ENCLOSURE

Commonwealth of Virginia
Round 3 Area Designation Recommendations
2010 SO_2 NAAQS
Supporting Information
January 12, 2017

Table of Contents

Lists of Tables and Figures

I. Summary of Virginia Recommendations

Virginia recommends that the U.S. Environmental Protection Agency (EPA) designate the jurisdictions listed in Table 1 as attainment/unclassifiable for the 2010 sulfur dioxide (SO_2) National Ambient Air Quality Standards (NAAQS). Air quality monitoring data, air quality dispersion modeling results, and emissions inventory data support these recommendations. Virginia is not changing any other recommendations from those supplied in the June 3, 2011, submittal made pursuant to §107(d)(1(A) of the Clean Air Act (CAA). The recommended designation for those areas continues to be "unclassifiable."

Table 1: 2010 SO_2 NAAQS Recommendations for Virginia Jurisdictions

Jurisdiction	FIPS	Designation Recommendation
Chesterfield County	51-041	Attainment/unclassifiable
City of Hopewell	51-670	Attainment/unclassifiable
City of Colonial Heights	51-570	Attainment/unclassifiable
Charles City County	51-036	Attainment/unclassifiable
Fairfax County	51-059	Attainment/unclassifiable
Henrico County	51-087	Attainment/unclassifiable
Roanoke County	51-161	Attainment/unclassifiable
Rockingham County	51-165	Attainment/unclassifiable
City of Norfolk	51-710	Attainment/unclassifiable
City of Poquoson	51-735	Attainment/unclassifiable
York County	51-199	Attainment/unclassifiable
City of Richmond	51-760	Attainment/unclassifiable
City of Newport News	51-700	Attainment/unclassifiable
City of Hampton	51-650	Attainment/unclassifiable
Halifax County	51-083	Attainment/unclassifiable
Charlotte County	51-037	Attainment/unclassifiable
Mecklenburg County	51-117	Attainment/unclassifiable
Buchanan County	51-027	Attainment/unclassifiable
City of Petersburg	51-730	Attainment/unclassifiable

Virginia may supply further recommendations by December 31, 2020, pending the review of data from source-specific air quality monitoring networks located in Giles County for Lhoist North America - Kimballton Plant, EIS identification number VA0000005107100001; Montgomery County for Roanoke Cement Company, EIS identification number VA0000005102300003; and the City of Covington for WestRock

Virginia Corporation – Covington (formerly Meadwestvaco), EIS identification number VA0000005158000003.

II. Background

EPA published a revision to the primary SO_2 NAAQS on June 22, 2010 (75 FR 35520), strengthening the standard to 75 parts per billion (ppb) or 196 micrograms per cubic meter ($\mu g/m^3$). This rule also changed the form of the standard, which became a three-year average of the 99^{th} percentile of daily maximum one-hour concentrations. Scientific evidence links health effects with short-term SO_2 exposure.

On June 3, 2011, Virginia submitted recommendations regarding jurisdictional designations for the 2010 SO_2 NAAQS as described in §107(d)(1)(A) of the CAA. Virginia's 2011 submittal also relied upon the March 24, 2011, EPA memorandum outlining data and analyses to be considered in the initial area designations. Based on the EPA guidance, Virginia recommended that all jurisdictions be designated unclassifiable.

EPA published a rule entitled, "Data Requirements Rule for the 2010 1-Hour Sulfur Dioxide (SO_2) Primary National Ambient Air Quality Standard (NAAQS)," on August 21, 2015 (80 FR 51052). This rule, referred to as the DRR, directed states to provide data characterizing air quality in areas with large sources of SO_2 emissions and to identify maximum one-hour SO_2 concentrations in ambient air. The DRR required that, at a minimum, air agencies characterize air quality around facilities that emitted 2,000 tons per year (tpy) or more of SO_2 in 2014. EPA estimated in the preamble to the DRR (80 FR 51061) that this threshold would include the facilities accounting for 89% of all SO_2 emitted nationally in 2011, based on the 2011 National Emissions Inventory (NEI). The DRR provided flexibility in the use of air quality modeling, air quality monitoring, or the use of emission limitations for these assessments. The DRR specifies submittals that states must make to EPA to support actions on the 2010 SO_2 NAAQS. Figure 1 provides this information.

TABLE 1—TIMELINE FOR DRR IMPLEMENTATION

Date	Action
From promulgation of this rule to January 15, 2016.	Air agency and the EPA Regional Office consult on list of SO_2 sources; air agency submits its list of sources to EPA by January 15, 2016.
July 1, 2016	Air agency specifies for each source whether it will characterize air quality with modeling, characterize air quality with monitoring, or establish a federally enforceable requirement limiting annual emissions of the source to less than 2,000 tpy. For source areas to be modeled, the air agency submits a modeling protocol. For source areas to be monitored, the air agency submits information about any new monitoring sites it will establish by January 1, 2017. For areas where enforceable emission limits will be established as an alternative to air quality characterization, the air agency submits a description of the planned emission limit.
January 1, 2017	Air agency ensures that SO_2 monitors to satisfy the Data Requirements Rule are installed and operational.
January 13, 2017	For any source identified for modeling pursuant to the July 1, 2016, milestone, air agency submits modeling analyses. For any source identified for emission limit approach, air agency submits documentation showing that limits requiring annual emissions to be less than 2,000 tpy are effective and federally enforceable.
May 2020	For any source area identified for monitoring approach, air agency certifies 2019 monitoring data, enabling official design values for the 2017–2019 time period to be calculated.

Figure 1: DRR State Submittal Timeline

On January 12, 2016, the Department of Environmental Quality (DEQ) submitted to EPA a listing of facilities located in the Commonwealth that emitted at least 2,000 tpy of SO_2 in 2014. Table 2 provides this listing of facilities, the 2014 and 2015 SO_2 emissions from each source, and the jurisdiction in which the facility resides.

Table 2: Virginia Facilities Emitting At Least 2,000 Tons of SO_2 in 2014

Federal ID	Facility	2014 SO_2 Emissions (tpy)	2015 SO_2 Emissions (tpy)	Jurisdiction
VA0000005112100006	US Army – RAAP	3,516	3,166	Montgomery County
VA0000005102700004	Jewell Coke Company LLP	4,964	4,845	Buchanan County
VA0000005116700003	American Electric Power - Clinch River Plant	3,302	2,059	Russell County
VA0000005158000003	WestRock Virginia Corporation – Covington (formerly MeadWestvaco)	5,558	6,230	City of Covington
VA0000005119900001	Dominion – Yorktown Power Station	9,756	4,549	York County
VA0000005104100002	Dominion - Chesterfield Power Station	2,181	2,547	Chesterfield County
VA0000005155000026	Dominion – Chesapeake Energy Center	10,218	<1	City of Chesapeake
VA0000005102300003	Roanoke Cement Company	2,393	2,300	Botetourt County
VA0000005107100004	Celanese Acetate LLC	7,120	845	Giles County
VA0000005108300046	Dominion/ODEC – Clover Power Station	2,084	1,774	Halifax County
VA0000005107100001	Lhoist North America - Kimballton Plant	6,294	6,118	Giles County

DEQ notified EPA of the method chosen by each facility for the characterization of peak one-hour SO_2 concentrations to demonstrate compliance with the 2010 SO_2 NAAQS on June 28, 2016. Table 3 contains that information, along with the date on which DEQ supplied EPA with the air quality dispersion modeling protocol for cases where the facility chose modeling as the compliance tool. Pursuant to 40 CFR §51.103(c)(1), the final Annual Monitoring Network Plan dated June 23, 2016, and approved by EPA on November 10, 2016, contained all relevant information about the monitoring sites for the three facilities that chose the monitoring methodology to demonstrate compliance.

Table 3: Methodology for Compliance Demonstrations

Federal ID	Facility	Methodology	Protocol Submittal Date to EPA, if applicable
VA0000005112100006	US Army – RAAP	Limitation	---
VA0000005102700004	Jewell Coke Company LLP	Modeling	6/27/2016
VA0000005116700003	American Electric Power - Clinch River Plant	Limitation	---
VA0000005158000003	WestRock Virginia Corporation – Covington (formerly MeadWestvaco)	Monitoring	---
VA0000005119900001	Dominion – Yorktown Power Station	Modeling	6/27/2016
VA0000005104100002	Dominion - Chesterfield Power Station	Modeling	6/27/2016
VA0000005155000026	Dominion – Chesapeake Energy Center	Limitation	---
VA0000005102300003	Roanoke Cement Company	Monitoring	---
VA0000005107100004	Celanese Acetate LLC	Limitation	---
VA0000005108300046	Dominion/ODEC – Clover Power Station	Modeling	6/27/2016
VA0000005107100001	Lhoist North America - Kimballton Plant	Monitoring	---

The DRR next requires states to submit modeling analyses by January 13, 2017, for those facilities that chose to demonstrate compliance with the 2010 SO_2 NAAQS using air quality dispersion modeling. States must also submit documentation supporting limitations on those facilities that chose to accept SO_2 emission constraints of less than 2,000 tpy. This submittal contains the required information and supports the designation recommendations.

In a July 22, 2016, memorandum entitled, "Area Designations for the 2010 Primary Sulfur Dioxide National Ambient Air Quality Standard – Round 3," EPA invited states to update area recommendations made in 2011 for all areas not installing monitoring networks. These recommendations will inform EPA's final designations for these areas. EPA must finalize these designations by December 31, 2017, to meet the requirements of the March 2, 2015, consent decree filed with the U.S. District Court for

the Northern District of California.[1] The July 22, 2016, memorandum also references the factors discussed in Attachment 2 of the March 20, 2015, memorandum entitled, "Updated Guidance for Area Designations for the 2010 Primary Sulfur Dioxide National Ambient Air Quality Standards." In this document, EPA provides five factors as a framework for area-specific analyses to support boundary determinations for the 2010 SO_2 NAAQS. These five factors are:

- Ambient air quality data or dispersion modeling results;
- Emissions-related data, including the location of sources and potential contributions to ambient SO_2 concentrations;
- Meteorology, including weather and transport patterns;
- Geography and topography, such as mountain ranges or other air basin boundaries; and
- Jurisdictional boundaries, such as counties, air districts, pre-existing nonattainment areas, and metropolitan planning areas.

The following sections provide information on the relevant factors for Virginia jurisdictions and facilities to support the recommended designations of attainment/unclassifiable for the jurisdictions listed in Table 1. This information also includes the required data elements due to EPA on January 13, 2017, as mandated by the DRR.

III. Virginia SO_2 Monitoring Network

Figure 2 shows the Virginia SO_2 monitoring network. Monitors denoted with a green triangle are ambient air quality monitors. Other than the Fairfax County monitor, which began operation in 2014, these sites have at least three years of data to support design value calculations. These monitoring sites meet EPA's siting criteria (40 CFR Part 58, Appendices D and E) and conform to EPA guidance documents and generally accepted air quality monitoring practices.

Monitoring sites denoted with a red triangle are SO_2 monitors designed to characterize the maximum one-hour SO_2 concentrations from facilities applicable to the DRR. These source-specific air quality monitoring networks are located in Giles County for Lhoist North America - Kimballton Plant, Montgomery County for Roanoke Cement Company, and the City of Covington for WestRock Virginia Corporation – Covington. The monitors in these source-specific networks began gathering data January 2017, and therefore these sites do not currently have the data necessary to develop a design value.

[1] http://www.csg.org/aapca_site/news/documents/SO2ConsentDecreeAsEntered.pdf

The DEQ - Air Quality Monitoring (AQM) division quality assures all data gathered from the Virginia air quality monitoring network in accordance with federal requirements noted in 40 CFR Part 58, Appendix A. The data are published annually in the *Virginia Ambient Air Monitoring Data Report* and are available from the DEQ website at http://www.deq.virginia.gov/Programs/Air/AirMonitoring/Publications.aspx.

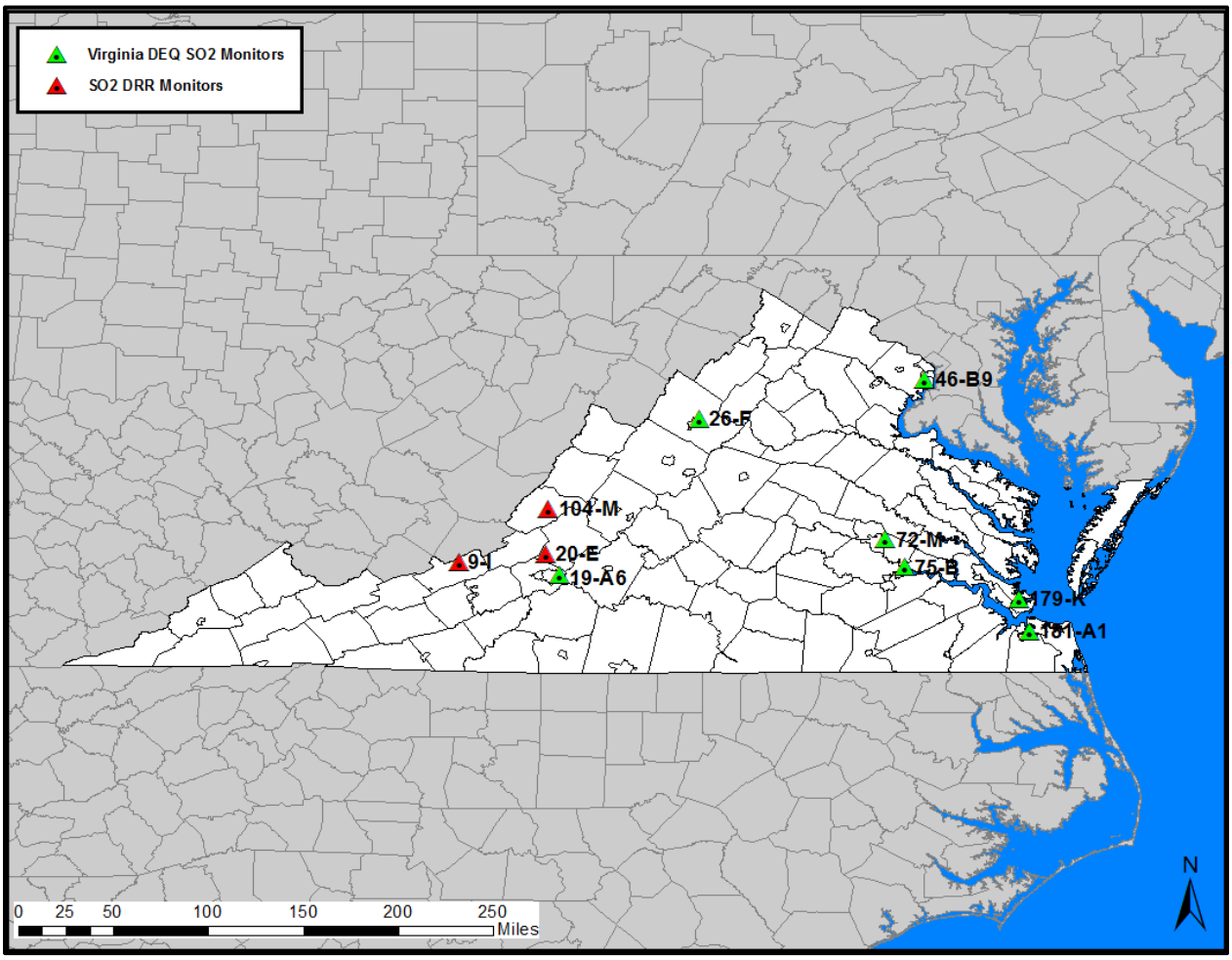

Figure 2: Virginia SO_2 Monitoring Network Operated by DEQ

Table 4 provides the 2013-2015 design values for each of the sites shown in Figure 2 that have available data (green triangles). Table 5 shows the 99th percentile of the one-hour, daily maximum values for years 2010-2015. These values are well under the 75 ppb standard, providing a significant buffer to protect public health.

Table 4: Monitoring Network Design Values

Facility Location	Site ID/ Station Number	2013-2015 Design Value	2012-2014 Design Value	2011-2013 Design Value	2010-2012 Design Value
Charles City County	51-036-0002 72-B	29 ppb	27 ppb	29 ppb	34 ppb
Fairfax County/Lee Park*	51-059-0030 46-B9	10 ppb	11 ppb	--	--
Henrico County	51-087-0014 72-M	8 ppb	7 ppb	11 ppb	16 ppb
Roanoke County/Vinton	51-161-1004 19-A6	5 ppb	5 ppb	6 ppb	8 ppb
Rockingham County/Harrisonburg	51-165-0003 26-F	5 ppb	5 ppb	5 ppb	6 ppb
City of Hampton/NASA	51-650-0008 179-K	36 ppb	37 ppb	37 ppb	39 ppb
City of Norfolk/NOAA	51-710-0024 181-A1	34 ppb	48 ppb	54 ppb	55 ppb

**Monitor does not yet have three years of data for complete design value calculation.*

Table 5: Daily Maximum Values, 2010-2015

Facility Location	Site ID/ Station Number	99th Percentile of Daily Maximum Values, ppb					
		2015	2014	2013	2012	2011	2010
Charles City County	51-036-0002 72-B	29	29	30	21	38	44
Fairfax County/Lee Park*	51-059-0030 46-B9	9	11	---	---	---	---
Henrico County	51-087-0014 72-M	8	8	6	8	21	20
Roanoke County/Vinton	51-161-1004 19-A6	5	6	6	5	9	10
Rockingham County/Harrisonburg	51-165-0003 26-F	3	7	4	4	6	8
City of Hampton/NASA	51-650-0008 179-K	30	41	38	33	39	45
City of Norfolk/NOAA	51-710-0024 181-A1	13	36	52	56	54	---

**Monitor does not yet have three years of data for complete design value calculation.*

Section IV discusses the SO_2 emission reductions achieved in Virginia over the past several years. These emission reductions, combined with reduced transport from upwind states as discussed in Section V, have lowered the ambient concentrations of SO_2 significantly. Figure 3 provides SO_2 monitoring data since year 2000 for monitoring locations throughout Virginia. This figure demonstrates the long-term, downward trend in SO_2 monitoring values experienced by every Virginia SO_2 monitoring site due to SO_2 emissions reductions both within and outside of the Commonwealth.

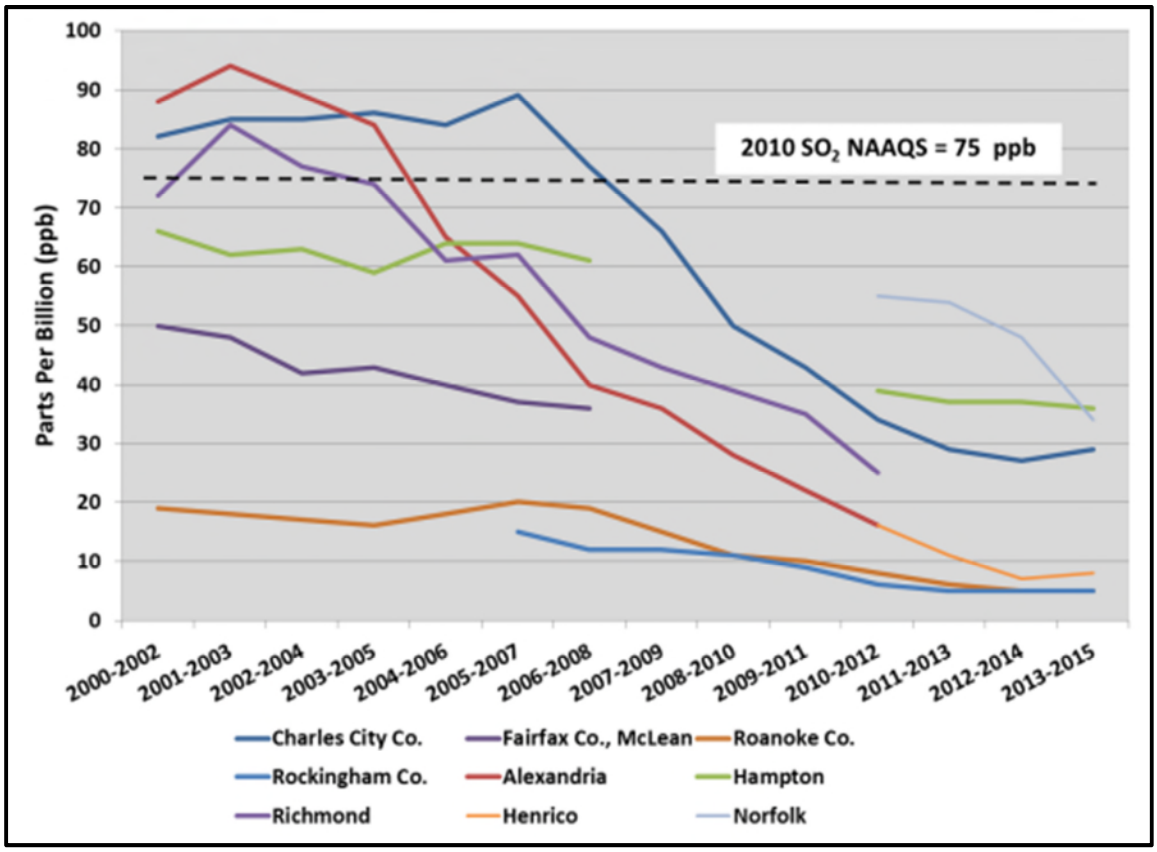

Figure 3: Historical SO_2 Monitoring Data

Virginia's 2016 Annual Monitoring Network Review contains additional information about the monitoring installations, shown as red triangles in Figure 2, for the three facilities that chose to perform air quality monitoring to determine compliance with the 2010 SO_2 NAAQS. As described in EPA guidance, these facilities used source-specific air quality modeling to determine the location of the SO_2 monitors.

IV. Virginia Emissions Inventory

In Virginia, the majority of the SO_2 emissions originate from fuel combustion, mainly in the point source sector. Table 6 provides the Tier 1 SO_2 emission summaries supplied by EPA's NEI database. This table shows that the electrical generating unit (EGU) sector (noted as Tier 1 ID=1) and the industrial fuel combustion sector (noted as Tier 1 ID=2) account for 84%, 77%, and 53% of Virginia SO_2 emissions in years 2008, 2011, and 2014, respectively. Emissions from fuel combustion in the electric utility sector and the industrial sector have decreased markedly. This decrease is the result of SO_2 controls being installed on EGUs burning coal, coal- and residual oil-fired boiler retirements, and the use of cleaner fuels in fuel-burning equipment. For larger emitting units, these changes are supported by federally- and state-enforceable requirements in consent decrees or permits.

Table 6: Virginia SO_2 Emissions, NEI*

Category	Tier 1 ID	SO_2 Emissions in Virginia, tpy		
		2008	2011	2014**
Fuel Combustion, Electric Utility (EGUs)	1	142,654.13	69,077.37	30,391.42
Fuel Combustion, Industrial	2	27,615.90	14,348.98	10,441.38
Fuel Combustion, Other	3	7,337.80	4,883.72	2,929.72
Chemical and Allied Product Manufacturing	4	999.39	203.37	3,314.69
Metals Processing	5	5,280.46	5,196.48	5,092.38
Petroleum and Related Industries	6	122.33	58.65	295.26
Other Industrial Processes	7	9,282.18	7,028.31	17,899.47
Storage and Transport	9	1.24	0.31	1.01
Waste Disposal and Recycling	10	0.08	0.03	1,933.37
Highway Vehicles	11	1,851.64	1,469.38	825.00
Off-Highway	12	935.34	712.75	1,995.28
Miscellaneous	14	4,492.87	3,354.62	1,558.36
Total:		**202,079.85**	**107,820.63**	**76,677.34**

**Data Source: https://www.epa.gov/air-emissions-inventories/national-emissions-inventory-nei*
***2014 NEI is currently a draft version.*

IV. A. Virginia Point Sources

DEQ maintains the Comprehensive Environmental Data System (CEDS), which tracks emissions annually from all Title V facilities within the Commonwealth. The system also tracks emissions from point sources that meet other registration requirements so that the universe of facilities and units tracked within CEDS is much broader than that included as point sources in the NEI. For 2015, CEDS contains emissions data for approximately 3,085 facilities listed as qualifying and active. Data in this system must be certified by the facility as true and complete to the best of their knowledge, and DEQ staff checks each submittal for quality assurance purposes. Figure 4 provides a summary of annual SO_2 emissions from the CEDS database in tpy from 2006 through 2015. Point source emissions have decreased from just over 250,000 tons in 2006 to just under 45,000 tons in 2015, a reduction of more than 80%.

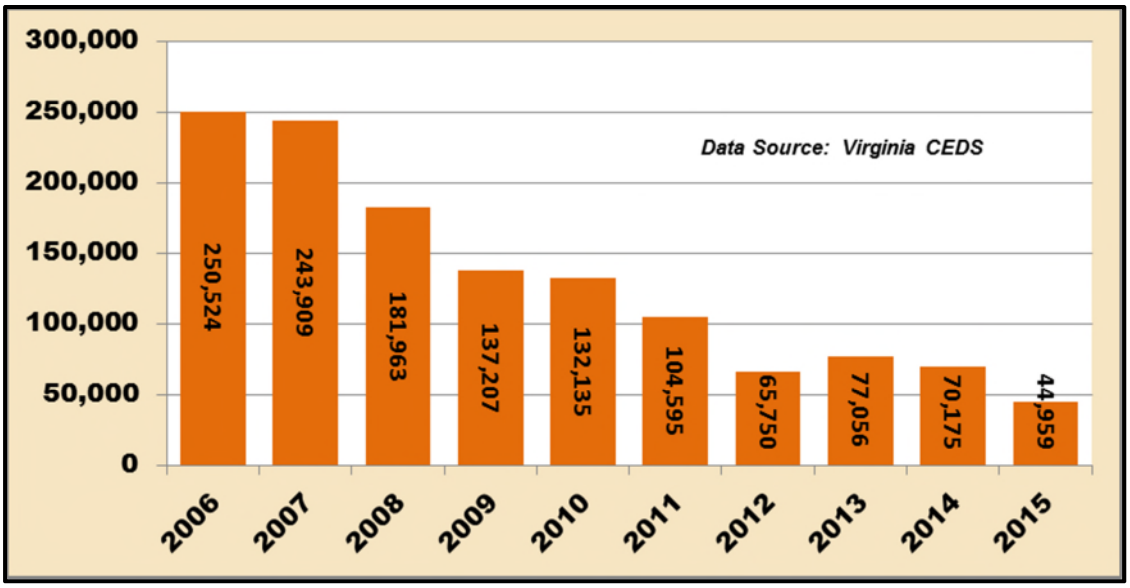

Figure 4: Virginia SO_2 Annual Emissions from Point Sources, tpy

IV. B. Virginia Acid Rain Units

The majority of the units in the EGU category report hourly emissions to the Clean Air Markets Division (CAMD) of EPA as required by the Acid Rain Program and 40 CFR Part 75. These Acid Rain Program units are a subset of the overall universe of units that report to CEDS annually. Figure 5 provides the annual emissions and emission rates of SO_2 from the Acid Rain Program EGUs in Virginia as well as the annual heat input to these units based on the data each facility supplies to CAMD.

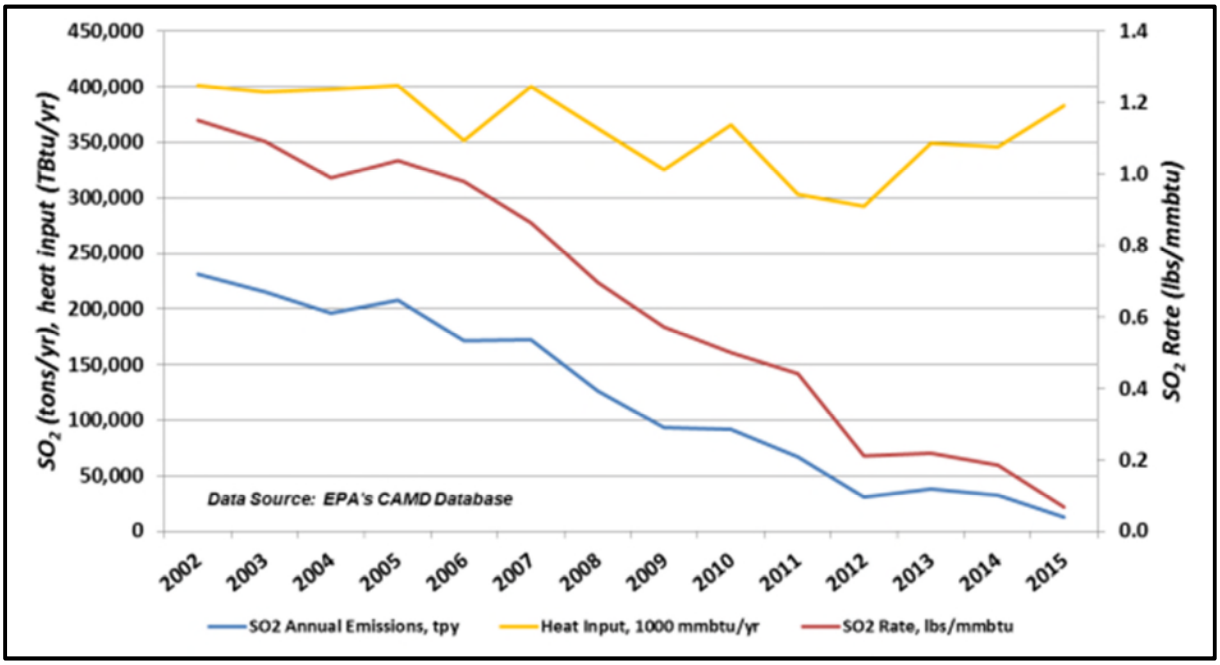

Figure 5: Virginia Acid Rain Program SO_2 Emissions, 2002-2015

Emission reductions from this source sector are attributable to a number of factors, including control programs such as the federal Mercury and Air Toxics Rule; retirement of older, high-emitting units; and the construction and operation of new, very low-emitting units. Between 2002 and 2015, Virginia SO_2 emissions and emission rates decreased significantly in this source sector, as shown in Figure 5. Emissions in tpy and emission rates in pounds per million British thermal units (lbs/mmbtu) decreased 94% during this period even though heat input activity, depicted by the yellow line in Figure 5, remained relatively constant.

IV. C. Virginia Combined Inventory by Jurisdiction

To analyze emissions on a jurisdictional basis, Appendix A contains emissions from each of the four emissions categories (point, area, non-road and on-road) by jurisdiction. The area and non-road sector data are from the 2011 NEI database since these data are the most current, final NEI data available. To augment this data with the most current point source information, Appendix A includes 2015 point source SO_2 emissions estimates from CEDS and segregated by jurisdiction. The jurisdiction-specific 2011 on-road data supplied in Appendix A are the product of Virginia-specific inputs and the MOVES2014 inventory tool. This methodology combines the most recent data available from each of the source sectors to provide the most accurate depiction possible of Virginia SO_2 emissions by sector and jurisdiction.

Figure 6 shows Virginia jurisdictions and their overall SO_2 emissions from the Appendix A analysis. Figure 6 has 12 jurisdictions colored orange, which indicates emissions of greater than 1,000 tpy SO_2 in the Appendix A analysis.

Table 7 lists these specific jurisdictions in Virginia with at least 1,000 tpy SO_2 in this analysis and the total emissions for each sector across Virginia. These 12 jurisdictions, indicated by the orange color in Figure 6, account for 41,657 tons of SO_2 out of the total Virginia sum of 55,954 tons, about 74% of the total emissions in Appendix A. The majority of the emissions are from the point source sector, the data for which is derived from the CEDS database. The point source sector from these 12 jurisdictions accounts for 39,704 tpy of SO_2, 71% of the total Virginia emissions of 55,954 tpy in Appendix A.

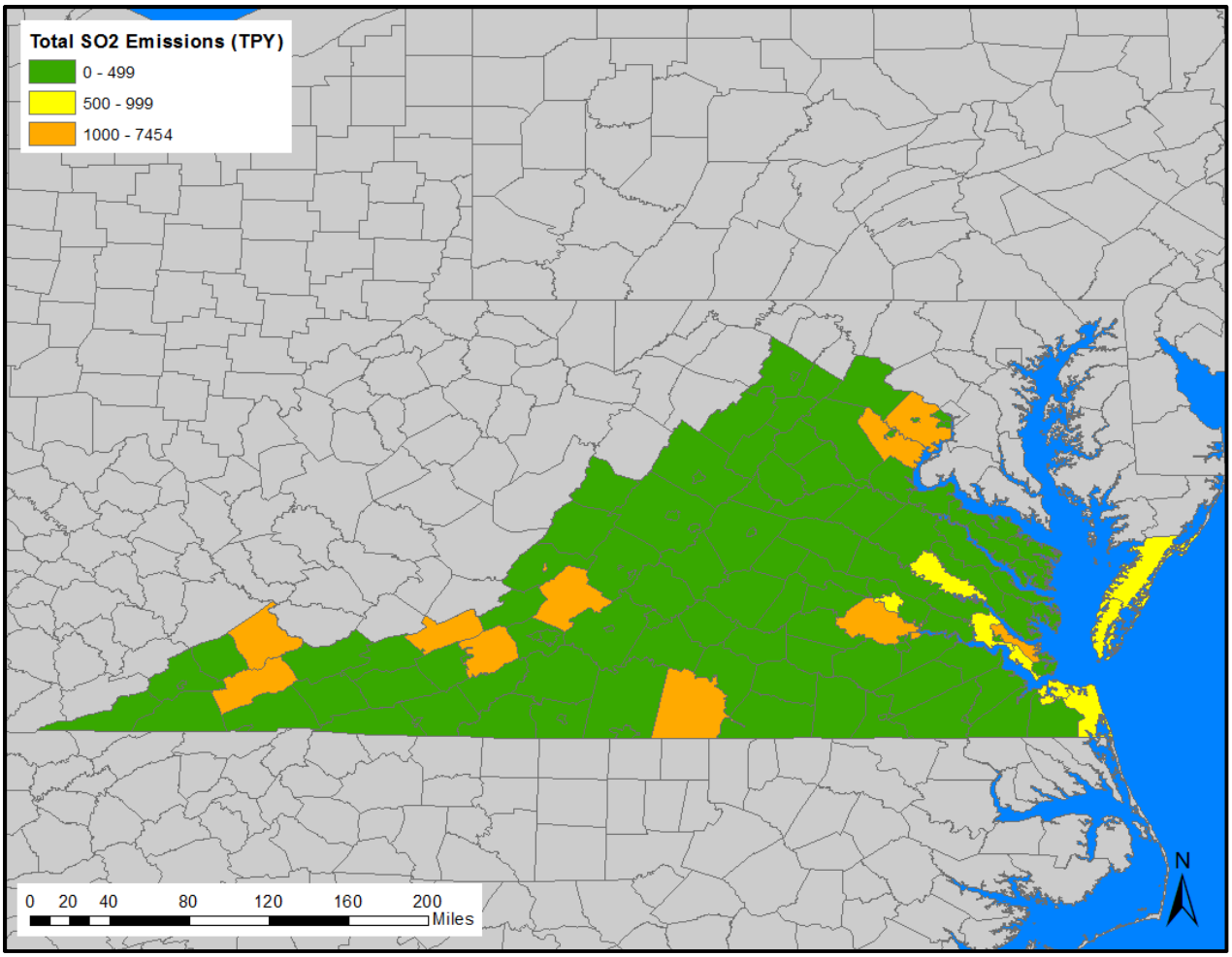

Figure 6: Appendix A Total SO_2 Emissions by Jurisdiction

Table 7: Jurisdictions with more than 1,000 tpy of SO_2 Emissions

Jurisdiction	FIPS	Point	Area	On Road	Non-Road	Total
Botetourt County	023	2,357.73	43.17	7.59	0.50	2,408.99
Buchanan County	027	4,871.02	22.52	2.25	0.25	4,896.04
Chesterfield County	041	2,686.54	248.80	30.96	2.76	2,969.05
Covington City	580	6,229.73	17.47	0.37	0.11	6,247.68
Fairfax County	059	154.71	806.89	89.07	8.87	1,059.54
Giles County	071	7,433.38	18.62	1.87	0.17	7,454.05
Halifax County	083	1,798.38	31.72	3.52	0.55	1,834.17
Hopewell City	670	2,283.95	18.68	1.02	0.14	2,303.79
Montgomery County	121	3,449.48	89.88	10.39	1.08	3,550.82
Prince William County	153	1,817.08	240.93	31.89	3.91	2,093.81
Russell County	167	2,071.68	28.89	3.00	0.24	2,103.80
York County	199	4,550.33	176.23	7.25	1.02	4,734.83
12 Jurisdiction Total Emissions	**---**	**39,704.01**	**1,744**	**189.18**	**19.60**	**41,656.67**
Total Virginia Emissions:	**---**	**45,801.02**	**9,257.56**	**798.17**	**97.06**	**55,953.86**

As discussed in Section VI and as shown in Table 2, most of these jurisdictions contain facilities that emitted at least 2,000 tpy of SO_2 in 2014 and are therefore subject to the DRR. If the DRR facility does not take a permit limit to reduce emissions to less than 2,000 tpy SO_2, the facility must conduct air quality modeling or air quality monitoring to demonstrate compliance with the 2010 SO_2 NAAQS. Table 8 compares these data to illustrate the fact that the 11 DRR facilities listed in Table 2 account for the majority of the emissions, between 89% and 99%, in each of the jurisdictions listed in Table 7.

Table 8: Top Emitting Jurisdictions and DRR Facilities

Jurisdiction	Appendix A Inventory Analysis, tpy SO_2					DRR Facilities in Jurisdiction	DRR Facility SO_2 Emissions for 2015	DRR % of Total SO_2 Emissions in Jurisdiction
	Point	Area	On Road	Non-Road	Total			
Botetourt County	2,357.73	43.17	7.59	0.50	2,408.99	Roanoke Cement Company	2,300	95%
Buchanan County	4,871.02	22.52	2.25	0.25	4,896.04	Jewell Coke Company	4,845	99%
Chesterfield County	2,686.54	248.80	30.96	2.76	2,969.05	Chesterfield Power Station	2,547	86%
Covington City	6,229.73	17.47	0.37	0.11	6,247.68	West Rock Virginia	6,230	99%
Fairfax County	154.71	806.89	89.07	8.87	1,059.54	n/a	n/a	n/a
Giles County	7,433.38	18.62	1.87	0.17	7,454.05	Celanese	845	93%
						Lhoist North America	6,118	
Halifax County	1,798.38	31.72	3.52	0.55	1,834.17	Clover Power Station	1,774	97%
Hopewell City	2,283.95	18.68	1.02	0.14	2,303.79	n/a	n/a	n/a
Montgomery County	3,449.48	89.88	10.39	1.08	3,550.82	RAAP	3,166	89%
Prince William County	1,817.08	240.93	31.89	3.91	2,093.81	n/a	n/a	n/a
Russell County	2,071.68	28.89	3.00	0.24	2,103.80	Clinch River Plant	2,059	98%
York County	4,550.33	176.23	7.25	1.02	4,734.83	York Power Station	4,549	96%

Three jurisdictions within the Appendix A analysis had total emissions of more than 1,000 tpy SO_2 and did not contain any DRR facilities. Sources with more than 50 tpy of SO_2 in 2014 within the City of Hopewell are part of the emissions inventory associated with that modeling effort and are considered within Chesterfield Power Station's modeling results showing compliance with the 2010 SO_2 NAAQS. This effort is discussed further in Section VI. B. 1.

Fairfax County has emissions of just over 1,000 tpy SO_2. However, the majority of these emissions (76%) are in the area source sector, which is heavily dependent on population data for emissions estimates. Fairfax County is the most populous jurisdiction in Virginia. For 2015, the population estimate for Fairfax County is

1,129,330 people, while Virginia's overall population estimate is 8,382,993 people.[2] One of 134 jurisdictions in Virginia, Fairfax County nonetheless accounts for over 13% of the total population within the Commonwealth. Best current inventory practice, therefore, assigns Fairfax County significant fuel burning activity at the residential level, and this methodology results in a very conservative estimate of SO_2 emissions for this jurisdiction in the area source sector.

Prince William County's SO_2 emissions estimates are dominated by a single point source facility, Possum Point Power Station. However, Possum Point Power Station is a predominantly natural gas-fired operation. The one large unit that operates at Possum Point Power Station on a fuel other than natural gas is Unit 5, which is subject to the Mercury and Air Toxics Rule and burns residual oil. Possum Point Power Station limits the annual usage of Unit 5 to less than 8% of its capacity to comply with requirements in the Mercury and Air Toxics Rule.

To illustrate the size of the SO_2 emissions from the units considered by the DRR, Figure 7 shows the map of Virginia jurisdictions. However, in this case the data does not include those facilities that are considered discreetly within DRR air quality modeling exercises, and the data has also been adjusted for limitations applied to facilities' potential to emit (PTE) of SO_2. As shown in this figure, remaining counties with any significant SO_2 emissions are those with facilities that have chosen to install air quality monitoring systems. These facilities are located in Botetourt County, Giles County and the City of Covington.

[2] http://www.coopercenter.org/demographics/virginia-population-estimates

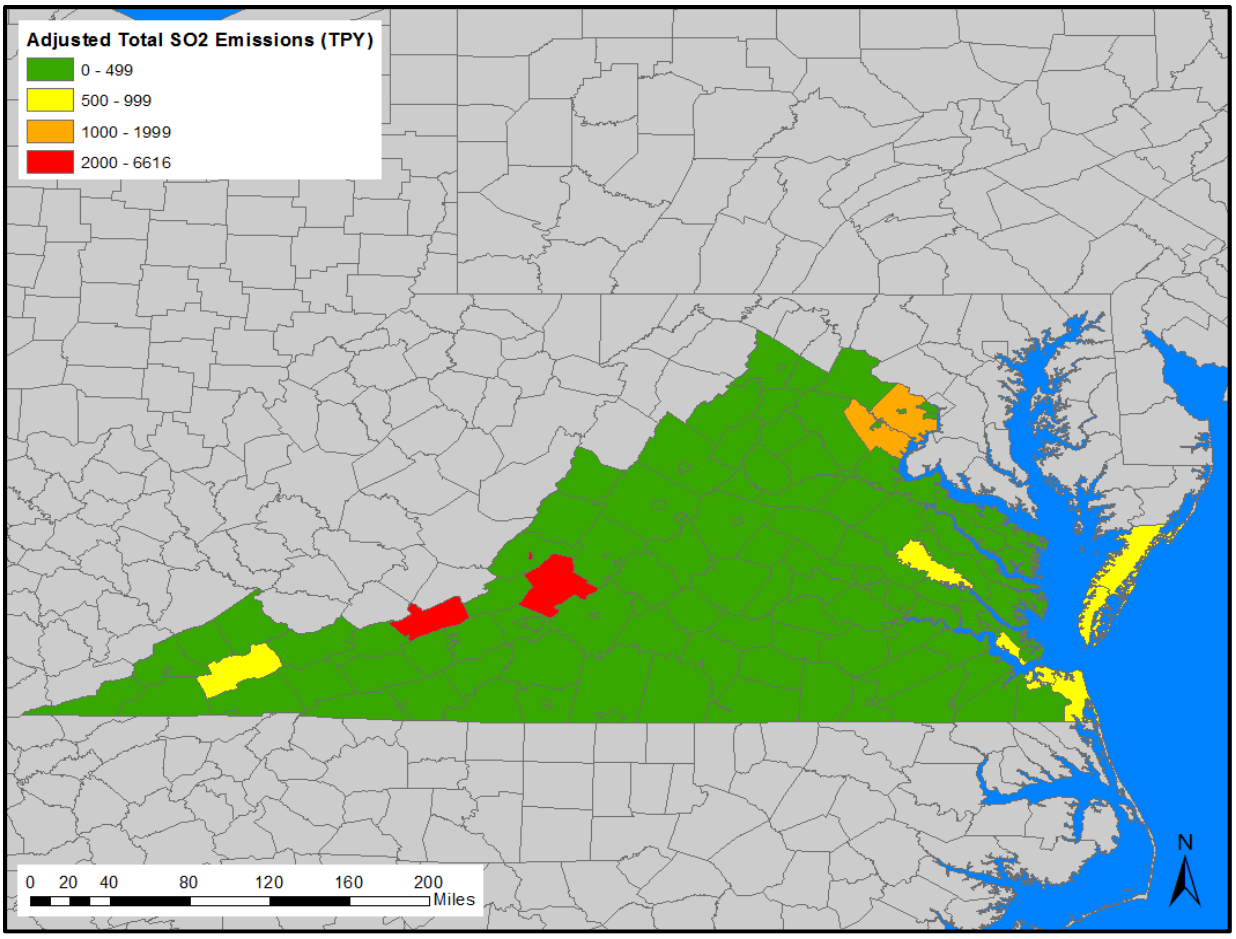

Figure 7: Appendix A SO_2 Emissions by Jurisdiction, Adjusted for DRR Modeling Facilities and PTE Thresholds

V. Regional Emission Reductions

Significant regional emission reductions have decreased the transport of SO_2 into Virginia. Table 9 provides the 2008, 2011, and draft 2014 NEI SO_2 emissions data summarized for the states within the Southeastern States Air Resource Managers (SESARM) organization. This organization consists of Alabama, Florida, Georgia, Kentucky, Tennessee, Mississippi, North Carolina, South Carolina, West Virginia, and Virginia. The NEI estimates reductions of 1,984,935 tons of SO_2 between 2008 and 2014 from these states, using draft 2014 NEI data.

Table 9: NEI SO_2 Emissions, SESARM States

Category	Tier 1 ID	2008 NEI Emissions, tpy	2011 NEI Emissions, tpy	2014 NEI Emissions, tpy*
Fuel Combustion, Electric Utility (EGUs)	1	2,613,553	1,191,386	838,335
Fuel Combustion, Industrial	2	272,261	177,124	142,641
Fuel Combustion, Other	3	40,023	27,359	17,153

Category	Tier 1 ID	2008 NEI Emissions, tpy	2011 NEI Emissions, tpy	2014 NEI Emissions, tpy*
Chemical and Allied Product Manufacturing	4	45,464	39,482	36,467
Metals Processing	5	41,021	33,405	28,771
Petroleum and Related Industries	6	33,585	34,321	14,688
Other Industrial Processes	7	65,535	44,820	64,404
Storage and Transport	8	27	48	21
Waste Disposal and Recycling	9	124	90	67
Highway Vehicles	10	6,464	3,971	8,518
Off-Highway	11	9,364	8,037	8,058
Miscellaneous	12	40,943	34,422	22,815
Fuel Combustion, Electric Utility (EGUs)	14	37,966	41,171	39,458
SESARM Total:		**3,206,331**	**1,635,635**	**1,221,396**

**2014 NEI is currently a draft version.*

The SESARM Acid Rain Program EGUs reporting to CAMD, a subset of the NEI emissions inventory, have reduced emissions significantly. Figure 8 shows an emissions and emissions rate analysis for the states within the SESARM organization using CAMD data. Between 2002 and 2015, SO_2 emissions from the Acid Rain Program units within these states have dropped from over 3,700,000 tons to about 514,000 tons, an 86% reduction. Heat input, however, has remained relatively constant during this timeframe. These reductions mean that Virginia is receiving less transported SO_2.

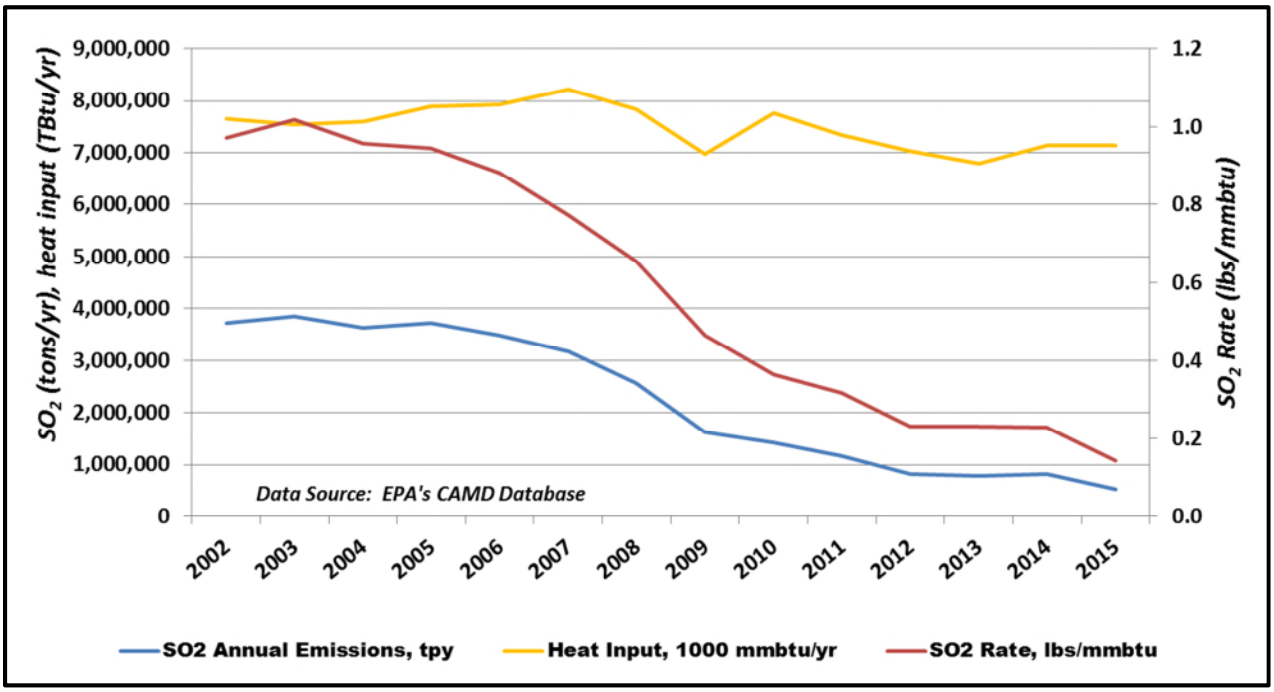

Figure 8: SESARM States Acid Rain Program SO_2 Emissions, 2002-2015

VI. Facilities in Virginia above 2,000 tons of SO_2

The DRR required states to identify facilities emitting more than 2,000 tons of SO_2 in 2014. These facilities, listed in Table 2, must accept federally enforceable limits on their PTE of SO_2, must perform air quality modeling showing compliance with the 2010 SO_2 NAAQS, or must install and operate an air quality monitoring network to demonstrate compliance with the 2010 SO_2 NAAQS.

VI. A. Facilities Receiving Emission Limits

The following facilities chose to accept limitations on their PTE of SO_2 to demonstrate compliance with the requirements in the DRR. The limitations reflect changes in operation at each facility that have drastically reduced or will greatly reduce SO_2 emissions.

VI. A. 1. US Army - Radford Army Ammunition Plant

The US Army – Radford Army Ammunition Plant (RAAP) is a United States Department of Defense facility operated by BAE System Ordnance Systems in Montgomery County. The facility manufactures specialty munitions, propellants, and chemicals. Emissions of SO_2 are mainly from coal combustion in process steam boilers. The facility is installing natural gas boilers with limited use of back up distillate oil to replace the coal-fired boilers. The new boilers received an air permit from DEQ on March 22, 2016, and the permit mandates the permanent shutdown of the coal-fired boilers. After the new, natural gas-fired units begin operations, the facility-wide calculated potential to emit of SO_2 will be 32.3 tpy. Until the boiler replacement project is complete, the permit also contains a condition effective January 1, 2017, that limits the use of coal at the facility to 30,000 tpy. This constraint limits the SO_2 PTE of the facility to 1,062.3 tpy until the new, natural gas-fired units begin operations. Appendix B contains the March 22, 2016, permit.

VI. A. 2. Celanese Acetate, LLC

This facility primarily manufactures cellulose acetate flake and fiber from acetic acid and cellulose/wood pulp. The majority of SO_2 emissions from this facility originated within the steam plant from the combustion of coal in seven large boilers. Celanese permanently retired these boilers in the fall of 2015 due to the installation and operation of six new, natural gas-fired units. DEQ issued the permit to construct and operate these new units on December 6, 2012. Appendix C contains this permit. The PTE of SO_2 for this facility due to the federally enforceable limits within this permit is 6.6 tpy.

VI. A. 3. Dominion - Chesapeake Power Station

This facility produces electrical power. The facility retired four coal-fired boilers and the associated coal and ash handling operations on December 23, 2014. These four boilers were the largest SO_2 emitters at the facility. Four simple cycle combustion turbines burning natural gas or distillate fuel oil, each with a capacity of 15 MW or less, and several emergency generators remain on site. The facility's Title V permit dated March 22, 2016, reflects these operational changes. Appendix D contains the relevant pages of this permit as well as a spreadsheet showing the PTE calculations. The PTE of SO_2 for this facility is 1,893 tpy. Actual emissions from these units are much lower. Emissions of SO_2 in 2015 were less than one ton facility-wide.

VI. A. 4. American Electric Power - Clinch River Plant

This facility produces electrical power. The facility retired one coal-fired boiler and switched two coal-fired boilers to the exclusive use of natural gas. The facility received a permit from DEQ for these changes on August 3, 2016. Appendix E contains this permit. As noted in Condition 10, the PTE of SO_2 for the facility after these changes is 813 tpy. Actual emissions from the operation of the natural gas units are expected to be much lower than this value.

VI. B. Facilities Opting for Air Quality Modeling

Under the DRR, facilities emitting more than 2,000 tons of SO_2 in 2014 could elect to use air quality modeling to characterize SO_2 air quality in the surrounding area. Virginia had four facilities choose this course of action. As required by the DRR, DEQ supplied EPA the air quality modeling protocols for each of these facilities on June 27, 2016. DEQ has also supplied to EPA, via electronic submittal on January 12, 2017, the final modeling analysis for each facility. The following sections provide an overview of each analysis. Each of these analyses used EPA's "SO_2 NAAQS Designations Modeling Technical Assistance Document" (TAD) to develop modeling procedures. Included within each modeled SO_2 design value is a background concentration derived using air quality monitoring data from a representative DEQ monitoring site. The monitoring data may be partially influenced by emissions from nearby SO_2 sources, and many of these nearby sources are also explicitly modeled in the analyses. Inclusion of a background concentration in the modeled SO_2 design value likely provides additional conservatism in the results.

VI. B. 1. Dominion - Chesterfield Power Station

Dominion's Chesterfield Power Station is located about 15 miles south of Richmond in Chesterfield County. The Station has the capability of generating more than 1,600 megawatts (MW) from four coal/oil-fired boilers and two natural gas/oil-fired

combined cycle combustion turbines. Flue gas desulfurization units control SO_2 emissions from the four coal-fired boilers.

Nearby sources of SO_2 within 20 kilometers of the Chesterfield Power Station that emitted at least 50 tpy of total actual SO_2 emissions were explicitly modeled in the analysis. Table 10 provides information on these units. This methodology resulted in an additional 30 units at other facilities being included as inputs to the model. These 30 units represent 96% of the actual SO_2 emissions in 2014 within 20 kilometers of the Chesterfield Power Station. They account for approximately 3,652 tpy of actual SO_2 emissions, beyond the 2,181 tpy in 2014 associated with the Chesterfield Power Station.

Table 10: Units Included in the Chesterfield Power Station Modeling Analysis

Plant Name	Jurisdiction	Stack Number	2014 SO_2 Actual Emissions (tpy)
Chemours James River Plant	Chesterfield County	2	50.58
Philip Morris USA Inc – Park 500	Chesterfield County	1002	8.52
Philip Morris USA Inc – Park 500	Chesterfield County	1003	89.46
		Chesterfield County Subtotal:	**148.56**
Honeywell Resins and Chemicals LLC-Hopewell	City of Hopewell	102	5.03
Honeywell Resins and Chemicals LLC-Hopewell	City of Hopewell	103	1.88
Honeywell Resins and Chemicals LLC-Hopewell	City of Hopewell	108	127.52
Honeywell Resins and Chemicals LLC-Hopewell	City of Hopewell	622	2.3
Honeywell Resins and Chemicals LLC-Hopewell	City of Hopewell	905	27.03
Honeywell Resins and Chemicals LLC-Hopewell	City of Hopewell	906	22.87
Honeywell Resins and Chemicals LLC-Hopewell	City of Hopewell	909	1.2
RockTenn CP LLC – Hopewell	City of Hopewell	1	9.51
RockTenn CP LLC – Hopewell	City of Hopewell	2	519.87
RockTenn CP LLC – Hopewell	City of Hopewell	4	9.06
James River Genco LLC	City of Hopewell	1	1,179.20
James River Genco LLC	City of Hopewell	2	763.6
Hopewell Cogeneration Ltd Partnership	City of Hopewell	1	20.24
Hopewell Cogeneration Ltd Partnership	City of Hopewell	2	10.55
Hopewell Cogeneration Ltd Partnership	City of Hopewell	3	12.13
Dominion-Hopewell Power Station	City of Hopewell	1	6.5
		City of Hopewell Subtotal:	**2,718.49**
Philip Morris USA Manufacturing Center	City of Richmond	1	139.64
Dominion – Bellemeade Power Station	City of Richmond	1	22.3
Dominion – Bellemeade Power Station	City of Richmond	2	19.4
Spruance Genco LLC	City of Richmond	1	152.29
Spruance Genco LLC	City of Richmond	2	134.64
Spruance Genco LLC	City of Richmond	3	144.13
Spruance Genco LLC	City of Richmond	4	153.42
		City of Richmond Subtotal:	**765.82**
Dominion – Darbytown CT Station	Henrico County	1	5.4
Dominion – Darbytown CT Station	Henrico County	2	4.3
Dominion – Darbytown CT Station	Henrico County	3	4.7
Dominion – Darbytown CT Station	Henrico County	4	4.9
		Henrico County Subtotal:	**19.3**
		Total Additional Tons of SO_2:	**3,652.17**

Figure 9 provides the locations of the additional SO_2 sources in relation to Chesterfield Power Station. While the City of Hopewell had no single facility that emitted at least 2,000 tpy of SO_2 in 2014, the multiple smaller emitters in the City of Hopewell, which combined emitted more than 2,000 tpy of SO_2 in 2014, are included in the Chesterfield Power Station's modeling analysis as background sources.

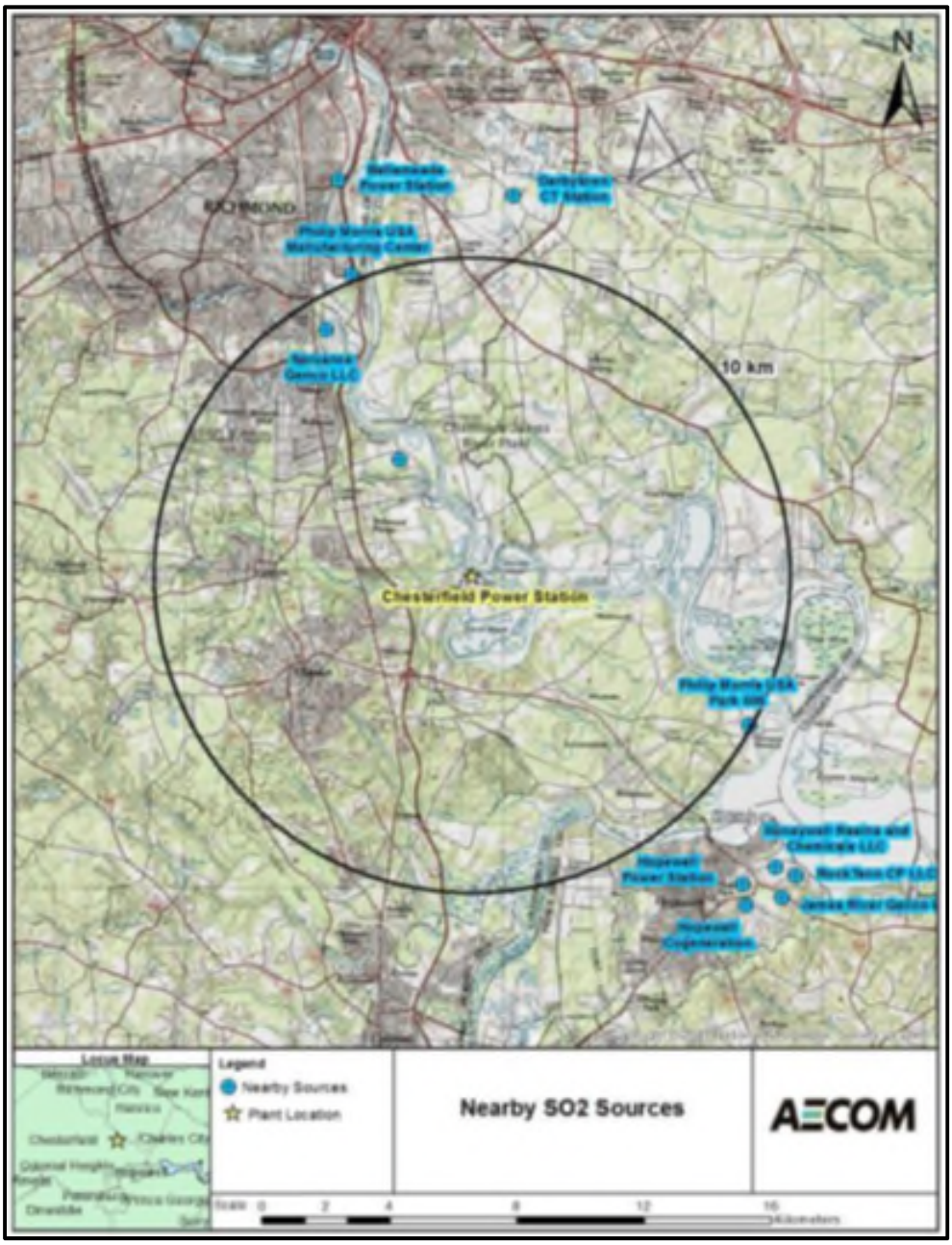

Figure 9: Location of Nearby SO_2 Emission Sources

Figure 10 shows the modeling receptor grid for the Chesterfield Power Station. This grid covers the City of Hopewell and the City of Colonial Heights entirely. The grid covers a significant portion of the City of Richmond, City of Petersburg, eastern Henrico County, eastern Chesterfield County, and western Charles City County. These portions contain the majority of the industrial point sources for each listed jurisdiction. The grid also covers portions of Dinwiddie County, Prince George County, Hanover County, and New Kent County.

The grid shown in Figure 10 extends 20 kilometers (12.4 miles). The maximum modeled design concentration is located approximately 15 kilometers southeast of the Chesterfield Power Station, in the City of Hopewell.

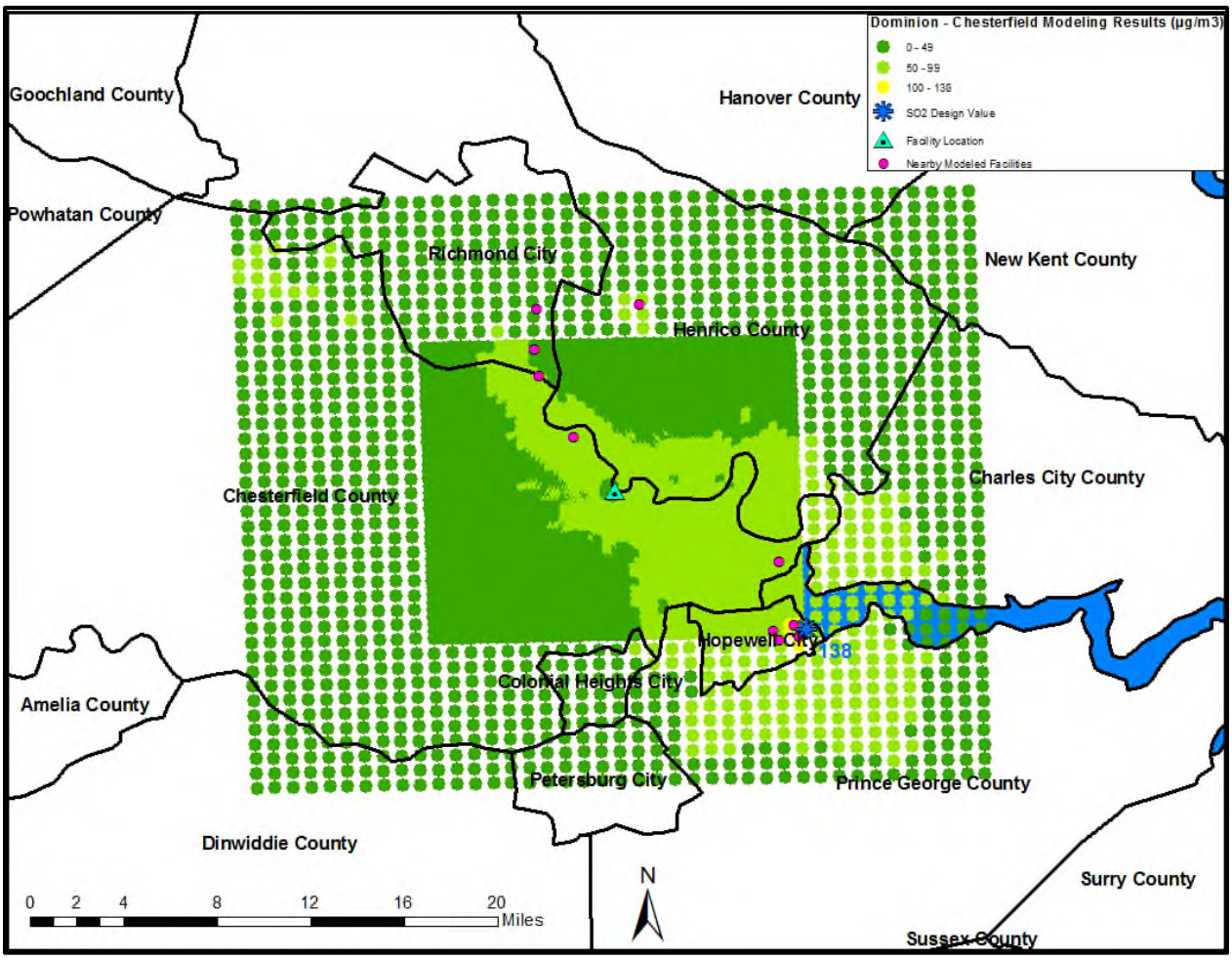

Figure 10: Chesterfield Power Station Modeling Grid and Results

Table 11 provides a summary of the results, showing a significant buffer between the 2010 SO_2 NAAQS and the modeled design value. The cumulative modeled design value from all sources was 138.09 µg/m^3; however, the contribution from the Chesterfield Power Station to the maximum design value was minimal (0.0072 µg/m^3). The facilities that significantly contribute to the maximum modeled design concentration are located in and near the City of Hopewell. The multiple smaller emitters in the Hopewell area resulted in the maximum modeled design value occurring in the City of Hopewell rather than closer to the Chesterfield Power Station, the primary source in this analysis. Concentrations beyond the City of Hopewell decrease substantially approaching the grid boundary. This illustrates that the grid size was adequate to capture the maximum design value. Another important observation is that the maximum modeled design value is well below the 2010 SO_2 NAAQS.

Table 11: Chesterfield Power Station Modeling Analysis Result Summary

	Modeled SO_2 Concentration	Monitored SO_2 Background Concentration	Total Concentration	Percent of NAAQS
Chesterfield Power Station	62.53 µg/m^3	18 µg/m^3	80.53 µg/m^3	41%
All modeled sources	120.09 µg/m^3	18 µg/m^3	138.09 µg/m^3	70%

Please refer to the detailed report included in the electronic submittal of the modeling files for additional information on this analysis.

VI. B. 2. Dominion - Yorktown Power Station

The Yorktown Power Station has the capability of generating up to approximately 1,141 MW of electrical output and is located three miles southeast of Yorktown, Virginia, in York County. Two coal-fired boilers and one residual oil-fired boiler produce the majority of the electrical output. Dominion, the owner of the facility, has noted in its most recent Integrated Resource Plan[3] submitted to the Virginia State Corporation Commission on April 29, 2016, that they expect to retire the two coal-fired units in 2017 after completion of additional transmission capacity in the area.

Applicable guidance in the TAD and various EPA modeling clarification memos suggests that nearby sources expected to cause a significant concentration gradient in the vicinity of the primary source should be included in the modeling analysis. Two additional sources emitted enough SO_2 (greater than 50 tpy of actual emissions) to warrant inclusion in the modeling analysis. These sources are the Williamsburg Sewage Treatment Plant and the NASA Steam Plant. Figure 11 provides the location of these units relative to the Yorktown Power Station. Table 12 provides information on

[3] https://www.dom.com/about-us/making-energy/2016-integrated-resource-planning

the units at these facilities that were included in the Yorktown Power Station modeling analysis

Figure 11: Location of Nearby SO_2 Emission Sources

Table 12: Units Included in the Yorktown Power Station Modeling Analysis

Plant Name	Jurisdiction	Stack Number	2014 SO_2 Actual Emissions (tpy)
Williamsburg Sewage Treatment Plant	City of Williamsburg	1	130.70
Hampton/NASA Steam Plant	City of Hampton	1,2	80.52
		Total Additional Tons of SO_2:	**211.22**

Figure 12 shows the gridded modeling results for the Yorktown Power Station analysis. The grid covers all of the City of Poquoson; nearly all of York County, the City of Newport News, and the City of Hampton; and portions of Mathews County, Gloucester County, James City County, Surry County, Isle of Wight County, and the City of Williamsburg.

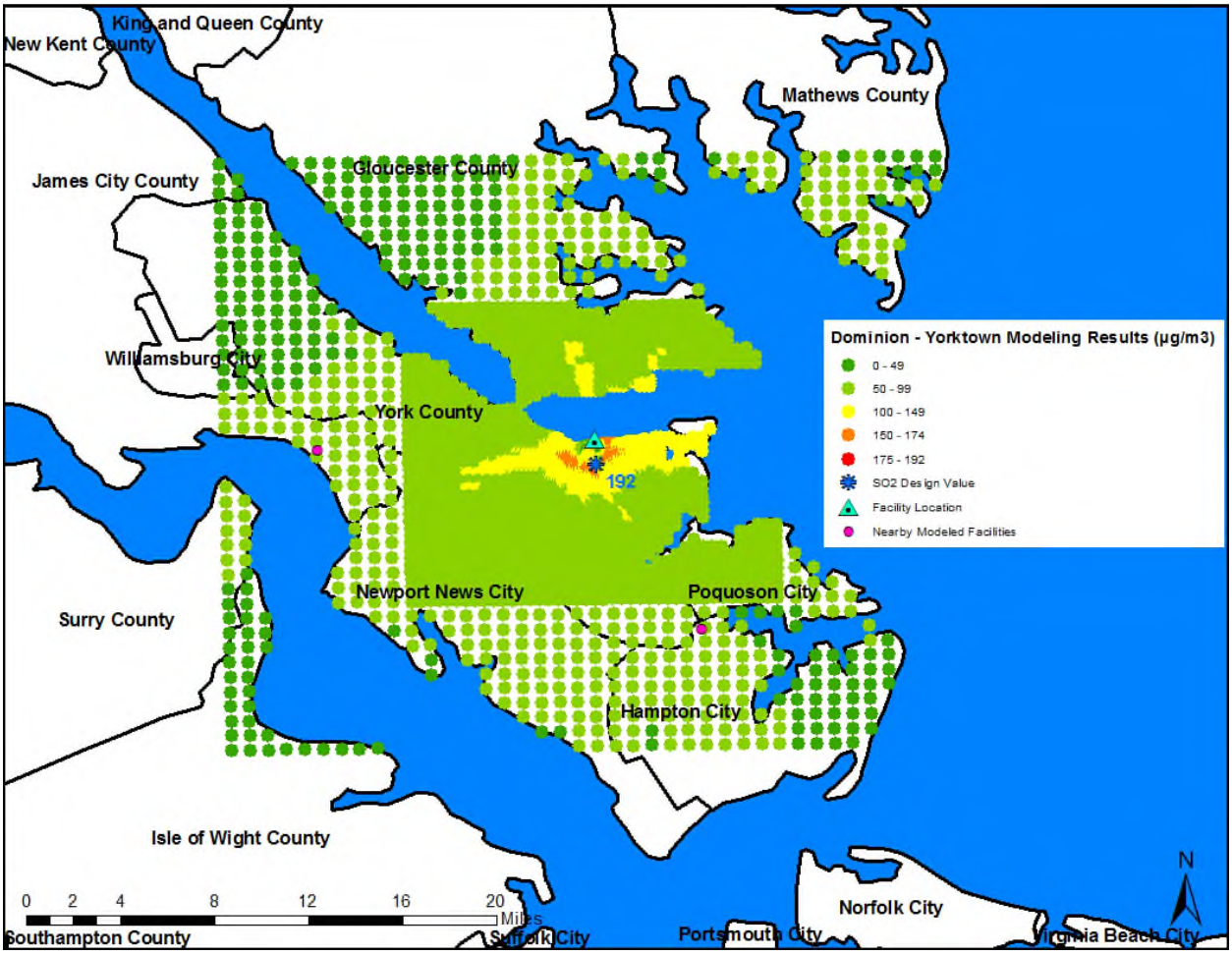

Figure 12: Yorktown Power Station Modeling Grid and Results

The maximum modeled SO_2 design concentration of 192.29 µg/m^3 is located near the Yorktown Power Station. Modeled concentrations substantially decrease toward the boundary of the modeling domain. Table 13 provides a summary of the results of this analysis.

Table 13: Yorktown Power Station Modeling Analysis Result Summary

Modeled SO_2 Concentration	Monitored SO_2 Background Concentration	Total Concentration	Percent of NAAQS
180.61 µg/m^3	11.68 µg/m^3	192.29 µg/m^3	98%

The estimated total concentration of 192.29 µg/m^3 is near the 2010 SO_2 NAAQS. However, Dominion's Integrated Resource Plan suggests that Boilers #1 and #2 will retire in the near future. Additionally, Boiler #3, a residual oil-fired unit, is subject to the Mercury and Air Toxics Standard. The owner chooses to operate the unit no more than 8% of the unit's annual capacity to ensure compliance with this rule. The conservative nature of the modeling analysis coupled with these operational issues ensures that the area is meeting and will continue to meet the 2010 SO_2 NAAQS.

Please refer to the detailed report included in the electronic submittal of the modeling files for additional information on this analysis.

VI. B. 3. Dominion - Clover Power Station

Clover Power Station is located in Halifax County within three miles of Clover, Virginia. The facility generates up to approximately 865 MW of electricity from two coal-fired boilers. These units are controlled with flue gas desulfurization units.

No nearby sources are expected to cause a significant concentration gradient in the vicinity of the Clover Power Station. Therefore, the analysis does not include any additional sources of SO_2 emissions.

Figure 13 shows the location of the Clover Power Station on a topographical map. Figure 14 illustrates the gridded modeling results. The modeling domain covers large portions of Halifax County, Charlotte County, and Mecklenburg County as well as small portions of Lunenburg County and Campbell County. These counties are sparsely populated and contain few industrial sources.

Figure 13: Location of Clover Power Station

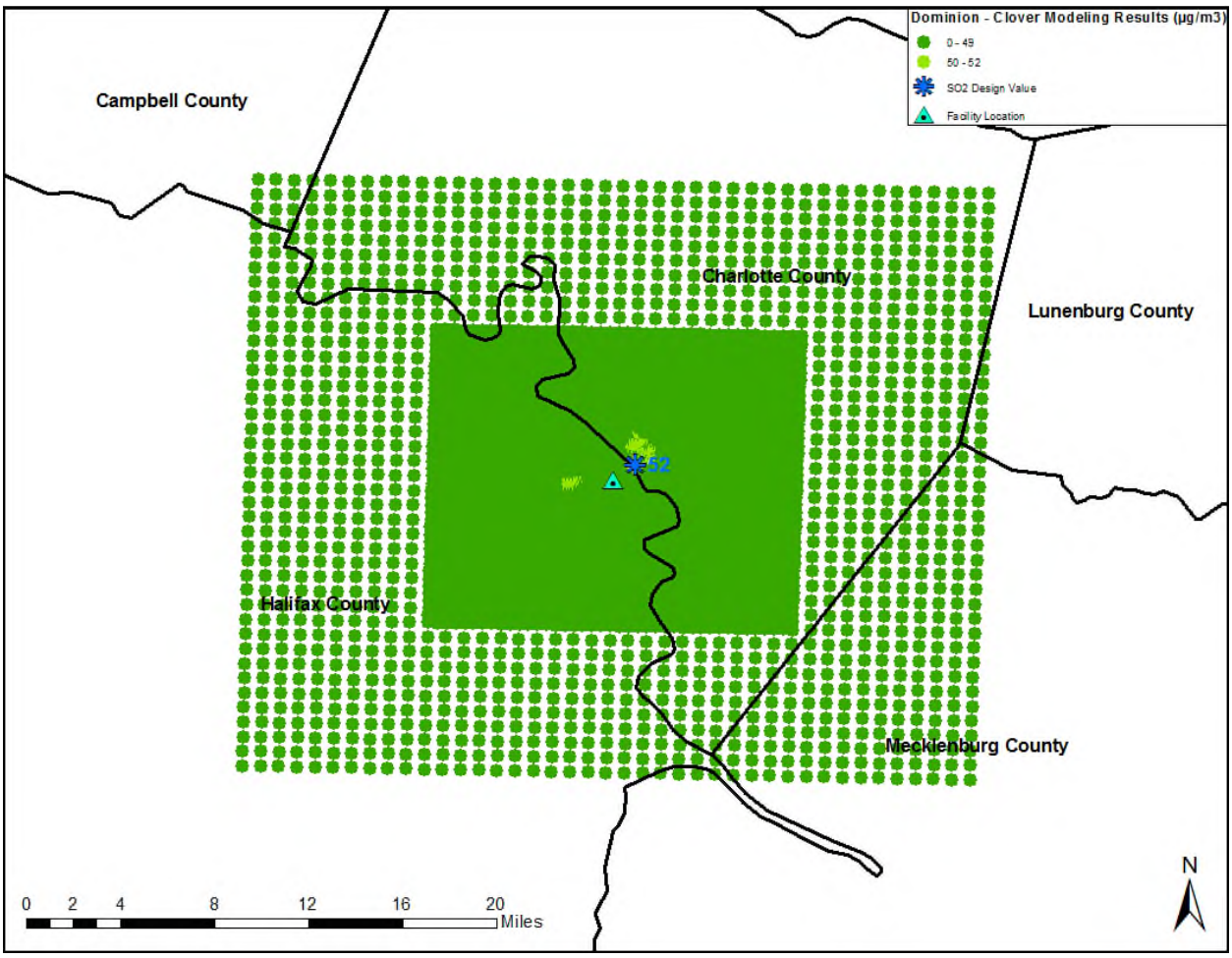

Figure 14: Clover Power Station's Modeling Grid and Results

The maximum estimated SO_2 design concentration of 52.15 µg/m^3 is located near the Clover Power Station. Concentrations decrease toward the edge of the modeling domain.

Table 14 provides a summary of the results for this analysis. The maximum modeled design value is well below the 2010 SO_2 NAAQS.

Table 14: Clover Power Station Modeling Analysis Result Summary

Modeled SO_2 Concentration	Monitored SO_2 Background Concentration	Total Concentration	Percent of NAAQS
38.09 µg/m^3	14.06 µg/m^3	52.15 µg/m^3	27%

Please refer to the detailed report included in the electronic submittal of the modeling files for additional information on this analysis.

VI. B. 4. Jewell Coke Company

Jewell Coke Company operates a non-recovery coke production facility in Buchanan County near Vansant, Virginia. The facility includes 142 coke ovens in six batteries. The main sources of SO_2 emissions are the vent stacks and the coal dryer stack.

No nearby sources are expected to cause a significant concentration gradient in the vicinity of the Jewell Coke Company. Therefore, the analysis does not include any additional sources of SO_2 emissions.

The EPA modeling TAD discusses limited ambient air locations that can be excluded from the modeling analysis based on the criteria that a monitor could not feasibly be placed in these areas. Terrain around the Jewell Coke Company is extremely steep and mountainous. Most of the terrain within 10 kilometers of the facility (and beyond the modeling domain) exhibits terrain slope percentages in excess of 30%, which reasonably precludes the installation of an ambient monitor in those areas. Therefore, the modeling grid excludes these receptors that are located within rugged terrain areas that have slopes equal to or greater than 30%. Figure 15 provides an aerial view of the facility and nearby terrain. Figure 16 provides a portion of the nearby receptor grid used in this analysis, depicting slopes of greater than 30% in blue.

Figure 15: Jewell Coke Company and Surrounding Terrain

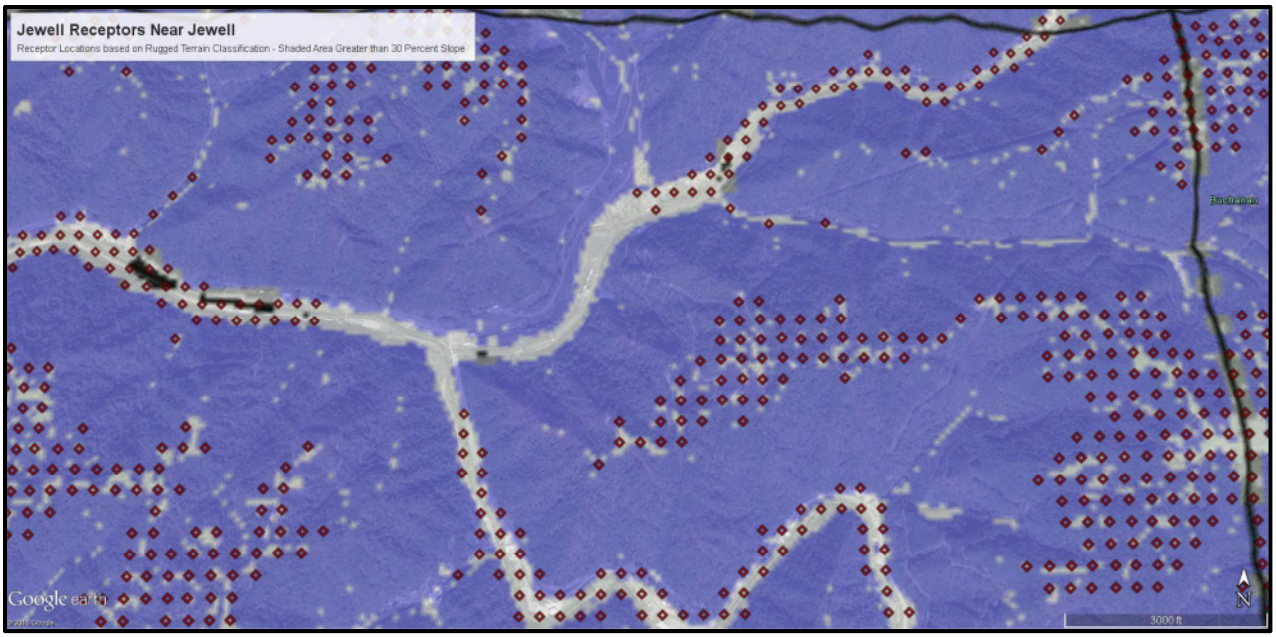

Figure 16: Nearby Portion of Jewell Receptor Grid and Terrain Shading

Figure 17 provides the gridded modeling results and jurisdictional boundaries. The modeling domain is located within the boundary of Buchanan County. Concentrations decrease in the modeling domain as distance from the facility increases.

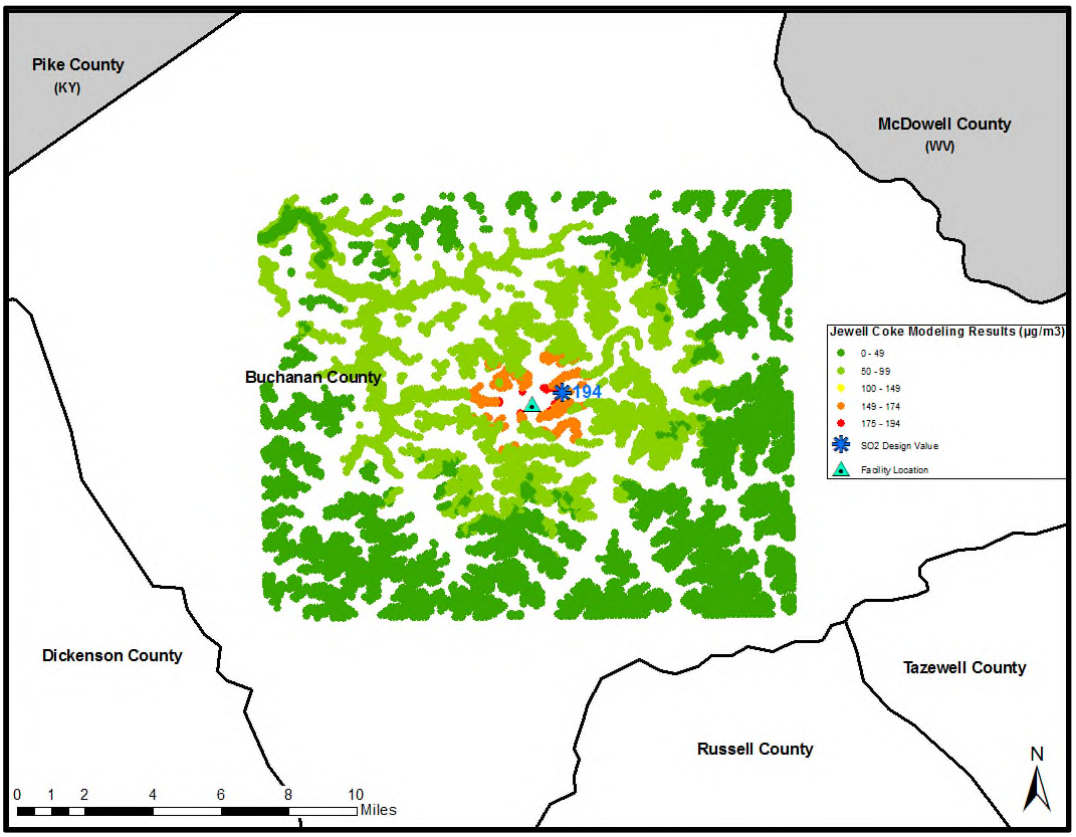

Figure 17: Jewell Receptor Grid and Jurisdiction Boundaries

The maximum modeled design value is located near Jewell Coke Company and is 194.5 µg/m^3, 99% of the 2010 SO_2 NAAQS. Table 15 provides a summary of the results for this analysis.

Table 15: Jewell Coke Company Modeling Analysis Result Summary

Modeled SO_2 Concentration	Monitored SO_2 Background Concentration	Total Concentration	Percent of NAAQS
181.5 µg/m^3	13.0 µg/m^3	194.5 µg/m^3	99%

Please refer to the detailed report included in the electronic submittal of the modeling files for additional information on this analysis.

VI. B. 5. Ongoing Data Requirements in the DRR

The DRR addresses ongoing requirements for facilities and areas using modeling to demonstrate compliance with the 2010 SO_2 NAAQS. Section 51.1205(b) (80 FR 51088) states the following:

> §51.1205(b) *Modeled areas.* For any area where modeling of actual SO_2 emissions serve as the basis for designating such area as attainment for the 2010 SO_2 NAAQS, the air agency shall submit an annual report to the EPA Regional Administrator by July 1 of each year, either as a stand alone document made available for public inspection, or as an appendix to its Annual Monitoring Network Plan (also due on July 1 each year under 40 CFR 58.10), that documents the annual SO_2 emissions of each applicable source in each such area and provides an assessment of the cause of any emissions increase from the previous year. The first report for each such area is due by July 1 of the calendar year after the effective date of the area's initial designation.
>
> (1) The air agency shall include in such report a recommendation regarding whether additional modeling is needed to characterize air quality in any area to determine whether the area meets or does not meet the 2010 SO_2 NAAQS. The EPA Regional Administrator will consider the emissions report and the air agency recommendation, and may require that the air agency conduct updated air quality modeling for the area and submit it to the EPA within 12 months.
>
> (2) An air agency will no longer be subject to the requirements of this paragraph (b) for a particular area if it provides air

quality modeling demonstrating that air quality values at all receptors in the analysis are not greater than 50 percent of the 1-hour SO_2 NAAQS, and such demonstration is approved by the EPA Regional Administrator.

Based on this information in the DRR, DEQ will submit such information as part of the Annual Monitoring Network Review for Buchanan County/Jewell Coke Company and York County/Yorktown Power Station. These areas and facilities provided demonstrations showing air quality impacts associated with the emissions from the primary source in the modeling exercise to be greater than 50% of the 2010 SO_2 NAAQS.

The air quality analysis summarized in Section VI. B. 1. for Chesterfield Power Station showed air quality impacts associated with the emissions from the Chesterfield Power Station to be less than 50% of the 2010 SO_2 NAAQS. However, the inclusion of additional SO_2 emission sources in the analysis showed impacts greater than 50% near Hopewell, Virginia. Therefore, DEQ will also submit the information described in 40 CFR 51.1205(b) in the Annual Network Monitoring Review for the City of Hopewell. Emissions from the Chesterfield Power Station are not significant at the modeled receptors exceeding 50% of the NAAQS, as noted in Section VI. B. 1. Therefore, this facility will not be included as part of the Annual Network Monitoring Review.

VI. C. Facilities Installing Monitoring Networks

Virginia may supply further recommendations by December 31, 2020, pending the review of data from source-specific air quality monitoring networks located in Giles County for Lhoist North America - Kimballton Plant, EIS identification number VA0000005107100001; Montgomery County for Roanoke Cement Company, EIS identification number VA0000005102300003; and the City of Covington for WestRock Virginia Corporation – Covington (formerly Meadwestvaco), EIS identification number VA0000005158000003.

VII. Jurisdictions Recommended to be Attainment/Unclassifiable

Of the five factors listed in Attachment 2 within the March 20, 2015, EPA memorandum, this document has provided detailed information on emissions inventory data, ambient air quality monitoring data, and dispersion modeling results. This data has been provided in context of the various jurisdictional boundaries within the Commonwealth of Virginia. Geography and topography are discussed within the air quality modeling analyses associated with those facilities located in mountainous terrain, such as Jewell Coke Company. What is clear from the modeling and monitoring data is that SO_2 concentrations in the ambient air appear to be directly proportional to

proximity of SO_2 emissions sources. It is unlikely that high SO_2 concentrations exist farther away from high emitting sources or groups of source. As shown in Section IV and Section VI. B., the 2,000 tpy threshold for analysis under the DRR subjected all high emitting sources and groups of sources within Virginia to scrutiny. Therefore, Virginia believes it is appropriate to use emissions inventory data, along with existing air quality monitoring data or air quality modeling data, as support for updating recommendations to attainment/unclassifiable for those jurisdictions where monitoring or modeling data are available.

Seven of the jurisdictions in Appendix A contain within their boundaries SO_2 monitors that are part of Virginia's air quality monitoring network. As detailed in Section III, the data from these monitoring sites show compliance with a significant margin of safety. Based on monitoring data and the inventory analysis in Appendix A, Virginia therefore recommends that these seven jurisdictions, listed in Table 16, be designated attainment/unclassifiable for the 2010 SO_2 NAAQS. Charles City County and Henrico County are also included in the modeling analysis for the Dominion – Chesterfield Power Station, and the City of Hampton is included in the modeling analysis for the Dominion – Yorktown Power Station. These modeling analyses demonstrate compliance with the 2010 SO_2 NAAQS and are summarized in Section VI. B.

Table 16: Jurisdictions Recommended Attainment/Unclassifiable Using Monitoring Network Data

Jurisdiction	FIPS	Recommended Designation
Charles City County	51-036	Attainment/unclassifiable
Fairfax County	51-059	Attainment/unclassifiable
Henrico County	51-087	Attainment/unclassifiable
Roanoke County	51-161	Attainment/unclassifiable
Rockingham County	51-165	Attainment/unclassifiable
City of Hampton	51-650	Attainment/unclassifiable
City of Norfolk	51-710	Attainment/unclassifiable

Air quality analyses discussed in Section VI. B. cover all or much of the following jurisdictions, and these analyses show compliance with the 2010 SO_2 NAAQS. Review of inventory data, including the data supplied in Appendix A, show that the air quality analyses consider all significant SO_2 sources or groups of sources within the modeling radii and that surrounding areas do not have significant SO_2 emissions. Virginia therefore recommends that these jurisdictions, listed in Table 17, be designated attainment/unclassifiable.

Table 17: Jurisdictions Recommended Attainment/Unclassifiable Using Modeling Results

Jurisdiction	FIPS	Recommended Designation
Chesterfield County	51-041	Attainment/unclassifiable
City of Petersburg	51-730	Attainment/unclassifiable
City of Hopewell	51-670	Attainment/unclassifiable
City of Colonial Heights	51-570	Attainment/unclassifiable
City of Richmond	51-760	Attainment/unclassifiable
City of Poquoson	51-735	Attainment/unclassifiable
York County	51-199	Attainment/unclassifiable
City of Newport News	51-700	Attainment/unclassifiable
Halifax County	51-083	Attainment/unclassifiable
Charlotte County	51-037	Attainment/unclassifiable
Mecklenburg County	51-117	Attainment/unclassifiable
Buchanan County	51-027	Attainment/unclassifiable

Appendix A: Emissions By Jurisdiction

To analyze emissions on a jurisdictional basis, DEQ developed Table A – 1, which contains SO_2 emissions from each of the four emissions categories (point, area, non-road and on-road) by jurisdiction. The area and non-road sectors are from the 2011 NEI database since these data are the most current, final NEI data available. To augment this data with the most current point source information, Table A - 1 includes 2015 point source SO_2 emissions estimates from CEDS by jurisdiction. The 2011 on-road data by jurisdiction supplied in this table reflects the use of Virginia-specific inputs and the MOVES2014 inventory tool.

Table A - 1: Annual SO_2 Emissions by Jurisdiction, tpy

Jurisdiction	FIPS	Point	Area	On-Road	Non-Road	Total
Accomack County	001	252.05	613.50	4.04	2.21	871.80
Albemarle County	003	9.81	97.65	11.79	1.65	120.89
Alexandria City	510	6.64	113.88	7.52	0.45	128.50
Alleghany County	005	2.54	19.41	2.85	0.67	25.48
Amelia County	007	3.26	10.33	1.75	0.25	15.58
Amherst County	009	6.75	28.69	3.26	0.41	39.11
Appomattox County	011	0.13	11.13	1.57	0.21	13.04
Arlington County	013	6.82	157.02	15.00	2.84	181.69
Augusta County	015	37.86	78.53	12.53	1.11	130.03
Bath County	017	9.00	3.55	0.50	0.10	13.15
Bedford City	515	-	10.57	0.50	0.07	11.14
Bedford County	019	41.78	59.29	5.70	0.92	107.69
Bland County	021	30.98	5.24	2.86	0.08	39.15
Botetourt County	023	2,357.73	43.17	7.59	0.50	2,408.99
Bristol City	520	1.17	23.40	2.30	0.26	27.14
Brunswick County	025	8.48	13.24	3.60	0.21	25.54
Buchanan County	027	4,871.02	22.52	2.25	0.25	4,896.04
Buckingham County	029	33.24	11.76	1.44	0.23	46.67
Buena Vista City	530	0.02	7.31	0.23	0.05	7.61
Campbell County	031	34.05	49.64	5.45	1.01	90.14
Caroline County	033	11.86	24.36	8.37	0.43	45.02
Carroll County	035	9.06	28.23	5.88	0.46	43.63
Charles City County	036	5.49	111.08	0.88	0.25	117.70
Charlotte County	037	3.43	13.45	1.28	0.20	18.36
Charlottesville City	540	20.29	41.32	2.22	0.32	64.15
Chesapeake City	550	18.30	187.66	20.59	1.18	227.73
Chesterfield County	041	2,686.54	248.80	30.96	2.76	2,969.05
Clarke County	043	0.38	13.69	2.50	0.29	16.87
Colonial Heights City	570	0.01	14.71	2.13	0.07	16.93
Covington City	580	6,229.73	17.47	0.37	0.11	6,247.68

Jurisdiction	FIPS	Point	Area	On-Road	Non-Road	Total
Craig County	045	0.60	3.11	0.36	0.06	4.13
Culpeper County	047	8.89	35.24	4.94	0.91	49.97
Cumberland County	049	0.00	6.89	0.76	0.10	7.75
Danville City	590	15.49	69.93	3.30	0.38	89.10
Dickenson County	051	6.33	16.26	1.27	0.18	24.03
Dinwiddie County	053	21.54	26.11	4.69	0.43	52.77
Emporia City	595	-	7.55	0.71	0.05	8.31
Essex County	057	1.11	12.33	1.41	0.30	15.15
Fairfax City	600	0.03	20.41	1.79	0.18	22.41
Fairfax County	059	154.71	806.89	89.07	8.87	1,059.54
Falls Church City	610	0.04	10.19	0.66	0.10	10.98
Fauquier County	061	10.63	49.49	11.75	1.73	73.61
Floyd County	063	9.09	12.15	1.19	0.20	22.64
Fluvanna County	065	13.79	17.70	1.68	0.32	33.49
Franklin City	620	1.03	5.90	0.35	0.02	7.30
Franklin County	067	81.22	46.17	5.16	0.83	133.38
Frederick County	069	70.97	77.25	11.04	2.39	161.65
Fredericksburg City	630	0.55	24.12	3.56	0.11	28.34
Galax City	640	19.18	9.17	0.50	0.14	28.99
Giles County	071	7,433.38	18.62	1.87	0.17	7,454.05
Gloucester County	073	5.98	24.15	3.05	0.61	33.79
Goochland County	075	32.98	21.64	5.80	0.60	61.02
Grayson County	077	1.98	13.85	1.08	0.21	17.12
Greene County	079	2.77	11.72	1.45	0.19	16.12
Greensville County	081	29.63	15.88	2.99	0.21	48.71
Halifax County	083	1,798.38	31.72	3.52	0.55	1,834.17
Hampton City	650	85.59	188.36	14.42	0.61	288.98
Hanover County	085	245.69	94.73	16.98	1.62	359.02
Harrisonburg City	660	1.88	57.14	3.14	0.35	62.51
Henrico County	087	38.20	278.46	31.05	3.83	351.54
Henry County	089	19.45	58.22	5.10	0.60	83.37
Highland County	091	0.00	1.77	0.25	0.05	2.08
Hopewell City	670	2,283.95	18.68	1.02	0.14	2,303.79
Isle of Wight County	093	265.35	94.64	5.36	0.69	366.04
James City County	095	408.27	107.73	4.94	1.22	522.16
King and Queen County	097	52.35	6.71	0.91	0.24	60.21
King George County	099	311.09	16.80	2.77	0.35	331.01
King William County	101	547.54	11.87	1.40	0.28	561.09
Lancaster County	103	0.00	10.30	1.24	0.39	11.92
Lee County	105	14.90	18.55	1.98	0.26	35.69
Lexington City	678	0.04	5.42	0.23	0.02	5.71
Loudoun County	107	9.96	222.79	22.77	5.92	261.44
Louisa County	109	24.83	30.94	4.89	0.53	61.20
Lunenburg County	111	1.49	9.09	0.88	0.17	11.64
Lynchburg City	680	47.63	119.24	5.52	0.64	173.03
Madison County	113	0.01	10.08	1.70	0.23	12.03
Manassas City	683	4.77	31.98	3.02	0.19	39.96

Jurisdiction	FIPS	Point	Area	On-Road	Non-Road	Total
Manassas Park City	685	-	8.85	0.31	0.10	9.26
Martinsville City	690	1.24	19.90	0.99	0.17	22.30
Mathews County	115	-	5.82	0.65	0.37	6.84
Mecklenburg County	117	299.56	33.07	4.75	0.96	338.33
Middlesex	119	-	10.25	1.11	0.31	11.67
Montgomery County	121	3,449.48	89.88	10.39	1.08	3,550.82
Nelson County	125	0.46	15.30	2.29	0.27	18.31
New Kent County	127	5.70	14.20	5.91	0.34	26.14
Newport News City	700	515.47	403.17	17.83	1.85	938.33
Norfolk City	710	239.36	281.99	21.19	3.16	545.71
Northampton County	131	0.02	635.22	2.33	1.50	639.08
Northumberland County	133	0.73	17.92	1.11	0.53	20.29
Norton City	720	0.01	5.04	0.46	0.03	5.53
Nottoway County	135	34.64	13.92	1.78	0.23	50.56
Orange County	137	3.13	28.81	2.67	0.52	35.13
Page County	139	0.96	25.21	1.63	0.38	28.17
Patrick County	141	2.87	21.63	1.46	0.35	26.32
Petersburg City	730	15.30	31.83	3.29	0.15	50.58
Pittsylvania County	143	164.09	48.48	5.72	0.75	219.04
Poquoson City	735	-	120.38	0.53	0.14	121.05
Portsmouth City	740	582.34	89.64	5.72	0.33	678.04
Powhatan County	145	37.34	18.36	2.88	0.40	58.98
Prince Edward County	147	33.09	19.49	2.32	0.27	55.16
Prince George County	149	0.53	59.18	6.20	0.44	66.36
Prince William County	153	1,817.08	240.93	31.89	3.91	2,093.81
Pulaski County	155	3.62	35.31	5.24	0.53	44.70
Radford City	750	0.08	19.97	0.77	0.08	20.90
Rappahannock County	157	-	5.08	0.88	0.13	6.08
Richmond City	760	454.90	218.55	18.72	1.30	693.47
Richmond County	159	2.52	8.09	1.08	0.31	12.01
Roanoke City	770	75.83	96.40	8.54	0.50	181.28
Roanoke County	161	4.30	82.14	8.74	1.06	96.25
Rockbridge County	163	1.88	23.29	7.78	0.38	33.33
Rockingham County	165	20.16	96.20	9.63	1.08	127.07
Russell County	167	2,071.68	28.89	3.00	0.24	2,103.80
Salem City	775	1.16	42.38	1.68	0.35	45.58
Scott County	169	7.40	25.30	2.57	0.28	35.55
Shenandoah County	171	30.05	40.66	8.74	0.60	80.05
Smyth County	173	71.07	39.15	4.36	0.41	114.99
Southampton County	175	36.83	17.89	3.39	0.52	58.62
Spotsylvania County	177	3.26	82.03	12.82	1.48	99.59
Stafford County	179	27.60	82.76	17.07	1.52	128.95
Staunton City	790	1.89	18.87	1.23	0.12	22.10
Suffolk City	800	42.85	65.65	9.71	1.11	119.31
Surry County	181	14.19	36.09	0.57	0.27	51.12
Sussex County	183	13.14	12.96	3.69	0.24	30.04
Tazewell County	185	24.80	47.81	3.92	0.33	76.86

Jurisdiction	FIPS	Point	Area	On-Road	Non-Road	Total
Virginia Beach City	810	171.32	580.87	30.87	4.10	787.16
Warren County	187	13.18	29.53	4.49	0.42	47.62
Washington County	191	41.13	64.00	7.50	0.64	113.26
Waynesboro City	820	1.41	22.52	1.35	0.19	25.47
Westmoreland County	193	1.52	14.09	1.42	0.35	17.38
Williamsburg City	830	0.14	11.44	0.93	0.07	12.59
Winchester City	840	0.55	37.05	1.45	0.25	39.30
Wise County	195	111.60	31.07	4.07	0.33	147.09
Wythe County	197	15.52	38.28	7.87	0.59	62.26
York County	199	4,550.33	176.23	7.25	1.02	4,734.83

Appendix B: US Army – Radford Army Ammunition Plant March 22, 2016, Permit

COMMONWEALTH of VIRGINIA

Molly Joseph Ward
Secretary of Natural Resources

DEPARTMENT OF ENVIRONMENTAL QUALITY
Blue Ridge Regional Office
www.deq.virginia.gov

David K. Paylor
Director

Robert J. Weld
Regional Director

Lynchburg Office
7705 Timberlake Road
Lynchburg, Virginia 24502
(434) 582-5120
Fax (434) 582-5125

Roanoke Office
3019 Peters Creek Road
Roanoke, Virginia 24019
(540) 562-6700
Fax (540) 562-6725

March 22, 2016

Alicia M. Masson
Lieutenant Colonel, Commanding
U.S. Army
P.O. Box 2
Radford, VA 24143-0002

William M. Barnett
General Manager, RFAAP
BAE Systems Ordnance Systems Inc.
P.O. Box 1
Radford, VA 24143-0100

Location: Montgomery County
Registration No.: 20656

Dear LTC Masson and Mr. Barnett:

Attached is a permit to construct and operate a project at the Radford Army Ammunition Plant in accordance with the provisions of the Virginia State Air Pollution Control Board Regulations for the Control and Abatement of Air Pollution. This permit supersedes your permit dated October 8, 2014.

In the course of evaluating the application and arriving at a final decision to approve the project, the Department of Environmental Quality (DEQ) deemed the application complete on March 16, 2016.

This permit contains legally enforceable conditions. Failure to comply may result in a Notice of Violation and/or civil charges. Please read all permit conditions carefully.

This permit approval to construct and operate shall not relieve Radford Army Ammunition Plant of the responsibility to comply with all other local, state, and federal permit regulations.

The proposed boilers are subject to 40 CFR 63, Maximum Achievable Control Technology, (MACT) Subpart DDDDD and 40 CFR 60, New Source Performance Standard

(NSPS), Subparts Db and Dc. Virginia has accepted delegation of these rules. In summary, the units are required to comply with certain federal emission standards and operating limitations. The Department of Environmental Quality (DEQ) advises you to review the referenced MACT and NSPS to ensure compliance with applicable emission and operational limitations. As the owner/operator you are also responsible for any monitoring, notification, reporting and recordkeeping requirements of the MACT and NSPS. Notifications shall be sent to both EPA, Region III and Virginia DEQ.

To review any federal rules referenced in the above paragraph or in the attached permit, the US Government Publishing Office maintains the text of these rules at www.ecfr.gov, Title 40, Part 60 and 63.

The Board's Regulations as contained in Title 9 of the Virginia Administrative Code 5-170-200 provide that you may request a formal hearing from this case decision by filing a petition with the Board within 30 days after this case decision notice was mailed or delivered to you. Please consult the relevant regulations for additional requirements for such requests.

As provided by Rule 2A:2 of the Supreme Court of Virginia, you have 30 days from the date you actually received this permit or the date on which it was mailed to you, whichever occurred first, within which to initiate an appeal of this decision by filing a Notice of Appeal with:

David K. Paylor, Director
Department of Environmental Quality
P. O. Box 1105
Richmond, VA 23218

If this permit was delivered to you by mail, three days are added to the thirty-day period in which to file an appeal. Please refer to Part Two A of the Rules of the Supreme Court of Virginia for information on the required content of the Notice of Appeal and for additional requirements governing appeals from decisions of administrative agencies.

If you have any questions concerning this permit, please contact the Regional Office at (540)562-6700.

Sincerely,

Robert J. Weld
Regional Director

Attachments: Permit
Source Testing Report Format

Cc: Manager/Inspector, Air Compliance

COMMONWEALTH of VIRGINIA

Molly Joseph Ward
Secretary of Natural Resources

DEPARTMENT OF ENVIRONMENTAL QUALITY
Blue Ridge Regional Office
www.deq.virginia.gov

David K. Paylor
Director

Robert J. Weld
Regional Director

Lynchburg Office
7705 Timberlake Road
Lynchburg, Virginia 24502
(434) 582-5120
Fax (434) 582-5125

Roanoke Office
3019 Peters Creek Road
Roanoke, Virginia 24019
(540) 562-6700
Fax (540) 562-6725

STATIONARY SOURCE PERMIT TO CONSTRUCT AND OPERATE
This permit includes designated equipment subject to New Source Performance Standards (NSPS).
This permit supersedes your permit dated October 8, 2014.

In compliance with the Federal Clean Air Act and the Commonwealth of Virginia Regulations for the Control and Abatement of Air Pollution,

The U.S. Army and BAE Systems Ordnance Systems, Inc.
Radford Army Ammunition Plant
Route 114, P.O. Box 1
Radford, VA 24143-0100
Registration No.: 20656

is authorized to construct and operate

a power and steam generation installation

located at

Radford Army Ammunition Plant
Montgomery County, Virginia

in accordance with the Conditions of this permit.

Approved on March 22, 2016.

Robert J. Weld
Regional Director

Permit consists of 14 pages.
Permit Conditions 1 to 34.

INTRODUCTION

This permit approval is based on the permit application dated December 9, 2015, including supplemental information dated January 11, 2016, February 8, 2016, February 10, 2016, February 22, 2016, March 4, 2016, and March 9, 2016. Any changes in the permit application specifications or any existing facilities which alter the impact of the facility on air quality may require a permit. Failure to obtain such a permit prior to construction may result in enforcement action. In addition, this facility may be subject to additional applicable requirements not listed in this permit.

Words or terms used in this permit shall have meanings as provided in 9VAC5-10-20 of the State Air Pollution Control Board Regulations for the Control and Abatement of Air Pollution. The regulatory reference or authority for each condition is listed in parentheses () after each condition.

Annual requirements to fulfill legal obligations to maintain current stationary source emissions data will necessitate a prompt response by the permittee to requests by the DEQ or the Board for information to include, as appropriate: process and production data; changes in control equipment; and operating schedules. Such requests for information from the DEQ will either be in writing or by personal contact.

The availability of information submitted to the DEQ or the Board will be governed by applicable provisions of the Freedom of Information Act, §§2.2-3700 through 2.2-3714 of the Code of Virginia, §10.1-1314 (addressing information provided to the Board) of the Code of Virginia, and 9VAC5-170-60 of the State Air Pollution Control Board Regulations. Information provided to federal officials is subject to appropriate federal law and regulations governing confidentiality of such information.

Equipment List - Equipment at this facility consists of:

Equipment included in the power and steam generation installation			
Ref. No.	**Equipment Description**	**Rated Capacity**	**Federal Requirements**
ECPB-01 – 04	Rentech D-Type Superheated Watertube Boiler (large boiler)	172 MMBtu/hr, each (NG); 163 MMBtu/hr, each (oil)	NSPS Db
ECPB-05 – 06	Rentech D-Type Superheated Watertube Boiler (small boiler)	75 MMBtu/hr, each (NG); 71 MMBtu/hr, each (oil)	NSPS Dc
Equipment previously installed			
PH1 – PH5	Coal/oil fired boiler	210 MMBtu/hr, each	
PH6, PH7	Ash Handling (silo and truck loading)		

Specifications included in this table are for informational purposes only and do not form enforceable terms or conditions of the permit.

PROCESS REQUIREMENTS

1. **Monitoring Devices** - Each boiler (ECPB-01 – 06) shall be equipped with a non-resettable hour meter to record the hours of operation of each unit when combusting each fuel. Each monitoring device shall be installed, maintained, calibrated and operated in accordance with the manufacturer's written requirements or recommendations. Each monitoring device shall be provided with adequate access for inspection and shall be in operation when the respective emissions unit is operating. (9VAC5-80-1180)

2. **Monitoring Devices** - Each boiler (ECPB-01 – 06) shall be equipped with a device to record the amount of each fuel delivered to the boiler. Each monitoring device shall be installed, maintained, calibrated and operated in accordance with the manufacturer's written requirements or recommendations. Each monitoring device shall be provided with adequate access for inspection and shall be in operation when the respective emissions unit is operating.
(9VAC5-80-1180)

3. **Emissions Testing** - The facility shall be constructed so as to allow for emissions testing upon reasonable notice at any time, using appropriate methods. This includes constructing the facility/equipment such that volumetric flow rates and pollutant emission rates can be accurately determined by applicable test methods and providing a stack or duct that is free from cyclonic flow. Sampling ports shall be provided when requested at the appropriate locations and safe sampling platforms and access shall be provided.
(9VAC5-50-30 F and 9VAC5-80-1180)

OPERATING LIMITATIONS

4. **Fuel Throughput** – Upon the earlier of January 1, 2017 or the first new emissions unit (ECPB-01 – 06) in the project becoming operational, the combustion of fuel oil in the coal boilers (PH-1 – PH-5) shall not exceed 386,175.0 gallons per year. 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. For the purpose of this permit, "becoming operational" does not include a shakedown period for each new emissions unit not to exceed 180 days after start-up. "Becoming operational" will have occurred no later than the beginning of the first initial performance test required pursuant to this permit or the respective subpart of 40CFR60 for each emissions unit.
(9VAC5-80-1180)

5. **Fuel Throughput** - Upon the first new emissions unit (ECPB-01 – 06) in the project becoming operational, the combustion of coal in the coal boilers (PH-1 – PH-5) shall not exceed 60,000 tons per year. Annual fuel combustion shall be calculated monthly as the sum of each consecutive 12-month period. For the purpose of this permit, "becoming operational" does not include a shakedown period for each new emissions unit not to exceed 180 days after start-up. "Becoming operational" will have occurred no later than the beginning of the first initial performance test required pursuant to this permit or the respective subpart of 40CFR60 for each emissions unit.
(9VAC5-80-1180)

6. **Fuel Throughput** – Regardless of the applicability of Condition 5, beginning January 1, 2017, the combustion of coal in the coal boilers (PH-1 – PH-5) shall not exceed 30,000 tons per year. Annual fuel combustion shall be calculated monthly as the sum of each consecutive 12-month period.
(9VAC5-80-1180)

7. **Permanent Shutdown** – Upon the fourth new emissions unit (ECPB-01 – 06) in the project becoming operational, the coal boilers (PH1 - PH5) and associated material handling equipment (PH6, PH7) shall permanently cease operation. Restarting operation for any of this equipment shall be considered a physical change or change in the method of operation at the facility.

(9VAC5-80-1180 and 9VAC5-20-220)

8. **Fuel** - The approved fuels for the boilers (ECPB-01 – 06) are distillate oil and natural gas. A change in the fuels shall be considered a physical change or change in the method of operation and may require a new or amended permit.
(9VAC5-80-1180)

9. **Fuel Specifications** - The approved fuels shall meet the specifications below:

   DISTILLATE OIL which meets the ASTM D396 specification for Grades 1 or 2 fuel oil:
   Maximum sulfur content per shipment: 0.0015%

   NATURAL GAS which meets the definition contained in 40CFR72.2 for "pipeline natural gas"

   (9VAC5-80-1180 and 9VAC5-50-260)

10. **Fuel Throughput** – The boilers (ECPB-01 – 06) shall consume no more than 238,560 MMBtu of distillate oil, per year, calculated monthly as the sum of each consecutive 12-month period. Of this amount, the small boilers (ECPB-05 – 06) shall consume no more than a combined total of 42,560 MMBtu of distillate oil, 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.
(9VAC5-80-1180)

11. **Fuel Throughput** – The large boilers (ECPB-01 – 04) shall consume no more than the following amount natural gas (in MMBtu), per year, calculated monthly as the sum of each consecutive 12-month period. The limitation shall be calculated for each 12-month period.

    Limit (MMBtu/yr) = 6,312,780.0 - (SDOU*1.12 + SNGU*1.06 + LDOU*1.06)

    Where:
    SDOU = the annual amount of distillate oil combusted in the small boilers (ECPB-05 – 06) in MMBtu
    SNGU = the annual amount of natural gas combusted in the small boilers (ECPB-05 – 06) in MMBtu
    LDOU = the annual amount of distillate oil combusted in the large boilers (ECPB-01 – 04) in MMBtu

    (9VAC5-80-1180)

12. **Fuel Certification** - The permittee shall obtain a certification from the fuel supplier with each shipment of fuel (distillate oil). Each fuel supplier certification shall include the following:

    a. The name of the fuel supplier;

    b. The date on which the fuel (distillate oil) was received;

    c. The quantity of fuel (distillate oil) delivered in the shipment;

d. A statement that the fuel (distillate oil) complies with the American Society for Testing and Materials specifications in Condition 9, or other DEQ approved fuel specifications;

e. The sulfur content of the fuel (distillate oil);

f. The heat content of the fuel (distillate oil);

Fuel sampling and analysis, independent of that used for certification, as may be periodically required or conducted by DEQ may be used to determine compliance with the fuel specifications stipulated in Condition 9. Exceedance of these specifications may be considered credible evidence of the exceedance of emission limits.
(9VAC5-80-1180)

EMISSION LIMITS

13. **Emission Limits** - Emissions from the operation of each large boiler (ECPB-01 – 04) shall not exceed the limits specified below:

	When Burning Distillate Oil	
PM		2.3 lb/hr
PM10		1.1 lb/hr
PM2.5		0.3 lb/hr
Nitrogen Oxides (as NO_2)	0.077 lb/MMBtu*	
Carbon Monoxide		6.0 lb/hr
Volatile Organic Compounds		0.2 lb/hr
	When Burning Natural Gas	
PM		0.3 lb/hr
PM10		1.2 lb/hr
PM2.5		1.2 lb/hr
Nitrogen Oxides (as NO_2)	0.011 lb/MMBtu*	

Carbon Monoxide	6.0 lb/hr
Volatile Organic Compounds	0.9 lb/hr

* - Calculated as a rolling 30-day average including periods of start-up and shutdown. For any 30-day period with multiple fuel combustion ("simultaneously combusts"), the limitation shall be calculated in accordance with 40CFR60.44b(b) except the emission limitations for natural gas and distillate oil shall be those from this condition.

(9VAC5-80-1180 and 9VAC5-50-260)

14. **Emission Limits** - Emissions from the operation of each small boiler (ECPB-05 – 06) shall not exceed the limits specified below:

	When Burning Distillate Oil
PM	1.0 lb/hr
PM10	0.5 lb/hr
PM2.5	0.1 lb/hr
Nitrogen Oxides (as NO_2)	0.077 lb/MMBtu*
Carbon Monoxide	2.8 lb/hr
Volatile Organic Compounds	0.1 lb/hr

	When Burning Natural Gas
PM	0.2 lb/hr
PM10	0.5 lb/hr
PM2.5	0.5 lb/hr
Nitrogen Oxides (as NO_2)	0.011 lb/MMBtu*

Carbon Monoxide	2.8 lb/hr
Volatile Organic Compounds	0.4 lb/hr

* - Calculated as a rolling 30-day average including periods of start-up and shutdown. For any 30-day period with multiple fuel combustion ("simultaneously combusts"), the limitation shall be calculated in accordance with 40CFR60.44b(b) except the emission limitations for natural gas and distillate oil shall be those from this condition.

(9VAC5-80-1180 and 9VAC5-50-260)

15. **Emission Limits** - Emissions from the operation of the boilers (ECPB-01 – 06) shall not exceed the limits specified below:

PM	7.4 tons/yr
PM10	22.1 tons/yr
PM2.5	22.1 tons/yr
Nitrogen Oxides (as NO_2)	42.6 tons/yr
Carbon Monoxide	110.5 tons/yr
Volatile Organic Compounds	15.8 tons/yr
Sulfur Dioxide	2.0 tons/yr

(9VAC5-80-1180)

16. **Visible Emission Limit** - Visible emissions from each boiler (ECPB-01 – 06) shall not exceed 10 percent opacity except during one six-minute period in any one hour in which visible emissions shall not exceed 20 percent opacity as determined by the EPA Method 9 (reference 40 CFR 60, Appendix A).
(9VAC5-80-1180)

CEMS/COMS

17. **CEMS** - Continuous Emission Monitoring Systems, meeting the design specifications of 40CFR Part 60, Appendix B, shall be installed to measure and record the emissions of nitrogen oxides (NOx) as lb/MMBtu and either the oxygen or carbon dioxide content of the flue gases from each boiler (ECPB-01 – 06). The CEMS shall be installed, calibrated, maintained, audited and operated in accordance with the requirements of 40CFR60.13 and NSPS Subpart Db, and Appendices B and F. Data shall be reduced to 30 day rolling averages per the procedures in 40 CFR 60 Subpart Db. (9VAC5-80-1180 and 9VAC5-50-40)

18. **CEMS Performance Evaluations** - Performance evaluations of the continuous monitoring systems shall be conducted in accordance with 40CFR Part 60, Appendix B, and shall take place during the performance tests under 9VAC5-50-30 or within 30 days thereafter. One copy of the performance evaluations report shall be submitted to the Blue Ridge Regional Office within 45 days of the evaluation. The continuous monitoring systems shall be installed and operational prior to conducting initial performance tests. Verification of operational status shall, as a minimum, include completion of the manufacturer's written requirements or recommendations for installation, operation and calibration of the device. A 30 day notification, prior to the demonstration of continuous monitoring system's performance, and subsequent notifications shall be submitted to the Blue Ridge Regional Office.
(9VAC5-80-1180 and 9VAC5-50-40)

19. **CEMS Quality Control Program** - A CEMS quality control program which meets the requirements of 40 CFR 60.13 and Appendix B or F shall be implemented for all continuous monitoring systems.
(9VAC5-80-1180 and 9VAC5-50-40)

20. **Reports for Continuous Monitoring Systems** - The permittee shall furnish written reports to the Blue Ridge Regional Office of excess emissions from any process monitored by a continuous monitoring system (CEMS) on a quarterly basis, postmarked no later than the 30th day following the end of the calendar quarter. These reports shall include, but are not limited to the following information:

    a. The magnitude of excess emissions, any conversion factors used in the calculation of excess emissions, and the date and time of commencement and completion of each period of excess emissions;

    b. Specific identification of each period of excess emissions that occurs during startups, shutdowns, and malfunctions of the process, the nature and cause of the malfunction (if known), the corrective action taken or preventative measures adopted;

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

d. When no excess emissions have occurred or the continuous monitoring systems have not been inoperative, repaired or adjusted, such information shall be stated in that report.

(9VAC5-80-1180 and 9VAC5-50-50)

INITIAL COMPLIANCE DETERMINATION

21. **Stack Test** - Initial performance tests shall be conducted for CO from each boiler (ECPB-01 – 06) when combusting natural gas to determine compliance with the emission limits contained in Conditions 13 and 14. The tests shall be performed and demonstrate compliance within 60 days after achieving the maximum production rate at which the facility will be operated but in no event later than 180 days after start-up of each boiler (ECPB-01 – 06). Tests shall be conducted and reported and data reduced as set forth in 9VAC5-50-30, and the test methods and procedures contained in each applicable section or subpart listed in 9VAC5-50-410. The details of the tests are to be arranged with the Blue Ridge Regional Office. The permittee shall submit a test protocol at least 30 days prior to testing. One copy of the test results shall be submitted to the Blue Ridge Regional Office within 60 days after test completion and shall conform to the test report format enclosed with this permit.
(9VAC5-50-30 and 9VAC5-80-1200)

22. **Visible Emissions Evaluation** - Concurrently with the initial performance tests for CO (lb/hr) required in Condition 21 for each boiler (ECPB-01 – 06), Visible Emission Evaluations (VEE) in accordance with 40 CFR Part 60, Appendix A, Method 9, shall be conducted by the permittee. Each test shall consist of 30 sets of 24 consecutive observations (at 15 second intervals) to yield a six minute average. The details of the tests are to be arranged with the Blue Ridge Regional Office. The permittee shall submit a test protocol at least 30 days prior to testing. The evaluation shall be performed and demonstrate compliance within 60 days after achieving the maximum production rate at which the boiler will be operated but in no event later than 180 days after start-up of each boiler (ECPB-01 – 06). Should conditions prevent concurrent opacity observations, the Blue Ridge Regional Office shall be notified in writing, within seven days, and visible emissions testing shall be rescheduled within 30 days. Rescheduled testing shall be conducted under the same conditions (as possible) as the initial performance tests. One copy of the results of each test shall be submitted to the Blue Ridge Regional Office within 60 days after test completion and shall conform to the test report format enclosed with this permit.
(9VAC5-50-30 and 9VAC5-80-1200)

23. **Stack Test** - Initial performance tests required in Conditions 21 and 22 shall also be conducted when firing distillate oil. These tests shall be performed within 45 days after the boiler (ECPB-01 – 06) has combusted any amount of distillate oil for more than 48 hours in any 12-month period, excluding periods of natural gas curtailment or supply interruption beyond the permittee's control. The test protocol shall be submitted with the notification required in Condition 25.e.
(9VAC5-50-30 and 9VAC5-80-1200)

RECORDS

24. **On Site Records** - 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 Blue Ridge Regional Office. These records shall include, but are not limited to:

    a. For each boiler (ECPB-01 – 06), daily, monthly, and annual consumption (in MMBtu) of natural gas and distillate oil. Annual throughput 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 totals for the preceding 11 months.

    b. For each boiler (ECPB-01 – 06), the hours of operation when firing any amount of distillate oil and the reason for each hour of operation in this mode. Annual hours of operation shall be calculated monthly as the sum of each consecutive 12-month period and shall exclude periods of natural gas curtailment or supply interruption beyond the permittee's control. These records shall be used to determine the testing requirements of Condition 23.

    c. Calculations of the applicable limitation for natural gas combustion in the four large boilers (ECPB-01 – 04). Calculations shall be performed in accordance with Condition 11.

    d. Beginning on the date the first new emissions unit (ECPB-01 – 06) becomes operational, monthly coal combustion in each of the five coal fired boilers (PH-1 – PH-5). Annual coal combustion shall be calculated monthly as the sum of each consecutive 12 month period to demonstrate compliance with the limitation in Condition 5.

    e. Beginning on January 1, 2017, monthly coal combustion in each of the five coal fired boilers (PH-1 – PH-5). Annual coal combustion shall be calculated monthly as the sum of each consecutive 12 month period to demonstrate compliance with the limitation in Condition 6.

    f. Beginning on the date the first new emissions unit (ECPB-01 – 06) becomes operational, monthly fuel oil combustion in each of the five coal fired boilers (PH-1 – PH-5). Annual fuel oil combustion shall be calculated monthly as the sum of each consecutive 12 month period to demonstrate compliance with Condition 4.

    g. All fuel supplier certifications.

    h. Monthly emissions calculations using calculation methods approved in writing by the Blue Ridge Regional Office to verify compliance with the ton/yr emissions limitations in Condition 15.

    i. Scheduled and unscheduled maintenance, and operator training.

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

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

l. For each boiler (ECPB-01 – 06) natural gas curtailment or supply interruption, the cause of the interruption, the duration of the interruption (in hours), the amount of distillate oil fired during the period, and the corrective actions taken to restore supply for on-site interruptions.

These records shall be available for inspection by the DEQ and shall be current for the most recent five years.
(9VAC5-80-1180 and 9VAC5-50-50)

NOTIFICATIONS

25. **Initial Notifications** - The permittee shall furnish written notification to the Blue Ridge Regional Office of:

a. The actual date on which construction of each emissions unit (ECPB-01 – 06) commenced within 30 days after such date.

b. The actual start-up date of each boiler (ECPB-01 – 06) within 15 days after such date.

c. The actual date on which each boiler (ECPB-01 – 06) becomes operational within 15 days after such date.

d. The anticipated date of continuous monitoring system performance evaluations postmarked not less than 30 days prior to such date.

e. The anticipated date of performance tests of each boiler (ECPB-01 – 06) postmarked at least 30 days prior to such date. Notification for the purposes of Condition 23 shall be within 15 days after the date on which the respective hours of operation was exceeded.

f. The date of permanent shutdown for each coal fired boiler (PH-1 – PH-5) within 15 days after such date.

Copies of the written notification referenced in items 25.a, 25.b, 25.d, and 25.e are to be sent to:

Associate Director
Office of Air Enforcement and Compliance Assistance (3AP20)
U.S. Environmental Protection Agency
Region III
1650 Arch Street
Philadelphia, PA 19103-2029

(9VAC5-50-50 and 9VAC5-80-1180)

GENERAL CONDITIONS

26. **Permit Invalidation** - This permit to construct the equipment shall become invalid, unless an extension is granted by the DEQ, if:

    a. A program of continuous construction or modification is not commenced within 18 months from the date of this permit.

    b. A program of construction or modification is discontinued for a period of 18 months or more, or is not completed within a reasonable time, except for a DEQ approved period between phases of the phased construction of a new stationary source or project.

    (9VAC5-80-1210)

27. **Permit Suspension/Revocation** - This permit may be suspended or revoked if the permittee:

    a. Knowingly makes material misstatements in the permit application or any amendments to it;

    b. Fails to comply with the conditions of this permit;

    c. Fails to comply with any emission standards applicable to a permitted emissions unit;

    d. Causes emissions from the stationary source which result in violations of, or interfere with the attainment and maintenance of, any ambient air quality standard; or

    e. Fails to operate in conformance with any applicable control strategy, including any emission standards or emissions limitations, in the State Implementation Plan in effect at the time an application for this permit is submitted.

    (9VAC5-80-1210 G)

28. **Right of Entry** - The permittee shall allow authorized local, state, and federal representatives, upon the presentation of credentials:

    a. To enter upon the permittee's premises on which the facility is located or in which any records are required to be kept under the terms and conditions of this permit;

    b. To have access to and copy at reasonable times any records required to be kept under the terms and conditions of this permit or the State Air Pollution Control Board Regulations;

    c. To inspect at reasonable times any facility, equipment, or process subject to the terms and conditions of this permit or the State Air Pollution Control Board Regulations; and

    d. To sample or test at reasonable times.

For purposes of this condition, the time for inspection shall be deemed reasonable during regular business hours or whenever the facility is in operation. Nothing contained herein shall make an inspection time unreasonable during an emergency.
(9VAC5-170-130 and 9VAC5-80-1180)

29. **Maintenance/Operating Procedures** - At all times, including periods of start-up, shutdown and malfunction, the permittee shall, to the extent practicable, maintain and operate the affected source, including associated air pollution control equipment, in a manner consistent with good air pollution control practices for minimizing emissions.

    The permittee shall take the following measures in order to minimize the duration and frequency of excess emissions, with respect to air pollution control equipment and process equipment which affect such emissions:

    a. Develop a maintenance schedule and maintain records of all scheduled and non-scheduled maintenance.

    b. Maintain an inventory of spare parts.

    c. Have available written operating procedures for equipment. These procedures shall be based on the manufacturer's recommendations, at a minimum.

    d. Train operators in the proper operation of all such equipment and familiarize the operators with the written operating procedures, prior to their first operation of such equipment. The permittee shall maintain records of the training provided including the names of trainees, the date of training and the nature of the training.

    Records of maintenance and training shall be maintained on site for a period of five years and shall be made available to DEQ personnel upon request.
    (9VAC5-50-20 E and 9VAC5-80-1180 D)

30. **Record of Malfunctions** - The permittee shall maintain records of the occurrence and duration of any bypass, malfunction, shutdown or failure of the facility or its associated air pollution control equipment that results in excess emissions for more than one hour. Records shall include the date, time, duration, description (emissions unit, pollutant affected, cause), corrective action, preventive measures taken and name of person generating the record.
    (9VAC5-20-180 J and 9VAC5-80-1180 D)

31. **Notification for Facility or Control Equipment Malfunction** - The permittee shall furnish notification to the Blue Ridge Regional Office of malfunctions of the affected facility or related air pollution control equipment that may cause excess emissions for more than one hour, by facsimile transmission, telephone or telegraph. Such notification shall be made as soon as practicable but no later than four daytime business hours after the malfunction is discovered. The permittee shall provide a written statement giving all pertinent facts, including the estimated duration of the breakdown, within two weeks of discovery of the malfunction. When the condition causing the

failure or malfunction has been corrected and the equipment is again in operation, the permittee shall notify the Blue Ridge Regional Office.
(9VAC5-20-180 C and 9VAC5-80-1180)

32. **Violation of Ambient Air Quality Standard** - The permittee shall, upon request of the DEQ, reduce the level of operation or shut down a facility, as necessary to avoid violating any primary ambient air quality standard and shall not return to normal operation until such time as the ambient air quality standard will not be violated.
(9VAC5-20-180 I and 9VAC5-80-1180)

33. **Change of Ownership** - In the case of a transfer of ownership of a stationary source, the new owner shall abide by any current minor NSR permit issued to the previous owner. The new owner shall notify the Blue Ridge Regional Office of the change of ownership within 30 days of the transfer.
(9VAC5-80-1240)

34. **Permit Copy** - The permittee shall keep a copy of this permit on the premises of the facility to which it applies.
(9VAC5-80-1180)

Appendix C: Celanese Acetate, LLC December 6, 2012, Permit

COMMONWEALTH of VIRGINIA

Douglas W. Domenech
Secretary of Natural Resources

DEPARTMENT OF ENVIRONMENTAL QUALITY
Blue Ridge Regional Office
www.deq.virginia.gov

David K. Paylor
Director

Robert J. Weld
Regional Director

Lynchburg Office
7705 Timberlake Road
Lynchburg, Virginia 24502
(434) 582-5120
Fax (434) 582-5125

Roanoke Office
3019 Peters Creek Road
Roanoke, Virginia 24019
(540) 562-6700
Fax (540) 562-6725

December 6, 2012

Mr. Bill Batson
Site Manager
Celanese Acetate LLC
PO Box 1000, Route 460
Narrows, VA 24124

Location: Giles County
Registration No.: 20304
AIRS ID: 51- 071-0004

Dear Mr. Batson:

Attached is a permit to construct and operate six natural gas fired boilers in accordance with the provisions of the Virginia State Air Pollution Control Board Regulations for the Control and Abatement of Air Pollution.

This permit contains legally enforceable conditions. Failure to comply may result in a Notice of Violation and/or civil charges. Please read all permit conditions carefully.

The Department of Environmental Quality (DEQ) deemed the application complete on August 15, 2012. The Department solicited written public comments by placing a newspaper advertisement in the *Virginian Leader* on October 17, 2012. The required comment period provided by 9 VAC 5-80-1775 expired on December 5, 2012. A public hearing was held on November 20, 2012.

This permit approval to construct and operate shall not relieve Celanese Acetate, LLC of the responsibility to comply with all other local, state, and federal permit regulations.

The Board's Regulations as contained in Title 9 of the Virginia Administrative Code 5-170-200 provide that you may request a formal hearing from this case decision by filing a petition with the Board within 30 days after this case decision notice was mailed or delivered to you. 9 VAC 5-170-180 provides that you may request direct consideration of the decision by the Board if the Director of the DEQ made the decision. Please consult the relevant regulations for additional requirements for such requests.

As provided by Rule 2A:2 of the Supreme Court of Virginia, you have 30 days from the date you actually received this permit or the date on which it was mailed to you, whichever occurred first, within which to initiate an appeal of this decision by filing a Notice of Appeal with:

David K. Paylor, Director
Department of Environmental Quality
P. O. Box 1105
Richmond, VA 23218

If this permit was delivered to you by mail, three days are added to the thirty-day period in which to file an appeal. Please refer to Part Two A of the Rules of the Supreme Court of Virginia for information on the required content of the Notice of Appeal and for additional requirements governing appeals from decisions of administrative agencies.

If you have any questions concerning this permit, please contact Patrick Corbett at (434)582-6230.

Sincerely,

Robert J. Weld
Regional Director

Attachment: Permit
Source Testing Report Format

cc: Director, OAPP (electronic file submission)
Manager, Data Analysis (electronic file submission)
Chief, Air Enforcement Branch (3AP13), U.S. EPA, Region III

COMMONWEALTH of VIRGINIA

Douglas W. Domenech
Secretary of Natural Resources

DEPARTMENT OF ENVIRONMENTAL QUALITY
Blue Ridge Regional Office
www.deq.virginia.gov

David K. Paylor
Director

Robert J. Weld
Regional Director

Lynchburg Office
7705 Timberlake Road
Lynchburg, Virginia 24502
(434) 582-5120
Fax (434) 582-5125

Roanoke Office
3019 Peters Creek Road
Roanoke, Virginia 24019
(540) 562-6700
Fax (540) 562-6725

PREVENTION OF SIGNIFICANT DETERIORATION PERMIT
STATIONARY SOURCE PERMIT TO CONSTRUCT AND OPERATE
This permit includes designated equipment subject to New Source Performance Standards (NSPS).

In compliance with the Federal Clean Air Act and the Commonwealth of Virginia Regulations for the Control and Abatement of Air Pollution,

Celanese Acetate, LLC
PO Box 1000, Route 460
Narrows, Virginia 24124
Registration No.: 20304

is authorized to construct and operate

six natural gas-fired boilers

located at

3520 Virginia Avenue near Narrows, Virginia

in accordance with the Conditions of this permit.

Approved on December 6, 2012.

Robert J. Weld
Regional Director

Permit consists of 14 pages.
Permit Conditions 1 to 36.

INTRODUCTION

This permit approval is based on the permit application dated May 8, 2012, including supplemental information dated July 19, 2012 and August 13, 2012. Any changes in the permit application specifications or any existing facilities which alter the impact of the facility on air quality may require a permit. Failure to obtain such a permit prior to construction may result in enforcement action. In addition, this facility may be subject to additional applicable requirements not listed in this permit.

Words or terms used in this permit shall have meanings as provided in 9VAC5-10-20 of the State Air Pollution Control Board Regulations for the Control and Abatement of Air Pollution. The regulatory reference or authority for each condition is listed in parentheses () after each condition.

Annual requirements to fulfill legal obligations to maintain current stationary source emissions data will necessitate a prompt response by the permittee to requests by the DEQ or the Board for information to include, as appropriate: process and production data; changes in control equipment; and operating schedules. Such requests for information from the DEQ will either be in writing or by personal contact.

The availability of information submitted to the DEQ or the Board will be governed by applicable provisions of the Freedom of Information Act, §§2.2-3700 through 2.2-3714 of the Code of Virginia, §10.1-1314 (addressing information provided to the Board) of the Code of Virginia, and 9VAC5-170-60 of the State Air Pollution Control Board Regulations. Information provided to federal officials is subject to appropriate federal law and regulations governing confidentiality of such information.

PROCESS REQUIREMENTS

1. **Equipment List** - Equipment at this facility includes, but is not limited to, the following:

Equipment to be Constructed			
Ref. No.	**Equipment Description**	**Rated Capacity**	**Federal Requirements**
B10 – B15	Six natural gas-fired boilers with distillate oil back-up	400 MMBtu/hr, each	NSPS Db
TK01 – TK03	Three distillate oil storage tanks	250,000 gallons, each	
Equipment Previously Installed			
Ref. No.	**Equipment Description**	**Rated Capacity**	**Federal Requirements**
B1	Babcox & Wilcox, Coal Boiler #1	91 MMBtu/hr	
B2	Babcox & Wilcox, Coal Boiler #2	91MMBtu/hr	
B3	Riley, Coal Boiler #3	184 MMBtu/hr	
B4	Riley, Coal Boiler #4	184 MMBtu/hr	
B5	Riley, Coal Boiler #5	246 MMBtu/hr	
B6	Riley, Coal Boiler #6	246 MMBtu/hr	
B7	Foster Wheeler, Coal Boiler #7	322 MMBtu/hr	
3BHSL001S1	Dry flyash handling system		
3BHSL001S1	Dry flyash handling system		
3BHSL001S1	Dry flyash handling system ash storage silo		
3BHAS002S1	Coal Handling & Storage		
3BHTK001S1	Fuel Oil Storage Tank	250,000 gal	

Specifications included in the permit under this Condition are for informational purposes only and do not form enforceable terms or conditions of the permit.
(9VAC5-80-1180 D.3 and 9VAC5-80-1985)

2. **Fuel** - The approved fuels for the natural gas-fired boilers (B10 – B15) are distillate oil and natural gas. A change in the fuels may require a permit to modify and operate. (9VAC5-80-1180 and 9VAC5-80-1985)

3. **Fuel Throughput** - The distillate oil storage tanks' (TK01 – TK03) combined throughput shall not exceed 6,470,720 gallons of distillate oil fuel per year, calculated as the sum of each consecutive 12 month period. Throughput shall be calculated using the volume unloaded into the tanks, excluding the initial filling event of each tank (i.e., a one-time unloading event). (9VAC5-80-1985, 9VAC5-80-1705, and 9VAC5-50-280)

4. **Fuel Throughput** – Consumption of coal in the coal fired boilers (B1 – B7) shall be limited by the following schedule:

   a. Upon the first natural gas-fired boiler (B10) becoming operational, coal consumption shall not exceed 7,779,410.6 MMBtu per year, calculated monthly as the sum of each consecutive 12-month period.

   b. Upon the second natural gas-fired boiler (B11) becoming operational, coal consumption shall not exceed 5,803,736.4 MMBtu per year, calculated monthly as the sum of each consecutive 12-month period.

   c. Upon the third natural gas-fired boiler (B12) becoming operational, coal consumption shall not exceed 3,828,062.1 MMBtu per year, calculated monthly as the sum of each consecutive 12-month period.

   d. Upon the fourth natural gas-fired boiler (B13) becoming operational, coal consumption shall not exceed 1,852,387.9 MMBtu per year, calculated monthly as the sum of each consecutive 12-month period.

   e. Upon the fifth natural gas-fired boiler (B14) becoming operational, the coal boilers (B1 – B7) and associated material handling equipment (3BHSL001S1, 3BHSL001S1, 3BHSL001S1, 3BHAS002S1) shall permanently cease operation. Restarting operation for any of this equipment shall be considered a physical change or change in the method of operation at the facility.

   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. For the purpose of this permit, "becoming operational" does not include a shakedown period for each new natural gas-fired boiler not to exceed 180 days after start-up. " Becoming operational" will have occurred no later than the beginning of the first initial performance test required pursuant to this permit or 40CFR60 Subpart Db for each boiler. (9VAC5-80-1180)

5. **Fuel Throughput** - The natural gas-fired boilers (B10 – B15) combined shall consume no more than 17,691,928 MMBtu of natural gas per year and 873,547.2 MMBtu of distillate oil per year,

calculated as the sum of each consecutive 12 month period. If both fuels are combusted during any consecutive 12 month period, the natural gas limitation shall not exceed the amount as calculated by the following equation:

$$NG = 17691928 - 1.3984 * DO$$

where

NG = all boilers combined annual limit on consumption of natural gas, in units of MMBtu/yr
DO = all boilers combined annual consumption of distillate oil, in units of MMBtu/yr

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.
(9VAC5-80-1180)

6. **Fuel Specifications** - The approved fuels shall meet the specifications below:

DISTILLATE OIL which meets the ASTM D396 specification for Grades 1 or 2 fuel oil:
Maximum sulfur content per shipment: 15 ppm

NATURAL GAS which meets the definition contained in 40CFR72.2 for "pipeline natural gas"

(9VAC5-80-1180 and 9VAC5-80-1985)

7. **Fuel Certification** - The permittee shall obtain a certification from the fuel supplier with each shipment of distillate oil. Each fuel supplier certification shall include the following:

a. The name of the fuel supplier;

b. The date on which the distillate oil was received;

c. The quantity of distillate oil delivered in the shipment;

d. A statement that the distillate oil complies with the American Society for Testing and Materials specifications ASTM D396 for Grades 1 or 2 fuel oil, or other DEQ approved fuel specifications;

e. The sulfur content of the distillate oil;

Fuel sampling and analysis, independent of that used for certification, as may be periodically required or conducted by DEQ may be used to determine compliance with the fuel specifications stipulated in Condition 6. Exceedance of these specifications may be considered credible evidence of the exceedance of emission limits.
(9VAC5-80-1180, 9VAC5-80-1985, and 9VAC5-50-410)

EMISSION LIMITS

8. **Emission Limits** - Emissions from the operation of each natural gas-fired boiler (B10 - B15) when firing distillate oil shall not exceed the limits specified below:

PM (filterable)	5.9 lbs/hr
PM-10	6.8 lbs/hr
Nitrogen Oxides (as NO_2)	30.7 lbs/hr

(9VAC5-80-1180)

9. **Emission Limits** - Emissions from the operation of each natural gas-fired boiler (B10 - B15) when firing only natural gas shall not exceed the limits specified below:

PM (filterable)	0.8 lbs/hr
PM-10	3.1 lbs/hr
Nitrogen Oxides (as NO_2)	14.6 lbs/hr

(9VAC5-80-1180)

10. **Emission Limits** - Emissions from the operation of each natural gas-fired boiler (B10 - B15) shall not exceed the limits specified below:

Nitrogen Oxides (distillate oil) (as NO_2)	0.077 lb/MMBtu*
Nitrogen Oxides (natural gas) (as NO_2)	0.036 lb/MMBtu*

* - Calculated as a rolling 30-day average including periods of start-up and shutdown. For any 30-day period with multiple fuel combustion ("simultaneously combusts"), the limitation shall be calculated in accordance with 40CFR60.44b(b) except the emission limitations for natural gas and distillate oil shall be those from this condition.

(9VAC5-80-1180)

11. **Emission Limits** - Emissions from the operation of each natural gas-fired boiler (B10 - B15) when firing distillate oil shall not exceed the limits specified below:

Carbon Monoxide	50 ppm @ 3% O_2*	(9VAC5-80-1705 and 9VAC5-50-280)
Carbon Monoxide	15.6 lbs/hr	(9VAC5-80-1715)
Volatile Organic Compounds	2.2 lbs/hr	(9VAC5-80-1705 and 9VAC5-50-280)

* - Calculated as a rolling 24-hour average including periods of start-up and shutdown

(9VAC5-80-1985)

12. **Emission Limits** - Emissions from the operation of each natural gas-fired boiler (B10 - B15) when firing only natural gas shall not exceed the limits specified below:

Carbon Monoxide	50 ppm @ 3% O_2*	(9VAC5-80-1705 and 9VAC5-50-280)
Carbon Monoxide	14.8 lbs/hr	(9VAC5-80-1715)
Volatile Organic Compounds	2.2 lbs/hr	(9VAC5-80-1705 and 9VAC5-50-280)

* - Calculated as a rolling 24-hour average including periods of start-up and shutdown

(9VAC5-80-1985)

13. **Emission Limits** - Total emissions from the natural gas-fired boilers (B10 – B15) combined shall not exceed the limits specified below:

PM	22.1 tons/yr
PM-10	70.0 tons/yr
Nitrogen Oxides (as NO_2)	333.3 tons/yr

These emissions are derived from the estimated overall emission contribution from operating limits. Exceedance of the operating limits may be considered credible evidence of the exceedance of emission limits. Compliance with these emission limits may be determined as stated in Conditions 5, 8, 9, 11, and 12.
(9VAC5-80-1180)

14. **Emission Limits** - Total emissions from the natural gas-fired boilers (B10 – B15) combined shall not exceed the limits specified below:

Carbon Monoxide	326.7 tons/yr
Volatile Organic Compounds	48.7 tons/yr

These emissions are derived from the estimated overall emission contribution from operating limits. Exceedance of the operating limits may be considered credible evidence of the exceedance of emission limits. Compliance with these emission limits may be determined as stated in Conditions 5, 8, 9, 11, and 12.
(9VAC5-80-1985)

15. **Visible Emission Limit** - Visible emissions from each natural gas-fired boiler (B10 - B15) shall not exceed 10 percent opacity except during one six-minute period in any one hour in which visible emissions shall not exceed 20 percent opacity as determined by the EPA Method 9 (reference 40 CFR 60, Appendix A).
(9VAC5-80-1180)

16. **Requirements by Reference** - Except where this permit is more restrictive than the applicable requirement, the NSPS equipment as described in Condition 1 shall be operated in compliance with the requirements of 40CFR60 Subpart Db.
(9VAC5-80-1180, 9VAC5-50-400, and 9VAC5-50-410)

CEMS/COMS

17. **CEMS** - Continuous Emission Monitoring Systems, meeting the design specifications of 40CFR Part 60, Appendix B, shall be installed to measure and record the emissions of nitrogen oxides (NOx) as lbs/MMBtu and either the oxygen or carbon dioxide content of the flue gases from each natural gas-fired boiler (B10 - B15). The CEMS shall be installed, calibrated, maintained, audited and operated in accordance with the requirements of 40CFR60.13, NSPS Subpart Db, and Appendices B and F. Data shall be reduced to 30 day rolling averages per the procedures in 40 CFR 60 Subpart Db.
(9VAC5-80-1180, 9VAC5-50-410, and 9VAC5-50-40)

18. **CEMS Performance Evaluations** - Performance evaluations of the continuous monitoring systems shall be conducted in accordance with 40CFR Part 60, Appendix B, and shall take place during the performance tests under 9VAC5-50-30 or within 30 days thereafter. Two copies of the performance evaluations report shall be submitted to the Blue Ridge Regional Office within 45 days of the evaluation. The continuous monitoring systems shall be installed and operational prior to conducting initial performance tests. Verification of operational status shall, as a minimum, include completion of the manufacturer's written requirements or recommendations for installation, operation and calibration of the device. A 30 day notification, prior to the demonstration of

continuous monitoring system's performance, and subsequent notifications shall be submitted to the Blue Ridge Regional Office.
(9VAC5-80-1180, 9VAC5-50-410, and 9VAC5-50-40)

19. **CEMS Quality Control Program** - A CEMS quality control program which meets the requirements of 40 CFR 60.13 and Appendix B or F shall be implemented for all continuous monitoring systems.
(9VAC5-80-1180, 9VAC5-50-410, and 9VAC5-50-40)

20. **Reports for Continuous Monitoring Systems** - The permittee shall furnish written reports to the Blue Ridge Regional Office of excess emissions from any process monitored by a continuous monitoring system (CEMS) on a quarterly basis, postmarked no later than the 30th day following the end of the calendar quarter. These reports shall include, but are not limited to the following information:

    a. The magnitude of excess emissions, any conversion factors used in the calculation of excess emissions, and the date and time of commencement and completion of each period of excess emissions;

    b. Specific identification of each period of excess emissions that occurs during startups, shutdowns, and malfunctions of the process, the nature and cause of the malfunction (if known), the corrective action taken or preventative measures adopted;

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

    d. When no excess emissions have occurred or the continuous monitoring systems have not been inoperative, repaired or adjusted, such information shall be stated in that report.

    (9VAC5-80-1180, 9VAC5-50-410, and 9VAC5-50-50)

INITIAL COMPLIANCE DETERMINATION

21. **Stack Test** - Initial performance tests shall be conducted for carbon monoxide (on both lb/hr and 24-hour ppm basis) and volatile organic compounds (lb/hr) from each natural gas-fired boiler (B10 - B15) to determine compliance with the emission limits contained in Condition12. The tests shall be performed and demonstrate compliance within 60 days after achieving the maximum production rate at which the facility will be operated but in no event later than 180 days after start-up of each natural gas-fired boiler (B10 - B15). Tests shall be conducted and reported and data reduced as set forth in 9VAC5-50-30, and the test methods and procedures contained in each applicable section or subpart listed in 9VAC5-50-410. The details of the tests are to be arranged with the Blue Ridge Regional Office. The permittee shall submit a test protocol at least 30 days prior to testing. One copy of the test results shall be submitted to the Blue Ridge Regional Office within 60 days after test completion and shall conform to the test report format enclosed with this permit.
(9VAC5-50-30 and 9VAC5-80-1675)

22. **Stack Test** - Initial performance test shall be conducted for NOx (lbs/hr) from the each natural gas-fired boiler (B10 - B15) to determine compliance with the emission limits contained in Conditions 8 and 9 (each fuel separately). The tests shall be performed concurrently with the CO (lb/hr) test required in Condition 21. The tests shall be performed and demonstrate compliance within 60 days after achieving the maximum production rate at which the facility will be operated but in no event later than 180 days after start-up of each natural gas-fired boiler (B10 - B15). Tests shall be conducted and reported and data reduced as set forth in 9VAC5-50-30, and the test methods and procedures contained in each applicable section or subpart listed in 9VAC5-50-410, unless an alternative method utilizing NOx CEMS data is approved in the protocol. The details of the tests are to be arranged with the Blue Ridge Regional Office. The permittee shall submit a test protocol at least 30 days prior to testing. One copy of the results of each test shall be submitted to the Blue Ridge Regional Office within 60 days after test completion and shall conform to the test report format enclosed with this permit.
(9VAC5-50-30 and 9VAC5-80-1200)

23. **Stack Test** - Initial performance tests shall be conducted for NOx (lbs/MMBtu) from each natural gas-fired boiler (B10 - B15) to determine compliance with the emission limit contained in Condition 10. The tests shall be performed and demonstrate compliance within 60 days after achieving the maximum production rate at which the facility will be operated but in no event later than 180 days after start-up of each natural gas-fired boiler (B10 - B15). Tests shall be conducted and reported and data reduced as set forth in 9VAC5-50-30, and the test methods and procedures contained in each applicable section or subpart listed in 9VAC5-50-410. The details of the tests are to be arranged with the Blue Ridge Regional Office. The permittee shall submit a test protocol at least 30 days prior to testing. One copy of the results of each test shall be submitted to the Blue Ridge Regional Office within 60 days after test completion and shall conform to the test report format enclosed with this permit.
(9VAC5-50-30, 9VAC5-80-1200, and 9VAC5-50-410)

24. **Visible Emissions Evaluation** - Concurrently with the initial performance test for CO (lb/hr) required in Condition 21 for each natural gas-fired boiler (B10 - B15), Visible Emission Evaluations (VEE) in accordance with 40 CFR Part 60, Appendix A, Method 9, shall be conducted by the permittee. Each test shall consist of 30 sets of 24 consecutive observations (at 15 second intervals) to yield a six minute average. The details of the tests are to be arranged with the Blue Ridge Regional Office. The permittee shall submit a test protocol at least 30 days prior to testing. The evaluation shall be performed and demonstrate compliance within 60 days after achieving the maximum production rate at which the facility will be operated but in no event later than 180 days after start-up of the permitted facility. Should conditions prevent concurrent opacity observations, the Blue Ridge Regional Office shall be notified in writing, within seven days, and visible emissions testing shall be rescheduled within 30 days. Rescheduled testing shall be conducted under the same conditions (as possible) as the initial performance tests. One copy of the results of each test shall be submitted to the Blue Ridge Regional Office within 60 days after test completion and shall conform to the test report format enclosed with this permit.
(9VAC5-50-30, 9VAC5-80-1200, and 9VAC5-50-410)

25. **Stack Test** - Initial performance tests and VEEs required in Conditions 21, 22, 24shall be conducted when firing distillate oil. These tests shall be performed within 45 days after the boiler (B10 – B15) has combusted any amount of distillate oil for more than 48 hours in any 12-month period, excluding periods of natural gas curtailment or supply interruption beyond the permittee's control. The test protocol shall be submitted with the notification required in Condition 27.e. (9VAC5-50-30, 9VAC5-80-1200, and 9VAC5-80-1675)

RECORDS

26. **On Site Records** - 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 Blue Ridge Regional Office. These records shall include, but are not limited to:

    a. For each natural gas-fired boiler (B10 - B15), daily, monthly, and annual consumption (in MMBtu) of natural gas and distillate oil. Annual throughput 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 totals for the preceding 11 months.

    b. For each boiler, the hours of operation when firing any amount of distillate oil and the reason for operation in this mode. Annual hours of operation shall be calculated monthly as the sum of each consecutive 12-month period and shall exclude periods of natural gas curtailment or supply interruption beyond the permittee's control. These records shall be used to determine the testing requirements of Condition 25.

    c. Monthly calculations demonstrating the annual natural gas combustion limitation in accordance with Condition 5.

    d. Beginning on the date the first natural gas-fired boiler becomes operational, monthly coal combustion in each of the seven coal fired boilers (B1 – B7). Annual coal combustion shall be calculated monthly as the sum of each consecutive 12 month period to demonstrate compliance with each separate limitation in Condition 4.

    e. Annual total distillate oil throughput for the distillate oil storage tanks (TK01 – TK03) calculated monthly as the sum of each consecutive 12-month period to demonstrate compliance with the limitation in Condition 3.

    f. All fuel supplier certifications.

    g. Monthly emissions calculations for NOx, CO, VOC, PM, PM-10, and PM-2.5 using calculation methods approved in writing by the Blue Ridge Regional Office to verify compliance with the ton/yr emissions limitations in Conditions 13 and 14.

    h. Scheduled and unscheduled maintenance, and operator training.

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

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

k. For each natural gas-fired boiler (B10 - B15), other records required to comply with Condition 16.

l. For each natural gas-fired boiler (B10 - B15) curtailment or supply interruption, the cause of the interruption, the duration of the interruption (in hours), the amount of distillate oil fired during the period, and the corrective actions taken to restore supply for on-site interruptions.

These records shall be available for inspection by the DEQ and shall be current for the most recent five years.
(9VAC5-80-1180, 9VAC5-80-1985, 9VAC5-50-410, and 9VAC5-50-50)

NOTIFICATIONS

27. **Initial Notifications** - The permittee shall furnish written notification to the Blue Ridge Regional Office of:

a. The actual date on which construction of each natural gas-fired boiler (B10 - B15) commenced within 30 days after such date.

b. The actual start-up date of each natural gas-fired boiler (B10 - B15) within 15 days after such date.

c. The actual date on which each natural gas-fired boiler (B10 - B15) becomes operational (as defined in Condition 4) within 15 days after such date.

d. The anticipated date of continuous monitoring system performance evaluations postmarked not less than 30 days prior to such date.

e. The anticipated date of performance tests of each natural gas-fired boiler (B10 - B15) postmarked at least 30 days prior to such date. Notification for the purpose of Condition 25 shall be within 15 days after the date on which the 48 hours was exceeded.

Copies of the written notification referenced in items a, b, d, and e above are to be sent to:

Associate Director
Office of Air Enforcement and Compliance Assistance (3AP20)
U.S. Environmental Protection Agency
Region III
1650 Arch Street
Philadelphia, PA 19103-2029

(9VAC5-50-50 and 9VAC5-80-1180)

GENERAL CONDITIONS

28. **Permit Invalidation** - This permit to construct the natural gas-fired boilers (B10 – B15) shall become invalid, unless an extension is granted by the DEQ, if:

    a. A program of continuous construction, reconstruction, or modification is not commenced within 18 months from the date of this permit; or

    b. A program of construction, reconstruction, or modification is discontinued for a period of 18 months or more, or is not completed within a reasonable time, except for a DEQ approved period between phases of a phased construction project.

    (9VAC5-80-1210 and 9VAC5-80-1985)

29. **Permit Suspension/Revocation** - This permit may be suspended or revoked if the permittee:

    a. Knowingly makes material misstatements in the permit application or any amendments to it;

    b. Fails to comply with the conditions of this permit;

    c. Fails to comply with any emission standards applicable to a permitted emissions unit;

    d. Causes emissions from the stationary source which result in violations of, or interfere with the attainment and maintenance of, any ambient air quality standard; or

    e. Fails to operate in conformance with any applicable control strategy, including any emission standards or emission limitations, in the State Implementation Plan in effect at the time an application for this permit is submitted.

    (9VAC5-80-1210 F and 9VAC5-80-1985)

30. **Right of Entry** - The permittee shall allow authorized local, state, and federal representatives, upon the presentation of credentials:

    a. To enter upon the permittee's premises on which the facility is located or in which any records are required to be kept under the terms and conditions of this permit;

    b. To have access to and copy at reasonable times any records required to be kept under the terms and conditions of this permit or the State Air Pollution Control Board Regulations;

    c. To inspect at reasonable times any facility, equipment, or process subject to the terms and conditions of this permit or the State Air Pollution Control Board Regulations; and

d. To sample or test at reasonable times.

For purposes of this condition, the time for inspection shall be deemed reasonable during regular business hours or whenever the facility is in operation. Nothing contained herein shall make an inspection time unreasonable during an emergency.
(9VAC5-170-130 and 9VAC5-80-1180)

31. **Maintenance/Operating Procedures** - At all times, including periods of start-up, shutdown, and malfunction, the permittee shall, to the extent practicable, maintain and operate the affected source, including associated air pollution control equipment, in a manner consistent with good air pollution control practices for minimizing emissions.

The permittee shall take the following measures in order to minimize the duration and frequency of excess emissions, with respect to the process equipment which affect such emissions:

a. Develop a maintenance schedule and maintain records of all scheduled and non-scheduled maintenance.

b. Maintain an inventory of spare parts.

c. Have available written operating procedures for equipment. These procedures shall be based on the manufacturer's recommendations, at a minimum.

d. Train operators in the proper operation of all such equipment and familiarize the operators with the written operating procedures, prior to their first operation of such equipment. The permittee shall maintain records of the training provided including the names of trainees, the date of training and the nature of the training.

Records of maintenance and training shall be maintained on site for a period of five years and shall be made available to DEQ personnel upon request.
(9VAC5-50-20 E and 9VAC5-80-1180 D)

32. **Record of Malfunctions** - The permittee shall maintain records of the occurrence and duration of any bypass, malfunction, shutdown or failure of the facility or its associated air pollution control equipment that results in excess emissions for more than one hour. Records shall include the date, time, duration, description (emission unit, pollutant affected, cause), corrective action, preventive measures taken and name of person generating the record.
(9VAC 5-20-180 J and 9VAC5-80-1180 D)

33. **Notification for Facility or Control Equipment Malfunction** - The permittee shall furnish notification to the Blue Ridge Regional Office of malfunctions of the affected facility or related air pollution control equipment that may cause excess emissions for more than one hour, by facsimile transmission, telephone or telegraph. Such notification shall be made as soon as practicable but no later than four daytime business hours after the malfunction is discovered. The permittee shall provide a written statement giving all pertinent facts, including the estimated duration of the

breakdown, within two weeks of discovery of the malfunction. When the condition causing the failure or malfunction has been corrected and the equipment is again in operation, the permittee shall notify the Blue Ridge Regional Office.
(9VAC5-20-180 C and 9VAC5-80-1180)

34. **Violation of Ambient Air Quality Standard** - The permittee shall, upon request of the DEQ, reduce the level of operation or shut down a facility, as necessary to avoid violating any primary ambient air quality standard and shall not return to normal operation until such time as the ambient air quality standard will not be violated.
(9VAC5-20-180 I and 9VAC5-80-1180)

35. **Change of Ownership** - In the case of a transfer of ownership of a stationary source, the new owner shall abide by any current permit issued to the previous owner. The new owner shall notify the Blue Ridge Regional Office of the change of ownership within 30 days of the transfer.
(9VAC5-80-1240 and 9VAC5-80-1975)

36. **Permit Copy** - The permittee shall keep a copy of this permit on the premises of the facility to which it applies.
(9VAC5-80-1180)

Appendix D: Dominion - Chesapeake Power Station Title V Permit Excerpt and Potential To Emit Calculations

COMMONWEALTH of VIRGINIA
DEPARTMENT OF ENVIRONMENTAL QUALITY
TIDEWATER REGIONAL OFFICE
5636 Southern Boulevard, Virginia Beach, Virginia 23462
(757) 518-2000 Fax (757) 518-2009
www.deq.virginia.gov

Molly Joseph Ward
Secretary of Natural Resources

David K. Paylor
Director

Maria R. Nold
Regional Director

Federal Operating Permit
Article 3

This permit is based upon Federal Clean Air Act acid rain permitting requirements of Title IV, federal operating permit requirements of Title V and Chapter 80, Article 3. Until such time as this permit is reopened and revised, modified, revoked, terminated or expires, the permittee is authorized to operate in accordance with the terms and conditions contained herein. This permit is issued under the authority of Title 10.1, Chapter 13, §10.1-1322 of the Air Pollution Control Law of Virginia. This permit is issued consistent with the Administrative Process Act, and 9VAC5-80-360 through 9VAC5-80-700.

Authorization to operate a Stationary Source of Air Pollution as described in this permit is hereby granted to:

Permittee Name:	Virginia Electric and Power Company
Facility Name:	Dominion Generation - Chesapeake Energy Center
Facility Location:	2701 Vepco Street Chesapeake, Virginia
Registration Number:	60163
Permit Number:	TRO-60163

This permit includes the following programs:

Federally Enforceable Requirements - Clean Air Act (Sections I through IX)
Federally Enforceable Requirements - Title IV Acid Rain (Section X)
Federally Enforceable Requirements – Cross State Air Pollution Rule (CSAPR) (Section XI)

March 22, 2016	**December 31, 2020**
Effective Date	Expiration Date
March 22, 2016	
Maria R. Nold	Signature Date

Table of Contents

I. Facility Information

Permittee
Virginia Electric and Power Company
5000 Dominion Boulevard
Glen Allen, Virginia 23060

Responsible Official
Kenneth J. Lazzaro
Station Director, Dominion - Chesapeake Energy Center

Acid Rain Designated Representative
David Craymer
Vice President - Power Generation
USEPA ATS-AAR ID Number 607952

Facility
Dominion - Chesapeake Energy Center
2701 Vepco Street
Chesapeake, Virginia 23323

Facility Contact Person
Scott Lawton
Director, Electric Environmental Business Support
(804) 273-2600

AFS Identification Number: 51-550-00026
ORIS Code: 3803
NATS Facility Identification Number: 003803000001

Facility Description (provided for informational purposes only): NAICS Code 221112 – Electrical Power Generation - Fossil fuel. The facility produces electrical power using four single cycle combustion turbines each of which is capable of burning either natural gas or diesel fuel / distillate oil. There is a gasoline dispensing facility onsite that is for fueling company vehicles. There are two emergency generators (one propane and one diesel) which have been replaced with 2014 and 2015 models.

The facility shut down four coal-fired boilers and the associated coal and ash handling operations along with the carbon burn out unit on December 23, 2014.

The facility is currently operating under a consent decree from EPA entered on October 3, 2003, however the units cited in the consent decree have been retired and have been dismantled (2015). EPA Region III permitting was contacted to find out if the consent decree should still be part of the permit. They contacted their legal department and we were informed that as long as the units are shutdown, the consent decree is no longer applicable to this facility. Therefore, the EPA consent decree is no longer an attachment to this permit.

The facility is now a Title V major source for NO_x, CO, and SO_2 and is a PSD size source. Due the facility retiring the coal fired boilers, the facility is now an area source of HAP. Although the coal fired boilers have been retired under the Acid Rain program, the facility is still subject to 40 CFR 72.7, 72.8 and Part 73, Subpart B, and 40 CFR 97.405, 505 and 605, so this permit is a Federal Operating Permit being written under 9VAC5 Chapter 80, Article 3.

This source is located in an attainment area for all pollutants. The facility is currently permitted by a State Operating Permit dated 9/3/96.

II. Emission Units

Equipment to be operated consists of:

Emission Unit ID	Stack ID	Emission Unit Description	Size/Rated Capacity*	Pollution Control Device (PCD) Description	PCD ID	Pollutant Controlled	Applicable Permit Date
Turbines							
ES-5	*EP-5*	*Unit 1 - Pratt & Whitney combustion turbine constructed in 1967. Fires diesel fuel / distillate oil or natural gas.*	*281 x 10^6 BTU/hr (nominal)*	-	-	-	*9/3/96*
ES-6	*EP-6*	*Unit 2 - Westinghouse 191 combustion turbine constructed in 1969. Fires diesel fuel / distillate oil or natural gas.*	*263 x 10^6 BTU/hr (nominal)*	-	-	-	*9/3/96*
ES-7	*EP-7*	*Unit 4 - Westinghouse 191 combustion turbine constructed in 1969. Fires diesel fuel / distillate oil or natural gas.*	*263 x 10^6 BTU/hr (nominal)*	-	-	-	*9/3/96*
ES-8	*EP-8*	*Unit 6 - Westinghouse 191 combustion turbine constructed in 1969. Fires diesel fuel / distillate oil or natural gas.*	*263 x 10^6 BTU/hr (nominal)*	-	-	-	*9/3/96*
Internal Combustion Engines							
ES-15	-	*Allis Chalmers Model 25000 black-start engine for ES-6 (CT Unit 2) (1969) 40 CFR 63, Subpart ZZZZ - Fires diesel fuel / distillate oil*	*450 HP*	-	-	-	-
ES-16	-	*Cummins NTA 855C black-start engine for ES-7 (CT unit 4) (1990) 40 CFR 63, Subpart ZZZZ - Fires diesel fuel / distillate oil*	*360 HP*	-	-	-	-
ES-17	-	*Cummins NTA 855C black-start engine for ES-8 (CT unit 6) (1992) 40 CFR 63, Subpart ZZZZ - Fires diesel fuel / distillate oil*	*360 HP*	-	-	-	-
ES-18	-	*Caterpillar 3304 Serial # 4B10168 fire pump (1975) 40 CFR 63 ZZZZ Fires diesel fuel / distillate oil*	*155 HP*	-	-	-	-
ES-22	-	*Cummins C25 N6 propane emergency generator engine at microwave tower (2014), NSPS JJJJ and MACT ZZZZ*	*0.32 mmBtu/hr 25 kW, 43.5 HP*	-	-	-	-
ES-23	-	*CAT C9 emergency generator engine. (2015) NSPS IIII and MACT ZZZZ - Fires diesel fuel / distillate oil*	*3.2 mmBtu/hr ≤ 300 kW, 375 HP*	-	-	-	-
Gas Fueling Station							
ES-24	-	*Gasoline Fueling Station and Above Ground Storage Tank , MACT CCCCCC (Installed prior to November 9, 2006)*	*3,000 gallons*	-	-	-	-

*The Size/Rated capacity is provided for informational purposes only, and is not an applicable requirement.

Potential To Emit Worksheet for Chesapeake Power Station

Dominion - Chesapeake Energy Center
Date: December 2016
Registration number: 60163

Combustion Turbine PTE Three 263 MMBtu/hr CTs + One 281 MMBtu/hr CT = **1070** MMBtu/hr CT Total

Natural Gas Heat content = 1020 Btu/scf
Total hourly usage of NG = 1.049 mmscf/hr

	Emission Factors		Hourly Potential		Annual Potential		
	lb/mmscf	lb/mmbtu	lb/hr		ton/yr		
	natural gas (ng)	distillate oil (DO)	ng	DO	ng	DO	Max Value
SO2	0.6	0.404	0.6	432.3	2.76	1893.39	1893.39

SO2 emission factor based on distillate oil with an annual average sulfur content of 0.4%.
Based on review of facilty history (10-year maximum of 0.2%) and current/projected distillate oil market, this is considered to be a conservative estimate.

Internal Combustion Engines

HP of engines			
450	diesel		
360	diesel		
360	diesel		
155	diesel	1325	Total Diesel HP
82	propane	82	total propane HP

0.11 mmbtu/hr

	Diesel emission factor	Diesel emissions		Propane Emission Factor			Total
	lb/HP-hr	lb/hr	ton/yr	lb/mmBtu	lb/hr	ton/yr	ton/yr
SO2	0.00205	2.7	0.68	0.000588	0.00006468	0.57	1.25

Appendix E: American Electric Power - Clinch River Plant August 3, 2016, Permit

COMMONWEALTH of VIRGINIA

DEPARTMENT OF ENVIRONMENTAL QUALITY

Molly Joseph Ward
Secretary of Natural Resources

SOUTHWEST REGIONAL OFFICE
355-A Deadmore Street, Abingdon, Virginia 24210
(276) 676-4800 Fax: (276) 676-4899
www.deq.virginia.gov

David K. Paylor
Director

Allen J. Newman, P.E.
Regional Director

August 3, 2016

Mr. Ricky L. Chafin
Plant Manager
AEP/Appalachian Power Company
Clinch River Plant
P.O. Box 370
Cleveland, Virginia 24225-0370

Location: Russell County, VA
Registration No. 10236
Facility ID No. 51-167-00003

Dear Mr. Chafin:

Attached is a minor amendment to your new source review permit dated January 13, 2015, to modify and operate the Clinch River Plant in accordance with the provisions of 9 VAC 5-80 Article 6 of the Commonwealth of Virginia State Air Pollution Control Board Regulations for the Control and Abatement of Air Pollution. This amendment involves changes to the definitions of startup and shutdown events for Units 1 and 2, and the removal of all conditions pertaining to the combustion of coal. This amended permit supersedes your permit dated January 13, 2015.

This amended permit contains legally enforceable conditions. Failure to comply may result in a Notice of Violation and civil charges. Please read all permit conditions carefully.

The Department of Environmental Quality (DEQ) deemed the application complete on July 6, 2016, and has determined that the application meets the requirements of a minor amendment to a new source review permit in accordance with 9 VAC 5-80-1280 A

This permit amendment approval shall not relieve Appalachian Power Company of the responsibility to comply with all other local, state, and federal permit regulations.

The Board's Regulations as contained in Title 9 of the Virginia Administrative Code 5-170-200 provide that you may request a formal hearing from this case decision by filing a petition with the Board within 30 days after this case decision notice was mailed or delivered to you. 9 VAC 5-170-200 provides that you may request direct consideration of the decision by the Board if the Director of the DEQ made the decision. Please consult the relevant regulations for additional requirements for such requests.

As provided by Rule 2A:2 of the Supreme Court of Virginia, you have 30 days from the date of service of this decision (the date you actually received this decision or the date on which it was mailed to you, whichever occurred first), within which to initiate an appeal of this decision by filing a Notice of Appeal with:

David K. Paylor, Director
Department of Environmental Quality
P. O. Box 1105
Richmond, VA 23218

If this permit was delivered to you by mail, three days are added to the thirty-day period in which to file an appeal. Please refer to Part Two A of the Rules of the Supreme Court of Virginia for information on the required content of the Notice of Appeal and for additional requirements governing appeals from decisions of administrative agencies.

If you have any questions concerning this permit amendment, please call me at (276) 676-4835.

Sincerely,

Rob Feagins
Air Permit Manager

GRF/TMD/td/PA-10236-16.docx

Attachments: Permit
Source Testing Report Format

c: Manager, Data Analysis (electronic file submission)

COMMONWEALTH of VIRGINIA

DEPARTMENT OF ENVIRONMENTAL QUALITY

Molly Joseph Ward
Secretary of Natural Resources

SOUTHWEST REGIONAL OFFICE
355-A Deadmore Street, Abingdon, Virginia 24210
(276) 676-4800 Fax: (276) 676-4899
www.deq.virginia.gov

David K. Paylor
Director

Allen J. Newman, P.E.
Regional Director

STATIONARY SOURCE PERMIT TO MODIFY AND OPERATE

This permit includes designated equipment subject to New Source Performance Standards (NSPS).

This permit supersedes your permit dated January 13, 2015.

In compliance with the Federal Clean Air Act and the Commonwealth of Virginia Regulations for the Control and Abatement of Air Pollution,

AEP / Appalachian Power Company
Clinch River Plant
3464 Power Plant Road
P.O. Box 370
Cleveland, Virginia 24225-0370
Registration No. 10236
Facility ID No. 51-167-00003

is authorized to modify and operate

an electric power generating facility

located at

3464 Power Plant Road, Carbo, in
Russell County, Virginia

in accordance with the conditions of this permit.

Approved on January 13, 2015 (as amended August 3, 2016).

Allen J. Newman, P.E.
Regional Director

Permit consists of 9 pages.
Permit Conditions 1 to 31.

INTRODUCTION

This permit approval is based on the permit applications dated July 1, 2016 (as amended July 6, 2016), September 4, 2013 (as revised November 17 and 18, 2014), June 25, 2013 (as amended July 12, 2013), February 1, 2010, June 25, 2008, and May 16, 2008, the permit application letter dated June 30, 2008, and addendum information received March 10, 2014, October 21, 23, and 24, 2013, September 16, 2013, August 7, 2013, July 29 and 31, 2013, February 8, 2010, March 2 and 5, 2010, July 8 and 18, 2008, and August 12, 15, and 22, 2008. Any changes in the permit application specifications or any existing facilities which alter the impact of the facility on air quality may require a permit. Failure to obtain such a permit prior to construction may result in enforcement action.

Words or terms used in this permit shall have meanings as provided in 9 VAC 5-10-20 of the State Air Pollution Control Board Regulations for the Control and Abatement of Air Pollution. The regulatory reference or authority for each condition is listed in parentheses ( ) after each condition.

Annual requirements to fulfill legal obligations to maintain current stationary source emissions data will necessitate a prompt response by the permittee to requests by the DEQ or the Board for information to include, as appropriate: process and production data; changes in control equipment; and operating schedules. Such requests for information from the DEQ will either be in writing or by personal contact.

The availability of information submitted to the DEQ or the Board will be governed by applicable provisions of the Freedom of Information Act, §§ 2.2-3700 through 2.2-3714 of the Code of Virginia, § 10.1-1314 (addressing information provided to the Board) of the Code of Virginia, and 9 VAC 5-170-60 of the State Air Pollution Control Board Regulations. Information provided to federal officials is subject to appropriate federal law and regulations governing confidentiality of such information.

Equipment List - Equipment at this facility consists of the following:

Ref. No.	Equipment Description	Rated Capacity	Federal Requirements	Original Permit Date
Equipment added under the modification dated 1/13/2015:				
CR4	English Boiler & Tube, natural gas-fired, Model 20 Dd 250 with superheater	33.4 MMBtu/hr	NSPS Dc	1/13/2015
CR5	Sigma Thermal natural gas-fired fuel heater (line heater)	16.42 MMBtu/hr	NSPS Dc	1/13/2015
Equipment modified under the permit dated 1/13/2015::				
CR1 & CR2	(2) Babcock and Wilcox radiant tube boilers; natural gas-fired	2461 MMBtu/hr, each	-	-
Previously permitted equipment:				
TL-1	Coal Truck Loading Operation	950 tons/hr	-	8/08/2013
SNCR1 & SNCR2	(2) Advanced Combustion Technology Selective Non-Catalytic Reduction Equipment with Urea Injection	2.6 gal/min of 50% urea solution + 22 gal/min H_2O	-	8/27/2008
Equipment removed from operation:				
CR3	Babcock and Wilcox radiant tube boiler	2100.9 MMBtu/hr	-	-
Conveyor 2	Coal Stackout Conveyor	950 tons/hr	-	6/23/2008
BDT1 & BDT2	(2) Dozer Trap Feeders	450 tons/hr	-	6/23/2008
BF1 & BF2	(2) Feed Transfer Conveyors			
Conveyors B1 & B2	(2) Blend Coal Feed Conveyor			

Specifications included in the above tables are for informational purposes only and do not form enforceable terms or conditions of the permit.

PROCESS REQUIREMENTS

1. **Emission Controls** – Nitrogen oxide emissions from Units 1 and 2 (CR1 and CR2) shall be controlled by low NO_X burners, good combustion practices, and selective non-catalytic reduction (SNCR). The low NO_X burners shall be installed and operated in accordance with manufacturer's specifications.
(9 VAC 5-80-1180)

2. **Emission Controls** – Carbon monoxide and volatile organic compound emissions from Units 1 and 2 (CR1 and CR2) shall be controlled by good combustion practices.
(9 VAC 5-50-260 and 9 VAC 5-80-1180)

3. **Fugitive Dust Emission Controls** - Fugitive dust and fugitive emission controls shall include the following, or equivalent, as a minimum:
   a. Dust from material handling, transfers and load-outs shall be controlled by wet suppression or equivalent (as approved by the DEQ).
   b. All material being stockpiled shall be kept adequately moist to control dust during storage and handling or covered at all times to minimize emissions.
   c. Dust from haul roads and traffic areas shall be controlled by the application of asphalt, water, suitable chemicals, or equivalent methods approved by the DEQ.
   d. Reasonable precautions shall be taken to prevent deposition of dirt on public roads and subsequent dust emissions. Dirt, product, or raw material spilled or tracked onto paved surfaces shall be promptly removed to prevent particulate matter from becoming airborne.
   (9 VAC 5-50-260 and 9 VAC 5-50-90)

4. **Deactivation** – Unit No. 3 (Reference No. CR3) was removed from operation prior to June 1, 2015, in accordance with the Mercury and Air Toxics (MATS) Extension Approval Letter dated June 3, 2013. Unit No. 3 shall not be reactivated without first obtaining a permit to construct and operate.
(9 VAC 5-80-1180)

OPERATING/EMISSION LIMITATIONS

5. **Fuel (Reference Nos. CR1 and CR2):** - The approved fuel for Units 1 and 2 (Reference Nos. CR1 and CR2) is natural gas exclusively. A change in the fuel may require a permit to modify and operate.
(9 VAC 5-50-260 and 9 VAC 5-80-1180)

6. **Fuel (Reference Nos. CR4 and CR5):** - The approved fuel for the auxiliary boiler (Reference No. CR4) and the fuel heater (Reference No. CR5) is natural gas. A change in the fuel may require a permit to modify and operate.
(9 VAC 5-50-260 and 9 VAC 5-80-1180)

7. **Consumption** – The consumption of natural gas in Unit 1, Unit 2, the auxiliary boiler, and the fuel heater (Reference Nos. CR1, CR2, CR4, and CR5, respectively) shall not exceed a combined total of 27,100,000,000 standard cubic feet 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.
(9 VAC 5-80-1180)

8. **Throughput** – The throughput of coal to the coal truck loading operations (Reference No. TL-1) shall not exceed 4,000,000 tons per year, calculated monthly as the sum of each consecutive 12-month period.
(9 VAC 5-80-1180)

9. **SNCR Ammonia Slip** – The ammonia slip in the boiler exhausts for Units 1 and 2 (Reference Nos. CR1 and CR2) shall not exceed 10.0 parts-per-million (ppm) as a monthly average. The ammonia slip in each boiler exhaust shall be monitored continuously and the average hourly concentration shall be recorded. The average monthly concentration shall be determined as the sum of the hourly concentrations recorded during that month divided by the unit operating time in hours.
(9 VAC 5-50-260 and 9 VAC 5-80-1180)

10. **Emission Limits** - Emissions from the combustion of natural gas in the Unit 1, Unit 2, and auxiliary boilers (Reference Nos. CR1, CR2, and CR4) shall not exceed the limits specified below:

Pollutant	Short-Term Limits			Annual Limits
	Units 1 and 2 (CR1 and CR2) (per unit)	Auxiliary Boiler (CR4)	Fuel Heater (CR5)	Facility-Wide
Sulfur Dioxide (SO_2):	144.78 lbs/hr	1.98 lbs/hr	0.96 lbs/hr	813.00 tons/yr
Carbon Monoxide (CO):	147.66 lbs/hr 0.06 lbs/MMBtu	4.68 lbs/hr	0.66 lbs/hr	233.00 tons/yr
Nitrogen Oxides (as NO_2):	442.98 lbs/hr 0.18 lb/MMBtu	0.89 lbs/hr	0.59 lbs/hr	1505.00 tons/yr
Volatile Organic Compounds (VOC):	9.84 lbs/hr 0.004 lbs/MMBtu	0.18 lbs/hr	0.07 lbs/hr	55.50 tons/yr
PM-10/PM-2.5:	27.99 lbs/hr	0.25 lbs/hr	0.16 lbs/hr	157.18 tons/yr

Annual emissions shall be calculated monthly as the sum of each consecutive 12-month period. These emissions are derived from the estimated overall emission contribution from operating limits. Exceedance of the operating limits shall be considered credible evidence of the exceedance of emission limits. Compliance with these emission limits may be determined as stated in Conditions 1, 2, 5, 6, 7, 9, 15, and 20.

Unless otherwise specified, the short-term CO emission limits on Units 1 and 2 (Reference Nos. CR1 and CR2) shall apply at all times except during periods of startup, shutdown, and malfunction. Periods of startup and shutdown are defined in Condition 11.
(9 VAC 5-50-260 and 9 VAC 5-80-1180)

11. **Startup and Shutdown Emission Limits** – During periods of startup and shutdown, the short-term emissions from the combustion of natural gas in the Unit 1 and Unit 2 boilers (Reference Nos. CR1 and CR2) shall meet the following criteria:

    a. Startup – A startup commences when the unit begins combusting fuel after a shutdown and ends when the unit is operating above 25% of design full load and shall not exceed a maximum duration of 18 hours. CO emissions from each unit shall not exceed 1800 lbs per startup.

b. Shutdown – A shutdown commences when the unit is being removed from service and drops below 25% of design full load and ends when the fuel supply to the unit ceases and shall not exceed a maximum duration of 9 hours. CO emissions from each unit shall not exceed 900 lbs per shutdown.

c. The permittee shall operate the continuous emission monitoring systems (as specified in Condition 15) during periods of startup and shutdown.

d. The permittee shall record the date, time, and duration of each startup and shutdown period.

e. The permittee shall operate the facility so as to minimize the frequency and duration of startup and shutdown periods.

(9 VAC 5-50-260 and 9 VAC 5-80-1180)

12. **Emission Limits** - Emissions from the coal truck loading operations (Reference No. TL-1) shall not exceed the limits specified below:

Coal Truck Loading:		
Particulate Matter	2.85 lbs/hr	6.00 tons/yr
PM-10	2.85 lbs/hr	6.00 tons/yr
PM-2.5	2.85 lbs/hr	6.00 tons/yr
Truck Loading Traffic:		
Particulate Matter	3.10 lbs/hr	6.37 tons/yr
PM-10	1.56 lbs/hr	3.20 tons/yr
PM-2.5	0.38 lbs/hr	0.78 tons/yr

These emissions are derived from the estimated overall emission contribution from operating limits. Exceedance of the operating limits shall be considered credible evidence of the exceedance of emission limits. Compliance with these emission limits may be determined as stated in Conditions 3 and 8.
(9 VAC 5-50-260 and 9 VAC 5-80-1180)

13. **Visible Emission Limit** – Visible emissions from the common exhaust stack serving Units 1 and 2 (Reference Nos. CR1 and CR2) shall not exceed ten percent (10%) opacity as determined by EPA Method 9 (reference 40 CFR 60, Appendix A). This condition applies at all times except during startup, shutdown and malfunction.
(9 VAC 5-50-80 and 9 VAC 5-50-260)

14. **Visible Emission Limit** - Visible emissions from the coal truck loading operations (Reference No. TL-1) shall not exceed twenty percent (20%) opacity as determined by EPA Method 9 (reference 40 CFR 60, Appendix A). This condition applies at all times except during startup, shutdown and malfunction.
(9 VAC 5-50-80 and 9 VAC 5-50-260)

CONTINUOUS EMISSION MONITORING SYSTEMS (CEMS)

15. **CEMS** –Continuous Emission Monitoring Systems (CEMS) shall be installed to measure and record the emissions of nitrogen oxides (NO_X) (measured as NO_2) and carbon monoxide (CO) from the boilers (Reference Nos. CR1 and CR2). CEMS for NO_X shall meet the design specifications of 40 CFR 75 whereas CEMS for CO shall be installed, evaluated, and operated according to DEQ-approved procedures which are equivalent to the requirements of 40 CFR 60.13 and Appendices B and F for compliance with the emission limits contained in Condition 10. NO_X and CO data shall be reduced to 1-hour block averages and 30-day rolling averages.
(9 VAC 5-50-40 and 9 VAC 5-80-1180)

16. **CEMS Performance Evaluations** – Performance evaluations of the NO_X and CO continuous monitoring systems shall be conducted in accordance with 40 CFR Part 60, Appendix B, and shall take place during the performance tests under 9 VAC 5-50-30 or within 30 days thereafter. Two copies of the performance evaluations report shall be submitted to the Director, Southwest Regional Office within 45 days of the evaluation. The continuous monitoring systems shall be installed and operational prior to conducting initial performance tests. Verification of operational status shall, as a minimum, include completion of the manufacturer's written requirements or recommendations for installation, operation and calibration of the device. A 30-day notification, prior to the demonstration of continuous monitoring system's performance, and subsequent notifications shall be submitted to the Director, Southwest Regional Office.
(9 VAC 5-50-40 and 9 VAC 5-80-1180)

17. **CEMS Quality Control Program** - A CEMS quality control program which is equivalent to the requirements of 40 CFR 60.13 and 40 CFR 60, Appendix F or Part 75 shall be implemented for all continuous monitoring systems.
(9 VAC 5-50-40 and 9 VAC 5-80-1180)

18. **Reports for Continuous Monitoring Systems** - The permittee shall furnish written reports to the Director, Southwest Regional Office, of excess emissions from any process monitored by a continuous monitoring system (CEMS) on a quarterly basis, postmarked no later than the 30th day following the end of the calendar quarter. These reports shall include, but are not limited to the following information:

    a. The magnitude of excess emissions, any conversion factors used in the calculation of excess emissions, and the date and time of commencement and completion of each period of excess emissions;

    b. Specific identification of each period of excess emissions that occurs during startups, shutdowns, and malfunctions of the process, the nature and cause of the malfunction (if known), the corrective action taken or preventative measures adopted;

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

    d. When no excess emissions have occurred or the continuous monitoring systems have not been inoperative, repaired or adjusted, such information shall be stated in that report.

    (9 VAC 5-50-50 and 9 VAC 5-80-1180)

RECORDS AND REPORTING

19. **On Site Records** - 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, Southwest Regional Office. These records shall include, but are not limited to:

    a. The annual consumption of natural gas in Unit 1, Unit 2, the auxiliary boiler, and the fuel heater (Reference Nos. CR1, CR2, CR4, and CR5), calculated monthly as the sum of each consecutive 12-month period.

    b. The annual processing of coal in the coal truck loading operations (Reference No. TL-1), calculated as the sum of each consecutive 12-month period.

    c. The average hourly and monthly ammonia slip concentration for each boiler exhaust, expressed in parts-per-million (ppm).

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

e. Monthly emissions calculations for VOC, PM-10, PM-2.5, and SO_2 from Unit 1, Unit 2, the auxiliary boiler, and the fuel heater (Reference Nos. CR1, CR2, CR4, and CR5).

f. Records of each startup and shutdown for Units 1 and 2, including the duration and total CO emissions during each event.

g. Scheduled and unscheduled maintenance and operator training.

h. Results of stack tests and visible emissions evaluations.

These records shall be available for inspection by the DEQ and shall be current for the most recent five years.
(9 VAC 5-50-50)

INITIAL COMPLIANCE DETERMINATION

20. **Stack Tests** - Initial performance tests shall be conducted for PM-10, nitrogen oxides (as NO_2), carbon monoxide (CO), and volatile organic compounds (VOC) from the exhaust stack for Units 1 and 2 (Reference Nos. CR1 and CR2) to determine compliance with the emission limits contained in Condition 10. The tests shall be performed within 60 days after achieving the maximum production rate at which the facility will be operated but in no event later than 180 days after conversion of Units 1 and 2 to fire natural gas. Tests shall be conducted and reported and data reduced as set forth in 9 VAC 5-50-30. The details of the tests are to be arranged with the Director, Southwest Regional Office. The permittee shall submit a test protocol at least 30 days prior to testing. A copy of the test results shall be submitted to the Director, Southwest Regional Office within 60 days after test completion and shall conform to the test report format enclosed with this permit.
(9 VAC 5-50-30 and 9 VAC 5-80-1200)

21. **Visible Emissions Evaluation** – Concurrently with the initial performance tests required in Condition 20, Visible Emission Evaluations (VEE) in accordance with 40 CFR Part 60, Appendix A, Method 9, shall be conducted by the permittee on the common stack for Units 1 and 2 (Reference Nos. CR1 and CR2) being tested. Each test shall consist of 30 sets of 24 consecutive observations (at 15 second intervals) to yield a six-minute average. The evaluation shall be performed, reported, and demonstrate compliance within 60 days after achieving the maximum production rate at which the facility will be operated but in no event later than 180 days after completion of the conversion of Units 1 and 2 to fire natural gas. Should conditions prevent concurrent opacity observations, the Southwest Regional Office shall be notified in writing, within seven days, and visible emissions testing shall be rescheduled within 30 days. Rescheduled testing shall be conducted under the same conditions (as possible) as the initial performance tests. The details of the tests are to be arranged with the Southwest Regional Office. One copy of the test result shall be submitted to the Director, Southwest Regional Office within 60 days after test completion and shall conform to the test report format enclosed with this permit.
(9 VAC 5-50-30 and 9 VAC 5-80-1200)

CONTINUING COMPLIANCE DETERMINATION

22. **Stack Tests** – Upon request by the DEQ, the permittee shall conduct additional tests on the common stack for Units 1 and 2 (Reference Nos. CR1 and CR2) to demonstrate compliance with the emission limits contained in this permit. The details of the tests shall be arranged with the Director, Southwest Regional Office.
(9 VAC 5-50-30 G and 9 VAC 5-80-1200)

23. **Visible Emissions Evaluation** – Upon request by the DEQ, the permittee shall conduct additional Visible Emissions Evaluations (VEE) in accordance with 40 CFR Part 60, Appendix A, Method 9 on the common boiler stack for Units 1 and 2 (Reference Nos. CR1 and CR2) to demonstrate compliance with the visible emission limits contained in this permit. The details of the tests shall be arranged with the Director, Southwest Regional Office.
(9 VAC 5-50-30 G and 9 VAC 5-80-1200)

GENERAL CONDITIONS

24. **Permit Suspension/Revocation** - This permit may be suspended or revoked if the permittee:
    a. Knowingly makes material misstatements in the permit application or any amendments to it;
    b. Fails to comply with the conditions of this permit;
    c. Fails to comply with any emission standards applicable to a permitted emissions unit;
    d. Causes emissions from the stationary source which result in violations of, or interfere with the attainment and maintenance of, any ambient air quality standard; or
    e. Fails to operate in conformance with any applicable control strategy, including any emission standards or emissions limitations, in the State Implementation Plan in effect at the time an application for this permit is submitted.
    (9 VAC 5-80-1210 G)

25. **Right of Entry** - The permittee shall allow authorized local, state, and federal representatives, upon the presentation of credentials:
    a. To enter upon the permittee's premises on which the facility is located or in which any records are required to be kept under the terms and conditions of this permit;
    b. To have access to and copy at reasonable times any records required to be kept under the terms and conditions of this permit or the State Air Pollution Control Board Regulations;
    c. To inspect at reasonable times any facility, equipment, or process subject to the terms and conditions of this permit or the State Air Pollution Control Board Regulations; and
    d. To sample or test at reasonable times.

    For purposes of this condition, the time for inspection shall be deemed reasonable during regular business hours or whenever the facility is in operation. Nothing contained herein shall make an inspection time unreasonable during an emergency.
    (9 VAC 5-170-130 and 9 VAC 5-80-1180)

26. **Maintenance/Operating Procedures** - The permittee shall take the following measures in order to minimize the duration and frequency of excess emissions, with respect to air pollution control equipment , monitoring devices, and process equipment which affect such emissions:
    a. Develop a maintenance schedule and maintain records of all scheduled and non-scheduled maintenance.
    b. Maintain an inventory of spare parts.
    c. Have available written operating procedures for equipment. These procedures shall be based on the manufacturer's recommendations, at a minimum.
    d. Train operators in the proper operation of all such equipment and familiarize the operators with the written operating procedures. The permittee shall maintain records of the training provided including the names of trainees, the date of training and the nature of the training.

Records of maintenance and training shall be maintained on site for a period of five years and shall be made available to DEQ personnel upon request.
(9 VAC 5-50-20 E)

27. **Record of Malfunctions** – The permittee shall maintain records of the occurrence and duration of any bypass, malfunction, shutdown or failure of the facility or its associated air pollution control equipment that results in excess emissions for more than one hour. Records shall include the date, time, duration, description (emission unit, pollutant affected, cause), corrective action, preventive measures taken and name of person generating the record.
(9VAC 5-20-180 J and 9 VAC 5-80-1180 D)

28. **Notification for Facility or Control Equipment Malfunction** - The permittee shall furnish notification to the Director, Southwest Regional Office, of malfunctions of the affected facility or related air pollution control equipment that may cause excess emissions for more than one hour, by facsimile transmission, telephone or telegraph. Such notification shall be made as soon as practicable but not later than four daytime business hours after the malfunction is discovered. The permittee shall provide a written statement giving all pertinent facts, including the estimated duration of the breakdown, within two weeks of discovery of the malfunction. When the condition causing the failure or malfunction has been corrected and the equipment is again in operation, the permittee shall notify the Director, Southwest Regional Office.
(9 VAC 5-20-180 C and 9 VAC 5-80-1180)

29. **Violation of Ambient Air Quality Standard** - The permittee shall, upon request of the DEQ, reduce the level of operation or shut down a facility, as necessary to avoid violating any primary ambient air quality standard and shall not return to normal operation until such time as the ambient air quality standard will not be violated.
(9 VAC 5-20-180 I and 9 VAC 5-80-1180)

30. **Change of Ownership** - In the case of a transfer of ownership of a stationary source, the new owner shall abide by any current permit issued to the previous owner. The new owner shall notify the Director, Southwest Regional Office of the change in ownership within 30 days of the transfer.
(9 VAC 5-80-1240)

31. **Permit Copy** - The permittee shall keep a copy of this permit on the premises of the facility to which it applies.
(9 VAC 5-80-1180)