ENGINEERING ANALYSIS

Source Name: **Hopewell Power Station,** Registration No.: **51019**

Source Location: **107 Terminal Street, Hopewell, VA** County-Plant No.: **670-0063**

Date: **March 15, 2012** Permit Writer: **ROS**

I. Introduction and Background

A. Company Background

Virginia Electric and Power Company (Dominion) submitted a Prevention of Significant Deterioration (PSD) permit application May 25, 2011 to convert the Hopewell Power Station (HPS) from burning coal to burning biomass. The HPS currently operates two primary coal-fired spreader stoker Babcox and Wilcox (B & W) boilers each rated at 391 MMBtu/hr and associated equipment as a cogeneration facility under a PSD permit issued on January 30, 2012 (51019-14). The HPS also has a state operating permit (SOP) issued on October 2, 2002 that limits the hazardous air pollutants (HAPs) from burning coal.

The UTM coordinates for the facility are Zone 18 Easting 297.604 and Northing 4,130.288. The company is located on a site that is suitable from an air pollution standpoint. The City of Hopewell has certified that the location and operation of the facility are consistent with all applicable ordinances adopted pursuant to Chapter 22 (Section15.2-22001-427 et seq.) of Title 15.2 of the Code of Virginia. The City of Hopewell signed the local governing body certification form on May 19, 2011.

B. Proposed Project Summary, Process and Equipment Description

Dominion proposes to modify the two primary B & W boilers to convert the boilers from burning coal to burning biomass. After the conversion, the facility will not be able to burn coal.

The biomass conversion project is considered a major modification under the PSD regulations, so a new PSD permit will be issued. This new PSD permit will supersede the facility's current (January 30, 2012) permit. The January 30, 2012 permit is the most recent version of the PSD permit originally issued in 1990 for the construction of the (then) coal-fired boilers. When the new PSD permit is issued, the Department of Environmental Quality (DEQ) plans to rescind the SOP issued on October 2, 2002 because the HPS is subject to 40 CFR 63, Subpart DDDDD (Boiler MACT). The State Toxic regulations at 9 VAC 5-60-300 C provide an exemption from the state toxic regulations for facilities subject to a MACT standard.

The HPS is a major stationary source because it is one of 28 source categories (fossil fuel-fired steam electric plant of more than 250 MMBtu/hr heat input) that emits or has the potential to emit more than 100 tons per year of a new source review (NSR) regulated pollutant. The facility also emits or has the potential to emit more than 250 tons per year of a NSR regulated pollutant.

The biomass conversion project is a PSD major modification because the Hopewell Power Station is a major stationary source and the conversion of the boilers from coal to biomass is a physical change that results in a significant emissions increase and a significant net emissions increase of carbon monoxide (CO).

After the conversion to biomass, the boilers will be subject to NSPS 40 CFR 60, Subpart Db because the boilers will not burn a fossil fuel with a capacity greater than 250 MMBtu/hr.

Equipment to be modified: Fuel Burning Equipment			
Reference No.	**Equipment Description**	**Rated Capacity**	**Delegated Federal Requirements**
001	One (1) B & W single drum, single pass stoker boiler that includes an overfire air (OFA) system to generate steam for process use and electricity generation (combusts biomass; startup – natural gas)	394 mmBTU/hr (maximum) 379 mmBTU/hr (nominal)	NSPS Subpart Db MACT Subpart DDDDD
002	One (1) B & W single drum, single pass stoker boiler that includes an overfire air (OFA) system to generate steam for process use and electricity generation (combusts biomass; startup – natural gas)	394 mmBTU/hr (maximum) 379 mmBTU/hr (nominal)	NSPS Subpart Db MACT Subpart DDDDD

The term biomass is described as those residuals that are akin to traditional cellulosic biomass including forest-derived biomass (*e.g.*, green wood, forest thinning, clean and unadulterated bark, sawdust, trim, and tree harvesting residuals from logging and sawmill materials), wood collected from forest fire clearance activities, trees and clean wood found in disaster debris, and clean biomass from land clearing operations, each as specified in the definition of Clean Cellulosic Biomass in 40 CFR 241.2, excluding any wood which contains chemical treatments or has affixed thereto paint and/or finishing materials or paper or plastic laminates. Approved biomass is biomass that does not contain contaminants at concentrations not normally associated with virgin biomass materials.

During the conversion from coal to biomass, Dominion will install an enhanced overfire (OFA) system in each B & W boiler to work with the undergrate air system, the fuel feed system and the combustion control system. The new OFA system will provide about 50 percent of the total combustion air above the grate and will replace the OFA system that was designed for coal. The enhanced OFA system is considered an integral part of the boiler modification and not an add-on control device. The boilers will have an emission rate of 0.30 lb/mmbtu of CO.

After the conversion to biomass, the B & W boilers will each be rated at 394 MMBtu/hr for maximum capacity and at 379 MMBtu/hr for nominal capacity. The maximum capacity rating of 394 MMBtu/hr is used to determine the emissions in terms of lb/hr and the nominal rating of 379 MMBtu/hr is used to determine the emissions in terms of tons/year. Each B & W boiler will not operate more than 8400 hours per year. There is a limit for the facility of 784,480 tons per year of biomass for the material handling system..

The primary biomass B & W boilers will use the existing control devices. Particulate emissions will be controlled by an in-line multiple cyclone, a lime water injection dryer (dry flue gas desulfurization) and a fabric filter rated at 99 percent control efficiency. Sulfur dioxide emissions will be controlled by a lime water injection spray injection spray dryer (dry FGD) rated at 75 percent control efficiency. Nitrogen dioxide will be controlled will be controlled by a continuous biomass feed system, staged combustion low excess air and selective non-catalytic reduction (SNCR) rated at 40 percent control efficiency.

In addition to the primary boilers, the HPS has other combustion sources: two natural gas-fired auxiliary boilers, an emergency diesel generator, an emergency diesel feed water pump, a portable welder diesel engine and a fire water diesel pump. None of these other emission units are included in the proposed project since Dominion has not indicated any intention to modify any of them.

There are also material handling systems at the facility for biomass, lime, fly ash and bottom ash.

According to Dominion's application concerning the biomass handling system, the HPS will receive biomass by tractor-trailer truck. Dominion will install hydraulic truck dumpers to unload tractor-trailers into live-bottom receiving hoppers. The live-bottom bins will transfer biomass to a belt conveyor that will discharge the biomass onto a rotary disc screen. The screened biomass will fall into a stacker/reclaimer for storage and the larger pieces will feed into a hammer mill for size reduction. The green wood will have a maximum size of 4 inches. The stacker/reclaimers will transfer this product to the boiler house. The biomass fuel handling system has an unloading design capacity of 269 tons/hr and boiler feed design capacity of 90 tons/hr.

The burning of biomass produces fly ash and bottom ash and Dominion plans to modify their ash handling system to accommodate biomass. According to the application, Dominion will: (1) Replace the existing furnace bottom ash pneumatic system with a submerged ash conveyor. The new conveyor will transport water quenched bottom ash to a roll off box. (2) Install a new ash drag serving the ash hoppers at the exit of the boiler generating bank. This drag conveyor will be furnished with a water spray nozzle to cool the ash prior to transferring the ash to a roll off box. (3) Install a new ash drag serving the ash hoppers on the existing mechanical collector. This dray conveyor will be furnished with a water spray nozzle to cool the ash prior to transferring the ash to a roll off box.

Dominions says that because flue gas will be cooled in the dry FGD system that fly ash discharged from the fabric filters will be handled by the existing pneumatic ash handling system. The ash will be removed from the site by 25-ton tractor-trailer trucks.

Concerning lime handling, Dominion plans to use the existing dry FGD system and baghouse for flue gas desulfurization. Each boiler has a dry FGD system to control sulfur emissions from the burning of coal. Although uncontrolled SO2 emissions from biomass are less than controlled SO2 emissions from coal, Dominion says it is necessary to operate the dry FGD system to cool the flue gas in order to prevent a baghouse fire from unburned carbon in the fly ash.

Equipment to be installed: Biomass Handling System			
Ref. No.	**Equipment Description**	**Rated Capacity**	**Delegated Federal Requirements**
101 A	One (1) biomass truck tipper to one (1) receiving hopper	269 tons	
101 B	One (1) biomass truck tipper to one (1) receiving hopper	269 tons	
101C	One (1) emergency reclaimer	90 tons	
102	One (1) biomass storage pile	3 mm cubic feet	
104-1	Truck Tipper Reclaim # 1 to Conveyor A Transfer Point	269 tons/hr	
104-2	Truck Tipper Reclaim # 2 to Conveyor A Transfer Point	269 tons/hr	
104-3	Conveyor B to Diverter Gate #2 Transfer Point	269 tons/hr	
104-4	Conveyor C to Stacker Transfer Point	269 tons/hr	
104-5	Reclaimer to Conveyor D Transfer Point	90 tons/hr	
104-6	Emergency Reclaimer to Conveyor D Transfer Point	90 tons/hr	
104-8	Conveyor D to Conveyor E Transfer Point	90 tons/hr	
104-9	Conveyor E to Conveyor F Transfer Point	90 tons/hr	
104-10	Conveyor F to Fuel Bunker Drag Chain Transfer Point	90 tons/hr	
106	Biomass Screening and Hogging System	269 tons/yr	
107	Ash Collection System (includes furnace bottom ash drag, boiler ash collection drag and mechanical collector ash collection drag)	N/A	

C. Project Schedule

Date permit application received in region: May 31, 2011
Date application was deemed complete: March 12, 2012
Proposed construction commencement date: Dominion plans to shut down the facility in June, 2013 for the conversion to biomass
Proposed start-up date: Dominion plans to restart the facility using biomass in September, 2013

D. Boilerplate Deviations

This permit uses the NSR boilerplate (amended in December, 2009) and the Hopewell Power Station permit issued on January 30, 2012.

II. Emissions Calculations (see attached spreadsheets)

Criteria Pollutants

To calculate the emissions from the two primary biomass boilers, Dominion used the following parameters:

394 MMBtu/hr – maximum heat input – used to determine lb/hr
379 MMBtu/hr – nominal heat input - used to determine tons/yr
6,109,480 MMBtu/yr – future annual operation of both boilers
8,400 hours of operation per year per boiler

For NOx, CO and SO2, Dominion uses a controlled emission factor in lb/mmbtu to calculate emissions as demonstrated in the following example:

394 mmbtu/hr x 0.135 lb/mmbtu NOx = 53.19 lb/hr NOx
6,109,480 mmbtu/yr x 0.135 lb/mmbtu NOx / 2000 lb/ton = 412.39 tons/yr NOx for 2 boilers

DEQ verified the Dominion emissions by using an uncontrolled emission factor times a control equipment efficiency. Here is an example:

394 mmbtu/hr x 0.225 lb/mmbtu NOx x (1-.40) = 53.19 lb/hr NOx
6,109,480 mmbtu/yr x 0.225 lb/mmbtu NOx / 2000 lb/ton x (1-.40) = 412.39 tons/yr NOx for 2 boilers

For PM (total), PM 10 (total), PM 2.5 (total), VOC, H2SO4, Dominion uses 8400 hrs/yr as shown in the following example:

78.8 tons/yr PM (total) baseline actual emissions – 1.54 tons/yr PM material handling + 25 tons/yr PSD PM threshold – 0.1 = 102.16 tons/yr PM (total) for two boilers
102.16 tons/yr PM (total) / 2 = 51.08 tons/yr PM (total) for one boiler
51.08 tons/yr PM (total) x 2000 lb/ton / 8400 hrs/yr = 12.16 lb/hr PM (total) for one boiler

For Fluorides, the permit uses the same values as the 01-30-12 permit.

Criteria Emissions from One Primary Biomass Boiler (Ref. No. 001 or 002)

Pollutants	**lbs/10^6 btu**	**lbs/hr**	**tons/yr**
Particulate Matter (PM)			
Total PM		12.16	51.08
Filterable PM	0.019	7.5	
PM 10			
Total PM 10		11.08	46.55
Filterable PM 10	0.017	6.7	
PM 2.5			
Total PM 2.5		10.55	44.31
Sulfur Dioxide	0.0125 ^^	4.9	19.1
Nitrogen Oxides*	0.135 ^^	53.2	206.4
Carbon Monoxide	0.30 ^^	118.3	458.6
Volatile Organic Compounds**	0.030	5.21	21.89
Fluorides, as HF		0.3	1.1
Sulfuric Acid Mist		0.90	3.78

*Lower limits may be imposed by the DEQ after review of in-stack testing and optimizing the SNCR system at various loads.
**Lower limits may be imposed by the DEQ after in-stack testing.
^^ Compliance is determined on a 30-day rolling average.

The criteria emissions from the operation of the two B & W biomass boilers (Ref. Nos. 001, 002) two auxiliary boilers (Ref. Nos. 003, 005) are:

Pollutant	Emissions
Particulate Matter (PM)	102.7 tons/yr
PM10,	93.5 tons/yr
CO,	917.8 tons/yr
NOx *	413.7 tons/yr
SO2,	42.3 tons/yr
VOC,**	44.3 tons/yr

These limitation are based on the primary biomass boilers operating at 8,400 hours per year and the auxiliary boilers combined operating at 360 hour per year.
*Lower limits may be imposed by the DEQ after review of in-stack testing and optimizing the SNCR system at various loads.
**Lower limits may be imposed by DEQ after in-stack testing.

III. Regulatory Review

The New Source Review (NSR) regulations are found in parts C and D of Title 1 of the Clean Air Act. The purpose of the regulations is to protect the public health and welfare, including the national parks and wilderness areas, while new sources are constructed and existing sources expand. The idea is that a source should install modern pollution control equipment when it is built (new source) or when it makes a major modification that significantly increases emissions (existing sources). There are two NSR programs: prevention of significant deterioration (PSD) for areas that meet the national ambient air quality standards (NAAQS) and nonattainment NSR for areas that do not meet the NAAQS.

9 VAC 5-80-1605 PSD Major New Source Review (Article 8)

The city of Hopewell meets all of the NAAQS and is an attainment area. A major source that locates in an attainment area is subject to PSD regulations. A source with the potential to emit greater than 250 tons per year, or 100 tons per year if it is one of 28 source categories, is a major stationary source. The HPS is a fossil fuel-fired steam electric plant of more than 250 million Btu/hr heat input. A fossil fuel-fired steam electric plant is one of the 28 source categories, thus it is a major source if the potential to emit is 100 tons per year. The HPS has the potential to emit more than 100 of CO, NOx and VOC. The HPS is a major stationary source subject to PSD. A source that is subject to PSD for one pollutant is subject to PSD for all pollutants that exceed the significant emission rates.

In major new source review, a major modification is any physical change or change in the method of operation of a major stationary source that would result in a significant emissions increase (SEI) of a regulated new source review pollutant, and a significant net emissions (SNEI) increase of that pollutant from the major stationary source (9 VAC 5-80-1615). The major new source review regulations allow a source to use the actual-to-projected actual applicability test to determine a significant emissions increase (SEI) for modified emission units such as the HPS primary boilers. For new emission units, such as the new HPS biomass fuel handling system, the regulations require the use of the new unit's potential-to-emit (PTE).

A significant emissions increase (SEI) is an emissions increase (EI) that exceeds the significance level for that pollutant. An EI resulting from a project is significant for a pollutant if the difference between the baseline actual emissions (BAE) and the projected actual emissions for any modified units in summation with the PTE of any new units is greater than the pollutant's significance levels. The regulations also allow the use of PTE instead of projected actual emissions for modified emission units. By agreeing to include the projected actual emissions from the modified primary boilers as practically enforceable PTE limitations in the proposed permit, the applicant has effectively adopted this approach for the proposed project.

The BAE are the average rate, in tons per year, at which a unit actually emitted a pollutant during any consecutive 24-month period selected by the owner within the five-year period immediately preceding when the owner begins actual construction of a project.

As the Chart 1 shows, the source used a consecutive 24-month period of operation from July, 2007 to June, 2009 within a five year period as the baseline period for the BAE. The source used the proposed PTE limitations as the future emissions and showed there was a significant emissions increase (SEI) of only one regulated new source review pollutant, CO, from the primary boilers. There were no contemporaneous increases or decrease in CO emissions, so the significant emissions increase is equivalent to the significant net emissions (SNEI) for CO emissions. The SNEI exceeds the PSD significant threshold for CO emissions, so best available technology (BACT) applies to the CO emissions.

Chart 1
PSD applicability (Article 8) – 9 VAC 5-80-1605
– BAE to PTE – emissions for two boilers

Pollutant	07/07 to 06/09 BAE* tons/yr	01-17-12 Response for Table 3-4 Potential To Emit (PTE)** tons/yr	Emissions Increase/ Decrease tons/yr	PSD 5-80-1650 Significant Threshold Level tons/yr	Is this a significant emissions increase (SEI)?	Contemp. Increase/ Decrease tons/yr	Is this a significant net emissions (SNEI) increase?	If SNEI Exceeds 5-80-1650 BACT Applies
PM (Total)	78.8	102.16	23.36	25	NO	N/A	NO	NO
PM10 (Total)	78.8	93.10	14.3	15	NO	N/A	NO	NO
SO2	65.9	38.2	-27.7	40	NO	N/A	NO	NO
VOC	3.9	43.79	39.9	40	NO	N/A	NO	NO
CO	64.6	916.4	851.8	100	YES	0	YES	YES
NOx	456.9	412.4	-44.5	40	NO	N/A	NO	NO
PM2.5 (Total)	78.8	88.63	9.83	10	NO	N/A	NO	NO

* BAE for PM, PM10, PM2.5 does not include 2.6 tons/yr material handling.

** Includes revised future projected actual for PM (total), PM10 (total), PM2.5 (total) from 03-12012 Dominion letter on boiler conversion details

In addition to the emission increases from the modified primary boilers, the permit applicability determination for the proposed project must also include any emission increases from the construction of the new biomass fuel handling system. For new emission units, Article 8 requires that permit applicability be based on PTE. As calculated in Dominion's application, verified by DEQ calculations and established in the proposed permit, the PTE of the new biomass fuel handling system is 1.54 tons/yr of PM, 0.6 tons/yr of PM10 and 0.1 tons/yr of PM2.5. As shown below, when added to the values for the primary boilers from Chart 1, there is no SNEI for PM, PM10 or PM2.5.

	Combined Boiler SNEI	Biomass Fuel Handling PTE	Total EI for Project	Exceeds Significance Level?
PM	23.36 tons/yr	1.54 tons/yr	24.9 tons/yr	No
PM10	14.3 tons/yr	0.6 tons/yr	14.9 tons/yr	No
PM2.5	9.83 tons/yr	0.1 tons/yr	9.9 tons/yr	No

9 VAC 5-80-1100 Minor New Source Review (Article 6)

A modification is any physical change, a change in the method of operation to a stationary source that would result in a net emissions increase of any regulated air pollutant (9 VAC 5-80-1100 C).

A net emissions increase, in the minor new source regulations, is any increase in the uncontrolled emission rate from a particular physical change or change in the method of operation. The uncontrolled emission rate is the emission rate when a unit is operating at maximum rated capacity without air pollution control equipment at 8,760 hours per year. If the unit or source is subject to a permit, then the enforceable permit conditions that determine the permit limits serve as the uncontrolled emission rate of the unit or source (9 VAC 5-80-1110 C).

The use of biomass at the HPS is a modified unit at a permitted source. Previously, the unit used coal. In this case, the APG-354 guidance says the net emissions increase (NEI) is found by determining the new uncontrolled emissions (uncontrolled emissions after the modification – post project) subtracting the current throughput or hours of operation without controls. If the NEI exceeds the levels in 9 VAC 5-80-1320 D, then the unit needs a permit. If the NEI does not exceed the levels in 9 VAC 5-80-1320 D, then the proposed change is a permit amendment.
As Chart 2 shows, there is a net emissions increase for CO only and so there is a modification under Article 6, minor new source review. However, CO is also subject to the Article 8 major new source review as shown in Chart 1. According to 9 VAC 5-80-1100 H. 1, Article 6 applies to sources and their emissions that are not subject to major new source review. Since CO is subject to major new source review (PSD), then CO cannot be also subject to Article 6, minor new source review. CO is also not subject to Article 6 BACT.

As previously mentioned, the proposed project also includes a new biomass fuel handling system. Since this system is new, the current uncontrolled emissions are designated as zero and the new uncontrolled emissions are calculated based on 8760 hours/yr of operation. The biomass fuel handling system is only expected to emit PM, PM10 and PM2.5. However, Article 6 does not currently address PM2.5, and an Article 6 PM analysis is not required as specified in 9 VAC 5-80-1320 D3. Dominion's application indicates and DEQ agrees that the uncontrolled emissions from the new biomass fuel handling system are 1.6 tons/yr of PM10. Since this value, both alone and in combination with the decrease in uncontrolled PM10 emissions calculated for the primary boilers in Chart 2, is less than the Article 6 exemption level (10 tons/yr) from 9 VAC 5-80-1320 D, the proposed project does not trigger Article 6 permitting requirements for any species of particulate matter.

Since, as described above, 9 VAC 5-80-1100 H1 exempts the only pollutant (CO) from the proposed project with a NEI above the 9 VAC 5-80-1320 D exemption level from Article 6 applicability, Article 6 is not applicable to the proposed project.

Chart 2

Net Emissions Increase (NEI) For Each Primary Boilers (Article 6) – 9 VAC 5-80-1180

Pollutants	Biomass - wood New Uncontrolled Max at 8760 hrs Without Controls 05-31-11 Request tons/yr	Minus	Coal Current Uncontrolled Permit Throughput Without Controls 01-30-12 Permit tons/yr	Net Emissions Increase (NEI) tons/yr	5-80-1320 D Exemption Levels tons/yr	Exceeds 5-80-1320 D Exemption Levels	If NEI Exceeds 5-80-1320 D BACT Applies
PM10 (total)	2,264.14	minus	2,865.24	(601.10)	10.00	No	No
SO2	86.29	minus	3,223.40	(3,137.11)	10.00	No	No
CO	517.72	minus	318.36	199.36	100.00	Yes	Yes
VOC	22.43	minus	47.75	(25.32)	10.00	No	No
NOx	388.29	minus	795.90	(407.61)	10.00	No	No

9 VAC 5-50-400 New Source Performance Standards (NSPS) (Article 5)

The HPS was constructed with two 391 mmbtu/hr coal-fired spreader stoker boiler (1990) that were also equipped with a 59.5 mmbtu/hr natural gas burner. These boilers were subject to NSPS Da because the boilers were an (1) electric utility steam generating unit that was (2) capable of burning 250 mmbtu/hr of (3) fossil fuel (alone or in combination with other fuel) which commenced construction after 09/18/1978.

After the conversion of the boilers to biomass and the inability to burn coal, a fossil fuel, DEQ asked the Environmental Protection Agency (EPA) if the boilers were subject to NSPS Subpart Da or NSPS Subpart Db.

On February 21, 2012, EPA, Region III responded to DEQ that "NSPS Subpart Da will no long apply to this operation as wood (biomass), under Section 60.40 Da, is not considered, and not defined, as a fossil fuel but Subpart Db will apply to these sources as they meet the definition of an affected facility under those regulations in Section 60.40b which accounts for all fuels."

A. Criteria Pollutant – See Section II, Emission Calculations

B. Toxic Pollutants – See Section II, Emission Calculations

The biomass boilers are subject to the Boiler MACT, 40 CFR 63, Subpart DDDDD, which was promulgated on 03/21/11. On January 9, 2012 the DC Circuit ruled that an EPA delay notice of the of the Boiler MACT regulation (76 FR 28,662, May 18, 2011) was unlawful and vacated the delay notice and remanded the delay notice to EPA for further proceedings. This court decision had the effect of reinstating the Boiler MACT and its applicability to the HPS.

The Virginia air pollution regulations at 9 VAC 5-60-300 C provide an exemption from the state toxic regulations for facilities subject to a MACT.

Dominion did provide an analysis of the toxic emissions from the primary boilers burning biomass. (Appendix B, Sheet 4 of the permit application). This analysis shows that each toxic is emitted at less than the significant ambient air concentration (SAAC) (Table 6-5) in the application.

C. Control Technology – See BACT Analysis.

D. Stack Testing:

Initial performance tests shall be conducted for particulate matter (filterable), particulate matter (total), PM 10 (filterable), PM10 (total), PM 2.5 (total), sulfur dioxide, oxides of nitrogen, volatile organic compounds, and carbon monoxide from the two primary biomass boilers.

E. VEEs:

Concurrently with the initial performance tests, Visible Emission Evaluations (VEE) in accordance with 40 CFR Part 60, Appendix A, Method 9, shall also be conducted on the primary biomass boilers.

F. Modeling

Modeling for CO was conducted to assure compliance with the national ambient air quality standards (NAAQS), and no unacceptable ambient air impacts were discovered. The maximum predicted 1-hour concentration of CO (386.8 micrograms per cubic meter) is less than the 1-hour CO NAAQS of 40,000 micrograms per cubic meter, and the maximum predicted 8-hour concentration of CO (126.7 micrograms per cubic meter) is less than the 8-hour CO NAAQS of 10,000 micrograms per cubic meter. There is no PSD increment for CO emissions, so no increment analysis was performed. See modeling results in the permit application for more details. The modeling protocols and data were approved by Central Office modeling staff. See the attached memorandum from the Modeling Section of Central Office. There is no net emission increase of any other pollutant that triggers any Article 6 or 8 modeling requirement.

G. Greenhouse Gas (GHG)

After July 1, 2011, new sources that have the potential to emit 100,000 tons or more of CO_2e and modified sources with a net emission increase of CO_2e over 75,000 tons year will be required to obtain a PSD permit.

Emissions of GHG (methane and N2O) for the biomass project at Hopewell are calculated to be 73,419 tons CO_2e after the project, which is less than the 75,000 tons CO_2e per year threshold. Therefore, GHG from the current project is not subject to PSD review.

IV. Continuing Compliance Determination

A. Record Keeping Requirements

The permittee shall maintain records of emission data and operating parameters as necessary to demonstrate compliance with this permit. The content and format of such records shall be arranged with the Director, Piedmont Regional Office. These records shall include, but are not limited to:

a. Continuous monitoring system calibrations and calibration checks, percent operating time, and excess emissions.

b. Results of all stack tests, visible emission evaluations and performance evaluations.

c. Monthly estimates of the mass of material processed by the ash unloading/truck loading system. The estimate shall be based upon the amount of biomass burned and/or the amount of lime sorbent used and/or a measurement of the amount of material unloaded. The assumptions and records used to estimate the emissions shall be documented and available on site for inspection by DEQ personnel. Annual estimates of material processed shall be calculated monthly as the sum of the material process for each consecutive 12 month period.

d. Any host steam agreement, excluding financial terms, shall be made available on site for review by the DEQ upon request.

e. The total annual heat input to the primary biomass boilers. The annual total shall be 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 total for the preceding 11 months.

f. Records of the maximum firing rate of each primary biomass boiler.

g. Throughput of biomass for the biomass handling system in tons/yr to the facility, calculated monthly as the sum of each consecutive 12 month period.

h. Throughput of natural gas to each boiler, calculated monthly as the sum of each consecutive 12 month period.

i. Throughput of distillate oil to each piece of equipment, calculated monthly as the sum of each consecutive 12 month period.

j. Fuel oil certifications identifying the sulfur content of the distillate oil.

k. Annual hours of operation for each primary biomass boiler, calculated monthly as the sum of each consecutive 12 month period.

l. Operational records showing compliance with the condition that says the auxiliary boilers and the primary biomass boilers shall not be operated concurrently, except during start up and shutdown and then for no more than 11 hours over any consecutive 24 hour period.

m. All records required by 40 CFR 60 Subpart Db.

B. Continuous Emissions Monitoring Systems

Continuous emission monitors shall be installed to measure and record opacity and the concentration of SO_2, NO_x (at each boiler outlet) and CO_2 or O_2 emitted from the primary biomass boilers. Also, a device shall be installed to continuously measure and record the exhaust gas flow rate.

Continuous Emission Monitoring Systems (CEMS), meeting the design specifications of 40 CFR Part 60, Appendix B Performance Specification 4A, shall be installed to measure and record the emissions of CO from each primary biomass boiler as lbs/mmbtu and lbs/hr. The CEMs shall be installed, calibrated, maintained, audited and operated in accordance with DEQ approved procedures which are equivalent to the requirements of 40 CFR 60.13 and Appendices B and F.

D. Further Testing: None required

V. Public Participation –

A. Informational Briefing

In accordance with Section 9 VAC 5-80-1775 C of the Regulations, an informational briefing was held by the applicant at 7 p.m. on September 1, 2011, at the Hopewell Public Library in Hopewell, VA. There were approximately 10 citizens in attendance.

C. Public Hearing

In accordance with 9 VAC 5-80-1775 E, a public hearing was held on April 16, 2012 at the Appomattox Regional Library, HMA Room (1st floor) at 209 E. Cawson Street, Hopewell, VA, 23860 at 6:00 p.m. There were thirteen people at the public hearing and there were three speakers. The speakers were Larry Labrie, Dominion; Ed Daley, Hopewell City manager and Becky McDonough, Hopewell Prince George Chamber of Commerce. The three speakers spoke in favor of the project.

The public hearing was advertised 30 days prior to the public hearing in the Richmond Times Dispatch on March 16, 2012.

The required comment period, as provided 9 VAC 5-80-1870, expired on May 1, 2012. On April 27, 2012, DEQ received four comments from EPA, Region III, about the permit. The EPA comments and the DEQ responses are contained in the Public Participation Memorandum.

D. Documents Concerning Public Comment Period

Public versions of the documents used in development of the draft permit were available for review at PRO and were available for review in Hopewell, VA at the Hopewell Public Library.

VI. NOTIFICATION OF OTHER GOVERNMENT AGENCIES

A. Local Zoning

Because the proposed project is a modification of a major stationary source subject to air permitting regulations, a local governing body notification form is required in accordance with Department policy and Section 10.1-1321.1 of the Code of Virginia. On May 19, 2011, the city of Hopewell certified that the facility is consistent with local zoning.

B. Federal Environmental Protection Agency (EPA)

In accordance with 9 VAC 5-80-1765, there are specific notification requirements to advise EPA of sources impacting federal class I areas. As of March 16, 2012, accordingly, a copy of the permit application and the initial letter of determination have been provided to EPA. EPA will also be provided with a copy of the draft permit and will be notified of the public comment period and the final determination on permit issuance.

C. Federal Land Managers

The facility to be modified is located approximately 165 km from the Shenandoah National Park, which is the closest Class I area to the facility. In accordance with agreements between DEQ, the SNP, and the Jefferson National Forest, FLMs request review of all PSD permits within the state, regardless of distance from the designated Class I areas. In communications with DEQ, the FLM indicated that they had no further interest in the proposed project

VIII. DOCUMENT LIST

A list of documents used in preparing this analysis is included as Attachment A.

X. Other Considerations

A. Confidentiality: This permit does NOT contain confidential information. The engineering analysis does NOT contain confidential information.

XI. Recommendations

Based on the information submitted, it is recommended that this permit be issued. Recommendations and limitations are provided in the draft permit letter.

Regional Engineer: Dick Stone Date: 05/22/2012

Reviewing Engineer: [signature] Date: 5/22/2012

BACT Determination: Biomass-fired stoker boilers with heat input greater than 250 mmbtu/hr

The Clean Air Act, Section 165 (a)(4), requires a best available control technology (BACT) analysis of any major stationary source or major modification subject to Prevention of Significant Deterioration (PSD). The BACT requirement is defined in the CAA, Section 169 (3) as " an emission limitation based on the maximum degree of reduction of each pollutant subject to regulation under the Clean Air Act which would be emitted from any proposed major stationary source or major modification which the Administrator, on a case-by-case basis, taking into account energy, environmental, and economic impacts and other costs determines is achievable..."

The "top-down" process for determining BACT was issued in an EPA memorandum on December 1, 1987 by former EPA Assistant Administrator J. Craig Potter. The top-down process requires a source to rank all available control technologies in descending order of effectiveness. The process calls on the source to consider the most stringent, or top, controls first, and either adopt the controls or explain why the controls were rejected.

The October 1990 draft of the New Source Review Workshop Manual presents the key steps in the "top-down" BACT process. The steps are:

1. **Identify** all control technologies
2. **Eliminate** technically infeasible options
3. **Rank** remaining control technologies by control effectiveness
4. **Evaluate** most effective controls and document results
5. **Select** BACT

The conversion of the two B & W primary boilers from burning coal to burning biomass is a major modification of a major stationary source, Hopewell Power Station, in an attainment area (PSD). This conversion is a significant increase and a significant net emissions increase of carbon monoxide (CO), which requires BACT. The two B & W primary boilers burning biomass are rated at a maximum capacity of 394 mmbtu/hr and a nominal capacity of 379 mmbtu/hr.

Carbon Monoxide (CO) BACT for each B & W primary stoker boiler rated at 394 mmbtu/hr max capacity burning biomass

Carbon monoxide (CO) emissions are the result of incomplete fuel combustion in the boiler. A source can reduce incomplete combustion by evaluating time, temperature and turbulence.

1. Identify all control technologies

In their application, Dominion states that Babcock and Wilcox (B & W) has designed an overfire (OFA) system compatible with the undergrate air system and the limits of time, temperature and combustion to control CO emissions for a stoker application. The enhanced OFA system will replace the existing OFA system for firing coal and can provide the biomass fuel with a desired 50 percent combustion air above the grate. The enhanced overfire (OFA) system is an example of combustion control (good combustion practice).

Dominion also identified post combustion controls, like regenerative thermal oxidation (RTO) and catalytic oxidization with a recuperative heat exchanger that could reduce CO emissions. These controls require increasing the temperature of the exhaust flow to oxidize CO.

Dominion provided a summary of the CO control technology determinations from the EPA RACT/BACT/LAER Clearinghouse (RBLC) in Appendix C of their application. DEQ verified this summary. The summary for biomass-fired stoker boilers with a heat input greater than 250 mmbtu/hr **identified** the following technologies to control CO emissions:

1. Regenerative Thermal Oxidation (RTO)
2. Catalytic Oxidation with Recuperative Heat Exchangers
3. Combustion Control (good combustion practices)

2. Eliminate technically infeasible options

In regard to RTO controls, Dominion states that the exhaust stream needs a high temperature and residence time in the presence of oxygen to destroy pollutants in the exhaust stream. "RTO technology is normally applied to exhaust streams from industrial operations in which the only contaminant is gaseous organic solvents (VOCs). This technology could potentially be installed downstream of the particulate removal systems for the Hopewell biomass boiler conversions. However, all qualified vendors of RTO systems do not recommend this technology due to the potential fouling of the regenerative media from residual particulate matter in the flue gas."

In this case the RTO would have to be placed after the particulate matter (PM) controls and would need a supplemental source of heat for the high temperature required by the RTO. DEQ's experience with the wood product industry has shown that in wood combustion exhaust stream, the heat transfer media beds are subject to rapid fouling and blocking. Also, there are no RTO's as controls for the biomass stoker boilers in the RBLC Clearinghouse summary.

For these reasons, Dominion's analysis determined that a RTO is technically infeasible and eliminated it from further consideration as BACT. DEQ concurs with the determination.

3. Rank Remaining Control Technologies by Control Effectiveness

Dominion **ranked** the remaining controls by their effectiveness as follows:

Control Technology	Control Efficiency (% Reduction)	lb/mmbtu
Catalytic Oxidation With Recuperative Heat Exchangers	70 to 90	< 0.10
Combustion Control	Baseline	0.30

The baseline emissions include the use of the enhanced overfire (OFA) system with the biomass-fired stoker boilers. These emissions are based on guarantees from the manufacturer (B & W).

4. Evaluate most effective controls and document results

Dominion **evaluated** the top ranked option, catalytic oxidation with recuperative heater exchangers (CORHE), on the basis of its **energy, environmental and economic impacts**.

From the **energy** aspect, Dominion said the reheat burner operating at 32 mmbtu/hr per boiler would require an additional 515,840 mmbtu per year of extra natural gas consumption (two boilers) without an increase in electrical output for the facility. Also, the pressure drop across the catalyst system would require an increase in the facility's internal electric consumption of 4 million kW-hrs.

From the **environmental** aspect, Dominion said the reheat burner would fire 32 mmbtu/hr of natural gas per boiler to cover the heat losses from the CORHE system. This would increase NOx and CO2 emissions.

From an **economic** aspect, Dominion provided an economic analysis that shows the cost of CO control using the CORHE system is $9,320 per ton of CO removed (see Appendix D, Sheet 1). DEQ reviewed the cost analysis and noted several points. Dominion used 8 percent interest where EPA uses a 7 percent interest rate. The EPA OAQPS guidance states that the direct installation cost (DIC) is usually 30 percent of the purchased equipment costs (PEC). In this case the DIC cost is equal to the PEC (100 percent of the PEC) because this project is a retrofit or a modification of an existing unit and the cost are higher. Dominion submitted a purchase order for the cost of the recuperative heat exchanger ($3,327,000) and a price quote for the oxidation catalyst ($505,000). With an interest rate of 7 percent, the cost of removing one ton of CO is $9,076, which is prohibitive.

Based on its evaluation of these energy, environmental and economic factors, Dominion's analysis concluded that CORHE was infeasible and eliminated it from further consideration as BACT. DEQ concurs with this conclusion.

5. Select BACT

Dominion identified regenerative thermal oxidation (RTO), catalytic oxidation with a recuperative heat exchange and combustion control (enhanced overfire air system) as controls that could reduce CO emissions for a biomass-fired stoker boiler rated at greater than 250 mmbtu/hr.

Dominion rejected regenerative thermal oxidation (RTO) as technically infeasible and rejected catalytic oxidation with a recuperative heat exchange as infeasible based on adverse energy, environmental and economic impacts.

Dominion **selected** the top ranked remaining control option, combustion control (good combustion) as BACT for CO. The combustion control uses the enhanced overfire air (OFA) system as part of the boiler and has an emission factor of 0.30 lb/mmbtu for CO.

DEQ agrees with the **selection** of combustion control (OFA system) and the emission factor of 0.30 lb/mmbtu as BACT for CO.

Document A

DOCUMENT LIST

1. Virginia Electric and Power Company (Dominion) permit application for the Hopewell Power Station (HPS), dated May 25, 2011 and signed by Robert McKinley.

2. Department of Environmental Quality (DEQ) Initial Letter of Determination (ILOD) signed by Richard Stone on June 29, 2011

3. Dominion's response to DEQ's ILOD signed by Robert M. Bisha on September 29, 2011

4. DEQ's request to Dominion for more information about Dominion's calculation of the baseline emissions data signed by James Kyle on December 2, 2011

5. DEQ's request to the Environmental Protection Agency (EPA) for a clarification of the status of NSPS Da versus Db for the biomass boilers signed by James Kyle on December 5, 2011.

6. Dominion's response to DEQ about the re-calculation of the baseline actual emissions using 24 contiguous months within a five year period signed by Robert M. Bisha on January 17, 2012.

7. Dominion's response to DEQ about to re-calculation of the baseline emissions to use revised values of 0.019 lb/mmBTU for PM and 0.017 lb/mmBTU for PM10 signed by Robert M. Bisha on January 31, 2012.

8. Dominion's request to DEQ to withdraw the BACT analysis for greenhouse gases because of the deferral of the applicability of the CO2 portion of the greenhouse gas rule to power generation facilities that burn biomass signed by Robert M. Bisha on February 9, 2012.

9. Dominion's letter to DEQ stating that the company will make modifications to the boiler to combust only biomass for power and steam production signed by Robert M. Bisha on February 16, 2012.

10. Environmental Protection Agency (EPA), Region III letter to DEQ that NSPS Subpart Da will no longer apply to the operation as wood (biomass) is not a fossil fuel, but that Subpart Db will apply to the affected emission sources signed by Diana Esher on February 21, 2012.

11. Dominion's letter to DEQ concerning the proposal to replace lb/mmBTU limits with lb/hr limits signed by Robert M. Bisha on March 12, 2012.

Virginia Department of Environmental Quality
Piedmont Regional Office
Memorandum

TO: File

FROM: Dick Stone, DEQ, PRO

SUBJECT: Public Participation Report on Proposed Hopewell Power Plant – biomass conversion project

DATE: May 22, 2012

The Public Participation Report summarizes the requirements of 9 VAC 5-80-1775.

1. **Public notification about the proposed project by the applicant**
   Public Notification Completed by Dominion via advertisement in the Hopewell News on 07/28/2011

2. **Informational briefing about the proposed project by the applicant, including:**

   - specific pollutants and the total quantity of each which the applicant estimates will be emitted
   - the control technology proposed to be used at the time of the informational briefing

   Information Briefing was held by Dominion at the Appomattox Regional Library, HMA Room (1st floor) at 209 E. Cawson Street, Hopewell, VA, 23860 at 7:00 p.m. on Thursday, September 1, 2011

3. **DEQ Public Hearing and advertisement of Public Comment Period and Hearing** – Public Hearing was held by DEQ on April 16, 2012 at the Appomattox Regional Library, HMA Room (1st floor) at 209 E. Cawson Street, Hopewell, VA, 23860 at 6:00 p.m. There were thirteen people at the public hearing and there were three speakers. The speakers were Larry Labrie, Dominion; Ed Daley, Hopewell City manager and Becky McDonough, Hopewell Prince George Chamber of Commerce. The three speakers spoke in favor of the project.

   - advertisement 30 days prior to hearing – Completed by DEQ on March 16, 2012 via advertisement in the Richmond Times Dispatch

- comment period runs from 30 days prior to hearing to 15 days after – completed by DEQ on May 1, 2012

4. **DEQ will consider all comments received in making a final decision on the on the application** – DEQ received four comments from the Environmental Protection Agency (EPA), Region III on April 27, 2012. Here are the questions and the responses that DEQ sent to EPA in a letter dated May 22, 2012.

Issues to be Addressed

1. **Region III comment**: *The draft permit authorizes DEQ to impose lower limits of nitrogen oxides (NOx) and volatile organic compound (VOC) emissions pending the review of stack test results. EPA believes a similar requirement should be added for carbon monoxide (CO) emissions.*

   DEQ, PRO response: The same footnote referenced by Region III for VOC,

   " ** Lower limits may be imposed by the DEQ, after in-stack testing"

   was added to CO in Conditions 35 and 39. It is noted that the NOx footnote was not used since it makes reference to the NOx-specific air pollution control technology (i.e., SNCR)

2. **Region III comment**: *A one-time initial performance test will be required for various pollutants, including particulate matter (PM) and fine particulate matter (PM10 and PM2.5) once the project is completed. Biomass is required to be clean cellulosic biomass, i.e. it will include forest-derived biomass, wood collected from forest fire clearance activities, trees and clean wood found in disaster debris, and clean biomass from land clearing operations. No information was provided on the homogeneity of the biomass with respect to moisture, composition, etc. or how emissions are expected to vary over the suite of allowable biomass sources. Therefore, it is unlikely that one performance test will be sufficient to assure compliance with emission limits for PM, PM10, and PM2.5 or to assure that emissions stay below significant emission rates.*

   DEQ, PRO response: The number of performance tests is increased to four for each size and species of PM; these tests are distributed over an extended time frame (i.e., subsequent test must be more than 75 and less than 105 days after the directly preceding test); and concurrent fuel quality analyses (heat content, and ultimate analyses) must be performed and recorded during each test. Furthermore, the permittee is required to fulfill the following on-going requirements (1) obtain and record fuel quality data (weekly heat content, and quarterly ultimate analyses, and (2) submit for DEQ approval a fuel sampling and analysis plan to be used to determine compliance with the permit with the permit allowable fuel specifications.

3. **Region III comment**: *The limits on potential to emit (PTE) for sulfuric acid mist and fluoride emissions appear to be very close to their respective significance levels. However, the permit does not require any testing, monitoring, or recordkeeping for these pollutants. The permit needs to include a method for ensuring compliance with these limits.*

   DEQ, PRO response: Initial performance testing requirements for fluorides, as HF and sulfuric acid mist (SAM) have been added to the permit. Although experience indicates that there should be a comfortable margin of compliance for both these pollutants, quarterly fluoride content analyses have been as added to the permit to ensure on-going compliance for HF, and it is noted that the facility has a permit required SO2 CEM which may be used as indicative of the SAM emissions.

4. **Region III comment**: *All reports to be sent to EPA should be sent to the Associate Director, Office of Enforcement and Compliance Assistance at the address that is listed.*

   DEQ, PRO response: The Region has made the address correction.

In addition, DEQ also made several typographical corrections to the permit.