STATE OF CONNECTICUT
DEPARTMENT OF ENVIRONMENTAL PROTECTION
BUREAU OF AIR MANAGEMENT

NEW SOURCE REVIEW PERMIT TO CONSTRUCT AND OPERATE A STATIONARY SOURCE

Issued pursuant to Title 22a of the Connecticut General Statutes (CGS) and Section 22a-174-3a of the Regulations of Connecticut State Agencies (RCSA).

Owner/Operator:	Plainfield Renewable Energy LLC
Address:	20 Marshall Street, Suite 300 Norwalk, CT 06854
Equipment Location:	Norwich Road, Plainfield, CT 06374
Equipment Description: power	37.5 MW (net) Biomass fluidized bed gasification power plant

Town-Permit Number:	149-0049
Premises Number:	74
Permit Issue Date:	
Expiration Date:	None

Gina McCarthy
Commissioner

Date

PERMIT FOR FUEL BURNING EQUIPMENT

STATE OF CONNECTICUT, DEPARTMENT OF ENVIRONMENTAL PROTECTION BUREAU OF AIR MANAGEMENT

The conditions on all pages of this permit and attached appendices shall be verified at all times except those noted as design specifications. Design specifications need not be verified on a continuous basis; however, if requested by the commissioner, demonstration of compliance shall be shown.

PART I. OPERATIONAL CONDITIONS

A. Process Description

The power plant will use a fluidized bed staged gasification process with a close-coupled boiler to power the steam turbine generator. The biomass fuel will come from various sources which includes forest management residues, land clearing debris, waste wood from industries, construction and demolition (C&D) waste.

During startup bio-diesel (B100) is used to supplement the solid fuel supply.

B. Operating Limits

1. Fuel Type(s): Wood biomass[1], bio-diesel (B100)[2]
2. Maximum wood biomass Consumption over any Consecutive 12 Month Period: 495,305 tons/year based on a design higher heating value (HHV) of 4,624 Btu/lb

   The maximum wood biomass fuel consumption rate is based upon the maximum allowable heat input rate to the boiler of 523.1 MMBtu/hr. The actual consumption rate varies as a function of the actual fuel higher heating value.

3. Maximum bio-diesel (B100) consumption[3]: 781 gal/hr based on a design heating value of 128,047 Btu/gal
4. Maximum Fuel Sulfur Content (% by weight, dry basis): 1 (biomass)
5. Maximum Chlorine Content (% by weight, dry basis): 0.15

[1]**Note: Allowable Biomass fuels are described in Table 1 of this permit and may utilize 100% of any of the fuels at any time. The Permittee shall comply with the "Biomass Wood Supply Quality Control Procedures" and "Operating, Sampling & Testing Requirements (Exhibit 1), documents dated 01/18/08, amended from time to time.**
[2]**Note: Bio-diesel (B100) fuel shall be derived from 100% non-fossil fuels.**
[3]**Note: There is no annual restriction on the quantity of Bio-diesel (B100) that can be combusted in this unit.**

FIRM NAME: Plainfield Renewable Energy LLC
EQUIPMENT LOCATION: Norwich Road, Plainfield, CT 06374
EQUIPMENT DESCRIPTION (MODEL, I.D. #): 37.5 MW (net) biomass fluidized bed gasification power plant

Town No: 145 Premises No: 74 Permit No: 0049 Stack No: 1

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PART I. OPERATIONAL CONDITIONS, continued

TABLE 1. Allowable Fuels:

Biomass Wood	Description
Land Clearing debris	Chipped trees, stumps, branches or brush as defined in RCSA 22a-208a-1
Recycled wood or clean wood	Recycled wood or clean wood means any wood or wood fuel which is derived from such products or processes as pallets skids, spools, packaging materials, bulky wood waste or scraps from newly built wood products, provided such wood is not treated wood. [CGS 22a-209a][RCSA 22a-208a-1]
Regulated wood fuel Processed Construction and Demolition wood	Regulated wood fuel means processed wood from construction and demolition activities which has been sorted to remove plastics, plaster, gypsum wallboard, asbestos, asphalt shingles and wood which contains creosote or to which pesticides have been applied or which contains substances defined as hazardous under section CGS 22a-115. [CGS 22a-209a]
Other Clean Wood	Other types if properly sized, clean, uncontaminated wood materials, such as sawdust, chips, bark, tree trimmings or other similar materials

***Note: "Treated wood" means wood which contains an adhesive, paint, stain, fire retardant, pesticide or preservative [CGS 22a-209a(2)]. The use of treated wood containing pesticide or preservatives shall not be considered an allowable fuel pursuant to the definition of "regulated wood fuel" [CGS 22a-209a(4)].**

6. The Permittee shall not cause or allow the bag house unit to operate at a temperature above the manufacturer's recommended design range for the bag material used. The filter media shall use acid resistant coatings.

7. Injection of additives (limestone, lime, dolomite or other materials), as determined during the initial performance test, into the bed material or dry scrubber shall be in sufficient quantities to maintain the SOx emissions rate in Part VI of this permit.

8. "Steady-state" operation shall be defined as operation of the fluid bed gasifier when the rate of change in load (i.e. lbs of steam), with respect to time, is less than 5 percent per hour; except for such operation that occurs during periods of start-up, shutdown, malfunction, fuel switching, and equipment cleaning. Additionally, steady-state operation shall include all modes of operation during which the fluid bed gasifier load exceeds 50% of the manufacturer's specified maximum.

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PART I. OPERATIONAL CONDITIONS, continued

9. "Transient" operation shall be defined as operation of the fluid bed gasifier when the rate of change in load, with respect to time, is greater than 5 percent per hour. Additionally, transient operation shall include and describe the operation of the fluid bed gasifier during all phases of start-up, shutdown, fuel switching and equipment cleaning where the load is less than 50% of the manufacturer's specified maximum.

10. "Malfunction" shall be defined as any sudden, infrequent, and not reasonably preventable failure of air pollution control equipment, process equipment or a process to operate in a normal or usual manner. Failures that were caused in part by poor maintenance or careless operation are not malfunctions.

11. Bio-diesel (B100) shall be defined as a petroleum replacement fuel consisting of 100% virgin and/or used vegetable oils (both edible & non-edible) and/or animal fats. No petroleum (distillate) fuel oil shall be blended with the B100 fuel.

12. For one calendar year from the date of commencement of commercial operation, the Permittee shall track emissions of CO, SOx, NOx, VOC and PM-10 during transient operation of the fluid bed gasifier. Emissions of SOx, NOx and CO shall be tracked by means of the required continuous emissions monitoring systems. Emissions of VOC and PM-10 shall be correlated to fuel flow, fluid bed gasifier output or the combination thereof during the initial stack tests performed in accordance with Part VII of this permit. Emissions of VOC and PM-10 shall be tracked during transient operation by monitoring fuel flow, fluid bed gasifier output, or the combination thereof and estimating the resulting emissions according to the correlation developed during the initial stack tests.

    Within sixty (60) days of the end of one (1) calendar year of commercial operation of the fluid bed gasifier, the Permittee shall submit a report of observed transient emissions and of any operating parameters observed in order to estimate transient emissions. This permit shall be subject to modification to include a table of emission limits for CO, SOx, NOx, VOC and PM-10 during transient operation of the fluid bed gasifier. All transient emissions shall be counted toward the annual emissions limits in Part VI of this permit.

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PART I. OPERATIONAL CONDITIONS, continued

13. The “Administrator” means the Administrator of the United States Environmental Protection Agency. [RCSA 22a-174-1(3)]

14. The “Commissioner” means the Commissioner of the Environmental Protection, or any member of the Department or any local air pollution control official or agency authorized by the commissioner, acting singly or jointly, to whom the commissioner assigns any function arising under the provisions of these regulations. [RCSA 22a-174-1(23)]

C. Design Specifications

Primary fuel

1. Maximum Fuel Firing Rate(s): 1,357 tons/day at a higher heating value (HHV) of 4,624 Btu/lb
2. Maximum Gross Heat Input (MMBTU/hr): 523.1
3. Nominal Steam Production (lbs/hr): 365,000
4. Nominal Electrical Generation (MW): 37.5 (net)

Auxiliary fuel: B100

1. Maximum Fuel Firing Rate(s): 781 gal/hr at a higher heating value (HHV) of 128,047 Btu/gallon
2. Maximum Gross Heat Input (MMBTU/hr): 100

D. Stack Parameters

Primary fuel

1. Minimum Stack Height (ft): 155
2. Minimum Exhaust Gas Flow Rate at maximum load (acfm): 206,585 (biomass); 25,992 (B100)
3. Stack Exit Temperature (^{o}F): 253
4. Minimum Distance from Stack to Property Line (ft): 69

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PART I. OPERATIONAL CONDITIONS, continued

E. Expected Control Efficiency

Type of control	Overall control efficiency	Pollutants Controlled
Selective Non-Catalytic Reduction (SNCR)	70%	NOx
Multicyclone	80%	PM
Spray Dryer	90% Efficiency includes bag house	SOx, HCL and metals
Bed Additive Injection	See Note[(a)]	SOx, HCL, H_2SO_4
Baghouse	99% PM/PM-10/PM-2.5 (filterable); 90% SOx, HCL, and metals	PM/PM-10/PM-2.5 (filterable), SOx, HCL and metals

Note (a): Expected overall control efficiency for combination of bed additive injection and spray dryer shall be as stated for the spray dryer. Bed additive injection shall be used to supplement spray dryer as necessary to achieve emission limits in Part VI.

PART II. CONTROL EQUIPMENT (Applicable if -X- Checked) (See Appendix E for Design Specifications)

A. Type

- ☐ None
- ☒ Scrubber: spray dryer
- ☐ Electrostatic Precipitator
- ☐ Cyclone
- ☒ Multi-Cyclone
- ☐ Thermal DeNOx
- ☒ Selective Non-Catalytic Reduction
- ☐ Selective Catalytic Reduction
- ☐ Low NOx Burner
- ☒ Fabric Filter: Bag House
- ☐ Particulate Trap
- ☒ Bed Additive Injection

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PART III. CONTINUOUS EMISSION MONITORING REQUIREMENTS AND ASSOCIATED EMISSION LIMITS (Applicable if -X- Checked)

CEM shall be required for the following pollutant/operational parameters and enforced on the following basis:

Pollutant/Operational Parameter	Averaging Times	Emission Limit	Units
☒ Baghouse leak detection	*	**	
☒ Opacity	six-minute block	10%	
☒ SOx	3 hour block	15.4	ppmvd @ 7% O_2
☒ NOx	24 hour block	45.3	ppmvd @ 7% O_2
☒ CO	8 hour block	103.7	ppmvd @ 7% O_2
☒ O_2	1 hour block		
☒ Ammonia	24 hour block	20	ppmvd @ 7% O_2
☒ Unit Load	4 hour block		steam flow
☒ Baghouse inlet temp.	24 hour block		
☒ Pressure drop across bag house	24 hour block		inches water

*** Note: Averaging time, sensitivity range, alarm set points and alarm delay time to be determined during the initial adjustment of the system.**

**** Note: The leak detection system emission output data will be determined based on whether the monitor uses a relative or absolute particulate matter output system. The baghouse leak detection data is to be used to ensure the integrity of the bags is not compromised during operation.**

The Permittee shall meet the performance and quality assurance specifications for the operation of CEM equipment pursuant to RCSA Section 22a-174-4.

(See Appendix A for General Requirements)

PART IV. MONITORING, RECORD KEEPING AND REPORTING REQUIREMENTS

A. Monitoring

1. The Permittee shall use a non-resettable totalizing fuel metering device to continuously monitor bio-diesel (B-100) fuel feed to this permitted source.

2. The Permittee shall comply with the monitoring requirements for sulfur dioxide (SO_2) emissions as required in 40 CFR 60.47b.

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PART IV. MONITORING, RECORD KEEPING AND REPORTING REQUIREMENTS, cont.

3. The Permittee shall comply with the monitoring requirements for particulate matter and nitrogen oxides (PM & NOx) emissions as required in 40 CFR 60.48b.

4. The Permittee shall install a bag leak detection system on the baghouse. The system shall be subject to the following:

   i. The bag leak detection system must be certified by the manufacturer to be capable of continuously detecting and recording particulate matter emissions at concentration of 1.0 milligrams per actual cubic meter.
   ii. The bag leak detection system shall provide output of relative or absolute particulate matter loadings.
   iii. The system shall be equipped with an alarm system that will sound an audible alarm when an increase in relative particulate loadings is detected over a preset level.
   iv. The system shall be installed and operated in a manner consistent with available written guidance from the U.S. Environmental Protection Agency or, in the absence of such written guidance, the manufacturer's written specifications and recommendations for installation, operation and adjustment of the system.

5. The O&M plan required pursuant to Part IX.D of this permit must include a corrective measures plan that specifies the procedures to be followed in the case of a bag leak detection system alarm. The corrective measures plan must include, at a minimum, the procedures used to determine and record the time and cause of the alarm as well as the corrective measures taken to correct the control device malfunction or minimize emissions as specified below:

   i. the applicant must initiate the procedures used to determine the cause of the alarm within 30 minutes of the time the alarm first sounds; and
   ii. must alleviate the cause of the alarm by taking the necessary corrective measure(s) which may include, but are not to be limited to inspecting the baghouse for air leaks, torn or broken filter elements, or any other malfunctions that may cause an increase in emissions; sealing off defective bags or filter media; replacing defective bags or filter media, or otherwise repairing the control device; sealing off a defective baghouse compartment; cleaning the bag leak detection probe, or otherwise repairing the bag leak detection system; or shutting down the combustor.

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PART IV. MONITORING, RECORD KEEPING AND REPORTING REQUIREMENTS, cont.

B. Record Keeping

1. The Permittee shall keep records of daily and annual fuel consumption. Annual fuel consumption shall be based on any consecutive 12 month time period and shall be determined by adding (for each fuel) the current month’s fuel usage to that of the previous 11 months. The Permittee shall make these calculations within 30 days of the end of the previous month.

2. The Permittee shall keep records of the fuel certification for each delivery of bio-diesel (B-100) fuel oil from the fuel supplier or a copy of the current contract with the fuel supplier supplying the fuel used by the equipment. The shipping receipt or contract shall include the date of delivery, the name of the fuel supplier and type of fuel delivered.

3. The Permittee shall keep records of all performance tests conducted to determine compliance with the emissions limits in Part VI of this permit.

4. The Permittee shall develop pollution control inspection procedures pursuant to the manufacturer’s recommendations. The Permittee shall keep records of all inspections to pollution control devices. These records shall include the date of inspection, any findings of pollution control failures and the time period for corrective action.

5. The Permittee shall develop a written startup, shutdown and malfunction plan.

6. The Permittee shall keep records for the bag leak detection system consisting of the date, time and duration of each alarm, the time corrective action was initiated and completed, a brief description of the cause of the alarm, and the corrective action taken.

7. The Permittee shall comply with the reporting and recordkeeping requirements as required in 40 CFR 60.49b.

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PART IV. MONITORING, RECORD KEEPING AND REPORTING REQUIREMENTS, cont.

8. The Permittee shall record each and every exceedance of an emission limit or operating parameter contained in this permit. Such records shall include the date and time of the exceedance, a description of the exceedance, and the duration of the exceedance. Such report shall contain copies of the exceedance records for the month, an explanation of the likely causes of the exceedances, and an explanation of remedial actions taken to correct the exceedance.

The Permittee shall keep all records required by this permit for a period of no less than five years and may maintain the above records at an off-site location and shall submit such records to the commissioner upon request.

C. Reporting

1. The Permittee shall submit all required reports pursuant to RCSA Sec. 22a-174-4(d) and Sec 22a-174-22(l).

PART V. SPECIAL REQUIREMENTS FOR EMERGENCY ENGINES ONLY

Not applicable

PART VI. ALLOWABLE EMISSION LIMITS

For steady-state operation, the Permittee shall not cause or allow the emissions from this stationary source to exceed the emissions limits stated herein. An exceedance of any emission limit contained in Part VI of this permit is allowed only during periods of start-up, shut-down, and malfunction for a period of time not to exceed 3 hours for each occurrence.

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PART VI. ALLOWABLE EMISSION LIMITS, continued

Primary Fuel: Biomass

Criteria Pollutants	lb/hr	lbs/MMBtu	Enforceable limits for pollutants monitored by CEMS (ppmvd @7% O_2)[a]	tpy
PM-10 (filterable)[b]	10.46	0.021		45.8
PM-2.5 (filterable)[b]	10.46	0.021		45.8
PM-2.5 (condensable)[d]	8.89	0.017		39.0
PM-2.5 (total)[d]	19.35	0.037		84.8
SOx	18.56	0.035[a]	15.4	81.29
NOx	39.23	0.075[a]	45.3	171.84
VOC	6.07	0.012		26.59
CO	54.67	0.105[a]	103.7	239.47
Pb	0.07	0.00014		0.32
Other Pollutants				
Hydrogen Chloride (HCL)		0.00436		(c)
Mercury		3.0E-6		
Ammonia			20	
Auxiliary Fuel: B100[e]				
PM-10	2.00			
SOx	0.17			
NOx	16.0			
VOC	0.27			
CO	4.0			

Note (a): Equivalent emission rate based on wood F-factor of 9,240 dscf/MMBtu. [40CFR Part 60, Appendix A, Table 19-2]

Note (b): Filterable particulate matter (PM-10 and PM-2.5) as measured by EPA Reference Method 5 or 17.

Note (c): The Permittee shall not emit more than 10 tons of any individual HAP or 25 tons of any combination of HAP, on an annual basis, listed in Section 112(b) of the Clean Air Act Amendments of 1990 at this premises.

FIRM NAME: Plainfield Renewable Energy LLC
EQUIPMENT LOCATION: Norwich Road, Plainfield, CT 06374
EQUIPMENT DESCRIPTION (MODEL, I.D. #): 37.5 MW (net) biomass fluidized bed gasification power plant

PART VI. ALLOWABLE EMISSION LIMITS, continued

Note (d): Condensable PM-2.5 and total PM-2.5, including condensables, are estimated based on EPA AP-42 emission factor for condensable PM from wood residue, Table 1.6-1, Fifth Edition, September 2003. Demonstration of compliance with PM-2.5 condensable emission limits shall be met by calculating the emission rates using the reference AP-42 emission factor.

Note (e): The use of B100 is not restricted to start-up operation. The B100 fuel can be fired in the auxiliary burners for initial/maintenance refractory curing and disposal beyond the typical 6-month shelf life.

At all times the Permittee shall comply with the requirements of Section 22a-174-29 of the RCSA, entitled "Hazardous Air Pollutants". The Permittee shall demonstrate compliance for each and every hazardous air pollutant emitted from this unit that is listed on Table 29-1, Table 29-2, or Table 29-3 of Section 22a-174-29 of the RCSA.

Hazardous Air Pollutant[3]	**MASC**[a] **(μg/m^3)**	**Hazardous Air Pollutant**	**MASC (μg/m^3)**
Sulfuric Acid	3,656	Formaldehyde	2,193.6
Ammonia	65,808.7	Lead	548.4
Arsenic	9.1	Manganese	3,656
Beryllium	1.8	Mercury	182.8
Cadmium	73.1	2,3,7,8-TCDD equivalents[b]	1.3E-04
Chromium	457	Selenium	731
Nickel	54.85	Hydrogen Chloride (HCL)	[c, d]
Copper	3,656	Styrene	2,834[d]
Benzene	2,834[d]	Silver	36.57
Titanium	54,848	Zinc	18,282

Note a: Maximum allowable stack concentration calculated based on maximum design exhaust gas flow rate of 214,655 acfm. For compliance purposes, actual stack concentrations must be compared to MASC values calculated based on exhaust gas volumes from performance testing.

Note b: Dioxin emissions as defined in RCSA § 22a-174-1(29).

Note c: No HLV value exists for HCL, stack testing is still required to determine emission rate.

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PART VI. ALLOWABLE EMISSION LIMITS, continued

Note d: The allowable MASC for these pollutants will exceed 10 tpy for each pollutant. These pollutants shall not exceed an actual stack concentrations (ASC) of 2,834 ug/m^3 (10 tons/year).

Demonstration of compliance with the above emission limits shall be met by calculating the emission rates using emission factors from the following sources:

1. CEM data for NOx, SOx, CO, and ammonia
2. Initial and annual stack testing (or fuel testing) for all other pollutants

The above statement shall not preclude the commissioner from requiring other means (e.g. stack testing) to demonstrate compliance with the above emission limits, as allowed by state or federal statute, law or regulation.

PART VII. STACK EMISSION TEST REQUIREMENTS (Applicable if -X- Checked)

Stack emission testing shall be required for the following pollutant(s):

☐ None at this time

☒ PM 10/PM 2.5 See Note (b) page 11/16 ☒ SOx ☒ NOx ☒ CO ☒ VOC ☒ Pb

☒ All hazardous air pollutants listed in Part VI of this permit. Compliance shall be determined by an annual performance test, either by fuel analysis and/or stack testing. Initial performance test shall require fuel sampling for all pollutants in listed in Part VI of this permit to compare the input concentrations to the stack emission rates for these pollutants.

☒ Initial Performance testing shall include the baseline operating parameters (i.e. flow rate, pressure drop, and temperature) of all control equipment listed in Appendix E of this permit.

NOTE: Stack testing shall be conducted at or above ninety percent (90%) of maximum rated capacity. If the source does not achieve ninety percent maximum rated capacity during the stack test, the Permittee shall apply for a minor modification of this permit to address the actual maximum rated capacity achieved in practice.

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PART VII. STACK EMISSION TEST REQUIREMENTS, continued

All stack emissions tests shall be conducted in accordance with the requirements of Section 22a-174-5 of the RCSA. The Commissioner may attach additional requirements to the requirements of Section 22a-174-5 in order to demonstrate continual compliance with the requirements of this permit.

(See Appendix B for General Requirements)

PART VIII. APPLICABLE REGULATORY REFERENCES

RCSA §§22a-174-3a; 22a-174-4; 22a-174-7; 22a-174-18; 22a-174-19; 22a-174-22; 22a-174-29(b);

These references are not intended to be all inclusive - other sections of the regulations may apply.

PART IX. SPECIAL REQUIREMENTS

A. The Permittee shall possess, at least, 210 tons of external emissions reductions of NOx to offset the quantity of NOx emitted from this source to comply with RCSA Subsection 22a-174-3(l). Such a quantity is sufficient to offset the emissions from the sources listed at a ratio of 1.2 tons of reduction for every 1 ton of NOx emissions allowed under this permit. Such offsets shall have been obtained and approved by the Department prior to the date of issuance of the final construction/operating permit for this unit. The Permittee shall maintain sole ownership and possession of these emissions reductions for the duration of this permit and any subsequent changes to the permit.

B. For one calendar year from the date of commencement of commercial operation, the Permittee shall track emissions of NOx and ammonia slip emissions during transient, steady-state and malfunction operation of the fluid bed gasifier. Emissions of NOx and ammonia shall be tracked by means of the required continuous emissions monitoring systems. During the initial calendar year of operation the permittee shall operate the fluid bed gasifier in a manner to optimize the NOx emissions.

PART IX. SPECIAL REQUIREMENTS, continued

Within sixty (60) days of the end of one (1) calendar year of commercial operation of the fluid bed gasifier, the Permittee shall submit a report of observed NOx and ammonia emissions, the report shall detail the lowest achievable NOx emission rate along with the corresponding ammonia slip emissions. This permit shall be subject to modification to include a change in the allowable emission limits for NOx and ammonia.

C. The permittee shall not exceed an emission rate of more than 0.00436 lbs/MMBtu for any Hazardous Air Pollutant (HAP) listed in Section 112(b) of the Clean Air Act Ammendments of 1990 at this premises.

In addition, the Permittee shall not emit more than 10 tons of any individual HAP or 25 tons of any combination of HAP, on an annual basis, listed in Section 112(b) of the Clean Air Act Amendments of 1990 at this premises.

D. The Permittee shall develop an operating and maintenance plan (O&M) for in accordance with the manufacturer’s specifications and written recommendations. Appropriate records shall be made to verify that there is proper operation, monitoring and maintenance of all pollution control devices. The plan shall detail the procedures for operation, inspection, maintenance and corrective measures for all components of the combustor, including all associated pollution control equipment.

E. The Permittee shall operate pollution control devices at all times during normal operation. Additionally, transient operation shall include and describe the operation of the plant during all phases of start-up, shutdown, fuel switching and equipment cleaning where the fluidized bed gasifier load is less than 50% of the manufacturer's specified maximum. During such times of transient operation pollution control devices shall be operated according to the manufacturers recommendations. The bag house can be operated in a by-pass mode during start-up/shut-down to avoid acid gas condensation on the filter media. The operation of the plant during start-up shall not exceed three (3) hours for each occurrence.

F. The Permittee shall comply with the “Biomass Wood Supply Quality Control Procedures” and the “Operating, Sampling & Testing Requirements Volume Reduction/Facilities Generating C&D Wood Chips for Delivery to PRE” documents dated January 18, 2008 as amended from time to time.

PART IX. SPECIAL REQUIREMENTS, continued

G. The Permittee shall comply with all applicable requirements of Section 22a-174-6 of the RCSA, entitled "Air Pollution Emergency Episode Procedures".

H. *Noise (for non-emergency use)*

The Permittee shall operate this facility at all times in a manner so as not to violate or contribute significantly to the violation of any applicable state noise control regulations, as set forth in RCSA Sections 22a-69-1 through 22a-69-7.4.

I. The Permittee shall comply with all applicable sections of the following New Source Performance Standard(s) at all times. (Applicable if -X- checked)

40 CFR Part 60, Subpart: ☒ Db ☐ Dc ☐ GG ☒ A

☐ None

(See Appendix C for Detailed Requirements)

J. The Permittee shall comply with all applicable sections of the following National Emission Standards for Hazardous Air Pollutants at all times. (Applicable if -X- checked)

Not Applicable

K. Unless directed otherwise by the Commissioner, if the proposed facility is not constructed within eighteen (18) months from the date of issuance of this permit, the Permittee shall be required to re-certify and conduct further BACT analysis.

PART X. ADDITIONAL TERMS AND CONDITIONS

A. This permit does not relieve the Permittee of the responsibility to conduct, maintain and operate the regulated activity in compliance with all applicable requirements of any federal, municipal or other state agency. Nothing in this permit shall relieve the Permittee of other obligations under applicable federal, state and local law.

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PART X. ADDITIONAL TERMS AND CONDITIONS, continued

B. Any representative of the DEP may enter the Permittee's site in accordance with constitutional limitations at all reasonable times without prior notice, for the purposes of inspecting, monitoring and enforcing the terms and conditions of this permit and applicable state law.

C. This permit may be revoked, suspended, modified or transferred in accordance with applicable law.

D. This permit is subject to and in no way derogates from any present or future property rights or other rights or powers of the State of Connecticut and conveys no property rights in real estate or material, nor any exclusive privileges, and is further subject to any and all public and private rights and to any federal, state or local laws or regulations pertinent to the facility or regulated activity affected thereby. This permit shall neither create nor affect any rights of persons or municipalities who are not parties to this permit.

E. Any document, including any notice, which is required to be submitted to the commissioner under this permit shall be signed by a duly authorized representative of the Permittee and by the person who is responsible for actually preparing such document, each of whom shall certify in writing as follows: “I have personally examined and am familiar with the information submitted in this document and all attachments thereto, and I certify that based on reasonable investigation, including my inquiry of those individuals responsible for obtaining the information, the submitted information is true, accurate and complete to the best of my knowledge and belief. I understand that any false statement made in the submitted information may be punishable as a criminal offense under section 22a-175 of the Connecticut General Statutes, under section 53a-157b of the Connecticut General Statutes, and in accordance with any applicable statute.”

F. Nothing in this permit shall affect the commissioner's authority to institute any proceeding or take any other action to prevent or abate violations of law, prevent or abate pollution, recover costs and natural resource damages, and to impose penalties for violations of law, including but not limited to violations of this or any other permit issued to the Permittee by the commissioner.

PERMIT FOR FUEL BURNING EQUIPMENT

STATE OF CONNECTICUT, DEPARTMENT OF ENVIRONMENTAL PROTECTION
BUREAU OF AIR MANAGEMENT

PART X. ADDITIONAL TERMS AND CONDITIONS, continued

G. Within 15 days of the date the Permittee becomes aware of a change in any information submitted to the commissioner under this permit, or that any such information was inaccurate or misleading or that any relevant information was omitted, the Permittee shall submit the correct or omitted information to the commissioner.

H. The date of submission to the commissioner of any document required by this permit shall be the date such document is received by the commissioner. The date of any notice by the commissioner under this permit, including but not limited to notice of approval or disapproval of any document or other action, shall be the date such notice is personally delivered or the date three days after it is mailed by the commissioner, whichever is earlier. Except as otherwise specified in this permit, the word "day" means calendar day. Any document or action which is required by this permit to be submitted or performed by a date which falls on a Saturday, Sunday or legal holiday shall be submitted or performed by the next business day thereafter.

I. Any document required to be submitted to the commissioner under this permit shall, unless otherwise specified in writing by the commissioner, be directed to: Office of Director; Engineering & Enforcement Division; Bureau of Air Management; Department of Environmental Protection; 79 Elm Street, 5th Floor; Hartford, Connecticut 06106-5127.

DRAFT

PERMIT FOR FUEL BURNING EQUIPMENT

STATE OF CONNECTICUT, DEPARTMENT OF ENVIRONMENTAL PROTECTION
BUREAU OF AIR MANAGEMENT

Appendices attached (Applicable if –X- checked):

☒ A Continuous Emission Monitoring Requirements

☒ B Stack Emission Test Requirements

☒ C New Source Performance Standards

☒ E Control Equipment Design Specifications

FIRM NAME: Plainfield Renewable Energy LLC
EQUIPMENT LOCATION: Norwich Road, Plainfield, CT 06374
EQUIPMENT DESCRIPTION (MODEL, I.D. #): 37.5 MW (net) biomass fluidized bed gasification power plant

Town No: 145 Premises No: 74 Permit No: 0049 Stack No: 1

APPENDIX E
Control Equipment Design Specifications

Air Pollution Control Equipment (applicable if -X- checked).

The following specifications need not be verified on a continuous basis, however, if requested by the Bureau, demonstration shall be shown. All specifications are considered to be preliminary until actual operating limits are established during initial performance test. This permit shall be subject to modification to include changes to preliminary design specifications.

☐ None

☒ Scrubber

Make and Model: Wheelabrator, McGill, Research-Cottrell or equivalent
Reagent: Hydrated Lime [$Ca(OH)_2$]
Reagent Flow Rate: 400-700 lb/hr
Pressure Drop (inches H_2O): <3.0
Minimum Gas Flow Rate at Maximum Rated Capacity (acfm): 22,110
PH: To be determined
Design Outlet Grain Loading (gr/dscf): 1.5-2.5 (estimated, depending on multicyclone performance and lime usage)
Design Removal Efficiency (%) : 90% SOx

☐ Electrostatic Precipitator (ESP)

Make and Model: ______
Number of Fields: ______
Minimum Gas Flow Rate at Maximum Rated Capacity (acfm): ______
Design Outlet Grain Loading (gr/dscf): ______
Design Removal Efficiency (%): ______

☐ Cyclone ☒ Multicyclone

Make and Model: Barron Industries or equivalent
Pressure Drop (inches H_2O): <3
Minimum Gas Flow Rate at Maximum Rated Capacity (acfm): 348,019

FIRM NAME: Plainfield Renewable Energy LLC
EQUIPMENT LOCATION: Norwich Road, Plainfield, CT 06374
EQUIPMENT DESCRIPTION (MODEL, I.D. #): 37.5 MW (net) biomass fluidized bed gasification power plant

APPENDIX E
Control Equipment Design Specifications

☒ Selective Non-catalytic Reduction (SNCR)

☒ Urea ☒ Ammonia

Make and Model: Energy Products of Idaho (EPI)
Injection Rate at Maximum Rated Capacity (lb/hr): 700-850 lbs/hr @ 32.5% urea solution and/or 750 lbs/hr @ 20% by weight aqueous ammonia solution
Operating Temperature Range (^oF): 1600-1800^0F (typical)
Minimum Gas Flow Rate at Maximum Rated Capacity (acfm): 636,000
Design Removal Efficiency (%): 70% (max)

☐ Selective Catalytic Reduction (SCR)

Make and Model: ______
Catalyst Type: ______
Minimum Gas Flow Rate at Maximum Rated Capacity (acfm): ______
Pressure Drop (in H_2O): ______
Ammonia Injection Rate at Maximum Rated Capacity (lb/hr): ______
Design Removal Efficiency (%): ______

☐ Low NOx Burner

Make and Model: ______
Guaranteed NOx Emission Rate (lb/MM BTU): ______
Design Removal Efficiency (%): ______

☐ Particulate Trap

Make and Model: ______
Design Removal Efficiency (%): ______

☒ Fabric Filter

Make and Model: McGill, Aeropulse, Wheelabrator or equivalent
Number of Bags in Use: TBD
Bag Material: P-84 felt or equivalent
Air/Cloth Ratio: <3.5:1
Net Cloth Area (ft^2): TBD
Cleaning Method: Pulse Jet
Pressure Drop (inches H_2O): 8
Minimum Gas Flow Rate at Maximum Rated Capacity (acfm): 204,507
Design Outlet Grain Loading (gr/dscf): 0.01 (filterable catch)
Design Removal Efficiency (%): 99.9

FIRM NAME: Plainfield Renewable Energy LLC
EQUIPMENT LOCATION: Norwich Road, Plainfield, CT 06374
EQUIPMENT DESCRIPTION (MODEL, I.D. #): 37.5 MW (net) biomass fluidized bed gasification power plant

Town No: 145 Premises No: 74 Permit No: 0049 Stack No: 1

APPENDIX E
Control Equipment Design Specifications

☒ Bed Injection Additive:

Injection of bed additives (limestone, lime, dolomite or other materials), as determined during the initial performance test, into the bed material shall be in sufficient quantities to maintain the SOx emissions rate in Part VI of this permit.

Plainfield Renewable Energy LLC

NSR Engineering Evaluation Attachment Coversheet
Connecticut Department of Environmental Protection
Bureau of Air Management

For Attachment:

☒ A Hazardous Air Pollutant (HAP) Review

☒ B Ambient Impact Analysis
- ☐ B1 SSSHG
- ☐ B2 Screening
- ☒ B3 Refined Modeling
- ☒ B4 Increment Consumption Analysis (See Modeling report)
- ☒ B5 Additional Analysis (soils, visibility, growth, etc.) (See Modeling Report)

☒ C Premises Non-attainment Pollutant Summary
- ☒ C1 Netting analysis
- ☐ C2 5 yr aggregation (Deminimis Rule)

☒ D Best Available Control Technology (BACT) Review; Lowest Achievable Emission Rate Review; Maximum Achievable Control Technology (MACT) Review

☒ E Analysis of Alternatives

☒ F Premises Emissions/Fee Calculations

☐ G Signatory Responsibility Certification

☒ H CGS 22a-6m: Compliance History

Findings:

Attachment Findings

A. All HAPs are in compliance with Section 29.

B. Modeling report shows that the facility will not cause or contribute significantly to a violation of any State AAQS, federal NAAQS or federal PSD increment.

C. Applicant is required to obtain 210 tons of NOx offsets prior to final CP/OP being issued.

D. BACT has been determined to be the following:

Pollutant	BACT/LAER	Compliance Demonstration
PM/PM-10	Mutlicyclone; Spray dryer adsorber; Fabric filter (bag house)	Stack test; COMS(10% 1 hour-block) CEM
NOx	210 tons of emission reduction credits; Selective Non-Catalytic Reduction (SNCR); Fluidized Bed Gasification(FBG)	Stack test; CEMS(24 hour-block)
SOx/HCL	FBG bed additives; Spray dryer; Bag House	Stack test; CEMS(3 hour-block)
CO	Fluidized Bed Gasification; Good combustion practices	Stack test; CEMS(8 hour-block)
VOC	Fluidized Bed Gasification; Good combustion practices	Stack test; CO CEMS as surrogate
NH_3 Slip	Complying with emission limit of 20 ppmvd, and optimization of SNCR system	Stack test; CEMS (24 hour-block)

E. Based on the analysis of alternatives provided by the applicant it has been determined that this project is a suitable method of power generation for this site.

F. The permit fee is $13,500.00.

H. No past or present violations prevent this permit from being issued.

NSR ENGINEERING EVALUATION

Connecticut Department of Environmental Protection
Bureau of Air Management

Date Recv'd: 08/09/06
PAMS No.: 200602226
EPE No.: 22281
Permit No.:145-0049
Prepared by:J. Grillo
Date Prepared: 10/24/07

Firm Name: Plainfield Renewable Energy LLC
Address: 20 Marshall Street, Suite 300, Norwalk, CT 06854
Contact Person (title & phone no.): Daniel J. Donovan, 203-549-0596
Equipment Location: Norwich Road, Plainfield, CT 06374
Equipment Description: 37.5 MW biomass fluidized bed staged gasification power plant

PART I. - Annual Emission Review: Tons Per Year

Pollutant	Premises PTE	Permit PTE[a]	New Premises PTE
PM[b]	0	45.82	46.55
PM-10/2.5[c]	0	84.8	84.8
SOx	0	81.29	81.29
NOx	0	171.84	174.25
VOC	0	26.59	26.66
CO	0	239.47	240.02
Pb	0	0.32	0.32
HAP (HCL)	0	<9.99	<24.99

Note (a): Premises wide emissions include biomass plant and an emergency engine to be operated under RCSA 22a-174-3b
Note (b): PM emissions are the total filterable emissions.
Note (c): PM10/2.5 emissions are the total filterable and condensable emissions

PART II. - Emissions Summary (TPY) for Major Modification Determination(see Attachment C)

Not applicable, New Major Source

PART III. - Emission Standards Review and Regulatory Authority:

a.

Reg Standard	Allowable Rate	Basis
PM: 0.2 lbs/MMBtu 20% 6-minute block RCSA 22a-174-18(e)(2)(D) RCSA 22a-174-18(b)(2)(A)	0.02 lbs/MMBtu 10% 1 hour-block	1,2
SO_x: 1% by weight dry basis RCSA 22a-174-19(a)(2)(i)	0.2%	1,2
NO_x:0.3 lbs/MMBtu RCSA 22a-174-22(e)(2)(A)	0.075 lbs/MMBtu	1,2
VOC: RCSA 22a-174-20	0.012 lbs/MMBtu	1,2
CO: RCSA 22a-174-21	0.105 lbs/MMBtu 400 ppm	1,2
Pb: MASC: 548.4 ug/m^3 RCSA 22a-174-29	ASC: 91 ug/m^3	1,2

NOTE: The basis for these emission rate calculations are:
1. Manufacturer's data.
2. All emissions rates to be verified by stack test data.

b. Source subject to:
- ☒ NSPS, Part 60, Subpart A, Subpart Db;
- ☐ NESHAP Part 61, Subpart ______;
- ☐ NESHAP Part 63, Subpart A, Subpart _____;
- ☐ none

Note: Any source subject to Part 63 NESHAP will be subject, in part, to Part 59 of the General Provisions as well.

c. Hazardous Air Pollutant compliance (RCSA 22a-174-29) ☒ yes ☐ no ☐ N/A (see Attachment A)

PART IV. - Ambient Impact Analysis:

Source is subject to Ambient Impact Analysis ☒ yes ☐ no
If no, check applicable box: ☐ PM/SO_x < 3 tpy ☐ NO_x/CO < 5 tpy

a. SSSHG analysis

☐ 3 < PM < 15 tpy ☐ 3 < SO_x < 15 tpy

Date SSSHG completed/approved:
(see attachment B1)

PART IV. - Ambient Impact Analysis, continued:

b. Screening

"Screening" is required when the allowable emissions for all equipment being permitted exceed any of the limits below.

☐ 5 < CO < 100 TPY ☐ 5 < NOx < 40 TPY

Date screening completed/approved: ________
(see Attachment B2)

☐ Screening analysis not required since SSSHG was completed/approved.

c. Refined Modeling

"Refined Modeling" is required when the allowable emissions for all equipment being permitted exceed any of the limits below.

☒ PM > 15 tpy ☒ NO_x > 40 tpy
☒ SO_x > 15 tpy ☐ Pb > 0.6 tpy
☒ CO > 100 tpy

Date refined modeling completed/approved: 10/12/07
(see Attachment B3)

PART V. - PSD Review:

Source is subject to PSD Review ☒ yes ☐ no

Source netted out of PSD Review ☐ yes ☒ no
(If yes, see Attachment C1)

a. Source has significant impact (per RCSA 22a-174-3a(i)) for:

☒ PM-10 ☒ SO_2 ☒ CO ☒ NO_x ☐ Dioxin ☐ Pb
(see Attachment B4)

b. ☒ PM ☒ SO_x ☒ NO_x Increment Consumption analysis completed.

c. Pre-construction monitoring required for___; ☒ waived

d. Visibility, soils, and vegetation impact analysis approved ☒

e. General commercial, residential, industrial and other associated growth analysis approved ☒

f. Ambient air quality impact projection analysis approved ☒
(see Attachment B5)

PART VI. - Non-attainment Review:

Source is subject to non-attainment review ☒ yes ☐ no
(see Attachment C2)

a. Pollutant(s): NOx

b. Emissions Increase over the last 5 years (tons): 174.25

c. Offset Ratio:1:2

d. Offsets Required: 210 tons

PART VII. - Control Technology Analysis:

a. BACT/LAER/MACT Compliance ☒ yes ☐ N/A

b. BACT/LAER Utilized: (See Attachment D)

Pollutant	BACT/LAER
PM/metals	0.02 lb/MMBtu emission limit, combination of a multicyclone, spray dryer, and baghouse.
CO	0.105 lbs/MMBtu (103.7 ppmvd @ 7% O_2), Fluidized Bed Gasification (FBG) and good combustion.
VOC	0.012 lb/MMBtu (20.2 ppmvd @ 7% O_2), Fluidized Bed Gasification (FBG) and good combustion.
NOx	BACT: FBG and SNCR LAER: 0.075 lb/MMBtu emission limit, FBG and SNCR
SOx	0.035 lbs/MMBtu (15.4 ppmvd @ 7% O_2), FBG additives, spray dryer and baghouse
HCL	0.00436 lb/MMBtu, FBG additives, spray dryer and baghouse
Ammonia	Ammonia slip $\leq$ 20 ppm.

PART VIII. Emission Testing Requirements:

a. Stack emission testing shall be required for the following pollutant(s):

☐ None at this time

☒ PM ☒ SO_x ☒ NO_x ☒ CO ☒ VOC ☒ Pb

☒ Opacity ☒ Other: All HAPs listed in Part VI of the permit

b. Testing schedule included in permit: ☒ yes ☐ no

c. AE 405 Stack Test Referral Form Completed: ☒ yes ☐ no

d. Recurring Tests required? ☒ yes ☐ no (If yes, notify Stack Test Group)
Frequency: Annually for HAPs

PART VIII. Emission Testing Requirements, continued:

e. CEMS requirements: ☐ None at this time

☒ SO_x ☒ NO_x ☒ CO ☒ PM

☒ Opacity ☒ Other O_2, NH_3, pressure drop across baghouse, unit load (steam flow)

PART IX - Administrative Criteria Review:

a. Ozone non-attainment area: ☐ severe ☒ serious

b. Premises size: ☐ <15 tpy; ☐ ≥15 <100 tpy; ☒ ≥ 100 tpy

c. Source size: ☐ <15 tpy; ☐ ≥15 <100 tpy; ☒ ≥ 100 tpy

d. The source is a new fossil fuel fired unit that serves a generator with a nameplate capacity of 15 MW or greater or is a new fossil fuel fired boiler or indirect heat exchanger with a maximum heat input capacity of 250 MMBTU or more: ☐ yes ☒ no (If yes, notify P&S NOx Budget Program)

e. Fee: $13,500.00 (See Attachment E)

f. Signatory Responsibilities authorized ☒yes ☐no (See Attachment F)

g. Source entered in PAMS Permit Tracking System ☒yes ☐no

h. Source entered in SAS Permit Tracking System ☐yes ☒no

PART X. - CGS 22a-6 and 22a-186a Compliance:

-6g	☒ yes	☐ no	☐ n/a	Certified Notice of Application
-6P	☐ yes	☐ no	☒ n/a	Posting of Notice Certification
-6m	☒ yes	☐ no	☐ n/a	Compliance Information (See Attachment G)
-186a	☒ yes	☐ no	☐ n/a	Conformance Certification

PART XI. - Special Requirements:

PART XII. - Summary:

On August 9, 2006, Plainfield Renewable Energy LLC submitted an application to construct and operate a 37.5 MW biomass (wood) fired fluidized bed gasification power plant. The planned start-up fuel for the plant is 100% bio-diesel (B100) and there will be no fossil fuel combusted in the boiler or gasifier.

This project will create a new major source of air pollution for NOx and CO. This premises is located in a non-attainment area for ozone pursuant to RCSA 22a-174-1(98). There are currently no emission sources at the premises. This project will be subject to PSD review for all criteria pollutants with the exception of lead pursuant to Sec. 22a-174-3a(k). In addition, this source is subject to non-attainment/LAER review for NOx pursuant to Sec. 22a-174-3a(l). The boiler will be subject to the New Source Performance Standard (NSPS) 40 CFR Part 60 Subpart Db. The applicant will be required to submit an application for a Title V permit within one (1) year after becoming subject to the Title V provisions pursuant to Sec. 22a-174-33(f)(2).

The applicant was required to apply for a NSR permit pursuant to 22a-174-3a(a)(1)(A) since this plant will be a new major source of air pollution for NOx and CO. Additionally, this source is subject to NSR permitting pursuant to 22a-174-3a(a)(1)(D), since the potential SOx, VOC, CO, NOx, and PM-10 emissions are greater than 15 TPY each.

The applicant initially indicated that the potential to emit for two federal HAPs (hydrogen chloride, and benzene) would be greater than (10) ten tons/year, making this source a new major source of HAPs and that the combined HAP emissions would be greater than 25 tons/year. However, on 10/24/07 the applicant submitted additional updated emission data that shows that this source should not be considered a major source of HAPs. The permit has requirements to stack test for all likely HAPs to ensure that this source will not emit more than the major source thresholds for HAPs.

The proposed gasification technology is an advanced, fluidized bed, staged gasification system that is close-coupled to a boiler that will generate steam to drive a steam turbine. The facility will use multiple control systems to reduce actual emissions. To control NOx, selective non-catalytic reduction (SNCR) will be used. To provide for initial particulate control a multi-cyclone will be used in the flue gas immediately after the boiler.

A spray dryer will be used to control SOx and other acid gases (HCL). The spray dryer uses a cooling tower for evaporative cooling of the gas stream and a dry venturi where a reagent is added to react with the acid gases, forming solid calcium sulfate and chloride salts. (See Attached Diagram)

Additional SOx control can be obtained with the injection of fluidized bed additives (limestone, lime, dolomite or other materials), as determined during the initial performance test, into the bed material in sufficient quantities to maintain the SOx emissions rate in Part VI of the permit. Bed additive injection shall only be used to supplement spray dryer as necessary to achieve emission limits in Part VI of the permit.

The bag house is used as a final control device to remove particulate matter and trace metals. There will be continuous emissions monitoring (CEMS) for SOx, NOx, CO, Opacity, O_2, NH_3, unit load, and pressure drop across the bag house.

There will be an emergency generator used on the premises that will be operated under Sec. 22a-174-3b(e). The allowable NOx emissions from this unit have been added to the NOx non-attainment calculation to determine the total NOx offsets required pursuant to Sec. 22a-174-3a(l)(4)(B)(x).

Although the cooling tower does have particulate emissions, the potential-to-emit is not greater than 15 tpy and is not subject to permitting pursuant to Sec.-3a(a)(1)(D).

NSPS requirements:
This boiler is subject to Subpart Db: Industrial-Commercial-Institutional Steam Generating Units. Subpart Db contains emission standards for PM, NOx, and SO_2. There are no applicable NOx and SO_2 standards since the facility only combusts wood/bio-diesel and there are no fossil fuels combusted. Subpart Db [60.43b((h)(1)] limits the boiler PM emission rate to 0.03 lb/MMBtu. The applicant has proposed a PM emission rate of 0.02 lbs/MMBtu. Based on the proposed emission rates and method of operation the boiler will easily comply with the applicable emissions standards. All required monitoring, record keeping and reporting will be complied with for Subpart Db. Subpart Db requires that either a stack test or a particulate CEM can be used as a method of compliance for particulate matter. The proposed plant will be using a particulate monitor for bag leak detection in the baghouse and will meet all particulate matter emission standards using stack testing.

Control of NOx:
The boiler is subject to Sec. 22a-174-22 since it will be a major stationary source of NOx and has potential emissions greater than two hundred seventy-four (274) pounds/day.[Sec. -22(b)]. Pursuant to Sec. -22(e)(2)(A), this boiler must meet an emission limit of 0.3 lbs/MMBtu @ 15% O_2. The applicant has proposed an emission rate of 0.075 lbs/MMBtu.

This source will not be considered a NOx Budget Program source, since it will not combust any fossil fuel and will not meet the applicability definition of a "Budget Unit" pursuant to Sec. - 22b(b).

This unit is subject to the provisions of Sec. 22a-174-22(k), Emission testing and monitoring, and 22a-174-22(l) Reporting and record keeping.

Non-attainment/LAER NOx Offsets:
This source is subject to non-attainment/LAER review for NOx pursuant to Sec. 22a-174-3a(l)(1)(A). Pursuant to Sec. 22a-174-3a(l)(4)(B)(x) the applicant must demonstrate that either internal NOx offsets or certified emission reduction credits (ERCs) are used to offset actual NOx emissions at a ratio of 1.2:1. Since this source is a new source there are no internal emission reductions to be considered.

The required NOx ERCs has been calculated as follows:

NOx Offset =(**Project increase** x **offset ratio**)

NOx Offset = (174.25 TPY x 1.2) = **210 Tons of NOx offsets**

The applicant will be required to obtain 210 tons of certified emissions reductions NOx credits from either a severe or serious NOx non-attainment area. The acquisition and transfer of the emissions reductions shall be approved by the Bureau of Air Management prior to the final construction/operating permit being issued.

Pursuant to Section 22a-174-3a(l)(2), the applicant is required to submit an 'Analysis of Alternatives'. This review has been submitted by the applicant and is attached and has been part of the review process. The applicant has demonstrated that the proposed project is best suited for both the economic and environmental benefit for the Plainfield area compared to alternative sites, sizes, process and control technologies for this premises. This premises is a former superfund site that has been reclaimed and is an ideal candidate for industrial development.

LAER for NOx has been determined to be SNCR and the requirement to obtain 210 tons of NOx offsets prior to issuance of final permit to construct/operate.

BACT/LAER requirements:
BACT applies to the following pollutants: PM, NOx, SOx, VOC, and CO, pursuant to Sec. 22a-174-3a(j)(1)(A) where potential emissions are above the significant emissions threshold in Table 3a(k)-1 of the RCSA. Pursuant to Sec. 22a-174-3a(j)(1)(C), BACT applies to hydrogen chloride (HCL) and ammonia (NH_3), where potential emissions are greater than 15 ton/year.

As stated previously, LAER applies to the NOx emissions pursuant to 22a-174-3a(l)(1)(A).

The determination of BACT for the above pollutants was based on the information provided in the application of similar biomass energy projects throughout the country and the following:

- Review of the potential emissions and minimum regulatory requirements.
- Review of the EPA RACT/BACT/LAER Clearinghouse to identify various control methods.
- Review of the technical feasibility of each control method.
- Rank the control technologies using a "top-down" approach, where energy, economic and environmental impacts are used to determine the best control technology for the project.

Although there are alternate methods of control technologies identified in the permit application, the proposed methods have been shown by the applicant to comply with the BACT requirements pursuant to Sec. 22a-174-3a(j). Some of the other control technologies considered provide no additional reduction in emissions, are technically infeasible, or have not been successfully demonstrated. The permit will require the applicant to resubmit for review and approval an updated BACT analysis if construction has not commenced within 18 months of the final construction/operating permit.

The BACT determination for the pollutants identified above was determined based on following:

PM/PM-10, NOX, SOX/HCL, NH_3: The applicant chose the top ranked control technologies, so no further analysis was required. There will be a bag leak detection system on the baghouse to ensure the integrity of the bags is not compromised during operation. As discussed above the applicant will show compliance with the PM emission rates by using stack testing.

CO and VOC: The applicant identified control options using oxidation catalyst that possibly could be used to reduce CO and VOC emissions further. The analysis has determined that there are only two locations in the country with oxidation catalyst as a control technology. There is one plant in New Hampshire that has never been able to demonstrate compliance due to catalyst contamination and is currently not operating due to legal issues. The other plants in Ohio have not completed construction and the permit limits for those plants are similar to the PRE proposed limits for these pollutants without the use of a catalyst. Since there has been no demonstrated use of oxidation catalyst for CO and VOC, the Department has determined that BACT for these pollutants is the use of fluidized bed gasification and good combustion practices.

The LAER determination has been based on reviewing the most stringent SIP limitation in any state or the most stringent limitation achieved in practice. The applicant has shown that there are no state SIP limits less than the proposed NOx emission rate. There are several similar units in Maine and New Hampshire with an equivalent NOx emission rate as proposed by the applicant.

BACT/LAER has been determined to be the following for each pollutant:

Pollutant	**BACT/LAER**	**Compliance Demonstration**
PM/PM-10	Mutlicyclone; Spray dryer adsorber; Fabric filter (bag house)	Stack test; COMS(10% 1 hour-block) CEM
NOx	0.075 lbs/MMBtu **(LAER)** 210 tons of emission reduction credits **(LAER)** Selective Non-Catalytic Reduction (SNCR)**(BACT)**; Fluidized Bed Gasification(FBG) **(BACT)**	Stack test; CEMS(24 hour-block)
SOx/HCL	FBG bed additives; Spray dryer; Bag House	Stack test; CEMS(3 hour-block)
CO	Fluidized Bed Gasification; Good combustion practices	Stack test; CEMS(8 hour-block)
VOC	Fluidized Bed Gasification; Good combustion practices	Stack test; CO CEMS as surrogate
NH_3 Slip	Complying with emission limit of 20 ppmvd, and optimization of SNCR system	Stack test; CEMS (24 hour-block)

Prevention of Significant Deterioration (PSD) Requirements:

Pursuant to 22a-174-3a(k) new major stationary sources are subject to PSD review if the source has the potential to emit above the Significant Emission Rate Thresholds listed in Table, 3a(k)-1 of the RCSA. The potential emissions for all criteria pollutants except lead are above the significant threshold listed in Table 3a(k)-1.

Refined modeling/PSD review was performed for PM10, PM2.5, CO, SO_2, NOx, Pb and total dioxin. The modeling report indicates that the facility would not cause or contribute significantly to a violation of the State AAQS, federal NAAQS or federal PSD increments.

Pursuant to Sec. -3a(k)(8)(iv), the owner /operator if a PSD source must include "a schedule for the construction of the subject source or modification." PRE estimates that initial startup would commence 24 months after issuance of the final CP/OP permit.

Acid Rain:

Since this power plant is not going to combust any fossil fuels, the Title IV Acid Rain rules do not apply to this source.

Applicability to the acid rain rules are as follows:

40 CFR Part 72.6:

(a) Each of the following units shall be an affected unit, and any source that includes such a unit shall be an affected source, subject to the requirements of the Acid Rain Program:

(1) A unit listed in table 1 of §73.10(a) of this chapter.
(2) A unit that is listed in table 2 or 3 of §73.10 of this chapter and any other existing utility unit, except a unit under paragraph (b) of this section.
(3) A utility unit, except a unit under paragraph (b) of this section, that:

This Unit does not qualify under §72.6(a)(1) and (2) but would be considered a "utility unit". Pursuant to §72.2, the definition of "unit" is defined as a fossil fuel-fired combustion device. The applicant submitted a formal request for an applicability determination on 05/09/07 to the EPA and has not had a response. Currently this unit should not be considered an Acid Rain source. This determination will not affect the NSR permit, if EPA determines that this source is subject to the Acid Rain regulations they will be required to obtain a separate Acid Rain permit.

Sec. -29 MASC:
This source complies with Sec. 22a-174-29 maximum allowable stack concentrations for all identified HAPs at this time. An annual stack test will be required for all the HAPs identified in Part VI of the permit.

Since this facility will be allowed to burn Construction & Demolition debris (C&D), the applicant developed a quality control/monitoring procedure (otherwise known as the Protocol) to ensure that only "regulated wood fuel" is burned in this unit [Sec. 22a-209a]. The sorting process discussed in this plan is designed to ensure that the following materials are removed from the fuel source: plastics, plaster, gypsum wallboard, asbestos, asphalt shingles and wood which contains creosote or to which pesticides have been applied or which contains substances defined as hazardous under section 22a-115.

The proposed permit has requirements that will limit all individual and any combination of HAPs listed in Section 112(b) of the Clean Air Act Amendments of 1990 to less than 10 tons and 25 tons/year respectively. The applicant will show compliance with these limitations with annual stack test and/or fuel sampling.

Compliance History Review:
The compliance record was reviewed in accordance with the Environmental Compliance History Policy. The applicant's submitted compliance information form was reviewed along with agency records, including the PAMS Enforcement database, for information to evaluate the applicant's compliance history and the relevance of such history to the activity for which authorization is being sought. Additionally, a review of air program compliance was requested from the Enforcement Section and that response forms a part of this record. There are currently no enforcement actions that prevent this permitting process from moving forward.

Based on the information submitted by the applicant, this engineering evaluation and the compliance history review, the granting of a permit to construct and operate a 37.5 MW biomass gasification power plant is recommended for Plainfield Renewable Energy LLC.

James A. Grillo, APCE 3/11/08
Date

Approvals:

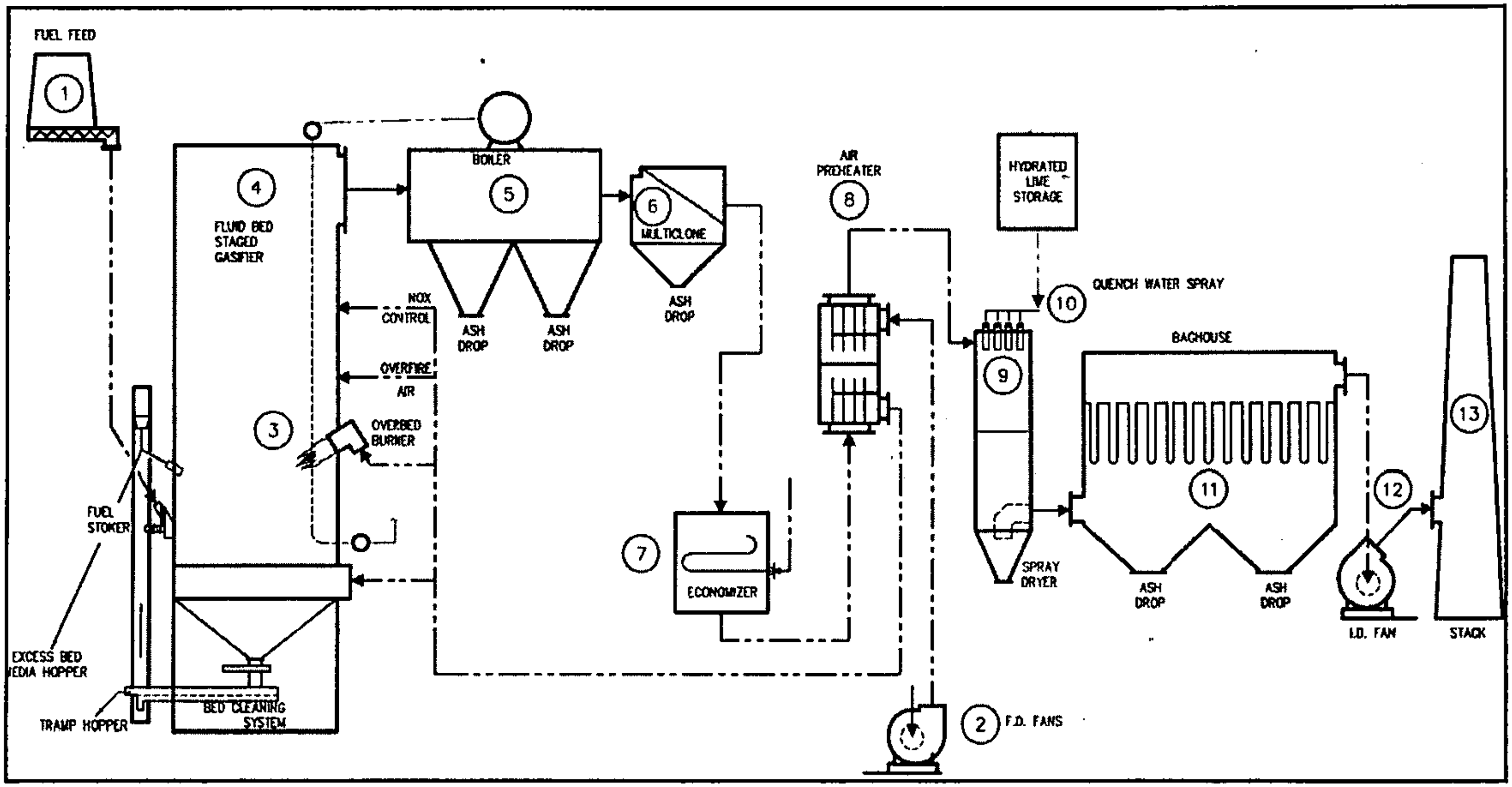
3/11/2008
Ernest Bouffard
Supervising APCE

3/11/08
Richard A. Pirolli
Assistant Director

03-12-08
Gary S. Rose
Director

/srj

Figure 1 - EPI Fluidized Bed Staged Gasifier Process Flow and Conceptual Arrangement Diagram



MEMORANDUM

TO: James Grillo APCE II

FROM: Jude Catalano APCE III

DATE: October 12, 2007

SUBJECT: **Review of the ambient air impact analysis performed in support of permits for a proposed ~37 megawatt wood burning fluidized bed gasification facility in Plainfield, Connecticut.**

I have completed my review of the ambient air impact analysis performed in support of a permit application for a wood fired fluidized bed staged gasification (FBG) boiler capable of generating a nominal 37 megawatts (MW) of electricity. The modeling analysis was performed by M.I. Holzman & Associates, LLC (MIH) and is documented in a December 2006 report entitled "Air Quality Impact Analysis Plainfield Renewable Energy Project Mill Brook Road Plainfield, CT" and in a follow-up revision letter report from Michael I. Holzman to James Grillo entitled "Plainfield Renewable Energy LLC Application... Revised PM2.5 Emissions Rates and NAAQS Compliance Demonstration", and dated July 23, 2007. The reports conclude that the facility will not cause or contribute significantly to a violation of any State Ambient Air Quality Standard (AAQS), National Ambient Air Quality Standard (NAAQS), or prevention of significant deterioration (PSD) increment.

Refined modeling was performed for PM_{10}, $PM_{2.5}$, CO, SO_2, NOx, Pb, and total Dioxin. The MIH modeling was performed in accordance with current modeling guidance based mainly on the CTDEP documents entitled "Ambient Impact Analysis Guideline", dated July 1988, and "CTDEP Interim PM2.5 New Source Review Modeling Policy and Procedures", dated August 21, 2007. Results indicate that the proposed new sources at the facility will not cause or contribute significantly to a violation of any State AAQS, federal NAAQS, or Federal PSD increment.

Attached is an air quality modeling checklist that documents my review. In addition to the model results, all proposed facility emission parameters assumed in the modeling could be found in the checklist. Model input and output files as well as the above-mentioned MIH reports can be found in the modeling group paper or electronic files. A summary of maximum predicted impacts from the facility and other nearby sources can be found in Table 4-5 and Table 6 attached to the checklist. Table 4-5 of the checklist can also be found in the above-sited December 2006 MIH modeling report, and Table 6 can also be found in the above-sited MIH letter report dated July 23, 2007. Maximum impacts for all pollutants modeled are expected to occur approximately 2.5 kilometers downwind of the proposed facility in an east-southeasterly direction.

cc: D. Wackter

AIR QUALITY MODELING CHECKLIST

Source Name: **Plainfield Renewable Energy, LLC**
Location: Mill Brook Road, Plainfield, Connecticut
Reviewer: Jude Catalano
Permit #:
Stack #:
Documentation: M.I.Holzman & Associates, LLC (MIH) performed dispersion modeling in support of permit applications to construct and operate a biomass fluidized bed staged gasification boiler power plant in Plainfield, Connecticut. The dispersion modeling performed by MIH is documented in their report entitled "Air Quality Impact Analysis Plainfield Renewable Energy Project Mill Brook Road Plainfield, CT", dated December 2006, and in a letter report to James Grillo (CTDEP) from Michael I. Holzman (MIH) entitled "Plainfield Renewable Energy… Revised PM2.5 Emission Rates and NAAQS Compliance Demonstration", and dated July 23, 2007. Further pertinent documentation used in the review of the modeling is contained on the MIH report entitled "Application For New Source Review Air Permit to Construct and Operate a Stationary Source Biomass Fluidized Bed Staged Gasifier Power Plant" and dated August 8, 2006. Finally, additional documentation is contained in electronic email files and dispersion model input and output files received from/and or sent to MIH. All above cited documentation can be found in the Bureau Planning and Standards modeling group paper and electronic files.

I. SOURCE CHARACTERISTICS

A. Description of operation including units and fuel to be used.
One 37.5 (net) megawatt (MW) biomass (wood) fluidized bed staged gasification combustion boiler system (FBG) to produce steam to drive a steam turbine generator. The effluent of the FBG unit will pass through selective non-catalytic NOx reduction (SNCR) control, a spray dryer for SOx, acid gases and metals control, and a fabric filter baghouse for particulate control. The effluent will enter the atmosphere via a 155 ft. stack. The fuel will consist of processed construction and demolition wood, recycled wood, and other types of clean wood that mainly includes stumps, bark, brush, sawdust and chipped trees.
Other operations and allowable emission rates at the premise:
One wet cooling tower and an internal combustion emergency diesel engine.
Comments:

B. Stack parameters: Stack velocity and temperatures represent 100% load operation. The source is located in UTM Zone 19. However coordinates for the modeling were all converted to Zone 18.

	CFG Boiler	Emergency Engine	Cooling Tower
Stack height (m)	47.24	3.05	13.06
Exit Temperature (0K)	396.	782.	310.
Diameter (m)	2.74	0.15	12.07
Velocity (m/s)	16.50 (25%C&D 75%wood)	101.6	7.55
X (UTM) E	756,096.	756,040.	756,037
Y (UTM) N	4,616,897.	4,616,867.	4,616,892
Z (feet above msl)	56.	54.	53

C. Emissions: Below is a list of allowable emissions rates for the FBG unit, the emergency engine and the cooling tower. Four operating scenarios were considered in the screening modeling to determine worst-case load conditions. See Table 2-1, attached, for a listing of the four operating scenario stack parameters and emission rates (Table 2-1 was taken directly from above sited December 2006 MIH report). Emission rates below represent 100% load operation burning 25% C&D waste wood and 75% wood except for CO, which represents a 91%load operation burning 100% C&D waste. PM10 and PM2.5 emission rates are based on expected total PM10/2.5 emissions that include both filterable and condensable fractions of the total. This value was used in the modeling. The engine and cooling tower values represent 100% load operation.

Pollutant	CFG Boiler (lb/hr)	CFG Boiler (tpy)	Diesel Engine (lb/hr)	Diesel Engine (tpy)	Cooling Tower (lb/hr)	Cooling Tower (tpy)		
$PM_{2.5}$	19.35	84.77	0.29	0.043	0.15	0.65		
PM_{10}	19.35	84.77	0.29	0.043	0.15	0.65		
SO_2	18.56	81.29	0.008	0.001	neg.	neg.		
NOx	39.23	171.84	16.09	2.41	neg	neg.		
VOC	NA	NA	NA	NA	NA	NA		
CO	54.67	239.47	3.69	0.55	neg.	neg.		
Pb	0.07	0.32	4.6E-05	7.0E-06	neg.	neg.		
Dioxin	4.6E-08	2.0E-07	?	?	neg.	neg.		
OTHER (Hg)	0.0013	0.006	NA	NA	neg.	neg.		

Comments: Revised PM emission rates were submitted to the DEP via the above sited letter report dated July 2007. Note that the emission rate of PM10/2.5 for the FBG boiler is higher than the enforceable PM limitation in the proposed permit. The enforceable permit limitation reflects the filterable fraction of total expected PM10/2.5 only. An enforceable total PM10/2.5 emission rate for the FBG will be determined within one year of the promulgation of a revised stack test method for condensable PM emissions.

D. Urban/Rural classification

The area within 3 kilometers of the proposed facility is mainly rural/residential with a limited amount (less than 10%) of industrial and commercial development. Well over 50% of the area can be considered rural for air dispersion purposes. Therefore, rural dispersion coefficients were used in the modeling. See Figure 1 attached for a topographic depiction of the area surrounding the facility.

E. Terrain characteristics

Source is located on the eastern side of the Quinebaug River valley. Terrain becomes modestly hilly approx 1.5 kilometers (km) to the east and 4.5 km to the west of the proposed facility. Terrain rises above the FBG boiler stack top approximately 1.8 kilometers to the east. See Figure 1 attached.

F. Meteorological surface station

Data from the National Weather Service surface station at Bradley International airport in Windsor Locks, CT and the upper air data from Albany County Airport was used in the ISC-Prime modeling. A five-year data set encompassing the years 1970 – 1974 was used from both sites.

II. SCREENING ANALYSIS

A. GEP Analysis performed?		Yes__X_ No___	
	FBG Stack	Engine Stack	Cooling Tower
GEP height (m)	78.49	78.49	78.49
Stack height (m)	47.24	3.06	13.06
Building height (m)	31.39	31.39	31.39
Building width (m)	68.19 (max)	68.19 (max)	68.19 (max)

Comments: The above dimensions represent Tier #4 of the Power House Boiler Building at the proposed facility. This structure results in the highest GEP height (78.40 m) for all three stacks listed above. A detailed spreadsheet GEP analysis for the FBG, Diesel Engine, and Cooling tower stacks, can be found in Tables 2-4, 2-5, and 2-6 (respectively) of the December 2006 MIH modeling report.

B. Cavity analysis performed?	Yes_X__ No___
What are the cavity impacts?	PM NO2 SO2 CO
1-hour (ug/m^3) (stack 1A / stack 1B)	See "Comments:" below
3-hour (ug/m^3)	See "Comments:" below
24-hour (ug/m^3)	See "Comments:" below
Annual (ug/m^3)	See "Comments:" below

Comments: Cavity concentration calculations were performed with the ISC-PRIME model in the single-source and multi-source modeling reviewed in Sections III and IV below. The ISC-Prime model has the ability to calculate cavity concentrations based on the building dimension information input to the model. The EPA approved PRIME cavity and downwash algorithms were used in the ISC-PRIME modeling. Therefore, cavity concentrations were not predicted with the either the SCREEN3 model or with the Appendix C hand calculations. No impacts are reported above because the cavity predictions are incorporated into the refined modeling results.

C. Does the source pass cavity analysis?	Yes _X__ No ___

Comments: See ISC-PRIME modeling results in Sections III and IV below.

D. Was ISC3 used in the screening mode?	Yes _X_ No ___
Are the ISC3 program options correct?	Yes X No ___
1. Gradual plume rise?	Yes X No ___
2. Stack-tip downwash?	Yes X No ___

3. Buoyancy-induced dispersion?	Yes X No ___
4. Calms processing routine?	Yes X No ___
5. Not use missing data processing routine?	Yes X No ___
6. Default wind profile exponents?	Yes X No ___
7. Default vertical potential temperature gradients?	Yes X No ___
Are the meteorological conditions correct?	Yes X No ___
Is the receptor grid correct?	Yes X No ___

Comments: ISC was run in the screening mode for the four FBG boiler-operating scenarios discussed above and found in the attached Table2-1. The model predicts the worst case PM, SO_2, NO_2 and Pb impacts to occur for "Case2", the 25%C&D/75% wood firing @ 100% load case. Worst-case CO impacts were predicted for "Case 1" the 100% C&D @ 91% load case. Therefore, the more refined modeling in Sections III and IV below used these worst case operating scenarios.

E. What are the receptor ring distances?

Receptors were placed along a single wind direction at 100-meter intervals from 100 meters to 2.0 km and at 500-meter intervals from 500 meters to 10.0 kilometers and at 1.0 km intervals out to 20 km. An additional receptor was placed at a distance of 3L (94 meters) from the stack. Terrain elevation for the receptors is the maximum elevation located anywhere within the annulus defined by half the distance between receptors.

Comments: A listing of the above receptors can be found I Table3-1 of the above-sited MIH December 2006 modeling report.

F. How many receptors above stack top are there?

28.

Comments:

G. Are there any discrete receptors? Yes __ No ___

Comments: See "E" above for a description of the receptor network.

III. SINGLE SOURCE MODELING ANALYSIS

A. Are the subject source's stack Parameters correct?	Yes _X_ No ___
Comments: Model input files were checked for accuracy. The wake influences were accounted for in the ISCST modeling with the assistance of the EPA BPIP building profile program found in Lakes Environmental ISC-AERMOD View interface program. A scaled CAD drawing was used (based on NAD27datum) to build an input file for BPIP. These building dimensions are based on a set of building tier and stack location coordinates and heights input to the BPIP software by the user. These building location and stack location data were checked for accuracy. Figure 4-1 of the MIH December modeling report represents the BPIP model CAD setup. BPIP determines for each 10 deg. sector, which structure may produce the greatest downwash effect. The 36 direction specific building dimensions were put into the ISC-Prime model. The BPIP output can be found in Appendix B of the MIH report.	

B. Are iscst3 program options corrects?	Yes _X_ No___
1. Gradual plume rise?	Yes _X_ No ___
2. Stack-tip downwash?	Yes _X_ No ___
3. Buoyancy-induced dispersion?	Yes _X_ No ___
4. Calms processing routine?	Yes _X_ No ___
5. Not use missing data processing routine?	Yes _X_ No ___
6. Default wind profile exponents?	Yes _X_ No ___
7. Default vertical potential temperature gradients?	Yes _X_ No ___
Comments:	

C. What are the receptor ring distances?

The receptor network was developed based on results of the screening modeling. The maximum impacts for both worst-case operating scenarios sited above was predicted to occur 94 meters downwind of the FBG stack. Therefore, a polar receptor grid was developed for the ISC-Prime-AERMOD View version of the ISC model as follows. A receptor ring spacing factor of 1.33 was used with the first ring being 94 meters from the stack. This resulted in receptor rings placed at 94, 194, 260, 340, 450, 600, 800, 1060, 1410, 1880, 2500, 3320, 4410, 5860, 7790, 10360, 13780, 18330, and 24380 meters from the FBG boiler stack. The polar grid was converted to UTM coordinated in order to import terrain elevations from the USGS Digital Elevation Model. An additional 58 discrete receptors were placed along the proposed property fence line. Finally, 40 additional discrete receptors were placed 50 meters away from the fence line at 50-meter intervals. Any receptors located within the proposed property fence line were eliminated before being input to the ISC model. Figure 4-4 in the MIH December 2006 modeling report depicts the near-field receptors, and Figure 4-5 depict the entire receptor network. All receptors with elevations above the proposed FBG boiler stack top were input into the PTMTPA-CONN complex-terrain screening model (as well as the ISC model). A total of 151 receptors were determined to have elevations above the FBG boiler stack. A complete listing of the PTMTPA complex terrain receptors can be found in Table 4-2 of the MIH December 2006 modeling report.

D. Are additional receptors needed?	Yes ___ No _X__
Comments: None other than discussed in C. above.	

E. What is the radius of significance for each pollutant modeled?

Comments: The proposed facility is predicted to have insignificant impacts of CO, for both the 8-hour and 1-hour averaging times. Therefore, no further CO modeling is required. The single source results for CO demonstrate compliance with the National Ambient Air Quality Standard (NAAQS).

The facility is predicted to have significant PM10/2.5 impacts out to a distance of 10,360 meters. This significant impact distance is based on the original PM modeling that was performed with an emission rate that is 54 % of the total estimated PM emission rate. A new significant distance was not calculated for PM since the maximum impact in the original PM modeling occurred 2.5 km downwind of the FBG stack. The PM2.5 SILs recommended by NESCAUM of 2.0 ug/m^3 24-hour average and 0.30 ug/m^3 annual average were used for the significant impact distance.

The facility is predicted to have significant SO_2 impacts out to a distance of 10,360 meters from the FBG boiler stack.

The facility is predicted to have significant annual NO_2 impacts out to a distance of 10,360 meters from the FBG boiler stack.

See Table 4-5, attached, for a summary of the ISC/PTMTPA single-source significant impact modeling results. This Table was taken directly from the MIH December 2006 modeling report. Note however that the PM10 and PM2.5 impacts reported on the attached Table 4-5 should be adjusted upwards by a factor of 1.85 to reflect the upwardly revised PM emission rates.

F. Are additional above stack-top receptors Needed?	Yes __ No_X_
Comments: No. See network description in C. above.	

G. Does the source impact significantly in a non-attainment area?	Yes ___ No _X_

Comments: The facility is predicted to have significant PM and SO_2 impacts in attainment areas only. Although the area is non-attainment for ozone, and NOx emissions are an ozone precursor, ozone modeling is not part of NSR permitting requirements. Ozone non-attainment issues are addressed with regional scale modeling and emission reduction strategies.

IV. MULTI-SOURCE MODELING ANALYSIS

A. Are ISCST3 program options correct?	Yes _X_ No___
1. Gradual Plume rise?	Yes _X_ No___
2. Stack-tip downwash?	Yes _X_ No___
3. Buoyancy-induced dispersion?	Yes _X_ No___
4. Calms processing routine?	Yes _X_ No___
5. Not use missing data processing routine?	Yes _X_ No___
6. Default wind profile exponents?	Yes _X_ No___
7. Default vertical potential temperature gradient?	Yes _X_ No___
Comments:	
B. Is the receptor input correct?	Yes _X_ No___
Comments: Spot-checking of receptors was conducted.	
C. Are the NAAQS source inputs correct for each pollutant modeled?	Yes _X_ No ___
Comments: Facility emission parameters input to the ISC and PTMTPA models were checked and verified.	
D. Are the PSD source inputs correct for each pollutant modeled?	Yes _X_ No ___
Comments: Note that PSD modeling was performed for emissions of PM_{10}, SOx, and NOx only. EPA has not yet established PSD increments for PM2.5. Multi-source PSD sources inputs for PM_{10} , SOx, and NOx were checked and verified as accurate.	
E. Were building dimensions used for sources subject to downwash?	Yes _X_ No ___
Comments: Building dimension information for the proposed Plainfield Energy facility sources were input to the ISC-Prime model as described above in "Section III A" above. Input and output files for the BPIP equivalent model are stored electronically in the modeling group files. The building dimensions generated by the BPIP model for input to the ISC model can be found in the model input or output files or in Appendix B of the MIH December 2006 modeling report.	
F. Inventory search for adjacent NAAQS Sources was it reviewed/revised?	Yes _X_ No ___
Multi-source modeling was required for PM_{10}, $PM_{2.5}$, NO_2, and SO_2. Multi-source modeling for CO was not required because the FBG boiler is predicted to have insignificant CO impacts at all receptors (see Section III above) An inventory of appropriate nearby sources to be included in the modeling was supplied to the applicant by CTDEP Air Bureau's inventory group. Note there were no existing nearby PM sources identified in the inventory search. A listing of the NO_2 and SO_2 sources and their appropriate emissions parameters can be found in Table 5-2 and 5-3 of the MIH December 2006 modeling report. The model input parameters were checked and verified with the search result provided to the applicant.	
Comments:	

G. Inventory search for adjacent PSD Sources, was it reviewed/revised?	Yes _X_ No ___

Comments: Note that PSD increments for PM2.5 have not been established therefore, no PSD modeling was required for PM $_{2.5}$. CTDEP Air Bureau provided the applicant with results of an inventory search of nearby existing NO_2, and SO_2 sources. A listing of these sources and their appropriate emission parameters can be found in Tables 5-5 and 5-6 if the December 2006 MIH modeling report. The model input parameters were checked and verified with the CTDEP inventory search results provided to the applicant.

H. Are there any adjacent sources not in Connecticut that should be included?	Yes ___ No _X_

Comments: A search of Rhode Island (RI) sources was conducted and no sources that meet CTDEP criteria for inclusion in a multi-source modeling review were found. See discussion on page 52 and 53 in the December 2006 MIH modeling report. Note that the RI state line is located 11 kilometers downwind of the FBG stack. This distance is just beyond the FBG boiler stack SIL's distances for PM, NO_2, and SO_2.

I. Did the Source pass a visibility Analysis?	Yes _X_ No __

Comments: A VISCREEN Level-1 analysis was performed for the worst cast FBG boiler operating scenario that resulted in the maximum NO_2, SO_2, and PM10 impacts (Case #2). Results of the VISCREEN model predict calculated plume perceptibility and contrast parameters to be below the EPA default criteria for a visibility screening analysis at the two nearest Federal Class I areas: Lye Brook VT. (185 km downwind); and Brigantine, NJ (320 km downwind). The VISCREEN model output can be found in Appendix F of the December 2006 MIH modeling report. A summary of the VISCREEN results can be found in Table 6-2 on pages 60 and 61 of the MIH report. Single source modeling discussed in Section III above demonstrates that the facility will have insignificant CO impacts at all receptors modeled for both the 1-hour and 8-hour averaging times. CO is not expected to effect current visibility conditions in Connecticut.

J. Did the source pass a soil and Vegetation analysis?	Yes _X_ No __

Comments: Maximum predicted FBG boiler concentrations from the single source refined modeling were compared the appropriate Air Quality Related Value (AQRV) screening concentrations provided in the USEPA document entitled "A Screening Procedure for the Impacts of Air Pollution Sources on Plants, Soils, and Animals". The AQRV for vegetation are equivalent to or exceed the NAAQS and or the PSD increment for all the criteria pollutants. Therefore , compliance with these standards ensures demonstrated compliance with the AQRVs. Table 6-3 pg. 62 of the MIH December 2006 modeling report shows that the maximum predicted impacts from the FBG boiler would not exceed any of the applicable AQRVs. The proposed facility is therefore not expected to negatively effect soils or vegetation growth in the area.

K. Did the source pass a growth analysis?	Yes _X_ No __

Comments: The proposed project is expected to employ approximately 200 people during the construction phase of the project and approximately 20 to 25 permanent jobs once the facility becomes operational. It is anticipated that people who already live in the area will fill many of the permanent jobs. Therefore, the project is not anticipated to have a significant impact on growth from the 25 permanent jobs that will be created. Due to the nature of the business of burning waste wood to generate electricity, it is not anticipated that any significant commercial or industrial development will be needed to support the operation of the facility. The operation of the proposed facility is not expected to result in significant ancillary Growth in the area, which may lead to an increase in area emissions and a degradation of local air quality.

L. Do the multi-source impacts exceed PSD Increments? Yes __ No_X_

Comments: Maximum predicted impacts for PM, SO_2, and NO_2 are listed in Table 6 attached. This table was taken directly from the MIH July 23, 2007 letter report to James Grillo of CTDEP. Please note that EPA has yet to promulgate PSD increments for PM2.5. Therefore no PSD modeling is required for PM2.5 at this time. The maximum PSD PM10 impacts are the same as those listed under the max. AAQS impacts for PM2.5, since no nearby existing sources of PM were found in the inventory search. Results indicate that operation of the facility as proposed in the permit application will not cause or contribute significantly to an violation of any PSD increment including the 24-hr and annual average increments for PM10 of $30ug/m^3$ and $17ug/m^3$ respectively.

M. Do the multi-source impacts exceed the NAAQS? Yes ___ No _X_

Comments: Maximum predicted impacts for PM2.5, SO_2 and NO_2 are also listed in attached Table 6. Maximum predicted PM10 impacts were left out of this table. The maximum predicted PM10 impacts are based on the single source refined modeling results discussed in Section III (above) of this checklist. The single source results were used because no additional nearby sources were identified in the radius search performed by the CTDEP Air Bureau. The maximum facility PM10 24-hour average impact of $38ug/m^3$ (which includes a background of $31ug/m^3$) was predicted by the PTMTPA model to occur 2500meters downwind on the 120 deg. azimuth. This impact compares to the NAAQS of $150ug/m^3$. The maximum facility annual PM10 impact was predicted to be $19ug/m^3$ (which includes a background level of $17ug/m^3$). This impact was predicted to occur at the same receptor location as the maximum 24-hour average impact. Note that source impacts for PM in attached Table 4-5 should be adjusted upward by a factor of 1.85 to reflect the upwardly revised PM emission rate that includes both filterable and condensable emissions. The revised PM emissions for the facility are documented in the July23, 2007 letter report from MIH to James Grillo of the CTDEP Air Bureau.

N. Does PTMTPA-CONN predict any PSD or NAAQS Violations in complex terrain? Yes __ No _X_

Comments: See comments in L. and M. above.

Table 4-5 – ISCST and PTMTPA Refined Single-Source Modeling Results

ISCST Modeled Impacts

Pollutant	Averaging Period	Max. Norm. (µg/m³)/(g/sec)[1]	Max. Impact (µg/m³)[1,4]	Signif. Impact Level (µg/m³)[5]	Signif. Impact Radius (m)	Pre-const. Monitoring De Minimis Levels (µg/m³)	Class II Allowable PSD Increments. (µg/m³)	Background Conc. (µg/m³)[6]	Total Conc. (µg/m³)	Ambient Standard (µg/m³)	Receptor Location of Maximum Impact			
											UTM East (m)	UTM North (m)	Distance from Stack (m)	Azimuth, degrees from N.
PM10	24-hour average	1.4	1.8	5	N/A	10	30	31	32.6	150	758,261	4,615,648	2,500	120
	Annual average	0.2	0.3	1	N/A	N/A	17	17	16.9	50	758,261	4,615,648	2,500	120
PM2.5	24-hour average	1.4	1.8 ≃ 3.3	2	N/A	N/A	N/A	33	34.9	65	758,261	4,615,648	2,500	120
	Annual average	0.2	0.29	0.3	N/A	N/A	N/A	9.8	10.1	15	758,261	4,615,648	2,500	120
NO_2	Annual average	0.2	1.1	1	2,830	14	25	33	33.8	100	758,261	4,615,648	2,500	120
SO_2	3-hour average	4.3	10.0	25	N/A	N/A	512	92	10.0	1300	759,366	4,617,474	3,320	80
	24-hour average	1.36	3.2	5	N/A	13	91	55	58.2	260	758,261	4,615,648	2,500	120
	Annual average	0.2	0.5	1	N/A	N/A	20	11	11.5	60	758,261	4,615,648	2,500	120
CO	1-hour average	9.22	64	2,000	N/A	N/A	N/A	20,000	20,064	40,000	758,261	4,615,648	2,500	120
	8-hour average	2.89	20	500	N/A	575	N/A	5,000	5,020	10,000	758,261	4,618,148	2,500	60
Pb	Quarterly average[2]	1.36	0.01	0.3	N/A	0.1	N/A		0.01	1.5	758,261	4,615,648	2,500	120
Dioxins	Annual average	0.22	1.3E-09	1.00E-07	N/A	N/A	N/A		1.3E-09	1.00E-06	758,261	4,615,648	2,500	120

PTMTPA-CONN Modeled Impacts

Pollutant	Averaging Period	Max. Norm. (µg/m³)/(g/sec)[1,3]	Max. Impact (µg/m³)[3,4]	Signif. Impact Level (µg/m³)[5]	Signif. Impact Radius (m)	Pre-const. Monitoring De Minimis Levels (µg/m³)	Class II Allowable PSD Increments. (µg/m³)	Background Conc. (µg/m³)[6]	Total Conc. (µg/m³)	Ambient Standard (µg/m³)	Receptor Location of Maximum Impact			
											UTM East (m)	UTM North (m)	Distance from Stack (m)	Azimuth, degrees from N.
PM_{10}	24-hour average	3.0	4.0 7.4	5	N/A	10	30	31	34.8	150	758,261	4,615,648	2500	120
	Annual average	0.8	0.99 1.84	1	N/A	N/A	17	17	17.6	50	758,261	4,615,648	2500	120
PM2.5	24-hour average	3.0	4.0	2	10,360	N/A	N/A	33	37.1	65	758,261	4,615,648	2500	120
	Annual average	0.8	0.99	0.3	10,360	N/A	N/A	9.8	10.8	15	758,261	4,615,648	2500	120
NO_2	Annual average	0.8	3.7	1	10,360	14	25	33	36.4	100	758,261	4,615,648	2500	120
SO_2	3-hour average	19.0	44	25	4,410	N/A	512	92	44.4	1300	758,261	4,615,648	2500	120
	24-hour average	3.0	7.0	5	4,410	13	91	55	62.0	260	758,261	4,615,648	2500	120
	Annual average	0.8	1.8	1	10,360	N/A	20	11	12.8	60	758,261	4,615,648	2500	120
CO	1-hour average	21.1	145	2,000	N/A	N/A	N/A	20,000	20,145	40,000	758,261	4,615,648	2500	120
	8-hour average	14.8	102	500	N/A	575	N/A	5,000	5,102	10,000	758,261	4,615,648	2500	120
Pb	Quarterly average[2]	3.0	0.03	0.3	N/A	0.1	N/A		0.03	1.5	758,261	4,615,648	2500	120
Dioxins	Annual average	0.8	4.3E-09	1.00E-07	N/A	N/A	N/A		4.3E-09	1.00E-06	758,261	4,615,648	2500	120

Table 4-5 (Continued)

Notes:

1. For ISCST model results, highest second high modeled concentrations were used to evaluate all short-term impacts (1-hour to 24-hour). Highest modeled concentrations were used to evaluate annual impacts.
2. Lead impacts were conservatively determined using 24-hour impacts.
3. PTMTPA-CONN provides maximum 3-hour and 24-hour concentrations for each receptor modeled. 1-hour and 8-hour concentrations were calculated by dividing the 3-hour value by 0.9 to calculate a 1-hour average, and then multiplying the 1-hour value by 0.7 to calculate an 8-hour average. Annual average concentrations were estimated by multiplying the maximum 24-hour concentration by 0.25 (the maximum ratio of the annual to 24-hr second high concentration modeled with ISCST was 0.2 at the maximum PTMTPA impact receptor). Maximum modeled results from all receptors were used to evaluate impacts for each averaging period.
4. Maximum impacts calculated by multiplying normalized impacts (μg/m3)/(g/sec) by the respective maximum g/sec emission rates (for any operating scenario) for each pollutant and applicable averaging period.
5. Significant Impact Levels (SIL) for PM2.5 are estimated, based on same ratio of SIL to AAQS for PM10.

			Significant Impact Radius (meters)						
Pollutant	Averaging Period	**Normalized PTMTPA impacts that correspond to significant impacts[1]**	**Recept. 1 - 30**	**Recept. 31-60**	**Recept. 61-90**	**Recept. 91-120**	**Recept. 121-150**	**Recept. 151**	**Max.**
PM2.5	24-hour average	1.52	10,360	10,360	10,360	10,360	7,790	0	10,360
PM2.5	Annual average (24-hr)	0.91	10,360	10,360	10,360	10,360	7,790	0	10,360
NO2	Annual average (24-hr)	0.81	10,360	10,360	10,360	10,360	7,790	0	10,360
SO2	3-hour average	10.69	4,410	4,410	4,410	0	0	0	4,410
SO2	24-hour average	2.14	4,410	4,410	4,410	2,500	1,880	0	4,410
SO2	Annual average (24-hr)	1.71	10,360	10,360	10,360	10,360	7,790	0	10,360

1 Equivalent normalized impacts corresponding to significant impacts for annual averages were calculated by dividing the annual averages by 0.25.

Table 6 – Summary of Updated Refined ISCST and PTMTPA Multiple-Source Modeling Analysis

ISCST Modeled Impacts

Pollutant	Averaging Period	Max. Impact AAQS Sources ($\mu g/m^3$)[1]	Max. Impact PSD Increment Consuming Sources ($\mu g/m^3$)[1]	Class II Allowable PSD Increments. ($\mu g/m^3$)	Background Conc. ($\mu g/m^3$)[3]	Total Conc. ($\mu g/m^3$)	AAQS ($\mu g/m^3$)	Receptor Location of Maximum Impact				Year
								UTM East (m)	UTM North (m)	Distance from Stack (m)	Azimuth, degrees from N.	
PM2.5	24-hour average	3	N/A	N/A	29	32	35	756,015	4,616,892	81	266	1973
	Annual average	1	N/A	N/A	9	10	15	758,261	4,615,648	2,500	120	1971
NO_2 *	Annual average	3	2	25	33	36	100	746,361	4,613,354	10,360	250	1970
SO_2 **	3-hour average	174	36	512	92	266	1300	746,361	4,613,354	10,360	250	1973
	24-hour average	71	9	91	55	126	260	746,361	4,613,354	10,360	250	1972
	Annual average	9	1	20	11	20	60	746,361	4,613,354	10,360	250	1970

* Receptor location and year of maximum impact listed for cumulative AAQS sources. For PSD increment consuming sources, maximum modeled impact receptor was (X, Y, Dist., Azimuth, Year):

	756,121	4,616,771	129.4	168.9	1971

** Receptor locations and years of maximum impact listed for cumulative AAQS sources. For PSD increment consuming sources, maximum modeled impact receptors were (X, Y, Dist., Azimuth, Year):

3-hour:	738,045	4,613,715	18,330	260	1974
24-hour:	740,222	4,607,733	18,330	240	1971
annual:	740,222	4,607,733	18,330	240	1970

PTMTPA-CONN Modeled Impacts

Pollutant	Averaging Period	Max. Impact AAQS Sources ($\mu g/m^3$)[2]	Max. Impact PSD Increment Consuming Sources ($\mu g/m^3$)[2]	Class II Allowable PSD Increments. ($\mu g/m^3$)	Background Conc. ($\mu g/m^3$)[3]	Total Conc. ($\mu g/m^3$)	AAQS ($\mu g/m^3$)	Receptor Location of Maximum Impact			
								UTM East (m)	UTM North (m)	Distance from Stack (m)	Azimuth, degrees from N.
PM2.5	24-hour average	6	N/A	N/A	29	35	35	758,261	4,615,648	2500	120
	Annual average	2	N/A	N/A	9	12	15	758,261	4,615,648	2500	120
NO_2	Annual average	4	4 ✓	25	33	37	100	758,261	4,615,648	2500	120
SO_2	3-hour average	132	46 ✓	512	92	224	1300	758,261	4,615,648	2500	120
	24-hour average	29	9 ✓	91	55	84	260	758,261	4,615,648	2500	120
	Annual average	7	2 ✓	20	11	18	60	758,261	4,615,648	2500	120

Table 2-1 – Screening Modeling Analysis Input Data – FBG Stack

SOURCE INFORMATION:

Company Name:	Plainfield Renewable Energy LLC
Equipment Location Address:	Mill Brook Rd., Plainfield, CT
Equipment Description:	EPI Fluidized Bed Staged Gasifier Energy System

ORIG (UTM, XY), meters (FBG stack)	X =	756,096	meters East	Y=	4,616,897	meters North	(Datum NAD27, Zone 18)
	X =	256,549	meters East	Y=	4,616,457	meters North	(Datum NAD27, Zone 19)
Latitude/Longitude	N	41°39'53"		W	71°55'27"		

Stack base elevation above MSL	184	ft.	56	meters

OPERATING DATA AND STACK PARAMETERS:

Case	1				2				3				4			
Description	100/0 C&D/Wood				25/75 C&D/Wood				65/35 C&D/Wood				25/75 C&D/Wood			
% Load	91%				100%				95%				75%			
Exhaust Gas Flow Rate	3474	ft^3/sec	98.40	m^3/sec	3443	ft^3/sec	97.51	m^3/sec	3578	ft^3/sec	101.32	m^3/sec	2738	ft^3/sec	77.53	m^3/sec
Stack Exhaust Temp.	253	deg. F	395.93	deg. K	253	deg. F	395.93	deg. K	253	deg. F	395.93	deg. K	253	deg. F	395.93	deg. K
Stack Height	155	ft.	47.24	m	155	ft.	47.24	m	155	ft.	47.24	m	155	ft.	47.24	m
Stack Diameter	9.00	ft.	2.74	m	9	ft.	2.74	m	9	ft.	2.74	m	9	ft.	2.74	m
Stack Velocity	54.61	ft/sec	16.65	m/sec	54.12	ft/sec	16.50	m/sec	56.24	ft/sec	17.14	m/sec	43.04	ft/sec	13.12	m/sec
Proposed Controlled Emission Rates (1-hour to 24-hour averages)																
PM_{10}	9.94	lb/hr	1.25	g/sec	10.57	lb/hr	1.33	g/sec	9.94	lb/hr	1.25	g/sec	7.74	lb/hr	0.98	g/sec
NO_2	35.64	lb/hr	4.49	g/sec	38.45	lb/hr	4.84	g/sec	37.03	lb/hr	4.67	g/sec	28.99	lb/hr	3.65	g/sec
SO_2	16.82	lb/hr	2.12	g/sec	18.56	lb/hr	2.34	g/sec	17.03	lb/hr	2.15	g/sec	13.99	lb/hr	1.76	g/sec
CO	49.98	lb/hr	6.30	g/sec	49.38	lb/hr	6.22	g/sec	49.78	lb/hr	6.27	g/sec	37.49	lb/hr	4.72	g/sec
Pb	0.067	lb/hr	0.0084	g/sec	0.073	lb/hr	0.0092	g/sec	0.069	lb/hr	0.0087	g/sec	0.055	lb/hr	0.0070	g/sec

Table 6 (cont.)

Maximum of ISCST-PRIME and PTMTPA Impacts

Pollutant	Averaging Period	Max. Impact AAQS Sources ($\mu g/m^3$)[1,2]	Max. Impact PSD Increment Consuming Sources ($\mu g/m^3$)[1,2]	Class II Allowable PSD Increments. ($\mu g/m^3$)	Background Conc. ($\mu g/m^3$)[3]	Total Conc. ($\mu g/m^3$)	AAQS ($\mu g/m^3$)
PM2.5	24-hour average	6	N/A	N/A	29	35	35
	Annual average	2	N/A	N/A	9	12	15
NO_2	Annual average	4	4	25	33	37	100
SO_2	3-hour average	174	46	512	92	266	1300
	24-hour average	71	9	91	55	126	260
	Annual average	9	2	20	11	20	60

1. For ISCST model results, highest second high modeled concentrations were used to evaluate all short-term impacts (1-hour to 24-hour), with the exception of PM2.5. For PM2.5, highest 6th high modeled concentrations were conservatively used (8th highest values are not an option with ISCST). Highest modeled concentrations were used to evaluate annual impacts.

2. PTMTPA-CONN provides maximum 3-hour and 24-hour concentrations for each receptor modeled. 1-hour and 8-hour concentrations were calculated by dividing the 3-hour value by 0.9 to calculate a 1-hour average, and then multiplying the 1-hour value by 0.7 to calculate an 8-hour average. Annual average concentrations were estimated by multiplying the maximum 24-hour concentration by 0.25 (the maximum ratio of the annual to 24-hr second high concentration modeled with ISCST was 0.2 at the maximum PTPTPA impact receptor). Maximum modeled results from all receptors were used to evaluate impacts for each averaging period, with the exception of PM2.5. For PM2.5, the PTMTPA model results were multiplied by a factor of 0.75 to estimate the 98th percentile or 8th high 24-hour impacts. The 0.75 ratio was derived by calculating the ratio of the 6th high to highest modeled ISC impacts at the maximum impact receptor for each of the 5 years of meteorological data. The ratios ranged between 0.66 to 0.79 and averaged 0.75. (The 0.75 factor has not been applied to the raw model results summarized above).

3. With exceptions noted as follows, background concentrations were obtained from the 2003-2005 average values from the 3 CT monitoring sites nearest to the project site (data provided by CTDEP). For PM2.5, background concentrations were obtained from the average of 2004-2006 data from the Norwich, CT and West Greenwich, RI monitoring sites. For PM10, the 24-hour background concentration was obtained from the average of the 2003-2005 values from East Hartford, CT and W. Greenwich, RI. The PM10 annual background concentration was obtained from the average of the 2003-2005 values from Waterbury,CT and W. Greenwich, RI.

Figure 1 – USGS Topographic Map Showing 3 KM Radius Land Use and Site Location

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Multi-HAP MASC Calculations

v 2.2

Applicant	Plainfield Renewable Energy LLC
Application Number	200602226

Stack Parameter Units	English		Use Adjustment Factor?	no
ASC/MASC Units	ug/m3			
Exhaust Flow Rate	214655	acfm		
Stack Height	155	ft		
Min. Distance to Property Line	69	ft		

Notes:

Component	HLV ug/m3	Emission rate lb/hr		ASC ug/m3	MASC ug/m3		Comply?
sulfuric acid	20	1.50E+00		1864.11	3656.54		yes
ammonia	360	7.80E+00		9693.39	65817.72		yes
arsenic	0.05	6.80E-03		8.45	9.14		yes
beryllium	0.01	5.80E-04		0.72	1.83		yes
cadmium	0.4	1.70E-02		21.13	73.13		yes
chromium	2.5	2.50E-03		3.11	457.07		yes
copper	20	5.20E-03		6.46	3656.54		yes
formaldehyde	12	9.90E-02		123.03	2193.92		yes
lead	3	7.30E-02		90.72	548.48		yes
manganese	20	3.10E-02		38.52	3656.54		yes
mercury	1	1.30E-03		1.62	182.83		yes
nickel	0.3	2.60E-03		3.23	54.85		yes
dioxin	7.00E-07	4.60E-08		0.00	0.00		yes
PAH	0.1	1.30E-03		1.62	18.28		yes
selenium	4	3.30E-03		4.10	731.31		yes
benzene	150	2.28E+00		2834.32	27424.05		yes
styrene	4300	2.28E+00		2834.32	786156.12		yes
hydrogen chloride (HCL)				0.00	0.00		no
silver	0.2	1.70E-02		21.13	36.57		yes
titanium	300	9.90E-01		1230.31	54848.10		yes
zinc	100	6.60E-01		820.21	18282.70		yes
				0.00	0.00		no
				0.00	0.00		no
				0.00	0.00		no
				0.00	0.00		no
				0.00	0.00		no
				0.00	0.00		no
				0.00	0.00		no
				0.00	0.00		no
				0.00	0.00		no
				0.00	0.00		no
				0.00	0.00		no
				0.00	0.00		no
				0.00	0.00		no
				0.00	0.00		no
				0.00	0.00		no
				0.00	0.00		no
				0.00	0.00		no
				0.00	0.00		no
				0.00	0.00		no
				0.00	0.00		no
				0.00	0.00		no
				0.00	0.00		no
				0.00	0.00		no
				0.00	0.00		no
				0.00	0.00		no
				0.00	0.00		no
				0.00	0.00		no
				0.00	0.00		no
				0.00	0.00		no

MEMORANDUM

TO: Steve Anderson, Supervising APCE
FROM: Ernest Bouffard, Supervising APCE
SUBJECT: SOURCE TEST REFERRAL

Date 02/14/08
Case Eng. J. Grillo
PAMS # 200602226
Permit Exp. Date ______

Town #	Permit #	Premises #	Stack #	Client #	Seq. #
149	0049	74	1		

REASON FOR TEST:

☒ Permit Compliance
☐ 100 ton ☒ HAP
☐ Odor ☐ S.O. ☐ Other

SOURCE TEST GROUP ONLY:

Assigned to:
ITT No.:

SOURCE INFORMATION:

Equipment Description: 37.5 MW Biomass fluidized bed gasification plant
Air Pollution Controls: SNCR, Spray Dryer, multicyclone, baghouse
Company Name: Plainfield Renewable Energy, LLC
Address: 20 Marshall Street, Suite 300, Norwalk, CT 06854
Equipment Location: Mill Brook Road, Plainfield, CT 06374

SOURCE STATUS: ☒ New ☐ Mod ☐ Existing ☐ CP/OP ☐ Revision

START-UP DATE: ____________

SOURCE SIZE CLASSIFICATION:

☒ Major ☐ Minor ☐ PSD ☒ NSPS Subpart Db ☐ NESHAP Subpart _____

TEST SCHEDULE:

ITT Due Date:

Initial Performance Test Date:

Test Report Due Date:

IS THE SOURCE REQUIRED TO REPEAT EMISSIONS TESTS? ☒ Yes ☐ No

IF YES, WHAT IS THE FREQUENCY OF TESTING?

☐ Every 5 Years

☒ Every Year: Hazardous Air Pollutants

☐ Other:

WHAT IS THE ANNIVERSARY DATE FOR TESTING DEADLINE?: date of last test

.2 9.

TEST REQUIREMENTS:

Pollutant	Permitted Emission Limit *	APCE Inlet	APCE/Stack Outlet	Specific Regulation if Applicable

* ☒ Permit emission limit table attached

STACK PARAMETERS:

Stack Height (ft): 155
Nearest distance from stack to property line (ft): 69

Operational Parameter	Range/Limit	Recording Time

For VOC Sources: ☐ capture efficiency test req'd; _____ % capture

ITT Received: ____________________
ITT Approved: ____________________
Test Results Approved: ____________________
Test Date: ________ Reschedule Date: ________ Test Completed: ________

Return copy to Permit Engineer when test results approved. Attach copy of test approval acceptance letter.

PERMIT FOR FUEL BURNING EQUIPMENT

STATE OF CONNECTICUT, DEPARTMENT OF ENVIRONMENTAL PROTECTION
BUREAU OF AIR MANAGEMENT

PART III. CONTINUOUS EMISSION MONITORING REQUIREMENTS AND ASSOCIATED EMISSION LIMITS (Applicable if -X- Checked)

CEM shall be required for the following pollutant/operational parameters and enforced on the following basis:

Pollutant/Operational Parameter	Averaging Times	Emission Limit	Units
☐ None			
☒ Opacity	six-minute block	10%	
☒ SOx	3 hour block	15.4	ppmvd @ 7% O_2
☒ NOx	24 hour block	45.3	ppmvd @ 7% O_2
☒ CO	8 hour block	103.7	ppmvd @ 7% O_2
☒ O_2	1 hour block		
☒ Ammonia	24 hour block	20	ppmvd @ 7% O_2
☒ Unit Load	4 hour block		steam flow
☒ Baghouse inlet temp.	24 hour block		
☒ Pressure drop across bag house	24 hour block		inches water

The Permittee shall meet the performance and quality assurance specifications for the operation of CEM equipment pursuant to RCSA Section 22a-174-4.

(See Appendix A for General Requirements)

PART IV. MONITORING, RECORD KEEPING AND REPORTING REQUIREMENTS

A. Monitoring

1. The Permittee shall use a non-resettable totalizing fuel metering device to continuously monitor bio-diesel (B-100) fuel feed to this permitted source.

2. The Permittee shall comply with the monitoring requirements for sulfur dioxide (SO) emissions as required in 40 CFR 60.47b.

3. The Permittee shall comply with the monitoring requirements for particulate matter and nitrogen oxides (PM & NO) emissions as required in 40 CFR 60.48b.

FIRM NAME: Plainfield Renewable Energy LLC
EQUIPMENT LOCATION: Mill Brook Road, Plainfield, CT 06374
EQUIPMENT DESCRIPTION (MODEL, I.D. #): 37.5 MW (net) biomass fluidized bed gasification power plant

PERMIT FOR FUEL BURNING EQUIPMENT

STATE OF CONNECTICUT, DEPARTMENT OF ENVIRONMENTAL PROTECTION
BUREAU OF AIR MANAGEMENT

PART VI. ALLOWABLE EMISSION LIMITS, continued

Primary Fuel: Biomass

Criteria Pollutants	lb/hr	lbs/MMBtu	Enforceable limits for pollutants monitored by CEMS (ppmvd @7% O_2)[a]	tpy
PM-10 (filterable)[b]	10.46	0.021		45.8
PM-2.5 (filterable)[b]	10.46	0.021		45.8
PM-2.5 (condensable)[c]	8.89	0.017		39.0
PM-2.5 (total)[c]	19.35	0.037		84.8
SOx	18.56	0.035[a]	15.4	81.29
NOx	39.23	0.075[a]	45.3	171.84
VOC	6.07	0.012		26.59
CO	54.67	0.105[a]	103.7	239.47
Pb	0.07	0.00014		0.32
Other Pollutants				
Hydrogen Chloride (HCL)		0.00436		
Mercury		3.0E-6		
Ammonia			20	
Auxiliary Fuel: B100[d]				
PM-10	2.00			
SOx	0.17			
NOx	16.0			
VOC	0.27			
CO	4.0			

Note (a): Equivalent emission rate based on wood F-factor of 9,240 dscf/MMBtu. [40CFR Part 60, Appendix A, Table 19-2]

Note (b): Filterable particulate matter (PM-10 and PM-2.5) as measured by EPA Reference Method 5 or 17.

FIRM NAME: Plainfield Renewable Energy LLC
EQUIPMENT LOCATION: Mill Brook Road, Plainfield, CT 06374
EQUIPMENT DESCRIPTION (MODEL, I.D. #): 37.5 MW (net) biomass fluidized bed gasification power plant

PERMIT FOR FUEL BURNING EQUIPMENT

STATE OF CONNECTICUT, DEPARTMENT OF ENVIRONMENTAL PROTECTION BUREAU OF AIR MANAGEMENT

PART VI. ALLOWABLE EMISSION LIMITS, continued

Note (c): Condensable PM-2.5 and total PM-2.5, including condensables, are estimated based on EPA AP-42 emission factor for condensable PM from wood residue, Table 1.6-1, Fifth Edition, September 2003. Demonstration of compliance with PM-2.5 condensable emission limits shall be met by calculating the emission rates using the reference AP-42 emission factor.

Note (d): The use of B100 is not restricted to start-up operation. The B100 fuel can be fired in the auxiliary burners for initial/maintenance refractory curing and disposal beyond the typical 6-month shelf life.

At all times the Permittee shall comply with the requirements of Section 22a-174-29 of the RCSA, entitled "Hazardous Air Pollutants". The Permittee shall demonstrate compliance for each and every hazardous air pollutant emitted from this unit that is listed on Table 29-1, Table 29-2, or Table 29-3 of Section 22a-174-29 of the RCSA.

Hazardous Air Pollutant[3]	**MASC**[a] **($\mu g/m^3$)**	**Hazardous Air Pollutant**	**MASC ($\mu g/m^3$)**
Sulfuric Acid	3,656	Formaldehyde	2,193.6
Ammonia	65,808.7	Lead	548.4
Arsenic	9.1	Manganese	3,656
Beryllium	1.8	Mercury	182.8
Cadmium	73.1	2,3,7,8-TCDD equivalents[b]	1.3E-04
Chromium	457	Selenium	731
Nickel	54.85	Hydrogen Chloride (HCL)	[c, d]
Copper	3,656	Styrene	786,156[d]
Benzene	27,424[d]	Silver	36.57
Titanium	54,848	Zinc	18,282

Note a: Maximum allowable stack concentration calculated based on maximum design exhaust gas flow rate of 214,655 acfm. For compliance purposes, actual stack concentrations must be compared to MASC values calculated based on exhaust gas volumes from performance testing.

Note b: Dioxin emissions as defined in RCSA § 22a-174-1(29).

Note c: No HLV value exists for HCL, stack testing is still required to determine emission rate.

FIRM NAME: Plainfield Renewable Energy LLC
EQUIPMENT LOCATION: Mill Brook Road, Plainfield, CT 06374
EQUIPMENT DESCRIPTION (MODEL, I.D. #): 37.5 MW (net) biomass fluidized bed gasification power plant

PERMIT FOR FUEL BURNING EQUIPMENT

STATE OF CONNECTICUT, DEPARTMENT OF ENVIRONMENTAL PROTECTION
BUREAU OF AIR MANAGEMENT

PART VI. ALLOWABLE EMISSION LIMITS, continued

Note d: The allowable MASC for these pollutants will exceed 10 tpy for each pollutant. These pollutants shall not exceed actual stack concentrations (ASC) of 2,834 ug/m^3.

Demonstration of compliance with the above emission limits shall be met by calculating the emission rates using emission factors from the following sources:

1. Manufacturer supplied data.
2. Hazardous Air Pollutant Emission Factors from AP-42 Tables 1.6-3 and 1.6-4, dated 09/03.

The above statement shall not preclude the commissioner from requiring other means (e.g. stack testing) to demonstrate compliance with the above emission limits, as allowed by state or federal statute, law or regulation.

PART VII. STACK EMISSION TEST REQUIREMENTS (Applicable if -X- Checked)

Stack emission testing shall be required for the following pollutant(s):

☐ None at this time

☒ PM 10/PM 2.5 See Note (b) page 10/16 ☒ SOx ☒ NOx ☒ CO ☒ VOC ☒ Pb

☒ All hazardous air pollutants listed in Part VI of this permit. Compliance shall be determined by an annual performance test, either by fuel analysis and/or stack testing. Initial performance test shall require fuel sampling for all pollutants in listed in Part VI of this permit to compare the input concentrations to the stack emission rates for these pollutants.

☒ Initial Performance testing shall include the baseline operating parameters (i.e. flow rate, pressure drop, and temperature) of all control equipment listed in Appendix E of this permit.

NOTE: Stack testing shall be conducted at or above ninety percent (90%) of maximum rated capacity. If the source does not achieve ninety percent maximum rated capacity during the stack test, the Permittee shall apply for a minor modification of this permit to address the actual maximum rated capacity achieved in practice.

FIRM NAME: Plainfield Renewable Energy LLC
EQUIPMENT LOCATION: Mill Brook Road, Plainfield, CT 06374
EQUIPMENT DESCRIPTION (MODEL, I.D. #): 37.5 MW (net) biomass fluidized bed gasification power plant

Connecticut Department of Environmental Protection, Bureau of Air Management
PREMISES ANNUAL EMISSION SUMMARY AND FEE CALCULATION
Attachment D

Source Name	Plainfiel Renewable Energy LLC	Permit Engineer	James Grillo
Source Address	20 Marshall Street, Suite 30 Norwalk, CT 06854	Date	3/20/2007
		# of Permits/Applications	1
Equipment Location	Mll Brook Road Plainfield, CT 06374	Source Size	(●) Major ( ) Minor
Contact Person	Daniel J. Donovan	Permit Type	New Major Stationary Source or Major Modification
Title		Base Fee per Permit	$6,000

Description of Equipment: 37.5 MW Biomass Power Plant - Fluidized bed gasification

PAMS No.	EPE No.	Client	Sequence	Town	Premises	Permit	Stack	Date Rec'd
200602226	22281	8464	1	145	74	49	1	8/10/2007

Premises Annual Potential Emissions (TPY)

Pollutant	Existing Equipment	Minus Desourced Equipment	New Permit	New Premises Total
TSP	0	0	45.82	46.55
PM-10	0	0	84.8	84.8
SOx	0	0	81.29	81.29
NOx	0	0	171.84	174.25
VOC/HC	0	0	26.59	26.66
CO	0	0	239.47	240.02
Pb	0	0	0.32	0.32
HAP	0	0	30.38	30.38

Permit Fee Calculation per Section 22a-174-26

Additional Application Fees:*

	Quantity	
BACT Review Section 22a-174-26(b)(2)(A)	4	
LAER Review Section 22a-174-26(b)(2)(B)	1	
Total Additional Permit Fees ($1500 for each review above) *Shall not be subtracted from Total Permit Fee	5	$7,500
		CP/OP
Permit Fee:		$6,000
Municipality (If "Yes", Reduced by 50%)	☐ Yes	$6,000
Application Fee Submitted	☑ Yes	$750
Was App fee paid prior to 8/21/03??	☐ Yes	
Money Owed		**$12,750**

Comments: BACT review for total PM (including cond.), SOx, NOx, CO

EMERGENCY EPISODE STANDBY PLAN
Plainfield Renewable Energy LLC
Plainfield, Connecticut

Prepared For:

Plainfield Renewable Energy LLC

Prepared By:

M.I. Holzman & Associates, LLC

July 2006
Revised October 5, 2007

TABLE OF CONTENTS

FIGURE(S)

TABLE(S)

1. INTRODUCTION

Plainfield Renewable Energy LLC (PRE) is proposing to construct and operate a 37.5 MW (net) biomass energy facility at a site located on Mill Brook Road in Plainfield, CT. The primary emissions source at the proposed power plant will be a fluidized bed staged gasification (FBG) process producing a gas stream derived from biomass to generate steam to drive a conventional steam turbine generator. In addition to the inherently low emissions design of the FBG, proposed emissions controls will include selective non-catalytic reduction (SNCR) for control of nitrogen oxides (NO_X); a spray dryer scrubber for control of sulfur oxides (SO_X), acid gases and metals emissions; and a baghouse for particulate matter (PM) emissions control.

Regulations of Connecticut State Agencies (RCSA) § 22a-174-6 (Air Pollution Emergency Episode Procedures) require emissions sources with the potential to emit more than 100 tons per year (TPY) of uncontrolled criteria pollutant emissions to be prepared to implement a preplanned abatement strategy for reducing air pollutant emissions during each of three stages of an industrial air pollution emergency episode. Although it is believed that an industrial air pollution emergency episode has not occurred in Connecticut since the regulations were promulgated, sources are nevertheless required by regulation to prepare written standby plans to be implemented in the event of an actual air pollution episode. This plan fulfills that requirement, while at the same time recognizing that the proposed PRE facility will emit less air pollution on a per MW-hr basis than existing oil and coal-fired electricity generating plants in the state.

The remainder of this document contains the following sections:

2. Site Description
3. Facility Description
4. Emission Analysis
5. Abatement Procedures

2. SITE DESCRIPTION

The PRE project will be a 37.5 MW (net) biomass energy facility at a site located on Mill Brook Road in Plainfield, CT. The Project will be located on 29 acres of industrial-zoned land in Plainfield, bounded by Mill Brook Road and State Route 12. The proposed site was previously a Superfund location that has been fully cleaned and remediated. Figure 2-1, Site Location and Topographic Map, shows the location of the facility.

Figure 2-1 Site Location Map

3. FACILTY DESCRIPTION

The proposed PRE power plant will use an advanced fluidized bed staged gasification (FBG) process to produce a gas stream derived from biomass to generate steam to drive a conventional steam turbine generator. Fluidized bed staged gasification of solid fuels will result in inherently lower air pollutant emissions than alternative grate or spreader-stoker type combustion systems. In addition, the PRE facility will employ state-of-the-art air pollution control systems, including selective non-catalytic reduction (SNCR) for control of nitrogen oxides (NO_X); a spray dryer scrubber for control of sulfur oxides (SO_X), acid gases and metals emissions; and a fabric filter (baghouse) for particulate matter (PM) emissions control.

The facility will accept and gasify biomass fuels from a range of sources, including: forest management residues, landclearing debris and waste wood from municipalities and other industries. In addition, the facility will accept and gasify wood derived from the processing of construction and demolition (C&D) debris obtained from CTDEP-regulated offsite fuel processing facilities adhering to strict specifications (size, quality, etc.).

Other ancillary emissions sources at the PRE biomass energy facility will include a wet cooling tower and a stationary internal combustion engine used to power an emergency generator.

4. EMISSIONS ANALYSIS

As described in Section 3, PRE's proposed biomass fluidized bed staged gasification energy system is designed to produce low NO_x emissions. With the addition of SNCR, NO_x emissions will be further controlled to 0.075 lb/MMBtu. Additional controls for SO_X and particulate control will include a spray dryer scrubber and baghouse. The use of these control technologies has been proposed to meet LAER (for NO_X) and BACT for all regulated criteria pollutants.

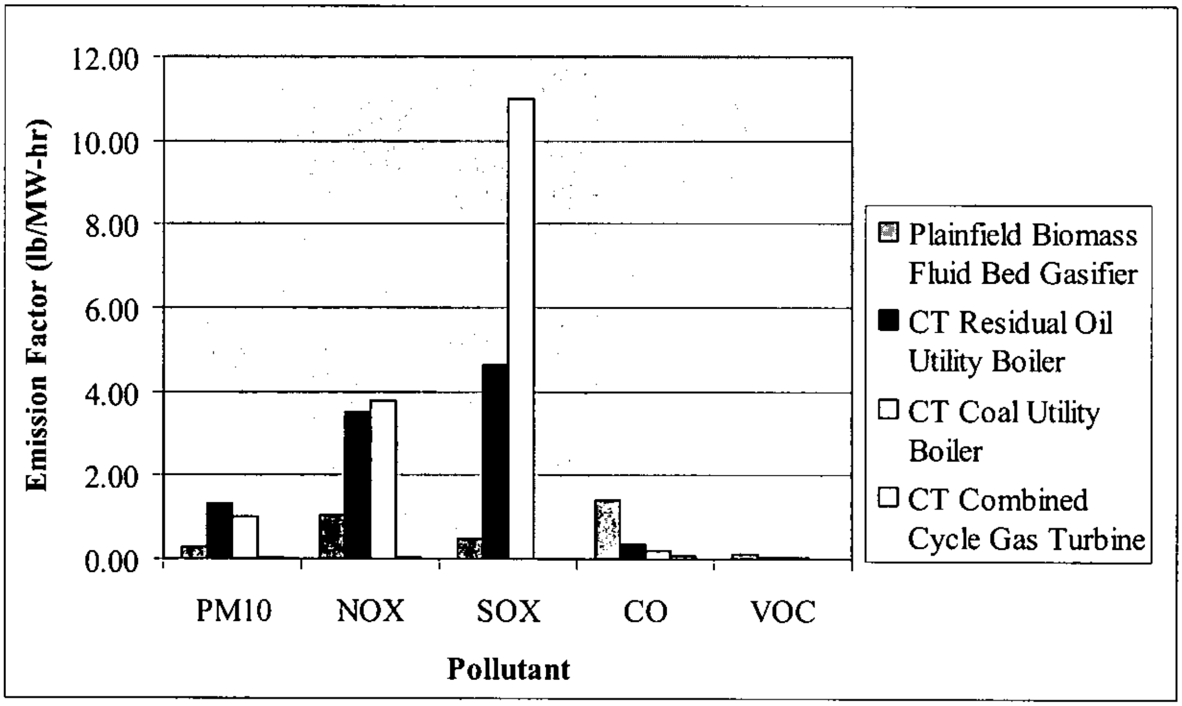
Emissions factors from the proposed PRE project are compared in Table 4-1 on a lb/MW-hr basis to those from fossil fuel fired power plants in Connecticut. The fossil fuel emission factors were derived from the average of several power plant permit limits for each fuel type. The comparison is also made graphically in Figure 4-1. Comparison of the normalized emission factors demonstrates that continued operation of the PRE project during air pollution episodes in preference to oil and coal fired power plants in Connecticut would result in a significant reduction in particulate, NO_X and SO_X emissions. This result was considered in developing the proposed Emergency Episode Standby Plan for PRE.

Table 4-1 Comparison of Plainfield Renewable Energy to CT Fossil Fuel Power Plants

(Emission Factors in lb/MW-hr)

Pollutant	Plainfield Biomass Fluid Bed Gasifier	Typical CT Residual Oil Utility Boiler	Typical CT Coal Utility Boiler	Typical CT Combined Cycle Gas Turbine
PM10	0.28	1.33	1.00	0.04
NOX	1.05	3.51	3.80	0.03
SOX	0.49	4.63	11.00	0.01
CO	1.40	0.35	0.20	0.09
VOC	0.14	0.06	0.05	0.01

Figure 4-1 Comparison of Plainfield Renewable Energy to CT Fossil Fuel Power Plants



5. ABATEMENT PROCEDURES

The Connecticut regulations for the Abatement of Air Pollution (RCSA § 22a-174-6) outline the pollution abatement steps to be taken during each stage of an air pollution episode. The proposed procedures to be followed at the PRE facility during each stage are described below. As mentioned previously, the state-of-the-art biomass gasification power plant with extensive NO_x, SO_X and PM control will emit less air pollution on a normalized lb/MW-hr basis than the oil and coal fired power plants in Connecticut. PRE's capacity should therefore be reduced only after higher pollutant emitters lower their capacity.

5.1. Industrial Alert

PRE will agree to limit operation to 90 percent of capacity in the unlikely event of an industrial alert (if still called upon by ISO-NE and/or CL&P). PRE will also agree not to perform any boiler lancing or soot blowing between the hours of 12 noon and 4 p.m. during an industrial alert.

5.2. Industrial Warning

In the unlikely event of an industrial warning, PRE will limit boiler operations/generating capacity to 75 percent of maximum capacity (if still called upon by ISO-NE and/or CL&P). PRE will also agree not to perform any boiler lancing or soot blowing between the hours of 12 noon and 4 p.m. and to terminate nonessential operation of motor vehicles during an industrial warning.

5.3. Industrial Emergency

In the extremely unlikely event of an industrial emergency, PRE will discontinue all boiler operations and generating capacity at the facility (if still called upon by ISO-NE and/or CL&P) by initiating normal shutdown procedures. PRE will also agree not to perform any boiler lancing or soot blowing between the hours of 12 noon and 4 p.m. and to terminate nonessential operation of motor vehicles during an industrial emergency.

Grillo, James

From: Milardo, Teraesa
Sent: Monday, October 29, 2007 11:22 AM
To: Grillo, James
Cc: Sinclair, Jaimeson
Subject: RE: Compliance History - Plainfield Renewable Energy LLC

-----Original Message-----
From: Grillo, James
Sent: Wednesday, October 24, 2007 8:05 AM
To: Sinclair, Jaimeson
Subject: Compliance History - Plainfield Renewable Energy LLC

Hi Jim,

The Air Bureau has no open or pending enforcement actions (and no enforcement actions have been taken with in the past 5 years) against this facility.

Jaimeson,

I need the compliance history for the above company.

The address is:

20 Marshall Street, Suite 300
Norwalk, CT 06854

Premises Address:
Mill Brook Road
Plainfield, CT

Client	8464
Seq.	1
Twn	145
Prem	74

Thanks,

Jim

APPENDIX A

Sec. 22a-174-4. Source monitoring, record keeping and reporting.

(a) Definitions. For the purposes of this section:

(1) "Calendar quarter" means a consecutive three (3) month period (nonoverlapping) beginning on January 1, April 1, July 1 or October 1.

(2) "Coal burning equipment" means fuel burning equipment that combusts coal.

(3) "Gaseous, liquid or solid fuel burning equipment" means fuel burning equipment that combusts gaseous, liquid or solid fuels.

(4) "Standby fuel burning equipment" means fuel burning equipment that is used only to provide backup heat or power.

(b) Opacity continuous emissions monitoring (CEM).

(1) Except as provided in subdivisions (2) and (3) of this subsection, the owner or operator of the stationary sources listed in subparagraphs (A) through (D) of this subdivision shall install opacity CEM equipment. The owner or operator shall operate and maintain installed opacity CEM equipment in accordance with subsections (c)(3) and (c)(4) of this section and retain the data generated in accordance with subsection (d) of this section:

(A) Any coal burning equipment;

(B) Any liquid or solid fuel burning equipment with a maximum rated heat input greater than or equal to two hundred fifty million Btu per hour (250,000,000 Btu/hr);

(C) Any incinerator with a maximum rated input in excess of two thousand pounds per hour (2,000 lbs/hr); and

(D) Any process source with particulate matter emissions exceeding twenty-five pounds per hour (25 lbs/hr) after the application of control equipment, when operated at maximum rated capacity.

(2) The provisions of subdivision (1)(A) of this subsection, concerning coal burning equipment, shall not apply to:

(A) Any space heater installed in any single family home on or before May 1, 1975, provided that such space heater does not combust coal with a sulfur content greater than or equal to three-quarters of one percent (0.75%) by weight (dry basis);

(B) Any coal burning equipment in a commercial establishment in regular operation on or before May 1, 1975, provided that such coal burning equipment does not combust coal with a sulfur content greater than or equal to three-quarters of one percent (0.75%) by weight (dry basis) and coal consumption is less than seventy-five (75) tons per year; and

(C) Any coal burning equipment used primarily for educational or historical demonstrations or exhibits, provided that such coal burning equipment does not combust coal with a sulfur content exceeding one and one-half (1.5%) by weight (dry basis). Such coal burning equipment includes, but is not limited to, blacksmiths' forges, steam locomotives, and steamboats

(3) The provisions of subdivision (1)(B) of this subsection, concerning gaseous, liquid or solid fuel burning equipment, shall not apply to:

(A) Any standby fuel burning equipment operating less than one hundred sixty-eight (168) hours in a calendar year. For the purpose of this subparagraph, the term "operating" shall not include emissions testing or operating only to maintain reliability in emergency situations; and

(B) Turbines combusting natural gas, liquid fuel or a mixture of liquid fuel and natural gas that comply with the applicable particulate matter and opacity limitations set forth in section 22a-174-18 of the Regulations of Connecticut State Agencies without utilizing pollution control equipment.

(4) The Commissioner may, in writing, request written documentation from the owner or operator of equipment listed in subdivisions (2) or (3) of this subsection to ascertain the applicability of subdivisions (2) or (3) of this subsection. An owner or operator shall deliver such documentation to the commissioner within thirty (30) days of receipt of such a written request.

(5) An owner or operator that claims subsection (b)(1) of this section is not applicable by virtue of compliance with subsection (b)(2) or (b)(3) of this section shall, upon notice from the commissioner, install, operate and maintain opacity CEM equipment according to this section, and comply with subsections (c) and (d) of this section, if the commissioner finds:

(A) Repeated noncompliance with section 22a-174-18 of the Regulations of Connecticut State Agencies has occurred;

(B) Noncompliance with the requirements, limitations or restrictions set forth in subdivisions (2) or (3) of this subsection has occurred;

(C) Operation of the subject source has interfered with or is likely to interfere with the attainment or maintenance of ambient air quality standards, create a health hazard or create a nuisance; or

(D) Monitoring equipment is technically feasible, economically feasible and needed to determine compliance with chapter 446c of the Connecticut General Statutes and regulations promulgated thereunder.

(6) The notice provided for in subsection (b)(5) of this section shall be in the form of a permit or order and shall specify requirements for opacity CEM equipment installation and operation including a day by which such installation and operation is to commence.

(c) General opacity and gaseous CEM equipment operation and performance.

(1) If, for a source of air pollution, the commissioner determines that opacity or gaseous CEM equipment is reasonably available, technically feasible, economically feasible and necessary for the commissioner to obtain opacity or emissions data to evaluate compliance with chapter 446c of the Connecticut General Statutes and regulations promulgated thereunder, the commissioner may require, by written notice to the owner or operator of such source, the installation and operation of CEM equipment. Such written notice shall be in the form of a regulation, permit or order and shall include requirements for installation and operation including a day by which such installation and operation is to commence.

(2) If the commissioner determines that CEM equipment is not reasonably available for a source of air pollution, the commissioner may, by written notice, require the owner or operator of such source to comply with an alternative monitoring technique or conduct intermittent stack testing to verify the source is in compliance the chapter 446c of the Connecticut General Statutes and regulation promulgated thereunder. Such written notice shall be in the form of a regulation, permit or order and shall include the requirements for such alternative monitoring or testing including a day by which such alternative monitoring or testing is to commence.

(3) Monitoring plan. Unless otherwise specified by permit or order of the commissioner, the owner or operator of any source for which construction commenced on or after the effective date of this amendment to this section who is required to install, operate and maintain opacity CEM equipment pursuant to subsection (b) of this section or gaseous or opacity CEM equipment pursuant to subdivision (1) of this subsection shall submit to the commissioner for approval, at least sixty (60) days before the initiation of the performance specification testing required by subdivision (4) of this subsection, a monitoring plan containing the information specified in subparagraphs (A) through (D) of this subdivision:

(A) A brief description of the source, including, but not limited to, type of unit or process, type of fuel combusted, type or types of emission control devices, and operation parameters;

APPENDIX A, continued

(B) A description of the monitoring equipment design, proposed monitor location and sampling site location. This description should include, but is not limited to, facility schematics and engineering drawings of the monitoring and sample probe locations, data acquisition system specifications, analytical monitoring technique and sampling system design;

(C) An explanation of the performance specification testing to be conducted by the owner or operator as required by subdivision (4) of this subsection; and

(D) A quality assurance plan including procedures for calibration, calibration drift determination and adjustment, preventative maintenance, data recording, calculation, audits and corrective action for monitoring system breakdowns.

(4) Performance specifications and quality assurance requirements. The owner or operator of any source required to install, operate and maintain CEM equipment pursuant to this section shall meet the following performance specifications and quality assurance requirements:

(A) The applicable performance specifications and quality assurance requirements of 40 CFR 60 Appendices B and F, unless the source is subject to 40 CFR 75, in which case the owner or operator shall meet the applicable performance specifications and quality assurance requirements of 40 CFR 75;

(B) For opacity CEM equipment, the following quality assurance requirements:

(i) Calibration shall be adjusted whenever the daily zero or upscale calibration exceeds plus/minus two percent (± 2%) opacity;

(ii) Data shall be invalid for calculating data availability in accordance with subdivision (5) of this subsection if the zero or upscale calibration value exceeds either the reference zero or the upscale calibration value recorded during the most recent clear-path calibration by plus/minus two percent (± 2%) opacity for five (5) consecutive days or plus/minus five percent (± 5%) opacity on any single day. The period of invalid data begins with either the fifth consecutive occurrence of a drift value exceeding plus/minus two percent (± 2%) opacity or with the last daily check preceding the single occurrence of a drift value exceeding plus/minus five percent (± 5%) opacity. The period of invalid data shall end when a calibration drift check, conducted after corrective action, demonstrates that reliable monitoring data is being generated,

(iii) Quality assurance audits shall be conducted during each calendar quarter in which the source operates,

(iv) The commissioner shall be notified, in writing, no fewer than thirty (30) days prior to the initially proposed quality assurance audit, and

(v) Quality assurance audits shall be conducted in accordance with the procedures contained in "Performance Audit Procedures for Opacity Monitors," EPA Document No. 450/4-92/010, dated April 1992. If EPA promulgates quality assurance procedures in 40 CFR 60, Appendix F, quality assurance audits shall be conducted according to such procedures. If either EPA Document No. 450/4-92/010 or subsequently promulgated procedures in 40 CFR 60, Appendix F, as applicable, does not contain audit procedures for the opacity CEM selected by the owner or operator, the owner or operator shall, in writing, propose audit procedures to the commissioner for review and written approval at least thirty (30) days prior to the initial opacity CEM audit; and

(C) If the results of a quality assurance audit fail to conform to the quality assurance requirements of subparagraph (B) of this subdivision, such opacity CEM data shall be deemed invalid by the commissioner, and the owner or operator will be deemed to have failed the quality assurance audit. Data collected after any failed quality assurance audit shall be invalid for calculating percent data availability in accordance with subdivision (5)(A) of this subsection.

(5) Data availability.

(A) The owner or operator of any source required to install, operate and maintain CEM equipment in accordance with this section shall meet the following data availability requirements on an emission limitation-specific basis:

(i) While the source is operating, the owner or operator shall operate required CEM equipment pursuant to section 22a-174-7(b) of the Regulations of Connecticut State Agencies, and allowable periods of missing data shall apply only to periods of deliberate shutdown allowed by section 22a-174-7(b) of the Regulations of Connecticut State Agencies, unavoidable system malfunction or as otherwise provided under this subdivision,

(ii) Except as provided in subparagraphs (B) and (C) of this subdivision, for opacity emissions, data shall be available for no less than ninety-five (95%) of the total operating hours of the source in any calendar quarter,

(iii) Except as provided in subparagraphs (B) and (C) of this subdivision, for air pollutant emissions other than opacity, data shall be available for no less than ninety percent (90%) of the total operating hours of the source in any calendar quarter, and

(iv) Percent data availability shall be calculated using the following equation:

$$\% \text{ Data Availability} = \left(\frac{\text{Unit Operating Time} - \text{Monitoring Downtime}}{\text{Unit Operating Time}}\right) * 100$$

where:

Unit operating time = total hours of source operation at any level during the calendar quarter.

Monitoring downtime = total hours of source operation at any level during the calendar quarter where either no CEM equipment data was collected or the CEM equipment data was invalid. Such periods include, but are not limited to, quality assurance activities such as calibration, preventative maintenance, and calibration drift exceedances or quality assurance audits that result in invalid data.

(B) The commissioner, in writing, may exempt the owner or operator of a source from the minimum data availability requirements of subparagraphs (A)(ii) and (A)(iv) of this subdivision if such source is equipped with properly operating opacity CEM equipment, and the source is operated less than or equal to five hundred four (504) hours in the calendar quarter.

(C) The commissioner, in writing, may exempt the owner or operator of a source from the minimum data availability requirements of subparagraphs (A)(iii) and (A)(iv) of this subdivision if such source is equipped with properly operating gaseous CEM equipment, and the source is operated less than or equal to three hundred thirty-six (336) hours in the calendar quarter.

(D) To obtain an exemption under subparagraphs (B) or (C) of this subdivision, the owner or operator of the source shall submit the following information to the commissioner within thirty (30) days following the last day of the calendar quarter for which the exemption is sought:

(i) A request for an exemption for a specified calendar quarter,

(ii) The actual operating hours of the source during the calendar quarter,

(iii) The duration of and nature of the CEM equipment breakdowns, repairs or adjustments made during the calendar quarter, and

(iv) The actual data availability achieved during the calendar quarter.

APPENDIX A, continued

(d) Record keeping and reporting.

(1) The commissioner may, by written notice, require the owner or operator of any source to create, maintain and submit data, records or reports of monitoring data and other information deemed necessary by the commissioner to evaluate compliance with chapter 446c of the Connecticut General Statutes and regulations promulgated thereunder. Such information shall be recorded, complied and submitted on forms furnished or prescribed by the commissioner. The written notice shall provide the data by which such data, records or reports shall be submitted to the commissioner.

(2) Any document, data, plan, record or report required to be submitted to the commissioner by this section shall include a certification signed by a responsible corporate officer or a duly authorized representative of such officer, as those terms are defined in subdivision (2) of subsection (b) of section 22a-430-3 of the Regulations of Connecticut State Agencies, and by the individual or individuals responsible for actually preparing such document, each of whom shall examine and be familiar with the information submitted in the document and all attachments there, and shall make inquiry of those individuals responsible for obtaining the information to determine that the information is true, accurate and complete, and each of whom shall certify in writing as follows:

> "I have personally examined and an familiar with the information submitted in this document and all attachments thereto, and I certify that based on reasonable investigation, including my inquiry of those individuals responsible for obtaining the information, the submitted information is true, accurate and complete to the best of my knowledge and belief. I understand that any false statement made in the submitted information may be punishable as a criminal offense under section 22a-175 of the Connecticut General Statutes or, in accordance with section 22a-6 of the Connecticut General Statutes, under section 53a-157b of the Connecticut General Statutes, and in accordance with any other applicable statute."

(3) The owner or operator of any source subject to the provisions of chapter 446c of the Connecticut General Statutes and regulated adopted thereunder shall maintain all data, document and reports required by this section in a legible and comprehensible form for at least five (5) years from the data such data, document or report is created.

(4) Each calendar quarter, the owner or operator of any opacity CEM equipment required pursuant to this section shall submit the following information to the commissioner:

(A) The data obtained through such equipment during the preceding calendar quarter that is required to determine compliance with an emission limitation or standard;

(B) A summary of such data;

(C) A copy of the quality assurance audit conducted for that calendar quarter; and

(D) A summary of all corrective actions taken in response to a failed CEM equipment audit.

(5) Submissions made to comply with subdivision (4) of this subsection shall be made no later than thirty (30) days following the end of each calendar quarter.

(e) The commissioner may exempt an owner or operator of a source subject to this section from the requirements of this section as they apply to a particular air pollutant if such owner or operator demonstrates in writing, for the commissioner's written approval, that such source is physically incapable of violating any applicable requirement for such air pollutant set forth in chapter 446c of the Connecticut General Statutes and regulations promulgated thereunder.

(f) Upon written notice in the form of a permit or order to an owner or operator of a source granted an exemption under subsection (e) of this section, such owner or operator shall install, operate and maintain CEM equipment in accordance with such notice if:

(1) The commissioner determines there is repeated noncompliance with section 22a-174-18 of the Regulations of Connecticut State Agencies;

(2) Operation of the subject source has interfered with or is likely to interfere with the attainment or maintenance of ambient air quality standards, create a health hazard or create a nuisance; or

(3) The source has been altered or the operations of the source have changed such that subsection (e) of this section is no longer applicable.

Appendix B: SOURCE STACK TESTING GENERAL REQUIREMENTS

The owner/operator shall conduct stack testing within 60 days of achieving the maximum production rate, but not later than 180 days after initial start up.

Pursuant to the Regulations of Connecticut State Agencies, the owner/operator of this facility shall submit an Intent-to-Test (ITT) package consisting of an ITT form (Form AE404) and a test protocol. The test protocol shall be consistent with the Bureau's Emission Source Test Guideline specifying the test methodology to be followed and the conditions under which the process and its control equipment will be operated. The process shall be operated at a minimum of 90% of the permitted maximum rated capacity and the control equipment shall be operated as specified in this permit.

All proposed test methods shall comply with appropriate Federal test methods or methods acceptable to the Bureau. The ITT package must demonstrate compliance with applicable requirements of the Code of Federal Regulations (CFR) Title 40 Parts 51, 60 and 61. Any proposed test methods that deviate from those specified in these regulations must be approved by the Bureau prior to stack testing. All sampling ports shall be installed and located in compliance with 40 CFR Part 60 Appendix A, Method 1. Final plans showing the location of all sampling ports shall be submitted with the ITT package to the Air Bureau's Stack Test Group for approval prior to stack testing. Please submit an original and one copy of the ITT package to: Bureau of Air Management, Compliance & Field Operations, Stack Test Group, 79 Elm Street, 5th Floor, Hartford, Connecticut 06106-5127.

An inspection of the source may be conducted to verify that appropriate instrumentation is available, and to determine the source process parameters, indicative of compliant operation, to be monitored during stack testing. Once the ITT package is approved, the owner/operator shall be notified, in writing, by the Bureau's Stack Test Group.

The source test must be scheduled, monitored by Bureau personnel, and completed within 60 days from the date of Bureau approval of the proposed ITT package. It is the source's responsibility to conduct preparatory testing for tuning or debugging purposes prior to the Bureau-monitored stack testing. An acceptable test report must be submitted to the Bureau within 45 days of the completion of emissions testing. The owner/operator shall respond to any test report deficiency within 15 days of notification by the Bureau.

Acceptable test results will be incorporated into the final permit to construct and operate. In the event that the stack test report is unacceptable, or the tested values show that the source is not in compliance with applicable permit conditions or regulations, a final permit to construct and operate will be not be issued until the owner/operator responds to and corrects any deficiencies. The Bureau may issue an Administrative Order if there is a likelihood that the source may demonstrate compliance through a process modification and a retest.

subpart A to the Administrator semiannually for each six-month period. All semiannual reports shall be postmarked by the 30th day following the end of each six-month period.

(k) The owner or operator of an affected facility may submit electronic quarterly reports for SO_2 and/or NO_X and/or opacity and/or Hg in lieu of submitting the written reports required under paragraphs (b), (g), and (i) of this section. The format of each quarterly electronic report shall be coordinated with the permitting authority. The electronic report(s) shall be submitted no later than 30 days after the end of the calendar quarter and shall be accompanied by a certification statement from the owner or operator, indicating whether compliance with the applicable emission standards and minimum data requirements of this subpart was achieved during the reporting period. Before submitting reports in the electronic format, the owner or operator shall coordinate with the permitting authority to obtain their agreement to submit reports in this alternative format.

§ 60.52Da Recordkeeping requirements.

The owner or operator of an affected facility subject to the emissions limitations in § 60.45Da shall provide notifications in accordance with § 60.7(a) and shall maintain records of all information needed to demonstrate compliance including performance tests, monitoring data, fuel analyses, and calculations, consistent with the requirements of § 60.7(f).

Subpart Db—Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units

SOURCE: 72 FR 32742, June 13, 2007, unless otherwise noted.

§ 60.40b Applicability and delegation of authority.

(a) The affected facility to which this subpart applies is each steam generating unit that commences construction, modification, or reconstruction after June 19, 1984, and that has a heat input capacity from fuels combusted in the steam generating unit of greater than 29 megawatts (MW) (100 million British thermal units per hour (MMBtu/hr)).

(b) Any affected facility meeting the applicability requirements under paragraph (a) of this section and commencing construction, modification, or reconstruction after June 19, 1984, but on or before June 19, 1986, is subject to the following standards:

(1) Coal-fired affected facilities having a heat input capacity between 29 and 73 MW (100 and 250 MMBtu/hr), inclusive, are subject to the particulate matter (PM) and nitrogen oxides (NO_X) standards under this subpart.

(2) Coal-fired affected facilities having a heat input capacity greater than 73 MW (250 MMBtu/hr) and meeting the applicability requirements under subpart D (Standards of performance for fossil-fuel-fired steam generators; § 60.40) are subject to the PM and NO_X standards under this subpart and to the sulfur dioxide (SO_2) standards under subpart D (§ 60.43).

(3) Oil-fired affected facilities having a heat input capacity between 29 and 73 MW (100 and 250 MMBtu/hr), inclusive, are subject to the NO_X standards under this subpart.

(4) Oil-fired affected facilities having a heat input capacity greater than 73 MW (250 MMBtu/hr) and meeting the applicability requirements under subpart D (Standards of performance for fossil-fuel-fired steam generators; § 60.40) are also subject to the NO_X standards under this subpart and the PM and SO_2 standards under subpart D (§ 60.42 and § 60.43).

(c) Affected facilities that also meet the applicability requirements under subpart J (Standards of performance for petroleum refineries; § 60.104) are subject to the PM and NO_X standards under this subpart and the SO_2 standards under subpart J (§ 60.104).

(d) Affected facilities that also meet the applicability requirements under subpart E (Standards of performance for incinerators; § 60.50) are subject to the NO_X and PM standards under this subpart.

(e) Steam generating units meeting the applicability requirements under subpart Da (Standards of performance for electric utility steam generating units; §60.40Da) are not subject to this subpart.

(f) Any change to an existing steam generating unit for the sole purpose of combusting gases containing total reduced sulfur (TRS) as defined under §60.281 is not considered a modification under §60.14 and the steam generating unit is not subject to this subpart.

(g) In delegating implementation and enforcement authority to a State under section 111(c) of the Clean Air Act, the following authorities shall be retained by the Administrator and not transferred to a State.

(1) Section 60.44b(f).

(2) Section 60.44b(g).

(3) Section 60.49b(a)(4).

(h) Any affected facility that meets the applicability requirements and is subject to subpart Ea, subpart Eb, or subpart AAAA of this part is not covered by this subpart.

(i) Heat recovery steam generators that are associated with combined cycle gas turbines and that meet the applicability requirements of subpart GG or KKKK of this part are not subject to this subpart. This subpart will continue to apply to all other heat recovery steam generators that are capable of combusting more than 29 MW (100 MMBtu/hr) heat input of fossil fuel. If the heat recovery steam generator is subject to this subpart, only emissions resulting from combustion of fuels in the steam generating unit are subject to this subpart. (The gas turbine emissions are subject to subpart GG or KKKK, as applicable, of this part.)

(j) Any affected facility meeting the applicability requirements under paragraph (a) of this section and commencing construction, modification, or reconstruction after June 19, 1986 is not subject to subpart D (Standards of Performance for Fossil-Fuel-Fired Steam Generators, §60.40).

(k) Any affected facility that meets the applicability requirements and is subject to an EPA approved State or Federal section 111(d)/129 plan implementing subpart Cb or subpart BBBB of this part is not covered by this subpart.

§60.41b Definitions.

As used in this subpart, all terms not defined herein shall have the meaning given them in the Clean Air Act and in subpart A of this part.

Annual capacity factor means the ratio between the actual heat input to a steam generating unit from the fuels listed in §60.42b(a), §60.43b(a), or §60.44b(a), as applicable, during a calendar year and the potential heat input to the steam generating unit had it been operated for 8,760 hours during a calendar year at the maximum steady state design heat input capacity. In the case of steam generating units that are rented or leased, the actual heat input shall be determined based on the combined heat input from all operations of the affected facility in a calendar year.

Byproduct/waste means any liquid or gaseous substance produced at chemical manufacturing plants, petroleum refineries, or pulp and paper mills (except natural gas, distillate oil, or residual oil) and combusted in a steam generating unit for heat recovery or for disposal. Gaseous substances with carbon dioxide (CO_2) levels greater than 50 percent or carbon monoxide levels greater than 10 percent are not byproduct/waste for the purpose of this subpart.

Chemical manufacturing plants mean industrial plants that are classified by the Department of Commerce under Standard Industrial Classification (SIC) Code 28.

Coal means all solid fuels classified as anthracite, bituminous, subbituminous, or lignite by the American Society of Testing and Materials in ASTM D388 (incorporated by reference, see §60.17), coal refuse, and petroleum coke. Coal-derived synthetic fuels, including but not limited to solvent refined coal, gasified coal, coal-oil mixtures, coke oven gas, and coal-water mixtures, are also included in this definition for the purposes of this subpart.

Coal refuse means any byproduct of coal mining or coal cleaning operations with an ash content greater than 50 percent, by weight, and a heating value less than 13,900 kJ/kg (6,000 Btu/lb) on a dry basis.

Cogeneration, also known as combined heat and power, means a facility that simultaneously produces both electric (or mechanical) and useful thermal energy from the same primary energy source.

Coke oven gas means the volatile constituents generated in the gaseous exhaust during the carbonization of bituminous coal to form coke.

Combined cycle system means a system in which a separate source, such as a gas turbine, internal combustion engine, kiln, etc., provides exhaust gas to a steam generating unit.

Conventional technology means wet flue gas desulfurization (FGD) technology, dry FGD technology, atmospheric fluidized bed combustion technology, and oil hydrodesulfurization technology.

Distillate oil means fuel oils that contain 0.05 weight percent nitrogen or less and comply with the specifications for fuel oil numbers 1 and 2, as defined by the American Society of Testing and Materials in ASTM D396 (incorporated by reference, see § 60.17).

Dry flue gas desulfurization technology means a SO_2 control system that is located downstream of the steam generating unit and removes sulfur oxides from the combustion gases of the steam generating unit by contacting the combustion gases with an alkaline reagent and water, whether introduced separately or as a premixed slurry or solution and forming a dry powder material. This definition includes devices where the dry powder material is subsequently converted to another form. Alkaline slurries or solutions used in dry flue gas desulfurization technology include but are not limited to lime and sodium.

Duct burner means a device that combusts fuel and that is placed in the exhaust duct from another source, such as a stationary gas turbine, internal combustion engine, kiln, etc., to allow the firing of additional fuel to heat the exhaust gases before the exhaust gases enter a steam generating unit.

Emerging technology means any SO_2 control system that is not defined as a conventional technology under this section, and for which the owner or operator of the facility has applied to the Administrator and received approval to operate as an emerging technology under § 60.49b(a)(4).

Federally enforceable means all limitations and conditions that are enforceable by the Administrator, including the requirements of 40 CFR parts 60 and 61, requirements within any applicable State Implementation Plan, and any permit requirements established under 40 CFR 52.21 or under 40 CFR 51.18 and 51.24.

Fluidized bed combustion technology means combustion of fuel in a bed or series of beds (including but not limited to bubbling bed units and circulating bed units) of limestone aggregate (or other sorbent materials) in which these materials are forced upward by the flow of combustion air and the gaseous products of combustion.

Fuel pretreatment means a process that removes a portion of the sulfur in a fuel before combustion of the fuel in a steam generating unit.

Full capacity means operation of the steam generating unit at 90 percent or more of the maximum steady-state design heat input capacity.

Gaseous fuel means any fuel that is present as a gas at ISO conditions.

Gross output means the gross useful work performed by the steam generated. For units generating only electricity, the gross useful work performed is the gross electrical output from the turbine/generator set. For cogeneration units, the gross useful work performed is the gross electrical or mechanical output plus 75 percent of the useful thermal output measured relative to ISO conditions that is not used to generate additional electrical or mechanical output (i.e., steam delivered to an industrial process).

Heat input means heat derived from combustion of fuel in a steam generating unit and does not include the heat derived from preheated combustion air, recirculated flue gases, or exhaust gases from other sources, such as gas turbines, internal combustion engines, kilns, etc.

Heat release rate means the steam generating unit design heat input capacity (in MW or Btu/hr) divided by the furnace volume (in cubic meters or cubic feet); the furnace volume is that volume bounded by the front furnace wall where the burner is located, the furnace side waterwall, and extending to the level just below or in front of the first row of convection pass tubes.

Heat transfer medium means any material that is used to transfer heat from one point to another point.

High heat release rate means a heat release rate greater than 730,000 J/sec-m^3 (70,000 Btu/hr-ft^3).

ISO Conditions means a temperature of 288 Kelvin, a relative humidity of 60 percent, and a pressure of 101.3 kilopascals.

Lignite means a type of coal classified as lignite A or lignite B by the American Society of Testing and Materials in ASTM D388 (incorporated by reference, see §60.17).

Low heat release rate means a heat release rate of 730,000 J/sec-m^3 (70,000 Btu/hr-ft^3) or less.

Mass-feed stoker steam generating unit means a steam generating unit where solid fuel is introduced directly into a retort or is fed directly onto a grate where it is combusted.

Maximum heat input capacity means the ability of a steam generating unit to combust a stated maximum amount of fuel on a steady state basis, as determined by the physical design and characteristics of the steam generating unit.

Municipal-type solid waste means refuse, more than 50 percent of which is waste consisting of a mixture of paper, wood, yard wastes, food wastes, plastics, leather, rubber, and other combustible materials, and noncombustible materials such as glass and rock.

Natural gas means: (1) A naturally occurring mixture of hydrocarbon and nonhydrocarbon gases found in geologic formations beneath the earth's surface, of which the principal constituent is methane; or (2) liquefied petroleum gas, as defined by the American Society for Testing and Materials in ASTM D1835 (incorporated by reference, see §60.17).

Noncontinental area means the State of Hawaii, the Virgin Islands, Guam, American Samoa, the Commonwealth of Puerto Rico, or the Northern Mariana Islands.

Oil means crude oil or petroleum or a liquid fuel derived from crude oil or petroleum, including distillate and residual oil.

Petroleum refinery means industrial plants as classified by the Department of Commerce under Standard Industrial Classification (SIC) Code 29.

Potential sulfur dioxide emission rate means the theoretical SO_2 emissions (nanograms per joule (ng/J) or lb/MMBtu heat input) that would result from combusting fuel in an uncleaned state and without using emission control systems.

Process heater means a device that is primarily used to heat a material to initiate or promote a chemical reaction in which the material participates as a reactant or catalyst.

Pulp and paper mills means industrial plants that are classified by the Department of Commerce under North American Industry Classification System (NAICS) Code 322 or Standard Industrial Classification (SIC) Code 26.

Pulverized coal-fired steam generating unit means a steam generating unit in which pulverized coal is introduced into an air stream that carries the coal to the combustion chamber of the steam generating unit where it is fired in suspension. This includes both conventional pulverized coal-fired and micropulverized coal-fired steam generating units. Residual oil means crude oil, fuel oil numbers 1 and 2 that have a nitrogen content greater than 0.05 weight percent, and all fuel oil numbers 4, 5 and 6, as defined by the American Society of Testing and Materials in ASTM D396 (incorporated by reference, see §60.17).

Spreader stoker steam generating unit means a steam generating unit in which solid fuel is introduced to the combustion zone by a mechanism that throws the fuel onto a grate from above. Combustion takes place both in suspension and on the grate.

Steam generating unit means a device that combusts any fuel or byproduct/waste and produces steam or heats water or any other heat transfer medium. This term includes any municipal-type solid waste incinerator with a heat recovery steam generating unit or any steam generating unit that combusts fuel and is part of a cogeneration system or a combined cycle system. This term does not include process heaters as they are defined in this subpart.

Steam generating unit operating day means a 24-hour period between 12:00 midnight and the following midnight during which any fuel is combusted at any time in the steam generating unit. It is not necessary for fuel to be combusted continuously for the entire 24-hour period.

Very low sulfur oil means for units constructed, reconstructed, or modified on or before February 28, 2005, an oil that contains no more than 0.5 weight percent sulfur or that, when combusted without SO_2 emission control, has a SO_2 emission rate equal to or less than 215 ng/J (0.5 lb/MMBtu) heat input. For units constructed, reconstructed, or modified after February 28, 2005, *very low sulfur oil* means an oil that contains no more than 0.3 weight percent sulfur or that, when combusted without SO_2 emission control, has a SO_2 emission rate equal to or less than 140 ng/J (0.32 lb/MMBtu) heat input.

Wet flue gas desulfurization technology means a SO_2 control system that is located downstream of the steam generating unit and removes sulfur oxides from the combustion gases of the steam generating unit by contacting the combustion gas with an alkaline slurry or solution and forming a liquid material. This definition applies to devices where the aqueous liquid material product of this contact is subsequently converted to other forms. Alkaline reagents used in wet flue gas desulfurization technology include, but are not limited to, lime, limestone, and sodium.

Wet scrubber system means any emission control device that mixes an aqueous stream or slurry with the exhaust gases from a steam generating unit to control emissions of PM or SO_2.

Wood means wood, wood residue, bark, or any derivative fuel or residue thereof, in any form, including, but not limited to, sawdust, sanderdust, wood chips, scraps, slabs, millings, shavings, and processed pellets made from wood or other forest residues.

§ 60.42b Standard for sulfur dioxide (SO_2).

(a) Except as provided in paragraphs (b), (c), (d), or (k) of this section, on and after the date on which the performance test is completed or required to be completed under § 60.8, whichever comes first, no owner or operator of an affected facility that commenced construction, reconstruction, or modification on or before February 28, 2005, that combusts coal or oil shall cause to be discharged into the atmosphere any gases that contain SO_2 in excess of 87 ng/J (0.20 lb/MMBtu) or 10 percent (0.10) of the potential SO_2 emission rate (90 percent reduction) and the emission limit determined according to the following formula:

$$E_s = \frac{(K_a H_a + K_b H_b)}{(H_a + H_b)}$$

Where:

E_s = SO_2 emission limit, in ng/J or lb/MMBtu heat input;

K_a = 520 ng/J (or 1.2 lb/MMBtu);

K_b = 340 ng/J (or 0.80 lb/MMBtu);

H_a = Heat input from the combustion of coal, in J (MMBtu); and

H_b = Heat input from the combustion of oil, in J (MMBtu).

Only the heat input supplied to the affected facility from the combustion of coal and oil is counted under this section. No credit is provided for the heat input to the affected facility from the combustion of natural gas, wood, municipal-type solid waste, or other fuels or heat derived from exhaust gases from other sources, such as gas turbines, internal combustion engines, kilns, etc.

(b) On and after the date on which the performance test is completed or required to be completed under § 60.8, whichever date comes first, no owner or operator of an affected facility that commenced construction, reconstruction, or modification on or before February 28, 2005, that combusts coal refuse alone in a fluidized bed combustion steam generating unit shall cause to be discharged into the atmosphere any gases that contain SO_2 in excess of 87 ng/J (0.20 lb/MMBtu) or 20 percent (0.20) of the potential SO_2 emission rate (80 percent reduction) and 520 ng/J (1.2 lb/MMBtu) heat input. If coal or oil is fired with coal refuse, the affected facility is subject to paragraph (a) or (d) of this section, as applicable.

(c) On and after the date on which the performance test is completed or is required to be completed under § 60.8, whichever comes first, no owner or operator of an affected facility that combusts coal or oil, either alone or in combination with any other fuel, and that uses an emerging technology for the control of SO_2 emissions, shall cause to be discharged into the atmosphere any gases that contain SO_2 in excess of 50 percent of the potential SO_2 emission rate (50 percent reduction) and that contain SO_2 in excess of the emission limit determined according to the following formula:

$$E_s = \frac{(K_c H_c + K_d H_d)}{(H_c + H_d)}$$

Where:

E_s = SO_2 emission limit, in ng/J or lb/MM Btu heat input;
K_c = 260 ng/J (or 0.60 lb/MMBtu);
K_d = 170 ng/J (or 0.40 lb/MMBtu);
H_c = Heat input from the combustion of coal, in J (MMBtu); and
H_d = Heat input from the combustion of oil, in J (MMBtu).

Only the heat input supplied to the affected facility from the combustion of coal and oil is counted under this section. No credit is provided for the heat input to the affected facility from the combustion of natural gas, wood, municipal-type solid waste, or other fuels, or from the heat input derived from exhaust gases from other sources, such as gas turbines, internal combustion engines, kilns, etc.

(d) On and after the date on which the performance test is completed or required to be completed under § 60.8, whichever comes first, no owner or operator of an affected facility that commenced construction, reconstruction, or modification on or before February 28, 2005 and listed in paragraphs (d)(1), (2), (3), or (4) of this section shall cause to be discharged into the atmosphere any gases that contain SO_2 in excess of 520 ng/J (1.2 lb/MMBtu) heat input if the affected facility combusts coal, or 215 ng/J (0.5 lb/MMBtu) heat input if the affected facility combusts oil other than very low sulfur oil. Percent reduction requirements are not applicable to affected facilities under paragraphs (d)(1), (2), (3) or (4) of this section.

(1) Affected facilities that have an annual capacity factor for coal and oil of 30 percent (0.30) or less and are subject to a federally enforceable permit limiting the operation of the affected facility to an annual capacity factor for coal and oil of 30 percent (0.30) or less;

(2) Affected facilities located in a noncontinental area; or

(3) Affected facilities combusting coal or oil, alone or in combination with any fuel, in a duct burner as part of a combined cycle system where 30 percent (0.30) or less of the heat entering the steam generating unit is from combustion of coal and oil in the duct burner and 70 percent (0.70) or more of the heat entering the steam generating unit is from the exhaust gases entering the duct burner; or

(4) The affected facility burns coke oven gas alone or in combination with natural gas or very low sulfur distillate oil.

(e) Except as provided in paragraph (f) of this section, compliance with the emission limits, fuel oil sulfur limits, and/or percent reduction requirements under this section are determined on a 30-day rolling average basis.

(f) Except as provided in paragraph (j)(2) of this section, compliance with the emission limits or fuel oil sulfur limits under this section is determined on a 24-hour average basis for affected facilities that (1) have a federally enforceable permit limiting the annual capacity factor for oil to 10 percent or less, (2) combust only very low sulfur oil, and (3) do not combust any other fuel.

(g) Except as provided in paragraph (i) of this section and § 60.45b(a), the SO_2 emission limits and percent reduction requirements under this section apply at all times, including periods of startup, shutdown, and malfunction.

(h) Reductions in the potential SO_2 emission rate through fuel pretreatment are not credited toward the percent reduction requirement under paragraph (c) of this section unless:

(1) Fuel pretreatment results in a 50 percent or greater reduction in potential SO_2 emissions and

(2) Emissions from the pretreated fuel (without combustion or post-combustion SO_2 control) are equal to or less than the emission limits specified in paragraph (c) of this section.

(i) An affected facility subject to paragraph (a), (b), or (c) of this section may combust very low sulfur oil or natural gas when the SO_2 control system is not being operated because of malfunction or maintenance of the SO_2 control system.

(j) Percent reduction requirements are not applicable to affected facilities combusting only very low sulfur oil. The owner or operator of an affected facility combusting very low sulfur oil shall demonstrate that the oil meets the definition of very low sulfur oil by: (1) Following the performance testing procedures as described in §60.45b(c) or §60.45b(d), and following the monitoring procedures as described in §60.47b(a) or §60.47b(b) to determine SO_2 emission rate or fuel oil sulfur content; or (2) maintaining fuel records as described in §60.49b(r).

(k)(1) Except as provided in paragraphs (k)(2), (k)(3), and (k)(4) of this section, on and after the date on which the initial performance test is completed or is required to be completed under §60.8, whichever date comes first, no owner or operator of an affected facility that commences construction, reconstruction, or modification after February 28, 2005, and that combusts coal, oil, natural gas, a mixture of these fuels, or a mixture of these fuels with any other fuels shall cause to be discharged into the atmosphere any gases that contain SO_2 in excess of 87 ng/J (0.20 lb/MMBtu) heat input or 8 percent (0.08) of the potential SO_2 emission rate (92 percent reduction) and 520 ng/J (1.2 lb/MMBtu) heat input.

(2) Units firing only very low sulfur oil and/or a mixture of gaseous fuels with a potential SO_2 emission rate of 140 ng/J (0.32 lb/MMBtu) heat input or less are exempt from the SO_2 emissions limit in paragraph 60.42b(k)(1).

(3) Units that are located in a noncontinental area and that combust coal or oil shall not discharge any gases that contain SO_2 in excess of 520 ng/J (1.2 lb/MMBtu) heat input if the affected facility combusts coal, or 215 ng/J (0.50 lb/MMBtu) heat input if the affected facility combusts oil.

(4) As an alternative to meeting the requirements under paragraph (k)(1) of this section, modified facilities that combust coal or a mixture of coal with other fuels shall not cause to be discharged into the atmosphere any gases that contain SO_2 in excess of 87 ng/J (0.20 lb/MMBtu) heat input or 10 percent (0.10) of the potential SO_2 emission rate (90 percent reduction) and 520 ng/J (1.2 lb/MMBtu) heat input.

§60.43b Standard for particulate matter (PM).

(a) On and after the date on which the initial performance test is completed or is required to be completed under §60.8, whichever comes first, no owner or operator of an affected facility that commenced construction, reconstruction, or modification on or before February 28, 2005 that combusts coal or combusts mixtures of coal with other fuels, shall cause to be discharged into the atmosphere from that affected facility any gases that contain PM in excess of the following emission limits:

(1) 22 ng/J (0.051 lb/MMBtu) heat input, (i) If the affected facility combusts only coal, or

(ii) If the affected facility combusts coal and other fuels and has an annual capacity factor for the other fuels of 10 percent (0.10) or less.

(2) 43 ng/J (0.10 lb/MMBtu) heat input if the affected facility combusts coal and other fuels and has an annual capacity factor for the other fuels greater than 10 percent (0.10) and is subject to a federally enforceable requirement limiting operation of the affected facility to an annual capacity factor greater than 10 percent (0.10) for fuels other than coal.

(3) 86 ng/J (0.20 lb/MMBtu) heat input if the affected facility combusts coal or coal and other fuels and

(i) Has an annual capacity factor for coal or coal and other fuels of 30 percent (0.30) or less,

(ii) Has a maximum heat input capacity of 73 MW (250 MMBtu/hr) or less,

(iii) Has a federally enforceable requirement limiting operation of the affected facility to an annual capacity factor of 30 percent (0.30) or less for coal or coal and other solid fuels, and

(iv) Construction of the affected facility commenced after June 19, 1984, and before November 25, 1986.

(4) An affected facility burning coke oven gas alone or in combination with

other fuels not subject to a PM standard under § 60.43b and not using a post-combustion technology (except a wet scrubber) for reducing PM or SO_2 emissions is not subject to the PM limits under § 60.43b(a).

(b) On and after the date on which the performance test is completed or required to be completed under § 60.8, whichever comes first, no owner or operator of an affected facility that commenced construction, reconstruction, or modification on or before February 28, 2005, and that combusts oil (or mixtures of oil with other fuels) and uses a conventional or emerging technology to reduce SO_2 emissions shall cause to be discharged into the atmosphere from that affected facility any gases that contain PM in excess of 43 ng/J (0.10 lb/MMBtu) heat input.

(c) On and after the date on which the initial performance test is completed or is required to be completed under § 60.8, whichever comes first, no owner or operator of an affected facility that commenced construction, reconstruction, or modification on or before February 28, 2005, and that combusts wood, or wood with other fuels, except coal, shall cause to be discharged from that affected facility any gases that contain PM in excess of the following emission limits:

(1) 43 ng/J (0.10 lb/MMBtu) heat input if the affected facility has an annual capacity factor greater than 30 percent (0.30) for wood.

(2) 86 ng/J (0.20 lb/MMBtu) heat input if (i) The affected facility has an annual capacity factor of 30 percent (0.30) or less for wood;

(ii) Is subject to a federally enforceable requirement limiting operation of the affected facility to an annual capacity factor of 30 percent (0.30) or less for wood; and

(iii) Has a maximum heat input capacity of 73 MW (250 MMBtu/hr) or less.

(d) On and after the date on which the initial performance test is completed or is required to be completed under § 60.8, whichever date comes first, no owner or operator of an affected facility that combusts municipal-type solid waste or mixtures of municipal-type solid waste with other fuels, shall cause to be discharged into the atmosphere from that affected facility any gases that contain PM in excess of the following emission limits:

(1) 43 ng/J (0.10 lb/MMBtu) heat input;

(i) If the affected facility combusts only municipal-type solid waste; or

(ii) If the affected facility combusts municipal-type solid waste and other fuels and has an annual capacity factor for the other fuels of 10 percent (0.10) or less.

(2) 86 ng/J (0.20 lb/MMBtu) heat input if the affected facility combusts municipal-type solid waste or municipal-type solid waste and other fuels; and

(i) Has an annual capacity factor for municipal-type solid waste and other fuels of 30 percent (0.30) or less;

(ii) Has a maximum heat input capacity of 73 MW (250 MMBtu/hr) or less;

(iii) Has a federally enforceable requirement limiting operation of the affected facility to an annual capacity factor of 30 percent (0.30) or less for municipal-type solid waste, or municipal-type solid waste and other fuels; and

(iv) Construction of the affected facility commenced after June 19, 1984, but on or before November 25, 1986.

(e) For the purposes of this section, the annual capacity factor is determined by dividing the actual heat input to the steam generating unit during the calendar year from the combustion of coal, wood, or municipal-type solid waste, and other fuels, as applicable, by the potential heat input to the steam generating unit if the steam generating unit had been operated for 8,760 hours at the maximum heat input capacity.

(f) On and after the date on which the initial performance test is completed or is required to be completed under § 60.8, whichever date comes first, no owner or operator of an affected facility that combusts coal, oil, wood, or mixtures of these fuels with any other fuels shall cause to be discharged into the atmosphere any gases that exhibit greater than 20 percent opacity (6-minute average), except for one 6-minute period per hour of not more than 27 percent opacity.

(g) The PM and opacity standards apply at all times, except during periods of startup, shutdown or malfunction.

(h)(1) Except as provided in paragraphs (h)(2), (h)(3), (h)(4), and (h)(5) of this section, on and after the date on which the initial performance test is completed or is required to be completed under § 60.8, whichever date comes first, no owner or operator of an affected facility that commenced construction, reconstruction, or modification after February 28, 2005, and that combusts coal, oil, wood, a mixture of these fuels, or a mixture of these fuels with any other fuels shall cause to be discharged into the atmosphere from that affected facility any gases that contain PM in excess of 13 ng/J (0.030 lb/MMBtu) heat input.

(2) As an alternative to meeting the requirements of paragraph (h)(1) of this section, the owner or operator of an affected facility for which modification commenced after February 28, 2005, may elect to meet the requirements of this paragraph. On and after the date on which the initial performance test is completed or required to be completed under § 60.8, no owner or operator of an affected facility that commences modification after February 28, 2005 shall cause to be discharged into the atmosphere from that affected facility any gases that contain PM in excess of both:

(i) 22 ng/J (0.051 lb/MMBtu) heat input derived from the combustion of coal, oil, wood, a mixture of these fuels, or a mixture of these fuels with any other fuels; and

(ii) 0.2 percent of the combustion concentration (99.8 percent reduction) when combusting coal, oil, wood, a mixture of these fuels, or a mixture of these fuels with any other fuels.

(3) On and after the date on which the initial performance test is completed or is required to be completed under § 60.8, whichever date comes first, no owner or operator of an affected facility that commences modification after February 28, 2005, and that combusts over 30 percent wood (by heat input) on an annual basis and has a maximum heat input capacity of 73 MW (250 MMBtu/h) or less shall cause to be discharged into the atmosphere from that affected facility any gases that contain PM in excess of 43 ng/J (0.10 lb/MMBtu) heat input.

(4) On and after the date on which the initial performance test is completed or is required to be completed under § 60.8, whichever date comes first, no owner or operator of an affected facility that commences modification after February 28, 2005, and that combusts over 30 percent wood (by heat input) on an annual basis and has a maximum heat input capacity greater than 73 MW (250 MMBtu/h) shall cause to be discharged into the atmosphere from that affected facility any gases that contain PM in excess of 37 ng/J (0.085 lb/MMBtu) heat input.

(5) On and after the date on which the initial performance test is completed or is required to be completed under § 60.8, whichever date comes first, an owner or operator of an affected facility that commences construction, reconstruction, or modification after February 28, 2005, and that combusts only oil that contains no more than 0.3 weight percent sulfur, coke oven gas, a mixture of these fuels, or either fuel (or a mixture of these fuels) in combination with other fuels not subject to a PM standard under § 60.43b and not using a post-combustion technology (except a wet scrubber) to reduce SO_2 or PM emissions is not subject to the PM limits under § 60.43b(h)(1).

§ 60.44b Standard for nitrogen oxides (NO_X).

(a) Except as provided under paragraphs (k) and (l) of this section, on and after the date on which the initial performance test is completed or is required to be completed under § 60.8, whichever date comes first, no owner or operator of an affected facility that is subject to the provisions of this section and that combusts only coal, oil, or natural gas shall cause to be discharged into the atmosphere from that affected facility any gases that contain NO_X (expressed as NO_2) in excess of the following emission limits:

Fuel/steam generating unit type	Nitrogen oxide emission limits (expressed as NO_2) heat input	
	ng/J	lb/MMBTu
(1) Natural gas and distillate oil, except (4):		
(i) Low heat release rate	43	0.10
(ii) High heat release rate	86	0.20
(2) Residual oil:		
(i) Low heat release rate	130	0.30
(ii) High heat release rate	170	0.40
(3) Coal:		
(i) Mass-feed stoker	210	0.50
(ii) Spreader stoker and fluidized bed combustion	260	0.60
(iii) Pulverized coal	300	0.70
(iv) Lignite, except (v)	260	0.60
(v) Lignite mined in North Dakota, South Dakota, or Montana and combusted in a slag tap furnace	340	0.80
(vi) Coal-derived synthetic fuels	210	0.50
(4) Duct burner used in a combined cycle system:		
(i) Natural gas and distillate oil	86	0.20
(ii) Residual oil	170	0.40

(b) Except as provided under paragraphs (k) and (l) of this section, on and after the date on which the initial performance test is completed or is required to be completed under § 60.8, whichever date comes first, no owner or operator of an affected facility that simultaneously combusts mixtures of coal, oil, or natural gas shall cause to be discharged into the atmosphere from that affected facility any gases that contain NO_X in excess of a limit determined by the use of the following formula:

$$E_n = \frac{(EL_{go}H_{go}) + (EL_{ro}H_{ro}) + (EL_cH_c)}{(H_{go} + H_{ro} + H_c)}$$

Where:

E_n = NO_X emission limit (expressed as NO_2), ng/J (lb/MMBtu);

EL_{go} = Appropriate emission limit from paragraph (a)(1) for combustion of natural gas or distillate oil, ng/J (lb/MMBtu);

H_{go} = Heat input from combustion of natural gas or distillate oil, J (MMBtu);

EL_{ro} = Appropriate emission limit from paragraph (a)(2) for combustion of residual oil, ng/J (lb/MMBtu);

H_{ro} = Heat input from combustion of residual oil, J (MMBtu);

EL_c = Appropriate emission limit from paragraph (a)(3) for combustion of coal, ng/J (lb/MMBtu); and

H_c = Heat input from combustion of coal, J (MMBtu).

(c) Except as provided under paragraph (l) of this section, on and after the date on which the initial performance test is completed or is required to be completed under § 60.8, whichever date comes first, no owner or operator of an affected facility that simultaneously combusts coal or oil, or a mixture of these fuels with natural gas, and wood, municipal-type solid waste, or any other fuel shall cause to be discharged into the atmosphere any gases that contain NO_X in excess of the emission limit for the coal or oil, or mixtures of these fuels with natural gas combusted in the affected facility, as determined pursuant to paragraph (a) or (b) of this section, unless the affected facility has an annual capacity factor for coal or oil, or mixture of these fuels with natural gas of 10 percent (0.10) or less and is subject to a federally enforceable requirement that limits operation of the affected facility to an annual capacity factor of 10 percent (0.10) or less for coal, oil, or a mixture of these fuels with natural gas.

(d) On and after the date on which the initial performance test is completed or is required to be completed under § 60.8, whichever date comes first, no owner or operator of an affected facility that simultaneously combusts natural gas with wood, municipal-type solid waste, or other solid fuel, except coal, shall cause to be discharged into the atmosphere from that affected facility any gases that contain NO_X in excess of 130 ng/J (0.30 lb/MMBtu) heat input unless the affected facility has an annual capacity factor for natural gas of 10 percent (0.10) or less and is subject to a federally enforceable requirement that limits operation of the affected facility to an annual capacity factor of 10 percent (0.10) or less for natural gas.

(e) Except as provided under paragraph (l) of this section, on and after the date on which the initial performance test is completed or is required to be completed under § 60.8, whichever date comes first, no owner or operator of an affected facility that simultaneously combusts coal, oil, or natural gas with byproduct/waste shall cause to be discharged into the atmosphere any gases that contain NO_X in excess of the emission limit determined by the following formula unless the affected facility has an annual capacity factor for coal, oil, and natural gas of 10 percent (0.10) or less and is subject to a federally enforceable requirement that limits operation of the affected facility to an annual capacity factor of 10 percent (0.10) or less:

$$E_n = \frac{(EL_{go}H_{go}) + (EL_{ro}H_{ro}) + (EL_cH_c)}{(H_{go} + H_{ro} + H_c)}$$

Where:

E_n = NO_X emission limit (expressed as NO_2), ng/J (lb/MMBtu);

EL_{go} = Appropriate emission limit from paragraph (a)(1) for combustion of natural gas or distillate oil, ng/J (lb/MMBtu);

H_{go} = Heat input from combustion of natural gas, distillate oil and gaseous byproduct/waste, J (MMBtu);

EL_{ro} = Appropriate emission limit from paragraph (a)(2) for combustion of residual oil and/or byproduct/waste, ng/J (lb/MMBtu);

H_{ro} = Heat input from combustion of residual oil, J (MMBtu);

EL_c = Appropriate emission limit from paragraph (a)(3) for combustion of coal, ng/J (lb/MMBtu); and

H_c = Heat input from combustion of coal, J (MMBtu).

(f) Any owner or operator of an affected facility that combusts byproduct/waste with either natural gas or oil may petition the Administrator within 180 days of the initial startup of the affected facility to establish a NO_X emission limit that shall apply specifically to that affected facility when the byproduct/waste is combusted. The petition shall include sufficient and appropriate data, as determined by the Administrator, such as NO_X emissions from the affected facility, waste composition (including nitrogen content), and combustion conditions to allow the Administrator to confirm that the affected facility is unable to comply with the emission limits in paragraph (e) of this section and to determine the appropriate emission limit for the affected facility.

(1) Any owner or operator of an affected facility petitioning for a facility-specific NO_X emission limit under this section shall:

(i) Demonstrate compliance with the emission limits for natural gas and distillate oil in paragraph (a)(1) of this section or for residual oil in paragraph (a)(2) or (l)(1) of this section, as appropriate, by conducting a 30-day performance test as provided in § 60.46b(e). During the performance test only natural gas, distillate oil, or residual oil shall be combusted in the affected facility; and

(ii) Demonstrate that the affected facility is unable to comply with the emission limits for natural gas and distillate oil in paragraph (a)(1) of this section or for residual oil in paragraph (a)(2) or (l)(1) of this section, as appropriate, when gaseous or liquid byproduct/waste is combusted in the affected facility under the same conditions and using the same technological system of emission reduction applied when demonstrating compliance under paragraph (f)(1)(i) of this section.

(2) The NO_X emission limits for natural gas or distillate oil in paragraph (a)(1) of this section or for residual oil in paragraph (a)(2) or (l)(1) of this section, as appropriate, shall be applicable to the affected facility until and unless the petition is approved by the Administrator. If the petition is approved by the Administrator, a facility-specific NO_X emission limit will be established at the NO_X emission level achievable when the affected facility is combusting oil or natural gas and byproduct/waste in a manner that the Administrator determines to be consistent with minimizing NO_X emissions. In lieu of amending this subpart, a letter will be sent to the facility describing the facility-specific NO_X limit. The facility shall use the compliance procedures detailed in the letter and make the letter

available to the public. If the Administrator determines it is appropriate, the conditions and requirements of the letter can be reviewed and changed at any point.

(g) Any owner or operator of an affected facility that combusts hazardous waste (as defined by 40 CFR part 261 or 40 CFR part 761) with natural gas or oil may petition the Administrator within 180 days of the initial startup of the affected facility for a waiver from compliance with the NO_X emission limit that applies specifically to that affected facility. The petition must include sufficient and appropriate data, as determined by the Administrator, on NO_X emissions from the affected facility, waste destruction efficiencies, waste composition (including nitrogen content), the quantity of specific wastes to be combusted and combustion conditions to allow the Administrator to determine if the affected facility is able to comply with the NO_X emission limits required by this section. The owner or operator of the affected facility shall demonstrate that when hazardous waste is combusted in the affected facility, thermal destruction efficiency requirements for hazardous waste specified in an applicable federally enforceable requirement preclude compliance with the NO_X emission limits of this section. The NO_X emission limits for natural gas or distillate oil in paragraph (a)(1) of this section or for residual oil in paragraph (a)(2) or (l)(1) of this section, as appropriate, are applicable to the affected facility until and unless the petition is approved by the Administrator. (See 40 CFR 761.70 for regulations applicable to the incineration of materials containing polychlorinated biphenyls (PCB's).) In lieu of amending this subpart, a letter will be sent to the facility describing the facility-specific NO_X limit. The facility shall use the compliance procedures detailed in the letter and make the letter available to the public. If the Administrator determines it is appropriate, the conditions and requirements of the letter can be reviewed and changed at any point.

(h) For purposes of paragraph (i) of this section, the NO_X standards under this section apply at all times including periods of startup, shutdown, or malfunction.

(i) Except as provided under paragraph (j) of this section, compliance with the emission limits under this section is determined on a 30-day rolling average basis.

(j) Compliance with the emission limits under this section is determined on a 24-hour average basis for the initial performance test and on a 3-hour average basis for subsequent performance tests for any affected facilities that:

(1) Combust, alone or in combination, only natural gas, distillate oil, or residual oil with a nitrogen content of 0.30 weight percent or less;

(2) Have a combined annual capacity factor of 10 percent or less for natural gas, distillate oil, and residual oil with a nitrogen content of 0.30 weight percent or less; and

(3) Are subject to a federally enforceable requirement limiting operation of the affected facility to the firing of natural gas, distillate oil, and/or residual oil with a nitrogen content of 0.30 weight percent or less and limiting operation of the affected facility to a combined annual capacity factor of 10 percent or less for natural gas, distillate oil, and residual oil with a nitrogen content of 0.30 weight percent or less.

(k) Affected facilities that meet the criteria described in paragraphs (j)(1), (2), and (3) of this section, and that have a heat input capacity of 73 MW (250 MMBtu/hr) or less, are not subject to the NO_X emission limits under this section.

(l) On and after the date on which the initial performance test is completed or is required to be completed under § 60.8, whichever date comes first, no owner or operator of an affected facility that commenced construction or reconstruction after July 9, 1997 shall cause to be discharged into the atmosphere from that affected facility any gases that contain NO_X (expressed as NO_2) in excess of the following limits:

(1) If the affected facility combusts coal, oil, or natural gas, or a mixture of these fuels, or with any other fuels: A limit of 86 ng/J (0.20 lb/MMBtu) heat input unless the affected facility has an annual capacity factor for coal, oil, and natural gas of 10 percent (0.10) or

less and is subject to a federally enforceable requirement that limits operation of the facility to an annual capacity factor of 10 percent (0.10) or less for coal, oil, and natural gas; or

(2) If the affected facility has a low heat release rate and combusts natural gas or distillate oil in excess of 30 percent of the heat input on a 30-day rolling average from the combustion of all fuels, a limit determined by use of the following formula:

$$E_n = \frac{(0.10 \times H_{go}) + (0.20 \times H_r)}{(H_{go} + H_r)}$$

Where:

E_n = NO_X emission limit, (lb/MMBtu);

H_{go} = 30-day heat input from combustion of natural gas or distillate oil; and

H_r = 30-day heat input from combustion of any other fuel.

(3) After February 27, 2006, units where more than 10 percent of total annual output is electrical or mechanical may comply with an optional limit of 270 ng/J (2.1 lb/MWh) gross energy output, based on a 30-day rolling average. Units complying with this output-based limit must demonstrate compliance according to the procedures of § 60.48Da(i) of subpart Da of this part, and must monitor emissions according to § 60.49Da(c), (k), through (n) of subpart Da of this part.

§ 60.45b Compliance and performance test methods and procedures for sulfur dioxide.

(a) The SO_2 emission standards under § 60.42b apply at all times. Facilities burning coke oven gas alone or in combination with any other gaseous fuels or distillate oil and complying with the fuel based limit under § 60.42b(d) or § 60.42b(k)(2) are allowed to exceed the limit 30 operating days per calendar year for by-product plant maintenance.

(b) In conducting the performance tests required under § 60.8, the owner or operator shall use the methods and procedures in appendix A (including fuel certification and sampling) of this part or the methods and procedures as specified in this section, except as provided in § 60.8(b). Section 60.8(f) does not apply to this section. The 30-day notice required in § 60.8(d) applies only to the initial performance test unless otherwise specified by the Administrator.

(c) The owner or operator of an affected facility shall conduct performance tests to determine compliance with the percent of potential SO_2 emission rate (% P_s) and the SO_2 emission rate (E_s) pursuant to § 60.42b following the procedures listed below, except as provided under paragraph (d) and (k) of this section.

(1) The initial performance test shall be conducted over 30 consecutive operating days of the steam generating unit. Compliance with the SO_2 standards shall be determined using a 30-day average. The first operating day included in the initial performance test shall be scheduled within 30 days after achieving the maximum production rate at which the affected facility will be operated, but not later than 180 days after initial startup of the facility.

(2) If only coal, only oil, or a mixture of coal and oil is combusted, the following procedures are used:

(i) The procedures in Method 19 of appendix A of this part are used to determine the hourly SO_2 emission rate (E_{ho}) and the 30-day average emission rate (E_{ao}). The hourly averages used to compute the 30-day averages are obtained from the continuous emission monitoring system (CEMS) of § 60.47b (a) or (b).

(ii) The percent of potential SO_2 emission rate (%P_s) emitted to the atmosphere is computed using the following formula:

$$\%P_s = 100\left(1 - \frac{\%R_g}{100}\right)\left(1 - \frac{\%R_f}{100}\right)$$

Where:

%P_s = Potential SO_2 emission rate, percent;

%R_g = SO_2 removal efficiency of the control device as determined by Method 19 of appendix A of this part, in percent; and

%R_f = SO_2 removal efficiency of fuel pretreatment as determined by Method 19 of appendix A of this part, in percent.

(3) If coal or oil is combusted with other fuels, the same procedures required in paragraph (c)(2) of this section are used, except as provided in the following:

(i) An adjusted hourly SO_2 emission rate ($E_{ho}{}^o$) is used in Equation 19–19 of

Method 19 of appendix A of this part to compute an adjusted 30-day average emission rate (E_{ao}^o). The Eho° is computed using the following formula:

$$E_{ho}^{o}=\frac{E_{ho}-E_{w}\left(1-X_{k}\right)}{X_{k}}$$

Where:

E_{ho}^o = Adjusted hourly SO_2 emission rate, ng/J (lb/MMBtu);

E_{ho} = Hourly SO_2 emission rate, ng/J (lb/MMBtu);

E_w = SO_2 concentration in fuels other than coal and oil combusted in the affected facility, as determined by the fuel sampling and analysis procedures in Method 19 of appendix A of this part, ng/J (lb/MMBtu). The value E_w for each fuel lot is used for each hourly average during the time that the lot is being combusted; and

X_k = Fraction of total heat input from fuel combustion derived from coal, oil, or coal and oil, as determined by applicable procedures in Method 19 of appendix A of this part.

(ii) To compute the percent of potential SO_2 emission rate ($\%P_s$), an adjusted $\%R_g$ ($\%R_g^o$) is computed from the adjusted E_{ao}^o from paragraph (b)(3)(i) of this section and an adjusted average SO_2 inlet rate (E_{ai}^o) using the following formula:

$$\%R_{g}^{o}=100\left(1.0-\frac{E_{ao}^{o}}{E_{ai}^{o}}\right)$$

To compute E_{ai}^o, an adjusted hourly SO_2 inlet rate (E_{hi}^o) is used. The E_{hi}^o is computed using the following formula:

$$E_{hi}^{o}=\frac{E_{hi}-E_{w}\left(1-X_{k}\right)}{X_{k}}$$

Where:

E_{hi}^o = Adjusted hourly SO_2 inlet rate, ng/J (lb/MMBtu); and

E_{hi} = Hourly SO_2 inlet rate, ng/J (lb/MMBtu).

(4) The owner or operator of an affected facility subject to paragraph (b)(3) of this section does not have to measure parameters E_w or X_k if the owner or operator elects to assume that X_k = 1.0. Owners or operators of affected facilities who assume X_k = 1.0 shall:

(i) Determine $\%P_s$ following the procedures in paragraph (c)(2) of this section; and

(ii) Sulfur dioxide emissions (E_s) are considered to be in compliance with SO_2 emission limits under § 60.42b.

(5) The owner or operator of an affected facility that qualifies under the provisions of § 60.42b(d) does not have to measure parameters E_w or X_k under paragraph (b)(3) of this section if the owner or operator of the affected facility elects to measure SO_2 emission rates of the coal or oil following the fuel sampling and analysis procedures under Method 19 of appendix A of this part.

(d) Except as provided in paragraph (j) of this section, the owner or operator of an affected facility that combusts only very low sulfur oil, has an annual capacity factor for oil of 10 percent (0.10) or less, and is subject to a federally enforceable requirement limiting operation of the affected facility to an annual capacity factor for oil of 10 percent (0.10) or less shall:

(1) Conduct the initial performance test over 24 consecutive steam generating unit operating hours at full load;

(2) Determine compliance with the standards after the initial performance test based on the arithmetic average of the hourly emissions data during each steam generating unit operating day if a CEMS is used, or based on a daily average if Method 6B of appendix A of this part or fuel sampling and analysis procedures under Method 19 of appendix A of this part are used.

(e) The owner or operator of an affected facility subject to § 60.42b(d)(1) shall demonstrate the maximum design capacity of the steam generating unit by operating the facility at maximum capacity for 24 hours. This demonstration will be made during the initial performance test and a subsequent demonstration may be requested at any other time. If the 24-hour average firing rate for the affected facility is less than the maximum design capacity provided by the manufacturer of the affected facility, the 24-hour average firing rate shall be used to determine the capacity utilization rate for the affected facility, otherwise the maximum design capacity provided by the manufacturer is used.

(f) For the initial performance test required under § 60.8, compliance with the SO_2 emission limits and percent reduction requirements under § 60.42b is based on the average emission rates and the average percent reduction for SO_2 for the first 30 consecutive steam generating unit operating days, except as provided under paragraph (d) of this section. The initial performance test is the only test for which at least 30 days prior notice is required unless otherwise specified by the Administrator. The initial performance test is to be scheduled so that the first steam generating unit operating day of the 30 successive steam generating unit operating days is completed within 30 days after achieving the maximum production rate at which the affected facility will be operated, but not later than 180 days after initial startup of the facility. The boiler load during the 30-day period does not have to be the maximum design load, but must be representative of future operating conditions and include at least one 24-hour period at full load.

(g) After the initial performance test required under § 60.8, compliance with the SO_2 emission limits and percent reduction requirements under § 60.42b is based on the average emission rates and the average percent reduction for SO_2 for 30 successive steam generating unit operating days, except as provided under paragraph (d). A separate performance test is completed at the end of each steam generating unit operating day after the initial performance test, and a new 30-day average emission rate and percent reduction for SO_2 are calculated to show compliance with the standard.

(h) Except as provided under paragraph (i) of this section, the owner or operator of an affected facility shall use all valid SO_2 emissions data in calculating $\%P_s$ and E_{ho} under paragraph (c), of this section whether or not the minimum emissions data requirements under § 60.46b are achieved. All valid emissions data, including valid SO_2 emission data collected during periods of startup, shutdown and malfunction, shall be used in calculating $\%P_s$ and E_{ho} pursuant to paragraph (c) of this section.

(i) During periods of malfunction or maintenance of the SO_2 control systems when oil is combusted as provided under § 60.42b(i), emission data are not used to calculate $\%P_s$ or E_s under § 60.42b(a), (b) or (c), however, the emissions data are used to determine compliance with the emission limit under § 60.42b(i).

(j) The owner or operator of an affected facility that combusts very low sulfur oil is not subject to the compliance and performance testing requirements of this section if the owner or operator obtains fuel receipts as described in § 60.49b(r).

(k) The owner or operator of an affected facility seeking to demonstrate compliance under §§ 60.42b(d)(4), 60.42b(j), and 60.42b(k)(2) shall follow the applicable procedures under § 60.49b(r).

§ 60.46b Compliance and performance test methods and procedures for particulate matter and nitrogen oxides.

(a) The PM emission standards and opacity limits under § 60.43b apply at all times except during periods of startup, shutdown, or malfunction. The NO_X emission standards under § 60.44b apply at all times.

(b) Compliance with the PM emission standards under § 60.43b shall be determined through performance testing as described in paragraph (d) of this section, except as provided in paragraph (i) of this section.

(c) Compliance with the NO_X emission standards under § 60.44b shall be determined through performance testing under paragraph (e) or (f), or under paragraphs (g) and (h) of this section, as applicable.

(d) To determine compliance with the PM emission limits and opacity limits under § 60.43b, the owner or operator of an affected facility shall conduct an initial performance test as required under § 60.8, and shall conduct subsequent performance tests as requested by the Administrator, using the following procedures and reference methods:

(1) Method 3B of appendix A of this part is used for gas analysis when applying Method 5 or 17 of appendix A of this part.

(2) Method 5, 5B, or 17 of appendix A of this part shall be used to measure the concentration of PM as follows:

(i) Method 5 of appendix A of this part shall be used at affected facilities without wet flue gas desulfurization (FGD) systems; and

(ii) Method 17 of appendix A of this part may be used at facilities with or without wet scrubber systems provided the stack gas temperature does not exceed a temperature of 160 °C (32 °F). The procedures of sections 2.1 and 2.3 of Method 5B of appendix A of this part may be used in Method 17 of appendix A of this part only if it is used after a wet FGD system. Do not use Method 17 of appendix A of this part after wet FGD systems if the effluent is saturated or laden with water droplets.

(iii) Method 5B of appendix A of this part is to be used only after wet FGD systems.

(3) Method 1 of appendix A of this part is used to select the sampling site and the number of traverse sampling points. The sampling time for each run is at least 120 minutes and the minimum sampling volume is 1.7 dscm (60 dscf) except that smaller sampling times or volumes may be approved by the Administrator when necessitated by process variables or other factors.

(4) For Method 5 of appendix A of this part, the temperature of the sample gas in the probe and filter holder is monitored and is maintained at 160±14 °C (320±25 °F).

(5) For determination of PM emissions, the oxygen (O_2) or CO_2 sample is obtained simultaneously with each run of Method 5, 5B, or 17 of appendix A of this part by traversing the duct at the same sampling location.

(6) For each run using Method 5, 5B, or 17 of appendix A of this part, the emission rate expressed in ng/J heat input is determined using:

(i) The O_2 or CO_2 measurements and PM measurements obtained under this section;

(ii) The dry basis F factor; and

(iii) The dry basis emission rate calculation procedure contained in Method 19 of appendix A of this part.

(7) Method 9 of appendix A of this part is used for determining the opacity of stack emissions.

(e) To determine compliance with the emission limits for NO_X required under §60.44b, the owner or operator of an affected facility shall conduct the performance test as required under §60.8 using the continuous system for monitoring NO_X under §60.48(b).

(1) For the initial compliance test, NO_X from the steam generating unit are monitored for 30 successive steam generating unit operating days and the 30-day average emission rate is used to determine compliance with the NO_X emission standards under §60.44b. The 30-day average emission rate is calculated as the average of all hourly emissions data recorded by the monitoring system during the 30-day test period.

(2) Following the date on which the initial performance test is completed or is required to be completed under §60.8, whichever date comes first, the owner or operator of an affected facility which combusts coal or which combusts residual oil having a nitrogen content greater than 0.30 weight percent shall determine compliance with the NO_X emission standards under §60.44b on a continuous basis through the use of a 30-day rolling average emission rate. A new 30-day rolling average emission rate is calculated each steam generating unit operating day as the average of all of the hourly NO_X emission data for the preceding 30 steam generating unit operating days.

(3) Following the date on which the initial performance test is completed or is required to be completed under §60.8, whichever date comes first, the owner or operator of an affected facility that has a heat input capacity greater than 73 MW (250 MMBtu/hr) and that combusts natural gas, distillate oil, or residual oil having a nitrogen content of 0.30 weight percent or less shall determine compliance with the NO_X standards under §60.44b on a continuous basis through the use of a 30-day rolling average emission rate. A new 30-day rolling average emission rate is calculated each steam generating unit operating day as the average of all of the hourly NO_X emission data for the preceding 30 steam generating unit operating days.

(4) Following the date on which the initial performance test is completed or required to be completed under §60.8, whichever date comes first, the owner or operator of an affected facility that has a heat input capacity of 73

MW (250 MMBtu/hr) or less and that combusts natural gas, distillate oil, or residual oil having a nitrogen content of 0.30 weight percent or less shall upon request determine compliance with the NO_X standards under § 60.44b through the use of a 30-day performance test. During periods when performance tests are not requested, NO_X emissions data collected pursuant to § 60.48b(g)(1) or § 60.48b(g)(2) are used to calculate a 30-day rolling average emission rate on a daily basis and used to prepare excess emission reports, but will not be used to determine compliance with the NO_X emission standards. A new 30-day rolling average emission rate is calculated each steam generating unit operating day as the average of all of the hourly NO_X emission data for the preceding 30 steam generating unit operating days.

(5) If the owner or operator of an affected facility that combusts residual oil does not sample and analyze the residual oil for nitrogen content, as specified in § 60.49b(e), the requirements of § 60.48b(g)(1) apply and the provisions of § 60.48b(g)(2) are inapplicable.

(f) To determine compliance with the emissions limits for NO_X required by § 60.44b(a)(4) or § 60.44b(l) for duct burners used in combined cycle systems, either of the procedures described in paragraph (f)(1) or (2) of this section may be used:

(1) The owner or operator of an affected facility shall conduct the performance test required under § 60.8 as follows:

(i) The emissions rate (E) of NO_X shall be computed using Equation 1 in this section:

$$E = E_{sg} + \left(\frac{H_g}{H_b}\right)\left(E_{sg} - E_g\right) \qquad \text{(Eq.1)}$$

Where:

E = Emissions rate of NO_X from the duct burner, ng/J (lb/MMBtu) heat input;

E_{sg} = Combined effluent emissions rate, in ng/J (lb/MMBtu) heat input using appropriate F factor as described in Method 19 of appendix A of this part;

H_g = Heat input rate to the combustion turbine, in J/hr (MMBtu/hr);

H_b = Heat input rate to the duct burner, in J/hr (MMBtu/hr); and

E_g = Emissions rate from the combustion turbine, in ng/J (lb/MMBtu) heat input calculated using appropriate F factor as described in Method 19 of appendix A of this part.

(ii) Method 7E of appendix A of this part shall be used to determine the NO_X concentrations. Method 3A or 3B of appendix A of this part shall be used to determine O_2 concentration.

(iii) The owner or operator shall identify and demonstrate to the Administrator's satisfaction suitable methods to determine the average hourly heat input rate to the combustion turbine and the average hourly heat input rate to the affected duct burner.

(iv) Compliance with the emissions limits under § 60.44b(a)(4) or § 60.44b(l) is determined by the three-run average (nominal 1-hour runs) for the initial and subsequent performance tests; or

(2) The owner or operator of an affected facility may elect to determine compliance on a 30-day rolling average basis by using the CEMS specified under § 60.48b for measuring NO_X and O_2 and meet the requirements of § 60.48b. The sampling site shall be located at the outlet from the steam generating unit. The NO_X emissions rate at the outlet from the steam generating unit shall constitute the NO_X emissions rate from the duct burner of the combined cycle system.

(g) The owner or operator of an affected facility described in § 60.44b(j) or § 60.44b(k) shall demonstrate the maximum heat input capacity of the steam generating unit by operating the facility at maximum capacity for 24 hours. The owner or operator of an affected facility shall determine the maximum heat input capacity using the heat loss method described in sections 5 and 7.3 of the ASME *Power Test Codes* 4.1 (incorporated by reference, see § 60.17). This demonstration of maximum heat input capacity shall be made during the initial performance test for affected facilities that meet the criteria of § 60.44b(j). It shall be made within 60 days after achieving the maximum production rate at which the affected facility will be operated, but not later than 180 days after initial start-up of each facility, for affected facilities meeting the criteria of § 60.44b(k). Subsequent demonstrations may be required by the Administrator at any other time. If this demonstration indicates that the maximum heat input capacity of the affected facility is less than that stated by the manufacturer of the affected facility, the maximum heat input capacity determined during this demonstration shall be used to determine the capacity utilization rate for the affected facility. Otherwise, the maximum heat input capacity provided by the manufacturer is used.

(h) The owner or operator of an affected facility described in §60.44b(j) that has a heat input capacity greater than 73 MW (250 MMBtu/hr) shall:

(1) Conduct an initial performance test as required under §60.8 over a minimum of 24 consecutive steam generating unit operating hours at maximum heat input capacity to demonstrate compliance with the NO_x emission standards under §60.44b using Method 7, 7A, 7E of appendix A of this part, or other approved reference methods; and

(2) Conduct subsequent performance tests once per calendar year or every 400 hours of operation (whichever comes first) to demonstrate compliance with the NO_x emission standards under §60.44b over a minimum of 3 consecutive steam generating unit operating hours at maximum heat input capacity using Method 7, 7A, 7E of appendix A of this part, or other approved reference methods.

(i) The owner or operator of an affected facility seeking to demonstrate compliance under paragraph §60.43b(h)(5) shall follow the applicable procedures under §60.49b(r).

(j) In place of PM testing with EPA Reference Method 5, 5B, or 17 of appendix A of this part, an owner or operator may elect to install, calibrate, maintain, and operate a CEMS for monitoring PM emissions discharged to the atmosphere and record the output of the system. The owner or operator of an affected facility who elects to continuously monitor PM emissions instead of conducting performance testing using EPA Method 5, 5B, or 17 of appendix A of this part shall comply with the requirements specified in paragraphs (j)(1) through (j)(13) of this section.

(1) Notify the Administrator one month before starting use of the system.

(2) Notify the Administrator one month before stopping use of the system.

(3) The monitor shall be installed, evaluated, and operated in accordance with §60.13 of subpart A of this part.

(4) The initial performance evaluation shall be completed no later than 180 days after the date of initial start-up of the affected facility, as specified under §60.8 of subpart A of this part or within 180 days of notification to the Administrator of use of the CEMS if the owner or operator was previously determining compliance by Method 5, 5B, or 17 of appendix A of this part performance tests, whichever is later.

(5) The owner or operator of an affected facility shall conduct an initial performance test for PM emissions as required under §60.8 of subpart A of this part. Compliance with the PM emission limit shall be determined by using the CEMS specified in paragraph (j) of this section to measure PM and calculating a 24-hour block arithmetic average emission concentration using EPA Reference Method 19 of appendix A of this part, section 4.1.

(6) Compliance with the PM emission limit shall be determined based on the 24-hour daily (block) average of the hourly arithmetic average emission concentrations using CEMS outlet data.

(7) At a minimum, valid CEMS hourly averages shall be obtained as specified in paragraphs (j)(7)(i) of this section for 75 percent of the total operating hours per 30-day rolling average.

(i) At least two data points per hour shall be used to calculate each 1-hour arithmetic average.

(ii) [Reserved]

(8) The 1-hour arithmetic averages required under paragraph (j)(7) of this section shall be expressed in ng/J or lb/MMBtu heat input and shall be used to calculate the boiler operating day daily arithmetic average emission concentrations. The 1-hour arithmetic averages shall be calculated using the data points required under §60.13(e)(2) of subpart A of this part.

(9) All valid CEMS data shall be used in calculating average emission concentrations even if the minimum CEMS data requirements of paragraph (j)(7) of this section are not met.

(10) The CEMS shall be operated according to Performance Specification 11 in appendix B of this part.

(11) During the correlation testing runs of the CEMS required by Performance Specification 11 in appendix B of this part, PM and O_2 (or CO_2) data shall be collected concurrently (or within a 30-to 60-minute period) by both the continuous emission monitors and the test methods specified in paragraphs (j)(7)(i) of this section.

(i) For PM, EPA Reference Method 5, 5B, or 17 of appendix A of this part shall be used.

(ii) For O_2 (or CO_2), EPA reference Method 3, 3A, or 3B of appendix A of this part, as applicable shall be used.

(12) Quarterly accuracy determinations and daily calibration drift tests shall be performed in accordance with procedure 2 in appendix F of this part. Relative Response Audit's must be performed annually and Response Correlation Audits must be performed every 3 years.

(13) When PM emissions data are not obtained because of CEMS breakdowns, repairs, calibration checks, and zero and span adjustments, emissions data shall be obtained by using other monitoring systems as approved by the Administrator or EPA Reference Method 19 of appendix A of this part to provide, as necessary, valid emissions data for a minimum of 75 percent of total operating hours per 30-day rolling average.

§ 60.47b Emission monitoring for sulfur dioxide.

(a) Except as provided in paragraphs (b), (f), and (h) of this section, the owner or operator of an affected facility subject to the SO_2 standards under § 60.42b shall install, calibrate, maintain, and operate CEMS for measuring SO_2 concentrations and either O_2 or CO_2 concentrations and shall record the output of the systems. For units complying with the percent reduction standard, the SO_2 and either O_2 or CO_2 concentrations shall both be monitored at the inlet and outlet of the SO_2 control device. If the owner or operator has installed and certified SO_2 and O_2 or CO_2 CEMS according to the requirements of § 75.20(c)(1) of this chapter and appendix A to part 75 of this chapter, and is continuing to meet the ongoing quality assurance requirements of § 75.21 of this chapter and appendix B to part 75 of this chapter, those CEMS may be used to meet the requirements of this section, provided that:

(1) When relative accuracy testing is conducted, SO_2 concentration data and CO_2 (or O_2) data are collected simultaneously; and

(2) In addition to meeting the applicable SO_2 and CO_2 (or O_2) relative accuracy specifications in Figure 2 of appendix B to part 75 of this chapter, the relative accuracy (RA) standard in section 13.2 of Performance Specification 2 in appendix B to this part is met when the RA is calculated on a lb/MMBtu basis; and

(3) The reporting requirements of § 60.49b are met. SO_2 and CO_2 (or O_2) data used to meet the requirements of § 60.49b shall not include substitute data values derived from the missing data procedures in subpart D of part 75 of this chapter, nor shall the SO_2 data have been bias adjusted according to the procedures of part 75 of this chapter.

(b) As an alternative to operating CEMS as required under paragraph (a) of this section, an owner or operator may elect to determine the average SO_2 emissions and percent reduction by:

(1) Collecting coal or oil samples in an as-fired condition at the inlet to the steam generating unit and analyzing them for sulfur and heat content according to Method 19 of appendix A of this part. Method 19 of appendix A of this part provides procedures for converting these measurements into the format to be used in calculating the average SO_2 input rate, or

(2) Measuring SO_2 according to Method 6B of appendix A of this part at the inlet or outlet to the SO_2 control system. An initial stratification test is required to verify the adequacy of the Method 6B of appendix A of this part sampling location. The stratification test shall consist of three paired runs of a suitable SO_2 and CO_2 measurement

train operated at the candidate location and a second similar train operated according to the procedures in section 3.2 and the applicable procedures in section 7 of Performance Specification 2. Method 6B of appendix A of this part, Method 6A of appendix A of this part, or a combination of Methods 6 and 3 or 3B of appendix A of this part or Methods 6C and 3A of appendix A of this part are suitable measurement techniques. If Method 6B of appendix A of this part is used for the second train, sampling time and timer operation may be adjusted for the stratification test as long as an adequate sample volume is collected; however, both sampling trains are to be operated similarly. For the location to be adequate for Method 6B of appendix A of this part 24-hour tests, the mean of the absolute difference between the three paired runs must be less than 10 percent.

(3) A daily SO_2 emission rate, E_D, shall be determined using the procedure described in Method 6A of appendix A of this part, section 7.6.2 (Equation 6A-8) and stated in ng/J (lb/MMBtu) heat input.

(4) The mean 30-day emission rate is calculated using the daily measured values in ng/J (lb/MMBtu) for 30 successive steam generating unit operating days using equation 19-20 of Method 19 of appendix A of this part.

(c) The owner or operator of an affected facility shall obtain emission data for at least 75 percent of the operating hours in at least 22 out of 30 successive boiler operating days. If this minimum data requirement is not met with a single monitoring system, the owner or operator of the affected facility shall supplement the emission data with data collected with other monitoring systems as approved by the Administrator or the reference methods and procedures as described in paragraph (b) of this section.

(d) The 1-hour average SO_2 emission rates measured by the CEMS required by paragraph (a) of this section and required under § 60.13(h) is expressed in ng/J or lb/MMBtu heat input and is used to calculate the average emission rates under § 60.42(b). Each 1-hour average SO_2 emission rate must be based on 30 or more minutes of steam generating unit operation. The hourly averages shall be calculated according to § 60.13(h)(2). Hourly SO_2 emission rates are not calculated if the affected facility is operated less than 30 minutes in a given clock hour and are not counted toward determination of a steam generating unit operating day.

(e) The procedures under § 60.13 shall be followed for installation, evaluation, and operation of the CEMS.

(1) Except as provided for in paragraph (e)(4) of this section, all CEMS shall be operated in accordance with the applicable procedures under Performance Specifications 1, 2, and 3 of appendix B of this part.

(2) Except as provided for in paragraph (e)(4) of this section, quarterly accuracy determinations and daily calibration drift tests shall be performed in accordance with Procedure 1 of appendix F of this part.

(3) For affected facilities combusting coal or oil, alone or in combination with other fuels, the span value of the SO_2 CEMS at the inlet to the SO_2 control device is 125 percent of the maximum estimated hourly potential SO_2 emissions of the fuel combusted, and the span value of the CEMS at the outlet to the SO_2 control device is 50 percent of the maximum estimated hourly potential SO_2 emissions of the fuel combusted. Alternatively, SO_2 span values determined according to section 2.1.1 in appendix A to part 75 of this chapter may be used.

(4) As an alternative to meeting the requirements of requirements of paragraphs (e)(1) and (e)(2) of this section, the owner or operator may elect to implement the following alternative data accuracy assessment procedures:

(i) For all required CO_2 and O_2 monitors and for SO_2 and NO_X monitors with span values less than 100 ppm, the daily calibration error test and calibration adjustment procedures described in sections 2.1.1 and 2.1.3 of appendix B to part 75 of this chapter may be followed instead of the CD assessment procedures in Procedure 1, section 4.1 of appendix F to this part. If this option is selected, the data validation and out-of-control provisions in sections 2.1.4 and 2.1.5 of appendix B to part 75 of this chapter shall be followed instead of the excessive CD and out-of-control criteria in Procedure 1, section 4.3 of appendix F to this part. For the purposes of data validation under this subpart, the excessive CD and out-of-control criteria in Procedure 1, section 4.3 of appendix F to this part shall apply to SO_2 and NO_X span values less than 100 ppm;

(ii) For all required CO_2 and O_2 monitors and for SO_2 and NO_X monitors with span values greater than 30 ppm, quarterly linearity checks may be performed in accordance with section 2.2.1 of appendix B to part 75 of this chapter, instead of performing the cylinder gas audits (CGAs) described in Procedure 1, section 5.1.2 of appendix F to this part. If this option is selected: The frequency of the linearity checks shall be as specified in section 2.2.1 of appendix B to part 75 of this chapter; the applicable linearity specifications in section 3.2 of appendix A to part 75 of this chapter shall be met; the data validation and out-of-control criteria in section 2.2.3 of appendix B to part 75 of this chapter shall be followed instead of the excessive audit inaccuracy and out-of-control criteria in Procedure 1, section 5.2 of appendix F to this part; and the grace period provisions in section 2.2.4 of appendix B to part 75 of this chapter shall apply. For the purposes of data validation under this subpart, the cylinder gas audits described in Procedure 1, section 5.1.2 of appendix F to this part shall be performed for SO_2 and NO_X span values less than or equal to 30 ppm; and

(iii) For SO_2, CO_2, and O_2 monitoring systems and for NO_X emission rate monitoring systems, RATAs may be performed in accordance with section 2.3 of appendix B to part 75 of this chapter instead of following the procedures described in Procedure 1, section 5.1.1 of appendix F to this part. If this option is selected: The frequency of each RATA shall be as specified in section 2.3.1 of appendix B to part 75 of this chapter; the applicable relative accuracy specifications shown in Figure 2 in appendix B to part 75 of this chapter shall be met; the data validation and out-of-control criteria in section 2.3.2 of appendix B to part 75 of this chapter shall be followed instead of the excessive audit inaccuracy and out-of-control criteria in Procedure 1, section 5.2 of appendix F to this part; and the grace period provisions in section 2.3.3 of appendix B to part 75 of this chapter shall apply. For the purposes of data validation under this subpart, the relative accuracy specification in section 13.2 of Performance Specification 2 in appendix B to this part shall be met on a lb/MMBtu basis for SO_2 (regardless of the SO_2 emission level during the RATA), and for NO_X when the average NO_X emission rate measured by the reference method during the RATA is less than 0.100 lb/MMBtu.

(f) The owner or operator of an affected facility that combusts very low sulfur oil or is demonstrating compliance under § 60.45b(k) is not subject to the emission monitoring requirements under paragraph (a) of this section if the owner or operator maintains fuel records as described in § 60.49b(r).

§ 60.48b Emission monitoring for particulate matter and nitrogen oxides.

(a) Except as provided in paragraph (j) of this section, the owner or operator of an affected facility subject to the opacity standard under § 60.43b shall install, calibrate, maintain, and operate a CEMS for measuring the opacity of emissions discharged to the atmosphere and record the output of the system.

(b) Except as provided under paragraphs (g), (h), and (i) of this section, the owner or operator of an affected facility subject to a NO_X standard under § 60.44b shall comply with either paragraphs (b)(1) or (b)(2) of this section.

(1) Install, calibrate, maintain, and operate CEMS for measuring NO_X and O_2 (or CO_2) emissions discharged to the atmosphere, and shall record the output of the system; or

(2) If the owner or operator has installed a NO_X emission rate CEMS to meet the requirements of part 75 of this chapter and is continuing to meet the ongoing requirements of part 75 of this chapter, that CEMS may be used to meet the requirements of this section, except that the owner or operator shall also meet the requirements of § 60.49b. Data reported to meet the requirements of § 60.49b shall not include data substituted using the missing data procedures in subpart D of part 75 of this chapter, nor shall the data have

been bias adjusted according to the procedures of part 75 of this chapter.

(c) The CEMS required under paragraph (b) of this section shall be operated and data recorded during all periods of operation of the affected facility except for CEMS breakdowns and repairs. Data is recorded during calibration checks, and zero and span adjustments.

(d) The 1-hour average NO_X emission rates measured by the continuous NO_X monitor required by paragraph (b) of this section and required under § 60.13(h) shall be expressed in ng/J or lb/MMBtu heat input and shall be used to calculate the average emission rates under § 60.44b. The 1-hour averages shall be calculated using the data points required under § 60.13(h)(2).

(e) The procedures under § 60.13 shall be followed for installation, evaluation, and operation of the continuous monitoring systems.

(1) For affected facilities combusting coal, wood or municipal-type solid waste, the span value for a continuous monitoring system for measuring opacity shall be between 60 and 80 percent.

(2) For affected facilities combusting coal, oil, or natural gas, the span value for NO_X is determined using one of the following procedures:

(i) Except as provided under paragraph (e)(2)(ii) of this section, NO_X span values shall be determined as follows:

Fuel	Span values for NO_X (ppm)
Natural gas	500.
Oil	500.
Coal	1,000.
Mixtures	500 (x + y) + 1,000z.

Where:

x = Fraction of total heat input derived from natural gas;

y = Fraction of total heat input derived from oil; and

z = Fraction of total heat input derived from coal.

(ii) As an alternative to meeting the requirements of paragraph (e)(2)(i) of this section, the owner or operator of an affected facility may elect to use the NO_X span values determined according to section 2.1.2 in appendix A to part 75 of this chapter.

(3) All span values computed under paragraph (e)(2)(i) of this section for combusting mixtures of regulated fuels are rounded to the nearest 500 ppm. Span values computed under paragraph (e)(2)(ii) of this section shall be rounded off according to section 2.1.2 in appendix A to part 75 of this chapter.

(f) When NO_X emission data are not obtained because of CEMS breakdowns, repairs, calibration checks and zero and span adjustments, emission data will be obtained by using standby monitoring systems, Method 7 of appendix A of this part, Method 7A of appendix A of this part, or other approved reference methods to provide emission data for a minimum of 75 percent of the operating hours in each steam generating unit operating day, in at least 22 out of 30 successive steam generating unit operating days.

(g) The owner or operator of an affected facility that has a heat input capacity of 73 MW (250 MMBtu/hr) or less, and that has an annual capacity factor for residual oil having a nitrogen content of 0.30 weight percent or less, natural gas, distillate oil, or any mixture of these fuels, greater than 10 percent (0.10) shall:

(1) Comply with the provisions of paragraphs (b), (c), (d), (e)(2), (e)(3), and (f) of this section; or

(2) Monitor steam generating unit operating conditions and predict NO_X emission rates as specified in a plan submitted pursuant to § 60.49b(c).

(h) The owner or operator of a duct burner, as described in § 60.41b, that is subject to the NO_X standards of § 60.44b(a)(4) or § 60.44b(l) is not required to install or operate a continuous emissions monitoring system to measure NO_X emissions.

(i) The owner or operator of an affected facility described in § 60.44b(j) or § 60.44b(k) is not required to install or operate a CEMS for measuring NO_X emissions.

(j) The owner or operator of an affected facility that meets the conditions in either paragraph (j)(1), (2), (3), (4), or (5) of this section is not required to install or operate a COMS for measuring opacity if:

(1) The affected facility uses a PM CEMS to monitor PM emissions; or

(2) The affected facility burns only liquid (excluding residual oil) or gaseous fuels with potential SO_2 emissions

rates of 26 ng/J (0.060 lb/MMBtu) or less and does not use a post-combustion technology to reduce SO_2 or PM emissions. The owner or operator must maintain fuel records of the sulfur content of the fuels burned, as described under § 60.49b(r); or

(3) The affected facility burns coke oven gas alone or in combination with fuels meeting the criteria in paragraph (j)(2) of this section and does not use a post-combustion technology to reduce SO_2 or PM emissions; or

(4) The affected facility does not use post-combustion technology (except a wet scrubber) for reducing PM, SO_2, or carbon monoxide (CO) emissions, burns only gaseous fuels or fuel oils that contain less than or equal to 0.30 weight percent sulfur, and is operated such that emissions of CO to the atmosphere from the affected facility are maintained at levels less than or equal to 0.15 lb/MMBtu on a steam generating unit operating day average basis. Owners and operators of affected facilities electing to comply with this paragraph must demonstrate compliance according to the procedures specified in paragraphs (j)(4)(i) through (iv) of this section.

(i) You must monitor CO emissions using a CEMS according to the procedures specified in paragraphs (j)(4)(i)(A) through (D) of this section.

(A) The CO CEMS must be installed, certified, maintained, and operated according to the provisions in § 60.58b(i)(3) of subpart Eb of this part.

(B) Each 1-hour CO emissions average is calculated using the data points generated by the CO CEMS expressed in parts per million by volume corrected to 3 percent oxygen (dry basis).

(C) At a minimum, valid 1-hour CO emissions averages must be obtained for at least 90 percent of the operating hours on a 30-day rolling average basis. At least two data points per hour must be used to calculate each 1-hour average.

(D) Quarterly accuracy determinations and daily calibration drift tests for the CO CEMS must be performed in accordance with procedure 1 in appendix F of this part.

(ii) You must calculate the 1-hour average CO emissions levels for each steam generating unit operating day by multiplying the average hourly CO output concentration measured by the CO CEMS times the corresponding average hourly flue gas flow rate and divided by the corresponding average hourly heat input to the affected source. The 24-hour average CO emission level is determined by calculating the arithmetic average of the hourly CO emission levels computed for each steam generating unit operating day.

(iii) You must evaluate the preceding 24-hour average CO emission level each steam generating unit operating day excluding periods of affected source startup, shutdown, or malfunction. If the 24-hour average CO emission level is greater than 0.15 lb/MMBtu, you must initiate investigation of the relevant equipment and control systems within 24 hours of the first discovery of the high emission incident and, take the appropriate corrective action as soon as practicable to adjust control settings or repair equipment to reduce the 24-hour average CO emission level to 0.15 lb/MMBtu or less.

(iv) You must record the CO measurements and calculations performed according to paragraph (j)(4) of this section and any corrective actions taken. The record of corrective action taken must include the date and time during which the 24-hour average CO emission level was greater than 0.15 lb/MMBtu, and the date, time, and description of the corrective action.

(5) The affected facility burns only gaseous fuels or fuel oils that contain less than or equal to 0.30 weight percent sulfur and operates according to a written site-specific monitoring plan approved by the appropriate delegated permitting authority. This monitoring plan must include procedures and criteria for establishing and monitoring specific parameters for the affected facility indicative of compliance with the opacity standard.

(k) Owners or operators complying with the PM emission limit by using a PM CEMS monitor instead of monitoring opacity must calibrate, maintain, and operate a CEMS, and record the output of the system, for PM emissions discharged to the atmosphere as specified in § 60.46b(j). The CEMS specified in paragraph § 60.46b(j) shall be operated and data recorded during all periods of operation of the affected facility except for CEMS breakdowns and repairs. Data is recorded during calibration checks, and zero and span adjustments.

§ 60.49b Reporting and recordkeeping requirements.

(a) The owner or operator of each affected facility shall submit notification of the date of initial startup, as provided by § 60.7. This notification shall include:

(1) The design heat input capacity of the affected facility and identification of the fuels to be combusted in the affected facility;

(2) If applicable, a copy of any federally enforceable requirement that limits the annual capacity factor for any fuel or mixture of fuels under §§ 60.42b(d)(1), 60.43b(a)(2), (a)(3)(iii), (c)(2)(ii), (d)(2)(iii), 60.44b(c), (d), (e), (i), (j), (k), 60.45b(d), (g), 60.46b(h), or 60.48b(i);

(3) The annual capacity factor at which the owner or operator anticipates operating the facility based on all fuels fired and based on each individual fuel fired; and

(4) Notification that an emerging technology will be used for controlling emissions of SO_2. The Administrator will examine the description of the emerging technology and will determine whether the technology qualifies as an emerging technology. In making this determination, the Administrator may require the owner or operator of the affected facility to submit additional information concerning the control device. The affected facility is subject to the provisions of § 60.42b(a) unless and until this determination is made by the Administrator.

(b) The owner or operator of each affected facility subject to the SO_2, PM, and/or NO_X emission limits under §§ 60.42b, 60.43b, and 60.44b shall submit to the Administrator the performance test data from the initial performance test and the performance evaluation of the CEMS using the applicable performance specifications in appendix B of this part. The owner or operator of each affected facility described in § 60.44b(j) or § 60.44b(k) shall submit to the Administrator the maximum heat input capacity data from the demonstration of the maximum heat input capacity of the affected facility.

(c) The owner or operator of each affected facility subject to the NO_X standard of § 60.44b who seeks to demonstrate compliance with those standards through the monitoring of steam generating unit operating conditions under the provisions of § 60.48b(g)(2) shall submit to the Administrator for approval a plan that identifies the operating conditions to be monitored under § 60.48b(g)(2) and the records to be maintained under § 60.49b(j). This plan shall be submitted to the Administrator for approval within 360 days of the initial startup of the affected facility. If the plan is approved, the owner or operator shall maintain records of predicted nitrogen oxide emission rates and the monitored operating conditions, including steam generating unit load, identified in the plan. The plan shall:

(1) Identify the specific operating conditions to be monitored and the relationship between these operating conditions and NO_X emission rates (*i.e.*, ng/J or lbs/MMBtu heat input). Steam generating unit operating conditions include, but are not limited to, the degree of staged combustion (*i.e.*, the ratio of primary air to secondary and/or tertiary air) and the level of excess air (*i.e.*, flue gas O_2 level);

(2) Include the data and information that the owner or operator used to identify the relationship between NO_X emission rates and these operating conditions; and

(3) Identify how these operating conditions, including steam generating unit load, will be monitored under § 60.48b(g) on an hourly basis by the owner or operator during the period of operation of the affected facility; the quality assurance procedures or practices that will be employed to ensure that the data generated by monitoring these operating conditions will be representative and accurate; and the type and format of the records of these operating conditions, including steam generating unit load, that will be maintained by the owner or operator under § 60.49b(j).

(d) The owner or operator of an affected facility shall record and maintain records of the amounts of each fuel combusted during each day and calculate the annual capacity factor individually for coal, distillate oil, residual oil, natural gas, wood, and municipal-type solid waste for the reporting period. The annual capacity factor is determined on a 12-month rolling average basis with a new annual capacity factor calculated at the end of each calendar month.

(e) For an affected facility that combusts residual oil and meets the criteria under §§ 60.46b(e)(4), 60.44b(j), or (k), the owner or operator shall maintain records of the nitrogen content of the residual oil combusted in the affected facility and calculate the average fuel nitrogen content for the reporting period. The nitrogen content shall be determined using ASTM Method D4629 (incorporated by reference, see § 60.17), or fuel suppliers. If residual oil blends are being combusted, fuel nitrogen specifications may be prorated based on the ratio of residual oils of different nitrogen content in the fuel blend.

(f) For facilities subject to the opacity standard under § 60.43b, the owner or operator shall maintain records of opacity.

(g) Except as provided under paragraph (p) of this section, the owner or operator of an affected facility subject to the NO_X standards under § 60.44b shall maintain records of the following information for each steam generating unit operating day:

(1) Calendar date;

(2) The average hourly NO_X emission rates (expressed as NO_2) (ng/J or lb/MMBtu heat input) measured or predicted;

(3) The 30-day average NO_X emission rates (ng/J or lb/MMBtu heat input) calculated at the end of each steam generating unit operating day from the measured or predicted hourly nitrogen oxide emission rates for the preceding 30 steam generating unit operating days;

(4) Identification of the steam generating unit operating days when the calculated 30-day average NO_X emission rates are in excess of the NO_X emissions standards under § 60.44b, with the reasons for such excess emissions as well as a description of corrective actions taken;

(5) Identification of the steam generating unit operating days for which pollutant data have not been obtained, including reasons for not obtaining sufficient data and a description of corrective actions taken;

(6) Identification of the times when emission data have been excluded from the calculation of average emission rates and the reasons for excluding data;

(7) Identification of "F" factor used for calculations, method of determination, and type of fuel combusted;

(8) Identification of the times when the pollutant concentration exceeded full span of the CEMS;

(9) Description of any modifications to the CEMS that could affect the ability of the CEMS to comply with Performance Specification 2 or 3; and

(10) Results of daily CEMS drift tests and quarterly accuracy assessments as required under appendix F, Procedure 1 of this part.

(h) The owner or operator of any affected facility in any category listed in paragraphs (h)(1) or (2) of this section is required to submit excess emission reports for any excess emissions that occurred during the reporting period.

(1) Any affected facility subject to the opacity standards under § 60.43b(e) or to the operating parameter monitoring requirements under § 60.13(i)(1).

(2) Any affected facility that is subject to the NO_X standard of § 60.44b, and that:

(i) Combusts natural gas, distillate oil, or residual oil with a nitrogen content of 0.3 weight percent or less; or

(ii) Has a heat input capacity of 73 MW (250 MMBtu/hr) or less and is required to monitor NO_X emissions on a continuous basis under § 60.48b(g)(1) or steam generating unit operating conditions under § 60.48b(g)(2).

(3) For the purpose of § 60.43b, excess emissions are defined as all 6-minute periods during which the average opacity exceeds the opacity standards under § 60.43b(f).

(4) For purposes of § 60.48b(g)(1), excess emissions are defined as any calculated 30-day rolling average NO_X emission rate, as determined under

§ 60.46b(e), that exceeds the applicable emission limits in § 60.44b.

(i) The owner or operator of any affected facility subject to the continuous monitoring requirements for NO_X under § 60.48(b) shall submit reports containing the information recorded under paragraph (g) of this section.

(j) The owner or operator of any affected facility subject to the SO_2 standards under § 60.42b shall submit reports.

(k) For each affected facility subject to the compliance and performance testing requirements of § 60.45b and the reporting requirement in paragraph (j) of this section, the following information shall be reported to the Administrator:

(1) Calendar dates covered in the reporting period;

(2) Each 30-day average SO_2 emission rate (ng/J or lb/MMBtu heat input) measured during the reporting period, ending with the last 30-day period; reasons for noncompliance with the emission standards; and a description of corrective actions taken;

(3) Each 30-day average percent reduction in SO_2 emissions calculated during the reporting period, ending with the last 30-day period; reasons for noncompliance with the emission standards; and a description of corrective actions taken;

(4) Identification of the steam generating unit operating days that coal or oil was combusted and for which SO_2 or diluent (O_2 or CO_2) data have not been obtained by an approved method for at least 75 percent of the operating hours in the steam generating unit operating day; justification for not obtaining sufficient data; and description of corrective action taken;

(5) Identification of the times when emissions data have been excluded from the calculation of average emission rates; justification for excluding data; and description of corrective action taken if data have been excluded for periods other than those during which coal or oil were not combusted in the steam generating unit;

(6) Identification of "F" factor used for calculations, method of determination, and type of fuel combusted;

(7) Identification of times when hourly averages have been obtained based on manual sampling methods;

(8) Identification of the times when the pollutant concentration exceeded full span of the CEMS;

(9) Description of any modifications to the CEMS that could affect the ability of the CEMS to comply with Performance Specification 2 or 3;

(10) Results of daily CEMS drift tests and quarterly accuracy assessments as required under appendix F, Procedure 1 of this part; and

(11) The annual capacity factor of each fired as provided under paragraph (d) of this section.

(l) For each affected facility subject to the compliance and performance testing requirements of § 60.45b(d) and the reporting requirements of paragraph (j) of this section, the following information shall be reported to the Administrator:

(1) Calendar dates when the facility was in operation during the reporting period;

(2) The 24-hour average SO_2 emission rate measured for each steam generating unit operating day during the reporting period that coal or oil was combusted, ending in the last 24-hour period in the quarter; reasons for noncompliance with the emission standards; and a description of corrective actions taken;

(3) Identification of the steam generating unit operating days that coal or oil was combusted for which SO_2 or diluent (O_2 or CO_2) data have not been obtained by an approved method for at least 75 percent of the operating hours; justification for not obtaining sufficient data; and description of corrective action taken;

(4) Identification of the times when emissions data have been excluded from the calculation of average emission rates; justification for excluding data; and description of corrective action taken if data have been excluded for periods other than those during which coal or oil were not combusted in the steam generating unit;

(5) Identification of "F" factor used for calculations, method of determination, and type of fuel combusted;

(6) Identification of times when hourly averages have been obtained based on manual sampling methods;

(7) Identification of the times when the pollutant concentration exceeded full span of the CEMS;

(8) Description of any modifications to the CEMS that could affect the ability of the CEMS to comply with Performance Specification 2 or 3; and

(9) Results of daily CEMS drift tests and quarterly accuracy assessments as required under Procedure 1 of appendix F 1 of this part. If the owner or operator elects to implement the alternative data assessment procedures described in §§ 60.47b(e)(4)(i) through (e)(4)(iii), each data assessment report shall include a summary of the results of all of the RATAs, linearity checks, CGAs, and calibration error or drift assessments required by §§ 60.47b(e)(4)(i) through (e)(4)(iii).

(m) For each affected facility subject to the SO_2 standards under § 60.42(b) for which the minimum amount of data required under § 60.47b(f) were not obtained during the reporting period, the following information is reported to the Administrator in addition to that required under paragraph (k) of this section:

(1) The number of hourly averages available for outlet emission rates and inlet emission rates;

(2) The standard deviation of hourly averages for outlet emission rates and inlet emission rates, as determined in Method 19 of appendix A of this part, section 7;

(3) The lower confidence limit for the mean outlet emission rate and the upper confidence limit for the mean inlet emission rate, as calculated in Method 19 of appendix A of this part, section 7; and

(4) The ratio of the lower confidence limit for the mean outlet emission rate and the allowable emission rate, as determined in Method 19 of appendix A of this part, section 7.

(n) If a percent removal efficiency by fuel pretreatment (*i.e.*, $\%R_f$) is used to determine the overall percent reduction (*i.e.*, $\%R_o$) under § 60.45b, the owner or operator of the affected facility shall submit a signed statement with the report.

(1) Indicating what removal efficiency by fuel pretreatment (*i.e.*, $\%R_f$) was credited during the reporting period;

(2) Listing the quantity, heat content, and date each pre-treated fuel shipment was received during the reporting period, the name and location of the fuel pretreatment facility; and the total quantity and total heat content of all fuels received at the affected facility during the reporting period;

(3) Documenting the transport of the fuel from the fuel pretreatment facility to the steam generating unit; and

(4) Including a signed statement from the owner or operator of the fuel pretreatment facility certifying that the percent removal efficiency achieved by fuel pretreatment was determined in accordance with the provisions of Method 19 of appendix A of this part and listing the heat content and sulfur content of each fuel before and after fuel pretreatment.

(o) All records required under this section shall be maintained by the owner or operator of the affected facility for a period of 2 years following the date of such record.

(p) The owner or operator of an affected facility described in § 60.44b(j) or (k) shall maintain records of the following information for each steam generating unit operating day:

(1) Calendar date;

(2) The number of hours of operation; and

(3) A record of the hourly steam load.

(q) The owner or operator of an affected facility described in § 60.44b(j) or § 60.44b(k) shall submit to the Administrator a report containing:

(1) The annual capacity factor over the previous 12 months;

(2) The average fuel nitrogen content during the reporting period, if residual oil was fired; and

(3) If the affected facility meets the criteria described in § 60.44b(j), the results of any NO_X emission tests required during the reporting period, the hours of operation during the reporting period, and the hours of operation since the last NO_X emission test.

(r) The owner or operator of an affected facility who elects to use the fuel based compliance alternatives in § 60.42b or § 60.43b shall either:

(1) The owner or operator of an affected facility who elects to demonstrate that the affected facility combusts only very low sulfur oil under

§ 60.42b(j)(2) or § 60.42b(k)(2) shall obtain and maintain at the affected facility fuel receipts from the fuel supplier that certify that the oil meets the definition of distillate oil as defined in § 60.41b and the applicable sulfur limit. For the purposes of this section, the distillate oil need not meet the fuel nitrogen content specification in the definition of distillate oil. Reports shall be submitted to the Administrator certifying that only very low sulfur oil meeting this definition and/or pipeline quality natural gas was combusted in the affected facility during the reporting period; or

(2) The owner or operator of an affected facility who elects to demonstrate compliance based on fuel analysis in § 60.42b or § 60.43b shall develop and submit a site-specific fuel analysis plan to the Administrator for review and approval no later than 60 days before the date you intend to demonstrate compliance. Each fuel analysis plan shall include a minimum initial requirement of weekly testing and each analysis report shall contain, at a minimum, the following information:

(i) The potential sulfur emissions rate of the representative fuel mixture in ng/J heat input;

(ii) The method used to determine the potential sulfur emissions rate of each constituent of the mixture. For distillate oil and natural gas a fuel receipt or tariff sheet is acceptable;

(iii) The ratio of different fuels in the mixture; and

(iv) The owner or operator can petition the Administrator to approve monthly or quarterly sampling in place of weekly sampling.

(s) Facility specific NO_X standard for Cytec Industries Fortier Plant's C.AOG incinerator located in Westwego, Louisiana:

(1) *Definitions.*

Oxidation zone is defined as the portion of the C.AOG incinerator that extends from the inlet of the oxidizing zone combustion air to the outlet gas stack.

Reducing zone is defined as the portion of the C.AOG incinerator that extends from the burner section to the inlet of the oxidizing zone combustion air.

Total inlet air is defined as the total amount of air introduced into the C.AOG incinerator for combustion of natural gas and chemical by-product waste and is equal to the sum of the air flow into the reducing zone and the air flow into the oxidation zone.

(2) *Standard for nitrogen oxides.* (i) When fossil fuel alone is combusted, the NO_X emission limit for fossil fuel in § 60.44b(a) applies.

(ii) When natural gas and chemical by-product waste are simultaneously combusted, the NO_X emission limit is 289 ng/J (0.67 lb/MMBtu) and a maximum of 81 percent of the total inlet air provided for combustion shall be provided to the reducing zone of the C.AOG incinerator.

(3) *Emission monitoring.* (i) The percent of total inlet air provided to the reducing zone shall be determined at least every 15 minutes by measuring the air flow of all the air entering the reducing zone and the air flow of all the air entering the oxidation zone, and compliance with the percentage of total inlet air that is provided to the reducing zone shall be determined on a 3-hour average basis.

(ii) The NO_X emission limit shall be determined by the compliance and performance test methods and procedures for NO_X in § 60.46b(i).

(iii) The monitoring of the NO_X emission limit shall be performed in accordance with § 60.48b.

(4) *Reporting and recordkeeping requirements.* (i) The owner or operator of the C.AOG incinerator shall submit a report on any excursions from the limits required by paragraph (a)(2) of this section to the Administrator with the quarterly report required by paragraph (i) of this section.

(ii) The owner or operator of the C.AOG incinerator shall keep records of the monitoring required by paragraph (a)(3) of this section for a period of 2 years following the date of such record.

(iii) The owner of operator of the C.AOG incinerator shall perform all the applicable reporting and recordkeeping requirements of this section.

(t) Facility-specific NO_X standard for Rohm and Haas Kentucky Incorporated's Boiler No. 100 located in Louisville, Kentucky:

(1) *Definitions.*

Air ratio control damper is defined as the part of the low NO_X burner that is adjusted to control the split of total combustion air delivered to the reducing and oxidation portions of the combustion flame.

Flue gas recirculation line is defined as the part of Boiler No. 100 that recirculates a portion of the boiler flue gas back into the combustion air.

(2) *Standard for nitrogen oxides.* (i) When fossil fuel alone is combusted, the NO_X emission limit for fossil fuel in § 60.44b(a) applies.

(ii) When fossil fuel and chemical byproduct waste are simultaneously combusted, the NO_X emission limit is 473 ng/J (1.1 lb/MMBtu), and the air ratio control damper tee handle shall be at a minimum of 5 inches (12.7 centimeters) out of the boiler, and the flue gas recirculation line shall be operated at a minimum of 10 percent open as indicated by its valve opening position indicator.

(3) *Emission monitoring for nitrogen oxides.* (i) The air ratio control damper tee handle setting and the flue gas recirculation line valve opening position indicator setting shall be recorded during each 8-hour operating shift.

(ii) The NO_X emission limit shall be determined by the compliance and performance test methods and procedures for NO_X in § 60.46b.

(iii) The monitoring of the NO_X emission limit shall be performed in accordance with § 60.48b.

(4) *Reporting and recordkeeping requirements.* (i) The owner or operator of Boiler No. 100 shall submit a report on any excursions from the limits required by paragraph (b)(2) of this section to the Administrator with the quarterly report required by § 60.49b(i).

(ii) The owner or operator of Boiler No. 100 shall keep records of the monitoring required by paragraph (b)(3) of this section for a period of 2 years following the date of such record.

(iii) The owner of operator of Boiler No. 100 shall perform all the applicable reporting and recordkeeping requirements of § 60.49b.

(u) *Site-specific standard for Merck & Co., Inc.'s Stonewall Plant in Elkton, Virginia.* (1) This paragraph (u) applies only to the pharmaceutical manufacturing facility, commonly referred to as the Stonewall Plant, located at Route 340 South, in Elkton, Virginia ("site") and only to the natural gas-fired boilers installed as part of the powerhouse conversion required pursuant to 40 CFR 52.2454(g). The requirements of this paragraph shall apply, and the requirements of §§ 60.40b through 60.49b(t) shall not apply, to the natural gas-fired boilers installed pursuant to 40 CFR 52.2454(g).

(i) The site shall equip the natural gas-fired boilers with low NO_X technology.

(ii) The site shall install, calibrate, maintain, and operate a continuous monitoring and recording system for measuring NO_X emissions discharged to the atmosphere and opacity using a continuous emissions monitoring system or a predictive emissions monitoring system.

(iii) Within 180 days of the completion of the powerhouse conversion, as required by 40 CFR 52.2454, the site shall perform a performance test to quantify criteria pollutant emissions.

(2) [Reserved]

(v) The owner or operator of an affected facility may submit electronic quarterly reports for SO_2 and/or NO_X and/or opacity in lieu of submitting the written reports required under paragraphs (h), (i), (j), (k) or (l) of this section. The format of each quarterly electronic report shall be coordinated with the permitting authority. The electronic report(s) shall be submitted no later than 30 days after the end of the calendar quarter and shall be accompanied by a certification statement from the owner or operator, indicating whether compliance with the applicable emission standards and minimum data requirements of this subpart was achieved during the reporting period. Before submitting reports in the electronic format, the owner or operator shall coordinate with the permitting authority to obtain their agreement to submit reports in this alternative format.

(w) The reporting period for the reports required under this subpart is each 6 month period. All reports shall be submitted to the Administrator and shall be postmarked by the 30th day following the end of the reporting period.

(x) Facility-specific NO_X standard for Weyerhaeuser Company's No. 2 Power Boiler located in New Bern, North Carolina:

(1) *Standard for nitrogen oxides.* (i) When fossil fuel alone is combusted, the NO_X emission limit for fossil fuel in §60.44b(a) applies.

(ii) When fossil fuel and chemical byproduct waste are simultaneously combusted, the NO_X emission limit is 215 ng/J (0.5 lb/MMBtu).

(2) *Emission monitoring for nitrogen oxides.* (i) The NO_X emissions shall be determined by the compliance and performance test methods and procedures for NO_X in §60.46b.

(ii) The monitoring of the NO_X emissions shall be performed in accordance with §60.48b.

(3) *Reporting and recordkeeping requirements.* (i) The owner or operator of the No. 2 Power Boiler shall submit a report on any excursions from the limits required by paragraph (x)(2) of this section to the Administrator with the quarterly report required by §60.49b(i).

(ii) The owner or operator of the No. 2 Power Boiler shall keep records of the monitoring required by paragraph (x)(3) of this section for a period of 2 years following the date of such record.

(iii) The owner or operator of the No. 2 Power Boiler shall perform all the applicable reporting and recordkeeping requirements of §60.49b.

(y) Facility-specific NO_X standard for INEOS USA's AOGI located in Lima, Ohio:

(1) *Standard for NO_X.* (i) When fossil fuel alone is combusted, the NO_X emission limit for fossil fuel in §60.44b(a) applies.

(ii) When fossil fuel and chemical byproduct/waste are simultaneously combusted, the NO_X emission limit is 645 ng/J (1.5 lb/MMBtu).

(2) *Emission monitoring for NO_X.* (i) The NO_X emissions shall be determined by the compliance and performance test methods and procedures for NO_X in §60.46b.

(ii) The monitoring of the NO_X emissions shall be performed in accordance with §60.48b.

(3) *Reporting and recordkeeping requirements.* (i) The owner or operator of the AOGI shall submit a report on any excursions from the limits required by paragraph (y)(2) of this section to the Administrator with the quarterly report required by paragraph (i) of this section.

(ii) The owner or operator of the AOGI shall keep records of the monitoring required by paragraph (y)(3) of this section for a period of 2 years following the date of such record.

(iii) The owner or operator of the AOGI shall perform all the applicable reporting and recordkeeping requirements of this section.

Subpart Dc—Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units

SOURCE: 72 FR 32759, June 13, 2007, unless otherwise noted.

§60.40c Applicability and delegation of authority.

(a) Except as provided in paragraph (d) of this section, the affected facility to which this subpart applies is each steam generating unit for which construction, modification, or reconstruction is commenced after June 9, 1989 and that has a maximum design heat input capacity of 29 megawatts (MW) (100 million British thermal units per hour (MMBtu/hr)) or less, but greater than or equal to 2.9 MW (10 MMBtu/hr).

(b) In delegating implementation and enforcement authority to a State under section 111(c) of the Clean Air Act, §60.48c(a)(4) shall be retained by the Administrator and not transferred to a State.

(c) Steam generating units that meet the applicability requirements in paragraph (a) of this section are not subject to the sulfur dioxide (SO_2) or particulate matter (PM) emission limits, performance testing requirements, or monitoring requirements under this subpart (§§60.42c, 60.43c, 60.44c, 60.45c, 60.46c, or 60.47c) during periods of combustion research, as defined in §60.41c.

(d) Any temporary change to an existing steam generating unit for the purpose of conducting combustion research is not considered a modification under §60.14.

Biomass Wood Supply Quality Control Procedures
Plainfield Renewable Energy LLC

January 18, 2008

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Contents

Introduction

Plainfield Renewable Energy LLC ("PRE") is developing a gasification/power plant facility at a site located on Mill Brook Road in Plainfield, Connecticut. Access to the facility is located near the intersection of Mill Brook Road and State Route 12 (Norwich Road). This document outlines PRE's multi-level fuel quality management plan to monitor, control, and report upon fuel quality for the facility (the "Protocol"). This approach is detailed in the following sections and summarized as follows:

1. PRE will pre-qualify all suppliers of wood fuel before accepting deliveries at the facility. The pre-qualification approach applicable to each potential supplier is described below in this Protocol and based upon the type of wood to be produced by each, taking into consideration issues of concern that may apply to each;
2. Each facility that produces qualifying wood fuel chips derived from construction and demolition debris ("C&D") must comply with the requirements of "Exhibit 1: Operating, Sampling & Testing Requirements; Volume Reduction / Facilities Generating C&D Wood Chips For Delivery to PRE";
3. PRE will conduct on-going sampling of wood fuel being introduced into the gasification system at its facility on a daily basis, with testing to be performed as discussed below;
4. Not less than twice per year, PRE will provide the Connecticut Department of Environmental Protection ("CTDEP") with a report prepared by an independent Connecticut Licensed Professional Engineer approved by the CTDEP of its efforts to monitor fuel quality, which report shall include: a.) a review of test information received from VRF's; b.) the results of its own fuel quality reviews, sampling, and testing pursuant to this Protocol; c.) a conclusion regarding the conformance of the fuel stream with these requirements based upon the information available; and, d.) a review of the number of tons of wood fuel both received and processed at the facility, including a breakdown of incoming wood fuel by regulatory category; and,
5. PRE will maintain at the facility records of wood fuel quality for not less than five (5) years.

Summary of PRE Wood Fuel Streams

Following are the types of wood fuel to be received at the facility:

Table 1: Wood Fuel Streams

Biomass Wood	Description/Example
Land Clearing Debris[1]	chipped trees, stumps, branches or brush
Recycled Wood[2] or Clean Wood[3]	chipped pallets, skids, spools, packaging materials, bulky wood waste or scraps from newly built wood products

[1] RCSA 22a-208a-1: "Land Clearing Debris" means trees, stumps, branches, or other wood generated from clearing land for commercial or residential development, road construction, routine landscaping, agricultural land clearing, storms, or natural disasters.

[2] CGS 22a-209a: "Recycled wood" means any wood or wood fuel which is derived from such products or processes as pallets, skids, spools, packaging materials, bulky wood waste or scraps from newly built wood products, provided such wood is not treated wood.

Biomass Wood	Description/Example
Regulated Wood Fuel[4] **Processed Construction and Demolition Wood**[5]	processed and chipped wood recovered from construction and demolition wastes
Other Clean Wood	other types of properly sized, clean. uncontaminated wood materials, such as sawdust, chips, bark, tree trimmings or other similar materials.

PRE Fuel Supplier Pre-Qualification Procedures

PRE will follow the following pre-qualification process, as applicable to each of the various types of wood fuel identified above to be delivered by potential suppliers.

Source: Landclearing Debris &/or Other Clean Wood

Suppliers of this category of wood fuel are expected to be comprised of parties such as:

- Municipal Operations (Public Works Operations, Parks Departments & Residents);
- Regional/State Agencies & Authorities;
- Tree Trimming/Utility Services;
- Developers and Landclearing Contractors; and,
- Forestry Management Professionals.

It is expected that most suppliers in this category of wood fuel will not have permitted volume reduction or recycling facilities and PRE-specification wood fuel may often not be generated at fixed locations, but produced at the location where the wood is harvested.

If a fixed facility location is involved, PRE will visit the site and inspect the nature of the operation and type of materials being handled. For all suppliers, PRE will discuss the following items, which will be incorporated into contract arrangements with the potential supplier:

- Source of wood fuel
- How wood is stored, if at all, prior to processing (chipping) and delivery to PRE
- Method used to size reduce wood to meet PRE's specifications
- Review of PRE's list of prohibited materials

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[3] RCSA 22a-208a-1: "Clean wood" means any wood which is derived from such products as pallets. skids, spools. packaging materials. bulky wood waste, or scraps from newly built wood products, provided such wood is not treated wood as defined in section 22a-209a of the General Statutes or demolition wood.

[4] Sec. 22a-209a: "Regulated wood fuel" means processed wood from construction and demolition activities which has been sorted to remove plastics, plaster, gypsum wallboard, asbestos, asphalt shingles and wood which contains creosote or to which pesticides have been applied or which contains substances defined as hazardous under section 22a-115. [Note: the statute also limits the amount of non-wood material other than dirt or metal fasteners to not more than one per cent by dry weight and limits to fifteen one-hundreds of one per cent. by dry weight total chlorine. Further, there are requirements for approved testing.]

[5] Sec. 22a-208x: "Processed Construction and Demolition Wood" means the wood portion of construction and demolition waste which has been sorted to remove plastics, plaster, gypsum wallboard, asbestos, asphalt shingles, regulated wood fuel as defined in section 22a-209a and wood which contains creosote or to which pesticides have been applied or which contains substances defined as hazardous waste under section 22a-115

- Execution of a fuel supply agreement that limits the type of wood fuel eligible for delivery by the supplier; and,
- Provided the potential supplier, its wood source and method of operations all comply with the above provisions, it will be allowed to commence deliveries.

Source: Recycled Wood and/or Clean Wood

Suppliers of this category of wood fuel are expected to be comprised of parties such as:

- Utilities and utility contractors;
- Wood products manufacturers; and,
- Municipal and private entities holding individual and general permits (permittees) for facilities such as transfer stations, VRFs, similar facilities

The majority of suppliers of wood fuel in this category are expected to operate at fixed locations. Further, some but not all of the suppliers will be permittees of solid waste facilities approved by CTDEP or nearby states. PRE's prequalification process for these potential suppliers is as follows:

- The supplier will provide PRE with a written description of its wood stream, wood screening, wood handling and management operations;
- Copies of all permits, registrations, and related documents including O&M plans will be provided to PRE for its review;
- A representative of PRE will visit the potential supplier once each month over a consecutive three-month period. Each visit shall include an inspection of the processing system and sampling of wood fuel proposed to be delivered to PRE's facility. PRE will have each such sample analyzed as specified below under "C&D Wood Chip Laboratory Analysis"; and,
- Provided the laboratory results confirm the wood fuel meets the limits and is also consistent with that associated with recycled wood or clean wood, and further provided PRE is satisfied with the business terms and results of the above investigations, PRE will enter into a fuel supply agreement that limits the type of wood fuel eligible for delivery by the supplier including delineation of prohibited materials, and the party will be allowed to commence deliveries.

Source: Regulated Wood Fuel and/or Processed Construction & Demolition Wood

Suppliers of this category of wood fuel or mixtures of this and other types of acceptable wood fuel are expected to be parties such as:

- Permittees with facilities such as transfer stations or a volume reduction facilities ("VRFs") permitted by CTDEP or another state.

The pre-qualification process for such suppliers and their facilities is as follows:

- PRE will provide each potential supplier with a copy of Exhibit 1, and meet with the management representative of such potential supplier to review the requirements enumerated therein and methods for compliance;
- Each potential supplier will be required to provide PRE with:
    - A description of its operations/facility plan for handling, sorting, and preparing acceptable wood fuel from C&D debris, including;
        - a description of its sorting approach;
        - description of storage approach;
        - description of employee training and monitoring;
        - steps to be taken to screen out unacceptable materials including unacceptable wood materials;

        - facility management structure and staffing;
        - prohibited materials;
        - method of delivering wood to PRE; and,
        - discussion of sources of material to the facility and related matters.
    - A copy of all current permits for the operation and management of the facility. If the permittee is required to modify or alter its permit or O&M plan to accommodate shredder/chippers, or sorting equipment and/or activities in order to comply with PRE's requirements, the permittee must demonstrate it has done so to the satisfaction of PRE;
- Review of PRE's list of prohibited materials;
- PRE will inspect the facility. Such inspection will include:
    - Consideration of the processing and sorting approach and its capacity to allow for segregation of acceptable from unacceptable wood materials;
    - Consideration of space for storage of the acceptable wood fuel supply, and suitability of the facility layout to allow the permittee to avoid contamination of the fuel supply desired to be delivered to PRE;
    - A representative of PRE will visit the potential supplier twice (2 times) each month over a consecutive three-month period. Each visit shall include an inspection of the processing system and sampling of wood fuel proposed to be delivered to PRE's facility. PRE will have each such sample analyzed as specified below under "C&D Wood Chip Laboratory Analysis";
- Provided the laboratory results confirm the wood fuel complies with the limits specified in the VRF Protocol, and PRE's determination that the business terms are acceptable, execution of a fuel supply agreement that limits the type of wood fuel eligible for delivery by the supplier; and,
- The supplier will be allowed to commence deliveries.

After the pre-qualification process for Regulated Wood Fuel or Processed Construction & Demolition Debris suppliers is completed, ongoing requirements will include:

- Suppliers are to be obligated to notify PRE of any subsequent change in their process flow or operating system. Such changes may trigger a complete re-qualification of the facility, or confirmation of the original qualification;
- Suppliers are to be obligated to provide PRE with copies of any new or modified permits;
- PRE will conduct random on-going inspections of all qualified suppliers of wood in this category not less than once each quarter for not less than eight consecutive quarters to insure that operations have remained consistent with the pre-qualification process, the requirements of Exhibit 1, and to re-sample wood fuel on-site prior to shipment to PRE.

PRE Facility Sampling & Wood Quality Management

PRE will implement and maintain an on-going wood sampling and quality control program at its facility as follows:

1. Only approved suppliers that have completed PRE's prequalification process as described above will be granted access to the facility for fuel deliveries.
2. PRE will review incoming wood fuel deliveries for conformance with its agreement with the individual suppliers. This review process may include a range of analytical approaches, including visual inspection, field analysis, and random sampling and laboratory analysis. The goals of this process will be to:

a. Evaluate consistency of the wood fuel deliveries to that which the supplier is authorized to deliver;
b. Evaluate consistency with size requirements (see PRE fuel specifications);
c. Provide enhanced oversight over new suppliers as a supplement to the prequalification process and to any individual supplier where a concern or question has arisen; and
d. Place suppliers in the position of having individual loads subject to unannounced sampling and/or detailed analysis.

From time-to-time on an unannounced basis, PRE will segregate individual deliveries to the facility for the purpose of this review process. Field analysis of incoming deliveries of Regulated Wood Fuel or Processed Construction & Demolition Wood will include the frequent use of a PAN indicator or an XRF hand-held device to detect treated wood, as discussed in Exhibit 1.

3. In order to provide a more homogenous fuel feed mixture to the power block facility, PRE will mix wood from the various suppliers, resulting in a more uniform moisture and BTU content feedstock;
4. PRE may utilize a shredder/chipper at the facility as-required to process any wood fuel that is oversized, as delivered. Such shredder/chipper may either be stationed at the facility permanently or mobilized if-and-as-required;
5. Daily samples of the wood fuel will be taken by PRE randomly from the wood storage area or from the in-feed conveyor system as wood fuel is being delivered to the power block unit. Such daily samples will be combined to form a monthly composite sample. A representative portion of such composite sample will be subjected to analysis as discussed below under "C&D Wood Chip Laboratory Analysis". Following the first year of operation and only provided PRE demonstrates that for each such testing the wood feedstock complied with the limits stated therein, PRE shall conduct such sampling and composite analysis one month each quarter during the second year of operations. Thereafter, PRE may request and CTDEP may approve elimination of this sampling requirement.
6. PRE will analyze the ash residue produced by the facility on a quarterly basis for total metals (arsenic, barium, cadmium, chromium, lead, mercury, selenium, silver). PRE will obtain representative hourly samples over an 8-hour period, to be combined to form a composite sample for laboratory analysis[6]. Provided such sampling and testing demonstrates the ash residue is not deemed hazardous for four consecutive quarterly test events, PRE may request and CTDEP may approve elimination of this sampling.
7. The results of all laboratory analysis performed on sampling performed by PRE at its facility or VRFs, and performed by VRFs at such locations, will be maintained at PRE's facility for a period of not less than five (5) years. Any result that does not comply with the stipulated Acceptance limits will be reported to CTDEP within fifteen (15) days following PRE's receipt of such test report. Such reporting will also contain PRE's plan for compliance.

[6] All Chemical Laboratory Analyses must be performed by a laboratory certified by the State of Connecticut Department of Public Health & Addiction Services. All analyses must be performed in accordance with EPA's *Test Methods for Evaluating Solid Wastes: Physical/Chemical Methods, SW-846, as revised* or DEP-approved equivalent.

C&D Wood Chip Laboratory Analysis[7]

Following is a description of the laboratory tests to be applied to wood chip sampling conducted on blended fuel delivered to the gasification power block unit under this document, including all wood fuels. See Exhibit 1 for laboratory analysis and acceptance limits that may apply to "Regulated Wood Fuel", "Processed Construction & Demolition Wood" or a mixture of such wood fuel chips with other types of acceptable wood as may be produced at permitted solid waste facilities such as volume reduction facilities, as discussed in this protocol:

Table 2: Laboratory Analysis & Acceptance Limits

Analytical Test	Test Method[8]	Acceptance Limits
Arsenic, Total	6010	Less than 20 ppm[9]
Cadmium, Total	6010	Less than 20 ppm
Chromium, Total	6010	Less than 200 ppm
Lead, Total	6010	Less than 250 ppm
Mercury, Total	7141	Less than 0.2 ppm
Selenium, Total	6010	Less than 20 ppm
Silver, Total	6010	Less than 100 ppm
Titanium, Total	6010	Less than 300 ppm
Zinc, Total	6010	Less than 200 ppm
Pesticides, Total[10]	8081A	Not Detected at 160 ppb
Herbicides, Total[11]	8151A	Not Detected at 500 ppb
Polychlorinated Biphenyls (PCBs), Total[12]	8082	<20 ppm[13]
O, M, & P Cresols,	8270	4,000 ppm for each
Plastics		Less than 1% dry weight
Chlorine (total)	EPA Method 330.5	Less than 0.15% dry weight
Total Non-Wood other than dirt and metal fasteners		Less than 1% dry weight

[7] Concurrent with initial stack emission testing conducted pursuant to PRE's CTDEP air permits, sampling and testing of wood fuel processed at the facility will also be conducted. Based upon the data so obtained (test results of Regulated Wood Fuel or Processed Construction & Demolition Wood mixtures as produced and measured at VRFs or similar processing facilities, testing of wood fuel blends as fed to the gasification system, and stack test results), these Acceptance Limits will be confirmed or modified, as approved by CTDEP, associated with compliance with Maximum Allowable Stack Concentrations in accordance with RCSA sec. 22a-174-29. PRE may propose subsequent modifications to such Acceptance Limits for CTDEP's consideration and potential approval.

[8] See note 6.

[9] ppm = parts per million

[10] Only tested if the wood source suggests it may have been exposed to pesticides.

[11] Only tested if the wood source suggests it may have been exposed to herbicides.

[12] Only tested if the wood source suggests it may have been exposed to transformers, hydraulic equipment, or PCB waste oil.

[13] If the original source had a PCB content of >50 ppm, then the material is rejected.

Exhibit 1

Operating, Sampling & Testing Requirements
Volume Reduction / Facilities Generating C&D Wood Chips
For Delivery to PRE

January 18, 2008

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Contents

[1] Attachments from "Guidance for the Management and Disposal of CCA-Treated Wood", draft August 2005 by Florida DEP, Florida Center for Solid and Hazardous Waste Management, University of Florida and University of Miami. http://www.dep.state.fl.us/waste/quick_topics/publications/shw/solid_waste/CCABMPDraft08-10-05.pdf

Background & Purpose

Plainfield Renewable Energy LLC ("PRE") is developing a gasification/power plant facility at a site located on Mill Brook Road in Plainfield, Connecticut. Access to the facility is located near the intersection of Mill Brook Road and State Route 12.

The PRE facility will employ state-of-the-art air pollution control systems, including a wet/dry scrubber for control of acid gasses and metals emissions, a high-efficiency baghouse for particulate collection, and SNCR reduction for NOx control. In addition, gasification technologies as part of power plant systems have been shown to be inherently preferable from emission perspectives. PRE expects the facility will be the first biomass wood gasification plant in the U.S. that will employ all of these pollution control systems.

The facility will accept and process biomass wood from a range of sources, including: forest management residues, landclearing debris, and waste wood from municipalities and a range of industries. In addition, the facility will be authorized to accept and gasify wood derived from the processing of construction and demolition debris ("C&D"). This document outlines the requirements that suppliers must meet as a condition of delivering to PRE an acceptable wood chip stream that is derived from C&D debris.

Before Delivering Material to PRE

C&D processing and recycling facilities in Connecticut have primarily been permitted by the Connecticut Department of Environmental Protection ("CTDEP") as volume reduction facilities ("VRF's").

As a prerequisite to commencing deliveries of acceptable biomass wood recovered from C&D (hereinafter "C&D Wood") and chipped to PRE's size specification, the responsible party of each such processing facility (the "Permittee") must:

1. Enter into the appropriate business agreement with PRE;
2. Adopt and implement this plan for separating and processing C&D derived wood fuel;
3. Compliance with PRE's requirement related to inspection, testing, operations, and reporting related to handling of C&D waste and preparation of acceptable wood fuel;
4. Provide PRE with a copy of all permits issued by CTDEP or any other regulatory body with respect to the facility, including modifications, renewals and re-issuances as may occur from time-to-time; and,
5. Perform the required sampling and analysis called for in this document, and provide timely reports of the analysis to PRE.

PRE will suspend and/or terminate deliveries from parties not complying with these requirements.

Wood Chip Specifications

C&D Wood must comply with the following in order to be acceptable for delivery to PRE:

- Reduced to not more than four inches (4") in size, with 90% not more than three inches (3") in any dimension, and not more than 10% smaller than ¼ inch.
- Have been prepared pursuant to a screening & sorting process to remove the following;
    - Plastics
    - Plaster
    - Gypsum
    - Asbestos
    - Asphalt shingles
    - Wood treated with or containing:
        - Creosote
        - Pesticides; and,
        - Hazardous waste per CGS §22a-115.
- Undercover storage of unprocessed and processed chips of wood sorted from C&D waste.

Permittee/Producer's Responsibility

It is the responsibility of the Permittee/producer of the C&D Wood chip stream to adopt operating procedures that comply with these requirements, and to perform the associated monitoring, sampling, testing and reporting activities.

Each supplier/VRF is also responsible to insure the appropriate permits have been issued for the receipt, storage and processing of C&D wastes at its facility (ies).

Facility Layout, Handling/Processing Approach

Each producer is to demonstrate to the satisfaction of PRE that its facility configuration and design does not inhibit and provides opportunities for the operating staff to reasonably perform the sorting, inspection, rejection, and screening activities called for herein under normal operating conditions, including the method of receiving and handling materials in the tipping area and production of a C&D Wood stream that complies with these requirements.

It is anticipated that producers may utilize a range of separation and processing approaches, including:

- Selective separation of clean, acceptable wood on a tipping floor for grinding or size reduction and delivery to PRE;
- Selective separation of treated unacceptable wood on a tipping floor to reduce the potential for contamination of the wood fuel stream intended for delivery to PRE;
- Use of a sorting line that may involve a range of technologies (such as screening, air classification, etc.) together with manual approaches to either positive-pick acceptable wood, or positive-pick unacceptable wood to produce an acceptable wood fuel stream in combination with grinding or size reduction technology;

- Acceptance of source-separated acceptable wood, in combination with inspection and quality control procedures; or,
- A combination of the above or other acceptable approaches.

Treated Wood Separation

Operating procedures are to be implemented and maintained for the screening and separation of wood waste treated with creosote, pesticides or hazardous waste (as defined in Connecticut General Statutes §22a-115). Such measures are to include;

- Where appropriate to the scale of the project, inspection of demolition sites where waste is generated;
- Customer Communications;
- Personnel Training for on-site load inspection and identification;
- Manual Sorting/Segregation; and,
- On-Site Testing as discussed below.

These strategies are discussed below.

Customer Communications

C&D processors shall communicate with customers to determine if incoming C&D wastes are known or suspected to contain treated wood. Many types of construction, reconstruction and demolition activities may include treated wood, including activities related to decks, landscaping, retaining walls, docks or other marine environment structures, and certain utility activities may reasonably be expected to include concentrations of treated wood.

Gaining advanced knowledge of the suspected presence of treated wood will make the efforts associated with segregating treated wood more efficient, enhancing success of the operation. If customers segregate treated wood at the source of generation, the Permittee shall handle such source-separated treated wood separately from the mixed C&D stream, so as to minimize the potential for including treated wood in the C&D Wood chips destined for PRE.

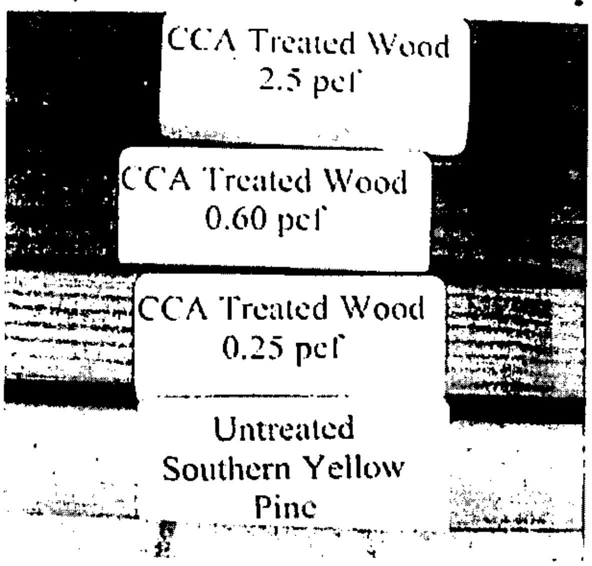
Personnel Training

Processors must train and supervise their labor pool to insure that good separation takes place. There are several types of wood preservatives that are in use and that have been in use in the past. One of the most prevalent historical preservatives is chromated copper arsenate ("CCA"), which is reported to have comprised up to 80% of the treated wood used in residential applications as recently as 2002, and the use of which was discontinued by the wood treating industry after December 31, 2003. Some level of CCA treated wood was sold thereafter, as the remaining production worked through the retail and distribution system after 2003. Other preservatives include alkaline copper quaternary ("ACQ") and copper boron azole ("CBA"). ACQ treated wood is common in retail stores in Connecticut at this time. Florida has determined that non-arsenic treatments (meaning ACQ and CBA) used in residential applications pose little or no significant risk to the environment or human health[1].

Other chemicals have been used in industrial wood treatment applications, including:
- Pentachlorophenol ("PCP") for utility poles, piling, highway posts and guardrails; and,
- Creosote for utility poles, railroad ties, highway crossing planks, panels and flanges, marine and other pilings, flooring blocks, Glulam (Glue-Laminated wood), and bridge timbers.

The primary means to identify treated industrial wood products is visual and dimensional. These materials are typically easy to identify and remove from the waste stream, and include telephone poles, bridge timbers, railroad ties, pilings and similar items. Oak and mixed hardwoods typically reflect over 90% of the treated rail crossties, switch and bridge ties, but only just over 10% of the total treated stream. Staff is to be trained to visually identify these materials and segregate them from the C&D wastes being further processed into C&D Wood chips for delivery to PRE.

According to extensive work done in other states, and Florida in particular[2], "the most common method for identifying untreated wood among treated lumber, timber and plywood is to look at the color of the wood. Untreated wood and borate-treated wood typically have a light yellow color." "Wood treated with copper, which includes CCA, ACQ and CBA treated wood varies in color from a very light green to an intense green color depending upon the amount of chemical impregnated into the wood." Further, treated wood in the C&D waste stream has been found to be mostly dimensional lumber and cutoffs[3].



The photo at the left is from the above referenced Florida report, and illustrates the gradations in coloring for treated wood, compared to untreated wood. Permittees are to train their staff in the visual identification of treated wood.

Weathered wood that has been treated with copper is reported to be converted to silver color, which is similar in appearance to untreated wood. Consequently, Permittees

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[1] "Guidance for the Management and Disposal of CCA-Treated Wood", published in draft form August 2005 by the Florida DEP, Florida Center for Solid and Hazardous Waste Management, University of Florida and University of Miami. http://www.dep.state.fl.us/waste/quick_topics/publications/shw/solid_waste/CCABMPDraft08-10-05.pdf

[2] See the Florida Guidance Document.

[3] *Alternative Chemicals and Improved Disposal-End Management Practices for CCA-Treated Wood*, July 7, 2000, Florida Center for Solid & Hazardous Waste Management, Report #00-03

need to train staff to be particularly vigilant in segregating and not process such material for delivery to PRE as C&D Wood chips if it could be treated wood. For example, much of typical treated wood components are dimensionally recognizable (decking, landscape lumber, industrial lumber, etc.). Permittees shall also maintain on-site and deploy a testing methodology for quality control purposes as discussed below under "On-Site Testing Approaches".

Where possible, Permittees should deploy and utilize sorting staff so that more than one opportunity to identify and remove treated wood is utilized, under a multi-screening approach. Such an approach may include:

- Initial Load Inspection. Inspection of the load prior to tipping if possible, but certainly as-tipped. This may include asking the driver what his/her observations were as the box was being picked up, and certainly include trained equipment operators, gate attendants, or other "spotters".
- Floor Inspection. Inspection of the load as it is tipped and spread on the tip floor before storage and processing, and use of floor pickers to remove unacceptable items that will not be processed into wood fuel.
- Sorting Line Pickers. Inspection of wood materials on a sorting line, if utilized, where workers have the ability to examine each wood item one or more times. Permittees are to "positive" pick wood that is suitable for delivery to PRE.

Permittees are to take advantage of the full compliment of operating and sorting personnel that inspect and observe materials from the point of entry into the plant, through to the final decision point for segregation of suitable C&D Wood for further chipping and transport to PRE.

Permittees are also to post one or more signs in the areas where sorting is conducted to remind workers to sort out treated wood for disposition consistent with the method of operations conducted at the C&D waste processing facility, and as approved by PRE. Permittees may elect to utilize one of the identification technologies discussed below to assist in evaluating whether a particular sample is treated. Attachment 1 is taken directly from the referenced report and will assist in training operating staff in the visual identification of treated wood.

Manual Sorting/Segregation

An individual facility's configuration will impact the approach used to manually sort and segregate treated wood from non-wood and unacceptable materials in the C&D wastestream. For example, certain process arrangements may require that treated wood be removed to the extent practical before the remaining C&D waste is "processed" by the system. A processing approach may provide sorting staff with an ideal location to inspect wood materials and to segregate treated and clean wood, preparing an acceptable stream of sorted, chipped C&D Wood chips for delivery to PRE.

Each Permittee should consider the configuration of its facility layout and sorting system, and take advantage of each opportunity available to identify and sort for the removal and/or omission of unacceptable materials and treated wood from the C&D Wood chips suitable for delivery to PRE.

On-Site Testing

Certain technologies have been developed that allow Permittees to perform further tests upon an individual piece of wood that is suspect to having been treated. Typically, these approaches are used for quality control, or to further review an individual piece of wood, complementing visual sorting efforts. Each such technology provides a means to help Permittees verify suspect or questionable materials, or to perform quality reviews on separated materials.

Permittees should have available on-site one or both of the following equipment and supplies so that segregated wood chips intended to be delivered to PRE can be further inspected for acceptability.

Any questionable items should be excluded in the normal practice, and only included if subjected to further screening by the Permittee.

Staining Technology

Chemical stains have been developed by the wood treatment industry, originally to assist in checking the depth of penetration of the preservative in wood. The industry refers to these as chrome azurol, PAN indicator, and rubeanic acid. Stains detect the presence of copper based treatments, which will include CCA and also other treatments of less concern such as ACQ. After applying the stain to treated wood, a distinctive color change occurs. PAN has been identified as the preferred stain due to its short reaction time (12 seconds) and low cost. Untreated wood turns orange, and treated wood changes to a color ranging from magenta to red. Also, it should be noted that the PAN indicator discussed below can give "false" indications that wood is treated due to sealants or surface treatments, since it is primarily detecting metals. PAN will test positive for the newer copper-based treated woods, resulting in sorting out of the C&D Wood stream materials that do not contain arsenic and which some states have considered acceptable. Over time, newer stains may become available. Attachment 2 contains information on the PAN stain, including how to obtain supplies. This technology is well-suited for use in sorting small quantities or quality control purposes.

The photo above is reproduced from the above referenced Florida Guidance document. The wood on the left is untreated, and the sample on the right is treated wood, showing the effect of various stains.

XRF Technology
Certain vendors also sell and rent hand-held X-ray fluorescence devices that have been used to identify arsenic in treated wood. These units are expensive (costing up to $30,000 each). XRF devices can also be used for quality control and validation purposes on individual pieces of wood. Contact PRE for information on these devices and vendors.

Removal of Non-Wood Operating Requirements

C&D processors must also remove non-wood materials from the C&D Wood chips delivered to PRE, paying particular attention to remove all of the following:

- Plastics
- Plaster
- Gypsum
- Asbestos
- Asphalt shingles
- Glass and metals

One of the regulatory classifications of C&D Wood that may be produced at the CTDEP Permitted VRF's is called "regulated wood fuel", about which Connecticut law (Sec. 22a-209a) says:

> *"No regulated wood fuel user shall use or burn (1) regulated wood fuel which contains nonwood material, other than dirt or metal fasteners, unless such material comprises less than one per cent, by dry weight, of such regulated wood fuel or (2) any such fuel which contains more than fifteen one-hundredths of one per cent, by dry weight, total chlorine. Any sampling or analysis to determine the percentage of total chlorine or the amount of nonwood material shall be provided for by the regulated wood fuel merchant and shall be certified by such merchant as having met any standards or methodologies for such sampling or analysis approved or required by the commissioner."*

In plain wording, the above law says that producers of regulated wood fuel cannot have more than 1% by weight non-wood material in the stream, excluding dirt or metal fasteners. Also, such regulated wood must contain less than 0.15 of 1% (or 0.15%) by weight total chlorine, as determined by laboratory analysis, discussed below.

Different facilities will use different approaches to minimizing the amount of non-wood materials in the wastestream.

Monitoring, Sampling & Testing

Permittees shall perform the monitoring, sampling, testing of wood chips and reporting requirements outlined below.

Managing Facility Operations

Each Permittee shall identify a site manager that is trained and responsible to direct operating and sorting staff in the removal of treated wood and non-wood materials from the C&D Wood destined for delivery to PRE.

Sampling

The Permittee's site manager shall take a representative sample of C&D Wood chips ready for shipment to PRE and assist PRE in its own sampling efforts according to the following:

Sampling Frequency

Prior to Commencing Delivery (Qualifying Phase)

PRE will conduct multiple qualifying sampling events at each candidate facility over a three month period before deliveries can be approved. Each Permittee is to cooperate with PRE by providing requested documentation and support PRE's efforts to inspect the facility and obtain representative samples.

While Deliveries are On-Going (Operating Phase)

Wood chips prepared for shipment to PRE shall be sampled by the Permittee not less often than once per week of operations, creating a calendar quarterly composite sample (such as: Jan-March, etc.). Once the quarterly composite is mixed thoroughly, a composite sample is to be obtained and sent by the Permittee to a laboratory for analysis as discussed below.

Sampling Location & Method

Depending upon the facility layout and handling approach, weekly samples of the sorted and chipped fuel ready for delivery to PRE may be taken from:

a. a cross-belt sample of the stream of the wood chips within the process line, provided such fuel has already been sorted and chipped to meet PRE's specifications; or,

b. a pile of wood chips prepared for delivery to PRE.

The site manager or other trained personnel are to take the sample reflecting the most recently generated wood chips for PRE delivery as available at that time. A sample size representing a large scoop or small shovel is recommended. Review with PRE the size and location of the weekly sample to be obtained.

Sample Storage

On-site samples are to be kept secure, preferably in a sealed container, properly labeled and located in a safe area of the facility where they are unlikely to be spilled, opened or otherwise contaminated.

Composite Sample

At the end of each calendar quarter during the operating phase, each producing facility is to thoroughly mix the composite of weekly samples, and randomly select approximately one gallon of material for laboratory analysis. Permittees shall also secure an additional, one gallon back-up sample, for use in the event the primary sample is lost or damaged, or to help answer any specific questions.

Laboratory Analysis

Following is a description of the laboratory tests to be performed[4]:

Analytical Test	Test Method[5]	Acceptance Limits
Arsenic, Total	6010	Less than 50 ppm[6]
Cadmium, Total	6010	Less than 20 ppm
Chromium, Total	6010	Less than 200 ppm
Lead, Total	6010	Less than 250 ppm
Mercury, Total	7141	Less than 0.2 ppm
Selenium, Total	6010	Less than 20 ppm
Silver, Total	6010	Less than 100 ppm
Titanium, Total	6010	Less than 300 ppm
Zinc, Total	6010	Less than 200 ppm
Pesticides, Total[7]	8081A	Not Detected at 160 ppb
Herbicides, Total[8]	8151A	Not Detected at 500 ppb
Polychlorinated Biphenyls (PCBs), Total[9]	8082	<20 ppm[10]
O, M, & P Cresols.	8270	4,000 ppm for each
Plastics		Less than 1% dry weight
Chlorine (total)	EPA Method 330.5	Less than 0.15% dry weight
Total Non-Wood other than dirt and metal fasteners		Less than 1% dry weight

Reporting

All laboratory analysis test results (including results of any exceedances with any "second" or subsequent tests as described below) of sampling activities are to be provided to PRE for reporting and maintenance for at least five years.

In the Event of an Exceedance

In the event testing results from on-going quarterly sampling indicate an exceedance occurred, the Permittee shall respond as follows:

- The Permittee is to notify PRE of its test results, and non-compliance;

[4] PRE, with approval of CTDEP, will update these Acceptance Limits following comprehensive stack testing at the facility after startup. Nonetheless, PRE may elect to discontinue receiving fuel from any supplier at any time in its sole discretion. Following initial establishment of Acceptance Limits, PRE may modify such limits and/or testing requirements in accordance with CTDEP authorizations.

[5] All Chemical Laboratory Analyses must be performed by a laboratory certified by the State of Connecticut Department of Public Health & Addiction Services. All analyses must be performed in accordance with EPA's *Test Methods for Evaluating Solid Wastes: Physical Chemical Methods, SW-846, as revised* or DEP-approved equivalent.

[6] ppm = parts per million

[7] Only tested if the wood source suggests it may have been exposed to pesticides.

[8] Only tested if the wood source suggests it may have been exposed to herbicides.

[9] Only tested if the wood source suggests it may have been exposed to transformers, hydraulic equipment, or PCB waste oil.

[10] If the original source had a PCB content of >50 ppm, then the material is rejected.

- If a back-up sample is available, a second test can be performed on the composite for that quarter.
- The Permittee will review its separation and sorting requirements with operating staff and PRE. As appropriate, adjustments to the separation procedures must be implemented to achieve compliance. An additional sampling/testing event will be conducted immediately following the implementation of such changes to its procedures.
- PRE may direct the Permittee to suspend or terminate deliveries in the event the circumstances that resulted in the exceedance are not corrected.

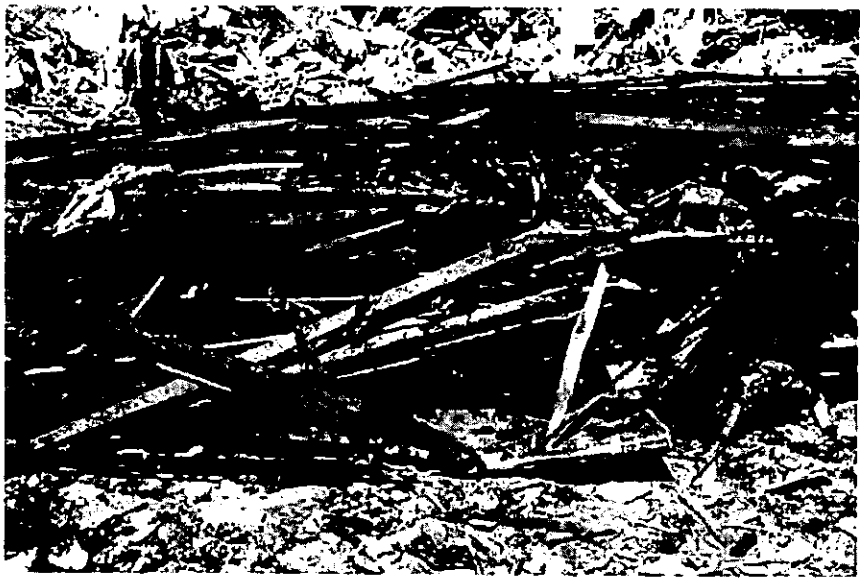
The results of the Permittee's review of its procedures and the additional testing shall be a.) maintained at the VRF facility for a period of not less than five (5) years; b.) provided to PRE within seven (7) days of receipt of the test results; and, c.) maintained at PRE's facility for five years.

ATTACHMENT 1

Pictures of Waste Loads That Typically Contain Treated Wood

Loads of yard waste may contain CCA-treated wood from fencing, fence posts or landscaping timbers. This piece of wood is likely treated due to its green hue and large dimensions.

This load is a mix of yard waste, CCA-treated fencing and CCA-treated landscaping timbers. Treated wood can be identified based on the fact that it is sawn and is characterized by a green hue. The sawn board in the bottom is obviously treated. It is difficult to tell for the highly weathered sawn boards.



Loads from the demolition of outdoor structures will typically contain CCA-treated wood. Pole at the upper left is treated. Complete recovery of untreated wood from this pile will likely require testing in addition to visual separation.

The green colored pole in the front of this pile is treated. Complete recovery of untreated wood from this pile will likely require testing in addition to visual separation.

This load is almost solely CCA-treated wood. It came from a marine construction contractor.

This load is from a construction company that builds trusses and floor joists. It contains treated wood. Green colored sawn boards are treated. Other sawn boars may be untreated. Additional testing may be needed to confirm treatment.

ATTACHMENT 2

Pan Indicator Stain

PAN Stain Indicator

Principle: PAN stands for the chemical name of 1-(2-pyridylazo)-2-naphthol, an orange-red solid with a molecular formula $C_{15}H_{11}N_3O$. It is used to determine the presence of almost all metals excluding alkali metals. The reaction with the metals in CCA-treated wood produces a magenta to red color. Untreated wood turns orange in color. It is important to note that the stain is not specific to arsenic within CCA. It reacts with the copper, so that wood treated with any copper-based preservative (such as ACQ and Copper Azole) will also test positive using this stain.

Safety: Gloves and safety goggles should be used during the application of the stain. The stain should be applied in a fashion that would prevent inhalation. The stain should not be ingested and should be kept in a safe place that would prevent children or animals from ingesting the solution. An MSDS sheet is also available on this product that supplies additional safety information. You may also want to contact the chemical supplier of the stain for additional safety instructions. Receipt of the stain kit normally requires that the recipient sign a liability waiver.

Reagents: The PAN Indicator solution (a.k.a. "stain") can be purchased as a pre-mixed solution or the basic chemical ingredients can be purchased and mixed at a laboratory. The pre-mixed solution is more convenient but usually more expensive, in particular if large quantities of the stain are needed. If large quantities of stain are needed, a more economical option would involve purchasing the basic chemical ingredients and mixing these ingredients in a laboratory. The pre-mixed solution can be purchased from Spectrum Chemicals. The phone number for Spectrum Chemicals is 1-800-772-8786. The catalog number for the pre-mixed PAN indicator solution is: P-358. The formula for mixing the stain from the basic ingredients is 0.65 grams of PAN into 1 liter of methanol. One company that can provide the methanol solution is Spectrum Chemical (Phone number: 1-800-772-8786, Spectrum Number HS006 for a 20 liter container). The PAN (1-(2-pyridylazo)-2-napththol) chemical can be purchased from Sigma Chemical (Phone number: 1-800-325-3010, Product Number P9506 for a 25 gram bottle).

Procedure for Use

1. Using a dropper bottle, apply the stain to the wood. If the wood is relatively clean, the stain can be added directly to the wood. If the wood is soiled we recommend that a small area of the wood be carefully cut away to expose a clean area (approx 1 square centimeter). The stain works best if the wood is dry.
2. If testing mulch, it may be easiest to use a spray bottle. When using a spray bottle, be careful to spray the solution downwind to avoid inhalation.
3. Wait for color development (about 15 seconds). Color development is fastest if applied to the transverse direction of the wood instead of the radial direction.
4. Note the color. If the sample turns a magenta color, then the wood is positive for copper. If the wood turns orange in color, then the wood is negative for most metals and is considered untreated.

Interferences

1. Stain will not work properly on colored mulches or mulches that are very soiled.
2. Stain will sometimes react as positive with paint and nails on wood, even though the wood may be untreated.