APPENDIX A

Permit Forms

Massachusetts Department of Environmental Protection

Supplemental Transmittal Form

(to accompany supplemental material or payment to previously submitted DEP permit applications)

1. Transmittal Number	Obtain from the upper right hand corner of the original application's Transmittal Form:	
	X224106	

2. Facility Information	(a) Facility Name:	(b) Facility Address:
	Dominion Energy Brayton Point	1 Brayton Point Road
	(c) Facility Town/City	(d) Telephone Number:
	Somerset	(508) 646-5000

3. Permit Information	(a) Permit Name:	(b) Permit Code: (from original application)
	Major Comprehensive Plan App.	BWP AQ 03

4. Reason For Supplemental Submission	☒	(a) Response to Request for Additional information	☐	(b) Response to Statement of Deficiency
	☐	(c) Supplemental Fee Payment	☐	(d) Withdrawal of Application
	☐	(e) Other (please specify below):		

5. Form Prepared by	(a) Name of individual or firm preparing this submission:	(b) Affiliation with application, i.e. applicant, consultant to applicant:
	Scott Lawton	Applicant
	(c) Contact Name:	(d) Contact Telephone #:
	Scott Lawton	(401) 457-9157

Enter your transmittal number → X224106
Transmittal Number

Your unique Transmittal Number can be accessed online: http://mass.gov/dep/service/online/trasmfrm.shtml or call MassDEP's InfoLine at 617-338-2255 or 800-462-0444 (from 508, 781, and 978 area codes).

Massachusetts Department of Environmental Protection

Transmittal Form for Permit Application and Payment

1. Please type or print. A separate Transmittal Form must be completed for each permit application.

2. Make your check payable to the Commonwealth of Massachusetts and mail it with a copy of this form to: DEP, P.O. Box 4062, Boston, MA 02211.

3. Three copies of this form will be needed.

Copy 1 - the original must accompany your permit application. **Copy 2** must accompany your fee payment. **Copy 3** should be retained for your records

4. Both fee-paying and exempt applicants must mail a copy of this transmittal form to:

MassDEP
P.O. Box 4062
Boston, MA
02211

*** Note:**
For BWSC Permits, enter the LSP.

A. Permit Information

1. Permit Code: 7 or 8 character code from permit instructions: BWP-AQ-03
2. Name of Permit Category: Major Comprehensive Plan Approval
3. Type of Project or Activity: Major Comprehensive Plan Approval

B. Applicant Information – Firm or Individual

1. Name of Firm - Or, if party needing this approval is an individual enter name below: Dominion Energy Brayton Point, LLC
2. **Last Name** of Individual:
3. **First Name** of Individual:
4. MI:
5. Street Address: 5000 Dominion Blvd.
6. City/Town: Glen Allen
7. State: VA
8. Zip Code: 23060-6711
9. Telephone #: 804-273-3641
10. Ext. #:
11. Contact Person: Diane Leopold
12. e-mail address (optional): Diane.Leopold@Dom.Com

C. Facility, Site or Individual Requiring Approval

1. Name of Facility, Site Or Individual: Dominion Energy Brayton Point, LLC - Brayton Point Station
2. Street Address: 1 Brayton Point Road
3. City/Town: Somerset
4. State: MA
5. Zip Code: 02726
6. Telephone #: 508-646-5200
7. Ext. #:
8. DEP Facility Number (if Known): 1200061
9. Federal I.D. Number (if Known):
10. BWSC Tracking # (if Known):

D. Application Prepared by (if different from Section B)*

1. Name of Firm Or Individual: Epsilon Associates Inc.
2. Address: 3 Clock Tower Place Suite 250
3. City/Town: Maynard
4. State: MA
5. Zip Code: 01754
6. Telephone #: 978-897-7100
7. Ext. #:
8. Contact Person: AJ Jablonowski
9. LSP Number (BWSC Permits only):

E. Permit - Project Coordination

1. Is this project subject to MEPA review? ☒ yes ☐ no
If yes, enter the project's EOEA file number - assigned when an Environmental Notification Form is submitted to the MEPA unit: 14235 and 13022
EOEA File Number

F. Amount Due

DEP Use Only

Permit No:

Rec'd Date:

Reviewer:

Special Provisions:

1. ☐ **Fee** Exempt (city, town or municipal housing authority)(state agency if fee is $100 or less).
There are no fee exemptions for BWSC permits, regardless of applicant status.
2. ☐ Hardship Request - payment extensions according to 310 CMR 4.04(3)(c).
3. ☐ Alternative Schedule Project (according to 310 CMR 4.05 and 4.10).
4. ☐ Homeowner (according to 310 CMR 4.02).

~~(pending fast-track agreement with MassDEP)~~

Check Number	Dollar Amount	Date

Fast Track Agreement
TF 31, dated 9/4/08

X224106
Transmittal Number

Facility ID (if known)

A. Facility Data

INSTRUCTIONS

This form is to be completed when filing for a comprehensive Plan Approval (CPA). A CPA is required for projects exceeding the thresholds for that of a Limited Plan Approval (LPA) and in other cases as determined by the Department. When filing a CPA, one or more of the following forms is also required according to the type of project: BWP AQ CPA-1 to BWP AQ CPA-5 for equipment; BWP AQ SFP-1 to BWP AQ SFP-5 for VOC application and noise; BWP AQ SFC-1 to BWP AQ SFC-6 for pollution control equipment.

1. Dominion Energy Brayton Point LLC - Brayton Point Station
Facility Name
1 Brayton Point Road, Somerset MA 02726
Location

2. Is the project for a new facility? ☐ Yes ☒ No

3. Previously approved? ☒ Yes ☐ No

If yes, list the previously issued air quality approval(s) for this process and associated emission limits in the table provided.

Application Number	Approval Date
4V95056 (Title V Operating Permit)	January 6, 2000 (original approval date)
4B06002 (Non-Major CPA)	December 20, 2006
~~4B05053 (Amended ECP Final Approval)~~	~~March 26, 2006~~
4B08050 (Amended ECP Final Approval)	December 29, 2008

4. Which permit category are you applying for? ☐ BPW AQ 02 ☒ BWP AQ O3

B. Applicability

1. POTENTIAL EMISSIONS are to be calculated from the maximum capacity of the equipment to emit pollutant under its physical and operational design. Any physical or operational limitation on the capacity of the equipment to emit a pollutant, including air pollution control equipment, restriction on hours of operation, or on the type or amount of material combusted, stored, or processed, shall be treated as part of its design only if the limitation is specifically stated in (a) plan approval(s) or if the facility proposes to incorporate such a restriction into this current plan approval. Fugitive emissions, to the extent quantifiable, are included in determining the potential emissions. Unless otherwise documented, potential emissions shall be based on 8,760 hours per year operation of source.

   Current Potential Emissions means the potential emissions for the entire facility as it currently exists. If this is for a new facility, then enter N/A in this column.

   Actual Baseline Emissions means the highest actual emissions for the facility in either of the previous two years. If this is for a new facility, then enter N/A in this column.

   Proposed Potential Emissions means the potential emissions for this proposed project alone.

B. Applicability (cont.)

Air Containment*	Current Potential Emissions (TPY)** (after control)	Actual Baseline Emissions (TPY)	Proposed Potential Emissions (TPY) (after control)
Particulate	4,189	384	~~4,578~~ 3,215
SO_x	41,759 (7.29 basis)	25,782	41,759 (7.29 basis)
NO_x	10,440 (7.29 basis)	6,213	10,440 (7.29 basis)
VOC	190	91	190
HOC	N/A	0	N/A
Lead	N/A	<0.1	N/A
CO	7,387	1,410	7,387
HAP	N/A	0.32	N/A
Other	35 (NH3)	1.5	35 (NH3)

*Complete only for air quality contaminants that will be affected by this project.
**TPY = tons per year

2. Is this project subject to:

- 310 CMR 7.00 Appendix A- Nonattainment Review? ☐ Yes ☒ No

  If yes, also complete section C- Nonattainment Review.

- Was netting used to avoid applicability? ☐ Yes ☒ No

  If yes, also complete Section III – Nonattainment Review

- Prevention of Significant Deterioration Permit (PSD) 40 CFR 52.21? ☒ Yes ☐ No
  Note: PSD applications are filed with the U.S. Environmental Protection Agency (EPA).
  If yes, also complete section D – PSD.

- Was netting used to prevent PSD? ☐ Yes ☒ No
  Note: PSD questions should be directed to EPA.
  If yes, also complete section D – PSD.

- New Source Performance Standards (40 CFR 60)? ☐ Yes ☒ No

  If yes, which subpart?

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Facility ID (if known)

B. Applicability (cont.)

- National Emissions Standards for Hazardous Air Pollutants (NESHAPS) – 40 CFR 61:

☐ Yes ☒ No

If yes, which subpart?

- Maximum Achievable Control Technology (MACT), 40 CFR 63?

☐ Yes ☒ No

If yes, which subpart?

C. Nonattainment Review

This section must be completed only if the construction or modification occurring at the facility is subject to 310 CMR 7.00 Appendix A (Nonatttainment Review) ***or*** would be subject to Nonatttainment Review if netting did not occur.

Offsets and **Netting**

1. If the proposed project would be subject to 310 CMR 7.0 Appendix A - Nonattainment Review in the absence of netting, or if emission reduction credits are used as offsets as part of the application, what is being shutdown, curtailed or further controlled to obtain the emission reduction credit (netting is not allowed to avoid review under 310 CMR 7.02):

   Emission reduction credits must be part of an enforceable plan approval to be used for either "netting out" or "offsetting emission increases".

   (NOT APPLICABLE)

2. For the source of emission credits, complete the following table:

Air Containment	Actual Baseline Emissions (TPY)	New Potential Emissions (TPY) (after control)	Emission Reduction Credit (TPY)

Actual Baseline Emissions means the average actual emissions for the source of emission credits in the previous two years.

New Potential Emissions means the potential emissions for the source of emission credits after project completion.

Emission Reduction Credit means the difference of Actual Baseline and New Potential Emissions.

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C. Nonattainment Review (cont.)

3. If emission reduction credits come from a facility other than where the construction or modification occurs, provide the name and location of the facility:

   (NOT APPLICABLE)

D. Affirmative Demonstration of Compliance

The signature below provides the affirmative demonstration pursuant to 310 CMR 7.02 (3) that any facility (ies) in Massachusetts, owned or operated by the proponent for this project (or by an entity controlling, controlled by or under common control with such proponent) that is subject to 310 CMR 7.00, et seq., is in compliance with, or on a Department approved compliance schedule to meet, all provisions of 310 CMR 7.00, et seq., and any plan approval, order, notice of noncompliance or permit issued thereunder. This form must be signed by a responsible official working at the location of the proposed new or modified facility. Even if an agent has been designated to fill out this form, the responsible official must sign it. (Refer to the definition given in 310 CMR 7.00.)

Certification: I certify that I have examined the responses provided herein and that to the best of my knowledge they are true and complete.

Diane Leopold
Print name

Diane Leopold
Signature of responsible official

VP F&H Merchant Operations
Position / title

Dominion Energy Brayton Point LLC
Representing

1/9/09
Date

Massachusetts Department of Environmental Protection
Bureau of Waste Prevention – Air Quality

BWP AQ CPA-1 (for use with BWP AQ 02, 03)

Comprehensive Plan Approval Application for Fuel Utilization Facilities

X224106
Transmittal Number

Facility ID (if known)

A. Applicability

This form is to be used to apply for approval to construct, substantially reconstruct or alter a fuel utilization facility, such as but not limited to a boiler, oven, space heaters, fuel-burning engines, turbines, or other stationary fuel burning devices, subject to 310 CMR 7.02 (3).

Please refer to 310 CMR 7.02 (5)(a). Simple burner replacement on existing units having an energy input capacity less than 100,000,000 Btu per hour may submit form BWP-AQ CPA-2, Comprehensive Plan Application for Burner Replacement.

B. Materials that Constitute a Comprehensive Plan Approval Application

Proposed projects that are subject to the Comprehensive Plan Approval Application requirements for fuel utilization facilities must submit the following items to the appropriate Regional Office for review and approval.

☐ **Manufacturer's Specifications** and Brochures*

The Following Item Must be Submitted in Duplicate and Must Bear the Seal And Signature of a Massachusetts Registered Professional Engineer

☒ **CPA forms** should reflect both existing units and the new or modified units at the facility.

☒ **Supplemental forms** for associated air pollution control equipment – If such equipment is present, the appropriate form must be included.

☐ **Standard Operating Procedure** – Clear, logical, sequential itemization of the manner in which the equipment is to be operated (normal and upset modes).*

☐ **Standard Maintenance Procedure** – Must describe the scheduling of routine maintenance and equipment adjustments.*

☒ **Plot Plan** – Scaled drawing indicating the outlines of the structures owned by the landlord of the building containing this project, as well as the locations of significant nearby structures and terrain features. Indicate the heights of the structures and the location and height of the stack(s) above ground level.*

☒ **Topographic Map** – United States Geodetic Survey (USGS) map, or equivalent, showing the topographic contours for a distance of 1500 feet beyond the boundary lines in every direction.

☐ **Roof Plan** – Scaled drawing indicating the locations of the stack(s) and all fresh air intakes, windows, and doors. (This can be part of **Plot Plan**.)*

☐ **Elevation Plan** – Scaled drawing locating the stack(s), fresh air intakes, windows, and doors.*

☐ **Breech/Stack Plan** – Scaled drawing to show the location of sampling ports, barometric dampers, and opacity monitor(s).*

☒ **Calculations** – Detailed calculation sheets showing the manner in which the pertinent quantitative data was determined.

☒ **Potential Emissions** – Detailed listing of proposed restrictions limiting potential emissions (see section E).

☒ **Miscellaneous** – The Department may require other materials if it considers them necessary to the plan's review. For example, modeling studies may be required, or monitoring data, or a noise survey. These special items are requested on the more complex or larger applications.

☐ **BACT Analysis**

* - Plans will be provided as soon as they are available. Specifications and procedures will be submitted no more than 60 days after Dominion accepts the proposed equipment.

X224106
Transmittal Number

Facility ID (if known)

C. Existing and Modified or New Combustion Unit(s) Data

Include all fuel utilization facilities at this address; attach another sheet when necessary. In this and subsequent sections, “Existing” refers to those combustion units that will remain in use at the facility, but will be unchanged by this project.

		Unit 3			
1.	Is Unit Existing, to be Modified, or New?	Existing			
2.	Description (boiler, oven, space heater, diesel, etc.)	Boiler			
3.	Manufacturer*	Babcock & Wilcox			
4.	Model number*	UP-52			
5.	Output rating (at 212° F) (indicate if Btu/hr or lbs. of steam/hr)	~650 MW			
6.	Input rating (in Btu per hour)	5,655 MMBtu/hr			
7.	For boilers, indicate the steam usage breakdown				
a.	% of steam for space heating use	0			
b.	% of steam for air conditioning use	0			
c.	% of steam for hot water or process use	100			
8.	For boilers, indicate if WT, FT, CIS, HRT	Radiant & Convection Surface			
9.	Boiler operating pressure [psigl]	3,800			
10.	Thermal efficiency at 100% rating	90.16% (Coal)			
11.	Maximum breaching temperature (°F)	255 F (Coal)			
12.	Furnace volume (if applicable)	371,007 ft^3			
13.	Grate area (if applicable)	N/A			
14.	Indicate how combustion air is supplied to the boiler room	Forced draft fan			

*If undetermined at time of application, indicate probable unit "or equivalent". Specific make and model must be provided prior to final approval.

C. Existing and Modified or New Combustion Unit(s) Data (cont.)

15. Describe combustion unit cleaning method

	Unit 3			
a. Air blown (yes or no)	Yes			
b. Steam blown (yes or no)	No			
c. Brushed and vacuumed (yes or no)	No			
d. Other (describe)	Sonic in Economizer			
e. Frequency of cleaning	As required			

D. Fuel Data

1. Primary fuel

	Unit 3			
a. Type and grade	Coal			
b. Sulfur content	<1.6% wt			
c. Gross heating value (give units)	12,500 Btu/lb			
d. Ash content (% by dry weight)	May exceed 9%			
e. Proposed fuel supplier	Various			

2. Standby or auxiliary fuel				
a. Type and grade	Natural Gas @ 10% MCR	Residual oil @ 100% MCR	distillate oil @ 100% MCR	
b. Sulfur content	negligible	<2.2% wt	0.17% wt	
c. Gross heating value (give units)	1,025 btu/SCF	18,000 Btu/lb	20,000 Btu/lb	
d. Ash content (% by dry weight)	N/A	<=4%	<=4%	
e. Proposed fuel supplier:	Various	Various	Various	
3. Fuel additive				
a. Manufacturer		Martin-Marietta or similar		
b. Additive name		Ultramag-Hus or similar		
c. Purpose of additive		Vanadium Control		

E. Potential Emissions

POTENTIAL EMISSIONS are used to determine applicability to air pollution control regulations and compliance fees. Unless otherwise restricted, potential emissions are calculated from the maximum operational capacity of the equipment as described in section C operated 8,760 hours per year. If you wish to limit potential emissions you must complete this section; this will be treated as part of the facility design and the limitation will be specifically stated in this Plan Approval.

1. In order to issue a permit limiting the facility's potential emissions, the Department must have a method to monitor compliance with the restriction. In other words, an enforceable permit condition must be available to the Department. The following questions require the facility to set a limit on the maximum amount of fuel combusted (per month and per year) and therefore, the maximum amount of emissions possible. This will become the means to monitor and enforce the restriction. Alternative methods of restricting potential emissions will be evaluated on a case-by-case basis and the applicant should contact the Department before proposing such alternatives. Any such alternative method must be consistent with the U.S. EPA's June 13, 1989 guidance entitled, "Guidance on Limiting Potential to Emit in New Source Permitting" (Copies of this guidance are available from DEP offices).

Proposed Fuel Restriction

Enter amount and units (gallons, cubic feet, etc.)

	Unit 3				
a. Maximum per month:					
primary fuel	N/A				
auxiliary	N/A				
b. Maximum per year:					
primary fuel	N/A				
auxiliary fuel	N/A				

2. Describe any other physical or operational limitation on the capacity of the equipment to emit a pollutant, including air pollution control equipment, restriction on hours of operation, etc., that will be used to restrict emissions:

N/A

F. Oil Viscosity Control Data

1. For #4, #5, or #6 fuel oil, indicate below the method used to maintain proper atomizing viscosity [e.g., oil tank heater, oil line heater, pre-heater type, or other (such as room heat)]:

   Fuel oil heaters for oil viscosity control

2. Description of Oil Viscosity Controller (if applicable):

   Dynatrol
   a. Manufacturer

   EC-312GA
   b. Model number

   DCS
   c. Recorder?

G. Burner Data

For fuel dependant parameters, assume primary fuel is being used.

	Unit 3			
1. Burner manufacturer	Babcock & Wilcox			
2. Burner model number	DRB XCL			
3. Type of atomization (steam, air, press, mesh, rotary cup)	Mech (Coal)			
4. Number of burners in each	40 (coal)			
5. Max fuel firing rate (all burners firing) (Gal/hr, lbs./hr, cubic ft per hr, etc.)	452,000 lb/hr (coal)			
6. If oil, temperature and viscosity at max rating	140-220 F @ 150 SSU			
7. Normal fuel firing rate (indicate units)	452,000 lb/hr (coal)			
8. Max theoretical air requirement (scfm)	1,450,000 cfm (coal)			
9. Percent excess air at 100% rating	18% (coal)			
10. Turndown ratio	2.5:1 (coal)			

11. Auto/Manual
    Burner modulation control (on/off, low/high fire, full automatic, manual)
12. Coal & Oil: Elec Spark/Gas; Gas: Elec/Igniters
    Main burner flame ignition method (electric spark, auto gas pilot, hand held torch, other)

H. Combustion Unit Operating Schedule

				Unit 3			
1.	Winter schedule	hrs/days	days/week	24/7			
2.	Spring schedule	hrs/days	days/week	24/7			
3.	Summer schedule	hrs/days	days/week	24/7			
4.	Autumn schedule	hrs/days	days/week	24/7			

I. Noise Suppression Equipment

The installation of some fuel burning units can cause a noise nuisance if precautions are not taken. This is especially true for diesel or turbine generators. Form BWP AQ SFP-3 must accompany the Plan Application for those units requiring noise suppression.

		Unit 3			
1.	Manufacturer of silencer	IDE Process Corp & others			
2.	Model Number	3-60-168H3S & others			

J. Auxiliary Equipment

		Unit 3			
1.	Opacity Monitoring Equipment				
a.	Manufacturer	~~United Sciences~~ Teledyne Monitor Labs			
b.	Model number	~~500C~~ Lighthawk 560			
c.	Lens cleaning method	Manual			
d.	Alarm type	Audible			
e.	Recorder manufacturer	CEM DAHS/DCS			
f.	Recorder model number	CEM DAHS			

The above device is required on all stacks serving equipment rated at an energy input capacity of 40,000,000 Btu per hour or greater which burn liquid or solid fuel. Other facilities, may also be required to install such equipment if the Department determines that it is necessary (310 CMR 7.04 (2)).

2.	Boiler Draft				
a.	Type (forced, included, or natural)	Balanced			
b.	Method used to control draft	Central Control			

J. Auxiliary Equipment (cont.)

3. **Air Pollution Control Equipment**

(Applicable supplemental forms must be submitted for these, see instructions)

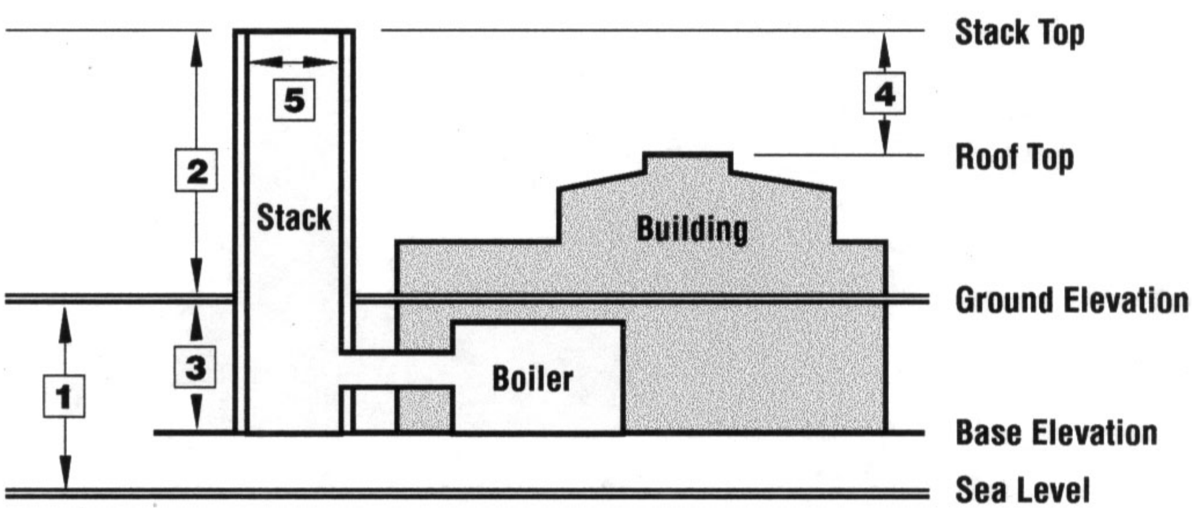
a. Type (scrubber, ESP, cyclone, etc.)	SCR	Dry scrubber	Fabric filter	PAC
b. Manufacturer	~~B&W~~ BPEI	TBD	TBD	Wheelabrator
c. Model number	TBD	TBD	TBD	TBD

4. Does this application represent Best Available Control Technology (BACT) as required in Regulation 310 CMR 7.02(3)(j) 6?

a. ☐ Yes ☐ No Not Applicable - See below

b. Describe
The Unit 3 DS/FF Project is not subject to Massachusetts BACT because there will not be any potential emission increases greater than 1 ton/year for any pollutant.

K. Existing and New or Modified Stack Data



Questions for the above diagram

	Stack 3			
1. Ht. of ground above sea level (arrow 1)	14.5 ft	ft	ft	ft
2. Ht. of stack top above ground (arrow 2)	352.8 ft	ft	ft	ft
3. Ht. of ground above stack base (arrow 3)	-0.5 Ft	ft	ft	ft
4. Ht. of stack top above roof (arrow 4)	142.3 ft	ft	ft	ft

K. Existing and New or Modified Stack Data (cont.)

	Stack 3			
5. Stack exit size (inside) (arrow 5)	234 In	in	in	ft
6. Is stack existing, new, or modified?	existing			
7. Which combustion units on which stacks?	Unit 3			
8. Inside shell material	brick			
9. Outside shell material	concrete			
10. Max gas exit velocity	118 ft/s (expected)			
11. Min gas exit velocity	34 ft/s (expected)			
12. Maximum stack gas exit temperature (^{0}F)	295			
13. Maximum stack gas volume (acfm)	2,113,300			
14. Type of rain protection	None			

NOTE: The rain protection device should be of such a design as to allow the unimpeded escape of the stack gases. "Rain Hats" are prohibited.

L. Energy Conservation Devices

	Unit 1	Unit 2	Unit 3	Unit 4
1. Feed water economizer (yes or no)	☒ Y ☐ N	☐ Y ☐ N	☐ Y ☐ N	☐ Y ☐ N
2. Combustion air preheater (yes or no)	☒ Y ☐ N	☐ Y ☐ N	☐ Y ☐ N	☐ Y ☐ N
3. Blowdown heat recovery (yes or no)	☐ Y ☒ N	☐ Y ☐ N	☐ Y ☐ N	☐ Y ☐ N
4. Oxygen trim control (yes or no)	☒ Y ☐ N	☐ Y ☐ N	☐ Y ☐ N	☐ Y ☐ N
5. Other (describe)	☒ Y ☐ N ARP	☐ Y ☐ N	☐ Y ☐ N	☐ Y ☐ N

M. Miscellaneous

1. 4911
Standard Industrial Classification (SIC) code(s) for this facility?

2. ~240
Number of employees at this facility?

3. Yes, site-generated waste oil fuel only (Transmittal 120431 (Class A); Permit S-09-020 (Class B(3)))
Is waste or recycled oil burned at this facility?

4. No. 6 Fuel Oil ash is collected in facility's wastewater treatment system. An outside contractor has dredged solids. The solids are transported to onsite lined landfills.
If numbers 4, 5, 6, fuel oil is used, identify who removes and disposes of the fuel oil sludge.

Include all fuel utilization facilities at this address; attach another sheet when necessary. In this and subsequent sections, "Existing" refers to those combustion units that will remain in use at the facility, but will be unchanged by this project.

		Unit 1	Unit 2	Unit 4	
1.	Is Unit Existing, to be Modified, or New?	Existing	Existing	Existing	
2.	Description (boiler, oven, space heater, diesel, etc.)	Boiler	Boiler	Boiler	
3.	Manufacturer*	Combustion Engineering	Combustion Engineering	Riley Stoker	
4.	Model number*	19407 - Type CC	19617 - Type CC	1SR	
5.	Output rating (at 212° F) (indicate if Btu/hr or lbs. of steam/hr)	255 MW	255 MW	446 MW	
6.	Input rating (in Btu per hour)	2,250,000,000	2,250,000,000	4,800,000,000	
7.	For boilers, indicate the steam usage breakdown				
a.	% of steam for space heating use	0	0	0	
b.	% of steam for air conditioning use	0	0	0	
c.	% of steam for hot water or process use	100	100	100	
8.	For boilers, indicate if WT, FT, CIS, HRT	Radiant & Convection Surface	Radiant & Convection Surface	Radiant & Convection Surface	
9.	Boiler operating pressure [psigl]	2,650	2,650	2,025	
10.	Thermal efficiency at 100% rating	90.54% (coal)	90.54% (coal)	86.9% (oil)	
11.	Maximum breaching temperature (°F)	266 (coal)	266 (coal)	392 (oil)	
12.	Furnace volume (if applicable)	131,770 cu.ft.	131,770 cu.ft.	143,700 cu. ft.	
13.	Grate area (if applicable)	N/A	N/A	N/A	
14.	Indicate how combustion air is supplied to the boiler room	Forced Draft Fan	Forced Draft Fan	Forced Draft Fan	

*If undetermined at time of application, indicate probable unit "or equivalent". Specific make and model must be provided prior to final approval.

C. Existing and Modified or New Combustion Unit(s) Data (cont.)

		Unit 1	Unit 2	Unit 4	
15.	Describe combustion unit cleaning method				
a.	Air blown (yes or no)	Yes	Yes	Yes	
b.	Steam blown (yes or no)	No	No	No	
c.	Brushed and vacuumed (yes or no)	No	No	No	
d.	Other (describe)	N/A	N/A	N/A	
e.	Frequency of cleaning	As required	As required	As required	

D. Fuel Data*

		Unit 1	Unit 2	Unit 4	
1.	Primary fuel				
a.	Type and grade	Coal	Coal	Residual Oil @ 100% MCR	
b.	Sulfur content	<1.6% wt	<1.6% wt	<2.2% wt	
c.	Gross heating value (give units)	12,500 BTU/lb	12,500 BTU/lb	18,000 BTU/lb	
d.	Ash content (% by dry weight)	may exceed 9%	may exceed 9%	N/A	
e.	Proposed fuel supplier	Various	Various	Various	
2a.	Standby or auxiliary fuel #1				
a.	Type and grade	Natural Gas @ 25% MCR	Natural Gas @ 25% MCR	Natural Gas @ 100% MCR	
b.	Sulfur content	Negligible	Negligible	Negligible	
c.	Gross heating value (give units)	1,025 BTU/scf	1,025 BTU/scf	1,025 BTU/scf	
d.	Ash content (% by dry weight)	N/A	N/A	N/A	
e.	Proposed fuel supplier:	Various	Various	Various	
2b.	Standby or auxiliary fuel #2				
a.	Type and grade	Residual Oil @ 100% MCR	Residual Oil @ 100% MCR	Propane (ignition)	
b.	Sulfur content	<2.2% wt	<2.2% wt	Negligible	
c.	Gross heating value (give units)	18,000 BTU/lb	18,000 BTU/lb	2,557 BTU/scf	
d.	Ash content (% by dry weight)	<= 4%	<= 4%	N/A	
e.	Proposed fuel supplier:	Various	Various	Various	
2c.	Standby or auxiliary fuel #3				
a.	Type and grade	Distillate Fuel Oil @ 100% MCR	Distillate Fuel Oil @ 100% MCR	N/A	
b.	Sulfur content	0.17% wt.	0.17% wt.		
c.	Gross heating value (give units)	20,000 BTU/lb	20,000 BTU/lb		
d.	Ash content (% by dry weight)	<= 4%	<= 4%		
e.	Proposed fuel supplier:	Various	Various		
3.	Fuel additive				
a.	Manufacturer	Martin-Marietta or similar	Martin-Marietta or similar	Martin-Marietta or similar	
b.	Additive name	Ultramag-Hus or similar	Ultramag-Hus or similar	Ultramag-Hus or similar	
c.	Purpose of additive	Vanadium Control	Vanadium Control	Vanadium Control	

** MCR = Maximum Capability Rating*

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E. Potential Emissions

POTENTIAL EMISSIONS are used to determine applicability to air pollution control regulations and compliance fees. Unless otherwise restricted, potential emissions are calculated from the maximum operational capacity of the equipment as described in section C operated 8,760 hours per year. If you wish to limit potential emissions you must complete this section; this will be treated as part of the facility design and the limitation will be specifically stated in this Plan Approval.

1. In order to issue a permit limiting the facility's potential emissions, the Department must have a method to monitor compliance with the restriction. In other words, an enforceable permit condition must be available to the Department. The following questions require the facility to set a limit on the maximum amount of fuel combusted (per month and per year) and therefore, the maximum amount of emissions possible. This will become the means to monitor and enforce the restriction. Alternative methods of restricting potential emissions will be evaluated on a case-by-case basis and the applicant should contact the Department before proposing such alternatives. Any such alternative method must be consistent with the U.S. EPA's June 13, 1989 guidance entitled, "Guidance on Limiting Potential to Emit in New Source Permitting" (Copies of this guidance are available from DEP offices).

Proposed Fuel Restriction

Enter amount and units (gallons, cubic feet, etc.)

	Unit 1	Unit 2	Unit 4		Total
a. Maximum per month:					
primary fuel	N/A	N/A	N/A		N/A
auxiliary	N/A	N/A	N/A		N/A
b. Maximum per year:					
primary fuel	N/A	N/A	N/A		N/A
auxiliary fuel	N/A	N/A	N/A		N/A

2. Describe any other physical or operational limitation on the capacity of the equipment to emit a pollutant, including air pollution control equipment, restriction on hours of operation, etc., that will be used to restrict emissions:

N/A

F. Oil Viscosity Control Data

1. For #4, #5, or #6 fuel oil, indicate below the method used to maintain proper atomizing viscosity [e.g., oil tank heater, oil line heater, pre-heater type, or other (such as room heat)]:

   Fuel oil heaters for oil viscosity control for all units.

2. Description of Oil Viscosity Controller (if applicable):

   Dynatrol
   a. Manufacturer

   EC-312GA
   b. Model number

   DCS
   c. Recorder?

G. Burner Data

For fuel dependant parameters, assume primary fuel is being used.

	Unit 1	Unit 2	Unit 4	
1. Burner manufacturer	ABB-Combustion Engineering	ABB-Combustion Engineering	Rodenhuis & Verloop	
2. Burner model number	LNCFS III	LNCFS III	TTL/MG50	
3. Type of atomization (steam, air, press, mesh, rotary cup)	Mech/Air (coal)	Mech/Air (coal)	Mech/Air (oil)	
4. Number of burners in each	32 (coal)	32 (coal)	24	
5. Max fuel firing rate (all burners firing) (Gal/hr, lbs./hr, cubic ft per hr, etc.)	200,000 lb/hr (coal)	200,000 lb/hr (coal)	266,667 lb/hr (oil)	
6. If oil, temperature and viscosity at max rating	140-220 °F @ 150SSU	140-220 °F @ 150SSU	140-220 °F @ 150SSU	
7. Normal fuel firing rate (indicate units)	200,000 lb/hr (coal)	200,000 lb/hr (coal)	266,667 lb/hr (oil)	
8. Max theoretical air requirement (scfm)	470,000 cfm (coal)	470,000 cfm (coal)	3,880.3 Mlb/hr (oil)	
9. Percent excess air at 100% rating	18% (coal)	18% (coal)	5%	
10. Turndown ratio	2.5 : 1 (coal)	2.5 : 1 (coal)	3 : 1 (oil)	

11. Auto/Manual (all units)
    Burner modulation control (on/off, low/high fire, full automatic, manual)

12. Unit #1 & #2: Coal&Oil -> Elec Spark/Gas ; Gas -> Elec Igniters
    Unit #4: Oil -> Gas Ignite ; Gas -> Elec Spark
    Main burner flame ignition method (electric spark, auto gas pilot, hand held torch, other)

H. Combustion Unit Operating Schedule

				Unit 1	Unit 2	Unit 4	
1.	Winter schedule	hrs/days	days/week	24/7	24/7	24/7	
2.	Spring schedule	hrs/days	days/week	24/7	24/7	24/7	
3.	Summer schedule	hrs/days	days/week	24/7	24/7	24/7	
4.	Autumn schedule	hrs/days	days/week	24/7	24/7	24/7	

I. Noise Suppression Equipment

The installation of some fuel burning units can cause a noise nuisance if precautions are not taken. This is especially true for diesel or turbine generators. Form BWP AQ SFP-3 must accompany the Plan Application for those units requiring noise suppression.

		Unit 1	Unit 2	Unit 4	
1.	Manufacturer of silencer	IDE Process Corp & others	IDE Process Corp & others	Misc. silencers and mufflers	
2.	Model Number	4-60-192M3 & others	4-60-192M3 & others	various	

J. Auxiliary Equipment

1.	Opacity Monitoring Equipment	Unit 1	Unit 2	Unit 4	
a.	Manufacturer	United Sciences	United Sciences	United Sciences	
b.	Model number	500C	500C	500C	
c.	Lens cleaning method	Manual	Manual	Manual	
d.	Alarm type	Audible	Audible	Audible	
e.	Recorder manufacturer	CEM DAHS/ DCS	CEM DAHS/ DCS	CEM DAHS/ DCS	
f.	Recorder model number	CEM DAHS	CEM DAHS	CEM DAHS	

The above device is required on all stacks serving equipment rated at an energy input capacity of 40,000,000 Btu per hour or greater which burn liquid or solid fuel. Other facilities, may also be required to install such equipment if the Department determines that it is necessary (310 CMR 7.04 (2)).

2. Boiler Draft

a.	Type (forced, included, or natural)	Balanced	Balanced	Forced	
b.	Method used to control draft	Central Control	Central Control	Central Control	

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J. Auxiliary Equipment (cont.)

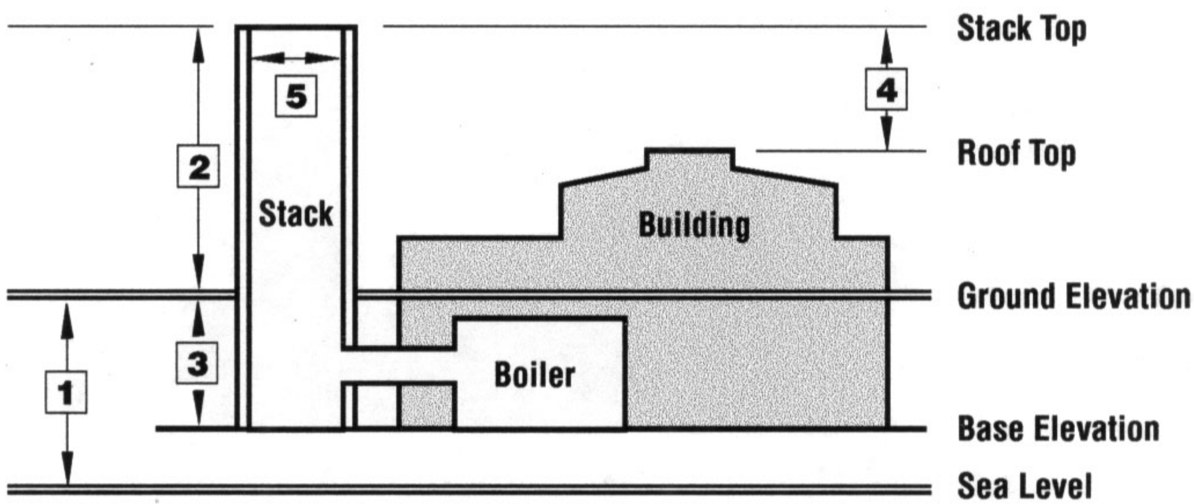
3. **Air Pollution Control Equipment**
(Applicable supplemental forms must be submitted for these, see instructions)

a. Type (scrubber, ESP, cyclone, etc.)	ESP/SCR/ SDA/FF/PAC	ESP/FGC/ SDA/FF/PAC	ESP/FGR	
b. Manufacturer	ESP- Koppers/ Research Cottrell SCR- BPEI SDA/FF/PAC- Wheelabrator	ESP- Koppers/ Research Cottrell FGC- Epricom SDA/FF/PAC- Wheelabrator	ESP- Research Cottrell FGR- Green Fuel Economizer Co.	
c. Model number	Kopper- 370226 R-C - UP-6031A SCR - 100247 SDA/FF - BP1 PAC - 3926	Kopper - 370226 R-C - UP-6031A Epricom - n/a SDA/FF - BP2 PAC - 3926	R-C - 6063 FGR - SA-RTS	

4. Does this application represent Best Available Control Technology (BACT) as required in Regulation 310 CMR 7.02(3)(j) 6?
a. ☐ Yes ☐ No Not Applicable

Existing units are unchanged and not subject to BACT.
b. Describe

K. Existing and New or Modified Stack Data



Questions for the above diagram

	Stack 1 **Unit 1**	Stack 2 **Unit 2**	Stack 4 **Unit 4**	
1. Ht. of ground above sea level (arrow 1)	14.5 ft	14.5 ft	14.5 ft	ft
2. Ht. of stack top above ground (arrow 2)	352.8 ft	352.8 ft	500.5 ft	ft
3. Ht. of ground above stack base (arrow 3)	-0.5 ft	-0.5 ft	-0.5 ft	ft

4.	Ht. of stack top above roof (arrow 4)	177 ft	192.3 ft	325 ft	ft

K. Existing and New or Modified Stack Data (cont.)

		Stack 1 **Unit 1**	Stack 2 **Unit 2**	Stack 4 **Unit 4**	
5.	Stack exit size (inside) (arrow 5)	174 in	174 in	222 in	ft
6.	Is stack existing, new, or modified?	Existing	Existing	Existing	
7.	Which combustion units on which stacks?	Unit #1	Unit #2	Unit #4	
8.	Inside shell material	Brick	Brick	Brick	
9.	Outside shell material	Concrete	Concrete	Concrete	
10.	Max gas exit velocity	99.4 ft/s	99.4 ft/s	111.6 ft/s	
11.	Min gas exit velocity	37.3 ft/s	37.3 ft/s	31.0 ft/s	
12.	Maximum stack gas exit temperature (^{0}F)	185	185	380	
13.	Maximum stack gas volume (acfm)	985,000	985,000	1,800,000	
14.	Type of rain protection	None	None	None	

NOTE: The rain protection device should be of such a design as to allow the unimpeded escape of the stack gases. "Rain Hats" are prohibited.

L. Energy Conservation Devices

		Unit 1	Unit 2	Unit 4	
1.	Feed water economizer (yes or no)	☒ Y ☐ N	☒ Y ☐ N	☒ Y ☐ N	☐ Y ☐ N
2.	Combustion air preheater (yes or no)	☒ Y ☐ N	☒ Y ☐ N	☒ Y ☐ N	☐ Y ☐ N
3.	Blowdown heat recovery (yes or no)	☐ Y ☒ N	☐ Y ☒ N	☐ Y ☒ N	☐ Y ☐ N
4.	Oxygen trim control (yes or no)	☒ Y ☐ N	☒ Y ☐ N	☒ Y ☐ N	☐ Y ☐ N
5.	Other (describe)	☒ Y ☐ N ARP	☐ Y ☒ N	☐ Y ☒ N	☐ Y ☐ N

C. Existing and Modified or New Combustion Unit(s) Data

Include all fuel utilization facilities at this address; attach another sheet when necessary. In this and subsequent sections, “Existing” refers to those combustion units that will remain in use at the facility, but will be unchanged by this project.

	Unit 5	Unit 6	Unit 7	Unit 8
1. Is Unit Existing, to be Modified, or New?	Existing	Existing	Existing	Existing
2. Description (boiler, oven, space heater, diesel, etc.)	Diesel Generator	Diesel Generator	Diesel Generator	Diesel Generator
3. Manufacturer*	General Motors	General Motors	General Motors	General Motors
4. Model number*	20-645-E4	20-645-E4	20-645-E4	20-645-E4
5. Output rating (at 212° F) (indicate if Btu/hr or lbs. of steam/hr)	2,750 kW	2,750 kW	2,750 kW	2,750 kW
6. Input rating (in Btu per hour)	28,000,000	28,000,000	28,000,000	28,000,000
7. For boilers, indicate the steam usage breakdown				
a. % of steam for space heating use	N/A	N/A	N/A	N/A
b. % of steam for air conditioning use	N/A	N/A	N/A	N/A
c. % of steam for hot water or process use	N/A	N/A	N/A	N/A
8. For boilers, indicate if WT, FT, CIS, HRT	N/A	N/A	N/A	N/A
9. Boiler operating pressure [psigl]	N/A	N/A	N/A	N/A
10. Thermal efficiency at 100% rating	11,656 BTU/kW	11,656 BTU/kW	11,656 BTU/kW	11,656 BTU/kW
11. Maximum breaching temperature (°F)	750	750	750	750
12. Furnace volume (if applicable)	N/A	N/A	N/A	N/A
13. Grate area (if applicable)	N/A	N/A	N/A	N/A
14. Indicate how combustion air is supplied to the boiler room	Forced Induction	Forced Induction	Forced Induction	Forced Induction

*If undetermined at time of application, indicate probable unit "or equivalent". Specific make and model must be provided prior to final approval.

C. Existing and Modified or New Combustion Unit(s) Data (cont.)

15. Describe combustion unit cleaning method	Unit 5	Unit 6	Unit 7	Unit 8
a. Air blown (yes or no)	N/A	N/A	N/A	N/A
b. Steam blown (yes or no)	N/A	N/A	N/A	N/A
c. Brushed and vacuumed (yes or no)	N/A	N/A	N/A	N/A
d. Other (describe)	N/A	N/A	N/A	N/A
e. Frequency of cleaning	N/A	N/A	N/A	N/A

D. Fuel Data

1. Primary fuel	Unit 5	Unit 6	Unit 7	Unit 8
a. Type and grade	No. 2 Distillate Oil	No. 2 Distillate Oil	No. 2 Distillate Oil	No. 2 Distillate Oil
b. Sulfur content	< 0.3% wt.	< 0.3% wt.	< 0.3% wt.	< 0.3% wt.
c. Gross heating value (give units)	138,900 BTU/gal	138,900 BTU/gal	138,900 BTU/gal	138,900 BTU/gal
d. Ash content (% by dry weight)	N/A	N/A	N/A	N/A
e. Proposed fuel supplier	Various	Various	Various	Various
2. Standby or auxiliary fuel	N/A	N/A	N/A	N/A
a. Type and grade	N/A	N/A	N/A	N/A
b. Sulfur content	N/A	N/A	N/A	N/A
c. Gross heating value (give units)	N/A	N/A	N/A	N/A
d. Ash content (% by dry weight)	N/A	N/A	N/A	N/A
e. Proposed fuel supplier:	N/A	N/A	N/A	N/A
3. Fuel additive				
a. Manufacturer				
b. Additive name				
c. Purpose of additive				

E. Potential Emissions

POTENTIAL EMISSIONS are used to determine applicability to air pollution control regulations and compliance fees. Unless otherwise restricted, potential emissions are calculated from the maximum operational capacity of the equipment as described in section C operated 8,760 hours per year. If you wish to limit potential emissions you must complete this section; this will be treated as part of the facility design and the limitation will be specifically stated in this Plan Approval.

1. In order to issue a permit limiting the facility's potential emissions, the Department must have a method to monitor compliance with the restriction. In other words, an enforceable permit condition must be available to the Department. The following questions require the facility to set a limit on the maximum amount of fuel combusted (per month and per year) and therefore, the maximum amount of emissions possible. This will become the means to monitor and enforce the restriction. Alternative methods of restricting potential emissions will be evaluated on a case-by-case basis and the applicant should contact the Department before proposing such alternatives. Any such alternative method must be consistent with the U.S. EPA's June 13, 1989 guidance entitled, "Guidance on Limiting Potential to Emit in New Source Permitting" (Copies of this guidance are available from DEP offices).

Proposed Fuel Restriction

Enter amount and units (gallons, cubic feet, etc.)

	Unit 5	Unit 6	Unit 7	Unit 8	Total
a. Maximum per month:					
primary fuel	N/A	N/A	N/A	N/A	N/A
auxiliary	N/A	N/A	N/A	N/A	N/A
b. Maximum per year:					
primary fuel	201,600 gal.	201,600 gal.	201,600 gal.	201,600 gal.	806,400 gal.
auxiliary fuel	N/A	N/A	N/A	N/A	N/A

2. Describe any other physical or operational limitation on the capacity of the equipment to emit a pollutant, including air pollution control equipment, restriction on hours of operation, etc., that will be used to restrict emissions:

N/A

F. Oil Viscosity Control Data

1. For #4, #5, or #6 fuel oil, indicate below the method used to maintain proper atomizing viscosity [e.g., oil tank heater, oil line heater, pre-heater type, or other (such as room heat)]:

   N/A

2. Description of Oil Viscosity Controller (if applicable):

   N/A
   a. Manufacturer

   N/A
   b. Model number

   N/A
   c. Recorder?

G. Burner Data

For fuel dependant parameters, assume primary fuel is being used.

	Unit 5	Unit 6	Unit 7	Unit 8
1. Burner manufacturer	General Motors	General Motors	General Motors	General Motors
2. Burner model number	522-88-95	522-88-95	522-88-95	522-88-95
3. Type of atomization (steam, air, press, mesh, rotary cup)	Fuel injection	Fuel injection	Fuel injection	Fuel injection
4. Number of burners in each	20 cylinders	20 cylinders	20 cylinders	20 cylinders
5. Max fuel firing rate (all burners firing) (Gal/hr, lbs./hr, cubic ft per hr, etc.)	220 gal/hr	220 gal/hr	220 gal/hr	220 gal/hr
6. If oil, temperature and viscosity at max rating	35.7 SFS @ 122 °F	35.7 SFS @ 122 °F	35.7 SFS @ 122 °F	35.7 SFS @ 122 °F
7. Normal fuel firing rate (indicate units)	200 gal/hr	200 gal/hr	200 gal/hr	200 gal/hr
8. Max theoretical air requirement (scfm)	N/A	N/A	N/A	N/A
9. Percent excess air at 100% rating	N/A	N/A	N/A	N/A
10. Turndown ratio	N/A	N/A	N/A	N/A

11. N/A
    Burner modulation control (on/off, low/high fire, full automatic, manual)

12. N/A
    Main burner flame ignition method (electric spark, auto gas pilot, hand held torch, other)

H. Combustion Unit Operating Schedule

				Unit 5	Unit 6	Unit 7	Unit 8
1.	Winter schedule	hrs/days	days/week	Less than 1000 hr/yr, based on a 365-day rolling average (no quarterly hrs limit)	Less than 1000 hr/yr, based on a 365-day rolling average (no quarterly hrs limit)	Less than 1000 hr/yr, based on a 365-day rolling average (no quarterly hrs limit)	Less than 1000 hr/yr, based on a 365-day rolling average (no quarterly hrs limit)
2.	Spring schedule	hrs/days	days/week				
3.	Summer schedule	hrs/days	days/week				
4.	Autumn schedule	hrs/days	days/week				

I. Noise Suppression Equipment

The installation of some fuel burning units can cause a noise nuisance if precautions are not taken. This is especially true for diesel or turbine generators. Form BWP AQ SFP-3 must accompany the Plan Application for those units requiring noise suppression.

		Unit 5	Unit 6	Unit 7	Unit 8
1.	Manufacturer of silencer	Exhaust Muffler & Engine Enclosure	Exhaust Muffler & Engine Enclosure	Exhaust Muffler & Engine Enclosure	Exhaust Muffler & Engine Enclosure
2.	Model Number	N/A	N/A	N/A	N/A

J. Auxiliary Equipment

		Unit 5	Unit 6	Unit 7	Unit 8
1.	Opacity Monitoring Equipment				
a.	Manufacturer	N/A	N/A	N/A	N/A
b.	Model number	N/A	N/A	N/A	N/A
c.	Lens cleaning method	N/A	N/A	N/A	N/A
d.	Alarm type	N/A	N/A	N/A	N/A
e.	Recorder manufacturer	N/A	N/A	N/A	N/A
f.	Recorder model number	N/A	N/A	N/A	N/A

The above device is required on all stacks serving equipment rated at an energy input capacity of 40,000,000 Btu per hour or greater which burn liquid or solid fuel. Other facilities, may also be required to install such equipment if the Department determines that it is necessary (310 CMR 7.04 (2)).

		Unit 5	Unit 6	Unit 7	Unit 8
2.	Boiler Draft				
a.	Type (forced, included, or natural)	Forced (turbo)	Forced (turbo)	Forced (turbo)	Forced (turbo)
b.	Method used to control draft	Governor	Governor	Governor	Governor

J. Auxiliary Equipment (cont.)

3. **Air Pollution Control Equipment**

(Applicable supplemental forms must be submitted for these, see instructions)

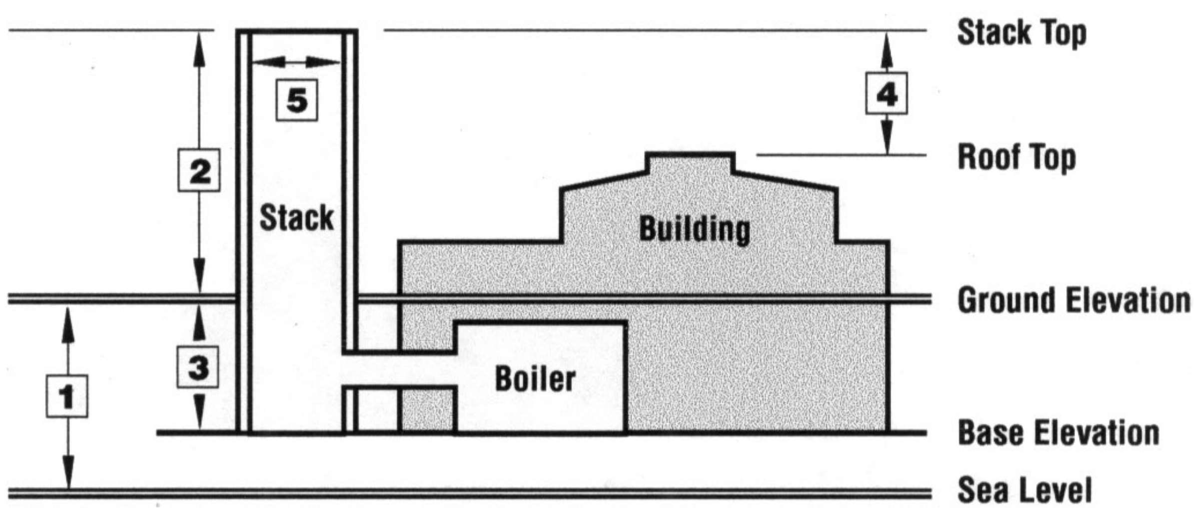
a. Type (scrubber, ESP, cyclone, etc.)	Ignition Retard for NOx	Ignition Retard for NOx	Ignition Retard for NOx	Ignition Retard for NOx
b. Manufacturer	N/A	N/A	N/A	N/A
c. Model number	N/A	N/A	N/A	N/A

4. Does this application represent Best Available Control Technology (BACT) as required in Regulation 310 CMR 7.02(3)(j) 6?

a. ☐ Yes ☐ No Not Applicable

Existing units are unchanged and not subject to BACT.
b. Describe

K. Existing and New or Modified Stack Data



Questions for the above diagram

	Stack 5 Unit 5	Stack 6 Unit 6	Stack 7 Unit 7	Stack 8 Unit 8
1. Ht. of ground above sea level (arrow 1)	30 ft	30 ft	30 ft	30 ft
2. Ht. of stack top above ground (arrow 2)	19.8 ft	19.8 ft	19.8 ft	19.8 ft
3. Ht. of ground above stack base (arrow 3)	0 ft	0 ft	0 ft	0 ft
4. Ht. of stack top above roof (arrow 4)	7.8 ft	7.8 ft	7.8 ft	7.8 ft

K. Existing and New or Modified Stack Data (cont.)

	Stack 5 Unit 5	Stack 6 Unit 6	Stack 7 Unit 7	Stack 8 Unit 8
5. Stack exit size (inside) (arrow 5)	31 in	31 in	31 in	31 ft
6. Is stack existing, new, or modified?	Existing	Existing	Existing	Existing
7. Which combustion units on which stacks?	Unit 5	Unit 6	Unit 7	Unit 8
8. Inside shell material	Carbon Steel	Carbon Steel	Carbon Steel	Carbon Steel
9. Outside shell material	Carbon Steel	Carbon Steel	Carbon Steel	Carbon Steel
10. Max gas exit velocity	101.5 ft/s	101.5 ft/s	101.5 ft/s	101.5 ft/s
11. Min gas exit velocity	0 ft/s	0 ft/s	0 ft/s	0 ft/s
12. Maximum stack gas exit temperature (^{0}F)	750	750	750	750
13. Maximum stack gas volume (acfm)	31,920	31,920	31,920	31,920
14. Type of rain protection	None	None	None	None

NOTE: The rain protection device should be of such a design as to allow the unimpeded escape of the stack gases. “Rain Hats” are prohibited.

L. Energy Conservation Devices

	Unit 1	Unit 2	Unit 3	Unit 4
1. Feed water economizer (yes or no)	☐ Y ☒ N	☐ Y ☒ N	☐ Y ☒ N	☐ Y ☒ N
2. Combustion air preheater (yes or no)	☐ Y ☒ N	☐ Y ☒ N	☐ Y ☒ N	☐ Y ☒ N
3. Blowdown heat recovery (yes or no)	☐ Y ☒ N	☐ Y ☒ N	☐ Y ☒ N	☐ Y ☒ N
4. Oxygen trim control (yes or no)	☐ Y ☒ N	☐ Y ☒ N	☐ Y ☒ N	☐ Y ☒ N
5. Other (describe)	☐ Y ☒ N	☐ Y ☒ N	☐ Y ☒ N	☐ Y ☒ N

Massachusetts Department of Environmental Protection
Bureau of Waste Prevention – Air Quality

BWP AQ CPA-1 (for use with BWP AQ 02, 03)

Comprehensive Plan Approval Application for Fuel Utilization Facilities

X224106
Transmittal Number

Facility ID (if known)

N. CPA Preparer

1. AJ Jablonowski, PE
   Person who complied the plans applications materials
2. Epsilon Associates, Inc.
   Representing
3. 3 Clock Tower Place, Suite 250, Maynard MA 01754
   Address
4. 978-897-7100
   Telephone number
5. August 26, 2008
   Date completed

O. Certifications

The seal and signature of a Massachusetts Registered Professional Engineer must be entered at right, and they must be the original seal impression or stamp and the original signature of the engineer. This is to certify that the information contained in this form has been checked for accuracy, and that the design represents good air pollution control engineering practice.

AJ Jablonowski
Print name

Authorized signature

Senior Consultant
Position/title

Epsilon Associates
Representing

August 28, 2008 rev Jan 9, 2009
Date

39123
PE number

COMMONWEALTH OF MASSACHUSETTS
ANDREW JABLONOWSKI
CHEMICAL
No. 39123
REGISTERED
PROFESSIONAL ENGINEER

Massachusetts Department of Environmental Protection
Bureau of Waste Prevention – Air Quality

BWP AQ CPA-3 (for use with BWP AQ 02, 03)

Comprehensive Plan Approval Application for Non Fuel Emissions

X224106
Transmittal Number

Facility ID (if known)

A. Applicability

This form is to be used to apply for approval to construct, substantially reconstruct or alter a facility, where the portion of the facility being constructed, substantially reconstructed or altered would result in an increase in potential emissions of equal to or greater than five tons per year of any criteria pollutant, or equal to or greater than five tons per year of any single other air contaminant.

Please note that an emission reduction of the same air contaminant at the facility may not be subtracted from the emissions resulting from the construction, substantial reconstruction or alteration to bring emissions below the five tons per year threshold. Products of combustion from any fuel utilization facility are not included in the sum. Please refer to 310 CMR 7.02(5)

B. Materials that Constitute a Comprehensive Plan Approval Application – Non Fuel Emissions

Proposed projects, which are subject to Comprehensive Plan Approval Application requirements for industrial and commercial facilities, must submit the following items to the appropriate Regional Office for technical review and approval.

☐ **Manufacturer's Specifications** and brochures for process equipment, add-on air pollution control equipment, fans/blowers, etc.

The following items should be submitted in duplicate and must bear the seal and signature of a Massachusetts Registered Professional Engineer

☒ **CPA Forms** should reflect the new or modified process equipment at the facility.

☒ **Supplemental Forms** for add-on air pollution control equipment fuel equipment, or for volatile organic compounds (VOCs), if applicable.

☐ **Standard Operating Procedure And Standard Maintenance Procedure** – See section J and section K of this form.*

☒ **Plot Plan** – Scaled drawing indicating the outlines of the significant structures within 1500 feet of the building containing this project. Topographic contours may be shown on this plan or on separate plan.

☒ **Potential Emissions** – Detailed listing of proposed restrictions limiting potential emissions (see section E).

* - Specifications and procedures will be submitted no more than 60 days after Dominion accepts the proposed equipment.

☒ **Topographic Map** – United States Geodetic Survey (USGS) map, or equivalent, showing the topographic contours for a distance of 1500 feet beyond the boundary lines in every direction. (This may be part of Plot Plan.)

☐ **Roof Plan; Building Elevation Plan** – Scaled drawings indicating the locations of all fresh air intakes, windows, and doors.*

☒ **Schematic Process Diagram** – Dimensioned plan showing process equipment, hoods, ductwork, dampers, fans, temperature/pressure sensing devices, other monitors, air pollution control equipment, and all vents, by-passes, or discharges to atmosphere.

☒ **Calculations** – Detailed calculation sheets showing the manner in which the pertinent quantitative data was determined. This is especially important for calculated emission rates, sizing of air pollution control equipment, and sizing of air moving equipment.

☒ **Miscellaneous** – The Department may require other materials if it considers them necessary to the plans review. For example, modeling studies may be required, or monitoring data, or a noise survey. These special items are not usually requested except on the more complex or larger projects.

☒ **BACT Analysis**

C. Project Description

1. For the purpose of determining a potential emission rate (or rates), give the maximum operating times proposed for this project.

   24
   a. hours/day

   7
   b. days/week

   52
   c. weeks/year

2. Fully describe the process equipment that will be constructed, substantially reconstructed or altered, identifying:

   a. maximum capacity of process equipment

   b. chemical identity of all raw materials

   c. chemical identity of all finished products

   d. sequence of process events keyed to the Process Diagram required in Section B

   e. process temperatures

   f. process pressures

   Use additional sheets of paper if necessary. If volatile organic compounds (VOC) are used in the application of coatings, attach separate formulation sheets and submit a BWP AQ SFP-1 form.

   See attached plan approval application report. Two cooling towers have a combined water flow of 720,000 gallons/minute circulating water, with dissolved solids up to 48,000 parts per million by weight. Chemical addition includes sodium hypochlorite (bleach) and much smaller amounts of other chemicals (e.g. anti-foam) as needed. Design hot water temperature 113 F. Natural draft cooling towers operate at about ambient pressure; piping includes needed pumping pressure.

3. Specify maximum consumption/usage rates of each raw material:

   See attached plan approval application report. At design conditions 48,000 gallons/minute water is withdrawn from the river, 14,000 gallons/minute water is evaporated, and 34,000 gallons/minute water is returned to the river.

4. Describe storage/handling procedures for raw materials:

   See attached plan approval application report. Water is pumped though the upper supply basin and the lower discharge basin.

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C. Project Description (cont.)

5. Specify maximum production rate(s) of finished products:

   Not applicable

6. Describe storage/handling procedures for finished products:

   Not applicable

7. Describe features of equipment layout designed to allow for future growth, emission control device add-on, or stack testing ports:

   Not applicable.

8. Describe how fugitive emissions will be minimized especially during process upsets, or disruptions:

   Not applicable

9. Explain those aspects of the design that have been required because of other environmental concerns, or safety concerns, or other regulations, such as; construction materials handling practices system interlocks, waste disposal procedures, etc.:

   See plan approval application text. Cooling tower(s) are being installed to comply with EPA and

   Mass DEP orders to implement the 2003 NPDES permit.

D. Emissions Data

1. Maximum Gaseous Emissions Rates:

	Chemical Name	Before Control (pounds/hour)	After Control (pounds/hour)	After Control (ppm of volume)
a.	Not applicable			
b.				
c.				

2. Maximum Particulate Emissions Rates:

	Chemical Name	Before Control (pounds/hour)	After Control (pounds/hour)	After Control (grains/DSCF)*
a.	PM/PM-10/PM-2.5	Not available	88.8 (2 tower operation)	~0.0004
b.				
c.				

* grains per dry standard cubic foot

3. Indicate how the above emission rates were obtained, and attach appropriate calculations and documentation:

See plan approval application text. Particulate emission rate is a function of circulating water flow rate, drift rate, and dissolved solids concentration.

4. a. Describe the potential for visible emissions (opacity) from this project:

None, exclusive of water vapor

b. Describe the potential for odor impacts from this project:

None expected

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E. Potential Emissions

POTENTIAL EMISSIONS are used to determine applicability to air pollution control regulations and compliance fees. Unless otherwise restricted, potential emissions are calculated from the maximum operational capacity of the equipment as described in section C operated 8,760 hours per year. If you wish to limit potential emissions you must complete this section; this will be treated as part of the facility design and the limitation will be specifically stated in this Plan Approval.

1. In order to issue a permit limiting the facility's potential emissions, the Department must have a method to monitor compliance with the restriction. In other words, an enforceable permit condition must be available to the Department. The following questions require the facility to set a limit on the maximum amount of raw materials used (per month and per year) and therefore, the maximum amount of emissions possible. This will become the means to monitor and enforce the restriction. Alternative methods of restricting potential emissions will be evaluated on a case-by-case basis and the applicant should contact the Department before proposing such alternatives. Any such alternative method must be consistent with the U.S. EPA's June 13, 1989 guidance entitled, "Guidance on Limiting Potential to Emit in New Source Permitting". (Copies of this guidance are available from DEP offices).

Note: This raw material restriction will become the facility's allowable usage. This amount can never be exceeded without prior Department approval.

Raw Material	Amount Used in Equipment 1		Amount Used in Equipment 2		Amount Used in Equipment 3		Total Used	
	per month	per year	per month	per year	per month	per year	per month	per year
Recirculating Water	32 billion gallons	379 billion gallons					32 billion gallons	379 billion gallons

Use additional paper if necessary

2. Describe any other physical or operational limitation on the capacity of the equipment to emit a pollutant, including air pollution control equipment, restriction on hours of operation, or on the type or amount of material combusted, stored or processed that will be used to restrict emissions:

Circulating water dissolved solids 48,000 ppmw.

F. Air Pollution Control Equipment

If new air pollution control equipment is proposed or if existing control equipment will be modified or affected by this project, then an equipment specific Supplemental Form must be submitted.

1. Is Emission Control System:

☒ Proposed? ☐ None?

Existing? (if existing, supply previous Approval number)

Drift eliminators
a. If proposed or existing, describe:

Not applicable
b. If existing, described purpose changed:

2. Control Efficiency:

Capture Efficiency (CE)

Not applicable
Percent by weight pollutants captured by the ventilation system

Destruction Efficiency (DE)

not applicable
Percentage by weight pollutants destroyed or captured in control device

Overall Control Efficiency:

Drift rate limited to 0.0005% of circulating water flow
Percentage by weight of overall efficiency of the control system (CE X DE)/100

Describe how capture efficiency was derived:
Vendor guarantee

3. Does this application represent Best Available Control Technology (BACT) as stated in Regulation 310 CMR 7.O2 (3)(j)6?

☒ Yes ☐ No

a. If yes, is required supplementary documentation attached?

☒ Yes ☐ No

b. If no, explain why this project is exempt:

(not applicable)

G. Air Handling System

This section is for the description of fans and those flow parameters associated with the processes and/or the air pollution control equipment.

	Fan A	Fan B	Fan C
1. Identify fan (from process schematic)	Not applicable		
2. Fan Manufacturer			
3. Fan Model Number			
4. Fan Type (axial, centrifugal etc.)			
5. Capacity (in SCFM)			

Manufacturer's fan performance curve or rating curve, with operating point indicated, must be submitted with this application if the fans are an integral part of the installed or modified equipment.

6. Fan Operating Point in this System

	Fan A	Fan B	Fan C
a. Actual RPM			
b. Temperature at the fan (^oF)			
c. Fan pressure (static pressure, in H_2O)			
d. Actual flow rate of fan (ACFM)			
e. Actual horsepower requirements			

H. Miscellaneous Data

1. Number of employees at this facility

~240

2. Standard Industrial Classification (SIC) Code for this facility

4911

3. Does municipal water supply to your process operations have the required back-flow preventer?

☐ Yes ☐ No Not applicable to this project

If Yes, is it registered with the DEP Division of Water Supply?

☐ Yes ☐ No

Massachusetts Department of Environmental Protection
Bureau of Waste Prevention – Air Quality

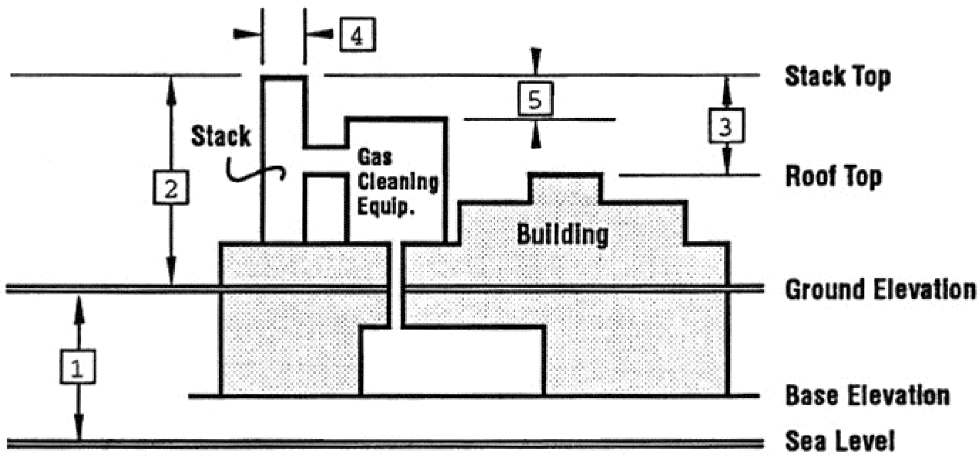
BWP AQ CPA-3 (for use with BWP AQ 02, 03)

Comprehensive Plan Approval Application for Non Fuel Emissions

X224106
Transmittal Number

Facility ID (if known)

I. Exhaust Stack Description



Questions for the above diagram

32ft 1. Height of Ground Above Sea Level (arrow 1)	497 ~~500~~ ft. 2. Height of Stack Top above Ground (arrow 2)
Not applicable 3. Height of Stack Top above Roof (arrow 3)	222 feet 4. Stack Exit Size (inside) (arrow 4)
Not applicable 5. Height of Stack Top above Control Equip. (arrow 5)	Vertical 6. Discharge direction (horizontal or vertical)
51 & 52 7. Identify Stack Nos. as they appear on Process Schematic	Concrete 8. Inside shell material
Concrete 9. Outside Shell Material	3.31 (design basis) 10. Range of gas exit velocity (ft/sec)
~32F to ~112 F 11. Range of stack gas exit temp. (°F)	24,320,000 (design basis) 12. Range of stack gas volume (acfm)
none 13. Type of Rain Protection	

The stack parameters will be evaluated to assure they provide sufficient protection from building, terrain, and stack tip downwash effects. Also, the “dew point” of the exhaust gases will be considered in the evaluation.

Note: The rain protection device should be of such a design as to allow the unimpeded escape of the stack gases. “Rain Hats” are prohibited.

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Facility ID (if known)

J. Standard Operating Procedure

Describe the start-up, operational, shutdown, and emergency procedures for the equipment that is integral to this project. The inscription must present, in sequence, the major steps that must be taken by the operator(s) to correctly and safely run the system. For each step, specify the duration and purpose, especially as it relates to maintaining safe operation and minimizing the emission of air contaminants. This inscription must detail the inter-relationship of the timing devices, the temperature indicators, the pressure indicators, the flow rate indicators, etc. **Specify which steps are under manual control and which are under automatic control**. Discuss the types, amounts, and duration of the release(s) of air contaminants during system fluctuations. Specify what measurements are observed and recorded to monitor performance. Use additional paper if necessary.

See plan approval application text. Standard operating procedures will be submitted no more than 60 days after Dominion accepts the proposed equipment.

K. Standard Maintenance Procedure

Describe preventive maintenance procedures for this **entire system**. Include such items as cleaning, part replacement, scrubbing solution renewal/replacement schedules, method of leak testing, frequency of leak testing and/or effluent sampling to establish adequacy of control systems. Include Manufacturer's maintenance requirements. Each air pollution control device requires a separate and detailed maintenance procedure. You are required to keep organized records at the facility that will document the monitored operating parameters, and the history of maintenance activities for the most recent two-year period. Describe your proposed record keeping system. Use additional paper if necessary.

See plan approval application text. Standard maintenance procedures will be submitted no more than 60 days after Dominion accepts the proposed equipment.

Massachusetts Department of Environmental Protection
Bureau of Waste Prevention – Air Quality

BWP AQ CPA-3 (for use with BWP AQ 02, 03)

Comprehensive Plan Approval Application for Non Fuel Emissions

X224106
Transmittal Number

Facility ID (if known)

L. Plans Application Preparer

1. AJ Jablonowski, PE
   Person who complied the plans application materials
2. Epsilon Associates, Inc.
   Representing
3. 3 Clock Tower Place, Suite 250
   Address
   Maynard MA 01754
4. 978-897-7100
   Telephone number
5. August 26, 2008
   Date completed

M. Certification

The seal and signature of a Massachusetts registered professional engineer must be entered below. This certifies that the information contained in this form has been checked for accuracy, and that the design represents good air pollution control engineering practice. (These must be originals. No photocopies, etc., of the seal and signature will be accepted.)

AJ Jablonowski
Print name

Authorized signature

Epsilon Associates, Inc.
Representing

COMMONWEALTH OF MASSACHUSETTS
ANDREW JABLONOWSKI
CHEMICAL
No. 39123
REGISTERED PROFESSIONAL ENGINEER

rev 1/9/09

August 28, 2008 | 39123
Date | PE number

Senior Consultant
Position/title

Massachusetts Department of Environmental Protection
Bureau of Waste Prevention – Air Quality

BWP AQ SFC-1 (for use with BWP AQ CPA-3)

Supplemental Form for Dry Air Filters (BP 3 FF)

X224106
Transmittal Number

Facility

A. Plan Application Requirements

Important: When filling out forms on the computer, use only the tab key to move your cursor - do not use the return key.

tab

return

This form is to be submitted together with form BWP AQ CPA-1, CPA-3, or CPA-4, whenever the construction, substantial reconstruction or alteration of a **Dry Air Filter** is desired.

B. Project Location

1. Name of facility:
   Dominion Energy Brayton Point, LLC – Brayton Point Station

2. Location of project site:
   1 Brayton Point Road — Street
   Somerset, MA — City/Town
   02726 — Zip code

C. Equipment Specifications

1. Manufacturer: TBD
2. Model Number - attach manufacturer's specifications: TBD
3. What is the capacity of the unit?
   1,800,000 ~~1,755,650~~ maximum with lime injection — ACFM
   ~~8 maximum~~ 6 to 10 — in. W.G. pressure drop
4. How many compartments are in the unit? 8 or 10 per baghouse
5. How many filter elements are in each compartment? 1,000 estimated
6. What type of filter material is used? PPS or equal
7. Is the filter material: X woven ☐ non-woven
8. Maximum recommended temperature: 375 — ^oF
9. Describe the filter elements: Bags — tubes, envelopes, cartridges, etc.
10. What is the real area per filter element? 30 ft^2 estimated — feet

D. Operating Conditions for this Permit

1. What is the average inlet gas flow?
   1,800,000 ~~1,755,650~~ maximum with lime injection — ACFM, wet
2. What is the moisture content in the inlet?
   2 to 12% — lbs./min
   — grains/ACF
3. What is the face velocity? TBD — ft/sec

D. Operating Conditions for this Permit (cont.)

4. What are the gas temperature (^{O}F, dry bulb) for the:

230 to 295 F
inlet

160 to 170 F w/lime injection
outlet

5. What is the pressure drop across the unit (in W.G.)?

6 ~~2~~ (across FF)
minimum

10 ~~8~~ (across FF)
maximum

NOTE: Supporting calculations and explanatory notes must be attached.

E. Particulate Collection Data

1. Describe the particle size weight to be emitted by the proposed unit:

	% of Total Weight	% of Friction Collected
a. < 1 micron:	TBD	TBD
b. 1 micron < 10 microns:	TBD	TBD
c. 10 microns < 50 microns:	TBD	TBD
d. > 50 microns:	TBD	TBD

2. What is the overall particulate collection efficiency? TBD upon final project design
3. What is the inlet particulate concentration? (gr/ACF) TBD upon final project design
4. What is the outlet particulate concentration? (gr/ACF) TBD upon final project design
5. What is the emission rate? (lbs/hr) ~~0.015 lb/MMBtu filterable~~
0.025 lb/MMBtu total

F. Cleaning Procedures and Particulate Disposal

1. Describe the cleaning mechanism: Pulse Jet
pulse jet, reverse jet, sonic, rapping, or other
2. What is the estimated time between cleaning phases? Based on pressure differential
seconds
3. How many filter elements are cleaned at the same time? One compartment-online cleaning
4. Describe the controller: PLC based on differential pressure
timer, pressure gauge, other?
5. What is the number of filter elements in operation during the cleaning phase? All compartments remain in service during online cleaning

F. Cleaning Procedures and Particulate Disposal (cont.)

6. Describe the collection hoppers and unloading schedule: Hoppers are emptied sequentially on a timed basis

7. How is the unloading schedule documented? In the PCL/DCS system

8. What is the ultimate disposal method? Landfill and potential re-use

9. Is the dust subject to 310 CMR 30.00, pertaining to Hazardous Waste? ☐ Yes ☒ No

G. Air Flow Data

1. What is the air flow into the filter system (ACFM)?

600,000
~~611,510~~ w/lime injection
Minimum

1,800,000
~~1,755,650~~ w/lime injection
Maximum

2. Describe what measure are taken to evenly distribute inlet air to all filter elements:

The design includes flow modeling and proper ductwork design of the inlet plenums to ensure proper flow distribution within the fabric filter.

2. What is the air to cloth ratio? (ACFM divided by the effective filter area):

~~4.42 at maximum flow conditions~~ tbd

NOTE: Detailed fan specifications must be supplied with this application. See form BWP AQ CPA-3 for instructions.
Detailed fan specifications will be provided to the Department upon final project design.

H. Drawing of Dry Air Filter Unit

A schematic drawing of the dry air filter unit must be **attached** to this form. The drawing must show all access doors, catwalks, ladders, and exhaust ductwork. In addition, the location of each pressure and temperature indicator must be shown.

A fabric filter drawing will be provided to the Department upon final project design.

Massachusetts Department of Environmental Protection
Bureau of Waste Prevention – Air Quality

BWP AQ SFC-1 (for use with BWP AQ CPA-3)

Supplemental Form for Dry Air Filters (BP 3 FF)

X224106
Transmittal Number

Facility

I. Failure Notification

1. How is the failure of the dry air filter made known to the operator during normal operations, (e.g. audible alarm, flashing lights, temperature indicator, pressure indicator, etc.)?

   Alarm indication at the HMI control screen.

2. Describe the record keeping procedures to be used in identifying the cause, duration and resolution of each failure (use a separate page if necessary):

   The BP3 Fabric Filter system record keeping procedures will be developed to identify the cause, duration, and resolution of each equipment failure. They will be similar to what is currently employed at the facility.

NOTE: The regional office must be notified immediately by telephone in the event of a dry air filter failure.

J. Certification

The seal and signature of a Massachusetts Registered Professional Engineer must be entered below. This certifies that the information contained in this form has been checked for accuracy, and that the design represents good air pollution control engineering practice. (These must be originals; no photocopies, etc. of the seal and signature will be accepted.)

AJ Jablonowski, PE
Print name

Authorized signature

Senior Consultant
Position/title

Epsilon Associates, Inc.
Representing

August 26, 2008 revised Jan 9, 2009
Date

39123
P.E. Number

COMMONWEALTH OF MASSACHUSETTS
ANDREW JABLONOWSKI
CHEMICAL
No. 39123
REGISTERED
PROFESSIONAL ENGINEER

Massachusetts Department of Environmental Protection
Bureau of Waste Prevention – Air Quality Control

BWP AQ SFC-4 (for use with BWP AQ 02,03 and BWP AQ CPA-3)

Supplemental Form for Adsorption Equipment (BP 3 DS)

X224106
Transmittal Number

Facility

A. Plan Applications Requirements

Important: When filling out forms on the computer, use only the tab key to move your cursor - do not use the return key.

This form is to be submitted together with form BWP AQ CPA-3, whenever the modification or the installation of **Adsorption Equipment** is desired.

B. Project Location

1. Name of facility:

Dominion Energy Brayton Point, LLC – Brayton Point Station

2. Location and Project Site:

1 Brayton Point Road
Street Address

Somerset
City/town

MA
State

02726
Zip code

C. Equipment Specifications

TBD
1. Manufacturer

Unit 3 Dry Scrubber (DS) System
2. Model number

3. Give the following information relative to the adsorbate:

2,100,000 ~~2,113,280~~ ACFM maximum flow
a. Total volume of process exhaust to adsorber(s) (SCFM)

160 to 170 F at outlet
b. Operating temperature of adsorber (^{O}F)

Expected to vary from 2 to 12% by weight
c. Inlet moisture content: lbs./min

d. Will the process steam be cooled? ☐ Yes ☐ No

If yes, explain:

N/A

e. List the chemical compounds to be adsorbed (generic name for each):

Chemical Name	Inlet Range (lbs./hr)	Inlet Range (ppm)
Flue gas Sulfur Dioxide	System will be designed to handle an inlet flue gas maximum SO_2 concentration of 11,500 lb/hr.	

C. Equipment Specifications (cont.)

f. Total concentration in air steam to be treated: The BP3 DS system will be designed to handle an inlet flue gas with a maximum of 9.1E-5 lb SO_2 per actual ft^3 of inlet flue gas.
$lb./ft^3$ & ppm

g. Temperature at the inlet: The BP3 DS system will be designed to handle expected inlet flue gas temperatures of 230 to 295
^oF If variable, give range

h. Temperature at the outlet: The BP3 DS system outlet flue gas temperature is expected to be 160 to 170°F
^oF If variable, give range

i. Describe the pre-cleaner, if applicable *: N/A

*__Note:__ An additional supplemental form for this equipment may be required.

D. Adsorber Information

Detailed supporting documentation is an essential part of this submittal. Attach all relevant materials to support design assumptions and parameters.

1. Construction material of the adsorber: Carbon steel/stainless steel
2. Type of adsorbent to be used: Lime and water
   give base material, mesh size, grade, etc.
3. surface area of the adsorbent? The surface area of the lime and water droplets will be great and sufficient to accomplish the required removal of SO_2 from the flue gas.
   m^2/g
   $ft^2/lb.$
4. Amount of adsorbent used per bed: The amount of lime reagent used by the BP3 DS system will vary depending on the inlet flue gas SO_2 content and the required SO_2 removal.
   lbs.
5. Pore size distribution: The size of the lime-water droplets will be small in order to insure that proper SO_2 removal occurs.
   angstroms
6. Polarity of the adsorbent: The lime-water will be alkali and readily react with the flue gas SO_2.
7. Estimated removal efficiency of the chemical compounds: The DS system will be designed to remove a maximum of 90% SO_2 from the inlet flue gas at full load design conditions, and 1.5% sulfur coal.
   %
8. How many vessels will the equipment have? Two (2) 50% reactor vessels.
9. Number of beds per vessel: N/A

D. Adsorber Information (cont.)

10. Face area per bed: N/A
square feet

11. Depth of the bed: N/A
feet

12. Velocity at face of bed: N/A
feet per minute

13. Pressure drop across the unit: 2 to 4 in wg across reactor vessel

(in. of H_2O)

(mm of Hg)

14. Bed volume N/A
cubic feet

15. Is the system designed to be pressurized for increased efficiency? ☐ Yes ☒ No

16. If yes, what is the system pressure? N/A
in. of H_2O
N/A
mm of Hg

17. Hours of operation for the production line(s): 24 hours/day operation. System will operate to meet the required SO_2 annual average emission limits.
hrs/day
7 – or as required to meet the SO_2 annual average emission limits.
days/week
52 – or as required to meet the SO_2 annual average emission limits.
week/year

18. How is the break point time determined and how is cleaning schedule maintained (explain briefly)?

Certain system components can be cleaned online and during station maintenance outages.

19. Is the system: ☐ regenerative? ☒ non-regenerative?
The BP3 DS system design is based on non-regenerative chemistry producing a solid byproduct from the reaction of flue gas SO_2 with lime-water reagent. Reagent is recycled to maximize reaction with flue gas SO_2

20. If regenerative, how will the saturated adsorbent be stripped?

N/A

21. If by steam, how many lbs./hr? N/A

N/A
@ psig
N/A
@ °F

D. Adsorber Information (cont.)

22. Is direction of stripping opposite to adsorption? ☐ Yes ☐ No N/A

23. Time required to adequately strip (min.)? N/A –the concept of stripping does not apply to the design of the system.
minutes

24. How will the bed be cooled & dried prior to re-use? N/A – the concept of stripping does not apply to the design of the system.

NOTE: The downstream design should be indicated on the attached Adsorption Flow Diagram.

25. For non-regenerative adsorbers, indicate the disposal method for the contaminated adsorbent (assigned site(s), contract(s) with licensed haulers, etc.):

The project design includes truck transport of the solid byproducts offsite, to be handled and disposed of in an environmentally acceptable manner. Methods for beneficial reuse is being researched.

26. Are these contaminants subject to 310 CMR 30.00 pertaining to the control of **Hazardous Waste**?

☐ Yes ☒ No

If yes, identify the company that will be disposing of the contaminated scrubbing liquid:

N/A

E. Miscellaneous Data

1. Will the collected chemical compounds be re-used?

☐ Yes ☒ No

If yes, describe collection and separation:

N/A

If no, describe the disposal method (assigned site(s), contract(s) with licensed haulers, etc.):

The BP3 DS system solid byproduct will be recycled. The solid byproduct will then be removed for disposal off site or possibly reused.

2. Chemical activity of adsorbate with adsorbent: Within the BP3 DS system, the lime-water reagent will react with the flue gas SO_2 to achieve the required SO_2 removal.

3. Give the retentively of adsorbate with adsorbent: The lime-water reagent reacts chemically with the flue gas SO2 to form a calcium sulfite/sulfate based byproduct. The byproduct solids will retain the sulfur in a stable form.

E. Miscellaneous Data (cont.)

4. How will the unit be winterized?

The BP3 DS system will be winterized using a combination of design methods. For example, where applicable, enclosures and/or heat tracing will be employed.

F. Standard Operating and Maintenance Procedures

See form BWP AQ CPA-3 for instructions concerning the required standard operating and maintenance procedures for this control equipment. **A standard operating and maintenance procedure for this control equipment will be submitted no later than 60 days after commencement of operation of the proposed control equipment.**

G. Failure Notification

1. How is the failure of the collection equipment made known to the operator (e.g. audible alarm, lights, etc.)?

   The BP3 DS system will be designed to be reliable. Any equipment failures will be made known to the operators by various means including lights and audible alarms. The system is designed with various alarm indication that notify the operator via the system HMI control screens.

2. Describe the record keeping procedures that will be used to identify the cause, duration, and resolution of each failure (use separate page if necessary):

   The BP3 DS system record keeping procedures will be developed to identify the cause, duration, and resolution of each equipment failure. They will be similar to what is currently employed at the facility.

H. Certification

The seal and signature of a Massachusetts Registered Professional Engineer must be entered below. This certifies that the information contained in this form has been checked for accuracy, and that the design represents good air pollution control engineering practice. (These must be originals; no photocopies, etc. of the seal and signature will be accepted.)

AJ Jablonowski
Print name

AJ Jablonowski
Authorized signature

Senior Consultant
Position/title

Epsilon Associates, Inc
Representing

August 26, 2008 rev Jan 9, 2009
Date

39123
PE number

COMMONWEALTH OF MASSACHUSETTS
ANDREW JABLONOWSKI
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PROFESSIONAL ENGINEER

Massachusetts Department of Environmental Protection
Bureau of Waste Prevention – Air Quality Control

BWP AQ SFC-4 (for use with BWP AQ 02,03 and BWP AQ CPA-3)

X224106
Transmittal Number

Facility

Supplemental Form for Adsorption Equipment (BP 3 PAC)

A. Plan Applications Requirements

Important: When filling out forms on the computer, use only the tab key to move your cursor - do not use the return key.

This form is to be submitted together with form BWP AQ CPA-3, whenever the modification or the installation of **Adsorption Equipment** is desired.

B. Project Location

1. Name of facility:

Dominion Energy Brayton Point, LLC-Brayton Point Station

2. Location and Project Site:

1 Brayton Point Road
Street Address

Somerset
City/town

MA
State

02726
Zip code

Note: The data represented in this form should be consistent with previous forms.

C. Equipment Specifications

Chemco Systems, LP
1. Manufacturer

Presently referred to as BP3 PAC System
2. Model number

3. Give the following information relative to the adsorbate:

2,100,000 ACFM max ~~1,660,000 SCFM (estimated at 68ºF, 1 atm,wet)~~
a. Total volume of process exhaust to adsorber(s) (SCFM)

160-170 F
Expected to be ~~230ºF - 295ºF~~
b. Operating temperature of adsorber (ºF)

Expected to vary from 2 to 12% by weight
c. Inlet moisture content: lbs./min

d. Will the process steam be cooled? ☐ Yes ☒ No

If yes, explain:

N/A

e. List the chemical compounds to be adsorbed (generic name for each):

Chemical Name	Inlet Range (lbs./hr)	Inlet Range (ppm)
Flue gas mercury (Hg)	System will be designed to handle an inlet flue gas maximum Hg concentration of 0.0378 lb/hr.	

C. Equipment Specifications (cont.)

f. Total concentration in air steam to be treated: max The BP3 PAC system will be deigned to handle an inlet flue gas with a maximum of ~~2,240,906~~ 2,100,000 acfm ~~(@ 300°)~~ resulting in a ratio of 2.8 x 10^{-10} lb Hg per actual ft^3 of inlet flue gas.
lb./ft^3 & ppm

g. Temperature at the inlet: The BP3 PAC system will be designed to handle expected inlet flue gas temperatures of ~~200~~ to ~~300~~°F. 230 to 295 F
°F If variable, give range

h. Temperature at the outlet: The BP3 PAC system outlet flue gas temperature is expected to be 200 to 300°F when the PAC system is in service.
°F If variable, give range

i. Describe the pre-cleaner, if applicable *: N/A

***Note:** An additional supplemental form for this equipment may be required.

D. Adsorber Information

Detailed supporting documentation is an essential part of this submittal. Attach all relevant materials to support design assumptions and parameters.

1. Construction material of the adsorber: Carbon steel material
2. Type of adsorbent to be used: Powder Activated Carbon (PAC) particle
give base material, mesh size, grade, etc.
3. surface area of the adsorbent? The surface area of the PAC particle will be great and sufficient to accomplish the required removal of Hg from the flue gas.
m^2/g $ft^2/lb.$
4. Amount of adsorbent used per bed: The amount of PAC used by the BP3 PAC system will vary depending on the inlet flue gas Hg content and the required Hg removal.
lbs.
5. Pore size distribution: The size of the PAC particle will be small in order to insure that proper Hg removal occurs.
angstroms
6. Polarity of the adsorbent: The PAC will be dry and readily react with the flue gas Hg.

D. Adsorber Information (cont.)

7. Estimated removal efficiency of the chemical compounds: The BP3 PAC system Hg removal efficiency will vary depending on the required Hg removal. The system will be designed to remove a maximum of 80% Hg from the inlet flue gas at full load design conditions.

8. How many vessels will the equipment have? BP3 will be equipped with one PAC system.

9. Number of beds per vessel: N/A

10. Face area per bed: N/A
square feet

11. Depth of the bed: N/A
feet

12. Velocity at face of bed: N/A
feet per minute

13. Pressure drop across the unit: N/A
(in. of H_2O)
(mm of Hg)

14. Bed volume: N/A
cubic feet

15. Is the system designed to be pressurized for increased efficiency? ☐ Yes ☒ No

16. If yes, what is the system pressure? N/A
in. of H_2O
N/A
mm of Hg

17. Hours of operation for the production line(s): 24 - maximum PAC operation. System will operate to meet the required Hg annual average emission limits.
hrs/day
7 – or as required to meet the Hg annual average emission limits.
days/week
52 – or as required to meet the Hg annual average emission limits.
week/years

18. How is the break point time determined and how is cleaning schedule maintained (explain briefly)?

Break point time is not applicable with this system. The PAC system will be designed to minimize the need for cleaning. Mercury collection performance is expected to indicate the need for maintenance.

19. Is the system: ☐ regenerative? ☒ non-regenerative?

The BP3 PAC system design is based on non-regenerative chemistry producing a solid byproduct.

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Facility

D. Adsorber Information (cont.)

20. If regenerative, how will the saturated adsorbent be stripped?

    N/A

21. If by steam, how many lbs/hr?

    N/A

    N/A
    @ psig

    N/A
    @ °F

22. Is direction of stripping opposite to adsorption? ☐ Yes ☐ No N/A

23. Time required to adequately strip (min.)?

    N/A
    minutes

24. How will the bed be cooled & dried prior to re-use?

    N/A

NOTE: The downstream design should be indicated on the attached Adsorption Flow Diagram.

25. For non-regenerative adsorbers, indicate the disposal method for the contaminated adsorbent (assigned site(s), contract(s) with licensed haulers, etc.):

    DS solid byproduct and PAC
    The project design includes truck transport of the ~~solid byproduct with the SDA byproduct~~ offsite, to be handled and disposed of in an environmentally acceptable manner.

26. Are these contaminants subject to 310 CMR 30.00 pertaining to the control of **Hazardous Waste**?

    ☐ Yes ☒ No

    If yes, identify the company that will be disposing of the contaminated scrubbing liquid:

    N/A

E. Miscellaneous Data

1. Will the collected chemical compounds be re-used?

    ☒ Yes ☐ No

    If yes, describe collection and separation:

    The BP3 PAC system solid byproduct will be collected in the fabric filter with the DS byproduct. A portion of the solids are recycled back to the DS system ~~recycled back to the Ash Reduction Process (ARP)~~

    If no, describe the disposal method (assigned site(s), contract(s) with licensed haulers, etc.):

    N/A

Massachusetts Department of Environmental Protection
Bureau of Waste Prevention – Air Quality Control

BWP AQ SFC-4 (for use with BWP AQ 02,03 and BWP AQ CPA-3)

Supplemental Form for Adsorption Equipment (BP 3 PAC)

X224106
Transmittal Number

Facility

E. Miscellaneous Data (cont.)

2. Chemical activity of adsorbate with adsorbent: Within the BP3 PAC system, the flue gas Hg attaches to the PAC particles to achieve the required Hg removal.
3. Give the retentively of adsorbate with adsorbent: The PAC sorbent adsorbs the flue gas Hg and retains the Hg in a stable form for disposal.
4. How will the unit be winterized? The BP3 PAC system will be winterized using a combination of design methods. For example, where applicable, enclosures and/or heat will be employed.

F. Standard Operating and Maintenance Procedures

See form BWP AQ CPA-3 for instructions concerning the required standard operating and maintenance procedures for this control equipment. **A standard operating and maintenance procedure for this control equipment will be submitted no later than 60 days after commencement of operation of the proposed control equipment.**

G. Failure Notification

1. How is the failure of the collection equipment made known to the operator (e.g. audible alarm, lights, etc.)?

   The BP3 PAC system will be designed to be reliable. Any equipment failures will be made known to the operators by various means including lights and audible alarms.

2. Describe the record keeping procedures that will be used to identify the cause, duration, and resolution of each failure (use separate page if necessary):

   The BP3 PAC system record keeping procedures will be developed to identify the cause, duration, and resolution of each equipment failure. They will be similar to what is currently employed at the facility.

H. Certification

The seal and signature of a Massachusetts Registered Professional Engineer must be entered below. This certifies that the information contained in this form has been checked for accuracy, and that the design represents good air pollution control engineering practice. (These must be originals; no photocopies, etc. of the seal and signature will be accepted.)

AJ Jablonowski
Print name

[signature]
Authorized signature

Senior Consultant
Position/title

Epsilon Associates, Inc
Representing

August 26, 2008 rev Jan 9, 2009
Date

39123
PE number

COMMONWEALTH OF MASSACHUSETTS
ANDREW JABLONOWSKI
CHEMICAL
No. 39123
REGISTERED PROFESSIONAL ENGINEER

Massachusetts Department of Environmental Protection
Bureau of Waste Prevention – Air Quality Control

BWP AQ SFC-7 (for use with BWP AQ CPA-1 through BWP AQ CPA-5)

X224106
Transmittal Number

Facility

Determination of Best Available Control Technology

Important: When filling out forms on the computer, use only the tab key to move your cursor - do not use the return key.

A. Applicability

Complete this form only if specifically requested to do so by the Department. Do not complete this without first consulting with the regional office. This form is not a requirement of all applicants. This form is intended as a supplement to forms BWP AQ CPA-1 through BWP AQ CPA-5 where the applicant is required to demonstrate that the source will utilize Best Available Control Technology (BACT) for the emission of a pollutant. This analysis utilizes the "top-down" approach to determination of BACT.

For additional guidance on the determination of BACT, refer to the June 1991 NESCAUM BACT GUIDELINE, attached to this form.

B. General

Dominion Energy Brayton Point LLC (cooling tower component)
Facility name

1 Brayton Point Road, Somerset, MA
Location

C. Pollutants

For the process under review, list each pollutant or class of pollutant that will be emitted and the **baseline (uncontrolled)** emission rate. These values should agree with values provided on CPA or other forms filed with this application.

Pollutant	**Uncontrolled Emission Rate**	
	Pounds per Hour*	Tons per Year**
Sulfur Dioxide (SO_2):	0	0
Nitrogen Oxides (NO_x):	0	0
Carbon Monoxide (CO):	0	0
Lead (Pb):	0	0
Particulates (PM)*:	1,425**	6,227
Volatile Organic Compounds (VOC):	0	0
Other Pollutants (list):		
1.		
2.		
3.		

*Pounds per hour is the maximum emission rate possible for the process.

**Tons per year is calculated from pounds per hour operating 8760 hours per year unless otherwise restricted (i.e. by a federally enforceable limit or permit on operation or production).

* Throughout this form, PM also refers to PM10 and PM2.5 at the same emission rate.
** "Uncontrolled" is not applicable to cooling tower drift – it is physically impossible for all the water to spray into the air. Listed emission rate is the baseline emission rate as shown in the attached BACT analysis.

Massachusetts Department of Environmental Protection
Bureau of Waste Prevention – Air Quality Control

BWP AQ SFC-7 (for use with BWP AQ CPA-1 through BWP AQ CPA-5)

X224106
Transmittal Number

Facility

Determination of Best Available Control Technology

D. Control Options

List, in order of resulting emission rates (1 = lowest, 6 = highest), all air pollution control measures and/or devices which would result in a lower emission rate than that of the project, as proposed. Do not, at this time, eliminate from consideration any options because of economics, technical or other considerations. See the last page of this form (section J) for some examples of control options; it is not, however, a comprehensive list.

You must include:

- technology required by any regulations;
- technology that is in use on similar types of sources (existing control technology);
- technology that is in use on other types of sources but not yet demonstrated specifically on your source (technology transfer);
- theoretically applicable technology but as yet unproven on full scale installations;
- add-on control equipment;
- process modifications that will reduce emissions;
- alternative raw materials; and
- alternative fuels.

Control Description	Emission Rate After Controls (pounds per hour)		
	Pollutant 1*	Pollutant 2*	Pollutant 3*
1. Air Cooled Condensers	0 (PM)		
2. Once-Through Cooling	0 (PM)		
3. Fresh Water	~5 (PM)		
4. Drift eliminators achieving <0.0005% drift rate*	36 (PM)		
5. Reduction in Cycles of Concentration	< 89 (PM)		
6.			

*Indicate pollutant

* a drift rate of 0.0002% is used to quantify emissions.

E. Option Feasibility

For each control option listed above, indicate the reason for not utilizing the option in this project and whether or not the technology has been demonstrated in use by a similar source.

Control Option	Basis of Elimination			Demonstrated in Use	
	Economic	Technical	Other	Yes	No
1.	☒	☒	☒	☒	☐
2.	☐	☐	☒	☒	☐
3.	☐	☒	☒	☒	☐
4.	☐	☒	☐	☐	☒
5.	☐	☒	☒	☒	☐
6.	☐	☐	☐	☐	☐

* Indicate Pollutant

F. Documentation

For each basis of elimination checked in section E on the previous page, provide a detailed explanation or calculation to substantiate the elimination of the control option. The substantiation shall include those items as delineated below:

Technical: Elimination based on technical grounds must specifically state the reason the technology is not feasible and why the system cannot be modified to accommodate the source. If the technology is in use on other sources, the difference prohibiting its use on this source must be stated in detail. Do not use cost or other qualifications in the technical documentation. **Be as specific and technical as possible.**

Economic: Elimination based on economic (cost of the control) must complete the Cost Analysis work sheet, section I. Approximations/estimates may be used as necessary. However, in the event that the Department does not concur with provided estimates, final determination of cost will be based on procedures outlined in the OAQPS Control Cost Manual (EPA Document 450/3-90-006) or other methods approved by the Department.

Other: Elimination based on other considerations must specifically state the reason the option is not feasible and why the system cannot be modified to accommodate this option**. Be as specific and detailed as possible.**

G. Additional Impacts

Describe other factors, beneficial and adverse, associated with the project and/or control option as appropriate. Include items such as:

Environmental Impacts – Describe environmental factors other than mass emissions to the air that are relevant, such as:

- visible emissions
- odor
- toxicity of emissions
- noise
- safety

Energy Impacts – Describe factors such as:

- energy consumption of different options
- impact of alternative fuel use

Impact on other media - Describe cross media impacts, such as:

- water pollution
- water supply
- solid waste
- hazardous waste, etc.

H. BWP SFC – 7 Preparer

AJ Jablonowski
Name

Epsilon Associates
Company

3 Clock Tower Place
Address

Maynard
City/town

MA
State

01754
Zip code

978-897-7100
Telephone number

January 9, 2009
Date

I. Cost Analysis Work Sheet

Total Capital Investment (TCI)

Direct Purchase Cost

$1,500,000,000 (air cooled condenser)
1. Primary control device auxiliary equipment

included in (1)
2. Fans

included in (1)
3. Ducts

included in (1)
4. Other

included in (1)
5. Instrumentation/controls

Indirect Capital Cost

included in (1)
6. Construction

included in (1)
7. Labor

included in (1)
8. Sales taxes*

included in (1)
9. Freight charges

see attached economic analysis

X224106
Transmittal Number

Facility

Determination of Best Available Control Technology

I. Cost Analysis Work Sheet (cont.)

Engineering/Planning

included in (1)
10. Contracting fees

included in (1)
11. Testing

included in (1)
12. Supervision

$1.5 billion
13. Total capital investment (add items 1 – 12)

$1.5bil * 0.1627= $244,000,000 (10 yr life, 10% interest)
$C[i(1+i)^n]/[(1+i)^n - 1]$
i = interest rate (assume 10%)
n = life of equipment (assume 10 years or less)*
C = Total Capital Investment (line 13)

Annual Operating and Maintenance Cost

Direct Operating Cost

conservatively assume zero
15. Labor

conservatively assume zero
16. Maintenance

conservatively assume zero
17. Replacement parts

Indirect Cost

conservatively assume zero
18. Property taxes*

conservatively assume zero
19. Insurance

conservatively assume zero
20. Fees

conservatively assume zero
21. Total annual operating costs (add items 15 – 20)

Energy Cost

50,000 kW x $0.05/kWhr x 8760 hr = $21,900,000

0
23. Annual auxiliary fuel

$21,900,000
24. Total annual energy cost (item 22 + 23)

assume zero
25. Annual waste treatment and disposal costs

conservatively assume zero
26. Miscellaneous annual expenses

0
27. Annual recourse recovery & resale

$265,950,000
28. Total annualized control costs
(items 14+21+25+26)-27

6227
29. Amount of pollutant controlled over Baseline Emissions
(Tons per year)

$42,700
30. Cost of control ($/ton) (divide 28 by 29)

*State and federal law may provide for certain tax exemptions and special loans for the purchase of control equipment. Contact the Massachusetts Industrial Finance Agency (MIFA) or Federal Small Business Association (SBA).

See attached economic analysis

J. Control Options (Partial list)

ADD-ON CONTROLS

- Thermal Incinerators
- Catalytic Incinerators
- Fabric Filters/Baghouses
- Cyclones
- Electrostatic Precipitators
- Condenser/Refrigeration Systems
- Wet Scrubbers:
  - Packed Bed
  - Spray Chamber
  - Other
- Carbon Adsorbers
- Other Media Adsorbers
- Dry Scrubbers
- Flares
- Non-Regenerative Carbon
- Biofilters/Soil Filters
- Non-Selective Catalytic Reduction
- Selective Catalytic Reduction
- Afterburners
- Other Add-on Control Devices

PROCESS MODIFICATION

- Reformulation of Raw Materials
- Use of Non-Hazardous/Non-Toxic Alternatives
- Combustion Controls
- Alternate Processing Techniques
- Electrostatic Spray Application
- High Volume Low Pressure (HVLP) Spray Application
- Recycling/Waste Minimization
- Alternative Fuels
- Powder Coating
- Aqueous Cleaning Compounds
- Other Process Changes

PSD PERMIT ONLY – NOT SUBJECT TO MASS DEP BACT

Massachusetts Department of Environmental Protection
Bureau of Waste Prevention – Air Quality Control

BWP AQ SFC-7 (for use with BWP AQ CPA-1 through BWP AQ CPA-5)

X224106
Transmittal Number

Facility

Determination of Best Available Control Technology

Important: When filling out forms on the computer, use only the tab key to move your cursor - do not use the return key.

A. Applicability

Complete this form only if specifically requested to do so by the Department. Do not complete this without first consulting with the regional office. This form is not a requirement of all applicants. This form is intended as a supplement to forms BWP AQ CPA-1 through BWP AQ CPA-5 where the applicant is required to demonstrate that the source will utilize Best Available Control Technology (BACT) for the emission of a pollutant. This analysis utilizes the "top-down" approach to determination of BACT.

For additional guidance on the determination of BACT, refer to the June 1991 NESCAUM BACT GUIDELINE, attached to this form.

B. General

Dominion Energy Brayton Point LLC (Unit 3 DS/FF Project)
Facility name

1 Brayton Point Road, Somerset, MA
Location

C. Pollutants

For the process under review, list each pollutant or class of pollutant that will be emitted and the **baseline (uncontrolled)** emission rate. These values should agree with values provided on CPA or other forms filed with this application.

Pollutant	**Uncontrolled Emission Rate**	
	Pounds per Hour*	Tons per Year**
Sulfur Dioxide (SO_2):	Not subject to review	Not subject to review
Nitrogen Oxides (NO_x):	Not subject to review	Not subject to review
Carbon Monoxide (CO):	Not subject to review	Not subject to review
Lead (Pb):	Not subject to review	Not subject to review
Particulates (PM)*:	1,425	14,614
Volatile Organic Compounds (VOC):	0	0
Other Pollutants (list):		
1.		
2.		
3.		

*Pounds per hour is the maximum emission rate possible for the process.

**Tons per year is calculated from pounds per hour operating 8760 hours per year unless otherwise restricted (i.e. by a federally enforceable limit or permit on operation or production).

* Throughout this form, PM refers to PM10 and PM2.5. See application text for discussion of total suspended particulate.

PSD PERMIT ONLY – NOT SUBJECT TO MASS DEP BACT

Massachusetts Department of Environmental Protection
Bureau of Waste Prevention – Air Quality Control

BWP AQ SFC-7 (for use with BWP AQ CPA-1 through BWP AQ CPA-5)

X224106
Transmittal Number

Facility

Determination of Best Available Control Technology

D. Control Options

List, in order of resulting emission rates (1 = lowest, 6 = highest), all air pollution control measures and/or devices which would result in a lower emission rate than that of the project, as proposed. Do not, at this time, eliminate from consideration any options because of economics, technical or other considerations. See the last page of this form (section J) for some examples of control options; it is not, however, a comprehensive list.

You must include:

- technology required by any regulations;
- technology that is in use on similar types of sources (existing control technology);
- technology that is in use on other types of sources but not yet demonstrated specifically on your source (technology transfer);
- theoretically applicable technology but as yet unproven on full scale installations;
- add-on control equipment;
- process modifications that will reduce emissions;
- alternative raw materials; and
- alternative fuels.

Control Description	**Emission Rate After Controls (pounds per hour)**		
	Pollutant 1*****	Pollutant 2*****	Pollutant 3*****
1. Fabric Filter with Wet ESP in series	56.55		
2.			
3.			
4.			
5.			
6.			

*Indicate pollutant: PM10/PM2.5

E. Option Feasibility

For each control option listed above, indicate the reason for not utilizing the option in this project and whether or not the technology has been demonstrated in use by a similar source.

Control Option	Basis of Elimination			Demonstrated in Use	
	Economic	Technical	Other	Yes	No
1.	☒	☒**	☐	☐	☒
2.	☐	☐	☐	☐	☐
3.	☐	☐	☐	☐	☐
4.	☐	☐	☐	☐	☐
5.	☐	☐	☐	☐	☐
6.	☐	☐	☐	☐	☐

* Indicate Pollutant : PM10/PM2.5

** Wet ESP in series may not be technically feasible. Please see attached BACT analysis.

F. Documentation

For each basis of elimination checked in section E on the previous page, provide a detailed explanation or calculation to substantiate the elimination of the control option. The substantiation shall include those items as delineated below:

Technical: Elimination based on technical grounds must specifically state the reason the technology is not feasible and why the system cannot be modified to accommodate the source. If the technology is in use on other sources, the difference prohibiting its use on this source must be stated in detail. Do not use cost or other qualifications in the technical documentation. **Be as specific and technical as possible.**

Economic: Elimination based on economic (cost of the control) must complete the Cost Analysis work sheet, section I. Approximations/estimates may be used as necessary. However, in the event that the Department does not concur with provided estimates, final determination of cost will be based on procedures outlined in the OAQPS Control Cost Manual (EPA Document 450/3-90-006) or other methods approved by the Department.

Other: Elimination based on other considerations must specifically state the reason the option is not feasible and why the system cannot be modified to accommodate this option. **Be as specific and detailed as possible.**

Massachusetts Department of Environmental Protection
Bureau of Waste Prevention – Air Quality Control

BWP AQ SFC-7 (for use with BWP AQ CPA-1 through BWP AQ CPA-5)

X224106
Transmittal Number

Facility

Determination of Best Available Control Technology

G. Additional Impacts

Describe other factors, beneficial and adverse, associated with the project and/or control option as appropriate. Include items such as:

Environmental Impacts – Describe environmental factors other than mass emissions to the air that are relevant, such as:

- visible emissions
- odor
- toxicity of emissions
- noise
- safety

Energy Impacts – Describe factors such as:

- energy consumption of different options
- impact of alternative fuel use

Impact on other media - Describe cross media impacts, such as:

- water pollution
- water supply
- solid waste
- hazardous waste, etc.

H. BWP SFC – 7 Preparer

AJ Jablonowski
Name

Epsilon Associates
Company

3 Clock Tower Place
Address

Maynard
City/town

MA
State

01754
Zip code

978-897-7100
Telephone number

January 9, 2009
Date

I. Cost Analysis Work Sheet

Total Capital Investment (TCI)

Direct Purchase Cost

$61,752,000 (Wet ESP)
1. Primary control device auxiliary equipment

included in (1)
2. Fans

included in (1)
3. Ducts

included in (1)
4. Other

$6,175,200
5. Instrumentation/controls

Indirect Capital Cost

$48,821,131
6. Construction

$41,534,395
7. Labor

$1,852,560
8. Sales taxes*

$3,087,600
9. Freight charges

Costs are based on EPA OAQPS Costing Factors & methods, incremental cost to add Wet ESP. Please see BACT Analysis in Section 4.3.4 & Appendix B for details.

PSD PERMIT ONLY – NOT SUBJECT TO MASS DEP BACT

Determination of Best Available Control Technology

I. Cost Analysis Work Sheet (cont.)

Engineering/Planning

Included in (7)
10. Contracting fees

Included in (7)
11. Testing

Included in (7)
12. Supervision

$163,222,886
13. Total capital investment (add items 1 – 12)

$15,406,608 (20 yr life, 7% interest)
14. Annualized capital cost
$C[i(1+i)^n]/[(1+i)^n - 1]$
i = interest rate (assume 10%)
n = life of equipment (assume 10 years or less)*
C = Total Capital Investment (line 13)

Annual Operating and Maintenance Cost

Direct Operating Cost

$23,296
15. Labor

$24,420
16. Maintenance

$617,520
17. Replacement parts

Indirect Cost

$1,632,229
18. Property taxes*

$1,632,229
19. Insurance

$3,661,776
20. Fees

$7,591,470
21. Total annual operating costs (add items 15 – 20)

Energy Cost

$83,649
22. Annual electrical energy expense

$2,306,924 (water)
23. Annual auxiliary fuel

$2,390,573
24. Total annual energy cost (item 22 + 23)

assume zero
25. Annual waste treatment and disposal costs

conservatively assume zero
26. Miscellaneous annual expenses

0
27. Annual recourse recovery & resale

$25,388,651
28. Total annualized control costs
(items 14+21+25+26)-27

372 incremental – see attached BACT analysis
29. Amount of pollutant controlled over Baseline Emissions
(Tons per year)

$68,249
30. Cost of control ($/ton) (divide 28 by 29)

*State and federal law may provide for certain tax exemptions and special loans for the purchase of control equipment. Contact the Massachusetts Industrial Finance Agency (MIFA) or Federal Small Business Association (SBA).

Costs are based on EPA OAQPS Costing Factors. Please see BACT Analysis in Section 4.3.4 & Appendix B for details.

J. Control Options (Partial list)

ADD-ON CONTROLS

- Thermal Incinerators
- Catalytic Incinerators
- Fabric Filters/Baghouses
- Cyclones
- Electrostatic Precipitators
- Condenser/Refrigeration Systems
- Wet Scrubbers:
  - Packed Bed
  - Spray Chamber
  - Other
- Carbon Adsorbers
- Other Media Adsorbers
- Dry Scrubbers
- Flares
- Non-Regenerative Carbon
- Biofilters/Soil Filters
- Non-Selective Catalytic Reduction
- Selective Catalytic Reduction
- Afterburners
- Other Add-on Control Devices

PROCESS MODIFICATION

- Reformulation of Raw Materials
- Use of Non-Hazardous/Non-Toxic Alternatives
- Combustion Controls
- Alternate Processing Techniques
- Electrostatic Spray Application
- High Volume Low Pressure (HVLP) Spray Application
- Recycling/Waste Minimization
- Alternative Fuels
- Powder Coating
- Aqueous Cleaning Compounds
- Other Process Changes

APPENDIX B

Supporting Calculations and Figures

DOMINION ENERGY BRAYTON POINT LLC
COOLING TOWER EMISSIONS CALCULATIONS & MONITORING METHODS

Air modeling and permitting inputs are a function of the circulating water flow, and the dissolved solids concentration. Modeling documents compliance with 24-hour and annual ambient air quality standards based on 5.6 grams per second per tower. Dominion proposes to document compliace on a 24-hr average basis and 12-month rolling average basis.

Gallons per minute circulating water flow will be measured continuously & recorded hourly using flow metering or the use of pump curves supplied by the manufacturer to calculate a flow rate. Dissolved solids will be calculated based on daily conducivity measurements in the circulating water or blowdown. Complince will be documented based on the drift rate calculated using these two parameters. Example calculations provided below.

Design Case	High Flow Case	High Solids Case	
360,000	**400,000**	**330,000**	gallons/minute circulating water flow, per tower
0.0005%	0.0005%	0.0005%	drift rate (best available drift eliminators)
1.8	2	1.65	gallons/minute water drift (gpm X drift)
8.57	8.57	8.57	pounds/gallon salt water density
926	1028	848	pounds/hour water drift (drift X density X min/hour)
48000	**43100**	**52250**	dissolved solids concentration (ppmw)
44.4	44.3	44.3	pounds/hour solids drift per tower (drift mass X ppmw solids)
5.6	5.6	5.6	grams per second per tower - model input against 24 hr, annual standards
389	388	388	Total PM increase (tons/year) for both towers

SCREENING ISC INPUTS
aj/Epsilon 12-16-2008

Unit	Fuel	DS on/off	Boiler Load	Exhaust Temperature,	Exhaust Velocity, feet/second	PM10&2.5, grams/second	PM10&2.5, lb/hr	PM10&2.5, lb/MMBtu	SO2, grams/second	SO2, lb/hr	SO2, lb/MMBtu	CO, grams/second	CO, lb/hr	CO, lb/MMBtu	NO2, grams/second	NO2, lb/hr	NO2, lb/MMBtu
CASE 1-4																	
3	Coal	On	Maximum	167	98.03	17.81	141.4	0.025				118.28	938.7	0.166	320.63	2544.8	0.450
3	Coal	On	Intermediate	162	60.67	11.02	87.5	0.025				73.20	581.0	0.166	198.45	1575.0	0.450
3	Coal	On	Minimum	160	34.14	6.30	50.0	0.025				41.83	332.0	0.166	113.40	900.0	0.450

CASE Y-1: SO2 scenario from 2006 NMCPA affected by Unit 3 DS/FF project																	
3	Coal	On	Maximum	167	98.03				175.28	1390	0.246						
3	Coal	On	Intermediate	162	60.67				108.48	860	0.246						
3	Coal	On	Minimum	160	34.14				61.99	492	0.246						

CASE Z-1: SO2 scenario from 2006 NMCPA affected by Unit 3 DS/FF project																	
3	Coal	On	Maximum	167	98.03				94.05	746	0.132						
3	Coal	On	Intermediate	162	60.67				58.21	462	0.132						
3	Coal	On	Minimum	160	34.14				33.26	264	0.132						

Unit	Fuel						PM-10, lb/hr	PM-10, lb/MMBtu		SO2, lb/hr	SO2, lb/MMBtu		CO, lb/hr	CO, lb/MMBtu		NO2, lb/hr	NO2, lb/MMBtu
EMISSION LIMITS FROM TITLE V, 2006 PLAN APPROVAL, 2008 MCPA																	
3	Coal							0.025			2.460			0.166			0.450

MMBtu/hr	Unit 3
Maximum Load	5,655
Intermediate Load	3,500
Minimum Load	2,000

BRAYTON POINT STATION

DOCUMENTATION THAT MODEL INPUTS CORRESPOND TO EXISTING & PROPOSED EMISSION LIMITS

Unit	Fuel	SDA on/off	Boiler Load	Temperature, Fahrenheit	Exhaust Velocity, feet/second	PM-10, grams/second	PM-10, lb/hr	PM-10, lb/MMBtu	PM-2.5, grams/second	PM-2.5, lb/hr	PM-2.5, lb/MMBtu	SO2, grams/second	SO2, lb/hr	SO2, lb/MMBtu	CO, grams/second	CO, lb/hr	CO, lb/MMBtu	NO2, grams/second	NO2, lb/hr	NO2, lb/MMBtu
CASE 1-4:																				
1	Coal	On	Maximum	185	99	22.68	180.0	0.080	22.68	180.0	0.080				23.53	186.8	0.083	107.73	855.0	0.380
2	Coal	On	Maximum	185	99	22.68	180.0	0.080	22.68	180.0	0.080				23.53	186.8	0.083	107.73	855.0	0.380
3	Coal	On	Maximum	167	98	17.81	141.4	0.025	17.81	141.4	0.025				118.28	938.7	0.166	320.63	2544.8	0.450
4	Oil	N/A	Maximum	380	111.6	18.14	144.0	0.030	18.14	144.0	0.030				47.17	374.4	0.078	163.29	1296.0	0.270
CASE 2: worst case impact per 2006 NMCPA for: 24-hr PM-10																				
1	Coal	On	Intermediat	150	50.4	14.19	112.5	0.080	14.19	112.5	0.080				14.72	116.8	0.083	67.41	534.6	0.380
2	Coal	On	Intermediat	150	50.4	14.19	112.5	0.080	14.19	112.5	0.080				14.72	116.8	0.083	67.41	534.6	0.380
3	Coal	On	Maximum	167	98	17.81	141.2	0.025	17.81	141.2	0.025				118.28	937.9	0.166	320.63	2542.5	0.450
4	Oil	N/A	Intermediat	350	54.6	9.22	73.1	0.030	9.22	73.1	0.030				23.97	190.1	0.078	82.97	657.9	0.270
CASE 3: worst case impact per 2006 NMCPA for: 8-hr CO, annual PM & NO2																				
1	Coal	On	Intermediat	150	50.4	14.19	112.5	0.080	14.19	112.5	0.080				14.72	116.8	0.083	67.41	534.6	0.380
2	Coal	On	Intermediat	150	50.4	14.19	112.5	0.080	14.19	112.5	0.080				14.72	116.8	0.083	67.41	534.6	0.380
3	Coal	On	Intermediat	162	60.7	11.02	87.4	0.025	11.02	87.4	0.025				73.20	580.5	0.166	198.45	1573.6	0.450
4	Oil	N/A	Intermediat	350	54.6	9.22	73.1	0.030	9.22	73.1	0.030				23.97	190.1	0.078	82.97	657.9	0.270
CASE 4: worst case impact per 2006 NMCPA for: 1-hr CO																				
1	Coal	On	Intermediat	150	50.4	14.19	112.5	0.080	14.19	112.5	0.080				14.72	116.8	0.083	67.41	534.6	0.380
2	Coal	On	Intermediat	150	50.4	14.19	112.5	0.080	14.19	112.5	0.080				14.72	116.8	0.083	67.41	534.6	0.380
3	Coal	On	Intermediat	162	60.7	11.02	87.4	0.025	11.02	87.4	0.025				73.20	580.5	0.166	198.45	1573.6	0.450
4	Oil	N/A	Maximum	380	111.6	18.14	143.9	0.030	18.14	143.9	0.030				47.17	374.1	0.078	163.29	1294.8	0.270
CASE Y-1: SO2 scenario from 2006 NMCPA affected by Unit 3 DS/FF project																				
1	Coal	Off	Maximum	265	91.8							698	5535	2.46						
2	Coal	Off	Maximum	265	91.8							698	5535	2.46						
3	Coal	On	Maximum	167	98							175.4	1392	0.246						
4	Oil	N/A	Maximum	380	111.6							734.7	5831	1.21						
												SO2 total lb/hr:	18292							
CASE Z-1: SO2 scenario from 2006 NMCPA affected by Unit 3 DS/FF project																				
1	Coal	Off	Maximum	265	91.8							373.62	2965.3	1.32						
2	Coal	Off	Maximum	265	91.8							373.62	2965.3	1.32						
3	Coal	On	Maximum	167	98							93.92	745.4	0.132						
4	Oil	N/A	Maximum	380	111.6							1463.58	11616	2.420						
												SO2 total lb/hr:	18292							

Unit	Fuel	PM-10, lb/hr	PM-10, lb/MMBtu	PM-2.5, lb/hr	PM-2.5, lb/MMBtu	SO2, lb/hr	SO2, lb/MMBtu	CO, lb/hr	CO, lb/MMBtu	NO2, lb/hr	NO2, lb/MMBtu
EMISSION LIMITS FROM TITLE V, 2006 PLAN APPROVAL, 2008 MCPA											
1	Coal		0.080		0.080		2.460		0.083		0.380
2	Coal		0.080		0.080		2.460		0.083		0.380
3	Coal		0.025		0.025		2.460		0.166		0.450
4	Oil		0.030		0.030		2.420		0.078		0.270

SO2 lb/hr limit with one or more SO2 controls operating: 18292

MMBtu/hr	Maximum Load	Intermediate Load	Minimum Load
Unit 1	2,250	1,408	854
Unit 2	2,250	1,408	854
Unit 3	5,655	3,500	2,000
Unit 4	4,800	2,439	435

Emission Calculations: CO

	Bituminous	Oil
EPA F-Factor, dscf/MMBtu	9,780	9190
CO ppmvd @ 3% O2	100.0	100.0
CO ppmvd @ 0% O2	117	117
CO ideal gas conversion, ppm to lb/scf	7.270E-08	7.270E-08
CO lb/MMBtu (HHV)	0.0830	0.0780
CO ppmvd @ 3% O2	200.0	
CO ppmvd @ 0% O2	234	
CO ideal gas conversion, ppm to lb/scf	7.270E-08	
CO lb/MMBtu (HHV)	0.1660	

Dominion Energy Brayton Point LLC
Control Cost Analysis: Wet Electrostatic Precipitator

System operation		8760	hours/year
		1,755,650	ACFM airflow
		1,660,000	SCFM airflow
Direct Costs			
Purchased Equipment Cost	$30		per SCFM capital cost, per EPA 452/F-03-030*
	1.24		cost index factor**
	$37.20		per SCFM capital cost, 2008 dollars
		$61,752,000	equipment capital cost
Instrumentation	0.1	$6,175,200	OAQPS Section 6 Table 3.16
Sales Taxes	0.03	$1,852,560	OAQPS Section 6 Table 3.16
Freight	0.05	$3,087,600	OAQPS Section 6 Table 3.16
Total Purchased Equipment Cost, PEC		**$72,867,360**	
Direct Installation Costs			
Foundations and supports	0.04	$2,914,694	OAQPS Section 6 Table 3.16
Handling and erection	0.5	$36,433,680	OAQPS Section 6 Table 3.16
Electrical	0.08	$5,829,389	OAQPS Section 6 Table 3.16
Piping	0.01	$728,674	OAQPS Section 6 Table 3.16
Insulation for ductwork	0.02	$1,457,347	OAQPS Section 6 Table 3.16
Painting	0.02	$1,457,347	OAQPS Section 6 Table 3.16
Total Direct Installation cost		**$48,821,131**	
Site preparation		$0	assume no incremental cost from proposed case
Buildings		$0	assume no incremental cost from proposed case
Total Direct Cost, DC		**$121,688,491**	
Indirect Costs - Installation			
Engineering	0.2	$14,573,472	OAQPS Section 6 Table 3.16
Construction and field expenses	0.2	$14,573,472	OAQPS Section 6 Table 3.16
Contractor fees	0.1	$7,286,736	OAQPS Section 6 Table 3.16
Start-up	0.01	$728,674	OAQPS Section 6 Table 3.16
Performance test	0.01	$728,674	OAQPS Section 6 Table 3.16
Model Study	0.02	$1,457,347	OAQPS Section 6 Table 3.16
Contingencies	0.03	$2,186,021	OAQPS Section 6 Table 3.16
Total Indirect Cost, IC		**$41,534,395**	
Total Capital Investment (TCI) = DC + IC		**$163,222,886**	

* Air Pollution Control Fact Sheet for Wet ESP - Plate Type, mid-range capital cost in 2002 dollars, at http://epa.gov/ttn/catc/products.html#cccinfo
** Engineering News Record Construction Cost Index, 2002 to 2008

Annual Costs			
Operating labor requirement	0.5		hours/shift per OAQPS Section 6 Chapter 3.4.1.1
hourly cost	$37		facility estimate
Operating labor cost		$20,258	
Supervisory labor cost		$3,039	15% of operating labor per OAQPS Section 6 Chapter 3.4.1.1
maintenance labor requirement	15		hr/week per OAQPS Section 6 Chapter 3.4.1.3
	44		weeks/year per OAQPS Section 6 Chapter 3.4.1.3
hourly cost	$37		facility estimate
Maintenance labor cost		$24,420	labor cost
maintenance material cost	1%	$617,520	of purchase cost
Electricity			
Wet ESP Power	40		W/kACFM, per OAQPS Section 6 Chapter 3.4.1.4
	70.2		kW
Fan Pressure Drop	0.38		inches WC pressure drop, per OAQPS Section 6 Table 3-11
Fan & Pump power	120.8		0.000181*ACFM*pressure drop, per OAQPS Section 6 Table 3-21
Electric power cost	0.05		$/kWhr, facility estimate
Electricity cost		$83,649	
water requirement	5		gal/min/kACFM per OAQPS Section 6 Chapter 3.4.1.6
	8778.25		gal/min
water unit cost	$0.5		per 1000 gallons
water cost		$2,306,924	
wastewater treatment cost		$0	assume usable elsewhere on site
solid waste disposal cost		$0	assume material can be addressed with current onsite material handling systems
total Direct Annual costs		**$3,055,809**	
Indirect annual costs			
overhead		$397,319	60% of op. labor, maint. labor, & maint. materials
administration		$3,264,458	2% of total capital investment
property tax		$1,632,229	1% of total capital investment
insurance		$1,632,229	1% of total capital investment
capital recovery	0.09439	$15,406,608	capital recovery factor based on 20-year life and 7% interest rate
total Indirect Annual Costs		**$22,332,842**	
total annualized cost		$25,388,651	
total controlled		372	tons/year
cost effectiveness $/ton		**$68,249**	

BRAYTON POINT PAST ACTUAL/FUTURE ACTAL CALCULATIONS
aj/Epsilon 1-5-09

This calculation follows techniques used in prior Mass DEP plan approvals for Brayton Point Station
Please see separate calculations for EPA PSD Netting Analysis

ACTUAL EMISSION CHANGE ESTIMATE (DS, SDA, FF, PAC, SCR & ARP)

		Past Actual Baseline[1]				Future Actual Estimate			Net Change	
		2006	**2007**	**Unit 3**		**lb/MMBtu**	**Unit 3**			
Fuel	MMBtu/yr	33,617,168	40,643,761	37,130,465	a		37,130,465	i		
Fuel	% of max.[2]	68%	82%	75%	b		75%	b		
NO_x	Tons/yr	2619.9	1965	2,292	c	0.07	1,300	j	**-993**	
CO	Tons/yr	950.6	1585.9	1,268	c		1,268	i	**0**	
VOC	Tons/yr	45.5	55.3	50.4	c		50.9	k	**0.5**	3
SO_2	Tons/yr	12873	15942.7	14,408	c	0.11	2,042	l	**-12366**	
H_2SO_4	Tons/yr	70.60	85.35	78	d	0.0029	54.6	m	**-23.4**	
PM	Tons/yr	121.3	147.4	134	e	0.012	222.8	n	**88**	4
PM10	Tons/yr	121.3	147.4	134	c	0.012	222.8	n	**88**	4
PM2.5	Tons/yr	121.3	147.4	134	e	0.012	222.8	n	**88**	4
Pb	Tons/yr	0.01	0.01	0.01	f		0.01	i	**0**	
Hg[5]	Tons/yr	0.034	0.041	0.038	g	0.00000029	0.005	o	**-0.032**	
NH_3	Tons/yr	0.55	0.77	0.66	c		0.66	i	**0.0**	
Opacity[6]	%	0-5	0-5	0-5	h		0-5	i	**0**	

Note:
1 - Average for years 2006 and 2007
2 - Equivalent heat input capacity factor.
3 - Increase due to VOC from FGD make-up water
4 - Increase based on dry scrubber reaction products, controlled via fabric filter. Estimates are filterable-only, consistent with prior filings.
5 - Future Actual Estimates of Hg are based on 310 CMR 7.29 rate of 0.0025 lb/GW-hr effective 2012
6 - Exclusive of uncombined water

<u>Calculation methods</u>

a	Clean Air Market Data (CAMD) data for January 1, 2006 through December 31, 2007
b	MMBtu/yr divided by (5655 MMBtu/hr * 8760 hr/yr)=49,537,800 MMBtu/yr
c	annual source registrations
d	2002 informational SO3 stack testing; assumes all SO3 emitted as H2SO4
e	assume equal to PM10
f	EPA AP-42 Table 1.1-16. Assumes 1 ppm lead concentration, 0.096 ash fraction consistent with prior filings
g	2001 stack testing
h	operational experience & consistency with prior filings
i	consistent with prior filings, no change in future operating rate expected resulting from this project
j	Design target SCR-controlled NO_x emission rate of 0.07 lb/mmBtu
k	increase of one half-ton per year VOC from organic material in make-up water, consistent with prior filings
l	Design target DS-controlled SO_2 emission rate of 0.11 lb/mmBtu
m	Expected 30% reduction of SO3 in dry scrubber, consistent with prior filings
n	Design target for filterable particulate emissions (PM/PM10/PM2.5)
o	Mercury emissions will meet the standards set forth in 310 CMR 7.29(5)(a)(3)

Brayton Point Unit 3 Dry Scrubber and Fabric Filter Project
Potential to Emit Analysis

	Baseline Potential Emissions			Future Potential Emissions					
	Emission Rate lb/MMBtu	Heat Input(1) MMBtu/yr	Emissions Tons/yr	Emission Rate lb/MMBtu	Heat Input(1) MMBtu/yr	Emissions Tons/yr	Net Emission Increase / Decrease Tons/yr	MassDEP 7.02 Significant Emission Increase Tons/yr	Significant Emission Increase Yes / No
NOx(2)	0.45	49,537,800	11,146	0.45	49,537,800	11,146	0	1	No
SO_2(2)	2.42	49,537,800	59,941	2.42	49,537,800	59,941	0	1	No
CO(2)	0.166	49,537,800	4,112	0.166	49,537,800	4,112	0	1	No
Filterable PM, PM10 & PM2.5 (2)(3)(4)	0.08	49,537,800	1,982	0.010	49,537,800	248	-1,734	1	No
Total PM, PM10 & PM2.5(3)(5)(6)	0.20	49,537,800	4,985	0.025	49,537,800	619	-4,366	1	No
VOC(7)	0.00235	49,537,800	58	0.00237	49,537,800	59	0.5	1	No
Lead(8)	4.30E-07	49,537,800	0.01	4.30E-07	49,537,800	0.01	0.00	1	No
Flourides(9)	6.00E-03	49,537,800	149	6.00E-03	49,537,800	149	0	1	No
H_2SO_4(10)(11)	0.099	49,537,800	2,444	0.099	49,537,800	2,444	0	1	No
Mercury(12)	2.03E-06	49,537,800	0.0503	2.03E-06	49,537,800	0.0503	0.0000	1	No
Ammonia(13)	1.00E-03	49,537,800	25	0.001	49,537,800	25	0	1	No
Opacity(14)	n/a	n/a	20%	n/a	n/a	10%	-10%	n/a	No

1 - All Potential Heat Input based upon 5,655 MMBtu/hr and 8,760 hours of operation

2 - Baseline NOx, SO2, CO and Filterable PM emission limits obtained from facility's Title V Operating Permit.

3 - The Facility does not have permit limits for Filterable PM10 & PM2.5 and Total PM, PM10 & PM2.5.It is conservatively estimated that all PM10 & PM2.5 emissions are equal to PM emissions

4 - Future Filterable PM, PM10 & PM2.5 potential emissions based upon 0.010 lb/MMBtu emission rate based upon BACT analysis

5 - Total PM, PM10 & PM2.5 includes filterable and condensable PM (CPM) emissions. CPM calculated from EPA AP-42, Table 1.1-5, where CPM=0.1*%S - 0.03, assuming 12,500 Btu/lb coal.

6 - Future Total PM, PM10 & PM2.5 potential emissions based upon 0.025 lb/MMBtu emission rate based upon BACT analysis

7 - VOC emission factor is EPA AP-42 based and serves as the basis for calculating VOC emissions for the facilitys annual Source Registration

8 - Lead emission factor from EPA AP-42 Table 1.1-16; assumes 1 ppm lead concentration, 0.096 ash fraction consistent with prior filings

9 - Flouride emission factor from EPA AP-42 Table 1.1-15 (hydrogen fluoride)

10 - Due to determining sulfuric acid (H_2SO_4) emission compliance with EPA Method 8, it is assumed all potential SO_3 formation converts to sulfuric acid. Existing flue gas conditioning systems have the following potential emission rates:

Unit 3:	25	ppmvd @ 3% O_2
	0.059	equivalent lb/mmBtu

11 - The following SO_2 to SO_3 conversion rate ranges were used to calculate the minimum SO_2 reduction and maximum SO_3/H_2SO_4 emissions:

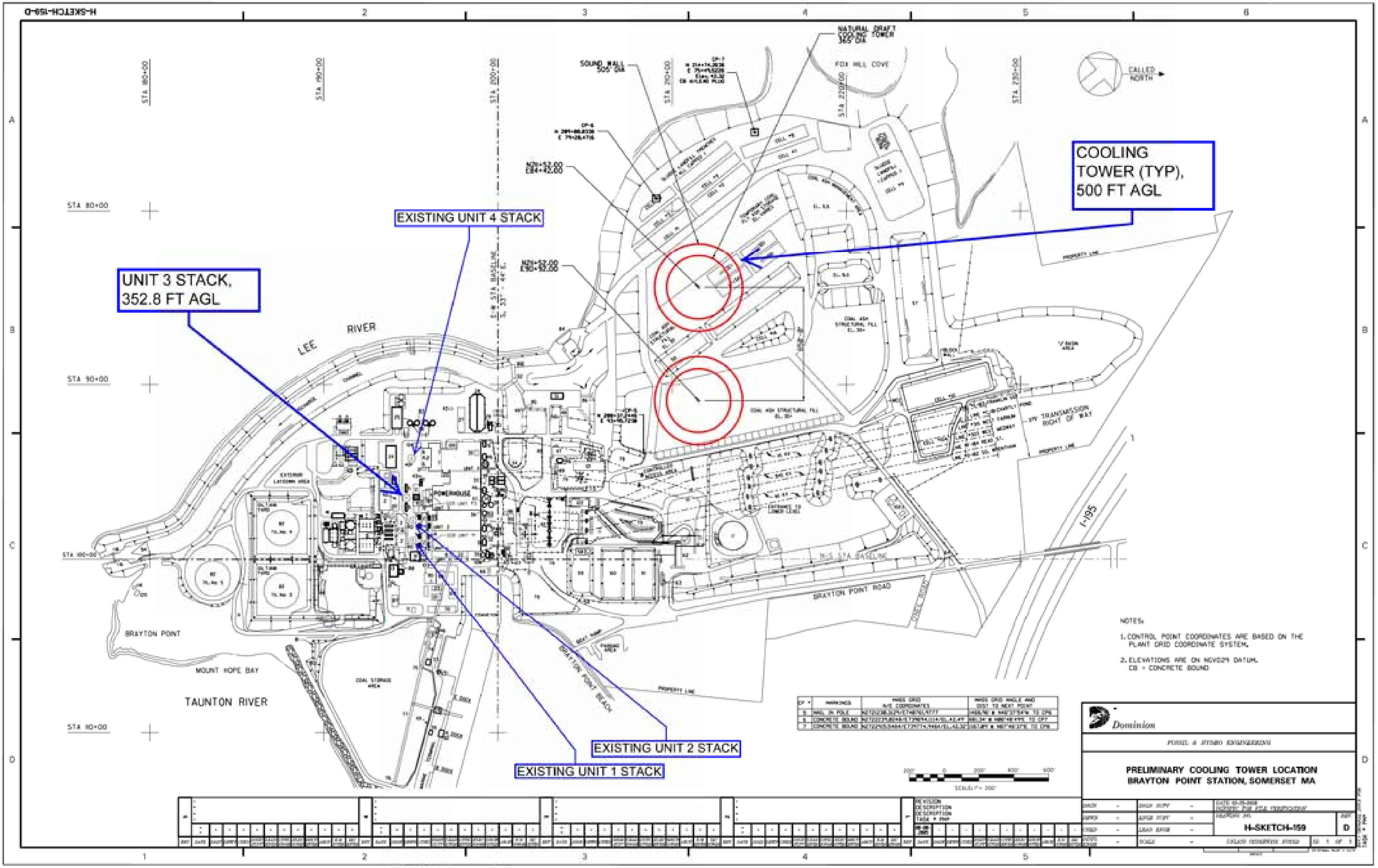
Minimum SO_2 --> SO_3 in boiler furnace =	0.5%
Maximum SO_2 --> SO_3 in boiler furnace =	1.0%
Minimum SO_2 --> SO_3 at SCR =	1.0%
Maximum SO_2 --> SO_3 at SCR =	1.4%

12 - Mercury emission factors were obtained from 2001 stack testing:

Units	Fuel	EF	Units	Reference
3	Coal	2.03E-06	lb/mmBtu	2001 emissions testing

13 - The ammonia slip of 2 ppmvd @ 3% O_2 is equivalent to an emission rate of 0.001 lb/mmBtu for Units 3.

14 - Baseline Opacity limit obtained from facility's Title V Operating Permit.



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PLOT PLAN

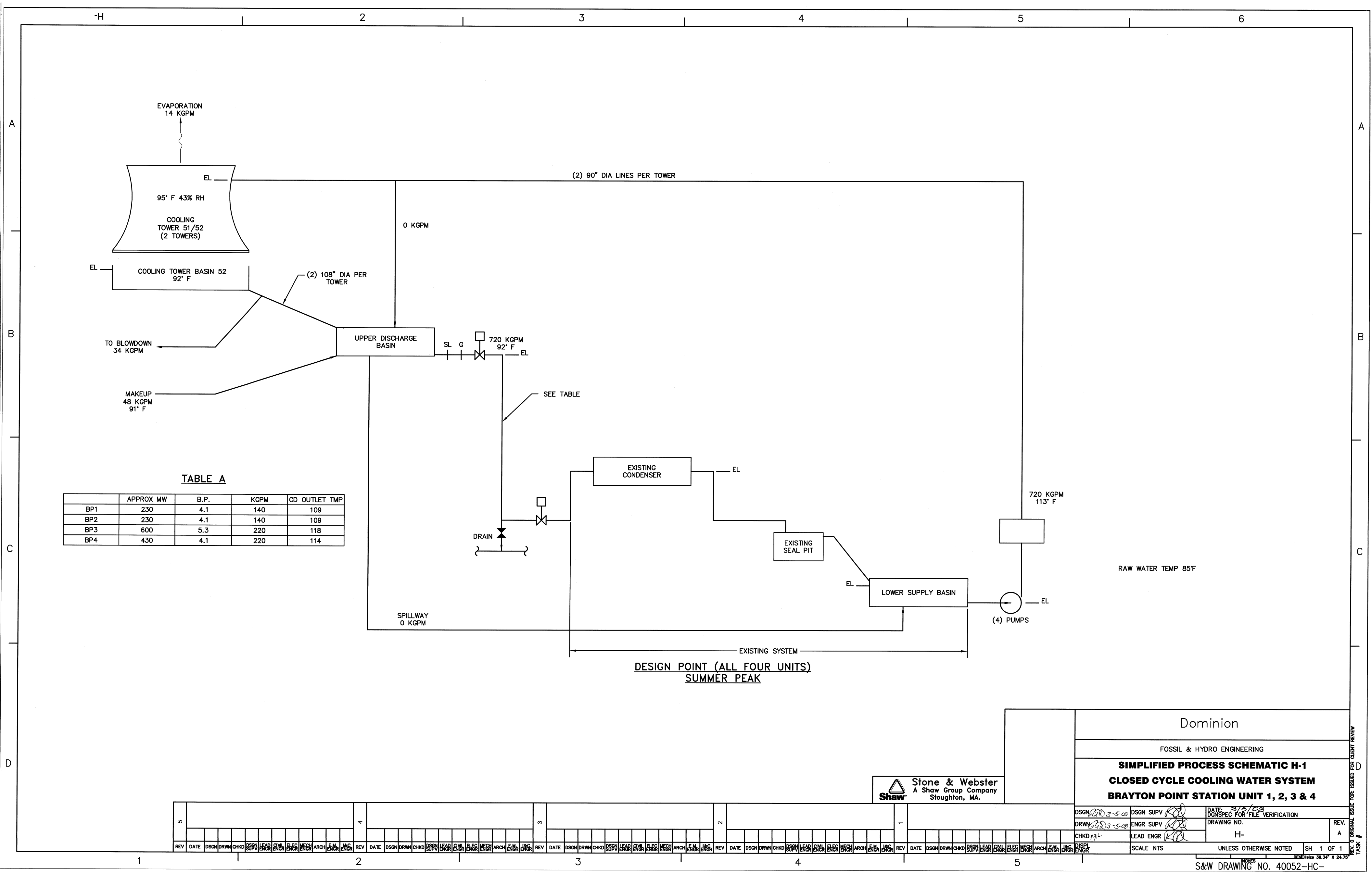

TABLE A

	APPROX MW	B.P.	KGPM	CD OUTLET TMP
BP1	230	4.1	140	109
BP2	230	4.1	140	109
BP3	600	5.3	220	118
BP4	430	4.1	220	114

SCHEMATIC PROCESS DIAGRAM

APPENDIX C

EPA and Mass DEP Orders

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
REGION I - NEW ENGLAND

IN THE MATTER OF Dominion Energy Brayton Point, LLC, Brayton Point Power Station Somerset, Massachusetts NPDES Permit No. MA0003654 Proceedings under Section 309(a)(3) of the Clean Water Act, as amended, 33 U.S.C. § 1319(a)(3)	DOCKET NO. 08-007 FINDINGS AND ORDER FOR COMPLIANCE

I. STATUTORY AUTHORITY

The following Findings are made and ORDER issued pursuant to Section 309(a)(3) of the Clean Water Act, as amended (the "Act"), 33 U.S.C. § 1319(a)(3), which grants to the Administrator of the U.S. Environmental Protection Agency ("EPA") the authority to issue orders requiring persons to comply with Sections 301, 302, 306, 307, 308, 318 and 405 of the Act and any permit condition or limitation implementing any of such sections in a National Pollutant Discharge Elimination System ("NPDES") permit issued under Section 402 of the Act, 33 U.S.C. § 1342. This authority has been delegated to EPA Region I's Regional Administrator, and in turn to the Director of the Office of Environmental Stewardship.

The Order herein is based on a finding that the Company will be in violation of Section 301 of the Act, 33 U.S.C. § 1311, and the conditions of NPDES Permit No. MA0003654 upon the effective date of the previously stayed permit conditions ("Effective Date"). Pursuant to Section 309(a)(5)(A) of the Act, 33 U.S.C. § 1319(a)(5)(A), the Order provides a schedule for compliance which the Director of the Office of Environmental Stewardship has determined to be reasonable.

II. DEFINITIONS

Unless otherwise defined herein, terms used in this Order shall have the meaning given to those terms in the Clean Water Act, 33 U.S.C. § 1251 et. seq., the regulations promulgated thereunder, and any applicable NPDES permit. For the purposes of this Order, "NPDES Permit" means the Dominion Energy Brayton Point, LLC, (the "Company" or the "Permittee" or "Dominion") Brayton Point Power Station NPDES Permit No. MA0003654, and all amendments or modifications thereto and renewals thereof as are applicable, and in effect at the time.

III. FINDINGS

The Director of the Office of Environmental Stewardship makes the following findings of fact:

1. Dominion Energy Brayton Point, LLC, Brayton Point Power Station has a place of business in Somerset, Massachusetts from which it discharges condenser cooling water, process wastewater and storm water.

2. The Company is a person under Section 502(5) of the Act, 33 U.S.C § 1362(5). The Company is the owner of an electrical power generating station (the "Facility") from which it discharges pollutants, as defined in Section 502(6) and (12) of the Act, 33 U.S.C. § 1362(6) and (12), from a point source, as defined in Section 502(14) of the Act, 33 U.S.C. § 1362(14), to Mount Hope Bay. Mount Hope Bay flows into Narragansett Bay which, in turn, empties into the Atlantic Ocean. All are waters of the United States as defined in 40 C.F.R. § 122.2 and, therefore, navigable waters under Section 502(7) of the Act, 33 U.S.C. § 1362(7).

3. On October 6, 2003, the Director of the Office of Ecosystem Protection of EPA, Region I,

issued the Permit under the authority given to the Administrator of EPA by Section 402 of the Clean Water Act, 33 U.S.C. § 1342. On November 5, 2003, the company filed a petition for review of the Permit with EPA's Environmental Appeals Board ("EAB"). The contested provisions of the Permit were stayed and all other provisions of the Permit became effective on May 26, 2004. Following resolution of the appeal before the EAB, EPA notified the Company by letter dated October 1, 2007 that the conditions of the Permit that had been stayed pending appeal would take effect on November 1, 2007. Those terms of the Permit were again stayed until December 17, 2007 and will take effect on December 18, 2007.

4. The Permit authorizes the Permittee to discharge pollutants from the Facility to Mount Hope Bay, subject to the effluent limitations, monitoring requirements and other conditions specified in the Permit.

5. Part I.A.4.a. of the Permit establishes a flow limit for outfall serial number 001, Discharge Canal, of 40 million gallons per day (average monthly) and 42 million gallons per day (maximum daily).[1]

6. Part I.A.4. b. of the Permit for outfall serial number 001, Discharge Canal, establishes an annual heat load limit to Mount Hope Bay of 1.7 Trillion BTUs.

7. Part I.A.4. c. of the Permit establishes a limit for the combined withdrawal of intake water of 56.2 million gallons per day ("MGD").

8. The Permittee discharges process water from outfall serial number 001, Discharge Canal,

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[1] This flow rate is the total blowdown from any cooling tower(s) used at the facility plus flow from the wastewater treatment facility. During periods of once-through cooling, the permittee may increase the flow rate to a flow rate of 56 million gallons per hour. The permittee may not increase to this flow rate for more than 122 hours per year.

at a flow rate that will exceed the Permit's effluent limitation for flow upon the Effective Date.

9. The Permittee discharges a heat load from outfall serial number 001, Discharge Canal, to Mount Hope Bay that will exceed the Permit's annual heat load limitation upon the Effective Date.

10. The Permittee's total water intake will exceed the Permit's limit for water intake of 56.2 MGD upon the Effective Date.

11. Section 301(a) of the Act, 33 U.S.C. § 1311(a), makes unlawful the discharge of pollutants to waters of the United States except in compliance with, among other things, the terms and conditions of a NPDES permit issued pursuant to Section 402 of the Act, 33 U.S.C. § 1342.

12. The Permittee's discharge of pollutants to Mount Hope Bay in excess of the limits contained in its NPDES Permit, will violate Section 301(a) of the Act, 33 U.S.C. § 1311(a) upon the Effective Date.

13. The Company will need to install closed-cycle cooling in order to comply with the previously stayed Permit limits. EPA issues this Order to provide a schedule for the Company to come into compliance with the Permit.

14. The Company has worked cooperatively with EPA in the development of this Order.

IV. ORDER

Accordingly, pursuant to Section 309(a)(3) of the Clean Water Act, it is hereby ordered that the Permittee shall:

1. Comply with the following schedule for construction and implementation of closed cycle

cooling at Brayton Point Power Station and for meeting the limits contained in the Permittee's NPDES Permit:

a. By January 2, 2008, commence the process to obtain all permits and approvals necessary to convert Brayton Point Station to closed cycle cooling in order to meet NPDES permit limits. This shall include the engineering to support the permitting, the permit applications, and all necessary supplementary data.

b. From January 2, 2008 until all permits and approvals are issued, provide timely and complete responses to all requests from each permitting and approval authority.

c. By January 10, 2008, initiate requests for pre-application meetings with permitting authorities.

d. By January 15, 2008, request approval from the United States Coast Guard for placement of monitoring equipment necessary to comply with Part I.26.a.1.iii of the Permit

e. By February 28, 2008, submit air modeling protocol to agencies for review.

f. By July 1, 2008, submit applications for all local permits.

g. By September 1, 2008, submit application(s) for air permit(s).

h. By October 1, 2008, complete submission of all other necessary permit applications and notices necessary to convert Brayton Point Station to closed cycle cooling.

i. Within five days of obtaining all permits and approvals or April 6, 2009, whichever is later, issue the Notice to Proceed with Engineering and Procurement for cooling tower construction to Dominion's contractor.

j. Within five days of obtaining all permits and approvals or April 6, 2009, whichever is later, issue the Notice to Proceed with Engineering and Procurement for the Pump Structure and Piping System.

k. Within nine months of obtaining all permits and approvals, commence construction of foundations for cooling towers.

l. No later than May 15th of the calendar year prior to the anticipated tie-in date for each unit, Dominion shall request a planned outage for that unit from ISO New England in accordance with, and pursuant to, ISO New England Operating Procedure No. 5, Revision No. 8, effective October 13, 2006 or as amended.

m. Within 29 months of obtaining all permits and approvals, complete tower construction.

n. Within 29 months of obtaining all permits and approvals, complete all piping installation for tie-in of condenser units to cooling towers.

o. Within 29 months of obtaining all permits and approvals, commence tie-in of condenser units to cooling towers.

p. Within 31 months of obtaining all permits and approvals, complete tie-in of condenser units 4 and 3.

q. Within 33 months of obtaining all permits and approvals, complete tie-in of condenser unit 2.

r. Within 36 months of obtaining all permits and approvals, complete tie-in of all condensor units such that all permit limits are met.

2. Where any compliance obligation requires Dominion to obtain a federal, state, or local permit or approval, Dominion shall submit timely and complete applications and responses to requests for information and take all other actions necessary to obtain all such permits or approvals. Dominion may seek relief under the Force Majeure provisions below for any delay in the performance of any such obligation resulting from a failure to obtain, or a delay in obtaining, any permit or approval required to fulfill such obligation, if Dominion has submitted timely and complete applications and has taken all other actions necessary to obtain all such permits or approvals.

Interim Effluent Limits

3. In the interim period from the effective date of this Order and during the Permittee's compliance with paragraphs 1 and 2 of this Section IV, the Permittee shall comply with the following effluent standards and limits:

a. for thermal discharges, intake cooling water withdrawals, and effluent flow, comply with all the requirements and conditions of the Memorandum of Agreement II ("MOA II") (Attachment 1) except that:

(1) During the period from the beginning of tie-in of condensor unit 4 and continuing until tie-in of condensor unit 3, the flow limitations of part 8.b. of MOA II will not be required to be met through "piggyback operation." Instead, the flow limitations will be met by blocking the existing unit 4 discharge at the tri-bridge and directing warm water from the tied-in unit to the cooling tower(s).

(2) During the period from the beginning of tie-in of condensor unit 4 and continuing until complete tie-in of all condensor units, the "delta T" limitation of part 8.c. of MOA II will apply when unit 4 is not in "piggyback operation" as long as the tie-in occurs between October 1 and May 31.

b. operate the intake screen wash for condenser units 1, 2, and 3 whenever the intake is in use.

c. during "targeted" chlorination, as discussed in Attachment 2, the total residual oxidant concentration shall not, at any time, exceed 0.2 milligrams/liter at the discharge from the unit being chlorinated during any one chlorination cycle as measured at the seal pit. The sampling type and frequency will be a daily grab sample for each generating unit.

d. comply with all other effluent limitations, monitoring requirements and other conditions specified in its NPDES Permit.

4. Within three (3) weeks of Coast Guard approval for the placement of monitoring

equipment necessary to comply with Part I.26.a.1.iii of the Permit, Dominion shall install monitoring equipment at the locations identified in Figure 6 of the Permit and commence monitoring in accordance with the Permit requirements.

5. As the following power generating units are tied into the cooling towers, the discharge from Brayton Point Station must comply with the following interim effluent limitations:

Unit 3	flow = 518 million gallons per day heat = MOA II limit
Unit 2	flow = 259 MGD heat = 2.01 trillion BTUs total per month

V. REPORTS ON COMPLIANCE

6. Beginning on the fifteenth day of April, 2008 and continuing until completion of construction, tie-in, and compliance with all of the NPDES limitations, Dominion shall report to EPA on its compliance with its obligations pursuant to paragraphs 1 through 5 every three months. Each progress report submitted under this Paragraph shall:

   a. Describe activities undertaken during the reporting period directed at achieving compliance with this Administrative Order;

   b. Describe the expected activities to be taken during the next reporting period in order to achieve compliance with this Administrative Order; and

   c. Report on compliance with the provisions outlined in paragraphs 3, 4 and 5 above.

7. Where this Order requires a specific action to be performed within a certain time frame, Dominion shall submit a written notice of compliance or noncompliance with each deadline. Notification must be mailed within fourteen (14) calendar days after each required deadline. The timely submission of a required report shall satisfy the

requirement that a notice of compliance be submitted.

8. If noncompliance is reported, notification should include the following information:

   a. A description of the noncompliance;

   b. A description of any actions taken or proposed by the Permittee to comply with the lapsed schedule requirements;

   c. A description of any factors that explain or mitigate the noncompliance; and

   d. An approximate date by which the Permittee will perform the required action.

9. After a notification of noncompliance has been filed, compliance with the past-due requirement shall be reported by submitting any required documents or providing EPA with a written report indicating that the required action has been achieved.

10. The reporting requirements set forth in this Section do not relieve Dominion of its obligation to submit any other reports or information as required by State, Federal or local law.

11. Within fourteen days of learning that it will fail, or has failed, to comply with a requirement of this Order, the Dominion shall provide written notice of such failure to EPA.

12. Submissions required by this Order shall be in writing and shall be mailed to the following address:

USEPA - New England
Office of Environmental Stewardship
1 Congress Street
Suite 1100 (SEW)
Boston, MA 02114-2023
Attn: Steven Couto

VI. FORCE MAJEURE

13. "Force majeure," for purposes of this Administrative Order, is defined as any event arising from causes beyond the control of Dominion, of any entity controlled by Dominion, or of Dominion's contractors, that delays or prevents the performance of any obligation under this Administrative Order despite all practicable efforts by Dominion to fulfill the obligation. The requirement that Dominion exercise "all practicable efforts to fulfill the obligation" includes using all practicable efforts to anticipate any potential force majeure event and all practicable efforts to address the effects of any such event (a) as it is occurring and (b) after it has occurred to prevent or minimize any resulting delay to the greatest extent possible. "Force Majeure" does not include normal inclement weather, unanticipated or increased costs or expenses of work, the financial difficulty of performing such work, or the failure of Dominion to make complete and timely application of any required approval or permit unless caused by a separate force majeure event. "Force Majeure" may include, but is not limited to, acts of God including floods, blizzards, hurricanes, and other extreme weather, labor strikes, fires, judicial orders, orders by governmental officials or ISO New England that direct Dominion to operate Brayton Point to supply electricity, ISO New England's failure to grant Dominion's request for an outage to permit unit tie-ins when that request was timely as specified in paragraph 1, and an inability to tie-in a unit due to the restrictions in paragraph 3 of this Order, including the Delta T, that are not waived by EPA. Under the definition of "Force Majeure" as set forth above in this paragraph, "Force Majeure" may or may not include construction, labor, and equipment delays.

14. If any event occurs or has occurred that may delay the performance of any obligation under this Administrative Order or causes Dominion to be in potential violation of any provision of this Order, whether or not caused by a force majeure event, Dominion shall provide notice orally or by electronic or facsimile transmission to:

Steven Couto, SEW
Water Technical Unit
Office of Enforcement
One Congress Street
Boston, Massachusetts 02114
617-918-1765
fax: 617-918-0765
couto.steven@epa.gov

within five (5) business days of when Dominion first knew that the event might cause a delay. In addition, Dominion shall notify the EPA in writing as soon as practicable but in no event later than ten (10) days following the date Dominion first knew that the event caused or may cause such delay or potential violation. In this written notice, Dominion shall provide an explanation and description of the reasons for the delay; the anticipated duration of the delay; all actions taken or to be taken to prevent or minimize the delay; a schedule for implementation of any measures to be taken to prevent or mitigate the delay or the effect of the delay; Dominion's rationale for attributing such delay to a force majeure event if it intends to assert such a claim; and a statement as to whether, in the opinion of Dominion, such event may cause or contribute to an endangerment to public health, welfare or the environment. Dominion shall include with any written notice all reasonably obtainable documentation supporting the claim that the delay was attributable to a force majeure. Failure to comply with the above requirements shall preclude Dominion from asserting any claim of force majeure for that event for the period of time of such failure to comply, and for any additional delay caused by such failure. Dominion shall be deemed to know of any circumstance of which Dominion, any entity controlled by Dominion, or Dominion's contractors knew or should have known by the exercise of due diligence.

15. If EPA agrees that the delay or anticipated delay is attributable to a force majeure event, the time for performance of the obligations under this Administrative Order that are affected by the force majeure event will be extended by EPA for such time as is necessary to complete those obligations. Any subsequent schedule deadlines that EPA agrees are affected by the force majeure event will also be extended. An extension of the time for performance of the obligations affected by the force majeure event shall not, of itself, extend the time for performance of any other obligation. EPA will notify Dominion in writing of the length of the extension, if any, for performance of the obligations affected by the force majeure event.

16. If EPA does not agree that the delay or anticipated delay has been or will be caused by a force majeure event, EPA will notify Dominion in writing of its decision.

VII. DISPUTE RESOLUTION

17. If Dominion objects to any EPA determination made pursuant to this Order regarding the adequacy of the work performed hereunder or whether a force majeure has occurred, it shall notify EPA in writing of its objection(s) within 15 days of such action, unless the objection(s) has been resolved informally. EPA and Dominion shall engage in a period of formal negotiations for 30 days from EPA's receipt of Dominion's written objection(s).

18. Any agreement reached by the parties pursuant to this Section shall be in writing and shall, upon signature of both parties, be incorporated into and become an enforceable part of this Order.

VIII. GENERAL PROVISIONS

19. This Order does not constitute a waiver or a modification of the terms and conditions of the NPDES Permit. The NPDES Permit remains in full force and effect. EPA reserves the right to seek any and all remedies available under Section 309 of the Act, 33 U.S.C. § 1319, as amended, for any violation cited in this Order.

20. This Order shall become effective upon receipt by Dominion.

12/17/07
Date

Susan Studlien
Susan Studlien, Director
Office of Environmental Stewardship
Environmental Protection Agency, Region 1

COMMONWEALTH OF MASSACHUSETTS
EXECUTIVE OFFICE OF ENERGY & ENVIRONMENTAL AFFAIRS
DEPARTMENT OF ENVIRONMENTAL PROTECTION

In the Matter of Dominion Energy Brayton Point, LLC (Successor-in-interest to USGen New England, Inc.)	ADMINISTRATIVE ORDER File No. UAO-BO-08-1N001 Somerset, MA

I. THE PARTIES

1. The Department of Environmental Protection ("MassDEP") is a duly constituted agency of the Commonwealth of Massachusetts established pursuant to M.G.L. c. 21A, §7. Its principal office is located at One Winter Street in Boston, Massachusetts 02108.

2. Dominion Energy Brayton Point, LLC (hereinafter "Dominion," "the Company," or the "Permittee"), is a Virginia corporation with a place of business in Somerset, Massachusetts.

3. MassDEP and the Company will hereinafter be referred to herein as "the Parties."

II. STATUTORY AUTHORITY

4. This ORDER is issued pursuant to M.G.L. c. 21, § 44(1) which authorizes MassDEP to order a discharger to apply forthwith for a permit, or for a new permit, or to take other appropriate action under rules and regulations adopted by it, subject to the provisions of M.G.L. c. 30A, and to cease and desist from making or allowing further discharges beyond a specified date until compliance with the order is fully achieved, whenever it appears that there are discharges of pollutants without a required permit, or that such discharges are in violation of a permit issued under this chapter, or in contravention of any regulation, standard or plan adopted by MassDEP.

III. DEFINITIONS

5. Unless otherwise defined herein, terms used in this Order shall have the meaning given to those terms in the Clean Water Act (the "Federal CWA"), 33 U.S.C. § 1251 et. seq., the regulations promulgated thereunder, and any applicable NPDES permit. For the purposes of this Order, "NPDES Permit" means the Company's Brayton Point Power Station NPDES Permit No. MA0003654, and all amendments or modifications thereto and renewals thereof as are applicable, and in effect at the time.

IV. FINDINGS OF FACT

6. Dominion Energy Brayton Point, LLC, Brayton Point Power Station has a place of business in Somerset, Massachusetts, from which it discharges condenser cooling water, process wastewater and storm water.

7. The Company is a person under Section 26A of the Massachusetts Clean Waters Act (the "Massachusetts CWA"), M.G.L. c. 21, §§ 26-53A, and 314 C.M.R. 3.00. The Company is the owner of an electrical power generating station (the "Facility") from which it discharges pollutants, as defined in M.G.L. c. 21, § 26A, from a point source, as defined in 314 C.M.R. 3.02, to Mount Hope Bay. Mount Hope Bay flows into Narragansett Bay which, in turn, empties into the Atlantic Ocean. All are waters of the Commonwealth as defined in M.G.L. c. 21, § 26A.

8. On October 6, 2003, the Director of the Office of Ecosystem Protection of the Environmental Protection Agency ("EPA"), Region I, and Glenn Haas, Director of Watershed Management for MassDEP, jointly issued the Permit under the authority given to the Administrator of EPA by Section 402 of the Federal CWA, 33 U.S.C. § 1342, and to the Director by the Massachusetts CWA .[1] On November 5, 2003, the Company filed a petition for review of the Permit under the Federal CWA with EPA's Environmental Appeals Board ("EAB"). The Company also filed parallel appeals of the Permit and associated State Water Quality Certification under the Massachusetts CWA with MassDEP. The contested provisions of the Permit were stayed and all other provisions of the Permit became effective on May 26, 2004. Following resolution of the appeal before the EAB, EPA notified the Company by letter dated October 1, 2007 that the conditions of the Permit that had been stayed pending the appeal under the Federal CWA would take effect on November 1, 2007. Those conditions of the Permit were again stayed until December 17, 2007 and took effect on December 18, 2007. The conditions of the Permit that had been stayed pending the appeal under the Massachusetts CWA will take effect on the date a Final Decision providing for the dismissal of the appeals of the Permit and associated State Water Quality Certification under the Massachusetts CWA is issued by the Commissioner or her designee (the "Effective Date").

9. The Permit authorizes the Permittee to discharge pollutants from the Facility to Mount Hope Bay, subject to the effluent limitations, monitoring requirements and other conditions specified in the Permit.

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[1] States that have received authorization from EPA under § 402(b) administer the NPDES permit program within their boundaries in lieu of the federal government. 33 U.S.C. § 1342(b), (c). To date, Massachusetts has not received such authorization. Although EPA issues NPDES permits in Massachusetts, the state maintains permitting authority under Massachusetts law. *See* M.G.L. c. 21, § 43; 314 C.M.R. 3.00. Generally, when EPA issues a NPDES permit in Massachusetts, MassDEP simultaneously issues a discharge permit under Massachusetts law, as it did in this case.

10. Part I.A.4.a. of the Permit establishes a flow limit for outfall serial number 001, Discharge Canal, of 40 million gallons per day (average monthly) and 42 million gallons per day (maximum daily).[2]

11. Part I.A.4. b. of the Permit for outfall serial number 001, Discharge Canal, establishes an annual heat load limit to Mount Hope Bay of 1.7 Trillion BTUs.

12. Part I.A.4. c. of the Permit establishes a limit for the combined withdrawal of intake water of 56.2 million gallons per day ("MGD").

13. The Permittee discharges process water from outfall serial number 001, Discharge Canal, at a flow rate that will exceed the Permit's effluent limitation for flow upon the Effective Date.

14. The Permittee discharges a heat load from outfall serial number 001, Discharge Canal, to Mount Hope Bay that will exceed the Permit's annual heat load limitation upon the Effective Date.

15. The Permittee's total water intake will exceed the Permit's limit for water intake of 56.2 MGD upon the Effective Date.

16. Section 43(2) of the Massachusetts CWA, M.G.L. c. 21, § 43(2) , makes unlawful the discharge of pollutants to waters of the Commonwealth except in conformance with, among other things, the terms and conditions of a permit issued under that Section.

17. The Company's discharge of pollutants to Mount Hope Bay in excess of the limits contained in its NPDES Permit, will result in a violation of a permit issued under M.G.L. c. 21, § 43 upon the Effective Date.

18. The Company will need to install closed-cycle cooling in order to comply with the previously stayed Permit limits. EPA issued an Order on December 17, 2007 to the Company to provide a schedule for the Company to come into compliance with the Permit.

19. The Company worked cooperatively with EPA in the development of the EPA Order. The Company, likewise, has worked cooperatively with MassDEP in the development of this Order.

V. ORDER

For the reasons stated above, MassDEP hereby Orders the following. This Order shall be binding on the Company and on its successors, heirs, and assigns. The Company shall not violate this Order, and shall not allow or suffer its employees, agents, or

[2] This flow rate is the total blowdown from any cooling tower(s) used at the facility plus flow from the wastewater treatment facility. During periods of once-through cooling, the permittee may increase the flow rate to a flow rate of 56 million gallons per hour. The permittee may not increase to this flow rate for more than 122 hours per year.

contractors to violate this Order. Pursuant to M.G.L. c. 21A, § 16 and 310 CMR 5.00, MassDEP hereby determines that the deadlines set forth below constitute reasonable time for coming into compliance with MassDEP's requirements. Accordingly, the Company shall:

20. Comply with the following schedule for construction and implementation of closed cycle cooling at Brayton Point Power Station and for meeting the limits contained in the Permittee's NPDES Permit:

    a. By the Effective Date, commence the process to obtain all permits and approvals necessary to convert Brayton Point Station to closed cycle cooling in order to meet NPDES permit limits. This shall include the engineering to support the permitting, the permit applications, and all necessary supplementary data;

    b. From the Effective Date until all permits and approvals are issued, provide timely and complete responses to all requests from each permitting and approval authority.

    c. By the Effective Date, initiate requests for pre-application meetings with permitting authorities.

    d. By the Effective Date, request approval from the United States Coast Guard for placement of monitoring equipment necessary to comply with Part T.26.a. 1 .iii of the Permit.

    e. By the effective Date, submit air modeling protocol to MassDEP for review.

    f. By July 1, 2008, submit applications for all local permits.

    g. By September 1, 2008, submit application(s) for air permit(s).

    h. By October 1, 2008, complete submission of all other necessary permit applications and notices necessary to convert Brayton Point Station to closed cycle cooling.

    i. Within five days of obtaining all permits and approvals or April 6, 2009, whichever is later, issue the Notice to Proceed with Engineering and Procurement for cooling tower construction to Dominion's contractor.

    j. Within five days of obtaining all permits and approvals or April 6, 2009, whichever is later, issue the Notice to Proceed with Engineering and Procurement for the Pump Structure and Piping System.

    k. Within nine months of obtaining all permits and approvals, commence construction of foundations for cooling towers.

    l. No later that May 15 of the calendar year prior to the anticipated tie-in date for each unit, Dominion shall request a planned outage for that unit from ISO New

England in accordance with, and pursuant to, ISO New England Operating Procedure No. 5, Revision No. 8, effective October 13, 2006 or as amended.

m. Within 29 months of obtaining all permits and approvals, complete tower construction.

n. Within 29 months of obtaining all permits and approvals, complete all piping installation for tie-in of condenser units to cooling towers.

o. Within 29 months of obtaining all permits and approvals, commence tie-in of condenser units to cooling towers.

p. Within 31 months of obtaining all permits and approvals, complete tie-in of condenser units 4 and 3.

q. Within 33 months of obtaining all permits and approvals, complete tie-in of condenser unit 2.

r. Within 36 months of obtaining all permits and approvals, complete tie-in of all condensor units such that all permit limits are met.

21. Where any compliance obligation requires Dominion to obtain a federal, state, or local permit or approval, Dominion shall submit timely and complete applications and responses to requests for information and take all other actions necessary to obtain all such permits or approvals. Dominion may seek relief under the Force Majeure provisions below for any delay in the performance of any such obligation resulting from a failure to obtain, or a delay in obtaining, any permit or approval required to fulfill such obligation, if Dominion has submitted timely and complete applications and has taken all other actions necessary to obtain all such permits or approvals.

Interim Effluent Limits

22. In the interim period from the effective date of this Order and during the Permittee's compliance with paragraphs 20 and 21 of this Section V, the Permittee shall comply with the following effluent standards and limits:

    a. for thermal discharges, intake cooling water withdrawals, and effluent flow, comply with all the requirements and conditions of the <u>Memorandum of Agreement II</u> ("MOA II") (Attachment 1) except that:

        (1) During the period from the beginning of tie-in of condensor unit 4 and continuing until tie-in of condensor unit 3, the flow limitations of part 8.b. of MOA II will not be required to be met through "piggyback operation." Instead, the flow limitations will be met by blocking the existing unit 4 discharge at the tri-bridge and directing warm water from the tied-in unit to the cooling tower(s).

(2) During the period from the beginning of tie-in of condensor unit 4 and continuing until complete tie-in of all condensor units, the "delta T" limitation of part 8.c. of MOA II will apply when unit 4 is not in piggyback operation" as long as the tie-in occurs between October 1 and - May31.

b. operate the intake screen wash for condenser units 1, 2, and 3 whenever the intake is in use.

c. during "targeted" chlorination, as defined in Attachment 2, the total residual oxidant concentration shall not, at any time, exceed 0.2 milligrams/liter at the discharge from the unit being chlorinated during any one chlorination cycle as measured at the seal pit. The sampling type and frequency will be a daily grab sample for each generating unit.

d. comply with all other effluent limitations, monitoring requirements and other conditions specified in its NPDES Permit.

23. Within three (3) weeks of Coast Guard approval for the placement of monitoring equipment necessary to comply with Part I.. 26.a. 1 .iii of the Permit, Dominion shall install monitoring equipment at the locations identified in Figure 6 of the Permit and commence monitoring in accordance with the Permit requirements.

24. As the following power generating units are tied into the cooling towers, the discharge from Brayton Point Station must comply with the following interim effluent limitations:

Unit 3	flow = 518 million gallons per day heat = MOA II limit
Unit 2	flow = 259MGD heat = 2.01 trillion BTUs total per month

VI. REPORTS ON COMPLIANCE

25. Beginning on the fifteenth day of April, 2008 and continuing until completion of construction, tie-in, and compliance with all of the NPDES limitations, Dominion shall report to MassDEP on its compliance with its obligations pursuant to paragraphs 20 through 24 every three months. Each progress report submitted under this Paragraph shall:

a. Describe activities undertaken during the reporting period directed at achieving compliance with this Administrative Order;

b. Describe the expected activities to be taken during the next reporting period in order to achieve compliance with this Administrative Order; and

c. Report on compliance with the provisions outlined in paragraphs 22, 23 and 24 above.

26. Where this Order requires a specific action to be performed within a certain time frame, Dominion shall submit a written notice of compliance or noncompliance with each deadline. Notification must be mailed within fourteen (14) calendar days after each required deadline. The timely submission of a required report shall satisfy the requirement that a notice of compliance be submitted.

27. If noncompliance is reported, notification should include the following information:

    a. A description of the noncompliance;

    b. A description of any actions taken or proposed by the Permittee to comply with the lapsed schedule requirements;

    c. A description of any factors that explain or mitigate the noncompliance; and

    d. An approximate date by which the Permittee will perform the required action.

28. After a notification of noncompliance has been filed, compliance with the past-due requirement shall be reported by submitting any required documents or providing MassDEP with a written report indicating that the required action has been achieved.

29. The reporting requirements set forth in this Section do not relieve Dominion of its obligation to submit any other reports or information as required by State, Federal or local law.

30. Within fourteen days of learning that it will fail, or has failed, to comply with a requirement of this Order, the Dominion shall provide written notice of such failure to MassDEP.

31. Submissions required by this Order shall be in writing and shall be mailed to the following address:

David Johnston, Deputy Regional Director
MassDEP
Southeast Regional Office
20 Riverside Drive
Lakeville, MA 02346

VII. FORCE MAJEURE

32. "Force majeure," for purposes of this Administrative Order, is defined as any event arising from causes beyond the control of Dominion, of any entity controlled by Dominion, or of Dominion's contractors, that delays or prevents the performance of any obligation under this Administrative Order despite all practicable efforts by Dominion to fulfill the obligation. The requirement that Dominion exercise "all practicable efforts to fulfill the obligation" includes using all practicable efforts to anticipate any potential force majeure event and all practicable efforts to address the effects of any such event

(a) as it is occurring and (b) after it has occurred to prevent or minimize any resulting delay to the greatest extent possible. "Force Majeure" does not include normal inclement weather, unanticipated or increased costs or expenses of work, the financial difficulty of performing such work, or the failure of Dominion to make complete and timely application of any required approval or permit unless caused by a separate force majeure event. "Force Majeure" may include, but is not limited to, acts of God including floods, blizzards, hurricanes, and other extreme weather, labor strikes, fires, judicial orders, orders by governmental officials or ISO New England that direct Dominion to operate Brayton Point to supply electricity, ISO New England's failure to grant Dominion's request for an outage to permit unit tie-ins when that request was timely as specified in paragraph 1, and an inability to tie-in a unit due to the restrictions in paragraph 3 of this Order, including the Delta T, that are not waived by MassDEP. Under the definition of "Force Majeure" as set forth above in this paragraph, "Force Majeure" may or may wit include construction, labor, and equipment delays.

33. If any event occurs or has occurred that may delay the performance of any obligation under this Administrative Order or causes Dominion to be in potential violation of any provision of this Order, whether or not caused by a force majeure event, Dominion shall provide notice orally or by electronic or facsimile transmission to:

David Johnston, Deputy Regional Director
MassDEP
Southeast Regional Office
20 Riverside Drive
Lakeville, MA 02346
By telephone at (508) 946-2708
By facsimile at (508) 047-6557
By email to: david.Johnston@state.ma.us

within five (5) business days of when Dominion first knew that the event might cause a delay. In addition, Dominion shall notify MassDEP in writing as soon as practicable but in no event later than ten (10) days following the date Dominion first knew that the event caused or may cause such delay or potential violation. In this written notice, Dominion shall provide an explanation and description of the reasons for the delay; the anticipated duration of the delay; all actions taken or to be taken to prevent or minimize the delay; a schedule for implementation of any measures to be taken to prevent or mitigate the delay or the effect of the delay; Dominion's rationale for attributing such delay to a force majeure event if it intends to assert such a claim; and a statement as to whether, in the opinion of Dominion, such event may cause or contribute to an endangerment to public health, welfare or the environment. Dominion shall include with any written notice all reasonably obtainable documentation supporting the claim that the delay was attributable to a force majeure. Failure to comply with the above requirements shall preclude Dominion from asserting any claim of force majeure for that event for the period of time of such failure to comply, and for any additional delay caused-by such failure Dominion shall be deemed to know of any circumstance of which Dominion, any entity controlled by Dominion, or Dominion's contractors knew or should have known by the exercise of due diligence.

34. If MassDEP agrees that the delay or anticipated delay is attributable to a force majeure event, the time for performance of the obligations under this Administrative Order that are affected by the force majeure event will be extended by MassDEP for such time as is necessary to complete those obligations. Any subsequent schedule deadlines that MassDEP agrees are affected by the force majeure event will also be extended. An extension of the time for performance of the obligations affected by the force majeure event shall not of itself extend the time for performance of any other obligation. MassDEP will notify Dominion in writing of the length of the extension, if any, for performance of the obligations affected by the force majeure event.

35. If MassDEP does not agree that the delay or anticipated delay has been or will be caused by a force majeure event, MassDEP will notify Dominion in writing of its decision.

VIII. DISPUTE RESOLUTION

36. If Dominion objects to any MassDEP determination made pursuant to this Order regarding the adequacy of the work performed hereunder or whether a force majeure has occurred, it shall notify MassDEP in writing of its objection(s) within 15 days of such action, unless the objection(s) has been resolved informally. MassDEP and Dominion shall engage in a period of formal negotiations for 30 days from MassDEP' s receipt of Dominion's written objection(s).

37. Any agreement reached by the parties pursuant to this Section shall be in writing and shall, upon signature of both parties, be incorporated into and become an enforceable part of this Order.

IX. GENERAL PROVISIONS

38. This Order does not constitute a waiver or a modification of the terms and conditions of the NPDES Permit. The NPDES Permit remains in full force and effect. MassDEP reserves the right to seek any and all remedies available under M.G.L. c. 21, § 44(1) for violation of this Order.

39. This Order shall become effective on the date a Final Decision providing for the dismissal of the appeals of the Permit and associated State Water Quality Certification under the Massachusetts CWA referenced in paragraph 8 above is issued by the Commissioner or her designee.

X. APPEALS

40. Dominion is hereby notified that it may request an adjudicatory hearing on this Order by filing a Notice of Claim for an Adjudicatory Appeal ("Notice of Claim") pursuant to General Laws c. 30A, § 10, and 310 C.M.R. 1.00. Complete adjudicatory appeal applications require the submittal of a <u>Notice of Claim</u>, a copy of this Unilateral Administrative Order and an <u>Adjudicatory Appeal Fee Transmittal Form</u>, a copy of which is attached hereto for convenience. A completed Fee Transmittal Form, including an appeal fee payment of $100.00, must be mailed to MassDEP's Lockbox at:

Department of Environmental Protection
Box 4062
Boston, MA 02211

The Notice of Claim (including a copy of the $100.00 appeal fee payment check and the completed Fee Transmittal Form) must be sent by United States mail or hand-delivered to MassDEP within 21 days after the date of issuance of this Order. The Notice of Claim must be addressed to:

Case Administrator
Department of Environmental Protection
One Winter Street – 2nd Floor
Boston, MA 02108

The Notice of Claim shall clearly and concisely set forth the facts related to the proceeding, the reasons the Order is considered to be inconsistent with General Laws c. 21, §§26-53 and 314 C.M.R. 3.00 and 4.00, and the relief sought through the adjudicatory appeal. Failure to submit all necessary information in accordance with 310 C.M.R. 1.00 may result in a dismissal by MassDEP of the Notice of Claim for an Adjudicatory Hearing. Failure to pay the filing fee as required is grounds for dismissal of the request for hearing. Upon a showing of undue financial hardship, MassDEP may waive the adjudicatory hearing filing fee. A person who believes that payment of the $100.00 filing fee would be an undue financial hardship must file, together with the request for adjudicatory hearing as provided above, an affidavit setting forth the facts the appellant believes constitute the undue financial hardship.

DEPARTMENT OF ENVIRONMENTAL PROTECTION

By: ______________________
Glenn Haas, Acting Assistant Commissioner for Resource Protection
Department of Environmental Protection
1 Winter Street – 3rd Floor
Boston, MA 02108

Date: 3/27/08

APPENDIX D

310 CMR 7.29 Emission Control Plan Amendment

Massachusetts Department of Environmental Protection
Bureau of Waste Prevention – Air Quality

BWP AQ 25

Emission Standards for Power Plants – Emission Control Plan (ECP)

X001323
Transmittal Number

Facility ID# (if known)

A. Facility Information

Important: When filling out forms on the computer, use only the tab key to move your cursor - do not use the return key.

1. Facility:

Dominion Energy Brayton Point, LLC - Brayton Point Station
Facility Name

1 Brayton Point Road
Street Address

Somerset	MA	02726-0440
City/Town	State	Zip Code

Mailing Address(if different from above):

Street/PO Box

City/Town	State	Zip Code

2. Facility Contact Person:

Ken Small
Name

Sr. Environmental Compliance Coordinator
Title

508-646-5220
Telephone Number

3. Facility Owner:

Dominion Energy Brayton Point, LLC
Owner or Corporation Name

5000 Dominion Boulevard
Richmond, VA 23060

4. Compliance Contact:

Barry A. Ketschke
Name

Director F&H Station III
Title

508-646-5236
Telephone Number

B. Facility Description

List all units at the affected facility that will be used to demonstrate compliance with 310 CMR 7.29(5).

*__See Attachment A__

C. Affected Facility Unit (Complete Section C for each unit)

1.	Unit Number	Unit #1	Unit #2	Unit #3	Unit #4
2.	Manufacturer	Combustion Engineering	Combustion Engineering	Babcock & Wilcox	Riley Stoker
3.	Model Number	19407-Type CC	19617 - Type CC	UP-52	1SR
4.	Maximum Continuous Rated Design Capacity:				
	a. Fuel heat Input	2,250 MMBtu/hr	2,250 MMBtu/hr	5,655 MMBtu/hr	4,800 MMBtu/hr
	b. Electrical Output	255 MW (net)	255 MW (net)	633 MW (net)	446 MW (net)
5.	Date of Installation	8/1/1963	7/1/1964	7/29/1969	12/19/1974

The unit specific data supplied in Section C of the ECP for heat input and electrical output are unit ratings and may not be consistent with actual measured CEMS data (which also contains a margin of error). The dates of installation specified in the Section C of the ECP are the dates of initial commercial operation.

D. Compliance Path

1. Will this affected facility comply with the emission standards in 310 CMR 7.29(5) by repowering a unit subject to 40 CFR Part 72 at the affected facility?

   ☐ Yes ☒ No

2. Will any unit at this affected facility be required to receive a plan approval pursuant to 310 CMR 7.02 for construction, substantial reconstruction or alteration of a facility subject to 40 CFR Part 72 for the purpose of compliance with 310 CMR 7.29?

   ☒ Yes ☐ No

   If yes, identify which units.
   Units No. 1, 2 & 3

E. Emissions Control for Nitrogen Oxides, Sulfur Dioxides, Particulate Matter, Mercury, Carbon Dioxide, and Carbon Monoxide (Complete Section E for each unit)

For each unit, indicate Existing Controls (if none, check "None" ONLY):

Unit Number:	Existing Controls:		
Unit #1	☒ Electrostatic Precipitators (ESP) ☒ Low NO_x Burners	☐ SNCR ☒ SCR	☐ None
Unit #2	☒ Electrostatic Precipitators (ESP) ☒ Low NO_x Burners	☐ SNCR ☐ SCR	☐ None
Unit #3	☒ Electrostatic Precipitators (ESP) ☒ Low NO_x Burners	☐ SNCR ☒ SCR	☐ None
Unit #4	☒ Electrostatic Precipitators (ESP) ☒ Low NO_x Burners	☐ SNCR ☐ SCR	☐ None

***See Attachment B for a complete list of existing and proposed controls**

F. Compliance Methods

A description of how the facility will comply with the emission standards contained in 310 CMR 7.29(5) for:

1. NO_x In accordance with the previously approved ECP and plan approvals, Brayton Point has installed Selective Catalytic Reduction (SCR) systems on Units No. 1 and 3. Brayton Point currently utilizes aqueous ammonia solution (19.5% NH_3 concentration maximum) to generate ammonia for injection at the SCR inlet. Aqueous ammonia is stored on-site in four 55,000-gallon storage tanks. These new controls in conjunction with the existing emission controls have resulted in significant reductions in NO_X emissions and allow the facility to continue to comply with the NO_X requirements of 310 CMR 7.29.

2. SO_2 In accordance with the previously approved ECP and plan approvals, Brayton Point has installed Spray Dryer Absorber (SDA) systems on Units No. 1 and 2. Each SDA system is also be equipped with a Fabric Filter (FF) baghouse to control particulate emissions. Additionally, a Dry Scrubber or increased natural gas firing capability is proposed for Unit #3. The Dry Scrubber system will also be equipped with a Fabric Filter (FF) baghouse to control particulate emissions. These new controls in conjunction with the existing emission control strategies have resulted in significant reductions in SO_2 emissions and will allow the facility to continue to comply with the SO_2 requirements of 310 CMR 7.29.

   Please note that in conjunction with the 310 CMR 7.29 control project, the EPRICON system has been removed from Unit 1 and the Chemithon Flue Gas Conditioning system has been removed from Unit 3; the replacement for this flue gas conditioning was described in the previously approved plan approvals.

3. CO_2 (e.g. sequestration, off-site reductions, on-site efficiency improvements)

   See Attachment C.

4. Hg See Attachment D.

G. Optimization Section

A description of how emission reduction measures implemented to achieve reductions in one pollutant will optimize reductions of other pollutants, for example mercury and CO_2.

<u>Mercury</u>:

As required by 310 CMR 7.29, baseline mercury emission stack testing was performed in 2001 and 2002 for Units 1, 2, 3 and 4. Stack test results indicated that combustion in Units 1, 2, and 3 already results in some of the mercury in the coal being emitted as oxidized mercury (Hg) that is well controlled by the existing ESPs. In May 2004, MADEP finalized revisions to 310 CMR 7.29 to incorporate the final mercury rule. The rule prescribes control requirements and/or emission limits for the coal-fired or ash re-burning units and establishes a mercury emissions cap of 146.6 pounds per year from Units 1, 2 and 3 based on the 2001-2002 mercury emission stack test results. As of January 1, 2008, Units 1, 2 and 3 are required to achieve 85% mercury emission control or meet an average total mercury emission rate of 0.0075 lb/GW-hr. As of October 1, 2012, Units 1, 2 and 3 will be required to achieve 95% mercury emission control or meet an average total mercury emission rate of 0.0025 lb/GW-hr.

The combination of Dry Scrubbers, Fabric Filters and PAC has been demonstrated to have higher mercury removal efficiencies than ESPs alone.

CO_2 / Greenhouse gases:

The facility intends to comply with the reduction obligations largely through on-site or off-site projects that reduce, avoid or sequester carbon dioxide (CO_2) or other greenhouse gases. As part of the 310 CMR 7.29 compliance projects that includes the SCR systems and scrubbers, an ash reduction process (ARP) has been installed. The ARP removes unburned carbon from the flyash from the combustion of coal. Removing the excess carbon allows the flyash to meet the specifications for beneficial use as a substitute for Portland cement in making concrete. The availability of this flyash means that less conventional Portland cement will be needed in the concrete mix, thus reducing greenhouse gas emissions associated with that raw materials production.

H. Proposed Schedule

Submit a proposed schedule with interim milestones for each activity leading to compliance with the requirements in 310 CMR 7.29(5). Such information shall include, but not be limited to, sufficient information to allow DEP to consult with the Division of Energy Resources and the Department of Telecommunications and Energy, to address any concerns with potential impacts to the reliability of the New England power system.

***See Attachment E**

I. Signature of the Facility Contact Responsible for Compliance with 310 CMR 7.29

The signature below is required pursuant to 310 CMR 7.29(6)(b)5. Even if an agent has been designated to fill out this form, the responsible official must sign it.

I certify that I have examined the responses provided herein and that to the best of my knowledge they are true and complete.

Diane Leopold
Print Name

Signature of Responsible Official

VP F&H Merchant Operations
Position/Title

Dominion Energy Brayton Point, LLC
Representing

October 30, 2008
Date

Attachment A

Brayton Point Station (ORIS Code 1619) consists of four (4) large utility boilers for electrical generation. Units #1, #2, and #3 are primarily fired by coal with No. 6 fuel oil as back-up, and to co-fire natural gas. Unit #4 burns natural gas and No. 6 residual fuel oil. Supporting auxiliary equipment includes coal, oil, and ash handling and storage systems. Brayton Point Station currently has monitoring plans in place that meet the requirements of 40 CFR Part 75.

Of the four units at the facility, Units #1, 2 and 3 will be modified to satisfy the requirements of 310 CMR 7.29 (the Regulation). Unit #4 will not be physically altered. The balance of oil versus natural gas in Unit #4 may be adjusted as needed to ensure that the emissions limitations of the Regulation are met.

The units are currently fueled as follows:

Brayton Point Station Current Fuel Characteristics

Item	Unit 1	Unit 2	Unit 3	Unit 4
Primary Fuel	Coal	Coal	Coal	Residual Oil/ Natural Gas
Backup Fuel	Natural Gas @ 25% MCR	Natural Gas @ 25% MCR	Natural Gas @ 10% MCR	
Backup fuel	Residual Oil @ 100% MCR	Residual Oil @ 100% MCR	Residual Oil @ 100% MCR	

Notes:

(1) Units #1, #2, and #3, also have the capability to combust small quantities of distillate oil.

(2) Maximum Capability Rating (MCR)

(3) The Station also includes four 2.5-MW diesel generators that are used for safe shutdown of the Station in the event of an electrical grid system failure. The generators are also capable of providing a small amount of electrical generation to the grid.

Attachment B

Unit No.	Pollution Control Measures (PCM)
1	Selective Catalytic Reduction (SCR)
	Ash Reduction Process
	R-C Electrostatic Precipitators
	Low NOx Burners with Over-Fire Air
	Management of Lower Sulfur Fuels
	Spray Dryer Adsorber (SDA)
	Fabric Filter Baghouse
	Powder Activated Carbon
2	Ash Reduction Process
	R-C Electrostatic Precipitators
	Low NOx Burners with Over-Fire Air
	Management of Lower Sulfur Fuels
	Epricon Flue Gas Conditioning System
	Spray Dryer Adsorber (SDA)
	Fabric Filter Baghouse
	Powder Activated Carbon
3	Selective Catalytic Reduction (SCR)
	Ash Reduction Process
	R-C Electrostatic Precipitators
	Low NOx Burners with Over-Fire Air
	Management of Lower Sulfur Fuels
	Dry Scrubber*
	Fabric Filter Baghouse*
	Powder Activated Carbon*[1]
4	Electrostatic Precipitators
	Management of Lower Sulfur Fuels
	Low NOx Burners
	Flue Gas Recirculation

[1] PAC is currently permitted to be injected upstream of the Unit No. 3 Electro-Static Precipitators. This ECP amendment proposes to also inject PAC upstream of the Dry Scrubber and Fabric Filter on Unit No. 3.

* - Proposed controls addressed in this ECP amendment.

Attachment C

Brayton Point intends to comply with 310 CMR 7.29 CO2 compliance obligations largely through on-site or off-site projects that reduce, avoid or sequester carbon dioxide (CO2) or other greenhouse gases. As part of the 310 CMR 7.29 compliance projects that includes the SCR systems and scrubbers, an ash reduction process (ARP) has been installed. The ARP removes unburned carbon contained from the flyash from the combustion of coal. Removing the excess carbon allows the flyash to meet the specifications for beneficial use as a substitute for Portland cement in making concrete. The availability of this flyash means that less conventional Portland cement will be needed in the concrete mix, thus reducing the greenhouse gas emissions associated with that raw material's production.

Brayton Point currently has a BWP-AQ-27 Application for Certification of Green House Gas (GHG) Credits under MassDEP review to certify the GHG reductions from the ARP process. Once this application is conditionally approved, Brayton point expects to submit one or more verification applications for this project.

Depending on its compliance volume position of GHG Credits, Brayton Point may additionally enter into an agreement(s) with a third party(ies) for the procurement of verified Massachusetts GHG Credits and/or may pay into the Massachusetts GHG Expendable Trust.

Attachment D

The following describes Brayton Point's mercury control strategy:

Annual Mercury Emissions Cap of 146.6 pounds– October 1, 2006

The Station is currently injecting PAC upstream of the existing ESPs on Units 1, 2 and 3 as required to allow collection of mercury in the ESP. The Station has optimized ESP performance[1] for improved mercury capture along with maintaining particulate collection.

0.0075 lb/net GWHr or 85% Mercury Collection Efficiency - January 1, 2008

The Station has installed SDA/FF systems on Units 1 and 2 with PAC injection upstream of the SDA to collect mercury. The PAC injection upstream of the ESPs will serve as a backup. Unit 3 will continue to inject PAC upstream of the ESPs as required to allow collection of mercury in the ESP. The Station will optimize the mercury control on the three units to obtain the most cost-effective combination.

0.0025 lb/net GWHr or 95% Mercury Collection Efficiency - October 1, 2012

In addition to the existing mercury control strategies listed above, with this EPC amendment Brayton Point is proposing to install a Dry Scrubber, Fabric Filter and PAC injection system on Unit No.3 for further control of mercury.

Notes:

[1] - In accordance with Plan Approval 4B06002, optimizing ESP performance may include taking the "old" (Koppers) ESPs out-of-service for Units 1, 2 and/or 3 in order to increase mercury capture with powder activated carbon by the existing "new" Research-Cottrell ESPs.

Attachment E

The following is a description of the milestones achieved to date and the proposed schedule for the revisions to the Emission Control Plan for Brayton Point Station. The following table provides the commercial operation date for each Emission Control installed in accordance with Plan Approval 4B04025.

Table E-1

Emission Control	Commercial Operation Date
Unit No. 1 SCR	December 19, 2006
Unit No. 3 SCR	August 17, 2006
Ash Reduction Process	August 11, 2006

The following table provides the commercial operation date and proposed schedule for each Emission Control installed in accordance with Plan Approval 4B06002.

Table E-2

Emission Control	Commercial Operation Date
Unit No. 1 PAC for existing Precipitators	December 17, 2007
Unit No. 2 PAC for existing Precipitators	December 17, 2007
Unit No. 3 PAC for existing Precipitators	December 17, 2007
Unit No. 1 FF & PAC	April 2008
Unit No. 2 FF & PAC	October 2008
	Proposed Schedule
Unit No. 1 SDA	o Contracts let: 4^{th} Quarter 2005 o Maintenance unit outage: System tie-in occurred during scheduled 1^{st} Quarter 2008 Outage o Construction commenced: 3^{rd} Quarter 2006 o Systems in service / shakedown period: $2^{nd}/3^{rd}$ Quarter 2008 o Systems performance testing: 4^{th} Quarter 2008 o Systems commercial operation: 4^{th} Quarter 2008
Unit No. 2 SDA	o Contracts let: 4^{th} Quarter 2005 o Maintenance unit outage: System tie-in occurred during scheduled 3^{rd} Quarter 2007 Outage o Construction commenced: 4^{th} Quarter 2007 o Systems in service / shakedown period: $1^{st}/2^{nd}/3^{rd}$ Quarter 2008 o Systems performance testing: 4^{th} Quarter 2008 o Systems commercial operation: 4^{th} Quarter 2008

The following table provides the proposed schedule for the Emission Control that will be included in the Plan Approval that will be submitted on or before September 2, 2008 for the Cooling Tower Project and the Unit No. 3 Dry Scrubber, Fabric Filter and Powder Activated Carbon Projects.

Table E-3

Emission Control	Proposed Schedule
Unit No.3 Dry Scrubber, FF and PAC	o Contracts let: 4^{th} Quarter 2010 o Maintenance unit outage: System tie-in will occur during scheduled 3^{rd} /4^{th} Quarter 2013 Outage o Construction commences: 4^{th} Quarter 2010 o Systems in service / shakedown period: 4^{th} Quarter 2013 o Systems performance testing: 4^{th} Quarter 2013 / 1^{st} Quarter 2014 o Systems commercial operation: 1^{st} Quarter 2014

In accordance with the Department's letter dated November 26, 2003, Brayton Point Station has proceeded with the proposed emission control plan in a two-phase approach. Phase one included the controls listed in Tables E-1 and E-2 while Phase Two will consist of the controls listed in Tables E-3.

COMMONWEALTH OF MASSACHUSETTS
EXECUTIVE OFFICE OF ENERGY & ENVIRONMENTAL AFFAIRS
DEPARTMENT OF ENVIRONMENTAL PROTECTION
SOUTHEAST REGIONAL OFFICE
20 RIVERSIDE DRIVE, LAKEVILLE, MA 02347 508-946-2700

DEVAL L. PATRICK
Governor

TIMOTHY P. MURRAY
Lieutenant Governor

IAN A. BOWLES
Secretary

LAURIE BURT
Commissioner

December 29, 2008

Diane Leopold
Dominion Energy Brayton Point, LLC
5000 Dominion Boulevard
Glen Allen, Virginia 03060-6711

RE: **AMENDED EMISSION CONTROL PLAN FINAL APPROVAL**
Application for: BWP AQ 25
310 CMR 7.29 Power Plant Emission Standards
Transmittal Number: X001323
Application Number: 4B08050
Source Number: 0061

AT: Dominion Energy Brayton Point, LLC
Brayton Point Station
Brayton Point Road
Somerset, Massachusetts 02726-0440

Dear Ms. Leopold:

The Southeast Region of the Department of Environmental Protection (Department), Bureau of Waste Prevention, has reviewed your amended application for approval of the Emission Control Plan (ECP) application dated October 30, 2008. This amended application has been submitted to describe how emission limitations and compliance schedules for the control of certain designated pollutants contained in 310 CMR 7.29, "Emission Standards for Power Plants," will be implemented for equipment and processes located at the Dominion Energy Brayton Point, LLC - Brayton Point Station ("Dominion") at Brayton Point Road in Somerset, Massachusetts. This application for approval of the ECP bears the signature of Diane Leopold as the company contact responsible for compliance with 310 CMR 7.29.

The amended ECP application proposes a Dry Scrubber (DS) for removal Sulfur Dioxide (SO_2) emissions from Unit 3 and continued utilization of the existing Unit 3 stack. The DS system will be equipped with Fabric Filter (FF) baghouse at the DS outlet for control of particulate matter emissions. The amended ECP application also proposes to install Powder Activated Carbon (PAC) injection systems upstream of the DS/FF system for the removal of mercury. The DS/FF and existing stack the top of which is 353 feet above ground level will be utilized versus the Unit 3 wet Flue Gas Desulfurization (FGD) system and the 505 foot tall stack previously approved by the Department, pursuant to 310 CMR 7.29. The Unit 3

DS/FF and PAC systems are planned to be in commercial operation during the first quarter 2014.

The Unit 1 and 3 Selective Catalytic Reduction (SCR) NO_x emission control systems that will use aqueous ammonia, the Unit 1 and 2 Spray Dryer Absorbers (SDA) for removal of Sulfur Dioxide (SO_2) emissions followed by the Fabric Filter (FF) baghouses at the SDA outlets for control of particulate matter emissions, the Unit 1 and 2 Powder Activated Carbon (PAC) injection systems upstream of the SDA/FF systems for the removal of mercury, the Unit 1, 2 and 3 PAC injection systems installed upstream of the Koppers ESPs with the Koppers ESPs taken out of service to provide additional residence time for the PAC for the removal of mercury (Hg) and the Ash Reduction Process (ARP) for Unit 1, 2 and 3 were previously approved by the Department, pursuant to 310 CMR 7.29.

This **Amended Emission Control Plan (ECP) Final Approval** supersedes the Amended ECP Final Approval (Application No. 4B05053), dated March 29, 2006, Amended ECP Final Approval (Application No. 4B04021), dated October 20, 2004 and ECP Final Approval (Application No. 4B01042), dated June 7, 2002.

LEGAL AUTHORITY

The Department has adopted 310 CMR 7.29 - a regulation to lower emissions of sulfur dioxide (SO_2), carbon dioxide (CO_2), nitrogen oxides (NO_x) and mercury (Hg) from certain power plants, and to establish a framework for reductions in emissions of carbon monoxide (CO) and fine particulate matter (PM 2.5) - pursuant to the Massachusetts General Laws, Chapter 111, Sections 142 A-M.

Regulation 310 CMR 7.29 requires any person who owns, leases, operates or controls an affected facility to comply with 310 CMR 7.29 in its entirety. An affected facility means a facility which emitted greater than 500 tons of SO_2 and 500 tons of NO_x during any of the calendar years 1997, 1998, or 1999, and which includes a unit which is a fossil fuel fired boiler or indirect heat exchanger that: (1) is regulated by 40 CFR Part 72 (the Federal Acid Rain Program); (2) serves a generator with a nameplate capacity of 100 megawatts (MW) or more; (3) was originally permitted prior to August 7, 1977; and (4) had not subsequently received a Plan Approval pursuant to 310 CMR 7.00: Appendix A or a Permit pursuant to the regulations for Prevention of Significant Deterioration, 40 CFR Part 52, prior to October 31, 1998. Dominion Energy Brayton Point, LLC is an affected facility.

The purpose of 310 CMR 7.29 is to control emissions of NO_x, SO_2, Hg, CO, CO_2, and PM 2.5 (together, "pollutants") from affected electric generating facilities in Massachusetts. 310 CMR 7.29 accomplishes this by establishing maximum output-based emission rates for NO_x, SO_2, and CO_2, establishing maximum output-based emission rates or minimum removal efficiencies for Hg, and establishing a cap on CO_2 and Hg emissions from affected facilities. The maximum output-based emission rate and cap for CO_2 is applicable through December 31, 2008 and as of January 1, 2009 CO_2 emissions will be subject to the provisions of 310 CMR 7.70 Massachusetts CO_2 Budget Trading Program. Emission limits for CO and PM 2.5 have not been addressed at this time.

Applicable requirements and limitations contained in 310 CMR 7.29 shall not supersede, relax or eliminate any more stringent conditions or requirements (e.g. emission limitation(s), testing, record keeping, reporting, or monitoring requirements) established by regulation or contained in a facility's previously issued source specific Plan Approval(s) or Emission Control

Plan(s). The facility must amend its Operating Permit application and revise their Operating Permit to include the Amended ECP Final Approval.

Based upon the above, the Department has determined that the referenced Amended ECP Application is administratively and technically complete and that the proposed modifications are in conformance with current air pollution control engineering practices and hereby issues this **Amended ECP FINAL Approval** for the proposed modifications of your power plant unit(s), with the conditions listed below.

* Legend to Abbreviated Terms within Tables 1 through 6:

EU # = Emission Unit Number
NO_x = Nitrogen Oxides
SO_2 = Sulfur Dioxide
Hg = Mercury
CO = Carbon Monoxide
CO_2 = Carbon Dioxide
PM 2.5 = Fine Particulate Matter
MMBTU/HR = fuel heat input in million British Thermal Units per hour
MW (NET) = net electrical output in Megawatts
lbs/MWh = pounds per Megawatt-hour of net electrical output
lbs/GWh = pounds per Gigawatt-hour of net electrical output
MFR = Manufacturer
CEMS = Continuous Emission Monitors
R-C = Research-Cottrell

1. EQUIPMENT DESCRIPTION

The following emission units (Table 1) are subject to and regulated by this **Amended ECP Final Approval:**

Table 1 *

EU #	DESCRIPTION OF EMISSION UNIT	EU DESIGN CAPACITY (MMBTU/HR)	EU DESIGN CAPACITY MW (NET)	POLLUTION CONTROL MEASURES (PCM)[1]
EU 1	Combustion Engineering MFR # 19407 Type CC, Water Tube Boiler	2,250	255	Selective Catalytic Reduction
				Ash Reduction Process
				R-C Electrostatic Precipitators
				Low NO_x Burners with Overfire Air
				Management of Lower Sulfur Fuels
				Spray Dryer Absorber
				Fabric Filter Baghouse
				Powder Activated Carbon
EU 2	Combustion Engineering MFR # 19617 Type CC, Water Tube Boiler	2,250	255	Ash Reduction Process
				R-C Electrostatic Precipitators
				Low NO_x Burners with Overfire Air
				Management of Lower Sulfur Fuels
				Spray Dryer Absorber
				Fabric Filter Baghouse
				Powder Activated Carbon
EU 3	Babcock & Wilcox Model # UP - 52 Water Tube Boiler	5,655	633	Selective Catalytic Reduction
				Ash Reduction Process
				R-C Electrostatic Precipitators
				Low NO_x Burners with Overfire Air
				Management of Lower Sulfur Fuels
				Dry Scrubber
				Fabric Filter Baghouse
				Powder Activated Carbon
EU 4	Riley Stoker Model # 1SR Water Tube Boiler	4,800	446	Electrostatic Precipitators
				Low NO_x Burners
				Management of Lower Sulfur Fuels
				Flue Gas Recirculation

<u>Table 1 Notes:</u>

1. Details of the Proposed Pollution Control Measures including alternatives under consideration are described in Sections E, F, and G of the application.

2. APPLICABLE REQUIREMENTS

A. EMISSION LIMITS AND RESTRICTIONS

Dominion shall comply with the emission limits/restrictions as contained in Table 2 below. The schedule for compliance with these emission limitations is contained in Table 6 of this **Amended ECP Final Approval**.

Table 2 *

EU #	POLLUTANT	EMISSION LIMIT/STANDARD	APPLICABLE REGULATION AND/OR APPROVAL NUMBER
EU 1, EU 2, EU 3, EU 4	NO_x	Shall not exceed 1.5 lbs/MWh calculated over any consecutive 12 month period, recalculated monthly.	310 CMR 7.29(5)(a)1.a.
		Shall not exceed 3.0 lbs/MWh calculated over any individual month.	310 CMR 7.29(5)(a)1.b.
	SO_2	Shall not exceed 6.0 lbs/MWh calculated over any consecutive 12 month period, recalculated monthly.	310 CMR 7.29(5)(a)2.a.
		Shall not exceed 3.0 lbs/MWh calculated over any 12 month period, recalculated monthly.	310 CMR 7.29(5)(a)2.b.i.
		Shall not exceed 6.0 lbs/MWh calculated over any individual month.	310 CMR 7.29(5)(a)2.b.ii.
EU 1, EU 2, EU 3	Hg	Total annual mercury emissions from combustion of solid fuels in units subject to 40 CFR Part 72 located at an affected facility or from re-burn of ash in Massachusetts shall not exceed the average annual emissions of 146.6 pounds per calendar year, calculated using the results of the stack tests required in 310 CMR 7.29(5)(a)3.d.ii..	310 CMR 7.29(5)(a)3.c.
		85% Removal Efficiency or 0.0075 lbs/GWh	7.29(5)(a)3.e.i. or ii.
		95% Removal Efficiency or 0.0025 lbs/GWh	7.29(5)(a)3.f.i. or ii.
EU 1, EU 2, EU 3, EU 4	CO	Reserved.[1]	310 CMR 7.29(5)(a)4.
	CO_2	Emissions of carbon dioxide from the affected facility in the calendar year, expressed in tons, from Part 72 units located at the affected facility shall not exceed historical actual emissions of 8,585,152 tons.[2, 3]	310 CMR 7.29(5)(a)5.a.
		Shall not exceed 1800 lbs/MWh in the calendar year.[3]	310 CMR 7.29(5)(a)5.b.
	PM 2.5	Reserved.[1]	310 CMR 7.29(5)(a)6.

Table 2 Notes:

1. The Department has reserved these areas in the regulations for further development.

2. If the Department has received a technically complete Plan Approval application under 310 CMR 7.02 for a new or re-powered electric generating unit subject to 40 CFR Part 72 at an affected facility prior to May 11, 2001, then the emissions from the new or re-powered unit may be included in the calculation of historical actual emissions. The calculation of historical actual emissions which includes emissions from a new or re-powered unit shall not include emissions from any unit shutdown or removed from operation at the affected facility that is included in the technically complete Plan Approval application pursuant to 310 CMR 7.02. Provisions for the quantification and certification of Greenhouse Gas (GHG) emission reductions, avoided emissions, or sequestered emissions for use in demonstrating compliance with the CO_2 emission limitations contained in 310 CMR 7.29 are contained in 310 CMR 7.00: Appendix B(7) Greenhouse Gas Credit Banking and Trading.

3. The CO_2 emission standards shall not apply to the emissions of CO_2 that occur after December 31, 2008.

B. COMPLIANCE DEMONSTRATION

The facility is subject to the monitoring/testing, record keeping, and reporting requirements as contained in Tables 3, 4 and 5 below and 310 CMR 7.29, as well as the applicable requirements contained in Table 2:

Table 3 *	
EU#	MONITORING/TESTING REQUIREMENTS
EU 1, EU 2, EU 3, EU 4	Actual emissions shall be monitored for individual units and monitored as a facility total for all units included in the calculation demonstrating compliance. Actual emissions shall be monitored in accordance with 40 CFR Part 75 for SO_2, CO_2 and NO_x and 310 CMR 7.29 for Hg. The Department shall detail the monitoring methodology for CO and PM 2.5 at the time regulations are promulgated by the Department for those parameters.
	Monitor actual net electrical output, expressed in megawatt-hours. Actual net electrical output shall be provided for individual units and as a facility total for all units included in the calculation demonstrating compliance.
EU 1, EU 2, EU 3	In accordance with 310 CMR 7.29(5)(a)3.c.i. and 310 CMR 7.29(5)(a)3.d.iii., the portion of total annual mercury emissions from combustion of solid fossil fuel in units subject to 40 CFR 72 located at or from re-burn of ash at an affected facility, determined using emissions testing at least every other calendar quarter from October 1, 2006 until mercury CEMS are used to demonstrate compliance with the standards contained in 310 CMR 7.29(5)(a)3.e. or f. and using mercury CEMS thereafter. Stack tests for mercury shall consist at a minimum of three runs at full load on each unit firing solid fossil fuel or ash according to a testing protocol acceptable to the Department. Stack tests for mercury, and certification and annual Relative Accuracy Test Audits for mercury CEMS, shall determine total and particulate-bound mercury.
	In accordance with 310 CMR 7.29(5)(a)3.c.ii.(i), when ash produced by an affected facility is used in Massachusetts as a cement kiln fuel, as an asphalt filler, or in other high temperature processes that volatilize mercury, the mercury content of the utilized ash shall be measured weekly using a method acceptable to the Department.
	In accordance with 310 CMR 7.29(5)(a)3.e. and f., any person who owns, leases, operates or controls an affected facility which combusts solid fossil fuel or ash shall monitor a facility's average total mercury removal efficiency or emissions rate for those units combusting solid fossil fuel or ash. This will be based on a mercury CEMS using the methodology approved by the Department in the monitoring plan required under 310 CMR 7.29(5)(a)3.g. and shall be calculated on a rolling 12 month basis.
	In accordance with 310 CMR 7.29(5)(a)3.g.i., by January 1, 2008, any person who owns, leases, operates or controls an affected facility which combusts solid fossil fuel or ash shall install, certify, and operate CEMS to measure mercury stack emissions from each solid fossil fuel- or ash-fired unit at a facility subject to 310 CMR 7.29.
	Actual emissions shall be monitored for individual units and monitored as a facility total for all units included in the calculation demonstrating compliance. Actual emissions shall be monitored in accordance with 310 CMR 7.29(7)(b)1.b., c., and d. for Hg.
	In accordance with 310 CMR 7.29(7)(g), operate each continuous emission monitoring system at all times that the emissions unit(s) is operating except for periods of CEMS calibrations checks, zero span adjustment, and preventive maintenance as described in the monitoring plan approved by the Department and as determined during certification. Notwithstanding such exceptions, in all cases obtain valid data for at least 75% of the hours per day, 75% of the days per month, and 90% of the hours per quarter during which the emission unit is combusting solid fossil fuel or ash.

Table 4 *	
EU#	RECORD KEEPING REQUIREMENTS
EU 1 EU 2 EU 3 EU 4	Maintain a record of actual emissions for each regulated pollutant for each of the preceding 12 months. Actual emissions shall be recorded for individual units and as a facility total for all units included in the calculation demonstrating compliance. Actual emissions provided under this section shall be recorded in accordance with 40 CFR Part 75 for SO_2, CO_2 and NO_x and 310 CMR 7.29 for Hg. The Department shall detail the monitoring methodology for CO, and PM 2.5 at the time regulations are promulgated by the Department for those parameters.
	Maintain a record of actual net electrical output for each of the preceding 12 months, expressed in megawatt-hours. Records of actual net electrical output shall be maintained for individual units and as a facility total for all units included in the calculation demonstrating compliance.
	Maintain a record of the resulting output-based emission rates for each of the preceding 12 months, and each of the 12 consecutive rolling month time periods, expressed in pounds per megawatt-hour. Output based emission rates shall be provided for individual emission units and as a facility total for all units included in the calculation demonstrating compliance.
	Keep all measurements, data, reports and other information required by 310 CMR 7.29 on-site for a minimum of five years, or any other period consistent with the affected facility's Operating Permit.
EU 1 EU 2 EU 3	In accordance with 310 CMR 7.29(5)(a)3., keep records of required mercury stack testing and ash testing.
	In accordance with 310 CMR 7.29(5)(a)3.g., maintain a record of all measurements, performance evaluations, calibration checks, and maintenance or adjustments for each mercury continuous emission monitor.
	In accordance with 310 CMR 7.29(7)(e), for units that apply carbon or other sorbent injection for mercury control, the records shall be kept until such time as mercury CEMS are installed at that unit.
	In accordance with 310 CMR 7.29(7)(i), any person subject to 310 CMR 7.29(5)(a)3. shall submit the results of all mercury emissions, monitor, and optimization test reports, along with supporting calculations, to the Department within 45 days after completion of such testing.
	Maintain a record of actual emissions for Hg for each of the preceding 12 months. Actual emissions shall be recorded for individual units and as a facility total for all units included in the calculation demonstrating compliance. Actual emissions shall be recorded in accordance with 310 CMR 7.29(7)(b)1.b., c. and d. for Hg.
	In accordance with 310 CMR 7.29(7), by January 30 of the year following the earliest applicable compliance date and January 30 of each calendar year thereafter, the facility shall submit a report to the Department demonstrating compliance with the emission standards contained in 310 CMR 7.29(5)(a) and in an approved emission control plan. For the mercury standards at 310 CMR 7.29(5)(a)3.c., the compliance reports due January 30, 2007 and 2008 shall include the quarterly emissions for each quarter beginning October 1, 2006. For the mercury standards at 310 CMR 7.29(5)(a)3.c., e., and f., the compliance report due January 30, 2009 and each report thereafter shall demonstrate compliance with any applicable annual standard for the previous calendar year and with any applicable 12-month standard for each of the 12 previous consecutive 12-month periods.

Table 5 *	
EU#	REPORTING REQUIREMENTS
EU 1 EU 2 EU 3 EU 4	By January 30 of the year following the earliest applicable compliance date for the affected facility under 310 CMR 7.29(6)(c), and January 30 of each calendar year thereafter, the company representative responsible for compliance shall submit a compliance report to the Department demonstrating the facility's compliance status with the emission standards contained in 310 CMR 7.29(5)(a) and in an approved Emission Control Plan. The report shall demonstrate the facility's compliance status with applicable monthly emission rates for each month of the previous calendar year, and each of the twelve previous consecutive 12-month periods. The compliance report shall include all statements listed in 310 CMR 7.29(7)(b)4.[1]
	The Department may verify the facility's compliance status by whatever means necessary, including but not limited to requiring the affected facility to submit information on actual electrical output of company generating units provided by the New England Independent System Operator (ISO), or any successor thereto.
EU 1 EU 2 EU 3	In accordance with 310 CMR 7.29(5)(a)3.d.iii., the results of each stack test for mercury shall be reported to the Department within 45 days after conducting each stack test.
	In accordance with 310 CMR 7.29(5)(a)3.c.ii.(iv), when ash produced by an affected facility is used in Massachusetts as a cement kiln fuel, as an asphalt filler, or in other high temperature processes that volatilize mercury, a proposal shall be submitted for Department approval at least 45 days prior to such use, or at least 45 days prior to October 1, 2006, whichever is later, detailing the proposed measurement methods to be used to comply with 7.29(5)(a)3.c.ii.(i) and (ii).
	In accordance with 310 CMR 7.29(5)(a)3.g., submit a CEMS monitoring plan for Department approval at least 45 days prior to equipment installation including, but not limited to, a sample calculation demonstrating compliance with the emission limits using conversion factors from 40 CFR Part 60 or Part 75 or other proposed factors.
	In accordance with 310 CMR 7.29(5)(a)3.g., submit for Department approval a CEMS certification protocol at least 21 days prior to certification testing for the CEMS, and any proposed adjustment to the certification testing at least seven days in advance.
	In accordance with 310 CMR 7.29(5)(a)3.g., submit a certification report within 45 days of the completion of the certification test for Department approval.
	Certify and operate each CEMS in accordance with 310 CMR 7.29(5)(a)3.g.
	Submit to the appropriate Department regional office a compliance report in accordance with 310 CMR 7.29(7)(b).
EU 1 EU 2 EU 3	In accordance with 310 CMR 7.29(7)(a), for the mercury standards at 310 CMR 7.29(5)(a)3.c., the compliance reports due January 30, 2007 and 2008 shall include the quarterly emissions for each quarter beginning October 1, 2006. For the mercury standards at 310 CMR 7.29(5)(a)3.c., e., and f., the compliance report due January 30, 2009 and each report thereafter shall demonstrate compliance with any applicable annual standard for the previous calendar year and with any applicable 12-month standard for each of the 12 previous consecutive 12-month periods. The compliance report shall contain items listed in 310 CMR 7.29(7)(b).
	In accordance with 310 CMR 7.29(7)(g), any person subject to 310 CMR 7.29(5)(a)3. shall submit the results of all mercury emissions, monitor, and optimization test reports, along with supporting calculations, to the Department within 45 days after completion of such testing.
FACILITY	Submit by January 15, April 15, July 15 and October 15 for the previous three months respectively, a 7.29 construction status report which identifies the construction activities which have occurred during the past three months, and those activities anticipated for the following three months, and progress toward achieving compliance with the implementation dates identified in Table 6 below.

Table 5 Notes:

1. If the ISO final settlement of actual electrical output is not available, the facility shall submit a compliance report based on provisional values of actual electrical output. Upon receiving certified ISO values of actual electrical output for all provisional months within the calendar year, the facility shall submit a revised compliance report within 30 days thereafter.

3. COMPLIANCE SCHEDULE

The affected facility shall be in full compliance with the applicable requirements in accordance with the dates below:

TABLE 6 *		
COMPLIANCE PATH		
POLLUTANT	**STANDARD**	**DATE**
NO_x SO_2	310 CMR 7.29(5)(a)1.a. 310 CMR 7.29(5)(a)2.a.	October 1, 2006
NO_x SO_2	310 CMR 7.29(5)(a)1.b. 310 CMR 7.29(5)(a)2.b.	October 1, 2008
CO_2	310 CMR 7.29(5)(a)5.a.	Calendar Year 2006
CO_2	310 CMR 7.29(5)(a)5.b.	Calendar Year 2008
Hg	310 CMR 7.29(5)(a)3.c.	October 1, 2006
Hg	7.29(5)(a)3.e.i. or ii.	January 1, 2008
Hg	7.29(5)(a)3.f.i. or ii.	October 1, 2012

The affected facility is subject to receiving a Plan Approval pursuant to 310 CMR 7.02 for alterations which will reduce stack gas exit temperature due to the construction of the Dry Scrubber (DS), Fabric Filter (FF) and Powdered Activated carbon (PAC) injection system.

Details of the compliance schedule/milestones are described in Section H of the amended ECP application.

4. SPECIAL CONDITIONS FOR ECP

1. The Department may verify compliance with 310 CMR 7.29(5) by whatever means necessary, including but not limited to: inspection of a unit's operating records; requiring the facility to submit information on actual electrical output of company generating units provided to that person by the New England Independent System Operator, or any successor thereto; testing emission monitoring devices; and, requiring the facility to conduct emissions testing under the supervision of the Department.

2. The Department is not approving or denying any off-site or non-contemporaneous proposed CO_2 reduction measures at this time. 310 CMR 7.29(5)(a)5.c. and d. provide that compliance with the CO_2 emission limitations may be demonstrated by using offsite reductions or sequestration in addition to onsite reductions, as long as certain established conditions are met. However, while there is a provision for using early reductions of SO_2 to meet the SO_2 emissions limit in 310 CMR 7.29(5)(a)2.a., there is no similar regulatory provision for use of early reductions of CO_2 for compliance with 310 CMR7.29(5)(a)5. Provisions for the quantification and certification of Greenhouse Gas (GHG) emission reductions, avoided emissions, or sequestered emissions for use in demonstrating compliance with the CO_2 emission limitations contained in 310 CMR 7.29 are contained in 310 CMR 7.00: Appendix B(7) Greenhouse Gas Credit Banking and Trading.

5. GENERAL CONDITIONS FOR ECP

1. The facility shall maintain continuous compliance at all times with the terms of this Amended ECP Final Approval and the applicable emission rates in 310 CMR 7.29.

2. This Amended ECP Final Approval may be suspended, modified, or revoked by the Department, if at any time the facility is violating any applicable Regulation(s) or condition(s) of this Amended ECP Final Approval letter.

3. This Amended ECP Final Approval consists of Dominion's application materials and this Amended ECP Final Approval letter. If conflicting information is found between these two documents, then the requirements of the Amended ECP Final Approval letter shall take precedence over the documentation in the application materials.

4. Should a condition of air pollution occur as a result of the operation of these units, then the facility shall immediately take appropriate steps to abate said condition even though the facility is otherwise in compliance with this Amended ECP Final Approval.

5. This Amended ECP Final Approval does not negate the responsibility of the facility to comply with this or any other applicable federal, state, or local regulations now or in the future. Nor does this Amended ECP Final Approval imply compliance with any other applicable federal, state, or local regulations now or in the future.

6. If provisions or requirements from any other regulation or permit conflict with a provision of 310 CMR 7.29, the more stringent of the provisions will apply unless

otherwise determined by the Department in the affected facility's Operating Permit.

7. Failure to comply with any of the above stated provisions will constitute a violation of the "Regulations", and can result in the revocation of the Amended ECP Final Approval granted herein.

6. MODIFICATION TO THE ECP

Amendments may be proposed to this approved Emission Control Plan. If the Department proposes to approve such amendments, or approve such amendments with conditions, then the Department will publish a notice of public comment on an Amended ECP Draft Approval, in accordance with M.G.L. c. 30A. The Department will allow a 30-day public comment period following publication of the notice, and may hold a public hearing. Modifications to an affected facility's monitoring systems approved pursuant to the requirements of 40 CFR Part 72 are not subject to such public comment prior to approval. All terms and conditions of this Amended ECP Final Approval shall remain in effect until otherwise modified by the Department in a subsequent Amended ECP Final Approval.

7. MASSACHUSETTS ENVIRONMENTAL POLICY ACT

An Environmental Notification Form (ENF) was submitted to the Executive Office of Energy and Environmental Affairs, for air quality control purpose, pursuant to the Massachusetts Environmental Policy Act (MEPA) and Regulation 301 CMR 11.00. The ENF was designated EOEA No. 13022. On May 22, 2003, the Secretary of Environmental Affairs issued a Certificate on the ENF with a determination the project does not require the preparation of an Environmental Impact Report.

In response to Notice of Project Changes the Secretary of Environmental Affairs issued Certificates, dated August 23, 2004 and March 24, 2006 indicating that no further review was required for the use of aqueous ammonia in place of the urea based system and for the SDA/FF systems and PAC injection systems.

In response to a response to a Notice of Project Change the Secretary of Energy and Environmental Affairs issued a Certificate, dated October 10, 2008, indicating that no further review was required for the Unit 3 DS/FF.

8. APPEAL OF APPROVAL

This Amended ECP Final Approval is an action of the Department. If you are aggrieved by this action, you may request an adjudicatory hearing. A request for a hearing must be made in writing and postmarked within twenty-one (21) days of the date of issuance of this Amended ECP Final Approval.

Under 310 CMR 1.01(6)(b), the request must state clearly and concisely the facts which are the grounds for the request, and the relief sought. Additionally, the request must state why the Amended ECP Final Approval is not consistent with applicable laws and regulations.

The hearing request along with a valid check payable to The Commonwealth of Massachusetts in the amount of one hundred dollars ($100.00) must be mailed to: The

Commonwealth of Massachusetts, Department of Environmental Protection, P.O. Box 4062, Boston, MA 02211.

The request will be dismissed if the filing fee is not paid, unless the appellant is exempt or granted a waiver as described below. The filing fee is not required if the appellant is a city or town (or municipal agency) county, or district of the Commonwealth of Massachusetts, or a municipal housing authority.

The Department may waive the adjudicatory hearing filing fee for a person who shows that paying the fee will create an undue financial hardship. A person seeking a waiver must file, together with the hearing request as provided above, an affidavit setting forth the facts believed to support the claim of undue financial hardship.

Enclosed is a stamped approved copy of the Amended ECP application.

Should you have questions concerning this matter or regarding the terms or conditions of this **Amended ECP Final Approval**, please do not hesitate to contact the undersigned at the Southeast Region at (508) 946-2779.

Very truly yours,

John K. Winkler, Chief
Permit Section
Bureau of Waste Prevention

Enclosure

ecc: Barry Ketschke, Dominion Energy Brayton Point, LLC
Pamela Faggert, Dominion Resources Services, Inc.
Scott Lawton, Dominion Resources Services, Inc.
Christina A. Wordell, Agent, Somerset Board of Health
Somerset Board of Selectmen
Stephen Rivard, Chief, Somerset Fire Department
Cynthia Giles, CLF RI Director
Shanna Cleveland, CLF MA
Cynthia Luppi, Clean Water Action
James Colman, MassDEP-Boston
Marilyn Levenson, MassDEP-Boston
Nancy Seidman, MassDEP-Boston
Yi Tian, MassDEP-Boston
Sharon Weber, MassDEP-Boston
Patricio Silva, MassDEP-Boston
William Lamkin, MassDEP-NERO
David Johnston, MassDEP-SERO
Laurel Carlson, MassDEP-SERO
Charlie Kitson, MassDEP-SERO
Laura Patriarca, MassDEP-SERO

APPENDIX E

Noise Protocol and Analysis
(Plan Approval Only)

⌊REVISIONS UNDER SEPARATE COVER⌋

APPENDIX F

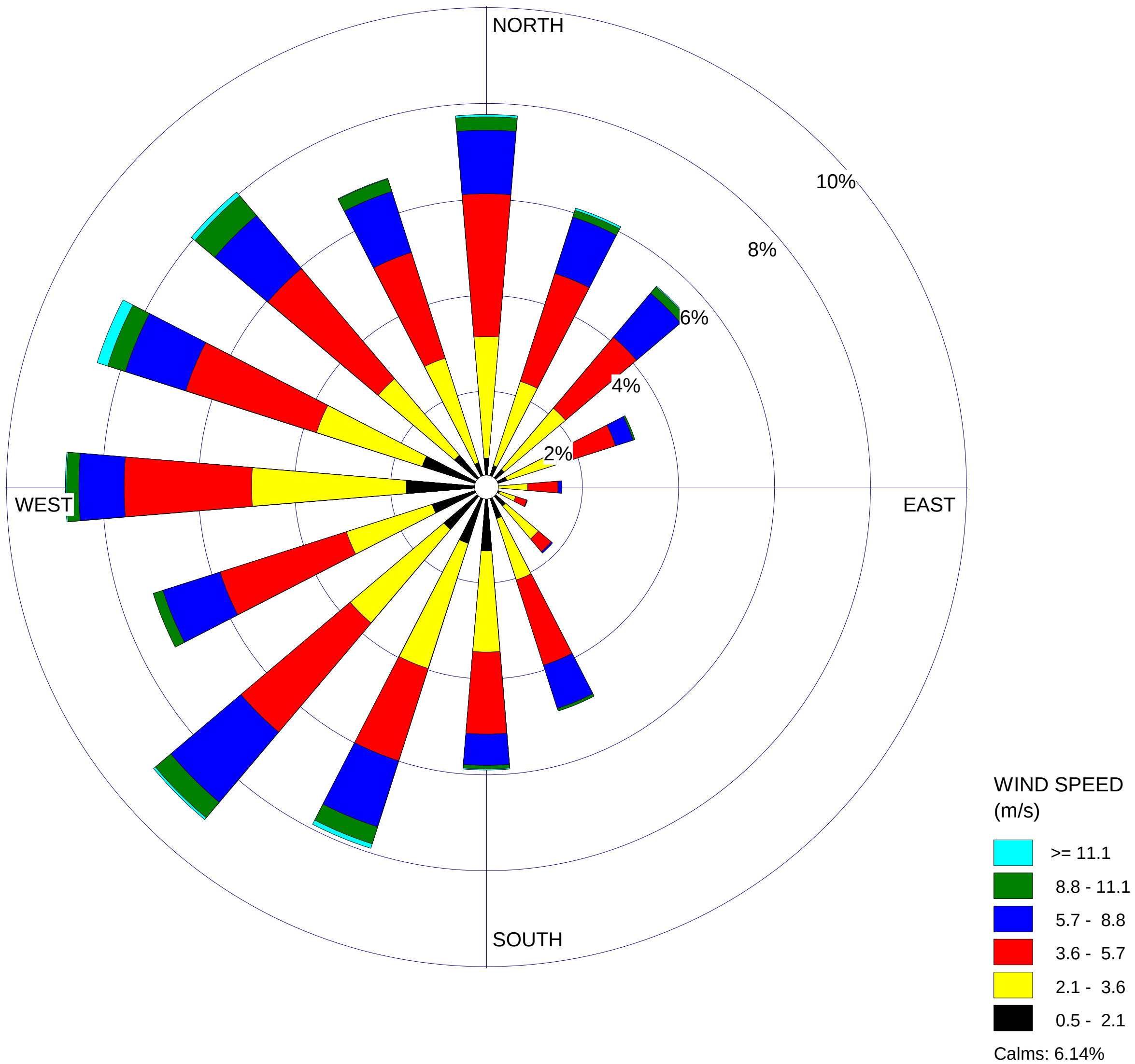
Wind Roses

WIND ROSE PLOT:

2002 Annual Wind Rose at T.F. Green Airport, Providence, RI

DISPLAY:

Wind Speed
Direction (blowing from)



COMMENTS:

Prepared for
Dominion - Brayton Point

DATA PERIOD:

2002
Jan 1 - Dec 31
00:00 - 23:00

COMPANY NAME:

CALM WINDS:

6.14%

TOTAL COUNT:

8274 hrs.

AVG. WIND SPEED:

4.14 m/s

2352

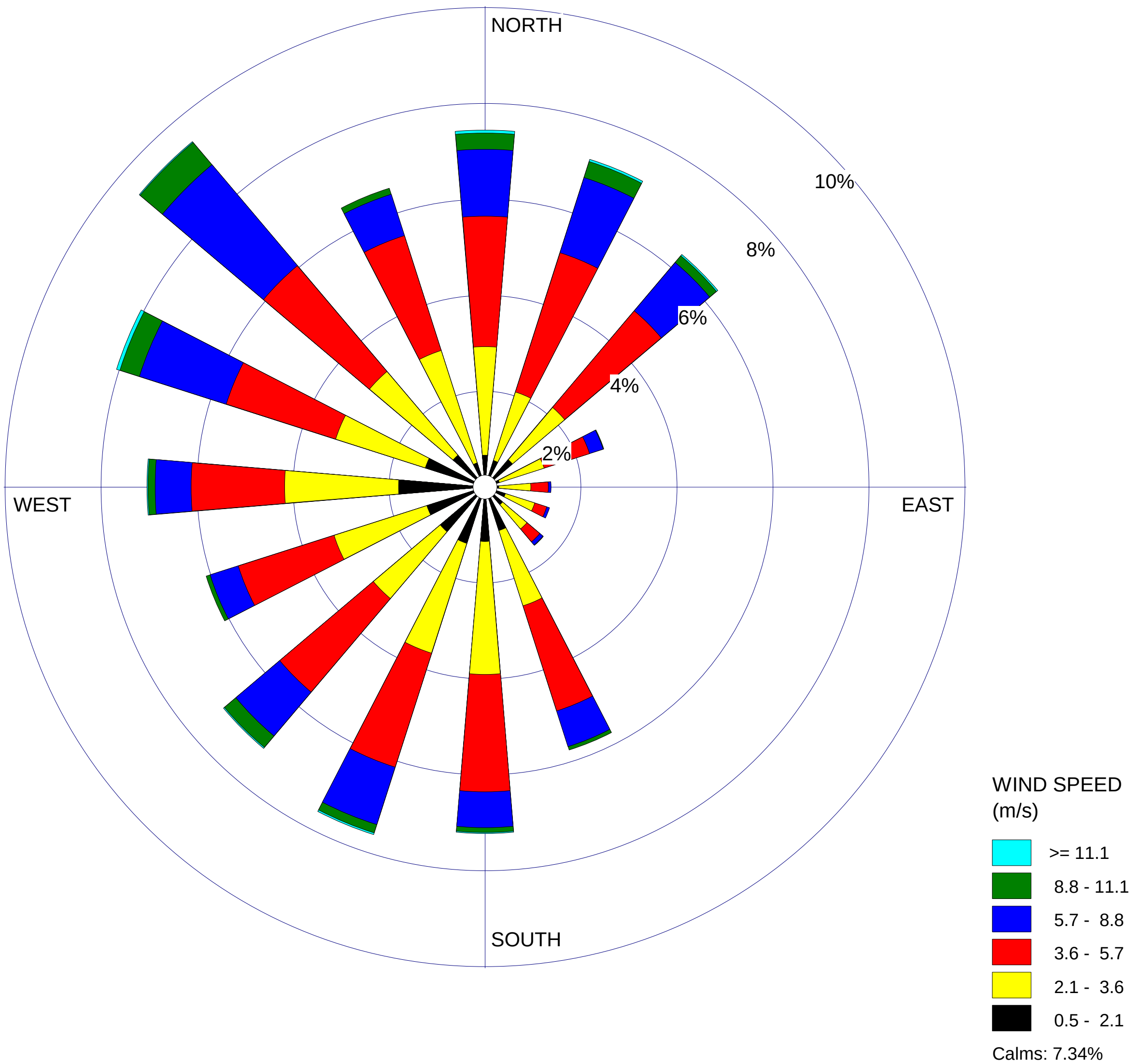
WRPLOT View - Lakes Environmental Software

WIND ROSE PLOT:

2004 Annual Wind Rose at T.F. Green Airport, Providence, RI

DISPLAY:

Wind Speed
Direction (blowing from)



COMMENTS:

Prepared for
Dominion - Brayton Point

DATA PERIOD:

2004
Jan 1 - Dec 31
00:00 - 23:00

COMPANY NAME:

CALM WINDS:

7.34%

TOTAL COUNT:

8284 hrs.

AVG. WIND SPEED:

4.06 m/s

PROJECT NO.:

2352

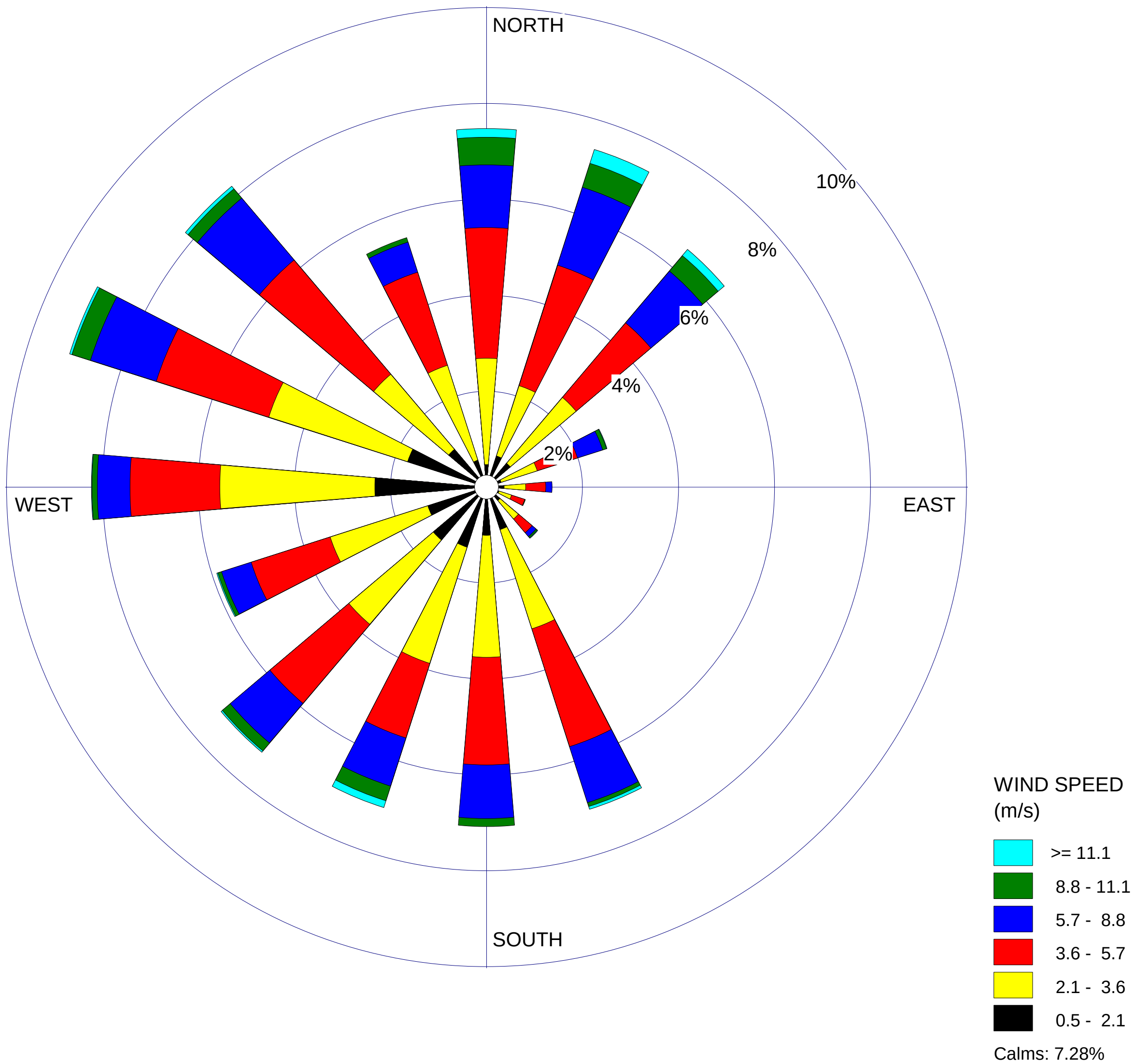
WRPLOT View - Lakes Environmental Software

WIND ROSE PLOT:

2005 Annual Wind Rose at T.F. Green Airport, Providence, RI

DISPLAY:

Wind Speed
Direction (blowing from)



COMMENTS: Prepared for Dominion - Brayton Point	DATA PERIOD: **2005** **Jan 1 - Dec 31** **00:00 - 23:00**	COMPANY NAME:
	CALM WINDS: **7.28%**	TOTAL COUNT: **8355 hrs.**
	AVG. WIND SPEED: **4.06 m/s**	PROJECT NO.: **2352**

Epsilon ASSOCIATES INC.

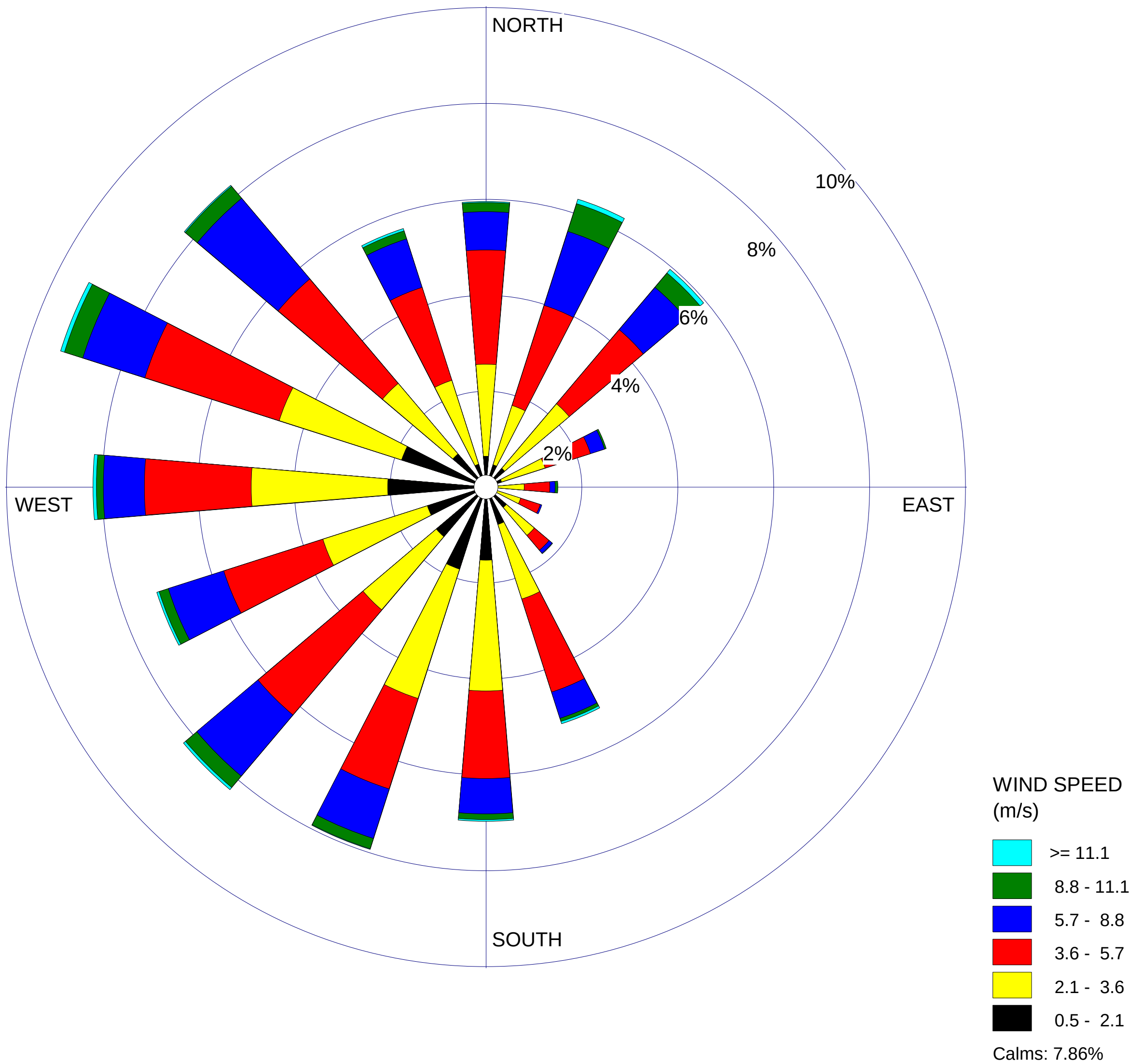
WRPLOT View - Lakes Environmental Software

WIND ROSE PLOT:

2006 Annual Wind Rose at T.F. Green Airport, Providence, RI

DISPLAY:

Wind Speed
Direction (blowing from)



COMMENTS:

Prepared for
Dominion - Brayton Point

DATA PERIOD:

2006
Jan 1 - Dec 31
00:00 - 23:00

COMPANY NAME:

CALM WINDS:

7.86%

TOTAL COUNT:

8414 hrs.

AVG. WIND SPEED:

4.02 m/s

PROJECT NO.:

2352

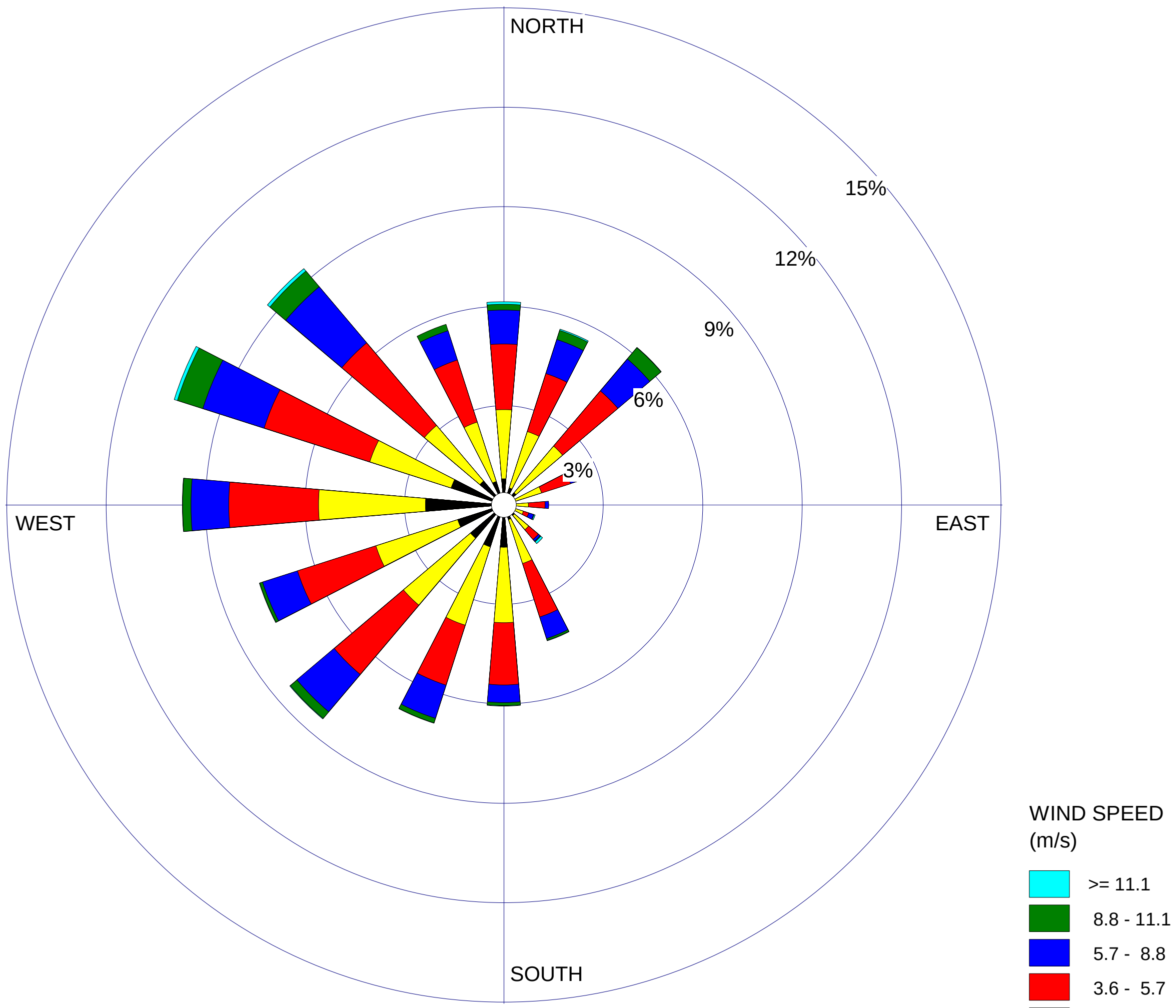
WRPLOT View - Lakes Environmental Software

WIND ROSE PLOT:

2007 Annual Wind Rose at T.F. Green Airport, Providence, RI

DISPLAY:

Wind Speed
Direction (blowing from)



COMMENTS: Prepared for Dominion - Brayton Point	DATA PERIOD: **2007** **Jan 1 - Dec 31** **00:00 - 23:00**	COMPANY NAME:	
	CALM WINDS: **7.26%**	TOTAL COUNT: **8357 hrs.**	Epsilon ASSOCIATES INC.
	AVG. WIND SPEED: **4.05 m/s**		PROJECT NO.: **2352**

WRPLOT View - Lakes Environmental Software

APPENDIX G

Meteorological Conditions for Controlling Predicted Impact Periods

APPENDIX G METEOROLOGICAL CONDITIONS

Predicted concentrations for the combined impact from Brayton Point Station (2 natural draft cooling towers and 4 main stacks) are shown in Table 5-9 of the Air Plan Application. A discussion of the meteorological conditions in the area (based on TF Green Airport observations) for the periods presented in Table 5-9 are presented below (in the order that they appear in the table).

May25, 2005 (PM_{10} 24-hr H2H)

This 24-hour period was characterized by winds from the NNE to NE sector ranging from 9.8 to 12.4 m/s throughout the day. It was a cloudy, overcast day with relative humidity ranging from 87% to 100%. The morning hours were stable, with an unstable midday, then characterized by a stable atmosphere again after sunset.

November 13, 2006 ($PM_{2.5}$ 24-hr H8H)

This 24-hour period can be characterized as a cloudy day with winds from the NNE to NE at 4.6 to 7.7 m/s. Hour 10 and hour 18 had missing parameters this day.

May 10, 2006 Hour ending 12 (SO_2 3-hr H2H), Hour ending 16 (CO 8-hr H2H)

May 10, 2006 was a cloudy day. The 3-hour period (hrs 10, 11 and 12) was characterized by fairly strong winds (7.7-9.8 m/s) from the sector between NNE and NE. There was upward heat flux causing an unstable atmosphere. This continues through the daytime hours (hrs 9-16), and the winds were steady out of the NNE to NE with speeds ranging from 6.7 to 9.8 m/s.

May 24, 2005 (SO_2 24-hr H2H)

May 24,2005 was a cloudy, humid day. The relative humidity remained above 87% for the entire day. The day was characterized by light winds (1.5 m/s) from the south giving way to increasing winds (up to 11.3 m/s) as they shifted to the east and northeast.

September 9, 2002 Hour 9 (CO 1-hr H2H)

This hour was characterized by light winds (1.5 m/s) from the south. The relative humidity was 61% with a near neutral atmosphere. Three tenths of the sky had cloud cover.

APPENDIX H

VISCREEN Model Output

Visual Effects Screening Analysis for
Source: BraytonPt 2 Natural Draft CTs & Unit 3
Class I Area: Lye Brook

*** Level-1 Screening ***

Input Emissions for

Particulates	68.25	G	/S
NOx (as NO2)	320.64	G	/S
Primary NO2	.00	G	/S
Soot	.00	G	/S
Primary SO4	.00	G	/S

**** Default Particle Characteristics Assumed

Transport Scenario Specifications:

Background Ozone:	.04 ppm
Background Visual Range:	40.00 km
Source-Observer Distance:	213.10 km
Min. Source-Class I Distance:	213.10 km
Max. Source-Class I Distance:	219.70 km
Plume-Source-Observer Angle:	11.25 degrees
Stability:	6
Wind Speed:	1.00 m/s

R E S U L T S

Asterisks (*) indicate plume impacts that exceed screening criteria

Maximum Visual Impacts INSIDE Class I Area
Screening Criteria ARE NOT Exceeded

					Delta E		Contrast	
Backgrnd	Theta	Azi	Distance	Alpha	Crit	Plume	Crit	Plume
SKY	10.	84.	213.1	84.	2.00	.074	.05	.000
SKY	140.	84.	213.1	84.	2.00	.020	.05	-.001
TERRAIN	10.	84.	213.1	84.	2.00	.003	.05	.000
TERRAIN	140.	84.	213.1	84.	2.00	.001	.05	.000

Maximum Visual Impacts OUTSIDE Class I Area
Screening Criteria ARE NOT Exceeded

					Delta E		Contrast	
Backgrnd	Theta	Azi	Distance	Alpha	Crit	Plume	Crit	Plume
SKY	10.	75.	206.3	94.	2.00	.077	.05	.000
SKY	140.	75.	206.3	94.	2.00	.021	.05	-.001
TERRAIN	10.	65.	198.8	104.	2.00	.004	.05	.000
TERRAIN	140.	65.	198.8	104.	2.00	.001	.05	.000

APPENDIX I

SACTI Salt Deposition Modeling

APPENDIX I SACTI SALT DEPOSITION MODELING

1 Overview

As described in the air plan approval/PSD permit application (Section 2.3), water droplets can escape the cooling towers as drift, and salt in that drift can deposit in the vicinity of the cooling towers. This analysis quantifies the potential salt deposition rates, and compares to available threshold values.

2 Model Selection

The Seasonal Annual Cooling Tower Impact (SACTI) model (version dated 11-1-90) was used to predict salt deposition rates. A journal article (Policastro et al., 1994) provides an excellent description of the fundamentals of the code and a description of the model evaluation study. SACTI drift deposition algorithms have been validated against field data[1].

SACTI accounts for the thermodynamic and latent heat effects of the moist warm cooling tower plume. It treats the influence of the cooling tower structure itself on the airflow and the cooling tower plume rise, and accounts for the orientation of the line of cooling towers to the wind direction. However, SACTI does not account for the effects of other buildings around the cooling towers, nor for the effects of terrain.

SACTI uses representative wind directions to compare the orientation of the towers with the wind direction and therefore to assess plume merging scenarios. The model accounts for enhanced plume merging when the wind is lined up with the orientation of the cooling tower cells.

Minimum required inputs are hourly surface meteorological data for at least one year, corresponding mixing depths from twice-daily radiosondes, cooling tower geometry, vertical speed (or momentum flux) from the tower mouth, total thermal output of the cooling tower to the atmosphere, and drift drop mass flux, chemical composition, and drop size distribution.

SACTI is a hybrid statistical-deterministic model which identifies a series of combinations of meteorological variables that represent the full range of atmospheric conditions affecting plume dispersion and drift deposition over a time period of a season or a year. 16 wind direction sectors are assumed by SACTI, with sector width of 22 ½ degrees. SACTI is comprised of three models: PREP, MULT and TABLES. PREP, a meteorological preprocessor, determines plume categories based on hourly meteorological data and cooling tower exhaust conditions. Representative cases are generated for each plume category. MULT carries out plume and drift predictions for each of the representative cases.

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[1] Policastro, et.al, Atmospheric Environment, 1994

TABLES generates summary reports from the data generated by the PREP and MULT programs. Summary tables show the resulting modeled drift deposition by wind direction and distance.

3 Model Inputs

SACTI was run 5 years of meteorological data (surface data from Providence RI, with mixing heights from Chatham MA for 1985, 86, 88, 89, and 90). Monthly clearness index and solar insolation values from Newport, RI were used for this analysis. These values were obtained from Appendix B of the SACTI User's Guide, and are presented in Table 1.

Table 1. Clearness Index and Solar Insolation Values for Newport, RI

Month	Clearness Index	Solar Insolation (mj/m^2)
January	0.45	6.48
February	0.49	9.66
March	0.52	13.80
April	0.49	16.52
May	0.52	20.45
June	0.54	22.50
July	0.54	21.62
August	0.52	18.78
September	0.54	15.89
October	0.53	11.42
November	0.47	7.32
December	0.46	5.90

Cooling tower input parameters were based on tower information provided by the vendor. The modeling assumed the worst-case circulating water salt concentration of 48,000 ppmw. Input parameters are shown in the Table 2 below.

Table 2. Brayton Point Cooling Tower Model Inputs for SACTI

Parameter	Value(s)	Model
Tower Height (m)	151.4	PREP
Effective Exit Diameter (m)	94.2	PREP
Total Heat Rejection (MW)	2356.2	PREP
Effective Input Airflow (kg/s)	25399.6	PREP
Number of Ports	2	MULT
Coordinates of CT1 (m)	-69.72, 121.31	MULT
Coordinates of CT2 (m)	69.72, -121.31	MULT
Total Drift Rate (g/s)	233.4	MULT
Cooling Water Salt Conc. (g salt/g water)	0.048	MULT
Salt Density (g/cm^3)	2.17	MULT
Number of Drop Sizes	10	MULT
Drop Diameter (μm)	**Mass Fraction**	MULT
1	0.12	
10	0.08	
15	0.20	
35	0.20	
65	0.20	
115	0.10	
170	0.05	
230	0.04	
375	0.008	
525	0.002	

4 Model Results

The maximum salt deposition rate over the 5 year period, 11.58 kg/km^2-month, is predicted at 2100 meters to the East of the cooling towers. There was no salt deposition predicted within 1300 m of the towers. The domain average predicted deposition rate is 0.332 kg/km^2-month, which results in a total average deposition of 104.3 kg/month over the 10km radius domain.

5 Comparison to Standards

EPA has not established any standards for the protection of vegetation from salt deposition. While not applicable to this project, the Nuclear Regulatory Commission provides the following guidance in its review procedures for salt deposition from cooling towers[2]: "If the degree of impact falls into the first order category (... a few kilograms of salt drift per hectare per year), the reviewer may conclude that these impacts are not of sufficient magnitude to warrant further evaluation."

The maximum deposition rate predicted by SACTI equates to 1.4 kilograms of salt drift per hectare per year; the domain average deposition rate equates to 0.04 kilograms of salt drift per hectare per year.

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[2] NUREG 1555, §5.33.2

APPENDIX J

MEPA Certificates

The Commonwealth of Massachusetts

Executive Office of Energy and Environmental Affairs
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May 23, 2008

CERTIFICATE OF THE SECRETARY OF ENERGY AND ENVIRONMENTAL AFFAIRS
ON THE
ENVIRONMENTAL NOTIFICATION FORM

PROJECT NAME	: Brayton Point Generating Station
PROJECT MUNICIPALITY	: Somerset
PROJECT WATERSHED	: Mount Hope Bay
EOEA NUMBER	: 14235
PROJECT PROPONENT	: USGen New England, Inc.
DATE NOTICED IN MONITOR	: April 23, 2008

Pursuant to the Massachusetts Environmental Policy Act (G. L. c. 30, ss. 61-62H) and Section 11.06 of the MEPA regulations (301 CMR 11.00), I determine that this project **does not require** the preparation of an Environmental Impact Report (EIR).

While the project will provide a significant benefit to the Mount Hope Bay marine environment, the proponent will be required to demonstrate that the project, in conjunction with other air emissions at the facility, will not cause or significantly contribute to exceedance of National Ambient Air Quality Standards (NAAQS) for any air pollutant. I note that the Department of Environmental Protection's (MassDEP) comment letter identifies a number of technical issues that must be addressed in order to assess the projects air quality impacts for MassDEP's permitting purposes. I am confident that MassDEP's rigorous, ongoing review will adequately address these remaining air quality impacts.

As described in the Environmental Notification Form, the proposed project consists of a retrofit to Brayton Point Station's existing open-cycle cooling system with a closed-cycle cooling system to comply with heat and flow limits specified in the October 2003 final National Pollutant Discharge Elimination System (NPDES) permit issued by the United States Environmental Protection Agency. The closed-cycle cooling system will consist of two natural draft cooling towers and supporting equipment.

The Brayton Point Station site consists of approximately 250 acres of land on Brayton Point, a peninsula in Somerset. The site is bordered by the Lee River to the west, the Taunton River to the east, a residential neighborhood and U.S. 195 to the north, and Mount Hope Bay to the south. This existing industrial facility, which has been operating since the 1960's, generates approximately 1,600 megawatts (MW) of power. It consists of boilers and associated air pollution control systems, including emission stacks. An Ash Reduction Process (ARP) enables the proponent to recycle 100% of the fly ash created. Coal ash is re-burned to produce a high quality ash with low carbon content that can be used as a replacement of Portland cement in the production of concrete. The facility includes a coal pile, a pier for barge deliveries, storage domes, an electrical distribution system, a stormwater treatment system, wastewater treatment system, access roads and parking lots.

Permits and Jurisdiction

The project is subject to environmental review pursuant to Section 11.03 (1)(b)(2), Section 11.03 (3)(b)(1)(e) and Section 11.03 (8)(b)(2) because it requires a state permit and consists of the creation of five or more acres of impervious land, the new fill or structure or Expansion of existing fill or structure in a velocity zone or regulated floodway, and the modification of an existing major stationary source resulting in a "significant net increase" in actual emissions of greater than 15 tons per year (tpy)of particulate matter (PM) as PM10. The project requires a Major Comprehensive Air Plan Approval, a Wastewater Treatment System Plan Approval, a modification to the Chapter 91 License, and a 401 Water Quality Certification from the MassDEP and Federal Coastal Zone Consistency Review from the Office of Coastal Zone Management (CZM). The project will also require an Order of Conditions from the Somerset Conservation Commission (and a Superseding Order of Conditions from the MassDEP if the local Order is appealed), a Federal Aviation Administration (FAA) Notification, a Prevention of Significant Deterioration (PSD) Permit from the US Environmental Protection Agency (EPA) and a Section 10/404 Permit from the Army Corps of Engineers (ACOE).

The proponent is not seeking financial assistance from the Commonwealth. Therefore, MEPA jurisdiction applies to those aspects of the project within the subject matter of required permits with the potential to cause Damage to the Environment. In this case, MEPA jurisdiction extends to air quality, water quality, tidelands, land and wetlands.

Water Quality and Habitat

Brayton Point is the largest industrial discharger to Mount Hope Bay. The station currently withdraws a total of approximately one billion gallons of water from the Taunton River and/or the Lee River intake structures and circulates it through the facility to condense the steam used to produce electricity. The water is then discharged back to the Bay at elevated temperatures of up to 95° Fahrenheit.

The NPDES permit for Brayton Point has been the subject of review by EPA, MassDEP, the Rhode Island Department of Environmental Management, Coastal Zone Management, the Division of Marine Fisheries (Marine Fisheries), Conservation Law Foundation, Save the Bay and many other state and federal agencies and public advocacy groups. EPA, in close coordination with MassDEP the RI Department of Environmental Management, issued a NPDES permit to ensure compliance with state and federal water quality standards and address the facility's impact on Mount Hope Bay. The decision established limitations on the volume, temperature and composition of the discharge, and established monitoring and reporting requirements. The permit does not authorize continued use of "once-through" cooling water and is based on the assumption that the facility would convert to closed-cycle and use mechanical-draft cooling tower technology to meet the permit's flow and heat load allowances. The volume of water and generation of waste heat will be reduced by over 95%.

The cessation of once-through cooling will ensure that Brayton Point will no longer withdraw and discharge nearly one billion gallons of water per day from Mount Hope Bay, greatly reducing the entrainment and impingement impacts on fish and other aquatic life, in addition to alleviating impacts associated with discharging large quantities of heat to the Bay. These changes are expected to help restore important estuarine habitat in the bay.

It is well established and documented that the Mount Hope Bay and the Taunton River provide valuable habitat for a diverse assemblage of finfish and invertebrates. The cooling process will result in the evaporation of 9,000 to 14,000 gallons of Taunton River water per minute. Marine Fisheries has raised concerns that the plume drift over nearby salt marshes could at times cause a high salinity precipitate adversely impacting these resource areas.
In addition, the salinity of the discharge waters will increase up to 1.5 times that of the ambient intake waters. The proponent should consult with Marine Fisheries to address the concerns raised in its comment letter.

Wetlands

Because Brayton Point is surrounded by the Lee and Taunton Rivers, much of the site may be included within the Riverfront Protection Area (RPA). The facility has been committed to this industrial use since the 1960s. The impacts to wetlands are limited to modification of discharge structures on site. Approximately 19,000 square feet of Land Under the Ocean, 300 linear feet of Coastal Bank, Designated Port Area, and Riverfront Area will be impacted. The site is also proximate to Salt Marsh, Coastal Beach, Land Containing Shellfish, and Bordering Vegetated Wetland. There were no plans available in the ENF to determine whether the extent of construction proposed would alter these areas.

The ENF indicates that compliance with the Stormwater Management Standards effective in January 2008 will be affected. Structures associated with and essential to an electric generating facility may be permitted pursuant to 310 CMR 10.24(7)(a)(5). I note that that those portions of the project subject to jurisdiction under Chapter 91 are exempt from the Riverfront Area requirements pursuant to 310 CMR 10.58(6)(i).

I advise the proponent that any Notice of Intent or 401 Water Quality Certification application submitted to MassDEPs' Wetlands Program must include plans illustrating the wetlands resource areas and details of the proposed construction and any temporary and/or permanent impacts to the each wetland resource; a narrative and plans showing how wetlands impacts have been avoided or minimized, as well as mitigation measures that are proposed to be taken; and detailed analyses, plans and calculations for compliance with Stormwater Management Standards.

Waterways

The project site is located within a Designated Port Area within the Town of Somerset. As indicated within the ENF, submittal of a Chapter 91 Waterways License application for a water-dependent use, as defined at 310 CMR 9.12, is required for this project. I note that any application submitted to the Chapter 91 Waterways Program shall include historic documentation, including copies of authorizations and/or licenses together with their accompanying plans, as further described pursuant to 310 CMR 9.11(3)(b) and (c). I advise the proponent to contact MassDEP's Waterways Program to address the Chapter 91 required material.

Air Quality

The ENF indicates that actual emissions would increase by 15 tons per year (tpy) of particulate matter (PM) as PM10. MassDEP has noted in its detailed comment letter that the potential emissions of 379 tons/year of PM 10 and PM2.5 may need to be permitted which could result in PM10 and PM2.5 actual emissions to be far in excess of 15 tons/year.

MassDEP agrees that currently there is uncertainty on how the potential PM2.5 and PM10 emissions will be predicted and how compliance with the future PM10 emission limit will be demonstrated. In consideration of this uncertainty, the proponent must provide in the plan approval application, to be submitted to MassDEP, information supporting the use of the ENF referenced methodology. The plan approval application will need to address, as a minimum, the following: copies of peer reviews on the calculation methodology; identification of projects that utilized this calculation methodology in air quality permitting and project(s) current status; a summary of available PM10 and PM2.5 stack (tower) emission test data in comparison to predicted emissions based on the referenced methodology; and proposed stack (tower) emission test method(s) and monitoring, including water droplet size distribution of the drift exiting the towers, to document compliance with PM10 and PM2.5 proposed emission limits developed utilizing the referenced calculation methodology.

I note that on a related matter concerning PM10 and PM2.5 emissions, Brayton Point Station will include additional modifications to Unit 3, a 633 MW net coal fired boiler, in the cooling tower plan approval application that must be submitted to MassDEP. The modifications will consist of the construction of spray dryer absorber (SDA) and fabric filter (FF) for the control of acid gases and particulate. This action may be subject to a Notice of Project Change from the MEPA Office for a previously submitted ENF (EEA No. 13022). The SDA/FF is likely to cause a net emission increase of potential PM emissions.

The ENF indicates that modeling will be performed to document that the project will not cause or significantly contribute to the violation of National Ambient Air Quality Standards (NAAQS) for any air pollutant. Condensed water vapor from the cooling towers will cause a visible exhaust plume and depending on weather conditions the condensed water vapor may cause ground level fogging or icing. MassDEP has stated in its comment letter that fogging and icing impacts are mitigated through the use of natural draft towers, which are much taller than mechanical draft cooling towers and reduce the likelihood of condensed water vapor reaching ground level.

A Major Comprehensive Plan Application (CPA) Approval will be required base upon a potential emission rate of 379 tons/year of PM10 and PM2.5. As indicated the CPA will need to include a demonstration of compliance with NAAQS, application of Best Available Control Technology (BACT) for particulate matter, and a demonstration of compliance with the MassDEP's noise policy.

Visual/Historic

As a general matter, the cooling towers will have significant visual impacts to the immediate area. I strongly encourage the proponent to implement all feasible means of minimizing and mitigating these impacts.

The Massachusetts Historical Commission (MHC) will be reviewing the project as a consulting party in compliance with Section 106 of the National Historic Preservation Act of 1966 as amended (36 CFR 800). MHC requests that the proponent undertake a visual effect study to evaluate the visual effects of the project on the character and setting of historic properties and historic districts in the visual area of potential effect for the project. Prior to undertaking this study, the proponent should consult with the Lead Federal Agency, which should notify the MHC and other consulting parties directly to consult on determining an appropriate study area and the methods and scope for the visual effect study (36 CFR 800.4(a)).

Conclusion

The ENF and ongoing permit processes have disclosed the potential impacts and proposed mitigation in detail; these issues are subject to ongoing review under local, state and federal permitting processes. Based on a review of the information provided in the ENF and consultation with relevant public agencies, I find that the potential impacts of this project do not warrant the preparation of an EIR.

May 23, 2008
Date

Ian A. Bowles

Comments Received:

04/24/08	Massachusetts Aeronautics Commission (forwarded by K. Lesser, Epsilon)
04/25/08	Russell Castonguay
05/08/08	Petition from the Mount Hope Condominium Resident Association
05/09/08	MA Office of Coastal Zone Management
05/12/08	Mass Audubon and the Taunton River Watershed

Comments Received(continued):

05/13/08	Department of Environmental Protection SERO
05/13/08	Division of Marine Fisheries
05/16/08	Massachusetts Historical Commission

IAB/ACC/acc

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October 10, 2008

CERTIFICATE OF THE SECRETARY OF ENERGY AND ENVIRONMENTAL AFFAIRS
ON THE
NOTICE OF PROJECT CHANGE

PROJECT NAME	: Brayton Point Generating Station Air Pollution Control Project
PROJECT MUNICIPALITY	: Somerset
PROJECT WATERSHED	: Mount Hope Bay
EOEA NUMBER	: 13022
PROJECT PROPONENT	: Dominion Energy Brayton Point, LLC
DATE NOTICED IN MONITOR	: September 10, 2008

Pursuant to the Massachusetts Environmental Policy Act (M.G.L. c. 30, ss. 61-62I) and Section 11.10 of the MEPA Regulations (301 CMR 11.00), I have reviewed the Notice of Project Change (NPC) submitted for this project and hereby determine that it **does not require** further MEPA review.

Project Description

The original project, described in the Environmental Notification Form (ENF) submitted in April 2003, consists of an air pollution control program to comply with 310 CMR 7.29 Emissions Standards for Power Plants, which were promulgated on May 11, 2001. The regulations require significant reductions in Nitrogen Oxides (NO_X), Sulfur Dioxide (SO_2), Carbon Dioxide (CO_2) and Mercury (Hg) emissions from the oldest power plants operating in the state. The purpose of the regulations is to bring these facilities in line with emission standards for newer plants and decrease the environmental and health impacts of power generation by reducing the pollutants that contribute to acid rain, regional haze, mercury emissions and global climate change. The ENF indicated that the project would reduce actual NO_X emissions by approximately 60%, from 12,976 tons per year (tpy) to 5,372 tpy, SO_2 emissions by approximately 50%, from 42,521 tpy to 23,988 tpy, Carbon Monoxide (CO) emissions by 4 tpy, and Sulfuric Acid Mist (H_2SO_4) by 15 tpy.[1] In addition, it indicated that the project would reduce Hg emissions by 88 pounds per year to 127 pounds per year. The May 22, 2003 Secretary's Certificate on the ENF did not require further MEPA review.

Project Change

As described in the NPC, the project change consists of a change in the proposed SO_2 emission controls on Unit 3, a 633 megawatt (MW) net coal fired boiler. The proposed wet flue gas desulfurization (FGD) will be replaced with a dry scrubber consisting of Spray Dryer Absorber (SDA) and a fabric filter, similar to the technology used for Units 1 and 2.

Project Site

The Brayton Point Station site consists of approximately 250 acres of land on Brayton Point, a peninsula in Somerset. The site is bordered by the Lee River to the west, the Taunton River to the east, a residential neighborhood and U.S. 195 to the north, and Mount Hope Bay to the south. This existing industrial facility, in operation since the 1960's, generates approximately 1,600 MW of power. It consists of three boilers fired primarily by coal and one boiler fired by fuel oil and natural gas (Units 1, 2, 3 and 4 respectively), and associated air pollution control systems, including four emission stacks.

Procedural History

Since the filing of the ENF, a NPC and subsequently an ENF for a related project were filed with MEPA. In February 2006, the first NPC was filed disclosing wetlands impacts associated with the installation of 1.8 miles of water main and describing an Amendment to the Emission Control Plan (ECP). The water main will transfer treated gray water from the Somerset publicly owned treatment works (POTW) to meet increased water demand. The NPC identified temporary impacts to 38,144 square feet (sf) of bordering vegetated wetlands (BVW). The ECP Amendment identified installation of Hg emission control equipment and additional SO_2 reduction equipment. The NPC indicated that Powder Activated Carbon (PAC) injection systems would be installed on Units 1, 2 and 3 to reduce Hg emissions and SDA technology would be installed on Units 1 and 2 to reduce SO_2 emissions. The March 24, 2006 Secretary's Certificate on the NPC did not require additional MEPA review.

In April 2008, an ENF (EEA #14235) was filed for the replacement of the Brayton Point Station's open-cycle cooling system with a closed-cycle cooling system to comply with the heat and flow limits specified in the October 2003 final National Pollutant Discharge Elimination System (NPDES) permit issued by the United States Environmental Protection Agency (EPA).

[1] These projections are based on past actual emissions for all units from the 2000-2001 baseline.

The proposed system includes two natural draft cooling towers and supporting equipment. The review of this ENF also identified modifications to the Unit 3 coal fired boiler that required the filing of another NPC related to the Air Pollution Control Project. The Secretary's Certificate on this ENF (EEA #14235), issued on May 23, 2008, did not require additional MEPA review; however, it did note that a second NPC should be filed for the Air Pollution Control Project to disclose and describe modifications to Unit 3.

Review of the NPC

With the exception of Unit 3, all of the air pollution controls described in the August 2008 ENF and the February 2006 NPC have been installed. As noted previously, the proposed wet flue gas desulfurization (FGD) proposed for Unit 3 will be replaced with a dry scrubber consisting of SDA and a fabric filter, similar to the technology used for Units 1 and 2. The project change will reduce SO_2 emissions for Unit 3 by 90%, will reduce water demand by 885,000 gallons per day (gpd) to 1,595,000 gpd, will reduce wastewater generation by 592,600 gallons per day (gpd) to approximately 1,000 gpd and eliminates the need for construction of a 500-foot tall emissions stack.

Applications submitted to MassDEP pursuant to 310 CMR 7.02(5) and 7.029(6) are under review. Comments from MassDEP indicate that the proposed project changes are minor in comparison to the overall pollution control project and that both SO_2 and particulate emissions will be substantially reduced as a result of the project change, including a 50% reduction in particulate emissions. Also, these comments note that MassDEP will accept public comments on the proposed changes prior to issuing a determination on the applications.

Permitting and Jurisdiction

The original project is subject to environmental review pursuant to Section 11.03 (8)(b)(2) because it requires a state permit and consists of a modification of an existing major stationary source resulting in a "significant net increase" in actual emissions of greater than 15 tpy of particulate matter (PM) as PM_{10}. In this case, the increase in PM_{10} is not a result of the combustion process but, rather, a byproduct of the air pollution control equipment that will be installed to achieve significant reductions in NO_x and SO_2. The original project and previous project changes required a Major Comprehensive Air Plan Approval and a 401 Water Quality Certificate from MassDEP and review of its National Pollutant Discharge Elimination System (NPDES) permit from EPA. Also, it required an Order of Conditions from the Somerset Conservation Commission (issued on January 23, 2006).

The project change requires a Modified Major Comprehensive Air Plan Approval and Modified Emission Control Plan from MassDEP. Also, it requires a Prevention of Significant Deterioration (PSD) Permit from EPA.

The proponent is not seeking financial assistance from the Commonwealth. Therefore, MEPA jurisdiction applies to those aspects of the project within the subject matter of required permits with the potential to cause Damage to the Environment as defined in the MEPA regulations. In this case, MEPA jurisdiction extends to air quality, water quality and wetlands.

Conclusion

As noted above, the project change described in the NPC will reduce environmental impacts including SO_2 and particulate emissions. Based on a review of the information provided in the NPC and consultation with relevant public agencies, I find that the potential impacts of this project do not warrant the preparation of a Environmental Impact Report (EIR). Therefore, no further MEPA review is required.

October 10, 2008
Date

Ian A. Bowles

Comments Received:

9/30/08	Department of Environmental Protection/Southeast Regional Office (MassDEP/SERO)
9/29/08	Division of Marine Fisheries

IAB/CDB/cdb

APPENDIX K

EPA RACT/BACT/LAER Clearinghouse Data

	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P	Q	R	S	T	U	V
1	RBLCID	FACILITYNAME	PERMIT DATE	FACILITYDESCRIPTION	OTHERPERMITTINGINFORMATION	PROCESSNAME	FUEL	THRUPUT	THRUPUTUNIT	PROCESSNOTES	POLLUTANT	CTRLDESC	EMIS LIMIT1	EMIS LIMIT1 UNIT	EMIS LIMIT1 AVGTIME CONDITION	EMISLIMIT2	EMISLIMIT2UNIT	EMISLIMIT2AVGTIMECONDITION	STDEMISSLIMIT	STDUNITLIMIT	STDLIMITAVGTIMECONDITION	POLLUTANT COMPLIANCE NOTES
2	VA-0311	VIRGINIA CITY HYBRID ENERGY CENTER	6/30/2008	ELECTRIC POWER GENERATING FACILITY	HEAT INPUT TO EACH CFB BOILER SHALL NOT EXCEED 27,436,320 MMBTU/YR; AUXILIARY BOILER SHALL OPERATE NO MORE THAN 4,000 HR/YR; FIE PUMP AND GENERATOR ENGINES SHALL OPERATE NO MORE THAN 100 HR/YR, EACH; THROUGHPUT OF BIOMASS TO EACH CFB BOILER SHALL NOT EXCEED 685,000 TONS/YR; SULFUR CONTENT OF COAL/COAL REFUSE TO CFB BOILERS NOT TO EXCEED 2.28% AS-FIRED AND 1.5% ON ANNUAL BASIS; SULFUR CONTENT OF DIESEL FUEL TO AUX BOILER AND EACH ENGINE NOT TO EXCEED 0.0015%. CFB BOILER LIMITS: PM: 246.92 TONS/YR, PM-10: 329.24 TONS/YR, PM-2.5: 329.24 TONS/YR, SO2: 603.6 TONS/YR, NOX: 1,920.54 TONS/YR, CO: 4,115.45 TONS/YR, VOC: 137.18 TONS/YR, SULFURIC ACID MIST: 96.03 TONS/YR, HF: 12.90 TONS/YR, HCL: 181.07 TONS/YR. AUXILIARY BOILER LIMITS: PM-10: 9.12 TONS/YR, PM-2.5: 9.12 TONS/YR, SO2: 76.76 TONS/YR, NOX: 45.60 TONS/YR, CO: 15.20 TONS/YR, VOC: 1.52 TONS/YR. EMERGENCY GENERATOR ENGINE LIMITS: NOX: 1.43 TONS/YR, CO: 1.43 TONS/YR. FIRE PUMP ENGINE LIMITS: NOX PLUS VOC: 3.17 TONS/YR, CO: 1.72 TONS/YR. COAL RECLAIM/LIMESTONE UNLOADING/EACH STORAGE SILO LIMITS: PM: 1.88 TONS/YR, PM-10: 1.66 TONS/Y	2 CIRCULATING FLUIDIZED BED BOILERS	COAL AND COAL REFUSE	3132	MMBTU/H	EMISSIONS ARE FOR ONE OF TWO UNITS	Particulate Matter (PM), Filterable	GOOD COMBUSTIONS PRACTICES AND BAGHOUSE	0.01	LB/MMBTU	3 HOURS	0.009	LB/MMBTU	30 DAY ROLLING AVERAGE				EMISSIONS ARE FOR 1 OF 2 BOILERS
3	VA-0311	VIRGINIA CITY HYBRID ENERGY CENTER	6/30/2008	ELECTRIC POWER GENERATING FACILITY	HEAT INPUT TO EACH CFB BOILER SHALL NOT EXCEED 27,436,320 MMBTU/YR; AUXILIARY BOILER SHALL OPERATE NO MORE THAN 4,000 HR/YR; FIE PUMP AND GENERATOR ENGINES SHALL OPERATE NO MORE THAN 100 HR/YR, EACH; THROUGHPUT OF BIOMASS TO EACH CFB BOILER SHALL NOT EXCEED 685,000 TONS/YR; SULFUR CONTENT OF COAL/COAL REFUSE TO CFB BOILERS NOT TO EXCEED 2.28% AS-FIRED AND 1.5% ON ANNUAL BASIS; SULFUR CONTENT OF DIESEL FUEL TO AUX BOILER AND EACH ENGINE NOT TO EXCEED 0.0015%. CFB BOILER LIMITS: PM: 246.92 TONS/YR, PM-10: 329.24 TONS/YR, PM-2.5: 329.24 TONS/YR, SO2: 603.6 TONS/YR, NOX: 1,920.54 TONS/YR, CO: 4,115.45 TONS/YR, VOC: 137.18 TONS/YR, SULFURIC ACID MIST: 96.03 TONS/YR, HF: 12.90 TONS/YR, HCL: 181.07 TONS/YR. AUXILIARY BOILER LIMITS: PM-10: 9.12 TONS/YR, PM-2.5: 9.12 TONS/YR, SO2: 76.76 TONS/YR, NOX: 45.60 TONS/YR, CO: 15.20 TONS/YR, VOC: 1.52 TONS/YR. EMERGENCY GENERATOR ENGINE LIMITS: NOX: 1.43 TONS/YR, CO: 1.43 TONS/YR. FIRE PUMP ENGINE LIMITS: NOX PLUS VOC: 3.17 TONS/YR, CO: 1.72 TONS/YR. COAL RECLAIM/LIMESTONE UNLOADING/EACH STORAGE SILO LIMITS: PM: 1.88 TONS/YR, PM-10: 1.66 TONS/Y	2 CIRCULATING FLUIDIZED BED BOILERS	COAL AND COAL REFUSE	3132	MMBTU/H	EMISSIONS ARE FOR ONE OF TWO UNITS	Particulate Matter < 10 ? (PM10)	GOOD COMBUSTION PRACTICES AND BAGHOUSE	0.012	LB/MMBTU	3 HOURS	0.012	LB/MMBTU	3 HOURS				EMISSIONS ARE FOR 1 OF 2 BOILERS
4	VA-0311	VIRGINIA CITY HYBRID ENERGY CENTER	6/30/2008	ELECTRIC POWER GENERATING FACILITY	HEAT INPUT TO EACH CFB BOILER SHALL NOT EXCEED 27,436,320 MMBTU/YR; AUXILIARY BOILER SHALL OPERATE NO MORE THAN 4,000 HR/YR; FIE PUMP AND GENERATOR ENGINES SHALL OPERATE NO MORE THAN 100 HR/YR, EACH; THROUGHPUT OF BIOMASS TO EACH CFB BOILER SHALL NOT EXCEED 685,000 TONS/YR; SULFUR CONTENT OF COAL/COAL REFUSE TO CFB BOILERS NOT TO EXCEED 2.28% AS-FIRED AND 1.5% ON ANNUAL BASIS; SULFUR CONTENT OF DIESEL FUEL TO AUX BOILER AND EACH ENGINE NOT TO EXCEED 0.0015%. CFB BOILER LIMITS: PM: 246.92 TONS/YR, PM-10: 329.24 TONS/YR, PM-2.5: 329.24 TONS/YR, SO2: 603.6 TONS/YR, NOX: 1,920.54 TONS/YR, CO: 4,115.45 TONS/YR, VOC: 137.18 TONS/YR, SULFURIC ACID MIST: 96.03 TONS/YR, HF: 12.90 TONS/YR, HCL: 181.07 TONS/YR. AUXILIARY BOILER LIMITS: PM-10: 9.12 TONS/YR, PM-2.5: 9.12 TONS/YR, SO2: 76.76 TONS/YR, NOX: 45.60 TONS/YR, CO: 15.20 TONS/YR, VOC: 1.52 TONS/YR. EMERGENCY GENERATOR ENGINE LIMITS: NOX: 1.43 TONS/YR, CO: 1.43 TONS/YR. FIRE PUMP ENGINE LIMITS: NOX PLUS VOC: 3.17 TONS/YR, CO: 1.72 TONS/YR. COAL RECLAIM/LIMESTONE UNLOADING/EACH STORAGE SILO LIMITS: PM: 1.88 TONS/YR, PM-10: 1.66 TONS/Y	2 CIRCULATING FLUIDIZED BED BOILERS	COAL AND COAL REFUSE	3132	MMBTU/H	EMISSIONS ARE FOR ONE OF TWO UNITS	Particulate Matter < 2.5 ? (PM2.5)	GOOD COMBUSTION PRACTICES AND BAGHOUSE	0.012	LB/MMBTU	3 HOURS	0.012	LB/MMBTU	3 HOURS				EMISSIONS ARE FOR 1 OF 2 BOILERS

	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P	Q	R	S	T	U	V
1	RBLCID	FACILITYNAME	PERMIT DATE	FACILITYDESCRIPTION	OTHERPERMITTINGINFORMATION	PROCESSNAME	FUEL	THRUPUT	THRUPUTUNIT	PROCESSNOTES	POLLUTANT	CTRLDESC	EMIS LIMIT1	EMIS LIMIT1 UNIT	EMIS LIMIT1 AVGTIME CONDITION	EMISLIMIT2	EMISLIMIT2UNIT	EMISLIMIT2AVGTIMECONDITION	STDEMISSLIMIT	STDUNITLIMIT	STDLIMITAVGTIMECONDITION	POLLUTANT COMPLIANCE NOTES
5	LA-0148	ACTIVATED CARBON FACILITY	5/28/2008	THE FACILITY WILL USE COAL AS A FEEDSTOCK TO MANUFACTURE ROUGHLY 350 MILLION POUNDS OF ACTIVATED CARBON (AC) PER YEAR.		MULTIPLE HEARTH FURNACES / AFTERBURNERS	COAL	7.78	LB/YR E+08	4 MULTI-HEARTH FURNACES. PROCESSES LIGNITE COAL. ALSO COMBUSTS 13.2 MM BTU /HR NATURAL GAS TO BALANCE HEAT LOADS.	Particulate Matter < 10 ? (PM10)	CYCLONE, AFTERBURNER, SDA SYSTEM AND FABRIC FILTER BAGHOUSE	48.3	LB/H	3-HOUR							
6	VA-0309	GEORGIA PACIFIC WOOD PRODUCTS - JARRATT	5/15/2008			KEELER BOILER	COAL	86.6	MMBTU/H	THE BOILER SHALL CONSUME NO MORE THAN 28,711 TONS OF COAL PER YEAR, CALCULATED MONTHLY AS THE SUM OF EACH CONSECUTIVE 12 MONTH PERIOD. COMPLIANCE FOR THE CONSECUTIVE 12 MONTH PERIOD SHALL BE DEMONSTRATED MONTHLY BY ADDING THE TOTAL FOR THE MOST RECENTLY COMPLETED CALENDAR MONTH TO THE INDIVIDUAL MONTHLY TOTALS FOR THE PRECEDING 11 MONTHS.	Particulate Matter (PM)	2 MULITCYCLONES AND GOOD COMBUSTION PRACTICES.	20	LB/H		88	T/YR					
7	VA-0309	GEORGIA PACIFIC WOOD PRODUCTS - JARRATT	5/15/2008			KEELER BOILER	COAL	86.6	MMBTU/H	THE BOILER SHALL CONSUME NO MORE THAN 28,711 TONS OF COAL PER YEAR, CALCULATED MONTHLY AS THE SUM OF EACH CONSECUTIVE 12 MONTH PERIOD. COMPLIANCE FOR THE CONSECUTIVE 12 MONTH PERIOD SHALL BE DEMONSTRATED MONTHLY BY ADDING THE TOTAL FOR THE MOST RECENTLY COMPLETED CALENDAR MONTH TO THE INDIVIDUAL MONTHLY TOTALS FOR THE PRECEDING 11 MONTHS.	Particulate Matter < 10 ? (PM10)	TWO MULTICYCLONES AND GOOD COMBUSTION PRACTICES.	14.5	LB/H		64	T/YR					
8	MO-0077	NORBORNE POWER PLANT	2/22/2008	TO CONSTRUCT A NEW SUPERCRITICAL PULVERIZED COAL-FIRED BOILER WITH RELATED MATERIAL HANDLING AND POLLUTION CONTROL EQUIPMENT AND A STEAM TURBINE GENERATOR WITH A NET ELECTRICAL OUTPUT OF 689 MEGAWATTS (780 MW GROSS OUTPUT).		MAIN BOILER	COAL	4E+06	T/YR	CONSTRUCT A NEW SUPERCRITICAL PULVERIZED COAL FIRED BOILER WITH A STEAM TURBINE GENERATOR WITH A NOMINAL NET ELECTRIC OUTPUT OF 689 MW.	Particulate Matter < 10 ? (PM10)	FABRIC FILTRATION SYSTEM (BAGHOUSE)	0.018	LB/MMBTU	3 HOURS ROLLING AVERAGE (TOTAL PAM10)	0.012	LB/MMBTU	3 HOURS ROLLING AVERAGE-FILTERABLE PM10				

	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P	Q	R	S	T	U	V
1	RBLCID	FACILITYNAME	PERMIT DATE	FACILITYDESCRIPTION	OTHERPERMITTINGINFORMATION	PROCESSNAME	FUEL	THRUPUT	THRUPUTUNIT	PROCESSNOTES	POLLUTANT	CTRLDESC	EMIS LIMIT1	EMIS LIMIT1 UNIT	EMIS LIMIT1 AVGTIME CONDITION	EMISLIMIT2	EMISLIMIT2UNIT	EMISLIMIT2AVGTIMECONDITION	STDEMISSLIMIT	STDUNITLIMIT	STDLIMITAVGTIMECONDITION	POLLUTANT COMPLIANCE NOTES
9	OH-0310	AMERICAN MUNICIPAL POWER GENERATING STATION	2/7/2008	TWO 5191 MMBTU/HOUR PULVERIZED COAL-FIRED BOILERS; ONE 150 MMBTU/HOUR NATURAL GAS AUXILIARY BOILER, ONE FLY ASH AND GYPSUM LANDFILL, COAL STORAGE, CRUSHERS, FERTILIZER PLANT, LIMESTONE AND FLY ASH HANDLING EQUIPMENT, AND COOLING CELLS	FUGITIVE EMISSIONS FROM STORAGE PILES (COAL,LIMESTONE, UREA), CONVEYING, HANDLING, ROADWAYS, BARGE OR TRUCK UNLOADING, EXCLUDING THE COAL CRUSHING OPERATIONS, WERE NOT ENTERED INTO THE DATABASE DUE TO THE INSIGNIFICANT EMISSIONS (MOST < 1 TON FUGITIVE PM) AND LACK OF PROCESS CODES TO ENTER THEM.	BOILER (2), PULVERIZED COAL FIRED	PULVERIZED COAL	5191	MMBTU/H	EACH BOILER 5191 MMBTU/HOUR WITH SELECTIVE CATALYTIC REDUCTION (SCR), BAGHOUSE, LIME OR NH3-BASED FLUE GAS DESULFURIZATION (FGD), AND WET ESP	Particulate Matter < 10 ? (PM10)	BAGHOUSE IN COMBINATION WITH A WET ELECTROSTATIC PRECIPITATOR (WESP)	129	LB/H	AS 3-HR AVERAGE	566	T/YR	PER ROLLING 12-MONTHS	HEAT INPUT, AS 3-HR AVERAGE	THESE LIMITS ARE FOR EACH OF 2 BOILERS; TOTAL EMISSIONS ARE TIMES 2.		
10	OH-0310	AMERICAN MUNICIPAL POWER GENERATING STATION	2/7/2008	TWO 5191 MMBTU/HOUR PULVERIZED COAL-FIRED BOILERS; ONE 150 MMBTU/HOUR NATURAL GAS AUXILIARY BOILER, ONE FLY ASH AND GYPSUM LANDFILL, COAL STORAGE, CRUSHERS, FERTILIZER PLANT, LIMESTONE AND FLY ASH HANDLING EQUIPMENT, AND COOLING CELLS	FUGITIVE EMISSIONS FROM STORAGE PILES (COAL,LIMESTONE, UREA), CONVEYING, HANDLING, ROADWAYS, BARGE OR TRUCK UNLOADING, EXCLUDING THE COAL CRUSHING OPERATIONS, WERE NOT ENTERED INTO THE DATABASE DUE TO THE INSIGNIFICANT EMISSIONS (MOST < 1 TON FUGITIVE PM) AND LACK OF PROCESS CODES TO ENTER THEM.	AUXILIARY BOILER	NATURAL GAS	150	MMBTU/H		Particulate Matter < 10 ? (PM10)		1.14	LB/H		0.5	T/YR	PER ROLLING 12-MONTHS				
11																						
12	OH-0314	SMART PAPERS HOLDINGS, LLC	1/31/2008	PAPER PRODUCTION, COATED AND UNCOATED PAPER PRODUCTS	THIS IS A PDS MODIFICATION TO TWO EXISTING BOILERS, TO INCREASE THEIR OPERATING HOURS, PRODUCE STEAM FOR THE PLANT, AND GENERATE MORE ELECTRICITY TO SELL TO THE POWER GRID. 429 MMBTU/H PULVERIZED COAL BOILER INSTALLED IN 1928. 249 MMBTU/H SPREADER STOKER COAL-FIRED BOILER INSTALLED IN 1975. OLD BOILERS INCREASING OPERATING HOURS. THE DAILY AVERAGE OPERATING RATE FOR BOTH BOILERS IS NOT TO EXCEED 603 MMBTU/H.	PULVERIZED DRY BOTTOM BOILER	COAL	420	MMBTU/H	EXISTING BOILER INSTALLED 1928, INCREASING USE TO PRODUCE STEAM FOR THE FACILITY AND TO SELL ELECTRICITY TO THE POWER GRID. COGENERATION PROJECT AT FACILITY. NUMBER 2 FUEL OIL BURNERS FOR SUPPLEMENTAL FIRING. RESTRICTED TO 219,000 MWHOURS ELECTRIC OUTPUT ON A GROSS BASIS. TOTAL COMBINED DAILY AVERAGE OPERATING RATE FOR BOTH BOILERS SHALL NOT EXCEED 603 MMBTU/HR	Particulate Matter (PM)		0.11	LB/MMBTU					0.11	LB/MMBTU		OLD BOILER, NO CONTROLS
13	OH-0314	SMART PAPERS HOLDINGS, LLC	1/31/2008	PAPER PRODUCTION, COATED AND UNCOATED PAPER PRODUCTS	THIS IS A PDS MODIFICATION TO TWO EXISTING BOILERS, TO INCREASE THEIR OPERATING HOURS, PRODUCE STEAM FOR THE PLANT, AND GENERATE MORE ELECTRICITY TO SELL TO THE POWER GRID. 429 MMBTU/H PULVERIZED COAL BOILER INSTALLED IN 1928. 249 MMBTU/H SPREADER STOKER COAL-FIRED BOILER INSTALLED IN 1975. OLD BOILERS INCREASING OPERATING HOURS. THE DAILY AVERAGE OPERATING RATE FOR BOTH BOILERS IS NOT TO EXCEED 603 MMBTU/H.	SPREADER STOKER COAL-FIRED BOILER	COAL	249	MMBTU/H	EXISTING BOILER INSTALLED 1975, INCREASING USE TO PRODUCE STEAM FOR THE FACILITY AND TO SELL ELECTRICITY TO THE POWER GRID. COGENERATION PROJECT AT FACILITY. TOTAL COMBINED DAILY AVERAGE OPERATING RATE FOR BOTH BOILERS SHALL NOT EXCEED 603 MMBTU/HR	Particulate Matter (PM)		0.11	LB/MMBTU					0.11	LB/MMBTU		

	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P	Q	R	S	T	U	V
1	RBLCID	FACILITYNAME	PERMIT DATE	FACILITYDESCRIPTION	OTHERPERMITTINGINFORMATION	PROCESSNAME	FUEL	THRUPUT	THRUPUTUNIT	PROCESSNOTES	POLLUTANT	CTRLDESC	EMISLIMIT1	EMIS LIMIT1 UNIT	EMIS LIMIT1 AVGTIME CONDITION	EMISLIMIT2	EMISLIMIT2UNIT	EMISLIMIT2AVGTIMECONDITION	STDEMISSLIMIT	STDUNITLIMIT	STDLIMITAVGTIMECONDITION	POLLUTANT COMPLIANCE NOTES
14	OH-0314	SMART PAPERS HOLDINGS, LLC	1/31/2008	PAPER PRODUCTION, COATED AND UNCOATED PAPER PRODUCTS	THIS IS A PDS MODIFICATION TO TWO EXISTING BOILERS, TO INCREASE THEIR OPERATING HOURS, PRODUCE STEAM FOR THE PLANT, AND GENERATE MORE ELECTRICITY TO SELL TO THE POWER GRID. 429 MMBTU/H PULVERIZED COAL BOILER INSTALLED IN 1928. 249 MMBTU/H SPREADER STOKER COAL-FIRED BOILER INSTALLED IN 1975. OLD BOILERS INCREASING OPERATING HOURS. THE DAILY AVERAGE OPERATING RATE FOR BOTH BOILERS IS NOT TO EXCEED 603 MMBTU/H.	SPREADER STOKER COAL-FIRED BOILER	COAL	249	MMBTU/H	EXISTING BOILER INSTALLED 1975, INCREASING USE TO PRODUCE STEAM FOR THE FACILITY AND TO SELL ELECTRICITY TO THE POWER GRID. COGENERATION PROJECT AT FACILITY. TOTAL COMBINED DAILY AVERAGE OPERATING RATE FOR BOTH BOILERS SHALL NOT EXCEED 603 MMBTU/HR	Particulate Matter < 10 µ (PM10)		0.072	LB/MMBTU		77.2	T/YR					
15	*WY-0064	DRY FORK STATION	10/15/2007	ONE PC BOILER RATED A 385 MW (NET)		PC BOILER (ES1-01)	COAL				Particulate Matter < 10 µ (PM10)	FABRIC FILTER (BAGHOUSE)	0.012	LB/MMBTU	ANNUAL	45.6	LB/H	ANNUAL	199.8	T/YR	ANNUAL	
16	ND-0024	SPIRITWOOD STATION	9/14/2007	LIGNITE FIRED COMBINED HEAT AND POWER PLANT RATED AT A NOMINAL 99 MWE (NET) AND A MAXIMUM OF 112 MWE (GROSS). BOILER IS RATED AT 1280.		ATMOSPHERIC CIRCULATING FLUIDIZED BED BOILER	LIGNITE	1280	MMBTU/H	BENEFICIATED (DRIED) LIGNITE IS THE PRIMARY FUEL, RAW LIGNITE IS THE BACKUP.	Particulate Matter (PM), Organic Condensables	SPRAY DRYER AND BAGHOUSE	0.018	LB/MMBTU	3 HOUR							THE PERMIT ONLY LIMITS TOTAL PM10 (FILTERABLE AND CONDENSABLE) TO 0.030 LB/MMBTU. THE FILTERABLE PM10 LIMIT IS 0.012 LB/MMBTU AND THE MAXIMUM EXPECTED CONDENSABLE PM10 EMISSION RATE IS 0.018 LB/MMBTU.
17	ND-0024	SPIRITWOOD STATION	9/14/2007	LIGNITE FIRED COMBINED HEAT AND POWER PLANT RATED AT A NOMINAL 99 MWE (NET) AND A MAXIMUM OF 112 MWE (GROSS). BOILER IS RATED AT 1280.		ATMOSPHERIC CIRCULATING FLUIDIZED BED BOILER	LIGNITE	1280	MMBTU/H	BENEFICIATED (DRIED) LIGNITE IS THE PRIMARY FUEL, RAW LIGNITE IS THE BACKUP.	Particulate Matter (PM), Filterable	BAGHOUSE	0.015	LB/MMBTU	3 H				0.015	LB/MMBTU		
18	ND-0024	SPIRITWOOD STATION	9/14/2007	LIGNITE FIRED COMBINED HEAT AND POWER PLANT RATED AT A NOMINAL 99 MWE (NET) AND A MAXIMUM OF 112 MWE (GROSS). BOILER IS RATED AT 1280.		ATMOSPHERIC CIRCULATING FLUIDIZED BED BOILER	LIGNITE	1280	MMBTU/H	BENEFICIATED (DRIED) LIGNITE IS THE PRIMARY FUEL, RAW LIGNITE IS THE BACKUP.	Particulate Matter < 10 µ (PM10)	BAGHOUSE	0.012	LB/MMBTU	3 H							
19	*UT-0070	BONANZA POWER PLANT WASTE COAL FIRED UNIT	8/30/2007	110 MW WASTE COAL FIRED UNIT		CIRCULATING FLUIDIZED BED BOILER, 1445 MMBTU/HR WASTE COAL FIRED	WASTE COAL/ BITUMINOUS BLEND				Particulate Matter (PM)	PULSE-JET FABRIC FILTER BAGHOUSE	0.03	LB/MMBTU	24-HOUR BLOCK AVERAGE (12 AM TO 12 AM)							
20	*UT-0070	BONANZA POWER PLANT WASTE COAL FIRED UNIT	8/30/2007	110 MW WASTE COAL FIRED UNIT		CIRCULATING FLUIDIZED BED BOILER, 1445 MMBTU/HR WASTE COAL FIRED	WASTE COAL/ BITUMINOUS BLEND				Particulate Matter (PM), Filterable	PULSE-JET FABRIC FILTER BAGHOUSE	0.012	LB/MMBTU	24-HOUR BLOCK AVERAGE							
21	*UT-0070	BONANZA POWER PLANT WASTE COAL FIRED UNIT	8/30/2007	110 MW WASTE COAL FIRED UNIT		CIRCULATING FLUIDIZED BED BOILER, 1445 MMBTU/HR WASTE COAL FIRED	WASTE COAL/ BITUMINOUS BLEND				Particulate Matter < 10 µ (PM10)	PULSE-JET FABRIC FILTER BAGHOUSE	0.012	LB/MMBTU	24-HOUR BLOCK AVERAGE							

	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P	Q	R	S	T	U	V
1	RBLCID	FACILITYNAME	PERMIT DATE	FACILITYDESCRIPTION	OTHERPERMITTINGINFORMATION	PROCESSNAME	FUEL	THRUPUT	THRUPUTUNIT	PROCESSNOTES	POLLUTANT	CTRLDESC	EMIS LIMIT1	EMIS LIMIT1 UNIT	EMIS LIMIT1 AVGTIME CONDITION	EMISLIMIT2	EMISLIMIT2UNIT	EMISLIMIT2AVGTIMECONDITION	STDEMISSLIMIT	STDUNITLIMIT	STDLIMITAVGTIMECONDITION	POLLUTANT COMPLIANCE NOTES
22	FL-0295	CRYSTAL RIVER POWER PLANT	5/18/2007	EXISTING POWER PLANT CONSITS OF FOUR FFFSG UNITS, TWO NATURAL DRAFT COOLING TOWERS, THREE MECHANICAL COOLING TOWERS, COAL/ASH HANDLING FACILITIES, AND RELOACATABLE DIESEL FIRED GENRATORS.	OTHER POLLUTANT EMISSIONS: SAM 449 TPY PM10 68.3 TPY AIR FACILITY NO. 0170004 DESCRIPTION OF POLLUTANT ABATEMENT STRATEGY: AFTER CAIR/CAMR PROJECTS ARE COMPLETE FFFSG UNIT WILL HAVE: ESP (PM); SCR (NOX); WET FGD (SO2) , AND ALKALI INJECTION (SAM).	FFFSG UNITS 4 AND 5	COAL	760	MW	AS PART OF ITS CAIR/CAMR STRATEGY, THE FACILITY IS INSTALLING SCR AND WET FGD SYSTEMS ON UNITS 4 AND 5. TO TAKE FULL ADVANTAGE OF THESE CONTROLS, THE PROJECT INCLUDES AN INCREASE IN THE FUEL SULFUR CONTENT. THE FACILITY IS ALSO REQUIRED TO INSTALL ALKALI INJECTION ON THESE UNITS TO CONTROL SAME EMISSIONS. THE BACT LIMITS FOR UNITS 4 AND 5 ARE IDENTICAL.	Particulate Matter < 10 µ (PM10)	MODIFIED ESP (IMPROVEMENTS)	0.03	LB/MMBTU								ALTERNATIVE LIMIT: 216 LB/HR (STACK TEST)
23	*PA-0257	SUNNYSIDE ETHANOL,LLC	5/7/2007	THIS PA IS FOR A 88 MILLION GALLON PER YEAR ETHANOL PRODUCTION PLANT POWERED BY A 24.7 MW COAL FIRED COGENERATION PLANT. THE PLANT IS LOCATED AT CURWENSVILLE BOROUGH IN CLEARFIELD COUNTY.		CFB BOILER	COAL	496.8	MMBTU/H		Particulate Matter < 10 µ (PM10)	CYCLONE AND BAGHOUSE	0.01	LB/MMBTU	FILTERABLE	0.05	LB/MMBTU	CONDENSABLE				
24	OK-0118	HUGO GENERATING STA	2/9/2007	GENERATING STATION		COAL-FIRED STEAM EGU BOILER (HU-UNIT 2)		750	MW		Particulate Matter < 10 µ (PM10)	FABRIC FILTER BAGHOUSE	0.015	LB/MMBTU	FILTERABLE	0.025	LB/MMBTU	TOTAL				
25	WY-0063	WYGEN 3	2/5/2007	100 MW PULVERIZED COAL FIRED ELECTRIC UTILITY		PC BOILER	SUB-BITUMINOUS COAL	1300	MMBTU/H		Particulate Matter (PM), Filterable	BAGHOUSE	0.012	LB/MMBTU	3 X 120 MINUTE TEST							
26	TX-0491	MEADWESTVACO TEXAS LP PULP AND PAPER MILL	1/24/2007	THE SOURCE IS A LARGE WOOD-FIRED BOILER FOR STEAM PRODUCTION LOCATED IN A PULP AND PAPER MILL. THE STEAM IS USED FOR BOTH PROCESSES AND FOR ELECTRICAL PRODUCTION IN THE PLANT.	PSD-TX-785M6	NO. 6 POWER BOILER	SCRAP WOOD AND BARK			SEE FACILITY NOTES	Particulate Matter < 10 µ (PM10)	VENTURI WET SCRUBBER	0.1	LB/MMBTU								
27	TX-0489	SOUTHWESTERN PUBLIC SERVICE COMPANY-HARRINGTON STATION	10/17/2006	COAL-FIRED ELECTICAL GENERATING FACILITY		UNIT 3 BOILER	PBR COAL	3870	MMBtu/h	COAL-FIRED, TANGENTIALLY ARRANGED, 3,870 MMBTU/H BOILER USED TO PRODUCE STEAM TO DRIVE A 389 MW (DESIGN CAP.) ELECTRICAL GENERATOR.	Particulate Matter < 10 µ (PM10)	COAL CRUSHERS OPERATE AT BELOW ATMOSPHERIC PRESSURE WITH COAL DUST CONTROLLED	0.09	LB/MMBTU	1,520 T/YR							
28	NE-0041	AGP SOY PROCESSING	9/11/2006	SOY PROCESSING PLANT	PERMIT IS FOR 382 MMBTU CFB COAL-FIRED BOILER	STEAM GENERATION	COAL	382	MMBtu/H		Particulate Matter (PM)	GOOD COMBUSTION PRACTICES	0.041	LB/MMBTU								
29	NE-0041	AGP SOY PROCESSING	9/11/2006	SOY PROCESSING PLANT	PERMIT IS FOR 382 MMBTU CFB COAL-FIRED BOILER	STEAM GENERATION	COAL	382	MMBtu/H		Particulate Matter (PM), Filterable	FABRIC FILTER	0.015	LB/MMBTU								

	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P	Q	R	S	T	U	V
1	RBLCID	FACILITYNAME	PERMIT DATE	FACILITYDESCRIPTION	OTHERPERMITTINGINFORMATION	PROCESSNAME	FUEL	THRUPUT	THRUPUTUNIT	PROCESSNOTES	POLLUTANT	CTRLDESC	EMIS LIMIT1	EMIS LIMIT1 UNIT	EMIS LIMIT1 AVGTIME CONDITION	EMISLIMIT2	EMISLIMIT2UNIT	EMISLIMIT2AVGTIMECONDITION	STDEMISSLIMIT	STDUNITLIMIT	STDLIMITAVGTIMECONDITION	POLLUTANT COMPLIANCE NOTES
30	WV-0024	WESTERN GREENBRIER CO-GENERATION, LLC	4/26/2006	NOMINAL 98 NET MEGAWATT WASTE COAL-FIRED STEAM ELECTRIC CO-GENERATION FACILITY. BOILER IS CFB TECHNOLOGY. FACILITY INCLUDES KILN TO PRODUCE CEMENTITIOUS MATERIAL FROM ASH GENERATED IN BOILER.	CURRENTLY UNDER APPEAL	CIRCULATING FLUIDIZED BED BOILER (CFB)	WASTE COAL	1070	mmbtu/h	NOMINAL 1,070 MMBTU WASTE-COAL FIRED CFB. MAXIMUM COAL THROUGHPUT AT WORST-CASE FUEL SCENARIO IS 157 TPH. ANNUAL HEAT INPUT SHALL NOT EXCEED 8,908,920 MMBTU. SULFUR AND ASH CONTENTS SHALL NOT EXCEED 1.47% AND 63.71%, RESPECTIVELY.	Particulate Matter (PM)	BAGHOUSE	0.03	LB/MMBTU	30-DAY				0.03	LB/MMBTU	30-DAY	TOTAL PARTICULATE (FILTERABLE + CONDENSIBLE)
31	WV-0024	WESTERN GREENBRIER CO-GENERATION, LLC	4/26/2006	NOMINAL 98 NET MEGAWATT WASTE COAL-FIRED STEAM ELECTRIC CO-GENERATION FACILITY. BOILER IS CFB TECHNOLOGY. FACILITY INCLUDES KILN TO PRODUCE CEMENTITIOUS MATERIAL FROM ASH GENERATED IN BOILER.	CURRENTLY UNDER APPEAL	CIRCULATING FLUIDIZED BED BOILER (CFB)	WASTE COAL	1070	mmbtu/h	NOMINAL 1,070 MMBTU WASTE-COAL FIRED CFB. MAXIMUM COAL THROUGHPUT AT WORST-CASE FUEL SCENARIO IS 157 TPH. ANNUAL HEAT INPUT SHALL NOT EXCEED 8,908,920 MMBTU. SULFUR AND ASH CONTENTS SHALL NOT EXCEED 1.47% AND 63.71%, RESPECTIVELY.	Particulate Matter < 10 µ (PM10)	BAGHOUSE	0.03	LB/MMBTU	30-DAY				0.03	LB/MMBTU	30-DAY	FILTERABLE + CONDENSIBLE
32	WV-0024	WESTERN GREENBRIER CO-GENERATION, LLC	4/26/2006	NOMINAL 98 NET MEGAWATT WASTE COAL-FIRED STEAM ELECTRIC CO-GENERATION FACILITY. BOILER IS CFB TECHNOLOGY. FACILITY INCLUDES KILN TO PRODUCE CEMENTITIOUS MATERIAL FROM ASH GENERATED IN BOILER.	CURRENTLY UNDER APPEAL	CIRCULATING FLUIDIZED BED BOILER (CFB)	WASTE COAL	1070	mmbtu/h	NOMINAL 1,070 MMBTU WASTE-COAL FIRED CFB. MAXIMUM COAL THROUGHPUT AT WORST-CASE FUEL SCENARIO IS 157 TPH. ANNUAL HEAT INPUT SHALL NOT EXCEED 8,908,920 MMBTU. SULFUR AND ASH CONTENTS SHALL NOT EXCEED 1.47% AND 63.71%, RESPECTIVELY.	Particulate Matter (PM), Filterable	BAGHOUSE	0.015	LB/MMBTU	30-DAY				0.015	LB/MMBTU	30-DAY	ASH CONTENT SHALL NOT EXCEED 63.71%,
33	CO-0055	LAMAR LIGHT & POWER POWER PLANT	2/3/2006	UTILITY ELECTRIC POWER FACILITY	A CIRCULATING FLUIDIZED BED BOILER USING BITUMINOUS/SUB-BITUMINOUS COALS WILL BE BE INSTALLED. THIS WILL REPLACE AN EXISTING NATURAL GAS FIRED BOILER. OTHER AUXILIARY SOURCES: COAL HANDLING & PREPARATION, LIMESTONE HANDLING & PREPARATION, INERT (SAND) HANDLING. RAIL MOVEMENT WITH WITH DIESEL LOCOMOTIVE, EMERGENCY ELECTRIC GENERATOR AND FIRE WATER PUMP ENGINES, FUGITIVE DUST SOURCES.	CIRCULATING FLUIDIZED BED BOILER	COAL COAL (BITUMINOUS/ SUBBITUMINOUS)	501.7	MMBTU/H	LIMESTONE INJECTED FOR SO2 CONTROL, SAND ISUSED AS INERT MATERIAL FOR FOR REGULATION OF CIRCULATING OF BED TEMPERATURE	Particulate Matter < 10 µ (PM10)	HIGH EFFICIENCY(MEMBRANE) LINED FABRIC FILTER BAGHAUSE FOR FILTEARABLE PARTICULATE MATTER. MAXIMIZATION OF HEAT EXTRACTION FROM COMBUSTION GASES PRIOR TO BAGHAUSE	0.012	LB/ MMBTU	DURATION OF TESTS	0.02	LB/MMBTU	DURATION OF TESTS	10	% OPACITY	6 MINUTES AVERAGE	
34	MO-0071	KANSAS CITY POWER & LIGHT COMPANY - IATAN STATION	1/27/2006	KCPL HAS APPLIED FOR THE AUTHORITY TO INSTALL A PULVERIZED COAL BOILER, AN AUXILLIARY BOILER, ASSOCIATED STORAGE, HANDELING AND POLLUTION CONTROL EQUIPMENT, A FUEL OIL STORAGE TANK AND A LANDFILL, ALL ADJACENT TO THE EXISTING IATAN GENERATION STATION (INSTALLATION ID 165-0007)		PULVERIZED COAL BOILER - UNIT 1	COAL	4000	T/H	THE UNIT 1 BOILER SHALL UTILIZE A LOW-SULFUR LESS THAN 1.4 LBS PER MMBTU SUBBITUMINOUS COAL AS A PRIMARY FUEL. THE HEAT INPUT TO THE BOILER SHALL NOT EXCEED 7,800 MMBTU/HR	Particulate Matter < 10 µ (PM10)	BAGHOUSE	0.0244	LB/MMBTU	30 DAYS ROLLING AVERAGE							PM10 = 0.0244 LB/MMBTU INCLUDES BOTH FILTERABLE AND CONDENSABLE FILTERABLE PM10 = 0.014 LB/MMBTU, BASED ON 3-HOUR ROLLING AVERAGE FILTERABLE PM = 0.015 LB/MMBTU, BASED ON 3 HOUR ROLLING AVERAGE

	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P	Q	R	S	T	U	V
1	RBLCID	FACILITYNAME	PERMIT DATE	FACILITYDESCRIPTION	OTHERPERMITTINGINFORMATION	PROCESSNAME	FUEL	THRUPUT	THRUPUTUNIT	PROCESSNOTES	POLLUTANT	CTRLDESC	EMISLIMIT1	EMIS LIMIT1 UNIT	EMIS LIMIT1 AVGTIME CONDITION	EMISLIMIT2	EMISLIMIT2UNIT	EMISLIMIT2AVGTIMECONDITION	STDEMISSLIMIT	STDUNITLIMIT	STDLIMITAVGTIMECONDITION	POLLUTANT COMPLIANCE NOTES
35	MO-0071	KANSAS CITY POWER & LIGHT COMPANY - IATAN STATION	1/27/2006	KCPL HAS APPLIED FOR THE AUTHORITY TO INSTALL A PULVERIZED COAL BOILER, AN AUXILLIARY BOILER, ASSOCIATED STORAGE, HANDELING AND POLLUTION CONTROL EQUIPMENT, A FUEL OIL STORAGE TANK AND A LANDFILL, ALL ADJACENT TO THE EXISTING IATAN GENERATION STATION (INSTALLATION ID 165-0007)		PULVERIZED COAL BOILER - UNIT 2	PULVERIZED COAL	4000	T/H	UNIT 2 PULVERIZED COAL BOILER AND ASSOCIATED POLLUTION CONTROL EQUIPMENT. UNIT 2 BOILER SHALL UTILIZE A LOW-SULFUR SUBBITUMINOUS COAL AS THE PRIMARY FUEL. NO 2 FUEL OIL WITH A SULFUR CONTENT OF LESS THAN 0.05% SHALL BE USED FOR LIGHT OFF, STARTUP AND FLAME STABILIZATION.	Particulate Matter < 10 µ (PM10)	KCPL SHALL INSTALL A FABRIC FILTRATION SYSTEM (BAGHOUSE) FOR THE UNIT 2 BOILER TO REDUCE PM10 EMISSIONS.	0.0236	LB/MMBTU	30 DAYS ROLLING AVERAGE FILTABLE/COND.	0.014	LB/MMBTU	3 HOURS ROLLING AVERAGE - FILTRABLE PM10	0.015	LB/MMBTU	3 HOURS ROLLING AVERAGE	
36	VA-0296	VIRGINIA TECH	9/15/2005		VPI'S COAL SUPPLIERS ARE UNABLE TO CONSISTENTLY PROVIDE COAL WHICH MEETS THE ASH CONTENT LIMITS IN CONDITION 11 OF THE PERMIT. SINCE PARTICULAT EMISSIONS FOR A STOKER BOILER AR NOT RELATED TO ASH CONTENT, THIS AMENDMENT REMOVES ASSOCIATED CONDITIONS FORM THE PSD PERMIT. WHILE AMENDMENTS ARE NOT ADDRESSED UNDER PSD REGULATIONS, THIS ACTION MOST CLOSELY MEETS THE DEFINITION OF A MINOR PERMIT AMENDMENT UNDER 9VAC 5-80- 1280 AND THUS DOES NOT REQUIRE PUBLIC PARTICIPATION UNDER 5-80 1170. HOWEVER, PUBLIC PARTICIPATION WILL BE REQUIRED DURING CONCURRENT PROCESSING OF THE TITLE 5 PERMIT WHICH ALSO CONTAINS THE ASH LIMITS.	OPERATION OF BOILER 11	COAL	146.7	mmbtu	ONE COAL FIRED MASS FEED STOKER BOILER RESTRICED TO COAL MINIMUM HEAT CONTENT OF 13,250 BTU/LB, MAXIMUM SULFUR CONTENT 1.4% PER SHIPMENT BY WEIGHT, AND MAXIMUM 42,000 TONS PER YEAR.	Total Suspended Particulates	BAGHOUSE WITH CEM	0.02	LB/MMBTU		2.9	LB/H		0.02	LB/MMBTU		TSP LIMITS ARE 11.1 TONS PER YEAR
37	VA-0296	VIRGINIA TECH	9/15/2005		VPI'S COAL SUPPLIERS ARE UNABLE TO CONSISTENTLY PROVIDE COAL WHICH MEETS THE ASH CONTENT LIMITS IN CONDITION 11 OF THE PERMIT. SINCE PARTICULAT EMISSIONS FOR A STOKER BOILER AR NOT RELATED TO ASH CONTENT, THIS AMENDMENT REMOVES ASSOCIATED CONDITIONS FORM THE PSD PERMIT. WHILE AMENDMENTS ARE NOT ADDRESSED UNDER PSD REGULATIONS, THIS ACTION MOST CLOSELY MEETS THE DEFINITION OF A MINOR PERMIT AMENDMENT UNDER 9VAC 5-80- 1280 AND THUS DOES NOT REQUIRE PUBLIC PARTICIPATION UNDER 5-80 1170. HOWEVER, PUBLIC PARTICIPATION WILL BE REQUIRED DURING CONCURRENT PROCESSING OF THE TITLE 5 PERMIT WHICH ALSO CONTAINS THE ASH LIMITS.	OPERATION OF BOILER 11	COAL	146.7	mmbtu	ONE COAL FIRED MASS FEED STOKER BOILER RESTRICED TO COAL MINIMUM HEAT CONTENT OF 13,250 BTU/LB, MAXIMUM SULFUR CONTENT 1.4% PER SHIPMENT BY WEIGHT, AND MAXIMUM 42,000 TONS PER YEAR.	Particulate Matter < 10 µ (PM10)	BAG HOUSE EQUIPED WITH CEM	0.018	LB/MMBTU		2.6	LB/H		0.018	LB/MMBTU		PM 10 EMISSION LIMIT IS 10 TONS PER YEAR
38	PA-0248	GREENE ENERGY RESOURCE RECOVERY PROJECT	7/8/2005	THIS PA IS FOR THE CONSTRUCTION OF A NEW 525 NET MW (580 GROSS) ELECTRIC GENERATING FACILITY. THE FACILITY CONSISTS OF 2 WASTE COAL FIRED CFB BOILERS, EACH RATED AT 2756 MMBTU/HR, CFB'S WILL DRIVE A SINGLE TURBINE/GENERATOR.	FACILITY IS PSD FOR NO2,PM-10,SO2,CO,HF,HCL,H2SO4 (MIST),PB AND NA-NSR FOR VOC, NO2. FACILITY IS ALSO SUBJECT, TITLE IV, TO 40 CFR, PART 60, SUBPARTS, DA, DB, Y AND OOO. ALSO SUBJECT TO STATE BAT AND CHAPTER 123 REQUIREMENTS.	2 CFB BOILERS	WASTE COAL	358	T/H (each)		Particulate Matter < 10 µ (PM10)	BAGHOUSE, 289.7 TPY WAS DETERMINED BY EPA METHODS 201,201A,202. PROVISION TO INCREASE IF CAN'T MEET LIMIT BECAUSE OF CONDENSIBLES PER METHOD 202	0.012	LB/MMBTU		289.7	T/YR	12 MONTH ROLLING AVERAGE				

	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P	Q	R	S	T	U	V
1	RBLCID	FACILITYNAME	PERMIT DATE	FACILITYDESCRIPTION	OTHERPERMITTINGINFORMATION	PROCESSNAME	FUEL	THRUPUT	THRUPUTUNIT	PROCESSNOTES	POLLUTANT	CTRLDESC	EMIS LIMIT1	EMIS LIMIT1 UNIT	EMIS LIMIT1 AVGTIME CONDITION	EMISLIMIT2	EMISLIMIT2UNIT	EMISLIMIT2AVGTIMECONDITION	STDEMISSLIMIT	STDUNITLIMIT	STDLIMITAVGTIMECONDITION	POLLUTANT COMPLIANCE NOTES
39	CO-0057	COMANCHE STATION	7/5/2005	COMANCHE STATION CONSISTS OF TWO EXISTING COAL FIRED UTILITY BOILERS. AS PART OF THIS PRO	THIS PERMIT PROJECT WAS THE ADDITION OF A NEW PC BOILER (750 MW) - UNIT 3. AS PART OF THE PROJECT CONTROLS WERE ADDED TO 2 EXISTING PC BOILERS TO REDUCE NOX AND SO2 EMISSIONS AND NET OUT OF PSD REVIEW FOR THOSE POLLUTANTS. ADDITIONAL EQUIPMENT IN ASSOCIATED FOR THE PROJECT INCLUDED A COOLING TOWER, COAL AND ASH HANDLING EQUIPMENT FOR THE NEW BOILER, AND VARIOUS REAGENT SILOS AND MIXERS FOR ADD-ON CONTROLS. WITH CONTROLS ON THE EXISTING UNITS, REDUCTIONS IN SOX ARE 9,556 TPY AND NOX 137.6 TPY, BASED ON ACTUAL 2002/2003 EMISSIONS FOR EXISTING UNITS 1 AND 2. OTHER PERMITS ISSUED WITH THIS PROJECT WERE 04PB1016 (COOLING TOWER), 04PB1017 (COAL STORAGE AND HANDLING), 04PB1018 (RECYCLE ASH HANDLING), 04PB1019 (LIME HANDLING), 04PB1020 (SORBENT HANDLING), 04PB1021 (FLY ASH/FGD WASTE HANDLING AND STORAGE) AND 04PB1022 (HAUL ROADS).	PC BOILER - UNIT 3	SUB-BITUMINOUS COAL	7421	MMBTU/H	PROPOSED NEW UNIT 3, PC BOILER, 750 MW. PRB COAL.	Particulate Matter (PM)	BAGHOUSE	0.013	LB/MMBTU	FILTERABLE, AVG OF 3 TEST RUNS	0.022	LB/MMBTU	TOTAL (FILT + COND), AVG OF 3 TEST RUNS	0.013	LB/MMBTU		PROVISIONS TO LOWER TOTAL (FILTERABLE AND CONDENSABLE) PM LIMIT IN PERMIT BASED ON INITIAL TESTING.
40	CO-0057	COMANCHE STATION	7/5/2005	COMANCHE STATION CONSISTS OF TWO EXISTING COAL FIRED UTILITY BOILERS. AS PART OF THIS PRO	THIS PERMIT PROJECT WAS THE ADDITION OF A NEW PC BOILER (750 MW) - UNIT 3. AS PART OF THE PROJECT CONTROLS WERE ADDED TO 2 EXISTING PC BOILERS TO REDUCE NOX AND SO2 EMISSIONS AND NET OUT OF PSD REVIEW FOR THOSE POLLUTANTS. ADDITIONAL EQUIPMENT IN ASSOCIATED FOR THE PROJECT INCLUDED A COOLING TOWER, COAL AND ASH HANDLING EQUIPMENT FOR THE NEW BOILER, AND VARIOUS REAGENT SILOS AND MIXERS FOR ADD-ON CONTROLS. WITH CONTROLS ON THE EXISTING UNITS, REDUCTIONS IN SOX ARE 9,556 TPY AND NOX 137.6 TPY, BASED ON ACTUAL 2002/2003 EMISSIONS FOR EXISTING UNITS 1 AND 2. OTHER PERMITS ISSUED WITH THIS PROJECT WERE 04PB1016 (COOLING TOWER), 04PB1017 (COAL STORAGE AND HANDLING), 04PB1018 (RECYCLE ASH HANDLING), 04PB1019 (LIME HANDLING), 04PB1020 (SORBENT HANDLING), 04PB1021 (FLY ASH/FGD WASTE HANDLING AND STORAGE) AND 04PB1022 (HAUL ROADS).	PC BOILER - UNIT 3	SUB-BITUMINOUS COAL	7421	MMBTU/H	PROPOSED NEW UNIT 3, PC BOILER, 750 MW. PRB COAL.	Particulate Matter < 10 µ (PM10)	BAGHOUSE	0.012	LB/MMBTU	FILTERABLE, AVG OF 3 TEST RUNS	0.02	LB/MMBTU	TOTAL (FILT + COND), AVG OF 3 TEST RUNS	0.012	LB/MMBTU		PERMIT INDICATES TOTAL (FILTERABLE AND CONDENSABLE) PM10 MAY BE LOWERED (TO AS LOW AS 0.0180 LB/MMBTU) BASED ON RESULTS OF INITIAL TEST.
41	ND-0021	GASCOYNE GENERATING STATION	6/3/2005	LIGNITE FIRED POWER PLANT RATED AT A NOMINAL 175 MW (NET) AND A MAXIMUM OF 220 MW (GROSS). BOILER IS RATED AT 2116 MMBTU/H.		BOILER, COAL-FIRED	LIGNITE	2116	MMBTU/H	ATMOSPHERIC CIRCULATING FLUIDIZED BED BOILER.	Particulate Matter (PM)	BAGHOUSE	0.0167	LB/MMBTU	3-H				0.0167	LB/MMBTU		THE LIMIT IS FOR FILTERABLE PM ONLY.
42	ND-0021	GASCOYNE GENERATING STATION	6/3/2005	LIGNITE FIRED POWER PLANT RATED AT A NOMINAL 175 MW (NET) AND A MAXIMUM OF 220 MW (GROSS). BOILER IS RATED AT 2116 MMBTU/H.		BOILER, COAL-FIRED	LIGNITE	2116	MMBTU/H	ATMOSPHERIC CIRCULATING FLUIDIZED BED BOILER.	Particulate Matter < 10 µ (PM10)	BAGHOUSE	0.013	LB/MMBTU	3-H				0.013	LB/MMBTU		LIMIT IS FOR FILTERABLE PM10. FOR FILTERABLE AND CONDENSIBLE PM10, THE LIMIT IS 0.0275 LB/MMBTU.
43	NV-0036	TS POWER PLANT	5/5/2005	200 MW PC COAL FIRED ELECTRICAL GENERATION UNIT	APPEALED TO EAB; EAB DENIED REVIEW ON DECEMBER 21, 2005. PERMIT BECAME EFFECTIVE ON DECEMBER 21, 2005.	200 MW PC COAL BOILER	POWDER RIVER BASIN COAL	2030	MMBTU/H		Particulate Matter < 10 µ (PM10)	FABRIC FILTER DUST COLLECTION	0.012	LB/MMBTU	24-HOUR ROLLING - FILTERABLE ONLY				0.012	LB/MMBTU	24-HOUR ROLLING - FILTERABLE ONLY	FILTERABLE FRACTION ONLY
44	PA-0247	BEECH HOLLOW POWER PROJECT	4/1/2005	PA FOR INSTALLATION OF 272 (NET) MEGAWATT WASTE COAL FIRED CFB AND ASSOCIATED AIR SOURCES CONTROLLED BY A LIMESTONE INJECTION ,SNCR AND BAGHOUSE.	PA IS SUBJECT TO 40 CFR 60, SUBPARTS DA, Y,OOO. ALSO SUBJECT TO NON-ATTAINMENT NEW SOURCE REVIEW WHICH INCLUDES PREVENTION OF SIGNIFICANT DETERIORATION REGULATIONS, TITLE IV AND COMPLIANCE WITH NAAQS. FINALLY SOME POLLUTANTS UNDER NESHAPS. OTHER MINOR EMISSION SOURCES INCLUDE MATERIAL HANDLING, DRYER, EMERGENCY GENERATOR AND FIRE PUMP.	COAL FIRED CFB	WASTE COAL			THE OUTPUT OF THE CFB IS ESTIMATED AT 272 MW FROM A MAX. HEAT INPUT OF 2800 MMBTU/HR.	Particulate Matter < 10 µ (PM10)	BAGHOUSE	0.012	LB/MMBTU		147.2	T/YR		0.012	LB/MMBTU		
45	NE-0031	OPPD - NEBRASKA CITY STATION	3/9/2005	EXISTING ELECTRICAL GENERATING PLANT, CONSTRUCTING A NEW 660 (NET) MW UNIT.		UNIT 2 BOILER	SUBBITUMINOUS COAL				Particulate Matter (PM)	FABRIC FILTER BAGHOUSES	0.018	LB/MMBTU	TEST METHOD AVERAGE				0.018	LB/MMBTU		

	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P	Q	R	S	T	U	V
1	RBLCID	FACILITYNAME	PERMIT DATE	FACILITYDESCRIPTION	OTHERPERMITTINGINFORMATION	PROCESSNAME	FUEL	THRUPUT	THRUPUTUNIT	PROCESSNOTES	POLLUTANT	CTRLDESC	EMIS LIMIT1	EMIS LIMIT1 UNIT	EMIS LIMIT1 AVGTIME CONDITION	EMISLIMIT2	EMISLIMIT2UNIT	EMISLIMIT2AVGTIMECONDITION	STDEMISSLIMIT	STDUNITLIMIT	STDLIMITAVGTIMECONDITION	POLLUTANT COMPLIANCE NOTES
46	MO-0060	CITY UTILITIES OF SPRINGFIELD - SOUTHWEST POWER STATION	12/15/2004	CITY UTILITIES OF SPRINGFIELD HAS APPLIED FOR THE AUTHORITY TO INSTALL A 275 MW (2,724 MMBTU/H) PULVERIZED COAL BOILER AND ASSOCIATED MATERIAL HANDLING EQUIPMENT AT THEIR EXISTING SOUTHWEST POWER STATION. THE EXISTING INSTALLATION HAS ONE 1,810 MMBTU/H BOILER AND TWO TWIN-PAC TURBINE GENERATORS. THE BOILER WAS INSTALL IN 1976. H2S04 MIST NOT AVAILABLE		PULVERIZED COAL FIRED BOILER	COAL	2724	MMBTU/H		Particulate Matter < 10 µ (PM10)	BAGHOUSE	0.018	LB/MMBTU						LB/MMBTU	NOT AVAILABLE - *SEE NOTES	* LOOK FOR CONTROL METHOD DESCRIPTION FOR PM
47	WI-0228	WPS - WESTON PLANT	10/19/2004	ELECTRICAL UTILITY	SUPER CRITICAL PULVERIZED COAL (SCPC) FIRED ELECTRIC STEAM BOILER AND ASSOCIATED OPERATIONS 500 MW BASELOAD	SUPER CRITICAL PULVERIZED COAL ELECTRIC STEAM BOILER (S04, P04)	PRB COAL	5173.1	MMBTU/H	500 MW CAPACITY, BASE LOAD OPERATION (30% TO 100% CAPACITY) BACKUP / STARTUP FUEL, NATURAL GAS (5.07 CF6) PRB COAL (~0.5 WT. % S MAX., 5.5 WT % ASH); ~ 8100 BTU / LB; 319.3 TPH	Particulate Matter (PM)	FABRIC FILTER BAGHOUSE (WHEN FIRING COAL). NATURAL GAS USE (W/O BAGHOUSE) IS LIMITED TO 500 MMBTU/HR.	0.02	LB/MMBTU	3 HR. AVG	103.52	LB/H	3 HR. AVG.			NOT AVAILABLE	POLLUTANT MEASUREMENT INCLUDES BACKHALF (METHOD 5 OR 5B + METHOD 202)
48	WI-0228	WPS - WESTON PLANT	10/19/2004	ELECTRICAL UTILITY	SUPER CRITICAL PULVERIZED COAL (SCPC) FIRED ELECTRIC STEAM BOILER AND ASSOCIATED OPERATIONS 500 MW BASELOAD	SUPER CRITICAL PULVERIZED COAL ELECTRIC STEAM BOILER (S04, P04)	PRB COAL	5173.1	MMBTU/H	500 MW CAPACITY, BASE LOAD OPERATION (30% TO 100% CAPACITY) BACKUP / STARTUP FUEL, NATURAL GAS (5.07 CF6) PRB COAL (~0.5 WT. % S MAX., 5.5 WT % ASH); ~ 8100 BTU / LB; 319.3 TPH	Particulate Matter < 10 µ (PM10)	FABRIC FILTER BAGHOUSE (WHEN FIRING COAL) NATURAL GAS USE (W/O BAGHOUSE) LIMITED TO 500 MMBTU/HR	0.018	LB/MMBTU	3 HOUR AVG.						NOT AVAILABLE	INCLUDES BACKHALF
49	UT-0065	INTERMOUNTAIN POWER GENERATING STATION - UNIT #3	10/15/2004	NEW PULVERIZED COAL FIRED ELECTRIC GENERATING UNIT #3, DESIGNED AT 950-GROSS MW (900-NETMW) WITH A DRY BOTTOM, TANGENTIALLY FIRED OR WALL-FIRED BOILER. UNIT #3 BOILER WILL BE EQUIPPED WITH WET FLUE GAS DESULPHURIZATION, LNB, OVER FIRE AIR, SELECTIVE CATALYTIC REDUCTION AND BAGHOUSES FOR CONTROL OF VARIOUS EMISSIONS. THE EXISTING PLANT HAS TWO DRUM-TYPE, PULVERIZED COAL FIRED BOILERS, DESIGNATED AS UNIT 1 AND UNIT 2, EACH WITH 950-GROSS MW		PULVERIZED COAL FIRED ELECTRIC GENERATING UNIT	BITUMINOUS OR BLEND	950	MW-gross		Particulate Matter (PM), Filterable	BAGHOUSE/FABRIC FILTER	0.013	LB/MMBTU	3-TEST RUN AVERAGE ANNUALLY				0.013	LB/MMBTU		
50	UT-0065	INTERMOUNTAIN POWER GENERATING STATION - UNIT #3	10/15/2004	NEW PULVERIZED COAL FIRED ELECTRIC GENERATING UNIT #3, DESIGNED AT 950-GROSS MW (900-NETMW) WITH A DRY BOTTOM, TANGENTIALLY FIRED OR WALL-FIRED BOILER. UNIT #3 BOILER WILL BE EQUIPPED WITH WET FLUE GAS DESULPHURIZATION, LNB, OVER FIRE AIR, SELECTIVE CATALYTIC REDUCTION AND BAGHOUSES FOR CONTROL OF VARIOUS EMISSIONS. THE EXISTING PLANT HAS TWO DRUM-TYPE, PULVERIZED COAL FIRED BOILERS, DESIGNATED AS UNIT 1 AND UNIT 2, EACH WITH 950-GROSS MW		PULVERIZED COAL FIRED ELECTRIC GENERATING UNIT	BITUMINOUS OR BLEND	950	MW-gross		Particulate Matter < 10 µ (PM10)	BAGHOUSE/FABRIC FILTER	0.012	LB/MMBTU	3-TEST RUN AVERAGE ANNUALLY	221	LB/H	24-BLOCK AVERAGE	0.012	LB/MMBTU		

	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P	Q	R	S	T	U	V
1	RBLCID	FACILITYNAME	PERMIT DATE	FACILITYDESCRIPTION	OTHERPERMITTINGINFORMATION	PROCESSNAME	FUEL	THRUPUT	THRUPUTUNIT	PROCESSNOTES	POLLUTANT	CTRLDESC	EMIS LIMIT1	EMIS LIMIT1 UNIT	EMIS LIMIT1 AVGTIME CONDITION	EMISLIMIT2	EMISLIMIT2UNIT	EMISLIMIT2AVGTIMECONDITION	STDEMISSLIMIT	STDUNITLIMIT	STDLIMITAVGTIMECONDITION	POLLUTANT COMPLIANCE NOTES
51	GA-0114	INLAND PAPERBOARD AND PACKAGING, INC. - ROME LINERBOARD MILL	10/13/2004	THIS FACILITY MANUFACTURES UNBLEACHED KRAFT LINERBOARD.		BOILER, COAL FIRED	COAL	565	MMBTU/H	MODIFICATION TO A 1962 BOILER	Particulate Matter < 10 µ (PM10)	ESP	0.05	LB/MMBTU					0.05	LB/MMBTU		
52	GA-0114	INLAND PAPERBOARD AND PACKAGING, INC. - ROME LINERBOARD MILL	10/13/2004	THIS FACILITY MANUFACTURES UNBLEACHED KRAFT LINERBOARD.		BOILER, OIL-FIRED	NO. 2 FUEL OIL	192	MMBTU/H	NATURAL GAS BACKUP	Particulate Matter < 10 µ (PM10)		0.05	LB/MMBTU					0.5	LB/MMBTU		
53	GA-0114	INLAND PAPERBOARD AND PACKAGING, INC. - ROME LINERBOARD MILL	10/13/2004	THIS FACILITY MANUFACTURES UNBLEACHED KRAFT LINERBOARD.		BOILER, SOLID FUEL	BARK	856	MMBTU/H	BARK, WASTEWATER SLUDGE, TDF, FUEL OIL; MAY BE USED TO INCIENRATE NCG GASES; NEW BOILER	Particulate Matter < 10 µ (PM10)	ESP	0.025	LB/MMBTU					0.025	LB/MMBTU		
54	SC-0104	SANTEE COOPER CROSS GENERATING STATION	2/5/2004	ELECTRIC UTILITY	THE FACILITY HAS TWO COAL FIRED BOILERS, EACH RATED AT 5,200 MILLION BTU/HR. THIS PROJECT ADDS TWO ADDITIONAL BOILERS, EACH RATED AT 5,700 MILLION BTU/HR. START UP OF NEW BOILERS AND ASSOCIATED MODIFICATIONS IS SCHEDULED FOR 2007.	BOILER, NO. 3 AND NO. 4	BITUMINOUS COAL	5700	MMBTU/H	THE EXISTING FACILITY HAS TWO COAL FIRED BOILERS, EACH RATED AT 5200 MMBTU/HR. THIS PROJECT ADDS TWO ADDITIONAL COAL FIRED BOILERS, EACH RATED AT 5700 MMBTU/HR. NETTED OUT OF PSD REVIEW FOR SO2, NOX, AND H2SO4 BY REDUCING EMISSIONS ON EXISTING SOURCES. THIS IS A PSD, NSPS, CASE BY CASE MACT, AND SYNTHETIC MINOR PROJECT. BOILERS PERMITTED TO BURN BITUMINOUS COAL (PULVERIZED), SYNFUEL, AND UP TO 30% PETCOKE.	Particulate Matter < 10 µ (PM10)	ESP	0.018	LB/MMBTU					0.018	LB/MMBTU		

	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P	Q	R	S	T	U	V
1	RBLCID	FACILITYNAME	PERMIT DATE	FACILITYDESCRIPTION	OTHERPERMITTINGINFORMATION	PROCESSNAME	FUEL	THRUPUT	THRUPUTUNIT	PROCESSNOTES	POLLUTANT	CTRLDESC	EMIS LIMIT1	EMIS LIMIT1 UNIT	EMIS LIMIT1 AVGTIME CONDITION	EMISLIMIT2	EMISLIMIT2UNIT	EMISLIMIT2AVGTIMECONDITION	STDEMISSLIMIT	STDUNITLIMIT	STDLIMITAVGTIMECONDITION	POLLUTANT COMPLIANCE NOTES
55	SC-0104	SANTEE COOPER CROSS GENERATING STATION	2/5/2004	ELECTRIC UTILITY	THE FACILITY HAS TWO COAL FIRED BOILERS, EACH RATED AT 5,200 MILLION BTU/HR. THIS PROJECT ADDS TWO ADDITIONAL BOILERS, EACH RATED AT 5,700 MILLION BTU/HR. START UP OF NEW BOILERS AND ASSOCIATED MODIFICATIONS IS SCHEDULED FOR 2007.	BOILER, NO. 3 AND NO. 4	BITUMINOUS COAL	5700	MMBTU/H	THE EXISTING FACILITY HAS TWO COAL FIRED BOILERS, EACH RATED AT 5200 MMBTU/HR. THIS PROJECT ADDS TWO ADDITIONAL COAL FIRED BOILERS, EACH RATED AT 5700 MMBTU/HR. NETTED OUT OF PSD REVIEW FOR SO2, NOX, AND H2SO4 BY REDUCING EMISSIONS ON EXISTING SOURCES. THIS IS A PSD, NSPS, CASE BY CASE MACT, AND SYNTHETIC MINOR PROJECT. BOILERS PERMITTED TO BURN BITUMINOUS COAL (PULVERIZED), SYNFUEL, AND UP TO 30% PETCOKE.	Particulate Matter (PM)	ESP	0.015	LB/MMBTU					0.015	LB/MMBTU		NSPS LIMIT IS 0.03 LB/MMBTU
56	WI-0225	MANITOWOC PUBLIC UTILITIES	12/3/2003	PUBLIC ELECTRIC UTILITY	CIRCULATING FLUIDIZED BED (CFB) BOILER W/LIME INJ. SNCR NETTED OUT OF PSD FOR MOST POLLUTANTS BY ELIMINATING COAL USAGE FROM BOILER #5. SUBJECT TO NSPS. SUBJECT TO BACT FOR CO. BOILER #5 WILL BE 100 MMBTU/HR NATURAL GAS ONLY (ORIGINALLY 221 MMBTU/HR COAL) CFB 650 MMBTU/HR COAL / PET COKE / PAPER PELLETS (NATURAL GAS STARTUP) 64 MW(E)	CIRCULATING FLUIDIZED BED BOILER (ELECTRIC GENERATION)	COAL / PET COKE	650	MMBTU/H	CIRCULATING FLUIDIZED BED (CFB) BOILER WITH LIME INJECTION 650 MMBTU/HR COAL / PET COKE / PAPER PELLETS (NATURAL GAS STARTUP)	Particulate Matter < 10 µ (PM10)	BAGHOUSE (PULSE JET) CFB DESIGN	0.03	LB/MMBTU								650 MMBTU/HR COAL / PET COKE / PAPER PELLETS (NATURAL GAS STARTUP) NETTED OUT OF PSD BACT BY ELIMINATING COAL FROM BOILER #5 BOTH PM / PM10
57	PA-0182	RELIANT ENERGY SEWARD POWER	8/26/2003	ELECTRIC GENERATING FACILITY	CONSTRUCTION OF 2 CFB BOILERS WITH 2,532 MMBTU/HR HEAT INPUT AND FUELED BY REFUSE COAL AND NO. 2 FUEL OIL. REPOWERING PROJECT.	BOILER, CIRCULATING FLUIDIZED BED, (2)	COAL	2532	MMBTU/H		Particulate Matter < 10 µ (PM10)	FABRIC FILTER BAGHOUSE	0.01	LB/MMBTU					0.01	LB/MMBTU		
58	AR-0074	PLUM POINT ENERGY	8/20/2003		THE FACILITY IS A SINGLE PULVERIZED COAL FIRED BOILER. BETWEEN 550 AND 800 MW.	BOILER , UNIT 1 - SN-01	SUB-BITUMINOUS COAL	800	MW	THE BOILER IS A 550-800 MW PULVERIZED COAL FIRED BOILER.	Particulate Matter < 10 µ (PM10)	BAGHOUSE	0.018	LB/MMBTU					0.018	LB/MMBTU		
59	AR-0079	PLUM POINT ENERGY	8/20/2003	PLUM POINT ENERGY ASSOCIATES, LLC (PERMITTEE) PROPOSES TO CONSTRUCT AND OPERATE A NOMINAL 550-800 MW COAL FIRED GENERATING STATION	THE FACILITY IS A SINGLE PULVERIZED COAL FIRED BOILER. BETWEEN 550 AND 800 MW.	BOILER - SN-01	SUB-BITUMINOUS COAL	800	MW	THE BOILER IS A 550-800 MW PULVERIZED COAL FIRED BOILER.	Particulate Matter < 10 µ (PM10)	BAGHOUSE	0.018	LB/MMBTU					0.018	LB/MMBTU		
60	OH-0231	TOLEDO EDISON CO. - BAYSHORE PLANT	7/31/2003	CIRCULATING FLUIDIZED BED BOILER FIRED WITH COKE AND COAL, INCLUDES: COKE, COAL, LIMESTONE, AND FLY ASH STORAGE, LOAD IN AND OUT, CONVEYING AND TRANSFERRING, DUMPING, SOLID FUEL AND LIMESTONE CRUSHING, STORAGE PILES, ROADWAYS, AND A LIMESTONE DRYER.	THIS PERMIT HAS BEEN MODIFIED 03/27/1998, 7/28/99, 10/24/02, AND NOW 7/31/03. IT WAS FIRST ISSUED AROUND 6/20/97. THE FACILITYWIDE POLLUTANTS INCREASES AND DECREASES ARE FROM THE MODIFICATION ISSUED 7/28/99, WHICH WAS PSD FOR CO. THIS MODIFICATION, 7/31/03, WAS TO CORRECT ERRORS IN PERMIT MODIFICATION OF 10/24/02.	BOILER, CFB, COKE/COAL-FIRED	PETROLEUM COKE	1764	MMBTU/H	CIRCULATING FLUIDIZED BED BOILER, MFG. BY FOSTER WHEELER. 1736 MMBTU/H ON PETROLEUM COKE, PRIMARY FUEL; AND 1764 MMBTU/H ON COAL. 136 MW THE MAXIMUM AMOUNT OF COKE LOADED-IN TO THIS FACILITY, FOR USE IN THIS BOILER, SHALL NOT EXCEED 730,000 TONS PER ROLLING 12-MONTHS.	Particulate Matter (PM)	BAGHOUSE	0.03	LB/MMBTU		232	T/YR		0.03	LB/MMBTU		

	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P	Q	R	S	T	U	V
1	RBLCID	FACILITYNAME	PERMIT DATE	FACILITYDESCRIPTION	OTHERPERMITTINGINFORMATION	PROCESSNAME	FUEL	THRUPUT	THRUPUTUNIT	PROCESSNOTES	POLLUTANT	CTRLDESC	EMIS LIMIT1	EMIS LIMIT1 UNIT	EMIS LIMIT1 AVGTIME CONDITION	EMISLIMIT2	EMISLIMIT2UNIT	EMISLIMIT2AVGTIMECONDITION	STDEMISSLIMIT	STDUNITLIMIT	STDLIMITAVGTIMECONDITION	POLLUTANT COMPLIANCE NOTES
61	OH-0231	TOLEDO EDISON CO. - BAYSHORE PLANT	7/31/2003	CIRCULATING FLUIDIZED BED BOILER FIRED WITH COKE AND COAL, INCLUDES: COKE, COAL, LIMESTONE, AND FLY ASH STORAGE, LOAD IN AND OUT, CONVEYING AND TRANSFERRING, DUMPING, SOLID FUEL AND LIMESTONE CRUSHING, STORAGE PILES, ROADWAYS, AND A LIMESTONE DRYER.	THIS PERMIT HAS BEEN MODIFIED 03/27/1998, 7/28/99, 10/24/02, AND NOW 7/31/03. IT WAS FIRST ISSUED AROUND 6/20/97. THE FACILITYWIDE POLLUTANTS INCREASES AND DECREASES ARE FROM THE MODIFICATION ISSUED 7/28/99, WHICH WAS PSD FOR CO. THIS MODIFICATION, 7/31/03, WAS TO CORRECT ERRORS IN PERMIT MODIFICATION OF 10/24/02.	BOILER, CFB, COKE/COAL-FIRED	PETROLEUM COKE	1764	MMBTU/H	CIRCULATING FLUIDIZED BED BOILER, MFG. BY FOSTER WHEELER. 1736 MMBTU/H ON PETROLEUM COKE, PRIMARY FUEL; AND 1764 MMBTU/H ON COAL. 136 MW THE MAXIMUM AMOUNT OF COKE LOADED-IN TO THIS FACILITY, FOR USE IN THIS BOILER, SHALL NOT EXCEED 730,000 TONS PER ROLLING 12-MONTHS.	Particulate Matter < 10 µ (PM10)	BAGHOUSE	0.025	LB/MMBTU		193	T/YR		0.025	LB/MMBTU		
62	*IA-0067	MIDAMERICAN ENERGY COMPANY	6/17/2003		THE PERMITS ASSOCIATED WITH THIS PROJECT HAVE BEEN AMENDED WITH THE FOLLOWING PROJECTS: 04-751: CHANGE IN CONTROL ON TRANSFER HOUSE 04-759: REPLACED 112G LIMITS WITH SUBPART DDDDD LIMITS ON AUX BOILER 06-541: AMENDED EXISTING PERMITS FOR UNPERMITTED CHANGES AND OBTAINED PERMITS FOR UNPERMITTED EMISSION UNITS INSTALLED DURING CONSTRUCTION. A NOTICE OF VIOLATION (NOV) WAS SENT FOR THE UNPERMITTED CHANGES.	CBEC 4 BOILER	PRB COAL	7675	MMBTU/H		Particulate Matter (PM), Filterable	BAGHOUSE	0.18	LB/MMBTU					0.18	LB/MMBTU		Standard was set through the 112g process.
63	*IA-0067	MIDAMERICAN ENERGY COMPANY	6/17/2003		THE PERMITS ASSOCIATED WITH THIS PROJECT HAVE BEEN AMENDED WITH THE FOLLOWING PROJECTS: 04-751: CHANGE IN CONTROL ON TRANSFER HOUSE 04-759: REPLACED 112G LIMITS WITH SUBPART DDDDD LIMITS ON AUX BOILER 06-541: AMENDED EXISTING PERMITS FOR UNPERMITTED CHANGES AND OBTAINED PERMITS FOR UNPERMITTED EMISSION UNITS INSTALLED DURING CONSTRUCTION. A NOTICE OF VIOLATION (NOV) WAS SENT FOR THE UNPERMITTED CHANGES.	CBEC 4 BOILER	PRB COAL	7675	MMBTU/H		Particulate Matter (PM)	BAGHOUSE	0.027	LB/MMBTU					0.027	LB/MMBTU		The BACT limit includes condensibles.
64	*IA-0067	MIDAMERICAN ENERGY COMPANY	6/17/2003		THE PERMITS ASSOCIATED WITH THIS PROJECT HAVE BEEN AMENDED WITH THE FOLLOWING PROJECTS: 04-751: CHANGE IN CONTROL ON TRANSFER HOUSE 04-759: REPLACED 112G LIMITS WITH SUBPART DDDDD LIMITS ON AUX BOILER 06-541: AMENDED EXISTING PERMITS FOR UNPERMITTED CHANGES AND OBTAINED PERMITS FOR UNPERMITTED EMISSION UNITS INSTALLED DURING CONSTRUCTION. A NOTICE OF VIOLATION (NOV) WAS SENT FOR THE UNPERMITTED CHANGES.	CBEC 4 BOILER	PRB COAL	7675	MMBTU/H		Particulate Matter < 10 µ (PM10)	BAGHOUSE	0.025	LB/MMBTU					0.025	LB/MMBTU		BACT limit includes condensibles

APPENDIX L

Industrial Process Water Utilization

Appendix L Industrial Process Water Utilization

1 Project Background

As part of Dominion Brayton Point's Emission Control Plan (ECP) to control SO_2, Brayton Point Station will install SO_2 reduction systems on Units 1, 2 and 3. A Spray Dryer Absorber (SDA) system has been installed on Units 1 and 2 and a dry scrubber system is proposed for Unit 3. Approximately 1.595 million gallons per day (MGD) of water is required to operate these systems (approximately 0.685 MGD is needed for the SDAs on Unit 1 and 2 and 0.910 MGD will be needed for the dry scrubber on Unit 3). Historically, uses such as these would have been supplied by municipal water. In order to reduce the quantity of municipal water required to operate these systems, Brayton Point is reclaiming the treated effluent from the Somerset Water Pollution Control Facility (WPCF) and the Station's Wastewater Treatment System (WWTS) for industrial process water to supply all of the SDA and dry scrubber system's water needs. A 1.8-mile pipeline has been constructed from the WPCF to Brayton Point Station to transfer up to 1.28 MGD of reclaimed water to be used as industrial process water in the SO_2 reduction systems.

2 Process Description

Reclaimed water from the Somerset WPCF and the Station's Wastewater Treatment System (WWTS)[1] Recycle Effluent System will be used as industrial process water in Units 1 and 2 SDA and Unit 3 dry scrubber. For the Somerset WPCF, this water will be taken from the Somerset WPCF after de-chlorination and prior to its release to the Taunton River. In the event that reclaimed water from the Somerset WPCF and Station's WWTS is unavailable or not enough is available, municipal water from the Town of Somerset will be used as a back-up water source.

2.1 Unit 1 and 2 SDA

The air emission control devices to be installed on Units 1 and 2 are dry SDAs. The SDA systems will utilize lime slurry to remove SO_2 from the flue gas. The daily average makeup water demand for both SDAs is 0.685 MGD. Industrial process water will be used to supply all of the system's make-up requirements to produce lime slurry and for equipment wash downs. Industrial process water will be mixed with Quick Lime and recycled SDA ash to produce lime slurry that will be injected into the SDA vessel to facilitate SO_2 capture. In addition, the SDA will be washed down periodically with industrial process water to remove material buildup within the system. Equipment wash down water will be collected and recycled back into the SDA process as make-up water for lime slurry and will not be discharged to the wastewater treatment system.

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[1] The waste streams through Brayton WWTS are the following: Equipment wash water and drains, stormwater, fly ash recycle system discharges, demineralization wastes, system blowdown, fireside and chemical cleaning wastes and chloride purge stream (when Unit 3 FGD is in service)

2.2 Unit 3 Dry Scrubber

The air emission control devices to be installed on Unit 3 are dry scrubbers. The dry scrubber system will utilize lime slurry to remove SO_2 from the flue gas. The daily average makeup water demand for the dry scrubber is approximately 0.910 MGD. Industrial process water will be used to supply all of the system's make-up requirements to produce lime slurry and for equipment wash downs. Industrial process water will be mixed with Quick Lime and recycled dry scrubber ash to produce lime slurry that will be injected into the dry scrubber vessel to facilitate SO_2 capture. In addition, the dry scrubber will be washed down periodically with industrial process water to remove material buildup within the system. Equipment wash down water will be collected and recycled back into the dry scrubber process as make-up water for lime slurry and will not be discharged to the wastewater treatment system.

2.3 WWTS Recycle Effluent System

The existing WWTS Recycle Effluent System at Brayton Point Station reclaims the treated effluent from the WWTS to supply water for equipment washes and makeup for the Unit 4 Fly Ash Recycle (FAR) System. The system consists of redundant pumps and a piping system that transfers water from the WWTS effluent sump to the Unit 4 FAR System. The system has the capacity to reclaim up to 1.44 MGD, but 0.315 MGD.

3 Regulatory Approvals

The use of reclaimed water at Brayton Point Station has been approved by Massachusetts Department of Environmental protection (MassDEP) for the air emissions control systems in a letter dated February 2, 2007. The approval requires monitoring of the reclaimed water, reporting and inspections.

COMMONWEALTH OF MASSACHUSETTS
EXECUTIVE OFFICE OF ENVIRONMENTAL AFFAIRS
DEPARTMENT OF ENVIRONMENTAL PROTECTION
SOUTHEAST REGIONAL OFFICE
20 RIVERSIDE DRIVE, LAKEVILLE, MA 02347 508-946-2700

DEVAL L. PATRICK
Governor

TIMOTHY P. MURRAY
Lieutenant Governor

IAN A. BOWLES
Secretary

ARLEEN O'DONNELL
Commissioner

February 2, 2007

Mr. John Bower, Chairman
Somerset Water and Sewer Commission
Town of Somerset
116 Walker Street
Somerset , .MA 02725

SOMERSET:WPC- Facility Modification
Plan Approval for SOMERSET /DOMINION
NPDES Permit #MA0100676
BRPWP-68 Transmittal No. W092723

Mr. Tom Moss, Project Director
Dominion-Brayton Point Station
One Brayton Point Road
Somerset, MA.02725

Dear Mr. Bower and Mr. Moss

The Department of Environmental Protection has completed a review of the application, engineering plans, Engineer's Report and associated documents depicting the proposed modifications for the conveyance of 1.28MGD of wastewater effluent from the discharge pipe of the Somerset wastewater facility to be utilized as process water(reclaimed water) for the air emission control systems being installed at the Brayton Point Power station. The plans prepared by Shaw-Stone & Webster, Inc, are comprised of multiple sheets under a cover sheet, which in part reads:
"

CONTRACT DRAWINGS CONSTRUCTION ISSUE
9-26-2006
BRAYTON POINT STATION UNITS 1,2, &3
EMISSION CONTROL PROJECTS RECLAIMED WATER SYSTEM
DOMINION ENERGY BRAYTON POINT, LCC
1 BRAYTON POINT ROAD
SOMERSET, MA 02726

SHAW/STONE & WEBSTER
100 TECHNOLOGY CENTER DRIVE
STOUGHTON, MA 02072 "

As described in the Engineers Report (Rev.1, Nov 2006) a concrete tie-in structure will be installed in the existing Somerset WPCF 30 inch discharge line with an isolation gate valve and a 16 inch pipeline flowing by gravity to the pump station sump. A new pump station will be constructed which will include two 1100 gpm, 480 volt, 100 horsepower submersible sump pumps installed in a concrete sump under the pump station. Redundancy will be provided by operating one pump at a time with the other as a spare standby. The pumps will be controlled by a programmable logic controller (plc) networked with a plc at the Brayton Point station. The new pump station will be equipped with instrumentation to control the operation of the pumps as well as alarms to indicate any operational problems with the the pumps. Process water quality will continuously be monitored for flow, turbidity, conductivity and pH in the sump to prevent any pumping of water that does not meet the desired quality needed.

The reclaimed water will be conveyed approximately 9800 feet to the Brayton Point station via a 10 inch diameter high density polyethylene (HDPE) butt-fusion welded pipeline to be constructed in an existing right of way with easements and permits granted to Dominion Energy Brayton PT. by the Town of Somerset, Somerset Conservation Commission (#SE 070-0406 1/23/06, amended 12/5/06), National Grid (11/15/06) and a roadway crossing permit #5-2006-0451 issued 8/3/06 by the Mass Highway Dept.The pipeline will be equipped with suitable cleanouts at either end and an air release vent installed at the system high point. Once at the Brayton Point Station the reclaimed water will be disinfected using an ultraviolet (UV) disinfection system with 100% redundancy and transferred to a new 300,000 gallon storage tank which is part of the new air emission control system to control SO2. This air emission control system was approved by the Department- BWP in correspondence dated 12/20/2006, Transmittal #W070639.

The Department hereby approves the proposed wastewater/reuse modifications and construction subject to the following:

1. Construction must be in accordance with TR-16 Guidelines for the Design of Wastewater Treatment Works, the approved plans and specifications cited above and provisions of this approval. Any deviations from TR-16, or major changes to the approved plans and specifications will require a written justification to the Department for approval prior to any construction changes.

2. The Engineering Report submitted for the project indicated on pg 6 of 21 that "The pipe will be installed approximately 3.5 feet below the surface". The Departments "Technical Design Guidance For Review of Sewer Connection / Extension Permit Application" requires a minimum cover of 48 inches. The installation of the 9800 feet conveyance pipeline needs to conform to that requirement. In those areas where compliance is not possible, insulation shall be provided to prevent freezing.

3. A clear water test using either potable water and/or treated effluent from the existing Somerset treatment facility must be performed prior to the conveyance system as described above being put on-line. The clear water test shall be scheduled at least fourteen (14) days in advance so that Department personnel can be present.

4. Fourteen (14) days prior to the clear water test, a final functional description and operation and maintenance standard operating procedures document, covering this

modification/reuse project, shall be prepared jointly by the Town of Somerset and Dominion and submitted to this office for review.

5. Twenty-four (24) hours prior to the clear water test (item #3), written certification that the conveyance system and reuse modification components were constructed in accordance with the approved plans shall be submitted by a Professional Engineer registered in the Commonwealth of Massachusetts. Nothing in this provision is intended to interfere with the right of any Local Municipal Inspector to inspect the facilities at any time during construction in order to assess compliance with the plans as approved by the Department.

6. Operation and maintenance of all components of the reclaimed water conveyance system must be in accordance with 314 CMR 12.00: "Operation and Maintenance and Pretreatment Standards for Wastewater Treatment Works and Indirect Discharges" and 257 CMR 2.00: "Rules and Regulations for Certification of Operators of Wastewater Treatment Facilities". and be consistent with the Department guidance entitled: "Interim Guidelines on Reclaimed Water (Revised) – January 3, 2000.

7. Discharges and/or releases of the reuse/reclaimed effluent from any point source not authorized by this approval shall be reported in accordance with item #12 (Twenty-four hour reporting)

8. The operation of the Somerset Treatment facility must continue to comply with all the requirements and limits listed in the NPDES Permit MA0100676 during all phases of upgrade/reuse construction

9. The owner/operator of the system (Dominion Energy Brayton PT.) shall properly operate and maintain the system at all times in accordance with the approved plan. Any major structural and/or process plan changes or deviations, shall be reported to the Department prior to being accomplished in accordance with item # 1 above.

10. The owner/operator of the reuse/reclaimed water system(Dominion) shall monitor, record and report the quality and quantity of the reclaimed water in accordance with the following schedule, other provisions of this approval and as stated on page 10 of 21 in the Engineering Report

PARAMETER	FREQUENCY of ANALYSIS	SAMPLE TYPE
BOD	weekly	24 hr composite
Fecal Coliform	daily during workweek(mon-fri)	Grab
Total Suspended Solids	Daily	24 hr composite
pH, Turbidity, Conductivity	Continuous	Continuous
Disinfection UV Intensity	Continuous	Continuous
Flow**	Continuous	Continuous

** Flow shall be monitored, recorded continuously and reported daily in conjunction with the reported flows from the Somerset Wastewater Facility commencing at 12:00 midnight on a 24 hour basis. Reclaimed/reuse flows pumped shall not exceed the daily limit of 1.28 mgd.

If the owner/operator (Dominion) monitors any pollutant more frequently then required by this approval, the results of this monitoring shall be included in the reporting of data submitted in the monitoring reports.

The owner/operator (Dominion) shall retain records of all monitoring information including all calibration and maintenance records and all original strip chart recordings for continuous monitoring instrumentation, copies of all reports required, for a period of at least three years. This period may be extended by request of the Department at any time.

11. Monitoring reports shall be submitted to the Department within 30 days of the last day of the reporting month. Reports shall be on an acceptable form, properly filled and signed and shall be sent to The Department of Environmental Protection, Southeast Regional Office, 20 Riverside Drive, Lakeville MA 02347, Attention: Jeffrey Gould and to the Department of Environmental Protection, Division of Watershed Permitting, One Winter Street, Boston MA 02108, Attention: David Ferris.

12. 24 Hour Reporting to the Department: The owner /operator (Dominion) shall report any non-compliance and/or release from the conveyance system. All pertinent information shall be provided orally within 24 hours from the time the owner/operator (Dominion) becomes aware of the circumstances. A written submission shall also be provided within five days of the time the owner/operator becomes aware of the circumstance. The written submission shall contain a description of the non-compliance/release, including exact dates and times and if the non-compliance/release has not been corrected, the anticipated time it is expected to continue; and steps taken or planned to reduce, eliminate and prevent reoccurrence of the non-compliance/release. The Somerset Sewer Commission and other Local/State agencies with regulatory interest shall also be promptly notified.

13. Within forty five (45) days following the completion of the facility/reuse upgrade, as-built plans, stamped by Professional Engineer registered in the Commonwealth of Massachusetts shall be submitted to the Department. A copy shall be kept onsite at the Somerset Wastewater Facility and also at the Dominion Brayton Point Station.

14. The owner/operator shall furnish the Department within a reasonable time any information, which the Department may request to determine whether cause exists for modifying, revoking, reissuing or terminating this approval or to determine whether the owner/operator is complying with the terms and conditions of this approval.

15. The facility served by the system and the system itself shall be open to inspection by the Department at all reasonable times.

16. The Department must approve in writing any other future uses of the reclaimed water except for those described for the Air Emission Control Plan. The approval for any other uses will be approved under a separate application.

17. Discharge Monitoring Reports submitted by the Town of Somerset in accordance with NPDES Permit # MA0100676 shall accurately represent only the quantity of flow actually discharged to the receiving water. The report shall also include an attachment indicating the quantity of effluent flow reclaimed/reused.

This approval does not predicate or supersede the necessity for the Applicant to obtain or conform to any other local regulations or approvals that are needed. If you have any questions, please contact Joseph Shepherd at (508) 946-2756.

Sincerely,

David Delorenzo, Deputy Regional Director
Bureau of Resource Protection

DD/JJS/

cc: Dominion Power
1 Brayton Point Road
Somerset, MA 02725
Attn. Barry Ketshke, Station Director
Meredith M. Simas, Environmental Specialist

Shaw Environmental
11 Northeastern Blvd
Salem, New Hampshire03079
ATTN Lee Lepage, Project Manager

Town of Somerset
Water Pollution Control Facility
116 Walker Street
Somerset , MA 02725
Attn. Frank D. Arnold, Superintendent

DEP-Boston
ATTN:Alan Slater, BRP

DEP-SERO
ATTN: Jeffrey Gould, BRP
Joseph Shepherd, BRP
David Johnston, DRD/BWP
John Winkler, BWP
June Mahala, BWP

USEPA- Region I
One Congress Street
Suite 1100
Boston, MA 02114
Attn.: Steven Couto

DEP-CERO
Attn. Paul Hogan, DWM

APPENDIX M

SPX Drift Rate Memo

DOMINION BRAYTON POINT
Natural Draft Cooling Towers
Drift Rate

Cooling tower drift rate is a function of the drift eliminator geometry, face velocity, spacing of the eliminator from the nozzles, and the tower water loading. The drift guarantee provided by SPX for the Brayton Point cooling towers is based on extensive laboratory testing of the TU-12 cellular drift eliminator which SPX will be providing on this project. This testing was conducted by SPX using the HBIK methodology over a wide range of eliminator velocities, water loadings, and geometrical configurations (i.e. spacing of the eliminators from the spray nozzles). To eliminate any effects of ambient air contamination that could adversely affect the test results, a rare element was utilized in the chemical analysis to calculate the drift rate results (Reference CTI-ATC-140). Although the laboratory test data suggests that this eliminator can provide a drift rate below .0005%, field verification is very difficult as discussed below.

Obviously field tests are more difficult to accurately perform than laboratory tests, however, rigorous field tests by independent testing agency's have verified that the TU-12 eliminator is capable of providing a drift rate of .0005% or less. Field drift tests utilize naturally occurring elements in the circulating water as a trace element. Those elements (normally calcium, sodium and magnesium) are also present in the atmosphere and they may cause a high bias in the test result (i.e., the measured drift rate is artificially high). Consequently, due to field test inaccuracies, the guaranteed drift rate must include a margin to assure attainment of the guaranteed drift rate.

It is generally recognized that a drift rate of .0005% is “state-of-the art” and SPX has never attempted nor considered guaranteeing a drift rate below this very low value. Further, due to the thermal design conditions for Brayton Point, the face velocity through the eliminators is relatively low (< 300 fpm). Thus options such as providing a second layer of eliminators is not viable as the eliminators will not eliminate the very small droplets which will pass through multiple sets of eliminators.

In summary, .0005% drift elimination efficiency is the current best available technology.

APPENDIX N

PSD Netting Analysis

Prevention of Significant Deterioration (PSD) Review

Prevention of Significant Deterioration review is a federally mandated program for review of new major sources of criteria pollutants or major modifications to existing sources. The Closed Cycle Cooling Project qualifies as a major modification to an existing PSD source. Additionally, the Unit 3 DS/FF project also qualifies as a major modification to an existing PSD. Details of that netting analysis are shown below.

Prior permitting of the air pollution control systems at Brayton Point Station have not been subject to PSD review because the modifications qualified under a pollution control exemption. That pollution control exemption is no longer available.

EPA administers the PSD permitting process in Massachusetts.

The Prevention of Significant Deterioration regulations at 40 CFR 52.21 mandate analyses as follows for a *major modification*:

40 CFR 52.21 (j): Control technology review

40 CFR 52.21 (k) Source impact analysis

40 CFR 52.21 (m) Air quality analysis

40 CFR 52.21 (n) Source information.

40 CFR 52.21 (o) Additional impact analyses.

40 CFR 52.21 (p) Sources impacting Federal Class I areas—additional requirements

Major modification is defined in 40 CFR 52.21(b)(2(i):

> *Major modification* means any physical change in or change in the method of operation of a major stationary source that would result in: a significant emissions increase (as defined in paragraph (b)(40) of this section) of a regulated NSR pollutant (as defined in paragraph (b)(50) of this section); and a significant net emissions increase of that pollutant from the major stationary source.

Each part of this definition is reviewed in-turn below:

"physical change in or change in the method of operation" – The Closed Cycle Cooling Project is a physical change. The Unit 3 DS/FF Project is a physical change.

"of a major stationary source" Brayton Point Station is a major stationary source because it is a fossil fuel-fired steam electric plants of more than 250 million British thermal units per hour heat input with the potential to emit 100 tons per year or more of any regulated NSR pollutant [40 CFR 52.21(b)(1)(i)(*a*)].

“a significant emissions increase of a regulated NSR pollutant” is per the table below [summarized from 40 CFR 52.21(a)(23)(i) and (ii)]:

Carbon Monoxide	100 tons per year (tpy)
Nitrogen oxides	40 tpy
Sulfur dioxide	40 tpy
Volatile organic compounds	40 tpy
Particulate matter*	25 tpy
PM10	15 tpy
PM2.5	10 tpy
Lead	0.6 tpy
Fluorides	3 tpy
Sulfuric Acid Mist	7 tpy
Hydrogen sulfide, total reduced sulfur, Reduced sulfur compounds: 10 tpy	10 tpy
Other regulated NSR pollutant	Any emission rate

* EPA rescinded the national ambient air quality standard for particulate matter in favor of a PM10 standard in 1987, and recent statutory and regulatory provisions impose controls and limitations on PM10, not particulate matter.

“and a significant net emissions increase of that pollutant from the major stationary source” To determine if a significant net emissions increase has occurred, Brayton Point Station follows the procedures in 40 CFR 52.21(a)(2)(iv)(*f*): “Hybrid test for projects that involve multiple types of emission units.” The actual-to-potential test in 40 CFR 52.21(a)(2)(iv)(*d*) is applied to the cooling tower, and the actual-to-projected-actual test in 50 CFR 52.21(a)(2))(iv)(*c*) is applied to the Unit 3 DS/FF project.

The results of the two tests are shown in the tables below. Calculation details are shown on the attached spreadsheets. Calculation methods follow the procedures instructed in 40 CFR 52.21.

Cooling tower – new emissions unit – Actual-to-Potential applicability test

Pollutant	Baseline Actual Emissions	Projected Actual Emissions	Emissions Increase
Carbon Monoxide	0	None expected	None expected
Nitrogen oxides	0	None expected	None expected
Sulfur dioxide	0	None expected	None expected
Volatile organic compounds	0	None expected*	None expected*
Filterable PM	0	389	389
Filterable PM10	0	389	389
Filterable PM2.5	0	389	389
Total PM	0	389	389
Total PM10	0	389	389
Total PM2.5	0	389	389
Lead	0.0	None expected	None expected
Fluorides	0	None expected	None expected
Sulfuric Acid Mist	0	None expected	None expected
Hydrogen sulfide, total reduced sulfur, Reduced sulfur compounds	0	None expected	None expected
Other NSR Pollutant	0	None expected	None expected

* some small amount of VOC could be emitted from stripping naturally-occurring volatile organics from the circulating water.

Unit 3 – modified emissions unit – Actual-to-Projected Actual applicability test

Pollutant	Baseline Actual Emissions	Projected Actual Emissions	Emissions Increase
Carbon Monoxide	1,268	1,268	0
Nitrogen oxides	6,167	1,300	-4,867
Sulfur dioxide	16,294	1,485	-14,809
Volatile organic compounds	50.4	50.9	0.5
Filterable PM	134	186	52
Filterable PM10	134	186	52
Filterable PM2.5	134	186	52
Total PM	670	464	-206
Total PM10	670	464	-206
Total PM2.5	670	464	-206
Lead	0.0	0.0	0.0
Fluorides	111	78	-33
Sulfuric Acid Mist	78	55	-23
Hydrogen sulfide, total reduced sulfur, Reduced sulfur compounds	none expected	none expected	None expected
Other NSR Pollutant	none expected	none expected	None expected

Total Project - Actual-to-Projected Actual applicability test

Pollutant	Baseline Actual Emissions	Projected Actual Emissions	Emissions Increase
Carbon Monoxide	1,268	1,268	0
Nitrogen oxides	6,167	1,300	-4,867
Sulfur dioxide	16,294	1,485	-14,809
Volatile organic compounds	50	50.5	0.5
Filterable PM	134	575	441
Filterable PM10	134	575	441
Filterable PM2.5	134	575	441
Total PM	670	853	183
Total PM10	670	853	183
Total PM2.5	670	853	183
Lead	0.0	0.0	0.0
Fluorides	111	78	-33
Sulfuric Acid Mist	78	55	-23
Hydrogen sulfide, total reduced sulfur, Reduced sulfur compounds	None expected	None expected	None expected
Other NSR Pollutant	None expected	None expected	None expected

Therefore, per the regulations in 40 CFR 52.21 the overall project is a major modification for particulate matter, PM10, and PM2.5.

For the above calculation, the "baseline actual" emissions are as defined in 40 CFR 52.21(b)(48)(i). Specifically, the baseline actual emissions from "any consecutive 24-month period selected by the owner or operator within the 5-year period immediately preceding when the owner or operator begins actual construction of the project." Per 40 CFR 52.21(b)(48)(i)(c), "a different consecutive 24-month period can be used for each regulated NSR pollutant." Dominion has selected January 2003 through December 2004 for NOx and SO2, and January 2006 through December 2007 for all other pollutants.

The "projected actual" emissions are as defined in 40 CFR 52.21(b)(41). Specifically, the projected actual emission rate is "the maximum annual rate, in tons per year, at which an existing emissions unit is projected to emit a regulated NSR pollutant in any one of the 5 years (12-month period) following the date the unit resumes regular operation after the project." Per 40 CFR 52.21(b)(41)(ii)(*a*), the projections rely on historical data, company projections, and compliance plans under the State Implementation Plan (the Massachusetts 7.29 Emission Control Plan). Reductions in sulfur dioxide, fluorides, and sulfuric acid mist are based on installation of the dry scrubber that is the subject of this application. Reductions in nitrogen oxides are based on projections for operation using the (previously permitted and installed) selective catalytic reduction system.

Per 40 CFR 52.21(b)(41)(ii)(*c*), the projections exclude increased utilization due to product (electricity) demand growth; that growth could have been accommodated by the unit during the baseline period. The increased utilization is not directly attributable to this project and therefore that utilization is specifically identified and excluded in the attached calculations.

The only unit-specific emissions data available for "baseline actual" emissions are based on USEPA Test Method 5 (filterable only). This was the test method applicable to Unit 3 during the baseline period and is consistent with historical estimates of particulate emissions from Unit 3. In this PSD analysis, the "filterable particulate matter - baseline actual" emission rate is based on this test data. The "filterable PM10& PM2.5 – baseline actual" emission rates are assumed to be the same as the PM emission rate.

Brayton Point Station has not tested or reported Unit 3 particulate emissions including condensable particulate. The "baseline actual" emission estimates for total PM, PM10, and PM2.5 include estimates of condensable particulate emissions from standard EPA AP-42 emission factors.

Because of the transition from filterable-only reporting to filterable-plus-condensable reporting of particulate emissions, this PSD netting analysis shows separate netting calculations for filterable particulate (PM/PM10/PM2.5) and total PM/PM10/PM2.5. Filterable PM/PM10/PM2.5 are not regulated NSR pollutants, but are shown in this analysis given the transition in testing and reporting.

Brayton Point Unit 3 Dry Scrubber and Fabric Filter Project
Expanded PSD Netting Calculations

	Baseline Actual Emissions		Future Actual Emission		Excludable Emissions Due to Demand Growth		Future Actual Emissions minus Excludable Emissions	Emission Increase / Decrease[w]	PSD Significant Emission Increase Threshold	PSD Significant Increase
Heat Input MMBtu/yr		37,130,465 [a]		45,565,410 [k]		8,434,945 [k]	37,130,465 [v]			
Pollutant	lb/MMBtu	Tons/ Year	lb/MMBtu	Tons/ Year	lb/MMBtu	Tons/ Year	Tons/ Year	Tons/ Year	Tons/ Year	Yes / No
NO_x	0.356	6,167 [c]	0.07	1,595 [m]	0.07	295 [m]	1,300 [m]	-4,867	40	No
SO_2	0.942	16,294 [d]	0.08	1,823 [n]	0.08	337 [n]	1,485 [n]	-14,809	40	No
CO	0.068	1,268 [b]	0.068	1,556 [l]	0.068	288 [l]	1,268 [l]	0	100	No
Filterable PM	0.0072	134 [d]	0.010	228 [p]	0.010	42 [p]	186 [p]	**52**	25	**Yes**
Filterable PM 10	0.0072	134 [e]	0.010	228 [q]	0.010	42 [q]	186 [q]	**52**	15	**Yes**
Filterable PM 2.5	0.0072	134 [f]	0.010	228 [e,r]	0.010	42 [e,r]	186 [e,r]	**52**	10	**Yes**
Total PM	0.0361	670 [g]	0.025	570 [r]	0.025	105 [r]	464 [r]	-206	25	No
Total PM 10	0.0361	670 [g]	0.025	570 [r]	0.025	105 [r]	464 [r]	-206	15	No
Total PM 2.5	0.0361	670 [f]	0.025	570 [r]	0.025	105 [r]	464 [r]	-206	10	No
VOC	0.0027	50.4 [b]	0.0027	62.3 [o]	0.0027	11.4 [o]	50.9 [o]	0.5	40	No
Lead	4.32E-07	0.008 [h]	4.32E-07	0.010 [s]	4.32E-07	0.002 [s]	0.008 [s]	0.000	0.6	No
Fluorides	6.00E-03	111 [i]	4.20E-03	96 [t]	4.20E-03	18 [t]	78 [t]	-33	3	No
Sulfuric Acid Mist	0.0042	78.0 [j]	0.0029	67.0 [u]	0.0029	12.4 [u]	54.6 [u]	-23	7	No

No H2S or other reduced sulfur emissions expected.

Notes

- a Baseline heat input obtained from Clean Air Market Data (CAMD) data for baseline period of January 1, 2006 through December 31, 2007
- b CO & VOC rate and total tons obtained from Annual Source Registration submittals for 2006 and 2007
- c NOx and SO2 rates and total tons obtained from Clean Air Market Data (CAMD) data for baseline period of January 1, 2003 through December 31, 2004
- d Filterable PM emissions rate of 0.0072 lb/MMBtu from Compliance Assurance Monitoring (CAM) plan stack testing in 2004
- e Filterable PM10 & PM2.5 assumed to be the same as filterable PM emissions, consistent with prior filings
- f Filterable and total PM-2.5 emissions assumed to be equal to respective PM-10 emissions
- g Total PM & PM-10 includes filterable and condensable PM (CPM) emissions. CPM calculated from EPA AP-42, Table 1.1-5, where CPM=0.1*%S - 0.03, assuming 12,500 Btu/lb coal.
- h EPA AP-42 Table 1.1-16; assumes 1 ppm lead concentration, 0.096 ash fraction consistent with prior filings and the Baseline Actual Heat Input for 2006 and 2007
- i EPA AP-42 Table 1.1-15 (hydrogen fluoride) and the Baseline Actual Heat Input for 2006 and 2007
- j Sulfuric acid mist emission rate from 2002 informational SO3 stack testing; assumes all SO3 emitted as H2SO4 and the Baseline Actual Heat Input for 2006 and 2007
- k Future Actual Heat Input based upon Dominion operational projections for 2015
- l Future CO emissions based upon prior emission rate of 0.068 lb/MMBtu and projected annual heat input
- m Future NOx emissions based upon Dominion projected emission rate of 0.07 lb/MMBtu and projected annual heat input
- n Future SO2 emissions based upon Dominion projected emission rate of 0.08 lb/MMBtu and projected annual heat input
- o Future VOC emissions based upon baseline emission rate of 0.0027 lb/MMBtu, projected annual heat input and a 0.5 ton increase from from organic material in make-up water, consistent with prior filings
- p Design target for PM based upon BACT analysis
- q Design target for PM10 & PM2.5 based upon BACT analysis
- r Design target for total PM, PM10 & PM2.5 emissions based upon BACT analysis
- s EPA AP-42 Table 1.1-16; assumes 1 ppm lead concentration, 0.096 ash fraction consistent with prior filings and the Future Actual Heat Input for 2015
- t Future Actual Fluoride (as HF) emission rate calculated from baseline rate with a 30% reduction which is consistent with the 30% H2SO4 reduction due to the dry scrubber
- u Future Actual Sulfuric Acid Mist emisisons assume a 30% reduction in dry scrubber, consistent with prior filings
- v Excluding demand growth, projected actual heat input is the same as baseline actual
- w Baseline Emissions minus Future Actual Emissions minus Excludable emissions

APPENDIX O

Updates to June 2006 Modeling Analysis

Brayton Point Load Analysis

- Modeling performed with ISCST3 using 1991-1995 Providence/Chatham meteorological data
- Original modeling performed by TRC in 2006
- Unit 3 source parameters are different for this project than in the TRC analysis, therefore the Unit 3 Load analysis was remodeled.
- The original TRC load analysis results are presented with the Unit 3 impacts crossed out, and the revised Unit 3 results are presented in the last table.

Load Analysis Results for the Boilers at Brayton Point Station
Maximum Modeled Concentrations (ug/m^3)

Brayton Point Station - Existing Unit 1, 2, & 4 Stacks with Unit 3 Exhausted Through the Auxiliary Discharge Stack (i.e., Existing Unit 3 Stack)

1-Hour	XOQ	yymmddhh	UTM E (m)	UTM N (m)	ELEV (m)	NO_2	CO	PM-10	Distance (m)	Direction (deg)
CASE011	1.35038	95092024	319,457	4,617,544	58.6	145.48	31.76	30.63	3,000	140
CASE012	1.39757	91081914	318,049	4,619,542	0.0	150.56	32.88	31.70	600	120
~~CASE013~~	~~0.85087~~	~~95030207~~	~~317,557~~	~~4,619,453~~	~~0.7~~	~~272.82~~	~~100.64~~	~~48.50~~	~~390~~	~~176~~
CASE014	0.39393	92070210	317,303	4,618,562	0.0	64.33	18.58	7.15	1,300	190
CASE021	2.43781	92052205	319,229	4,616,898	58.3	164.28	35.86	34.59	3,400	150
CASE022	2.6888	92082605	318,116	4,620,271	8.8	181.20	39.58	38.15	727	54
~~CASE023~~	~~1.33113~~	~~94122320~~	~~317,208~~	~~4,619,459~~	~~0.0~~	~~280.86~~	~~103.60~~	~~49.93~~	~~500~~	~~220~~
CASE024	0.62865	95062811	316,758	4,620,761	4.6	52.17	15.07	5.80	1,200	320
CASE031	2.68272	92052205	319,229	4,616,898	58.3	109.72	23.96	23.10	3,400	150
CASE032	3.14019	92082605	318,116	4,620,271	8.8	128.43	28.04	27.04	727	54
~~CASE033~~	~~1.69285~~	~~91050204~~	~~318,045~~	~~4,620,171~~	~~6.1~~	~~209.52~~	~~77.30~~	~~37.24~~	~~612~~	~~57~~
CASE034	0.75315	93101112	316,779	4,621,141	5.0	11.15	3.22	1.24	1,500	330
3-Hour	**XOQ**	**yymmddhh**	**UTM E (m)**	**UTM N (m)**	**ELEV (m)**	**NO_2**	**CO**	**PM-10**	**Distance (m)**	**Direction (deg)**
CASE011	0.86633	95082903	317,879	4,619,236	0.0	93.33	20.38	19.65	700	150
CASE012	0.85006	95082903	317,879	4,619,236	0.0	91.58	20.00	19.28	700	150
~~CASE013~~	~~0.4704~~	~~94122324~~	~~317,079~~	~~4,619,306~~	~~0.0~~	~~150.83~~	~~55.64~~	~~26.81~~	~~700~~	~~220~~
CASE014	0.13131	92070212	317,303	4,618,562	0.0	21.44	6.19	2.38	1,300	190
CASE021	1.56117	95082903	317,879	4,619,236	0.0	105.21	22.96	22.15	700	150
CASE022	1.48228	95082903	317,879	4,619,236	0.0	99.89	21.82	21.03	700	150
~~CASE023~~	~~0.64663~~	~~92042806~~	~~318,224~~	~~4,615,903~~	~~59.0~~	~~136.43~~	~~50.33~~	~~24.26~~	~~4,000~~	~~170~~
CASE024	0.22499	95062812	316,610	4,620,614	2.8	18.67	5.39	2.07	1,200	310
CASE031	1.88431	95082903	317,879	4,619,236	0.0	77.07	16.83	16.22	700	150
CASE032	1.77018	95082903	317,879	4,619,236	0.0	72.40	15.81	15.24	700	150
~~CASE033~~	~~1.0616~~	~~92111003~~	~~317,515~~	~~4,619,411~~	~~1.0~~	~~131.39~~	~~48.47~~	~~23.36~~	~~431~~	~~182~~
CASE034	0.37548	95021503	318,093	4,619,637	0.2	5.56	1.61	0.62	600	110
8-Hour	**XOQ**	**yymmddhh**	**UTM E (m)**	**UTM N (m)**	**ELEV (m)**	**NO_2**	**CO**	**PM-10**	**Distance (m)**	**Direction (deg)**
CASE011	0.50653	92042808	318,311	4,615,411	63.1	54.57	11.91	11.49	4,500	170
CASE012	0.53973	92042808	318,224	4,615,903	59.0	58.15	12.70	12.24	4,000	170
~~CASE013~~	~~0.27288~~	~~92111008~~	~~317,529~~	~~4,613,342~~	~~88.8~~	~~87.50~~	~~32.28~~	~~15.55~~	~~6,500~~	~~180~~
CASE014	0.05838	91061416	320,029	4,615,512	60.0	9.53	2.75	1.06	5,000	150
CASE021	0.89917	92111008	317,583	4,619,491	0.9	60.60	13.23	12.76	355	171
CASE022	0.95253	92111008	317,557	4,619,453	0.7	64.19	14.02	13.52	390	176
~~CASE023~~	~~0.44227~~	~~92042808~~	~~318,224~~	~~4,615,903~~	~~59.0~~	~~93.31~~	~~34.42~~	~~16.59~~	~~4,000~~	~~170~~
CASE024	0.11617	91061416	319,229	4,616,898	58.3	9.64	2.78	1.07	3,400	150
CASE031	1.12888	92111008	317,583	4,619,491	0.9	46.17	10.08	9.72	355	171
CASE032	1.17945	92111008	317,557	4,619,453	0.7	48.24	10.53	10.16	390	176
~~CASE033~~	~~0.709~~	~~92111008~~	~~317,515~~	~~4,619,411~~	~~1.0~~	~~87.75~~	~~32.37~~	~~15.60~~	~~431~~	~~182~~
CASE034	0.22094	92102824	318,073	4,620,211	7.3	3.27	0.95	0.36	658	56
24-Hour	**XOQ**	**yymmddhh**	**UTM E (m)**	**UTM N (m)**	**ELEV (m)**	**NO_2**	**CO**	**PM-10**	**Distance (m)**	**Direction (deg)**
CASE011	0.2402	93062324	317,651	4,619,153	0.0	25.88	5.65	5.45	700	170
CASE012	0.26886	93062324	317,651	4,619,153	0.0	28.96	6.33	6.10	700	170
~~CASE013~~	~~0.13554~~	~~91103024~~	~~317,069~~	~~4,619,457~~	~~0.0~~	~~43.46~~	~~16.03~~	~~7.73~~	~~600~~	~~230~~
CASE014	0.02112	92020224	317,529	4,612,842	91.0	3.45	1.00	0.38	7,000	180
CASE021	0.40306	91102024	317,651	4,619,153	0.0	27.16	5.93	5.72	700	170
CASE022	0.43883	93062324	317,651	4,619,153	0.0	29.57	6.46	6.23	700	170
~~CASE023~~	~~0.19905~~	~~91103024~~	~~317,069~~	~~4,619,457~~	~~0.0~~	~~42.00~~	~~15.49~~	~~7.47~~	~~600~~	~~230~~
CASE024	0.055	92020224	317,529	4,612,842	91.0	4.56	1.32	0.51	7,000	180
CASE031	0.48446	91102024	317,651	4,619,153	0.0	19.81	4.33	4.17	700	170
CASE032	0.51497	93062324	317,651	4,619,153	0.0	21.06	4.60	4.43	700	170
~~CASE033~~	~~0.29942~~	~~93062324~~	~~317,633~~	~~4,619,251~~	~~0.0~~	~~37.06~~	~~13.67~~	~~6.59~~	~~600~~	~~170~~
CASE034	0.12981	95021224	319,586	4,617,391	61.0	1.92	0.56	0.21	3,200	140
Annual	**XOQ**	**Year**	**UTM E (m)**	**UTM N (m)**	**ELEV (m)**	**NO_2**	**CO**	**PM-10**	**Distance (m)**	**Direction (deg)**
CASE011	0.01753	1994	317,979	4,619,306	0.0	1.89	0.41	0.40	700	140
CASE012	0.02141	1994	318,087	4,620,231	8.0	2.31	0.50	0.49	680	55
~~CASE013~~	~~0.0079~~	~~1991~~	~~318,073~~	~~4,620,211~~	~~7.3~~	~~2.53~~	~~0.93~~	~~0.45~~	~~658~~	~~56~~
CASE014	0.00117	1992	317,529	4,612,842	91.0	0.19	0.06	0.02	7,000	180
CASE021	0.03308	1994	317,979	4,619,306	0.0	2.23	0.49	0.47	700	140
CASE022	0.04183	1994	318,087	4,620,231	8.0	2.82	0.62	0.59	680	55
~~CASE023~~	~~0.0158~~	~~1991~~	~~318,073~~	~~4,620,211~~	~~7.3~~	~~3.33~~	~~1.23~~	~~0.59~~	~~658~~	~~56~~
CASE024	0.00289	1993	317,529	4,612,842	91.0	0.24	0.07	0.03	7,000	180
CASE031	0.04003	1994	317,979	4,619,306	0.0	1.64	0.36	0.34	700	140
CASE032	0.04995	1994	318,087	4,620,231	8.0	2.04	0.45	0.43	680	55
~~CASE033~~	~~0.02401~~	~~1991~~	~~318,073~~	~~4,620,211~~	~~7.3~~	~~2.97~~	~~1.10~~	~~0.53~~	~~658~~	~~56~~
CASE034	0.00805	1994	319,586	4,617,391	61.0	0.12	0.03	0.01	3,200	140

Case01? – Maximum operating load for each boiler (? = Boiler 1, 2, 3, or 4)
Case02? – Intermediate operating load for each boiler (? = Boiler 1, 2, 3, or 4)
Case03? – Minimum operating load for each boiler (? = Boiler 1, 2, 3, or 4)

Scenario Y-1 Load Analysis Results for the Boilers at Brayton Point Station
Maximum Modeled Concentrations (ug/m^3)

Brayton Point Station - Scenario Y-1

1-Hour	XOQ	yymmddhh	UTM E (m)	UTM N (m)	ELEV (m)	SO_2	Distance (m)	Direction (deg)
CASE011	1.22694	92052205	319,229	4,616,898	58.3	855.68	3,400	150
CASE012	1.24438	91081914	317,962	4,619,592	0.0	867.84	500	120
~~CASE013~~	~~0.74018~~	~~93070811~~	~~318,281~~	~~4,619,569~~	~~0.0~~	~~129.74~~	~~800~~	~~110~~
CASE014	0.39393	92070210	317,303	4,618,562	0.0	289.42	1,300	190
CASE021	1.75467	92052205	319,229	4,616,898	58.3	765.51	3,400	150
CASE022	1.73966	92052104	321,074	4,619,217	61.0	758.96	3,600	100
~~CASE023~~	~~0.96189~~	~~93070811~~	~~318,187~~	~~4,619,603~~	~~0.2~~	~~110.94~~	~~700~~	~~110~~
CASE024	0.62865	95062811	316,758	4,620,761	4.6	234.72	1,200	320
CASE031	2.05856	92052205	319,229	4,616,898	58.3	545.11	3,400	150
CASE032	2.03776	92052104	321,074	4,619,217	61.0	539.60	3,600	100
~~CASE033~~	~~1.15662~~	~~93070811~~	~~318,187~~	~~4,619,603~~	~~0.2~~	~~78.26~~	~~700~~	~~110~~
CASE034	0.75315	93101112	316,779	4,621,141	5.0	50.19	1,500	330
3-Hour	**XOQ**	**yymmddhh**	**UTM E (m)**	**UTM N (m)**	**ELEV (m)**	**SO_2**	**Distance (m)**	**Direction (deg)**
CASE011	0.71334	95082903	317,879	4,619,236	0.0	497.49	700	150
CASE012	0.70621	95082903	317,879	4,619,236	0.0	492.52	700	150
~~CASE013~~	~~0.29807~~	~~94070609~~	~~320,473~~	~~4,621,542~~	~~14.7~~	~~52.25~~	~~3,400~~	~~60~~
CASE014	0.13131	92070212	317,303	4,618,562	0.0	96.47	1,300	190
CASE021	1.09639	95082903	317,879	4,619,236	0.0	478.32	700	150
CASE022	1.06162	95082903	317,879	4,619,236	0.0	463.15	700	150
~~CASE023~~	~~0.36343~~	~~94122324~~	~~317,015~~	~~4,619,229~~	~~0.0~~	~~41.92~~	~~800~~	~~220~~
CASE024	0.22499	95062812	316,610	4,620,614	2.8	84.00	1,200	310
CASE031	1.39214	95082903	317,879	4,619,236	0.0	368.64	700	150
CASE032	1.33055	95082903	317,879	4,619,236	0.0	352.33	700	150
~~CASE033~~	~~0.53989~~	~~94071709~~	~~315,129~~	~~4,619,842~~	~~0.0~~	~~36.53~~	~~2,400~~	~~270~~
CASE034	0.37548	95021503	318,093	4,619,637	0.2	25.02	600	110
8-Hour	**XOQ**	**yymmddhh**	**UTM E (m)**	**UTM N (m)**	**ELEV (m)**	**SO_2**	**Distance (m)**	**Direction (deg)**
CASE011	0.4472	92042808	318,311	4,615,411	63.1	311.88	4,500	170
CASE012	0.47444	92042808	318,224	4,615,903	59.0	330.88	4,000	170
~~CASE013~~	~~0.18461~~	~~91072116~~	~~319,457~~	~~4,617,544~~	~~58.6~~	~~32.36~~	~~3,000~~	~~140~~
CASE014	0.05838	91061416	320,029	4,615,512	60.0	42.89	5,000	150
CASE021	0.65986	92111008	317,583	4,619,491	0.9	287.88	355	171
CASE022	0.70466	92111008	317,557	4,619,453	0.7	307.42	390	176
~~CASE023~~	~~0.23064~~	~~94072016~~	~~317,147~~	~~4,622,009~~	~~10.4~~	~~26.60~~	~~2,200~~	~~350~~
CASE024	0.11617	91061416	319,229	4,616,898	58.3	43.37	3,400	150
CASE031	0.86532	92111008	317,583	4,619,491	0.9	229.14	355	171
CASE032	0.91107	92111008	317,557	4,619,453	0.7	241.25	390	176
~~CASE033~~	~~0.26582~~	~~91072116~~	~~319,457~~	~~4,617,544~~	~~58.6~~	~~17.99~~	~~3,000~~	~~140~~
CASE034	0.22094	92102824	318,073	4,620,211	7.3	14.72	658	56
24-Hour	**XOQ**	**yymmddhh**	**UTM E (m)**	**UTM N (m)**	**ELEV (m)**	**SO_2**	**Distance (m)**	**Direction (deg)**
CASE011	0.21148	95021224	317,979	4,619,306	0.0	147.49	700	140
CASE012	0.22397	93062324	317,651	4,619,153	0.0	156.20	700	170
~~CASE013~~	~~0.06204~~	~~91072124~~	~~319,457~~	~~4,617,544~~	~~58.6~~	~~10.87~~	~~3,000~~	~~140~~
CASE014	0.02112	92020224	317,529	4,612,842	91.0	15.52	7,000	180
CASE021	0.31028	95021224	317,979	4,619,306	0.0	135.37	700	140
CASE022	0.31989	95021224	317,979	4,619,306	0.0	139.56	700	140
~~CASE023~~	~~0.08834~~	~~91071424~~	~~317,529~~	~~4,612,842~~	~~91.0~~	~~10.19~~	~~7,000~~	~~180~~
CASE024	0.055	92020224	317,529	4,612,842	91.0	20.54	7,000	180
CASE031	0.38448	95021224	317,979	4,619,306	0.0	101.81	700	140
CASE032	0.39279	95021224	317,979	4,619,306	0.0	104.01	700	140
~~CASE033~~	~~0.12119~~	~~91071424~~	~~317,529~~	~~4,613,342~~	~~88.8~~	~~8.20~~	~~6,500~~	~~180~~
CASE034	0.12981	95021224	319,586	4,617,391	61.0	8.65	3,200	140
Annual	**XOQ**	**Year**	**UTM E (m)**	**UTM N (m)**	**ELEV (m)**	**SO_2**	**Distance (m)**	**Direction (deg)**
CASE011	0.01509	1994	317,979	4,619,306	0.0	10.52	700	140
CASE012	0.01807	1994	318,087	4,620,231	8.0	12.60	680	55
~~CASE013~~	~~0.00333~~	~~1995~~	~~317,529~~	~~4,612,842~~	~~91.0~~	~~0.58~~	~~7,000~~	~~180~~
CASE014	0.00117	1992	317,529	4,612,842	91.0	0.86	7,000	180
CASE021	0.02314	1994	317,979	4,619,306	0.0	10.10	700	140
CASE022	0.02782	1994	318,087	4,620,231	8.0	12.14	680	55
~~CASE023~~	~~0.00532~~	~~1995~~	~~317,529~~	~~4,612,842~~	~~91.0~~	~~0.61~~	~~7,000~~	~~180~~
CASE024	0.00289	1993	317,529	4,612,842	91.0	1.08	7,000	180
CASE031	0.02908	1994	317,979	4,619,306	0.0	7.70	700	140
CASE032	0.03473	1994	318,087	4,620,231	8.0	9.20	680	55
~~CASE033~~	~~0.00782~~	~~1995~~	~~317,529~~	~~4,612,842~~	~~91.0~~	~~0.53~~	~~7,000~~	~~180~~
CASE034	0.00805	1994	319,586	4,617,391	61.0	0.54	3,200	140

Case01? – Maximum operating load for each boiler (? = Boiler 1, 2, 3, or 4)
Case02? – Intermediate operating load for each boiler (? = Boiler 1, 2, 3, or 4)
Case03? – Minimum operating load for each boiler (? = Boiler 1, 2, 3, or 4)

Scenario Z-1 Load Analysis Results for the Boilers at Brayton Point Station
Maximum Modeled Concentrations (ug/m^3)

Brayton Point Station - Scenario Z-1

1-Hour	XOQ	yymmddhh	UTM E (m)	UTM N (m)	ELEV (m)	SO_2	Distance (m)	Direction (deg)
CASE011	1.22699	92052205	319,229	4,616,898	58.3	458.45	3,400	150
CASE012	1.24437	91081914	317,962	4,619,592	0.0	464.95	500	120
~~CASE013~~	~~0.74018~~	~~93070811~~	~~318,281~~	~~4,619,569~~	~~0.0~~	~~69.51~~	~~800~~	~~110~~
CASE014	0.39393	92070210	317,303	4,618,562	0.0	576.56	1,300	190
CASE021	1.75481	92052205	319,229	4,616,898	58.3	410.15	3,400	150
CASE022	1.73978	92052104	321,074	4,619,217	61.0	406.64	3,600	100
~~CASE023~~	~~0.96189~~	~~93070811~~	~~318,187~~	~~4,619,603~~	~~0.2~~	~~59.44~~	~~700~~	~~110~~
CASE024	0.62865	95062811	316,758	4,620,761	4.6	467.58	1,200	320
CASE031	2.05832	92052205	319,229	4,616,898	58.3	292.01	3,400	150
CASE032	2.03755	92052104	321,074	4,619,217	61.0	289.07	3,600	100
~~CASE033~~	~~1.15662~~	~~93070811~~	~~318,187~~	~~4,619,603~~	~~0.2~~	~~41.93~~	~~700~~	~~110~~
CASE034	0.75513	93101112	316,779	4,621,141	5.0	100.25	1,500	330
3-Hour	**XOQ**	**yymmddhh**	**UTM E (m)**	**UTM N (m)**	**ELEV (m)**	**SO_2**	**Distance (m)**	**Direction (deg)**
CASE011	0.71337	95082903	317,879	4,619,236	0.0	266.54	700	150
CASE012	0.70624	95082903	317,879	4,619,236	0.0	263.88	700	150
~~CASE013~~	~~0.29807~~	~~94070609~~	~~320,473~~	~~4,621,542~~	~~14.7~~	~~27.99~~	~~3,400~~	~~60~~
CASE014	0.13131	92070212	317,303	4,618,562	0.0	192.19	1,300	190
CASE021	1.09648	95082903	317,879	4,619,236	0.0	256.28	700	150
CASE022	1.0617	95082903	317,879	4,619,236	0.0	248.15	700	150
~~CASE023~~	~~0.36343~~	~~94122324~~	~~317,015~~	~~4,619,229~~	~~0.0~~	~~22.46~~	~~800~~	~~220~~
CASE024	0.22499	95062812	316,610	4,620,614	2.8	167.35	1,200	310
CASE031	1.39198	95082903	317,879	4,619,236	0.0	197.48	700	150
CASE032	1.3304	95082903	317,879	4,619,236	0.0	188.74	700	150
~~CASE033~~	~~0.53989~~	~~94071709~~	~~315,129~~	~~4,619,842~~	~~0.0~~	~~19.57~~	~~2,400~~	~~270~~
CASE034	0.37856	95021503	318,093	4,619,637	0.2	50.26	600	110
8-Hour	**XOQ**	**yymmddhh**	**UTM E (m)**	**UTM N (m)**	**ELEV (m)**	**SO_2**	**Distance (m)**	**Direction (deg)**
CASE011	0.44721	92042808	318,311	4,615,411	63.1	167.10	4,500	170
CASE012	0.47446	92042808	318,224	4,615,903	59.0	177.28	4,000	170
~~CASE013~~	~~0.18461~~	~~91072116~~	~~319,457~~	~~4,617,544~~	~~58.6~~	~~17.34~~	~~3,000~~	~~140~~
CASE014	0.05838	91061416	320,029	4,615,512	60.0	85.45	5,000	150
CASE021	0.65991	92111008	317,583	4,619,491	0.9	154.24	355	171
CASE022	0.7047	92111008	317,557	4,619,453	0.7	164.71	390	176
~~CASE023~~	~~0.23064~~	~~94072016~~	~~317,147~~	~~4,622,009~~	~~10.4~~	~~14.25~~	~~2,200~~	~~350~~
CASE024	0.11617	91061416	319,229	4,616,898	58.3	86.41	3,400	150
CASE031	0.86524	92111008	317,583	4,619,491	0.9	122.75	355	171
CASE032	0.91099	92111008	317,557	4,619,453	0.7	129.24	390	176
~~CASE033~~	~~0.26582~~	~~91072116~~	~~319,457~~	~~4,617,544~~	~~58.6~~	~~9.64~~	~~3,000~~	~~140~~
CASE034	0.22272	92102824	318,073	4,620,211	7.3	29.57	658	56
24-Hour	**XOQ**	**yymmddhh**	**UTM E (m)**	**UTM N (m)**	**ELEV (m)**	**SO_2**	**Distance (m)**	**Direction (deg)**
CASE011	0.21149	95021224	317,979	4,619,306	0.0	79.02	700	140
CASE012	0.22398	93062324	317,651	4,619,153	0.0	83.69	700	170
~~CASE013~~	~~0.06204~~	~~91072124~~	~~319,457~~	~~4,617,544~~	~~58.6~~	~~5.83~~	~~3,000~~	~~140~~
CASE014	0.02112	92020224	317,529	4,612,842	91.0	30.91	7,000	180
CASE021	0.3103	95021224	317,979	4,619,306	0.0	72.53	700	140
CASE022	0.31991	95021224	317,979	4,619,306	0.0	74.77	700	140
~~CASE023~~	~~0.08834~~	~~91071424~~	~~317,529~~	~~4,612,842~~	~~91.0~~	~~5.46~~	~~7,000~~	~~180~~
CASE024	0.055	92020224	317,529	4,612,842	91.0	40.91	7,000	180
CASE031	0.38445	95021224	317,979	4,619,306	0.0	54.54	700	140
CASE032	0.39276	95021224	317,979	4,619,306	0.0	55.72	700	140
~~CASE033~~	~~0.12119~~	~~91071424~~	~~317,529~~	~~4,613,342~~	~~88.8~~	~~4.39~~	~~6,500~~	~~180~~
CASE034	0.13082	95021224	319,586	4,617,391	61.0	17.37	3,200	140
Annual	**XOQ**	**Year**	**UTM E (m)**	**UTM N (m)**	**ELEV (m)**	**SO_2**	**Distance (m)**	**Direction (deg)**
CASE011	0.01509	1994	317,979	4,619,306	0.0	5.64	700	140
CASE012	0.01807	1994	318,087	4,620,231	8.0	6.75	680	55
~~CASE013~~	~~0.00333~~	~~1995~~	~~317,529~~	~~4,612,842~~	~~91.0~~	~~0.31~~	~~7,000~~	~~180~~
CASE014	0.00117	1992	317,529	4,612,842	91.0	1.71	7,000	180
CASE021	0.02314	1994	317,979	4,619,306	0.0	5.41	700	140
CASE022	0.02782	1994	318,087	4,620,231	8.0	6.50	680	55
~~CASE023~~	~~0.00532~~	~~1995~~	~~317,529~~	~~4,612,842~~	~~91.0~~	~~0.33~~	~~7,000~~	~~180~~
CASE024	0.00289	1993	317,529	4,612,842	91.0	2.15	7,000	180
CASE031	0.02908	1994	317,979	4,619,306	0.0	4.13	700	140
CASE032	0.03473	1994	318,087	4,620,231	8.0	4.93	680	55
~~CASE033~~	~~0.00782~~	~~1995~~	~~317,529~~	~~4,612,842~~	~~91.0~~	~~0.28~~	~~7,000~~	~~180~~
CASE034	0.00828	1994	319,586	4,617,391	61.0	1.10	3,200	140

Case01? – Maximum operating load for each boiler (? = Boiler 1, 2, 3, or 4)
Case02? – Intermediate operating load for each boiler (? = Boiler 1, 2, 3, or 4)
Case03? – Minimum operating load for each boiler (? = Boiler 1, 2, 3, or 4)

Load Analysis Results for Unit 3 at Brayton Point Station

1-Hour	XOQ	yymmddhh	UTM E (m)	UTM N (m)	Elev. (m)	NO2 (µg/m^3)	CO (µg/m^3)	PM-10 (µg/m^3)	SO2 Y-1 (µg/m^3)	SO2 Z-1 (µg/m^3)	Distance (m)	Direction (deg)
Case013	1.03856	94122320	317282	4619533	0.6	332.99	122.84	18.50	182.04	97.68	399	218
Case023	1.54037	94122320	317079	4619306	0.0	305.69	112.76	16.97	167.10	89.66	700	220
Case033	2.13067	92052409	317282	4619533	0.6	241.62	89.13	13.42	132.08	70.87	399	218
3-Hour	XOQ	yymmddhh	UTM E (m)	UTM N (m)	Elev. (m)	NO2 (µg/m^3)	CO (µg/m^3)	PM-10 (µg/m^3)	SO2 Y-1 (µg/m^3)	SO2 Z-1 (µg/m^3)	Distance (m)	Direction (deg)
Case013	0.56097	94122324	317143	4619383	0.0	179.86	66.35	9.99	98.33	52.76	600	220
Case023	0.75135	94122324	317282	4619533	0.6	149.11	55.00	8.28	81.51	43.74	399	218
Case033	1.53607	91110112	317069	4619457	0.0	174.19	64.25	9.68	95.22	51.09	600	230
8-Hour	XOQ	yymmddhh	UTM E (m)	UTM N (m)	Elev. (m)	NO2 (µg/m^3)	CO (µg/m^3)	PM-10 (µg/m^3)	SO2 Y-1 (µg/m^3)	SO2 Z-1 (µg/m^3)	Distance (m)	Direction (deg)
Case013	0.34146	94122324	317282	4619533	0.6	109.48	40.39	6.08	59.85	32.11	399	218
Case023	0.44688	94122324	317143	4619383	0.0	88.68	32.71	4.92	48.48	26.01	600	220
Case033	0.72689	91110116	317069	4619457	0.0	82.43	30.41	4.58	45.06	24.18	600	230
24-Hour	XOQ	yymmddhh	UTM E (m)	UTM N (m)	Elev. (m)	NO2 (µg/m^3)	CO (µg/m^3)	PM-10 (µg/m^3)	SO2 Y-1 (µg/m^3)	SO2 Z-1 (µg/m^3)	Distance (m)	Direction (deg)
Case013	0.18096	91103024	317069	4619457	0.0	58.02	21.40	3.22	31.72	17.02	600	230
Case023	0.25730	91103024	317069	4619457	0.0	51.06	18.83	2.84	27.91	14.98	600	230
Case033	0.36834	92121224	317282	4619533	0.6	41.77	15.41	2.32	22.83	12.25	399	218
Annual	XOQ	Year	UTM E (m)	UTM N (m)	Elev. (m)	NO2 (µg/m^3)	CO (µg/m^3)	PM-10 (µg/m^3)	SO2 Y-1 (µg/m^3)	SO2 Z-1 (µg/m^3)	Distance (m)	Direction (deg)
Case013	0.00610	1993	317529	4612842	91	1.956	0.72	0.11	1.07	0.57	7000	180
Case023	0.00989	1993	317529	4612842	91	1.963	0.72	0.11	1.07	0.58	7000	180
Case033	0.01649	1993	317529	4613342	89	1.870	0.69	0.10	1.02	0.55	6500	180

ISCST3 (02035) Modeling with 1991-1995 Providence/Chatham meteorological data
Case013 = Maximum operating load for Boiler 3
Case023 = Intermediate operating load for Boiler 3
Case033 = Minimum operating load for Boiler 3

TABLE FROM JUNE 2006 APPLICATION
SHOWING SO2 OPERATING SCENARIOS

Table 4-3: Representative Station SO_2 Operating Scenarios – Modeling Matrix

Scenario	Description	Unit	Emissions Basis	Emission Rate (lb/MMBtu)	Emission Rate (lb/hr)	Total Station Emission Rate (lb/hr)	AFFECTED BY PROPOSED UNIT 3 CHANGE?
A-2	Units 1&2 Scrubbed Units 3&4 Unscrubbed	1	Scrubbed[a]	0.66	1,479	18,292	NO
		2	Scrubbed[a]	0.66	1,479		
		3	Unscrubbed/Low Sulfur Coal[b]	0.66	3,718		
		4	Maximum SO_2 Limit	2.42	11,616		
B-2	Units 1&2 Scrubbed Unit 3 Unscrubbed Unit 4 Firing Low Sulfur Oil	1	Scrubbed	0.39	870	18,292	NO
		2	Scrubbed	0.39	870		
		3	Maximum SO_2 Limit	2.46	13,911		
		4	0.05%S Oil	0.55	2,640		
E-1	Unit 1 Scrubbed Units 2&3 Unscrubbed Unit 4 Off-line/Natural Gas Fired	1	Scrubbed	0.225	506	18,292	NO
		2	Unscrubbed	2.25	5,063		
		3	Unscrubbed	2.25	12,724		
		4	Off-line/Natural Gas Fired	0.00	0		
E-2	Unit 1 Scrubbed Units 2, 3&4 Unscrubbed	1	Scrubbed[c]	0.25	563	18,292	NO
		2	Unscrubbed/Low Sulfur Coal[b]	0.77	1,740		
		3	Unscrubbed/Low Sulfur Coal[b]	0.77	4,373		
		4	Maximum SO_2 Limit	2.42	11,616		
F-2	Units 1&2 Unscrubbed Unit 3 Off-line Unit 4 Unscrubbed	1	Unscrubbed	1.48	3,338	18,292	NO
		2	Unscrubbed	1.48	3,338		
		3	Off-line	0.00	0		
		4	Maximum SO_2 Limit	2.42	11,616		
G-2	Unit 1 Off-line Units 2&3 Firing Low Sulfur Coal Unit 4 Unscrubbed	1	Off-line[d]	0.00	0	18,292	NO
		2	Unscrubbed/Low Sulfur Coal[b]	0.84	1,900		
		3	Unscrubbed/Low Sulfur Coal[b]	0.84	4,776		
		4	Maximum SO_2 Limit	2.42	11,616		
Y-1	Units 1, 2,&4 Unscrubbed Unit 3 Scrubbed	1	Maximum SO_2 Limit	2.46	5,535	18,292	YES
		2	Maximum SO_2 Limit	2.46	5,535		
		3	Scrubbed	0.246	1,391		
		4	Unscrubbed	1.21	5,831		
Z-1	Units 1, 2,&4 Unscrubbed Unit 3 Scrubbed	1	Unscrubbed	1.32	2,965	18,292	YES
		2	Unscrubbed	1.32	2,965		
		3	Scrubbed	0.132	745		
		4	Maximum SO_2 Limit	2.42	11,616		
H-1	Units 1,2&3 Unscrubbed	1	Unscrubbed	1.66	3,735	16,857	NO

TABLE FROM JUNE 2006 APPLICATION
SHOWING SO2 OPERATING SCENARIOS

Scenario	Description	Unit	Emissions Basis	Emission Rate (lb/MMBtu)	Emission Rate (lb/hr)	Total Station Emission Rate (lb/hr)	
	Unit 4 Off-line/Natural Gas Fired	2	Unscrubbed	1.66	3,735		
		3	Unscrubbed	1.66	9,387		
		4	Off-line/Natural Gas Fired	0.00	0		
H-2	Units 1,2,3&4 Unscrubbed	1	Unscrubbed	1.13	2,536	16,857	NO
		2	Unscrubbed	1.13	2,536		
		3	Unscrubbed	1.13	6,374		
		4	Unscrubbed	1.13	5,411		
H-3	Units 1,2,3&4 Unscrubbed	1	Unscrubbed	0.52	1,161	16,857	NO
		2	Unscrubbed	0.52	1,161		
		3	Unscrubbed	0.52	2,919		
		4	Maximum SO_2 Limit	2.42	11,616		

[a] This unit operating mode could also represent an unscrubbed unit (with higher stack temperature) with low-sulfur coal.

[b] This unit operating mode might also be representative for a scrubbed unit (with lower Stack Temperature) operating below design SO_2 removal efficiency.

[c] Thus unit operating mode (only Unit 1 scrubbed) is also representative of a scenario where only Unit 2 is scrubbed because of the similar stack and exhaust parameters and proximity of the stacks for the two units.

[d] This unit operating mode (Unit 1 off-line) is also representative scenario where Unit 2 is off-line because of the similar stack and exhaust parameters and proximity of the stacks for the two units.