 17, 2020).

Applicable Standards and Limitations:
A. Control of Visible Emissions
COMAR 26.11.09.05A(2) – Fuel Burning Equipment
"Areas III and IV. In Areas III and IV, a person may not cause or permit the discharge of emissions from any fuel burning equipment, other than water in an uncombined form, which is visible to human observers except that, for the purpose of demonstrating compliance using COM data, emissions that are visible to a human observer are those that are equal to or greater than 10 percent opacity."
COMAR 26.11.09.05A(3) - Exceptions. "Section A(1) and (2) of this regulation do not apply to emissions during load changing, soot blowing, startup, or adjustments or occasional cleaning of control equipment if:
(a) The visible emissions are not greater than 40 percent opacity; and
(b) The visible emissions do not occur for more than 6 consecutive minutes in any sixty minute period."

Compliance Demonstration
The Permittee shall verify that there are no visible emissions when burning No. 2 fuel oil. An observer shall perform an EPA Reference Method 9 observation of stack emissions for an 18-minute period at least once for every 168 hours of operation on oil or at a minimum once per calendar year. If the turbine operates for less than 100 hours in a calendar year, the visual observation requirement for that calendar year is waived.
The Permittee shall perform the following, if emissions are visible to human observer:
(a) inspect combustion control system and combustion turbine operations,

(b) perform all necessary adjustments and/or repairs to the combustion turbine within 48 hours of operation so that visible emissions are eliminated; and
(c) document in writing the results of inspections, adjustments and/or repairs to the combustion turbine.
After 48 hours of operation if the required adjustments and/or repairs had not eliminated the visible emissions, the Permittee shall perform another Method 9 observation once daily when the combustion turbine is operating on No.2 fuel oil for 18 minutes until corrective actions have eliminated visible emissions.
The Permittee shall maintain records of the results of visual emissions observations for a period of at least 5 years.
The Permittee shall report incidents of visible emissions in accordance with Permit Condition 4, Section III, "Report of Excess Emissions and Deviations."
[Reference: COMAR 26.11.03.06C].

B. Control of Particulate Matter Emissions
PSD Approval
CPCN Order No. 68841 (Case 8228) condition 5 limits total combined annual emissions under non-emergency conditions of particulate matter (Total and PM_{10}) in any consecutive 12-month period to 90 tons per year for CT-3, 4, 5 & 6.

For E-CT3 and E-CT4 Only
CPCN Order No. 68841 (Case 8228) condition 8 limits particulate emissions (Total and PM_{10}) to 5 pounds per hour for natural gas and 34 pounds per hour for No. 2 oil.

For E-CT5 and E-CT6 Only
CPCN Order No. 68841 (Case 8228) condition 9 limits particulate emissions (Total and PM_{10}) to 5 pounds per hour for natural gas and 10 pounds per hour for No. 2 oil.

Compliance Demonstration
The Permittee shall perform preventative maintenance to maintain the combustion turbines in a manner such that they continue to operate as designed. The Permittee shall maintain for at least five years records of the preventive maintenance that relates to combustion performance. The Permittee shall submit records of maintenance to the Department upon request. **[Reference: COMAR 26.11.03.06C]**

C. Control of Carbon Monoxide Emissions
PSD Approval

CPCN Order No. 68841 (Case 8228) condition 5 limits total combined annual emissions of CO under non-emergency conditions in any consecutive 12-month period to 148 tons per year for CT-3, 4, 5 & 6.

For E-CT3 and E-CT4 Only
CPCN Order No. 68841 (Case 8228) condition 8 limits CO emissions to 60 pounds per hour for natural gas and 60 pounds per hour for No. 2 oil.

For E-CT5 and E-CT6 Only
CPCN Order No. 68841 (Case 8228) condition 9 limits CO emissions to 24 pounds per hour for natural gas and 28 pounds per hour for No. 2 oil.

Compliance Demonstration
The Permittee shall perform preventative maintenance to maintain the combustion turbines in a manner such that they continue to operate as designed. The Permittee shall maintain for at least five years records of the preventive maintenance that relates to combustion performance. The Permittee shall submit records of maintenance to the Department upon request. **[Reference: COMAR 26.11.03.06C]**

D. Control of Sulfur Oxides Emissions
(1) **COMAR 26.11.09.07**: Control of Sulfur Oxides From Fuel Burning Equipment.
"A. Sulfur Content Limitations for Fuel. A person may not burn, sell, or make available for sale any fuel with a sulfur content by weight in excess of or which otherwise exceeds the following limitations:
(2) In Areas III and IV:
(a) All solid fuels, 1.0 percent;
(b) Distillate fuel oils, 0.3 percent;
(c) Residual fuel oils, 1.0 percent.

Compliance Demonstration
See PSD Approval Requirements.

---

(2) PSD Approval
CPCN Order No. 68841 (Case 8228), condition 13 limits sulfur in fuel content to 0.2%.

CPCN Order No. 68841 (Case 8228), condition 5 limits total combined annual emissions under non-emergency conditions in any consecutive 12-month period for SO_2 are limited to 768 tons per year for CT-3, 4, 5, & 6.

For E-CT3 and E-CT4 Only
CPCN Order No. 68841 (Case 8228), condition 8 limits sulfur emissions from each CT to 2 lbs. per hour for natural gas firing and 249 lbs. per hour for distillate oil firing.

For E-CT5 and E-CT6 Only
CPCN Order No. 68841 (Case 8228), condition 9 limits sulfur emissions from each CT to 2 lbs. per hour for natural gas firing and 292 lbs. per hour for distillate oil firing.

Compliance Demonstration
The Permittee shall comply with the monitoring requirements of New Source Performance Standards (NSPS), Subpart GG, 40, CFR 60.334. The Permittee shall comply with the record keeping monitoring requirements of New Source Performance Standards (NSPS), Subpart A, 40 CFR 60.7(f). **[Reference: CPCN Order No. 68841 (Case 8228) condition 2]**
The Permittee shall obtain fuel supplier certifications stating that the fuel oil is in compliance with the sulfur content in the fuel limitation. The Permittee shall retain the fuel supplier certifications for at least five years. **[Reference: COMAR 26.11.03.06C].**
The Permittee shall submit quarterly reports to the Department that contain monthly summaries of the hours of operation burning oil, hours of operation burning natural gas, total hours of operation, average and maximum sulfur contents of the fuel oil, average and maximum nitrogen contents of the fuel oil, average sulfur content of the natural gas, total calculated SOx (expressed as SO_2) emissions and total calculated NOx emissions. Data used for developing the above summaries shall be maintained on file at the plant for at least 2 years and shall be readily available for inspection by the Department. **[Reference: CPCN Order No. 68841 (Case 8228) condition 15]**
Note: The Part 70 general record keeping requirements requires records to be maintained for 5 years.

---

(3). NSPS Subpart GG standard
40 CFR §60.333 which limits sulfur in fuel content to 0.8%.

Compliance Demonstration
40 CFR 60.334:

(h)(1)" The owner or operator of any stationary gas turbine subject to the provisions of this subpart shall monitor the total sulfur content of the fuel being fired in the turbine, except as provided in paragraph (h)(3) of this section. The sulfur content of the fuel must be determined using total sulfur methods described in §60.335(b)(10). Alternatively, if the total sulfur content of the gaseous fuel during the most recent performance test was less than 0.4 weight percent (4000 ppmw), ASTM D4084-82, 94, D5504-01, D5504-01, D6228-98, or Gas Processors Association Standard 2377-86 (all of which are incorporated by reference- see §60.17), which measure the major sulfur compounds may be used";

(h)(3) "Notwithstanding the provisions of paragraph (h) (1) of this section, the owner or operator may elect not to monitor the sulfur content of the gaseous fuel combusted in the turbine, if the gaseous fuel is demonstrated to meet the definition of natural gas in §60.331(u), regardless of whether an existing custom schedule approved by the administrator for subpart GG requires such monitoring. The owner or operator shall use one of the following sources of information to make the required demonstration:

(i) The gas quality characteristics in a current, valid purchase contract, tariff sheet or transportation contract for the gaseous fuel, specifying that the maximum total sulfur content of the fuel is 20.0 grains/100 scf or less; or

(ii) Representative fuel sampling data which show that the sulfur content of gaseous fuel does not exceed 20 grains/100 scf. At a minimum, the amount of fuel sampling data specified in section 2.3.1.4 or 2.3.2.4 of Appendix D to part 75 of this chapter is required."

(h)(4)" For any turbine that commenced construction, reconstruction or modification after October 3, 1977, but before July 8, 2004, and for which a custom fuel monitoring schedule has previously been approved, the owner or operator may, without submitting a special petition to the Administrator, continue monitoring on this schedule".

(i) "The frequency of determining the sulfur and nitrogen content of the fuel shall be as follows:

(1) Fuel oil. For fuel oil, use one of the total sulfur sampling options and the associated sampling frequency described in sections 2.2.3, 2.2.4.1, 2.2.4.2, and 2.2.4.3 of appendix D to part 75 of this chapter (i.e., flow proportional sampling, daily sampling, sampling from the unit's storage tank after each addition of fuel to the tank, or sampling each delivery prior to combining it with fuel oil already in the intended storage tank). If an emission allowance is being claimed for fuel-bound nitrogen, the nitrogen content of the oil shall be determined and recorded once per unit operating day."

40CFR60.7(f):
"(f) Any owner or operator subject to the provisions of this part shall maintain a file of all measurements, including continuous monitoring system, monitoring device, and performance testing measurements; all continuous monitoring system performance evaluations; all continuous monitoring system or monitoring device calibration checks; adjustments and maintenance performed on these systems or devices; and all other information required by this part recorded in a permanent form suitable for inspection."

40CFR 60.334(j)- For the purpose of reports required under §60.7(c), periods of excess emissions that shall be reported are defined as follows:
(1) (Nitrogen oxides requirement)
(2) Sulfur dioxide.
(i) "For samples of gaseous fuel and for oil samples obtained using daily sampling, flow proportional sampling, or sampling from the unit's storage tank, an excess emission occurs each unit operating hour included in the period beginning on the date and hour of any sample for which the sulfur content of the fuel being fired in the gas turbine exceeds 0.8 weight percent and ending on the date and hour that a subsequent sample is taken that demonstrates compliance with the sulfur limit."
(iii) "A period of monitor downtime begins when a required sample is not taken by its due date. A period of monitor downtime also begins on the date and hour of a required sample, if invalid results are obtained. The period of monitor downtime shall include only unit operating hours, and ends on the date and hour of the next valid sample."

§60.7(c) - "Each owner or operator required to install a continuous monitoring device shall submit excess emissions and monitoring systems performance report (excess emissions are defined in applicable subparts) and-or summary report form (see paragraph (d) of this section) to the Administrator semiannually, except when: more frequent reporting is specifically required by an applicable subpart; or the Administrator, on a case-by-case basis, determines that more frequent reporting is necessary to accurately assess the compliance status of the source. All reports shall be postmarked by the 30th day following the end of each six-month period. Written reports of excess emissions shall include the following information:
(1) The magnitude of excess emissions computed in accordance with §60.13(h), any conversion factor(s) used, and the date and time of commencement and completion of each time period of excess emissions. The process operating time during the reporting period.
(2) Specific identification of each period of excess emissions that occurs during startups, shutdowns, and malfunctions of the affected facility. The nature and

cause of any malfunction (if known), the corrective action taken or preventative measures adopted.
(3) The date and time identifying each period during which the continuous monitoring system was inoperative except for zero and span checks and the nature of the system repairs or adjustments.
(4) When no excess emissions have occurred or the continuous monitoring system(s) have not been inoperative, repaired, or adjusted, such information shall be stated in the report."

(4). Acid Rain Provisions
The Permittee shall comply with the requirements of the renewal Phase II Acid Rain Permit issued in conjunction with this Part 70 permit. The Acid Rain Permit is attached to the Part 70 permit as Appendix A.

Compliance Demonstration
See the requirements for the continuous monitoring, recordkeeping and reporting for sulfur dioxide for 40 CFR Part 75- Acid Rain Program. **[Reference: Acid Rain Permit, 40 CFR 75 subpart B, subpart F & subpart G]**

(5). Cross-State Air Pollution Rule
See Table IV-5: CSAPR for requirements.

E. Control of Nitrogen Oxides Emissions
(1) **PSD Approval**
CPCN Order No. 68841 (Case 8228) condition 3 for CT 3 & 4 and condition 4 for CT 5&6 limits NO_x emissions to no more than 25 parts per million dry (ppmvd) at 15% O_2 when firing natural gas.

During emergency conditions (as defined in CPCN condition 6), NO_x emissions from E-CT5 and E-CT6 shall be limited to no more than 42 ppmvd at 15% O_2.

When firing No. 2 fuel oil, NO_x emissions, in ppmd at 15% O_2, will be limited to no more than the following:

For E-CT3 and E-CT4 only

38 for $N < 0.015$ and
$38 + 400N$ for $N > 0.015$

For E-CT5 and E-CT6 only

$$57 \quad \text{for } N < 0.015$$
$$57 + 400N \quad \text{for } N > 0.015$$

where N is the nitrogen content of the fuel in percent by weight. Compliance with this condition will be demonstrated using the procedures described in the NSPS, Subpart GG, 40 CFR 60.335.

CPCN Order No. 68841(Case 8228) condition 12 limits the annual average nitrogen content of the fuel oil burned in the combustion turbines not to exceed 0.05% by weight.

CPCN Order No. 68841 (Case 8228) condition 5 which limits total combined annual emissions for NOx in any consecutive 12-month period to 1071 tons per year for CT-3, 4, 5 & 6.

For **E-CT3** and **E-CT4** Only
CPCN Order No. 68841 (Case 8228) condition 8 limits NOx emissions from each CT to 119 pounds per hour for natural gas and 281 pounds per hour for No. 2 oil.
For **E-CT5** and **E-CT6** Only
CPCN Order No. 68841 (Case 8228) condition 9 limits NOx emissions from each CT to 121 pounds per hour for natural gas and 421 pounds per hour for No. 2 oil

Compliance Demonstration
The Permittee is required to perform NOx testing on the four turbines to satisfy the requirements of the Acid Rain Program. The Permittee currently performs testing in accordance with Appendix E of 40 CFR Part 75 once every 5 years. The results of this testing will be used to support the demonstration of compliance with NOx standards and limits of the PSD Approval and NSPS Subpart GG. See quality assurance requirements for the continuous monitoring for NOx for 40 CFR Part 75- Acid Rain Program. **[Reference: Acid Rain Permit, 40 CFR 75 Appendix E]**
CPCN Order No. 68841 (Case 8228) condition 7: The Permittee shall submit quarterly to the Department any one-hour period during which the average water-to-fuel ratio fell below the water-to-fuel ratio used to demonstrate compliance with the NOx emission concentration limits given in CPCN conditions 3 and 4.

The Permittee shall submit the calculation of the annual average nitrogen content of the oil burned in the combustion turbines by January 31st of the following calendar year. **[Reference: COMAR 26.11.03.06C]**

(2) NSPS Subpart GG Standard

40 CFR §60.332 - Standard for nitrogen oxides.

"No owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere a from any stationary gas turbine, any gases which contain nitrogen oxides in excess of:

$STD = (0.0075 \times (14.4/Y)) + F$

Where:
STD = allowable NO_X emissions (percent by volume at 15 percent oxygen and on a dry basis)
Y = manufacturer's rated heat rate at manufacturer's rated load (kilojoules per watt hour) or, actual measured heat rate based on lower heating value of fuel as measured at actual peak load for the facility. The value of Y shall not exceed 14.4 kilojoules per watt hour.
F = NO_X emission allowance for fuel-bound nitrogen as defined in 40 CFR §60.332(a)(3)

Fuel-Bound Nitrogen (percent by weight)	F (NO_X percent by volume)
N < 0.015	0
0.015 < N < 0.1	0.04(N)
0.1 < N < 0.25	0.004 + 0.0067(N – 0.1)
N > 0.25	0.005

Compliance Demonstration

40CFR60.334:

(a) "Except as provided in paragraph (b) of this subpart, the owner or operator of any stationary gas turbine subject to the provisions of this subpart and using water or steam injection to control NO_X emissions shall install, calibrate, maintain and operate a continuous monitoring system to monitor and record the fuel consumption and the ratio of water or steam to fuel being fired in the turbine."

40CFR60.7(f):

"(f)Any owner or operator subject to the provisions of this part shall maintain a file of all measurements, including continuous monitoring system, monitoring device, and performance testing measurements; all continuous monitoring system performance evaluations; all continuous monitoring system or monitoring device calibration checks; adjustments and maintenance performed on these systems or devices; and all other information required by this part recorded in a permanent form suitable for inspection."

40CFR60.334:

"(j) For each affected unit required to continuously monitor parameters or emissions, or to periodically determine the fuel sulfur content or fuel nitrogen content under this subpart, the owner or operator shall submit reports of excess emissions and monitor downtime, in accordance with §60.7(c). Excess emissions shall be reported for all periods of unit operation, including startup, shutdown, and malfunction. For the purpose of reports required

under §60.7(c), periods of excess emissions and monitor downtime that shall be reported are defined as follows:"

(1) "Nitrogen oxides".

"**(i)** For turbines using water or steam to fuel ratio monitoring:"

(A) "An excess emissions shall be any unit operating hour for which the average steam or water to fuel ratio, as measured by the continuous monitoring system, falls below the acceptable steam or water to fuel ratio needed to demonstrate compliance with §60.332, as established during the performance test required in §60.8. Any unit operating hour in which no water or steam is injected into the turbine shall also be considered an excess emission."

(B) "A period of monitor downtime shall be any unit operating hour in which water or steam is injected into the turbine, but the essential parametric data needed to determine the steam or water to fuel ratio are unavailable or invalid."

(C) "Each report shall include the average steam or water to fuel ratio, average fuel consumption, ambient conditions (temperature, pressure, and humidity), gas turbine load, and (if applicable) the nitrogen content of the fuel during each excess emission. You do not have to report ambient conditions if you opt to use the worst case ISO correction factor as specified in §60.334(b)(3)(ii), or if you are not using the ISO correction equation under the provisions of §60.335(b)(1)."

§60.7(c) - "Each owner or operator required to install a continuous monitoring device shall submit excess emissions and monitoring systems performance report (excess emissions are defined in applicable subparts) and-or summary report form (see paragraph (d) of this section) to the Administrator semiannually, except when: more frequent reporting is specifically required by an applicable subpart; or the Administrator, on a case-by-case basis, determines that more frequent reporting is necessary to accurately assess the compliance status of the source. All reports shall be postmarked by the 30th day following the end of each six-month period. Written reports of excess emissions shall include the following information:

(1) The magnitude of excess emissions computed in accordance with §60.13(h), any conversion factor(s) used, and the date and time of commencement and completion of each time period of excess emissions. The process operating time during the reporting period.

(2) Specific identification of each period of excess emissions that occurs during startups, shutdowns, and malfunctions of the affected facility. The nature and cause of any malfunction (if known), the corrective action taken or preventative measures adopted.

(3) The date and time identifying each period during which the continuous monitoring system was inoperative except for zero and span checks and the nature of the system repairs or adjustments.
(4) When no excess emissions have occurred or the continuous monitoring system(s) have not been inoperative, repaired, or adjusted, such information shall be stated in the report."

---

(3) NO_x RACT Requirements:
COMAR 26.11.09.08G – Requirements for Fuel-Burning Equipment with a Capacity Factor of 15 percent or less and Combustion Turbines with a Capacity Factor Greater than 15 percent.
(1) A person who owns or operates fuel-burning equipment with a capacity factor (as defined in 40 CFR Part 72.2) of 15 percent or less shall:
(a) Provide certification of the capacity factor of the equipment to the Department in writing;
(b) For fuel-burning equipment that operates more than 500 hours during a calendar year, perform a combustion analysis and optimize combustion at least once annually;
(c) Maintain the results of the combustion analysis and any stack tests at the site for at least 2 years and make these results available to the Department and the EPA upon request;
(d) *Not Applicable*, and
(e) *Not Applicable*.
(2) A person who owns or operates a combustion turbine with a capacity factor greater than 15 percent shall meet an hourly average NO_x emission rate of not more than 42 ppm when burning gas or 65 ppm when burning fuel oil (dry volume at 15 percent oxygen) or meet applicable Prevention of Significant Deterioration limits, whichever is more restrictive."

Compliance Demonstration
The Permittee shall perform a combustion analysis and optimize combustion at least once annually on each turbine that operates more than 500 hours during a calendar year. **[Reference: COMAR 26.11.09.08G(1)(b)]**
The Permittee shall maintain the results of the combustion analysis and any stack tests at the site for at least 5 years and make these results available to the Department and the EPA upon request. **[Reference: COMAR 26.11.09.08G(1)(c) & COMAR 26.11.03.06C]**
The Permittee shall provide certification of the capacity factor of the equipment to the Department in writing by April 1st of the following calendar year. **[Reference: COMAR 26.11.09.08G(1)(a) & COMAR 26.11.03.06C]**

---

(4) Acid Rain Provisions
These units are not subject to a NOx limitation under Acid Rain because they are not coal-fired. However, the Permittee is required to comply with the continuous NOx monitoring requirement of 40CFR Part 75 and associated record keeping and reporting requirements.

Compliance Demonstration
See quality assurance requirements for the continuous monitoring, record keeping and reporting for sulfur dioxide for 40 CFR Part 75- Acid Rain Program. **[Reference: Acid Rain Permit, 40 CFR part 75, Appendix D, F & G]**

---

(5) Cross State Air Pollution Rule
See Table IV-5: CSAPR for requirements.

F. Control of VOC Emissions
Synthetic minor limitation to avoid non-attainment major new source review requirements:
CPCN Order No. 68841 (Case 8228) condition 5 which limits total combined annual emissions for VOC in any consecutive 12-month period to 27.5 tons per year for CT-3, 4, 5 & 6.

For E-CT3 and E-CT4 Only
CPCN Order No. 68841 (Case 8228) condition 8 limits VOC emissions to 2.5 pounds per hour for natural gas and 6 pounds per hour for No. 2 oil.

For E-CT5 and E-CT6 Only
CPCN Order No. 68841 (Case 8228) condition 9 limits VOC emissions to 10 pounds per hour for natural gas and 10 pounds per hour for No. 2 oil.

Compliance Demonstration
The Permittee shall perform preventative maintenance to maintain the combustion turbines in a manner such that they continue to operate as designed. The Permittee shall maintain for at least five years records of the preventive maintenance that relates to combustion performance. The Permittee shall submit records of maintenance to the Department upon request. **[Reference: COMAR 26.11.03.06C]**

G. Operational Limitations

CPCN Order No. 68841 (Case No. 8228) condition 1 states that "The combustion turbines shall use natural gas only to generate electricity. This requirement shall not apply during those times when the delivered cost per million Btu of natural gas exceeds the delivered cost per million Btu of No. 2 fuel oil by 15 percent or during those times when the natural gas supply to the unit is curtailed or interrupted under the delivery contract. At such times, the unit shall use No. 2 fuel oil only. Natural gas service curtailments or interruptions shall be verified by a letter to PEPCO each year from the unit's natural gas supplier identifying the dates on which the gas service was curtailed or interrupted." (Note: The reference to "PEPCO" is now "The Permittee")

CPCN Order No. 68841 (Case No. 8228) condition 5 states that "the four combustion turbines shall not operate more than 6000 hours in the aggregate in any calendar year during normal conditions and no more than an additional 2000 hours in the aggregate in any calendar year, inclusive of emergency conditions. At no time shall any one combustion turbine operate more than 2500 hours in any calendar year, inclusive of emergency conditions. Emergency conditions shall be defined at any operations during reserve shortages as described in Section 3 of the PJM Interconnection and Operation Instructions, OI 8.13, Alert and Emergency Procedures, dated May 1989. Any change affecting the definition of emergency conditions for the purposes of this permit must have approval of the Maryland Air and Radiation Management Administration" (Note: The PJM reference has been revised to Manual M-13, Emergency Operations, Section 2,Dated May 1, 2003.)

See Note in Record Keeping Requirement dated February 2, 2006 from MDE on oil operations.

Compliance Demonstration

The Permittee shall maintain records to support the basis for burning fuel oil, either those times when the delivered cost per million Btu of natural gas exceeds the delivered cost per million Btu of No. 2 oil by 15 percent or during those times when the natural gas supply to the unit is curtailed or interrupted under the delivery contract. **[Reference: COMAR 26.11.03.06C]**

The Permittee shall maintain a record of the hours of operation identified as operations under non-emergency conditions or emergency conditions. **[Reference: COMAR 26.11.03.06C]**

Note: The Department, in a February 2, 2006 letter to GenOn, concurred with GenOn's proposal to clarify natural gas curtailments as follows:

Gas pipeline is out of service for maintenance or repair. Documentation of these events will be obtained through postings on the gas supplier's web site;
Gas supply is interrupted under the delivery contract. Documentation of these events will be obtained through postings on the gas supplier's web site;
One or more of the CT Units is called for by PJM to start or extend operation during periods of time when the pipeline operator is not open for business, typically between 6:00 PM and 10:00 AM daily. GenOn will document PJM dispatch notices during these occasions and will purchase gas upon opening of the commercial gas trading market- typically, 10:00 AM, provided the price of delivered gas is not 15% or more of the price of delivered oil.

The 15% cost differential between natural gas and #2 fuel oil will be determined on the following basis:
Daily publications from the Platts service will be utilized as representative industry benchmarks of natural gas and #2 oil pricing. GenOn will document delivered gas-to-oil cost differential using these benchmarks. The delivered cost of #2 oil for GenOn facilities is calculated by taking the Platts *Oilgram* New York Harbor Barge price and adding $0.0564/gallon in delivery charges. The delivered cost of natural gas for GenOn facilities is calculated by taking the Platts *Gas Daily* Transco Zone 6 Non-New York price and adding $0.10/MMBtu for delivery and $0.22/MMBtu in Park and Loan fees. The delivered prices for #2 oil and natural gas are calculated on a daily basis to determine if the 15% cost differential is met for the current day unit dispatch.

CTs are allowed to run on oil for test purposes after repairs or maintenance of the fuel oil system and its appurtenances for operability assurance.

Emission Units: SMECO-CT1: Combustion Turbine

SMECO-CT1 – One (1) General Electric, GE-7EA combustion turbine rated at 93 megawatts. This turbine is fired with natural gas as a primary fuel and No. 2 fuel oil as a secondary.

Compliance Status
Capacity factor reported for 2018 ECR for **SMECO CT1** is 0.5% operated 70 hrs. (11 days). On August 14, 2018 NO_X emission rate testing was conducted on the SMECO-CT1. The purpose of the test was to measure to NO_X emission rate at a single load point. **SMECO-CT1** is a LME qualifying unit under the requirements of 40 CFR Part 75. During the test, the unit was operating on fuel oil at a load of 43 MW. The result was a NO_X rate of 37.3 ppm in compliance with the limit of 65 ppm).
Capacity factor reported for 2019 ECR is 0.13%.

Applicable Standards and Limitations:

A. Control of Visible Emissions

COMAR 26.11.09.05A(2) – Fuel Burning Equipment

"Areas III and IV. In Areas III and IV, a person may not cause or permit the discharge of emissions from any fuel burning equipment, other than water in an uncombined form, which is visible to human observers except that, for the purpose of demonstrating compliance using COM data, emissions that are visible to a human observer are those that are equal to or greater than 10 percent opacity."

COMAR 26.11.09.05A(3) - Exceptions. "Section A(1) and (2) of this regulation do not apply to emissions during load changing, soot blowing, startup, or adjustments or occasional cleaning of control equipment if:

(a) The visible emissions are not greater than 40 percent opacity; and

(b) The visible emissions do not occur for more than 6 consecutive minutes in any sixty minute period."

Compliance Demonstration

The Permittee shall verify that there are no visible emissions when burning No. 2 fuel oil. An observer shall perform an EPA Reference Method 9 observation of stack emissions for 18-minute period once every 168 hours of operation on oil or at a minimum once per calendar year. If the turbine operates for less than 100 hours in a calendar year, this visible observation requirement is waived for that calendar year.

The Permittee shall perform the following, if emissions are visible to human observer:

(a) inspect combustion control system and combustion turbine operations,

(b) perform all necessary adjustments and/or repairs to the combustion turbine within 48 hours of operation so that visible emissions are eliminated; and

(c) document in writing the results of inspections, adjustments and/or repairs to the combustion turbine.

The Permittee shall after 48 hours of operation, if the required adjustments and/or repairs had not eliminated the visible emissions, perform another Method 9 observation once daily when combustion turbine operating on No.2 fuel oil for 18 minutes until corrective actions have eliminated visible emissions.

The Permittee shall maintain records of the results of visual emissions observations for a period of at least 5 years. The Permittee shall report incidents of visible emissions in accordance with Permit Condition 4, Section III, "Report of Excess Emissions and Deviations." **[Reference: COMAR 26.11.03.06C].**

B. Control of Particulate Matter Emissions
CPCN Order No. 68587 (Case 8102) condition 17 limits particulate emissions to 5 pounds per hour when burning natural gas and 10 pounds per hour when burning No. 2 oil.

Compliance Demonstration
The Permittee shall perform preventative maintenance to maintain the combustion turbine in a manner such that they continue to operate as designed. The Permittee shall maintain for at least five years records of the preventive maintenance that relates to combustion performance. The Permittee shall submit records of maintenance to the Department upon request. **[Reference: COMAR 26.11.03.06C**

C. Control of Carbon Monoxide Emissions
CPCN Order No. 68587 (Case 8102) condition 17 limits CO emissions to 24 pounds per hour when burning natural gas and 25 pounds per hour when burning No. 2 oil.

Compliance Demonstration
The Permittee shall perform preventative maintenance to maintain the combustion turbine in a manner such that they continue to operate as designed. The Permittee shall maintain for at least five years records of the preventive maintenance that relates to combustion performance. The Permittee shall submit records of maintenance to the Department upon request. **[Reference: COMAR 26.11.03.06C**

D. Control of Sulfur Oxides Emissions
(1) SIP Limitation
COMAR 26.11.09.07A(2) – Control of Sulfur Oxides from fuel burning equipment. "A person may not burn, sell, or make available for sale any fuel with a sulfur content by weight in excess of or which otherwise exceeds the following limitations: In Areas III and IV:
(a) All solid fuels, 1.0 percent;
(b) Distillate fuel oil, 0.3 percent;
(c) Residual fuel oil, 1.0 percent."

Compliance Demonstration
The Permittee shall obtain fuel supplier certifications stating that the fuel oil is in compliance with the sulfur content in the fuel limitation. **[Reference: COMAR 26.11.03.06C]**

(2) PSD Approval - CPCN
CPCN Order No. 68587 (Case 8102) condition 16 limits sulfur in fuel content to 0.3%.

CPCN Order No 68587 (Case No. 8102) condition 17 which limits sulfur oxides (as SO_2) to 20 pounds per hour when burning natural gas and 380 pounds per hour when burning No. 2 oil.

Compliance Demonstration
CPCN Order No. 68587 (Case 8102) condition 18 The Permittee shall submit quarterly reports to the Department that contain monthly summaries of the hours of operation burning oil, hours of operation burning natural gas, total hours of operation, **average and maximum sulfur contents of the fuel oil**, average and maximum nitrogen contents of the fuel oil, **average sulfur content of the natural gas, total calculated SO_x (expressed as SO_2) emissions** and total calculated NO_x (expressed as NO_2) emissions. Data used for developing the above summaries shall be maintained on file at the plant for at least 2 years and shall be readily available for inspection by the Department personnel.

(3) NSPS Subpart GG Standard
40 CFR §60.333 which limits sulfur in fuel content to 0.8%.

Compliance Demonstration
40CFR60.334:
(h)(1) "The owner or operator of any stationary gas turbine subject to the provisions of this subpart shall monitor the total sulfur content of the fuel being fired in the turbine, except as provided in paragraph (h)(3) of this section. The sulfur content of the fuel must be determined using total sulfur methods described in §60.335(b)(10). Alternatively, if the total sulfur content of the gaseous fuel during the most recent performance test was less than 0.4 weight percent (4000 ppmw), ASTM D4084-82, 94, D5504-01, D5504-01, D6228-98, or Gas Processors Association Standard 2377-86 (all of which are incorporated by reference- see §60.17), which measure the major sulfur compounds may be used";
(h)(3) "Notwithstanding the provisions of paragraph (h) (1) of this section, the owner or operator may elect not to monitor the sulfur content of the gaseous fuel combusted in the turbine, if the gaseous fuel is demonstrated to meet the definition of natural gas in §60.331(u), regardless of whether an existing custom schedule approved by the administrator for subpart GG requires such monitoring. The owner or operator shall use one of the following sources of information to make the required demonstration:

(i) The gas quality characteristics in a current, valid purchase contract, tariff sheet or transportation contract for the gaseous fuel, specifying that the maximum total sulfur content of the fuel is 20.0 grains/100 scf or less; or
(ii) Representative fuel sampling data which show that the sulfur content of gaseous fuel does not exceed 20 grains/100 scf. At a minimum, the amount of fuel sampling data specified in section 2.3.1.4 or 2.3.2.4 of Appendix D to part 75 of this chapter is required".
(h)(4) "For any turbine that commenced construction, reconstruction or modification after October 3, 1977, but before July 8, 2004, and for which a custom fuel monitoring schedule has previously been approved, the owner or operator may, without submitting a special petition to the Administrator, continue monitoring on this schedule."

(i) "The frequency of determining the sulfur and nitrogen content of the fuel shall be as follows:"
(1) "Fuel oil. For fuel oil, use one of the total sulfur sampling options and the associated sampling frequency described in sections 2.2.3, 2.2.4.1, 2.2.4.2, and 2.2.4.3 of appendix D to part 75 of this chapter (i.e., flow proportional sampling, daily sampling, sampling from the unit's storage tank after each addition of fuel to the tank, or sampling each delivery prior to combining it with fuel oil already in the intended storage tank). If an emission allowance is being claimed for fuel-bound nitrogen, the nitrogen content of the oil shall be determined and recorded once per unit operating day."

40CFR60.7(f):
"(f) Any owner or operator subject to the provisions of this part shall maintain a file of all measurements, including continuous monitoring system, monitoring device, and performance testing measurements; all continuous monitoring system performance evaluations; all continuous monitoring system or monitoring device calibration checks; adjustments and maintenance performed on these systems or devices; and all other information required by this part recorded in a permanent form suitable for inspection."

40CFR 60.334(j) – "For the purpose of reports required under §60.7(c), periods of excess emissions that shall be reported are defined as follows:"
(1) (Nitrogen oxides requirement)
(2) Sulfur dioxide.
(i) For samples of gaseous fuel and for oil samples obtained using daily sampling, flow proportional sampling, or sampling from the unit's storage tank, an excess emission occurs each unit operating hour included in the period beginning on the date and hour of any sample for which the sulfur content of the fuel being fired in the gas turbine exceeds 0.8 weight percent and ending on the

date and hour that a subsequent sample is taken that demonstrates compliance with the sulfur limit.
(iii) A period of monitor downtime begins when a required sample is not taken by its due date. A period of monitor downtime also begins on the date and hour of a required sample, if invalid results are obtained. The period of monitor downtime shall include only unit operating hours, and ends on the date and hour of the next valid sample.

§60.7(c) - "Each owner or operator required to install a continuous monitoring device shall submit excess emissions and monitoring systems performance report (excess emissions are defined in applicable subparts) and-or summary report form (see paragraph (d) of this section) to the Administrator semiannually, except when: more frequent reporting is specifically required by an applicable subpart; or the Administrator, on a case-by-case basis, determines that more frequent reporting is necessary to accurately assess the compliance status of the source. All reports shall be postmarked by the 30th day following the end of each six-month period. Written reports of excess emissions shall include the following information:
(1) The magnitude of excess emissions computed in accordance with §60.13(h), any conversion factor(s) used, and the date and time of commencement and completion of each time period of excess emissions. The process operating time during the reporting period.
(2) Specific identification of each period of excess emissions that occurs during startups, shutdowns, and malfunctions of the affected facility. The nature and cause of any malfunction (if known), the corrective action taken or preventative measures adopted.
(3) The date and time identifying each period during which the continuous monitoring system was inoperative except for zero and span checks and the nature of the system repairs or adjustments.
(4) When no excess emissions have occurred or the continuous monitoring system(s) have not been inoperative, repaired, or adjusted, such information shall be stated in the report."

E. Control of Nitrogen Oxides
(1) PSD Approval - CPCN
CPCN Order No. 68587 (Case 8102) condition 17 limits nitrogen oxides (as NO_2) to 199 pounds per hour when burning natural gas and 400 pounds per hour when burning No. 2 oil.

CPCN Order No. 68587 (Case 8102) condition 13 limits NOx emissions to no more than 42 parts per million dry (ppmvd) at 15% O_2 when firing natural gas.

When firing No. 2 fuel oil, NOx emissions, in ppmvd (at 15% O_2), will be limited to no more than

65 for $N \leq 0.015$ and
$58 + 460N$ for $N > 0.015$
where N is the nitrogen content of the fuel (percent by weight).

CPCN Order No. 68587 (Case 8102) condition 14 limits the annual average nitrogen content of the fuel oil not to exceed 0.05%, by weight.

Compliance Demonstration
The Permittee shall submit quarterly reports of the average and maximum nitrogen content of the fuel oil and total calculated NOx (expressed as NO_2) emissions. Data used for developing the above summaries shall be maintained on file at the plant and shall be made readily available for inspection by Department personnel. **[Reference: CPCN Order No. 68587 (Case 8102) condition 18]**

---

(2) NSPS Subpart GG Standard
40 CFR §60.332 - Standard for nitrogen oxides.
"No owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere a from any stationary gas turbine, any gases which contain nitrogen oxides in excess of:

$STD = (0.0075 \times (14.4/Y)) + F$
Where:
STD = allowable NOx emissions (percent by volume at 15 percent oxygen and on a dry basis)
Y = manufacturer's rated heat rate at manufacturer's rated load (kilojoules per watt hour) or, actual measured heat rate based on lower heating value of fuel as measured at actual peak load for the facility. The value of Y shall not exceed 14.4 kilojoules per watt hour.
F = NOx emission allowance for fuel-bound nitrogen as defined in 40 CFR §60.332(a)(3):

Fuel-Bound Nitrogen (percent by weight)	F (NOx percent by volume)
$N < 0.015$	0
$0.015 < N < 0.1$	$0.04(N)$
$0.1 < N < 0.25$	$0.004 + 0.0067(N - 0.1)$
$N > 0.25$	0.005

Compliance Demonstration
40CFR60.334:
(a) "Except as provided in paragraph (b) of this subpart, the owner or operator of any stationary gas turbine subject to the provisions of this subpart and using water or steam injection to control NOx emissions shall install, calibrate, maintain

and operate a continuous monitoring system to monitor and record the fuel consumption and the ratio of water or steam to fuel being fired in the turbine."

40CFR60.7(f):

"(f)Any owner or operator subject to the provisions of this part shall maintain a file of all measurements, including continuous monitoring system, monitoring device, and performance testing measurements; all continuous monitoring system performance evaluations; all continuous monitoring system or monitoring device calibration checks; adjustments and maintenance performed on these systems or devices; and all other information required by this part recorded in a permanent form suitable for inspection."

40CFR60.334:

"(j) For each affected unit required to continuously monitor parameters or emissions, or to periodically determine the fuel sulfur content or fuel nitrogen content under this subpart, the owner or operator shall submit reports of excess emissions and monitor downtime, in accordance with §60.7(c). Excess emissions shall be reported for all periods of unit operation, including startup, shutdown, and malfunction. For the purpose of reports required under §60.7(c), periods of excess emissions and monitor downtime that shall be reported are defined as follows:"

(1)" Nitrogen oxides".

(i) "For turbines using water or steam to fuel ratio monitoring:"

(A) "An excess emissions shall be any unit operating hour for which the average steam or water to fuel ratio, as measured by the continuous monitoring system, falls below the acceptable steam or water to fuel ratio needed to demonstrate compliance with §60.332, as established during the performance test required in §60.8. Any unit operating hour in which no water or steam is injected into the turbine shall also be considered an excess emission."

(B) "A period of monitor downtime shall be any unit operating hour in which water or steam is injected into the turbine, but the essential parametric data needed to determine the steam or water to fuel ratio are unavailable or invalid".

(C) "Each report shall include the average steam or water to fuel ratio, average fuel consumption, ambient conditions (temperature, pressure, and humidity), gas turbine load, and (if applicable) the nitrogen content of the fuel during each excess emission. You do not have to report ambient conditions if you opt to use the worst case ISO correction factor as specified in §60.334(b)(3)(ii), or if you are not using the ISO correction equation under the provisions of §60.335(b)(1)."

§60.7(c) - "Each owner or operator required to install a continuous monitoring device shall submit excess emissions and monitoring systems performance report (excess emissions are defined in applicable subparts) and-or summary report form (see paragraph (d) of this section) to the Administrator semiannually, except when: more frequent reporting is specifically required by an applicable subpart; or the Administrator, on a case-by-case basis, determines that more

frequent reporting is necessary to accurately assess the compliance status of the source. All reports shall be postmarked by the 30th day following the end of each six-month period. Written reports of excess emissions shall include the following information:
(1) The magnitude of excess emissions computed in accordance with § 60.13(h), any conversion factor(s) used, and the date and time of commencement and completion of each time period of excess emissions. The process operating time during the reporting period.
(2) Specific identification of each period of excess emissions that occurs during startups, shutdowns, and malfunctions of the affected facility. The nature and cause of any malfunction (if known), the corrective action taken or preventative measures adopted.
(3) The date and time identifying each period during which the continuous monitoring system was inoperative except for zero and span checks and the nature of the system repairs or adjustments.
(4) When no excess emissions have occurred or the continuous monitoring system(s) have not been inoperative, repaired, or adjusted, such information shall be stated in the report."

---

(3) NOx RACT Requirement
COMAR 26.11.09.08G – Requirements for Fuel-Burning Equipment with a Capacity Factor of 15 percent or less and Combustion Turbines with a Capacity Factor Greater than 15 percent. "A person who owns or operates fuel-burning equipment with a capacity factor (as defined in 40 CFR Part 72.2) of 15 percent or less shall:
(a) Provide certification of the capacity factor of the equipment to the Department in writing;
(b) For fuel-burning equipment that operates more than 500 hours during a calendar year, perform a combustion analysis and optimize combustion at least once annually;
(c) Maintain the results of the combustion analysis and any stack tests at the site for at least 2 years and make these results available to the Department and the EPA upon request;
(d) *Not Applicable*; and
(e) *Not Applicable*.

Compliance Demonstration
The Permittee shall perform a combustion analysis and optimize combustion at least once annually in any calendar year that the turbine operates more than 500 hours. **[Reference: COMAR 26.11.09.08G(1)(b)]**

The Permittee shall maintain the results of the combustion analysis and any stack tests at the site for at least 5 years and make these results available to the Department and the EPA upon request. **[Reference: COMAR 26.11.09.08G(1)(c) & COMAR 26.11.03.06C]**
The Permittee shall provide certification of the capacity factor of the equipment to the Department in writing by April 1 of the following calendar year. **[Reference: COMAR 26.11.09.08G(1)(a) & COMAR 26.11.03.06C]**

---

(4). Cross State Air Pollution Rule
See Table IV-5: CSAPR for requirements.

F. Control of VOC Emissions
CPCN Order No. 68587 (Case 8102) condition 17 limits VOC (hydrocarbons) emissions to 11 pounds per hour when burning natural gas and 11 pounds per hour when burning No. 2 oil.

Compliance Demonstration
The Permittee shall perform preventative maintenance to maintain the combustion turbine in a manner such that they continue to operate as designed. The Permittee shall maintain for at least five years records of the preventive maintenance that relates to combustion performance. The Permittee shall submit records of maintenance to the Department upon request. **[Reference: COMAR 26.11.03.06C**

G. Operational Limitations
CPCN Order No. 68587 (Case 8102) condition 9 limits the total annual hours of operation to no more than 1000 hours, and

CPCN Order No. 68587 (Case 8102) condition 11 states that the unit shall generate electricity using natural gas only. This requirement shall not apply during times when the delivered cost of natural gas per MMBtu exceeds the delivered cost per MMBtu of No. 2 oil by 15 percent or during those hours when the natural gas supply to the unit is curtailed or interrupted under the delivery contract. At such times, the unit shall use No. 2 oil only. Natural gas service curtailments or interruptions shall be verified by a letter each year from the unit's natural gas supplier identifying the dates on which gas service was restricted. This condition can be reconsidered in the future, if relief is requested by SMECO.
Compliance Demonstration
The Permittee shall maintain a record of the hours of operation for each day. **[Reference: COMAR 26.11.03.06C]**

The Permittee shall submit the record of the hours of operation with the support data in the annual emissions certification report due April 1 of each calendar year. **[Reference: COMAR 26.11.02.19C]**

Note: The Department, in a February 2, 2006 letter to GenOn, concurred with GenOn's proposal to clarify natural gas curtailments as follows:
Gas pipeline is out of service for maintenance or repair. Documentation of these events will be obtained through postings on the gas supplier's web site;
Gas supply is interrupted under the delivery contract. Documentation of these events will be obtained through postings on the gas supplier's web site;
One or more of the CT Units is called for by PJM to start or extend operation during periods of time when the pipeline operator is not open for business, typically between 6:00 PM and 10:00 AM daily. GenOn will document PJM dispatch notices during these occasions and will purchase gas upon opening of the commercial gas trading market- typically, 10:00 AM, provided the price of delivered gas is not 15% or more of the price of delivered oil.

The 15% cost differential between natural gas and #2 fuel oil will be determined on the following basis:
Daily publications from the Platts service will be utilized as representative industry benchmarks of natural gas and #2 oil pricing. GenOn will document delivered gas-to-oil cost differential using these benchmarks. The delivered cost of #2 oil for GenOn facilities is calculated by taking the Platts *Oilgram* New York Harbor Barge price and adding $0.0564/gallon in delivery charges. The delivered cost of natural gas for GenOn facilities is calculated by taking the Platts *Gas Daily* Transco Zone 6 Non-New York price and adding $0.10/MMBtu for delivery and $0.22/MMBtu in Park and Loan fees. The delivered prices for #2 oil and natural gas are calculated on a daily basis to determine if the 15% cost differential is met for the current day unit dispatch.

CTs are allowed to run on oil for test purposes after repairs or maintenance of the fuel oil system and its appurtenances for operability assurance.

Emission Units: E-3 & E-4: Boilers, E-CT2 thru E-CT6 and SMECO-CT1 Cont'd

Cross State Air Pollution Rule (CSAPR)

E-3 & E-4: Two (2) tangentially fired, sub-critical, cycling boilers each rated at 640 megawatts and 6,970 MMBtu/hr. heat input. Units fire natural gas and No. 6 fuel oil. No. 2 fuel oil or natural gas may be used for ignition, warm-up and flame stabilization purposes. **[4-0998 & 4-4-0999]**

E-CT2: One (1) Westinghouse (W-251) combustion turbine rated capacity of 35 megawatts (420 MMBtu/hr. heat input) used for black start capability and peaking service. This turbine is fired with No. 2 fuel oil. **[4-1145]**

E-CT3 & E-CT4: Two (2) General Electric Frame-7EA combustion turbines each rated capacity of 99 megawatts used for peaking service. This turbine is fired with natural gas as a primary fuel and No. 2 fuel oil as a secondary fuel and injects water in the combustion zone for NOx control. **[9-0752 & 9-0753]**

E-CT5 & E-CT6: Two (2) Kraftwork Union V84.2 combustion turbines each rated capacity of 120 megawatts used for peaking service. These turbines fire with natural gas as a primary fuel and No. 2 fuel oil as a secondary fuel and injects water in the combustion zone for NOx control when firing No. 2 fuel oil and dry low NOx combustors when firing natural gas. **[9-0754 & 9-0755]**

SMECO-CT1: One (1) General Electric GE-7EA combustion turbine rated capacity of 93 megawatts. This turbine is fired with natural gas as a primary fuel and No. 2 fuel oil as a secondary. This unit was owned by Southern Maryland Electric Cooperative until 2015 when NRG purchased the unit. **[5-0749]**

Applicable Standards and Limitations:

COMAR 26.11.28.02 - Requirements.

A. This chapter incorporates by reference the U.S. EPA CSAPR and the CSAPR Update, including the definitions, criteria, and procedures therein.

B. Trading Program Requirements.

(1) This chapter incorporates by reference provisions of the CSAPR NOx Annual Trading Program set forth in 40 CFR Part 97, Subpart AAAAA, as published July 1, 2017, and associated reference methods, performance specifications, and other test methods referenced by these standards, as applicable to existing and new units in Maryland, except the provisions at 40 CFR §97.411(b)(2) and (c)(5)(iii), 97.412(b), and 97.421(h) and (j).

(2) This chapter incorporates by reference provisions of the CSAPR NOx Ozone Season Group 2 Trading Program set forth in 40 CFR Part 97, Subpart EEEEE, as published July 1, 2017, and associated reference methods, performance specifications and other test methods referenced by these standards, as applicable to existing and new units in Maryland, except the provisions at 40 CFR §§97.811(b)(2) and (c)(5)(iii), 97.812(b), and 97.821(h) and (j). (***This is superseded by Group 3 Subpart GGGGG published April 30, 2021, effective June 29, 2021***).

(3) This chapter incorporates by reference provisions of the CSAPR SO_2 Group 1 Trading Program set forth in 40 CFR Part 97, Subpart CCCCC, as published July 1, 2017, and associated reference methods, performance specifications and

other test methods referenced by these standards, as applicable to existing and new units in Maryland, except the provisions at 40 CFR §§97.611(b)(2) and (c)(5)(iii), 97.612(b), and 97.621(h) and (j).

A. 40 CFR Part 97 Subpart AAAAA-CSAPR NOx Annual Trading Program
CSAPR NOx Annual Trading Program requirements (40 CFR 97.406)
The Permittee shall comply with the provisions and requirements of §97.401 through §97.435
Note: §97.406(c) NOx emissions requirements. For CSAPR NOx Annual emissions limitation: As of the allowance transfer deadline for a control period in a given year, the owners and operators of each CSAPR NOx Annual source and each CSAPR NOx Annual unit at the source shall hold, in the source's compliance account, CSAPR NOx Annual allowances available for deduction for such control period under §97.424(a) in an amount not less than the tons of total NOx emissions for such control period from all CSAPR NOx Annual units at the source.

Allowance transfer deadline means, for a control period in a given year, midnight of March 1 (if it is a business day), or midnight of the first business day thereafter (if March 1 is not a business day), immediately after such control period and is the deadline by which a CSAPR NOx Annual allowance transfer must be submitted for recordation in a CSAPR NOx Annual source's compliance account in order to be available for use in complying with the source's CSAPR NOx Annual emissions limitation for such control period in accordance with §§97.406 and 97.424.

B. 40 CFR Part 97 Subpart CCCCC-CSAPR SO_2 Group 1 Trading Program
CSAPR SO_2 Group 1 Trading Program requirements (40 CFR 97.606)
The Permittee shall comply with the provisions and requirements of §97.601 through §97.635
Note: §97.606(c) SO_2 emissions requirements. For CSAPR SO_2 Group 1 emissions limitation: As of the allowance transfer deadline for a control period in a given year, the owners and operators of each CSAPR SO_2 Group 1 source and each CSAPR SO_2 Group 1 unit at the source shall hold, in the source's compliance account, CSAPR SO_2 Group 1 allowances available for deduction for such control period under §97.624(a) in an amount not less than the tons of total SO_2 emissions for such control period from all CSAPR SO_2 Group 1 units at the source.

Allowance transfer deadline means, for a control period in a given year, midnight of March 1 (if it is a business day), or midnight of the first business day thereafter (if March 1 is not a business day), immediately after such control period and is the deadline by which a CSAPR SO_2 Group 1 allowance transfer must be

submitted for recordation in a CSAPR SO_2 Group 1 source's compliance account in order to be available for use in complying with the source's CSAPR SO_2 Group 1 emissions limitation for such control period in accordance with §§97.606 and 97.624.

C. 40 CFR Part 97 Subpart GGGGG-CSAPR NOx Ozone Season Group 3 Trading Program

CSAPR NOx Ozone Season Group 3 Trading Program Requirements (40 CFR 97.1006)

The Permittee shall comply with the provisions and requirements of §97.1001 through §97.1035.

Note: §97.1006(c) NOx emissions requirements. For CSAPR NOx Ozone Season Group 3 emissions limitation: As of the allowance transfer deadline for a control period in a given year, the owners and operators of each CSAPR NOx Ozone Season Group 3 source and each CSAPR NOx Ozone Season Group 3 unit at the source shall hold, in the source's compliance account, CSAPR NOx Ozone Season Group 3 allowances available for deduction for such control period under §97.1024(a) in an amount not less than the tons of total NOx emissions for such control period from all CSAPR NOx Ozone Season Group 3 units at the source.

Allowance transfer deadline means, for a control period in a given year, midnight of March 1 (if it is a business day), or midnight of the first business day thereafter (if March 1 is not a business day), immediately after such control period and is the deadline by which a CSAPR NOx Ozone Season Group 3 allowance transfer must be submitted for recordation in a CSAPR NOx Ozone Season Group 3 source's compliance account in order to be available for use in complying with the source's CSAPR NOx Ozone Season Group 3 emissions limitation for such control period in accordance with §§97.1006 and 97.1024.

Compliance Demonstration

The Permittee shall comply with the monitoring, record keeping, and reporting requirements found in §97.406, §97.430, §97.431, §97.432, and §97.433 for the CSAPR NOx Annual Trading Program; §97.1006, §97.1030, §97.1031, §97.1032, §97.1033 and §97.1034 for the CSAPR NOx Ozone Season Group 3 Trading Program; and §97.606, §97.630, §97.631, §97.632, and §97.633 and §97.634 for CSAPR SO_2 Group 1 Trading Program.

The Permittee operates continuous emission monitoring system (CEMS) pursuant to 40 CFR Part 75, Subpart B (for SO_2 monitoring) and 40 CFR Part 75, Subpart H (for NOx monitoring).

Emission Units: AUX-4 thru AUX-7: Auxiliary Boilers

AUX-4 thru AUX-7: Four (4) Combustion Engineering, Model #30VP-12W, auxiliary boilers, each rated at 186.6 MMBtu/hr. These boilers are fired with No. 2 fuel oil.

AUX-4 thru AUX-7 were all installed prior to the June 19, 1984 applicability date for the NSPS standards found at 40 CFR Subpart Db- Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units greater than 100 million Btu/hr. NSPS standards, therefore, do not apply.

These boilers are used for preheating the large utility boilers on start-up, so they have limited hours of operation.

Compliance Status
Capacity factors reported for the Auxiliary boilers in the 2018 ECR are as follows: **AUX-5** = 5.2% operated 131 days; **AUX-6** = 4.9% operated 142 days; and **AUX-7** = 3.0% operated 95 days.
Based on the Full Compliance Inspection Report August 16, 2018): Method 9 Observations were conducted as required. Fuel records show that the average fuel sulfur as 0.12% wt.
Capacity factors reported for the Auxiliary boilers in the 2019 ECR are as follows: **AUX-5** = 2.81%; **AUX-6** = 3.13%; and **AUX-7** = 2.56%. **AUX-3** & Aux-4 were out of service.

Applicable Standards and Limitations:

A. Control of Visible Emissions

COMAR 26.11.09.05A(2) – Fuel Burning Equipment
"Areas III and IV. In Areas III and IV, a person may not cause or permit the discharge of emissions from any fuel burning equipment, other than water in an uncombined form, which is visible to human observers except that, for the purpose of demonstrating compliance using COM data, emissions that are visible to a human observer are those that are equal to or greater than 10 percent opacity."
COMAR 26.11.09.05A(3) - Exceptions. "Section A(1) and (2) of this regulation do not apply to emissions during load changing, soot blowing, startup, or adjustments or occasional cleaning of control equipment if:
(a) The visible emissions are not greater than 40 percent opacity; and
(b) The visible emissions do not occur for more than 6 consecutive minutes in any sixty minute period."

Compliance Demonstration

The Permittee shall verify that there are no visible emissions when operating. An observer shall perform an EPA Reference Method 9 observation of stack emissions for 18-minute period once every 168 hours of operation or at a minimum once per year. If the boiler operates for less than 100 hours in a calendar year, the visual observation for that calendar year is waived.
The Permittee shall perform the following, if emissions are visible to human observer:
(a) inspect combustion control system and boiler operations,
(b) perform all necessary adjustments and/or repairs to the boiler within 48 hours of operation so that visible emissions are eliminated; and
(c) document in writing the results of inspections, adjustments and/or repairs to the auxiliary boiler.
(d) after 48 hours of operation, if the required adjustments and/or repairs had not eliminated the visible emissions, the Permittee shall perform a Method 9 observation once daily for an 18 minute period until corrective actions have eliminated visible emissions
The Permittee shall maintain records of all visible emissions observations. The Permittee shall report incidents of visible emissions in accordance with Permit Condition 4,Section III, Plant Wide Condition, "Report of Excess Emissions and Deviations" **[Reference: COMAR 26.11.03.06C]**

B. Control of Sulfur Oxides Emissions

COMAR 26.11.09.07: Control of Sulfur Oxides From Fuel Burning Equipment.
"A. Sulfur Content Limitations for Fuel. A person may not burn, sell, or make available for sale any fuel with a sulfur content by weight in excess of or which otherwise exceeds the following limitations:
(2) In Areas III and IV:
(a) All solid fuels, 1.0 percent;
(b) Distillate fuel oils, 0.3 percent;
(c) Residual fuel oils, 1.0 percent."

Compliance Demonstration

The Permittee shall obtain a certification from the fuel supplier indicating that the fuel oil complies with the limitation on sulfur content of the fuel oil. **[Reference: COMAR 26.11.03.06C].**
The Permittee shall retain annual fuel supplier certifications stating that the fuel oil is in compliance with this regulation must be maintained for at least 5 years. The Permittee shall report annual fuel supplier certification to the Department upon request. **[Reference: COMAR 26.11.09.07C].**

C. Control of Nitrogen Oxides Emissions
(1) NOx RACT Requirements
COMAR 26.11.09.08B(5) - Operator Training.
(a) For purposes of this regulation, the equipment operator to be trained may be the person who maintains the equipment and makes the necessary adjustments for efficient operation.
(b) The operator training course sponsored by the Department shall include an in-house training course that is approved by the Department."
COMAR 26.11.09.08G – Requirements for Fuel-Burning Equipment with a Capacity Factor of 15 percent or less and Combustion Turbines with a Capacity Factor Greater than 15 percent. "A person who owns or operates fuel-burning equipment with a capacity factor (as defined in 40 CFR Part 72.2) of 15 percent or less shall:
(a) Provide certification of the capacity factor of the equipment to the Department in writing;
(b) For fuel-burning equipment that operates more than 500 hours during a calendar year, perform a combustion analysis and optimize combustion at least once annually;
(c) Maintain the results of the combustion analysis and any stack tests at the site for at least 2 years and make these results available to the Department and the EPA upon request;
(d) Require each operator of an installation, except combustion turbines, to attend operator training programs at least once every 3 years, on combustion optimization that are sponsored by the Department, the EPA, or equipment vendors; and
(e) Maintain a record of training program attendance for each operator at the site, and make these records available to the Department upon request."

Compliance Demonstration
The Permittee shall perform a combustion analysis and optimize combustion at least once annually for any of the auxiliary boiler that operates more than 500 hours during a calendar year. **[Reference: COMAR 26.11.09.08G(1)(b)]**
The Permittee shall maintain records of the results of the combustion analyses on site for at least five years and make them available to the Department and EPA upon request. **[Reference: COMAR 26.11.09.08G(1)(c) & COMAR 26.11.03.06C]**.
The Permittee shall maintain record of training program attendance for each operator on site for at least five years and make the records available to the Department upon request. **[Reference: COMAR 26.11.09.08G(e) & COMAR 26.11.03.06C]**.
The Permittee shall provide certification of the annual capacity factor of the equipment to the Department with support documentation in Annual Emissions certification Report. **[Reference: COMAR 26.11.03.06C].**

The Permittee shall submit a list of trained operators to the Department upon request. **[Reference: COMAR 26.11.09.08G(e) and COMAR 26.11.03.06C].**

Emission Units: AUX-4 thru AUX-7: Auxiliary Boilers (Cont'd)

The auxiliary boilers are subject to the MACT for Industrial, Commercial, and Institutional Boilers and Process Heaters, 40 CFR part 63, subpart DDDDD (Boiler MACT).

Applicable Standards and Limitations:
Control of HAPs Emissions
40 CFR Part 63, Subpart DDDDD—National Emission Standards for Hazardous Air Pollutants for Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters
§63.7485 - Am I subject to this subpart?
You are subject to this subpart if you own or operate an industrial, commercial, or institutional boiler or process heater as defined in §63.7575 that is located at, or is part of, a major source of HAP, except as specified in §63.7491. For purposes of this subpart, a major source of HAP is as defined in §63.2, except that for oil and natural gas production facilities, a major source of HAP is as defined in §63.7575.
§63.7495 - When do I have to comply with this subpart?
"(b) If you have an **existing boiler** or process heater, you must comply with this subpart no later than **January 31, 2016**, except as provided in §63.6(i)."
"(d) You must meet the notification requirements in §63.7545 according to the schedule in §63.7545 and in subpart A of this part. Some of the notifications must be submitted before you are required to comply with the emission limits and work practice standards in this subpart."

§63.7500 - What emission limitations, work practice standards, and operating limits must I meet?
"(a) You must meet the requirements in paragraphs (a)(1) through (3) of this section, except as provided in paragraphs (b), through (e) of this section. You must meet these requirements at all times the affected unit is operating, except as provided in paragraph (f) of this section."
"(c) Limited-use boilers and process heaters must complete a tune-up every 5 years as specified in §63.7540. They are not subject to the emission limits in Tables 1 and 2 or 11 through 13 to this subpart, the annual tune-up, or the energy assessment requirements in Table 3 to this subpart, or the operating limits in Table 4 to this subpart."

"(f) These standards apply at all times the affected unit is operating, except during periods of startup and shutdown during which time you must comply only with Table 3 to this subpart."

Table 3 to Subpart DDDDD of Part 63—Work Practice Standards
As stated in §63.7500, you must comply with the following applicable work practice standards:

If your unit is...	You must meet the following...
1. A new or **existing** boiler or process heater with a continuous oxygen trim system that maintains an optimum air to fuel ratio, or a heat input capacity of less than or equal to 5 million Btu per hour in any of the following subcategories: unit designed to burn gas 1; unit designed to burn gas 2 (other); or unit designed to burn light liquid, or **a limited use boiler** or process heater	Conduct a tune-up of the boiler or process heater every 5 years as specified in §63.7540.

Limited-use boiler *or process heater* means any boiler or process heater that burns any amount of solid, liquid, or gaseous fuels and has a federally enforceable average annual capacity factor of no more than 10 percent. [§63.7575]

Operational Limits
Aux-4 thru Aux-7: Auxiliary Boilers 4–7 operations shall be limited to an annual capacity factor of 10 percent or less or an annual heat input of not greater than 163,462 million Btu per boiler.
These units shall be defined as limited use boilers as defined in §63.7500(c) & §63.7575.

Compliance Demonstration
§63.7510 - What are my initial compliance requirements and by what date must I conduct them?
"(e) For existing affected sources (as defined in §63.7490), you must complete the initial compliance demonstration, as specified in paragraphs (a) through (d) of this section, no later than 180 days after the compliance date that is specified for your source in §63.7495 and according to the applicable provisions in §63.7(a)(2) as cited in Table 10 to this subpart, except as specified in paragraph (j) of this section. You must complete an initial tune-up by following the procedures described in §63.7540(a)(10)(i) through (vi) no later than the compliance date specified in §63.7495, except as specified in paragraph (j) of this section. You must complete the one-time energy assessment specified in Table 3 to this subpart no later than the compliance date specified in §63.7495, except as specified in paragraph (j) of this section."

§63.7515 - When must I conduct subsequent performance tests, fuel analyses, or tune-ups?

"(d) If you are required to meet an applicable tune-up work practice standard, you must conduct an annual, biennial, or 5-year performance tune-up according to §63.7540(a)(10), (11), or (12), respectively. Each annual tune-up specified in §63.7540(a)(10) must be no more than 13 months after the previous tune-up. Each biennial tune-up specified in §63.7540(a)(11) must be conducted no more than 25 months after the previous tune-up. Each 5-year tune-up specified in §63.7540(a)(12) must be conducted no more than 61 months after the previous tune-up. For a new or reconstructed affected source (as defined in §63.7490), the first annual, biennial, or 5-year tune-up must be no later than 13 months, 25 months, or 61 months, respectively, after the initial startup of the new or reconstructed affected source."

§63.7530 - How do I demonstrate initial compliance with the emission limitations, fuel specifications and work practice standards?

"(f) You must submit the Notification of Compliance Status containing the results of the initial compliance demonstration according to the requirements in §63.7545(e)."

Continuous Compliance Requirements

§63.7540 - How do I demonstrate continuous compliance with the emission limitations, fuel specifications and work practice standards?

"(a) You must demonstrate continuous compliance with each emission limit in Tables 1 and 2 or 11 through 13 to this subpart, the work practice standards in Table 3 to this subpart, and the operating limits in Table 4 to this subpart that applies to you according to the methods specified in Table 8 to this subpart and paragraphs (a)(1) through (19) of this section."

"(10) If your boiler or process heater has a heat input capacity of 10 million Btu per hour or greater, you must conduct an annual tune-up of the boiler or process heater to demonstrate continuous compliance as specified in paragraphs (a)(10)(i) through (vi) of this section. **This frequency does not apply to limited-use boilers and process heaters, as defined in §63.7575**, or units with continuous oxygen trim systems that maintain an optimum air to fuel ratio.

(i) As applicable, inspect the burner, and clean or replace any components of the burner as necessary (you may delay the burner inspection until the next scheduled unit shutdown). Units that produce electricity for sale may delay the burner inspection until the first outage, not to exceed 36 months from the previous inspection. 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;

(ii) 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;

(iii) Inspect the system controlling the air-to-fuel ratio, as applicable, and ensure that it is correctly calibrated and functioning properly (you may delay the inspection until the next scheduled unit shutdown). Units that produce electricity for sale may delay the inspection until the first outage, not to exceed 36 months from the previous inspection;
(iv) Optimize total emissions of CO. This optimization should be consistent with the manufacturer's specifications, if available, and with any NOx requirement to which the unit is subject;
(v) 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
(vi) Maintain on-site and submit, if requested by the Administrator, an annual report containing the information in paragraphs (a)(10)(vi)(A) through (C) of this section,
(A) 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 or process heater;
(B) A description of any corrective actions taken as a part of the tune-up; and
(C) 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."
"(12) If your boiler or process heater has a continuous oxygen trim system that maintains an optimum air to fuel ratio, or a heat input capacity of less than or equal to 5 million Btu per hour and the unit is in the units designed to burn gas 1; units designed to burn gas 2 (other); or units designed to burn light liquid subcategories, or **meets the definition of limited-use boiler or process heater in §63.7575**, you must conduct a tune-up of the boiler or process heater every 5 years as specified in paragraphs (a)(10)(i) through (vi) of this section to demonstrate continuous compliance. You may delay the burner inspection specified in paragraph (a)(10)(i) of this section until the next scheduled or unscheduled unit shutdown, but you must inspect each burner at least once every 72 months."
"(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."

Notification, Reports, and Records
§63.7555 - What records must I keep?
"(a) You must keep records according to paragraphs (a)(1) and (2) of this section.

(1) A copy of each notification and report that you submitted to comply with this subpart, including all documentation supporting any Initial Notification or Notification of Compliance Status or semiannual compliance report that you submitted, according to the requirements in §63.10(b)(2)(xiv).
(2) Records of performance tests, fuel analyses, or other compliance demonstrations and performance evaluations as required in §63.10(b)(2)(viii)."

§63.7560 - In what form and how long must I keep my records?
"(a) Your records must be in a form suitable and readily available for expeditious review, according to §63.10(b)(1).
(b) As specified in §63.10(b)(1), you must keep each record for 5 years following the date of each occurrence, measurement, maintenance, corrective action, report, or record.
(c) You must keep each record on site, or they must be accessible from on site (for example, through a computer network), for at least 2 years after the date of each occurrence, measurement, maintenance, corrective action, report, or record, according to §63.10(b)(1). You can keep the records off site for the remaining 3 years."

§63.7545 - What notifications must I submit and when?
"(a) You must submit to the Administrator all of the notifications in §§63.7(b) and (c), 63.8(e), (f)(4) and (6), and 63.9(b) through (h) that apply to you by the dates specified."
"(e) If you are required to conduct an initial compliance demonstration as specified in §63.7530, you must submit a Notification of Compliance Status according to §63.9(h)(2)(ii). For the initial compliance demonstration for each boiler or process heater, you must submit the Notification of Compliance Status, including all performance test results and fuel analyses, before the close of business on the 60th day following the completion of all performance test and/or other initial compliance demonstrations for all boiler or process heaters at the facility according to §63.10(d)(2). The Notification of Compliance Status report must contain all the information specified in paragraphs (e)(1) through (**8**), as applicable. If you are not required to conduct an initial compliance demonstration as specified in §63.7530(a), the Notification of Compliance Status must only contain the information specified in paragraphs (e)(1) and (**8**)."
"(8) In addition to the information required in §63.9(h)(2), your notification of compliance status must include the following certification(s) of compliance, as applicable, and signed by a responsible official:
(i) "This facility complies with the required initial tune-up according to the procedures in §63.7540(a)(10)(i) through (vi)."

§63.7550 - What reports must I submit and when?
"(a) You must submit each report in Table 9 to this subpart that applies to you.

(b) Unless the EPA Administrator has approved a different schedule for submission of reports under §63.10(a), you must submit each report, according to paragraph (h) of this section, by the date in Table 9 to this subpart and according to the requirements in paragraphs (b)(1) through (4) of this section. **For units that are subject only to a requirement to conduct** an annual, biennial, or **5-year tune-up according to §63.7540(a)(10)**, (11), or (12), respectively, and **not subject to emission limits or operating limits, you may submit only an annual, biennial, or 5-year compliance report, as applicable, as specified in paragraphs (b)(1) through (4) of this section, instead of a semi-annual compliance report.**

(1) The first compliance report must cover the period beginning on the compliance date that is specified for each boiler or process heater in §63.7495 and ending on July 31 or January 31, whichever date is the first date that occurs at least 180 days (or 1, 2, or 5 years, as applicable, if submitting an annual, biennial, or 5-year compliance report) after the compliance date that is specified for your source in §63.7495.

(2) The first compliance report must be postmarked or submitted no later than July 31 or January 31, whichever date is the first date following the end of the first calendar half after the compliance date that is specified for each boiler or process heater in §63.7495. The first annual, biennial, or 5-year compliance report must be postmarked or submitted no later than January 31.

(3) Each subsequent compliance report must cover the semiannual reporting period from January 1 through June 30 or the semiannual reporting period from July 1 through December 31. **Annual, biennial, and 5-year compliance reports must cover the applicable 1-, 2-, or 5-year periods from January 1 to December 31.**

(4) Each subsequent compliance report must be postmarked or submitted no later than July 31 or January 31, whichever date is the first date following the end of the semiannual reporting period. **Annual, biennial, and 5-year compliance reports must be postmarked or submitted no later than January 31**.

"(c) A compliance report must contain the following information depending on how the facility chooses to comply with the limits set in this rule.

(1) If the facility is subject to a the requirements of a tune up they must submit a compliance report with the information in paragraphs (c)(5)(i) through (iv) and (xiv) of this section."

"(xiv) Include the date of the most recent tune-up for each unit subject to only the requirement to conduct an annual, biennial, or **5-year tune-up** according to §63.7540(a)(10), (11), or (12) respectively. Include the date of the most recent burner inspection if it was not done annually, biennially, or on a 5-year period and was delayed until the next scheduled or unscheduled unit shutdown."

"(h) You must submit the reports according to the procedures specified in paragraphs (h)(1) through (3) of this section."

"(3) You must submit all reports required by Table 9 of this subpart electronically using CEDRI that is accessed through the EPA's Central Data Exchange (CDX) (*www.epa.gov/cdx*). However, if the reporting form specific to this subpart is not available in CEDRI at the time that the report is due the report you must submit the report to the Administrator at the appropriate address listed in § 63.13. At the discretion of the Administrator, you must also submit these reports, to the Administrator in the format specified by the Administrator."

Emission Units: 9-1346

One (1) Emergency Fire Pump and one (1) Quench Pump: CT2 Starting engine, CT site fire pump. Main plant fire pump, MTS bldg. emergency generator - Diesel-Fired IC engines.

The purpose of these pumps is to protect the internal parts of the FGD scrubbers whenever a unit trips and there is a loss of electrical power and supply of slurry/water to the scrubbers. The pumps will operate only for testing, maintenance, and emergency incidents.

Compliance Status
The small diesel-fired IC engines have operated in compliance with the applicable standards. They have a capacity factor of less than 15% and have operated less than 500 hours during each calendar year. Fuel records are kept onsite to show compliance with the 0.3% sulfur limit.

Applicable Standards and Limitations:
A. Control of Visible Emissions
1. COMAR 26.11.09.05E(2), Emission During Idle Mode. "A person may not cause or permit the discharge of emissions from any engine, operating at idle, greater than 10 percent opacity." This requirement is not applicable during Preventative Maintenance.
COMAR 26.11.09.05E(3), Emission During Operating Mode. "A person may not cause or permit the discharge of emissions from any engine, operating at other than idle conditions, greater than 40 percent opacity." This requirement is not applicable during Preventative Maintenance.
Exceptions. **COMAR 26.11.09.05E(4)**
"(a) Section E(2) does not apply for a period of 2 consecutive minutes after a period of idling of 15 minutes for the purpose of clearing exhaust system.

(b) Section E(2) does not apply to emissions resulting directly from cold engine start-up and warm-up for the following maximum periods:
(i) Engines that are idled continuously when not in service: 30 minutes;
(ii) All other engines: 15 minutes.
(c) Section E(2) and E(3) does not apply while maintenance, repair, or testing is being performed by qualified mechanics."

Compliance Demonstration
The Permittee shall properly operate and maintain the engines in a manner to minimize visible emissions. **[Reference: COMAR 26.11.03.06C]**
The Permittee shall retain records of preventative maintenance that relate to combustion performance on site for at least 5 years and make these records available to the Department upon request. **[Reference: COMAR 26.11.03.06C]**
The Permittee shall report incidents of visible emissions in accordance with Permit Condition 4, Section III, "Report of Excess Emissions and Deviations."

---

2. 40 CFR Part 60 Subpart IIII - Standards of Performance (NSPS) for Stationary Compression Ignition (CI) Internal Combustion Engines (ICE).
§89.113 - Smoke emission standard.
(a) Exhaust opacity from compression- ignition non-road engines for which this subpart is applicable must not exceed:
(1) 20 percent during the acceleration mode;
(2) 15 percent during the lugging mode; and
(3) 50 percent during the peaks in either the acceleration or lugging modes.

Compliance Demonstration
The Permittee must operate and maintain the stationary CI internal combustion engine according to the manufacturer's written instructions or procedures developed by the owner or operator that are approved by the engine manufacturer. **[Reference: §60.4211(a)]**
The Permittee shall report incidents of visible emissions in accordance with Permit Condition 4, Section III, "Report of Excess Emissions and Deviations."

Rationale:
The Permittee purchased engines that meet the EPA Tier III standards for non-road IC engines. The engines came online in conjunction with the FGD scrubbers. The Permittee operates and maintains the stationary CI engine according to the manufacturer's written instructions.

B. Control of Particulate Matter Emissions
NSPS Subpart IIII

§60.4205b - What emission standards must I meet for emergency engines if I am an owner or operator of a stationary CI internal combustion engine?
"(b) Owners and operators of 2007 model year and later emergency stationary CI ICE with a displacement of less than 30 liters per cylinder must comply with the emission standards for new non-road CI engines in **§60.4202,**for all pollutants, for the same model year and maximum engine power for their 2007 model year and later emergency stationary CI ICE.".

Compliance Demonstration
The Permittee must operate and maintain the stationary CI engine according to the manufacturer's written instructions or procedures developed by the owner or operator that are approved by the engine manufacturer. **[Reference: §60.4211(a)]**

Rationale:
The Permittee purchased engines that meet the EPA Tier III standards for non-road IC engines. The engines came online in conjunction with the FGD scrubbers.

C. Control of Sulfur Oxides Emissions
COMAR 26.11.09.07A(2) – Control of Sulfur Oxides from fuel burning equipment. "A person may not burn, sell, or make available for sale any fuel with a sulfur content by weight in excess of or which otherwise exceeds the following limitations: In Areas III and IV:
(a) All solid fuels, 1.0 percent;
(b) **Distillate fuel oils, 0.3 percent;**
(c) Residual fuel oils, 1.0 percent. "

Compliance Demonstration
The Permittee shall obtain a certification from the fuel supplier indicating that the fuel oil is in compliance with the limitation on the sulfur content of the fuel oil or obtain sulfur in fuel analyses of oil that is representative of the oil burned.
[Reference: COMAR 26.11.03.06C]
The Permittee shall maintain records of fuel supplier's certification or sulfur in fuel analyses and shall make records available to the Department upon request.
[Reference: COMAR 26.11.09.07C]

---

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

"(a) Beginning October 1, 2007, owners and operators of stationary CI ICE subject to this subpart that use diesel fuel must use diesel fuel that meets the requirements of 40 CFR 80.510(a).
(b) Beginning October 1, 2010, owners and operators of stationary CI ICE subject to this subpart with a displacement of less than 30 liters per cylinder that use diesel fuel must use diesel fuel that meets the requirements of 40 CFR 80.510(b) for non-road diesel fuel."

Compliance Demonstration
Although there is no specific testing, monitoring, record keeping, and reporting requirements for the NSPS subpart IIII sulfur in fuel limitation, the fuel supplier certification requirement for COMAR will be used for the compliance demonstration.

Rationale:
Maryland's Comptroller's office Fuel Tax Division enforces the regulatory sulfur in fuel specifications for diesel fuel sold in the State of Maryland. Diesel fuel that may be sold in the State of Maryland is sampled on a monthly basis to ensure compliance.

D. Control of Nitrogen Oxides Emissions
COMAR 26.11.09.08G – Requirements for Fuel-Burning Equipment with a Capacity Factor of 15 percent or less and Combustion Turbines with a Capacity Factor Greater than 15 percent.

(1) "A person who owns or operates fuel-burning equipment with a capacity factor (as defined in 40 CFR Part 72.2) of 15 percent or less shall:
(a) Provide certification of the capacity factor of the equipment to the Department in writing;
(b) For fuel-burning equipment that operates more than 500 hours during a calendar year, perform a combustion analysis and optimize combustion at least once annually;
(c) Maintain the results of the combustion analysis and any stack tests at the site for at least 2 years and make these results available to the Department and the EPA upon request;
(d) Require each operator of an installation, except combustion turbines, to attend operator training programs at least once every 3 years, on combustion optimization that are sponsored by the Department, the EPA, or equipment vendors; and
(e) Maintain a record of training program attendance for each operator at the site and make these records available to the Department upon request."

Compliance Demonstration
The Permittee shall perform a combustion analysis and optimize combustion at least once annually when the hours of operation exceed 500 during the year. **[Reference: COMAR 26.11.09.08G(1)(b)]**
The Permittee shall calculate the capacity factor of the engines for each calendar year within 30 days after the end of each year. **[Reference: COMAR 26.11.03.06C]**
The Permittee shall maintain:
(1) Records of the calculated capacity factors. **[Reference: COMAR 26.11.03.06C]**
(2) Records of hour of operation. **[Reference: COMAR 26.11.02.19.C(1)(b)]**
(3) Records of combustion analysis performed if the hours of operation exceed 500. **[Reference: COMAR 26.11.09.08G(1)(c)]**
(4) Record of training program attendance for each operator. **[Reference: COMAR 26.11.09.08G(1)(e)]**
The Permittee shall provide certification of the capacity factor of the equipment to the Department in writing as part of the April 1 emission certification report. **[Reference: COMAR 26.11.09.08G(1)(a) & COMAR 26.11.03.06C]**
The Permittee shall submit a record of training program attendance for each operator to the Department upon request. **[Reference: COMAR 26.11.09.08G(1)(e)]**

NSPS Subpart IIII
§60.4205b - What emission standards must I meet for emergency engines if I am an owner or operator of a stationary CI internal combustion engine?
"(b) Owners and operators of 2007 model year and later emergency stationary CI ICE with a displacement of less than 30 liters per cylinder must comply with the emission standards for new non-road CI engines in §60.4202,for all pollutants, for the same model year and maximum engine power for their 2007 model year and later emergency stationary CI ICE.".

Compliance Demonstration
The Permittee must operate and maintain the stationary CI internal combustion engine according to the manufacturer's written instructions or procedures developed by the owner or operator that are approved by the engine manufacturer. **[Reference: §60.4211(a)]**

E. Control of Hazardous Air Pollutants (HAPS) Emissions
40CFR 63 Subpart ZZZZ—National Emissions Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines
"**§63.6590** - What parts of my plant does this subpart cover?

This subpart applies to each affected source.
(c) Stationary RICE subject to Regulations under 40 CFR Part 60. An affected source that meets any of the criteria in paragraphs (c)(1) through (7) of this section must meet the requirements of this part by meeting the requirements of **40 CFR part 60 subpart IIII**, for compression ignition engines or 40 CFR part 60 subpart JJJJ, for spark ignition engines. *No further requirements apply for such engines under this part.*
(1) A new or reconstructed stationary RICE located at an area source."

Compliance Demonstration
By complying with the NSPS Subpart IIII requirements, the Permittee complies with NESHAP Subpart ZZZZ requirements.

F. NSPS subpart IIII Operational limitations
§60.4209(a) - What are the monitoring requirements if I am an owner or operator of a stationary combustion engine?
"(a) If you are an owner or operator of an emergency stationary CI internal combustion engine, you must install a non-resettable hour meter prior to startup of the engine."

§60.4206 How long must I meet the emission standards if I am an owner or operator of a stationary CI internal combustion engine?
"Owners and operators of stationary CI ICE must operate and maintain stationary CI ICE that achieve the emission standards as required in §§60.4204 and **60.4205** according to the manufacturer's written instructions or procedures developed by the owner or operator that are approved by the engine manufacturer, over the entire life of the engine."

§60.4211(a) and (e) - What are my compliance requirements if I am an owner or operator of a stationary CI internal combustion engine?
"(a) If you are an owner or operator and must comply with the emission standards specified in this subpart, you must operate and maintain the stationary CI internal combustion engine and control device according to the manufacturer's written instructions or procedures developed by the owner or operator that are approved by the engine manufacturer. In addition, owners and operators may only change those settings that are permitted by the manufacturer. You must also meet the requirements of 40 CFR parts 89, 94 and/or 1068, as they apply to you."

"(e) Owners or operators may operate the stationary CI ICE 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, or the insurance company associated with the engine. Maintenance checks and readiness testing shall be limited to 100 hours per year. There is no time limit on the use of emergency stationary ICE in emergency situations. Anyone may petition the Administrator for approval of additional hours to be used for maintenance checks and readiness testing, but a petition is not required if the owner or operator maintains records indicating that Federal, State, or local government standards require maintenance and testing of emergency ICE beyond 100 hours per year. Any operation other than emergency operation, and maintenance and testing, is prohibited.

Compliance Demonstration

(1) The Permittee shall maintain a log for the emergency generator indicating the amounts of fuel oil combusted or the hours of operation, and reason for generator operation (i.e., maintenance or operational testing, power outage, etc.).

(2) The Permittee shall maintain on site for the life of the source the following records for the emergency diesel generator(s):

(a) Documentation of the manufacture date of the diesel engine, if manufactured prior to April 1, 2006 and the manufacturer model year of the diesel engine;

(b) The installation date of each emergency diesel generator; and

(c) The certifications of compliance or manufacturer engine test data required by 40 CFR §60.4211 and §60.4214(b

(3) Beginning October 1, 2007, for any NSPS emergency diesel generator the Permittee shall for each fuel delivery obtain from the fuel supplier a fuel supplier certification consisting of the name of the oil supplier, the date of delivery, the amount of fuel delivered, and a statement from the fuel supplier that the diesel fuel oil complies with the specifications of 40 CFR §80.510. The Permittee shall maintain the required records on site for at least five (5) years.

[Reference: COMAR 26.11.03.06C]

The Permittee shall report the amounts of fuel oil combusted or the hours of operation, and reason for generator operation (i.e., maintenance or operational testing, power outage, etc.) to the Department in the annual emission certification report due on April 1 of each year. **[Reference: COMAR 26.11.03.06C]**

COMPLIANCE SCHEDULE

Chalk Point Generation Station is currently in compliance with all applicable air quality regulations.

TITLE IV – ACID RAIN

Chalk Point Generation Station is subject to the Acid Rain Program requirements. The Phase II Acid Rain Permit renewal will be issued in conjunction with this Part 70 permit.

TITLE VI – OZONE DEPLETING SUBSTANCES

Chalk Point Generation Station is not subject to Title VI requirements.

SECTION 112(r) – ACCIDENTAL RELEASE

Chalk Point Generation Station is not subject to the requirements of Section 112(r).

PERMIT SHIELD

The Chalk Point Generation Station facility requested that a permit shield be expressly included in the Permittee's Part 70 permit. Permit shields are granted on an emission unit by emission unit basis. If an emission unit is covered by a permit shield, a permit shield statement will follow the emission unit table in Section IV - Plant Specific Conditions of the permit. In this case, a permit shield was granted for each emission unit covered by the permit.

INSIGNIFICANT ACTIVITIES

This section provides a list of insignificant emissions units that were reported in the Title V permit application. The applicable Clean Air Act requirements, if any, are listed below the insignificant activity.

(1) No. **10** Fuel burning equipment using gaseous fuels or no. 1 or no. 2 fuel oil, and having a heat input less than 1,000,000 Btu (1.06 gigajoules) per hour;

[For Areas III and IV]

These *affected fuel burning units* are subject to the following requirements:

COMAR 26.11.09.05A(2), which establishes that the Permittee may not cause or permit the discharge of emissions from any

fuel burning equipment, other than water in an uncombined form, which is visible to human observers.

Exceptions: COMAR 26.11.09.05A(2) does not apply to emissions during load changing, soot blowing, start-up, or adjustments or occasional cleaning of control equipment if:

(a) The visible emissions are not greater than 40 percent opacity; and

(b) The visible emissions do not occur for more than 6 consecutive minutes in any sixty minute period.

[For Distillate Fuel Oil]
COMAR 26.11.09.07A(2)(b), which establishes that the Permittee may not burn, sell, or make available for sale any distillate fuel with a sulfur content by weight in excess of 0.3 percent.

(2) No. **2** Stationary internal combustion engines with an output less than 500 brake horsepower (373 kilowatts) and which are not used to generate electricity for sale or for peak or load shaving;

The *affected units* are subject to the following requirements:

(A) COMAR 26.11.09.05E(2), Emissions During Idle Mode: The Permittee may not cause or permit the discharge of emissions from any engine, operating at idle, greater than 10 percent opacity.

(B) COMAR 26.11.09.05E(3), Emissions During Operating Mode: The Permittee may not cause or permit the discharge of emissions from any engine, operating at other than idle conditions, greater than 40 percent opacity.

(C) Exceptions:

(i) COMAR 26.11.09.05E(2) does not apply for a period of 2 consecutive minutes after a period of idling of 15 consecutive minutes for the purpose of clearing the exhaust system.

(ii) COMAR 26.11.09.05E(2) does not apply to emissions resulting directly from cold engine start-up and warm-up for the following maximum periods:
(a) Engines that are idled continuously when not in service: 30 minutes
(b) all other engines: 15 minutes.

(iii) COMAR 26.11.09.05E(2) & (3) do not apply while maintenance, repair or testing is being performed by qualified mechanics.

(3) ✓ Space heaters utilizing direct heat transfer and used solely for comfort heat; (**25 heaters**)

(4) No. **50** Unheated VOC dispensing containers or unheated VOC rinsing containers of 60 gallons (227 liters) capacity or less;

The *affected units* are subject to COMAR 26.11.19.09D, which requires that the Permittee control emissions of volatile organic compounds (VOC) from cold degreasing operations by meeting the following requirements:

(a) COMAR 26.11.19.09D(2)(b), which establishes that the Permittee shall not use any VOC degreasing material that exceeds a vapor pressure of 1 mm Hg at 20 °C;

(b) COMAR 26.11.19.09D(3)(a—d), which requires that the Permittee implement good operating practices designed to minimize spills and evaporation of VOC degreasing material. These practices, which shall be established in writing and displayed such that they are clearly visible to operators, shall include covers (including water covers), lids, or other methods of minimizing evaporative losses, and reducing the time and frequency during which parts are cleaned;

(c) COMAR 26.11.19.09D(4), which prohibits the use of any halogenated VOC for cold degreasing.

The Permittee shall maintain on site for at least five (5) years, and shall make available to the Department upon request, the following records of operating data:

(a) Monthly records of the total VOC degreasing materials used; and

(b) Written descriptions of good operating practices designed to minimize spills and evaporation of VOC degreasing materials.

(5) ✓ Equipment for drilling, carving, cutting, routing, turning, sawing, planing, spindle sanding, or disc sanding of wood or wood products; (**5**)

(6) ✓ Brazing, soldering, or welding equipment, and cutting torches related to manufacturing and construction activities that emit HAP metals and not directly related to plant maintenance, upkeep and repair or maintenance shop activities; (**10**)

(7) ✓ Equipment for washing or drying products fabricated from metal or glass, provided that no VOC is used in the process and that no oil or solid fuel is burned; (**2**)

(8) Containers, reservoirs, or tanks used exclusively for:

(a) ✓ Dipping operations for applying coatings of natural or synthetic resins that contain no VOC; (**2**)

(b) ✓ Storage of butane, propane, or liquefied petroleum, or natural gas; (**2**)

(c) No. **9** Storage of lubricating oils;

(d) No. **1** Unheated storage of VOC with an initial boiling point of 300 °F (149 °C) or greater;

(e) No. **10** Storage of Numbers 1, 2, 4, 5, and 6 fuel oil and aviation jet engine fuel;

(f) No. **1** Storage of motor vehicle gasoline and having individual tank capacities of 2,000 gallons (7.6 cubic meters) or less;

(g) No. **50** The storage of VOC normally used as solvents, diluents, thinners, inks, colorants, paints, lacquers, enamels, varnishes, liquid resins, or other surface coatings and having individual capacities of 2,000 gallons (7.6 cubic meters) or less;

(9) ✓ Gaseous fuel-fired or electrically heated furnaces for heat treating glass or metals, the use of which does not involve molten materials; **(2)**

(10) ✓ Charbroilers and pit barbecues as defined in COMAR 26.11.18.01 with a total cooking area of 5 square feet (0.46 square meter) or less; **(2)**

(11) ✓ First aid and emergency medical care provided at the facility, including related activities such as sterilization and medicine preparation used in support of a manufacturing or production process;

(12) ✓ Certain recreational equipment and activities, such as fireplaces, barbecue pits and cookers, fireworks displays, and kerosene fuel use;

(13) ✓ Potable water treatment equipment, not including air stripping equipment; **(2)**

(14) ✓ Comfort air conditioning subject to requirements of Title VI of the Clean Air Act; **(5)**

(15) ✓ Natural draft hoods or natural draft ventilators that exhaust air pollutants into the ambient air from manufacturing/industrial or commercial processes; **(5)**

(16) ✓ Laboratory fume hoods and vents;

STATE ONLY ENFORCEABLE REQUIREMENTS

This section of the permit contain state-only enforceable requirements. The requirements in this section will not be enforced by the U.S. Environmental Protection Agency. The requirements in this section are not subject to COMAR 26.11.03 10 - Public Petitions for Review to EPA Regarding Part 70 Permits.

1. **Applicable Regulations**:

COMAR 26.11.06.08 – Nuisance. "An installation or premises may not be operated or maintained in such a manner that a nuisance or air pollution is created. Nothing in this regulation relating to the control of emissions may in any manner be consumed as authorizing or permitting the creation of, or maintenance of, nuisance or air pollution."

COMAR 26.11.06.09 - Odors. "A person may not cause or permit the discharge into the atmosphere of gases, vapors, or odors beyond the property line in such a manner that a nuisance or air pollution is created."

Emissions Unit Number(s): E-3 and E-4: Boilers Cont'd

E-3 and E-4: Two (2) tangentially fired, sub-critical, cycling boilers, each rated at 640 megawatts and 6970 million Btu per hour heat input. They are fired on natural gas and No. 6 fuel oil. No. 2 fuel oil or natural gas may be used for ignition, warm-up, and flame stabilization purposes.

Applicable Standards/Limits:

Control of Particulate Matter Emissions
(3) 2011 Consent Decree
3. Subject to Paragraph 4, GenOn Chalk Point, LLC ("GenOn") shall comply with the provisions of Subparagraphs (a) through (d) of this Paragraph.

(a) On days that GenOn is dispatched by PJM Interconnection ("PJM"), pursuant to the PJM's tariff, to operate Chalk Point Unit 3 and/or Unit 4, GenOn will request natural gas deliveries in the quantities GenOn anticipates will be needed to meet GenOn's estimate of PJM's hourly dispatch; provided that GenOn shall not be required to contract for natural gas delivery greater than the minimum operating load consistent with the PJM dispatch if doing so might require GenOn to accept delivery of natural gas in excess of the quantity needed to meet demand.

(b) GenOn may burn fuel oil only to the extent necessary to maintain operations, perform stack testing, respond to a PJM dispatch directive, or meet the required generation need where the natural gas supply company or pipeline operator interrupts natural gas service. Natural gas service is interrupted within the meaning of this Paragraph when:

(i) A natural gas supply company has limited GenOn's consumption of natural gas due to high demand or inadequate supply;

(ii) A pipeline operator will not permit GenOn to draw natural gas in non-ratable quantities sufficient to meet the dispatch profile authorized by PJM;

(iii) GenOn must discontinue or curtail gas consumption to comply with a directive from a pipeline operator;

(iv) GenOn is unable to obtain delivery of natural gas because natural gas scheduling nominations have closed; or

(v) The gas spur and pressure reducing station that connects the Chalk Point Facility and the pipeline is out of service.

(c) GenOn shall utilize its dual-fuel firing capabilities to burn natural gas to the maximum extent consistent with the provisions of Subparagraphs (a) and (b), and safety and engineering constraints where an interruption of natural gas requires load shaping with oil.

(d) When natural gas has been interrupted, GenOn will attempt to obtain natural gas in quantities needed to meet its generation needs consistent with Subparagraph (a) at the next available nomination period.

4. Notwithstanding the provisions of Paragraph 3, GenOn shall contract for interruptible gas transportation to supply natural gas as the primary fuel for operation of Chalk Point Unit 3 and Unit 4, and shall burn natural gas for no less than 75.0 % of the annual heat input of the Units, calculated on a calendar yearly basis. Note: Unit 4 is also subject to New Source Performance Standard ("NSPS") set forth in 40 C.F.R. § 60.42, which establishes a particulate emissions limitation of 0.10 lbs./MMBtu for residual oil burning units (see condition 9).

5. If the Pipeline or the spur to the plant is damaged, destroyed, or is otherwise not available, the requirements of Paragraphs 3 and 4 shall not apply until the Pipeline or spur is repaired, rebuilt or otherwise made available. Further, if

PJM issues a dispatch order for Chalk Point Units 3 and/or 4 to run under Emergency Procedures or Abnormal Bulk Electric System Operations, invoked to maintain system reliability, stability, and/or avoid load shedding events, the requirements of Paragraphs 3 and 4 shall not apply for the duration of that dispatch order.

6. Notwithstanding Paragraphs 3 and 4 and COMAR 26.11.09.06B(6)(a), particulate emissions from GenOn Chalk Point Unit 3 and Unit 4 shall not exceed an emissions limitation of 0.020 grains per standard cubic foot of dry exhaust gas (gr/scfd). .....

Ozone Season Restrictions

11. (a) Notwithstanding and subject to Paragraph 4 and Subparagraph (b) of this Paragraph, GenOn shall burn natural gas in Units 3 and 4 for 95 % of their heat input during the Ozone Season, which begins on May 1 and ends on September 30 of each year.

(b) In the event GenOn burns natural gas for less than 95 % of the Units' Ozone Season heat input, GenOn shall record such shortfall and:

burn the equivalent amount of natural gas to make up such shortfall outside the Ozone Season; or

if GenOn is unable to make up the shortfall outside the Ozone Season before the installation of controls described in Paragraph 15, GenOn agrees to burn the equivalent amount of gas to make up such shortfall following installation of the control equipment referenced in Paragraph 15 of this Consent Decree.

(c) In no event shall the shortfall exceed 3.84 million MMBtu derived from No. 6 fuel oil.

Visible Emissions

12. Upon entry of this Consent Decree GenOn shall:

(a) use natural gas for start-up of Units 3 and 4 when gas is available from the Pipeline under GenOn's interruptible gas service contract;

(b) twice per year, optimize the air-to-fuel ratio in the boilers for Units 3 and 4;

(c) continue use of a chemical additive with Number 6 fuel oil in Units 3 and 4 to reduce opacity; and

(d) wash down the boiler tubes in Units 3 and 4 during each PJM planned outage to reduce opacity during soot blowing.

13. GenOn shall continue to maintain and operate a human machine interface (HMI), or other similar technology on Units 3 and 4, which includes proactive alarming and feedback from opacity monitors to controls to manage the duration and frequency of soot blowing.

14. GenOn shall demonstrate that Units 3 and 4 comply with the visible emission standard set forth in COMAR 26.11.09.05A(2) through the submission of continuous opacity monitor system ("COMS") data, in accordance with Paragraph 22.

Pollution Control Equipment

15. Except for the requirements of Paragraph 11(b)(ii), the requirements of Paragraphs 11, 12, and 13 will terminate as to each Unit after GenOn installs and successfully tests, to the satisfaction of the Department, an electrostatic precipitator or other particulate pollution control equipment on such Unit that GenOn demonstrates, and the Department's satisfaction, is comparable to an electrostatic precipitator in its effectiveness. Prior to terminating the requirements of Paragraphs 11, 12, and 13, except for 11(b)(ii), the Department will secure written concurrence of its determination from the United States Environmental Protection Agency ("USEPA").

Fuel Sulfur Content

16. Unit 3 shall operate in compliance with the requirements of COMAR 26.11.09.07A(2), which establishes the standards for sulfur content in residual oil. In order to demonstrate compliance with this Paragraph, GenOn shall maintain appropriate documentation evidencing the fuel sulfur content from each delivery of residual fuel oil.

Testing Requirements:

Control of Particulate Matter Emissions

(3) 2011 Consent Decree

6....GenOn shall demonstrate compliance with this emissions limitation through the use of stack testing in accordance with the provisions of Subparagraphs (a) through (e) of this Paragraph.

(a) GenOn shall perform an initial stack test on Unit 3 and Unit 4 in the 2011 calendar year.

(b) Beginning January 1, 2012, GenOn shall perform subsequent stack testing when either Unit 3 or Unit 4 exceeds 570,000 MMBtu (approximately 100 hours of operation) derived from residual fuel oil during any calendar year (the "Trigger"). In the event that GenOn fails a particulate matter stack test under Paragraph 6, the Trigger shall be reduced to 475,000 MMBtu for subsequent stack tests triggered by residual fuel oil usage. When GenOn has performed four (4) consecutive stack tests triggered by residual fuel oil usage which demonstrate compliance with the particulate matter standard in Paragraph 6, the Trigger shall be reset to 570,000 MMBtu.

(c) Stack testing shall be performed on the corresponding stack serving the Unit meeting the Trigger and shall occur within the one-hundred-eighty (180) days from the date the Trigger is met.

(d) A stack test conducted in accordance with Paragraphs 6 or 7 shall be exempt from the requirements of Paragraph 3 and residual fuel oil burned during such test shall not count towards the Trigger.

(e) Stack testing on oil shall be conducted in accordance with EPA Method 5, under conditions representative of normal operation.

(f) GenOn shall submit stack test protocols for each of Units 3 and 4 to the Department for approval and notify the Department of the scheduled test date(s) at least thirty (30) days in advance of the test(s). GenOn shall submit the stack test results to the Department no later than forty-five (45) days following completion of the applicable test.

7. In the event GenOn fails the stack test for compliance under Paragraph 6 for either Unit 3 or Unit 4 (as applicable), GenOn shall perform a second stack test no later than sixty (60) days following receipt of the stack test results. GenOn shall notify the Department of the scheduled test date at least two weeks in advance of the test(s).

8. In the event GenOn fails to pass the second stack test, GenOn shall evaluate the reasons for the failure, and no later than ninety (90) days following receipt of the second stack test results, submit to the Department for approval, a plan to achieve compliance at the applicable unit through the installation of control technology, fuel switching, or other measures.

9. Stack testing on Unit 4 performed in 2010 in accordance with the requirements of EPA National Stack Testing Guidance dated April 27, 2009, satisfies GenOn's obligations to determine compliance with the New Source Performance Standard ("NSPS") set forth in 40 C.F.R. § 60.42, which

establishes a particulate emissions limitation of 0.10 lbs./MMBtu for residual oil burning units.

10. The residual oil burned during a stack test required by Paragraphs 6 or 7 shall not count toward the annual heat input of Chalk Point Unit 3 and Unit 4, for purposes of calculating compliance with Paragraph 4, if the residual oil burned during the stack test:

(a) Accounts for 50.0% or more of the residual oil burned at the corresponding Unit during the calendar year in which the stack test was conducted; and
(b) The required stack test causes GenOn to violate the requirements of Paragraph 4.

Monitoring Requirements:

Control of Particulate Matter
(3) 2011 Consent Decree
See Record Keeping and Reporting Requirements.

Record Keeping Requirements:
Note: All records must be maintained for a period of at least 5 years.
[Reference: COMAR 26.11.03.06C(5)(g)]

A. Control of Particulate Matter Emissions
(3) 2011 Consent Decree
17. GenOn shall preserve for a minimum of five (5) years all fuel use data and other information relied upon to establish compliance with Paragraphs 3 and 4 of this Consent Decree for the time period beginning with entry of this Consent Decree through December 31, 2011. Such documentation shall include the documents described in Paragraph 19(a) and (b). GenOn shall provide the data and information to the Department within 30 days of receiving the Department's written request.

24. Except for that information retention governed by Paragraph 17, GenOn shall preserve from the date of lodging of this Consent Decree, and for a minimum of five (5) years following the date of termination of this Consent Decree, all emissions data and other data relied upon to establish compliance with applicable regulatory standards as required by this Consent Decree.

Reporting Requirements:

Control of Particulate Matter Emission

(3) 2011 Consent Decree

18. Beginning January 1, 2012, GenOn shall submit quarterly reports to the Department detailing the status of GenOn's compliance with Paragraphs 3 and 4 of this Consent Decree. Each quarterly report shall be submitted no later than 30 days following the end of the quarter, unless such date falls on a weekend or holiday, in which case the report shall be due on the next business day.

19. Each quarterly report submitted under Paragraph 18 shall document GenOn's attempts to procure and use natural gas to operate Chalk Point Unit 3 and Unit 4, and shall, at a minimum, include:

(a) Documentation of the dates, hours, and the quantity of fuel burned, and for days where residual oil is burned, the reason natural gas was not used;

(b) For days where any residual oil is burned, the nominating documents and burn profiles submitted to the pipeline operator, and purchase orders between GenOn and any natural gas supplier. Equivalent documentation used in normal and ordinary course of industry practice may be substituted for specific documents described above. If the pipeline operator has notified GenOn in advance that GenOn will be required to take gas ratably and GenOn expects that it will not be dispatched for all 24 hours in that day (the "Notification"), GenOn will not submit a nominating document or burn profile to the pipeline operator nor enter into a purchase order with any natural gas supplier. Instead, GenOn will produce a memorandum or email memorializing the pipeline operator's Notification. In addition to providing that memorandum in its quarterly report, GenOn shall submit the memorandum to the Department within 11 business days of the Notification.

(c) A statement certifying the percent of the annual heat input of the Units derived from the burning of natural gas, as calculated from the beginning of the calendar year through the end of the applicable calendar quarter; and

(d) A compliance certification, signed by a responsible official under the penalty of perjury as to truth, accuracy and completeness of the report, indicating the compliance status with regard to each term of this Consent Order and whether that compliance was continuous or intermittent.

20. Beginning with the quarterly report for the quarter ending September 30 following entry of this Consent Decree, and each third-quarter report thereafter, GenOn shall submit to the Department documentation of its compliance with the requirements of Paragraph 11. Progress in addressing any shortfall shall be included in subsequent quarterly reports submitted pursuant to Paragraph 18.

21. GenOn shall submit semi-annual NSPS reports that comply with the requirements of 40 CFR § 60.45(g).

22. GenOn shall submit quarterly opacity reports in accordance with COMAR 26.11.01.10D(2)(c). GenOn shall accurately calculate each Unit's operating time in accordance with the procedures in COMAR 26.11.01.10.

23. All reports and submissions required by this Consent Decree shall be mailed to:

Program Manager
Air Quality Compliance Program
Maryland Department of the Environment
1800 Washington Boulevard
Baltimore, Maryland 21230

Emissions Unit Number(s): E3 & E4: Boilers Cont'd

Alternate Operating Scenario for Emission Units **E3 & E4**

E-3 & E-4: Two (2) tangentially fired, sub-critical, cycling boilers each rated at 640 megawatts and 6,970 MMBtu/hr. heat input. Units fire natural gas and No. 6 fuel oil. No. 2 fuel oil or natural gas may be used for ignition, warm-up and flame stabilization purposes. **[4-0998 & 4-0999]**

The Permittee shall burn used oil and boiler chemical cleaning waste materials in the utility boilers.

Applicable Regulations:

COMAR 26.11.09.10 - Requirements to Burn Used Oil and Waste Combustible Fluid as Fuel.

A. General Requirements.
"(1) A person who proposes to burn used oil in fuel-burning equipment shall submit the following information to the Department:
(a) A description of any fuel-burning equipment in which used oil is to be burned, including the unit's location and rated heat input capacity;
(b) The type and amount of fuel currently being used in any fuel-burning equipment in which used oil is to be burned and the gallons of used oil expected to be burned annually;
(c) The maximum blend (percent) of used oil to be burned as fuel in any fuel-burning equipment at any time; and
(d) An analysis by an independent laboratory of a representative sample of the used oil, which shall include the concentration of each of the materials listed in §B of this regulation, the sulfur content, the PCB concentration, and the flash point.
(2) A person who burns fuel oil in fuel-burning equipment with a rated heat input capacity less than 50 million Btu per hour in accordance with a permit to construct or a registration pursuant to COMAR 26.11.02.02A may burn on-specification used oil in that equipment after submitting the information in §A(1) of this regulation.
(3) A person who is burning used oil or WCF under a current written approval from the Department may continue to burn the approved material if:
(a) The person demonstrates that any WCF being burned satisfies the definition of that term in Regulation .01B of this chapter;
(b) The used oil or WCF is being burned in an authorized installation;
(c) The conditions of the approval are continuously met; and
(d) The sulfur requirement in §B(1)(g) of this regulation is not exceeded.
(4) A person shall obtain written approval from the Department before burning:
(a) On-specification used oil in any fuel-burning equipment that has not been registered or previously issued a permit to construct pursuant to COMAR 26.11.02.02 to burn fuel oil;
(b) On-specification used oil in any fuel-burning equipment that has a rated heat input capacity of 50 million Btu per hour or greater;
(c) On-specification used oil in any installation other than fuel-burning equipment; or
(d) Waste combustible fluid or off-specification used oil as fuel in any installation.
(5) A person who obtains written approval from the Department to burn used oil or WCF shall burn only those materials for which approval has been obtained.
(6) Except as provided in §A(7) of this regulation and notwithstanding any applicable conditions in permits issued by the Department, a person may burn off-specification used oil only in those installations listed at 40 CFR §279.12(c).

(7) The requirement to burn off-specification used oil only in those installations listed at 40 CFR §279.12(c) does not apply if the used oil is off-specification only because of the sulfur content."

B. Specifications for Used Oil.
"(1) Except as provided in §B(2) of this regulation, used oil specifications are as follows:

Material	Allowable Level
(a) Lead	100 ppm
(b) Total halogens	1,000 ppm
(c) Arsenic	5 ppm
(d) Cadmium	2 ppm
(e) Chromium	10 ppm
(f) Flash point	100°F minimum
(g) Sulphur content	0.5 weight percent

(2) For used oil that satisfies the rebuttable presumption for halogens at 40 CFR §279.10(b)(1)(ii) and 40 CFR §279.63, the maximum allowable level for halogens is 4,000 ppm."

C. Additional Requirements for Burning Used Oil or WCF Containing Polychlorinated Biphenyls (PCBs).
"(1) Used oil or WCF containing quantifiable levels of PCB (i.e. 2 ppm or greater, but less than 50 ppm) may be burned only in those installations listed at 40 CFR §279.12(c) or 40 CFR §761.
(2) Used oil or WCF with a PCB concentration of 50 ppm or greater is hazardous waste and may only be burned in accordance with the requirements in COMAR 26.13.07 and 40 CFR §761."

D. Reporting Requirements. "By April 1of each year, a person subject to this regulation shall submit a report, in accordance with COMAR 26.11.01.05C, that provides information on:
(1) The quantity of used oil or WCF burned during the previous year; and
(2) The equipment in which the used oil or WCF was burned."