APPENDIX K

March 30, 2017
From: MANE-VU Technical Support Committee
To: MANE-VU Air Directors

Re: Four-Factor Data Collection

Introduction

In order to submit a Long Term Strategy (LTS) every state that reasonably contributes to a Class I area must assess whether it would be reasonable to control sources or groups of sources in the next planning period by considering the following, which gets termed the Four-Factor Analysis:

(1) costs of compliance,
(2) time necessary for compliance,
(3) energy and non-air quality environmental impacts of compliance, and
(4) remaining useful life of any potentially affected sources. (40 CFR 51.308(f)(2)(i))

It is also important for Class I states to have information that will be considered by contributing states so that during the interstate consultation process they can make reasonable asks for controls to be implemented. To achieve these two ends the MANE-VU Four-Factor/Contribution Assessment Workgroup, a subset of the Technical Support Committee, worked to collect the information.

During the first regional haze planning cycle, MANE-VU through MARAMA through the contractor MACTEC documented six sectors that had emissions that were reasonable anticipated to contribute to visibility degradation in MANE-VU: Electric Generating Units (EGUs), Industrial/Commercial/Institutional Boilers (ICI Boilers), Cement Kilns, Heating Oil, Residential Wood Combustion, and Outdoor Wood Boilers.[1] For the former three sectors, information on individual point sources was also collected in additional to sector level data.

Due to resource constraints a contractor could not be hired to update the original report in its entirety nor expand upon it, but through a combination of contractor work and data collection by state staff the information needed by states for their SIP planning for the second regional haze planning period was collected. The remainder of the memorandum explains what was collected for each of the six sectors and where information is located.

Sectors that Reasonably Contribute to Visibility Impairment

EGUs

Sector level information needed to assess the four factors for EGUs were updated through a contract with SRA and has been posted to MARAMA's website for download.[2] As part of the contract

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[1] MACTEC Federal Programs, Inc., *Assessment of Reasonable Progress for Regional Haze in MANE-VU Class I Areas*, July 9, 2007, http://www.marama.org/publications_folder/visibility/RPG/FinalReport/RPGFinalReport_070907.pdf.
[2] Ed Sabo, *2016 Updates to the Assessment of Reasonable Progress for Regional Haze in MANE-VU Class I Areas*, January 31, 2016,

information on the cost of controls was reviewed and some controls were updated in MARAMA's EMF system to allow for states to have access to more recent information if they opt to use EMF and the full list of control factors updated are included as an Appendix to "2016 Updates to the Assessment of Reasonable Progress for Regional Haze in MANE-VU Class I Areas." It should be noted that a bug was found in the EMF code during this review that as of writing had not been fixed by EPA and would need to be accounted for.

Information was also collated on the 444 EGUs that were determined following an initial round of CALPUFF modeling to warrant further scrutiny based on their emissions of SO_2 and NO_X.[3] Several sources of data were available to rely on for information on the capacity and installed controls on individual units. Information from NEEDS v5.15[4], ERTAC EGU v2.5L2[5], data collection on NOX controls conducted by Maryland Department of Environment, and MANE-VU's "167 Stack Retrospective."[6] The individual facility information is in the spreadsheet title "EGU Data for Four-factor Analyses (Only CALPUFF Units)."[7] You can view the locations of the facilities in Figure 1. MANE-VU States were given the opportunity to review the data in early November of 2016.

ICI Boilers

Sector level information needed to assess the four factors for ICI boilers were updated through a contract with SRA and has been posted to MARAMA's website for download. [8] As part of the contract information on the cost of controls was updated in MARAMA's EMF system to allow for states to have access to more recent information if they opt to use EMF and the full list of control factors updated are included as an Appendix to "2016 Updates to the Assessment of Reasonable Progress for Regional Haze in MANE-VU Class I Areas."

Information was also collected on the 50 facilities that according to 2011 Q/d contributed the must to visibility impact in each Class I area from sulfate.[9] Since many of these facilities were duplicates the number of sites data was collected for totaled 82. Later in the data collection process the number of sources was limited to only sources that cumulatively contributed to 50% of the impairment. The

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http://www.marama.org/images/stories/documents/publications/FINAL_Updates_to_4Factor_Reasonable_Progress_Report_2016_01_31.pdf.

[3] MANE-VU Technical Support Committee, "EGU Data for Four-Factor Analyses (Only CALPUFF Units)," January 10, 2017.

[4] US EPA, "NEEDS v.5.15 User Guide," August 2015.

[5] ERTAC Workgroup, "Documentation of ERTAC EGU CONUS Versions 2.5 and 2.5L2," December 12, 2016, http://www.marama.org/images/stories/documents/events/Documentation_of_ERTAC_EGU_CONUS_2_5L_2017_12_10_FINAL_TO_POST_resized.pdf.

[6] MANE-VU Technical Support Committee, *Status of the Top 167 Electric Generating Units (EGUs) That Contributed to Visibility Impairment at MANE-VU Class I Areas during the 2008 Regional Haze Planning Period*, July 25, 2016, http://otcair.org/MANEVU/Upload/Publication/Reports/Status%20of%20the%20Top%20167%20Stacks%20from%20the%202008%20MANE-VU%20Ask.pdf.

[7] MANE-VU Technical Support Committee, "EGU Data for Four-Factor Analyses (Only CALPUFF Units)."

[8] Sabo, *2016 Updates to the Assessment of Reasonable Progress for Regional Haze in MANE-VU Class I Areas*.

[9] MANE-VU Technical Support Committee, *MANE-VU Updated Q/d*C Contribution Assessment*, April 6, 2016, http://otcair.org/MANEVU/Upload/Publication/Reports/MANE-VU%20TSC%20-%20Updated%20QC%20over%20d%20Contribution%20Assessment%20-%20Final.pdf.

facilities are listed in Table 1 with information on 2011 SO2 emissions, number of Class I sites affected. The individual facility information is in the spreadsheet title "Industrial Source Data for Four-factor Analyses" along with data needed for base year modeling.[10] The data was provided for stakeholder review, including to states in upwind Regional Planning Organizations, OTC/MANE-VU Spring Committee Meeting in Washington, DC on April 12, 2016 and then again at the OTC/MANE-VU Fall Committee Meeting in Washington, DC on September 20, 2016. You can view the locations of the facilities in Figure 1.

Table 1: 82 Industrial Sources that Impact Class I Areas

State	*Facility ID*	*Facility Name*	*2011 SO_2 Tons*	***#Sites Top 50***	***#Sites >= 50%***
IL	**7793311**	Tate & Lyle Ingredients Americas, LLC	102.90	5	3
IL	**8065311**	Aventine Renewable Energy Inc.	21.51	5	5
IN	**3986511**	Indiana Harbor East	1,332.52	5	0
IN	**4553211**	Indiana University	2,467.99	1	0
IN	**4873211**	Ball State University	1,045.58	4	0
IN	**4885311**	Citizens Thermal	124.94	5	4
IN	**5552011**	University of Notre Dame Du Lac	4,291.94	2	0
IN	**7364611**	Sabic Innovative Plastics Mt. Vernon, LLC	9,570.03	5	4
IN	**7376411**	Tate & Lyle, Lafayette South	908.83	4	0
IN	**7376511**	ArcelorMittal Burns Harbor Inc.	309.55	5	5
IN	**8181811**	Alcoa Inc., Warrick Operations	1,495.20	5	2
IN	**8192011**	US Steel, Gary Works	1,063.30	5	3
IN	**8198511**	ESSROC Cement Corp	1,516.32	1	0
IN	**8223611**	Eli Lilly & Co., Clinton Labs	4,434.03	2	0
KY	**6096411**	E I DuPont, Inc.	2,045.96	1	0
KY	**7352311**	Century Aluminum Sebree, LLC	1,917.99	5	2
KY	**7365311**	Isp Chemicals Inc.	2,207.50	1	0
MA	**7236411**	Solutia, Inc.	19,696.90	2	0
MD	**6117011**	Naval Support Facility, Indian Head	1,728.88	1	0
MD	**7763811**	Luke Paper Company	2,133.08	5	5
MD	**8239711**	Sparrows Point, LLC	2,033.07	1	1
ME	**5253911**	Madison Paper	1,444.64	2	0
ME	**5691611**	Huhtamaki Inc., Waterville	1,420.05	1	0
ME	**5692011**	FMC Biopolymer	992.04	2	0
ME	**5974211**	Woodland Pulp, LLC	680.87	2	0
ME	**7764711**	Verso Paper, Androscoggin Mill	1,018.69	2	0
ME	**7945211**	The Jackson Laboratory	1,754.70	1	0
ME	**8200111**	Sappi, Somerset	983.53	2	0
MI	**8126511**	Escanaba Paper Company	297.11	2	0
MI	**8160611**	St. Mary's Cement, Inc. (U.S.)	1,279.00	2	0
MI	**8483611**	US Steel, Great Lake Works	1,046.43	5	5
NC	**7920511**	Blue Ridge Paper Products, Canton Mill	2,043.68	5	5
NC	**8048011**	KapStone Kraft Paper Corporation	1,467.51	1	0
NC	**8122511**	DAK Americas, LLC	2,181.00	1	0
NH	**7199811**	Dartmouth College	22,024.21	1	0
NH	**7866711**	Gorham Paper & Tissue, LLC	2,400.59	1	0
NJ	**12804611**	Gerresheimer Moulded Glass	3,007.04	1	0
NJ	**8093211**	Atlantic County Utilities Authority Landfill	907.88	1	0
NY	**7814711**	Morton Salt Division	1,143.29	4	1
NY	**7968211**	Alcoa, Massena Operations (West Plant)	805.13	4	2
NY	**7991711**	International Paper Ticonderoga Mill	1,917.74	4	3
NY	**8090911**	Norlite Corporation	2,887.99	1	0
NY	**8091511**	Kodak Park Division	681.06	5	5
NY	**8105211**	Lafarge Building Materials, Inc.	2,102.47	5	5
NY	**8176611**	CARGILL SALT CO- WATKINS GLEN PLANT	1,280.09	3	0
NY	**8325211**	Finch Paper LLC	2,265.36	1	1
OH	**15485811**	Fluor-B&W Portsmouth LLC	102.90	1	0
OH	**7219511**	Youngstown Thermal	21.51	1	0

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[10] MANE-VU Technical Support Committee, "Industrial Source Data for Four-Factor Analyses," March 30, 2017.

State	Facility ID	Facility Name	2011 SO_2 Tons	#Sites Top 50	#Sites >= 50%
OH	**7416411**	Cargill, Inc., Salt Division, Akron	1,332.52	4	0
OH	**7997111**	Morton Salt, Inc.	2,467.99	5	5
OH	**8008811**	AK Steel Corporation	1,045.58	4	0
OH	**8063611**	BDM Warren Steel Operations, LLC	124.94	5	0
OH	**8130511**	Kraton Polymers U.S. LLC	4,291.94	5	1
OH	**8131111**	P. H. Glatfelter Company, Chillicothe Facility	9,570.03	5	5
OH	**8170411**	City of Akron Steam Generating	908.83	5	0
OH	**8252111**	The Medical Center Company	309.55	5	2
OH	**9301711**	DTE St. Bernard, LLC	1,495.20	3	0
PA	**3186811**	Penn State Univ	1,063.30	5	0
PA	**3881611**	Hercules Cement Co. LP, Stockertown	1,516.32	5	1
PA	**4966711**	United Refining Co., Warren Plant	4,434.03	2	0
PA	**6463511**	PPG IND, Inc., Works No. 6	2,045.96	1	0
PA	**6532511**	AMER REF Group, Bradford	1,917.99	3	0
PA	**6582111**	International Waxes, Inc., Farmers Valley	2,207.50	5	3
PA	**6582211**	Keystone Portland Cement, East Allen	19,696.90	3	0
PA	**6652211**	Philadelphia Energy SOL REF/ PES	1,728.88	1	0
PA	**7409311**	USS CORP, Edgar Thomson Works	2,133.08	4	0
PA	**7872711**	Appleton Papers, Spring Mill	2,033.07	2	0
PA	**7873611**	Sunoco Inc. (R&M), Marcus Hook Refinery	1,444.64	5	2
PA	**8204511**	USS, Clairton Works	1,420.05	4	0
PA	**9248211**	Team Ten, Tyrone Paper Mill	992.04	5	1
TN	**3982311**	Eastman Chemical Company	680.87	5	5
TN	**4963011**	Packaging Corporation of America	1,018.69	1	0
TN	**5723011**	Cargill Corn Milling	1,754.70	2	0
VA	**4182011**	Smurfit Stone Container Corporation, West Point	983.53	1	0
VA	**4183311**	GP Big Island LLC	297.11	1	0
VA	**4938811**	Huntington Ingalls, Inc., NN Shipbldg Div	1,279.00	1	0
VA	**5039811**	Roanoke Cement Company	1,046.43	4	1
VA	**5748611**	Radford Army Ammunition Plant	2,043.68	5	1
VA	**5795511**	Philip Morris USA, Inc., Park 500	1,467.51	1	0
WV	**4878911**	DuPont, Washington Works	2,181.00	5	1
WV	**4987611**	Capitol Cement, Essroc Martinsburg	22,024.21	3	1
WV	**5782411**	Bayer Cropscience	2,400.59	5	1

Cement Kilns

Sector level information needed to assess the four factors for cement kilns. Control factors are in MARAMA's EMF system but are those that came installed with the system and represent control costs found in EPA's CoST Manual.[11] Concerning data for individual point sources, cement kilns were included in the work to use Q/d to determine the industrial sources with the most impact on Class I areas. As a result data was collected on individual cement kilns and the cement kilns that were in the list of the 82 industrial sources with the most impact and individual facility information is in the spreadsheet title "Industrial Source Data for Four-factor Analyses" along with data needed for base year modeling.[12]

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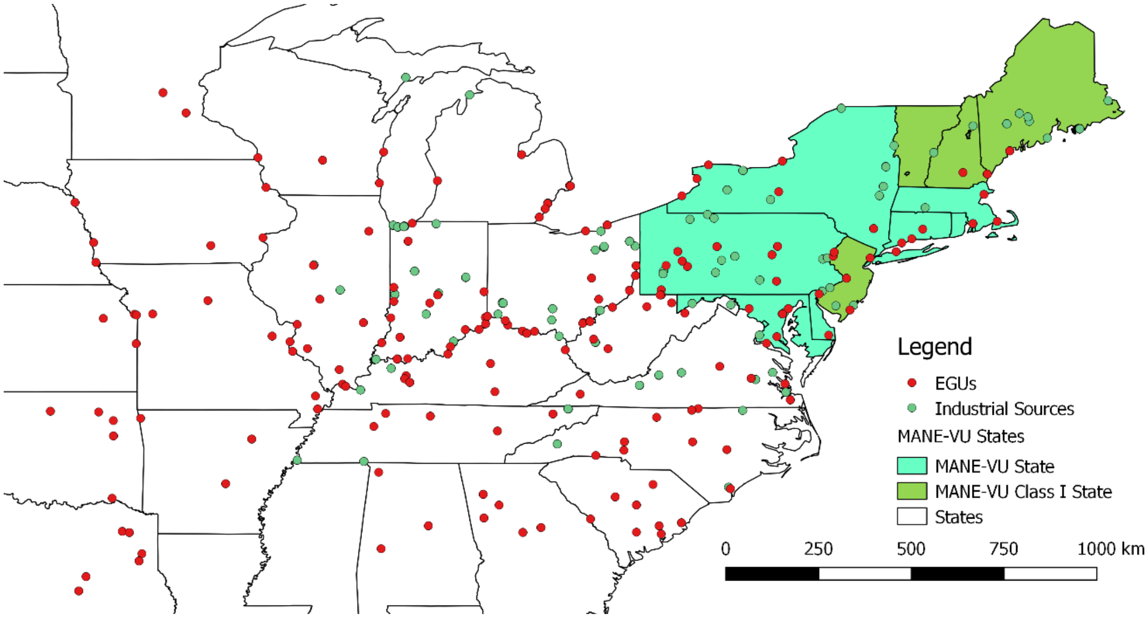
[11] US EPA, *Control Strategy Tool (CoST) Development Documentation*, June 9, 2010.

[12] MANE-VU Technical Support Committee, "Industrial Source Data for Four-Factor Analyses."

Figure 1: EGUs and Industrial Sources for which Data Collection Occurred



Heating Oil

Sector level information needed to assess the four factors for heating oil were updated through a contract with SRA and has been posted to MARAMA's website for download.[13] As part of the contract information on the cost of controls was updated in MARAMA's EMF system to allow for states to have access to more recent information if they opt to use EMF and the full list of control factors updated are included as an Appendix to "2016 Updates to the Assessment of Reasonable Progress for Regional Haze in MANE-VU Class I Areas." Since heating oil is an area source no specific point source data was collected.

Residential Wood Stoves (RWS)

Sector level information needed to assess the four factors for RWSs were updated through a contract with SRA and has been posted to MARAMA's website for download.[14] As part of the contract information on the cost of controls was updated in MARAMA's EMF system to allow for states to have access to more recent information if they opt to use EMF and the full list of control factors updated are included as an Appendix to "2016 Updates to the Assessment of Reasonable Progress for Regional Haze in MANE-VU Class I Areas." Since RWS is an area source no specific point source data was collected.

Outdoor Wood-fired Boilers (OWB)

Sector level information needed to assess the four factors for OWBs were updated through a contract with SRA and has been posted to MARAMA's website for download.[15] As part of the contract information on the cost of controls was updated in MARAMA's EMF system to allow for states to have

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[13] Sabo, *2016 Updates to the Assessment of Reasonable Progress for Regional Haze in MANE-VU Class I Areas*.

[14] Ibid.

[15] Ibid.

access to more recent information if they opt to use EMF and the full list of control factors updated are included as an Appendix to “2016 Updates to the Assessment of Reasonable Progress for Regional Haze in MANE-VU Class I Areas.” Since OWB is an area source no specific point source data was collected.

Summary

Sector	**Sector Level Data**		**Source Level Data**		**CoST Data**
	Update?	**Location**	**Update?**	**Location**	**Update?**
EGUs	Yes	2016 Updates to the Assessment of Reasonable Progress for Regional Haze in MANE-VU Class I Areas	Yes	EGU Data for Four-Factor Analyses	Yes
ICI Boilers	Yes	2016 Updates to the Assessment of Reasonable Progress for Regional Haze in MANE-VU Class I Areas	Yes	Industrial Source Data for Four-Factor Analyses	Yes
Cement Kilns	No	Assessment of Reasonable Progress for Regional Haze in MANE-VU Class I Areas	Yes	Industrial Source Data for Four-Factor Analyses	No
Heating Oil	Yes	2016 Updates to the Assessment of Reasonable Progress for Regional Haze in MANE-VU Class I Areas		n/a	Yes
RWS	Yes	2016 Updates to the Assessment of Reasonable Progress for Regional Haze in MANE-VU Class I Areas		n/a	Yes
OWB	Yes	2016 Updates to the Assessment of Reasonable Progress for Regional Haze in MANE-VU Class I Areas		n/a	Yes

APPENDIX L

2016 UPDATES TO THE ASSESSMENT OF REASONABLE PROGRESS FOR REGIONAL HAZE IN MANE-VU CLASS I AREAS

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Memorandum: Updates to CoST Control Measure Database

EXECUTIVE SUMMARY

In 2007, the Mid-Atlantic Regional Air Management Air Association, Inc. (MARAMA) sponsored an analysis of the costs of potential measures to improve visibility in Class I areas in and near the Mid-Atlantic and Northeast region. The effort resulted in a report prepared for MANE-VU by MACTEC Engineering and Consulting Inc. entitled *Assessment of Reasonable Progress for Regional Haze in MANE-VU Class I Areas*[1]. The report considered four factors to help MANE-VU members determine which emission control measures may be needed to make reasonable progress in improving visibility:

- costs of compliance,
- time necessary for compliance,
- energy and non-air quality environmental impacts of compliance, and
- remaining useful life of any existing source subject to such requirements.

In 2015, MARAMA issued a contract for SRA International, Inc. to conduct appropriate analysis to update the cost information in the following chapters of the 2007 Report:

- Chapter 2 - Source Category Analysis: EGUs;
- Chapter 4 - Source Category Analysis: Industrial, Commercial, and Institutional Boilers;
- Chapter 8 - Heating Oil;
- Chapter 9 - Residential Wood Combustion;
- Chapter 10 - Outdoor Wood Fired Boilers.

In addition, the Chapters regarding EGUs and ICI boilers were expanded to describe NO_x emissions control options and costs.

MARAMA has developed the capability to run EPA's Control Strategy Tool (CoST) model. CoST allows users to estimate the emission reductions and costs associated with future-year emission control strategies, and then to generate emission inventories that reflect the effects of applying the control strategies. Some of the underlying control and cost information in CoST tool is dated, and EPA's project to update this data has been delayed due to resource constraints. As part of SRA's contract, updates to the CoST Control Measures Database were prepared to reflect the updated cost information for the source categories addressed in this project.

This document presents the updated analyses of the economic and environmental impacts of potential control scenarios that could be implemented by MANE-VU States to reduce emissions from the above source categories in order to make reasonable progress toward meeting visibility improvement goals. This document also includes a memorandum documenting the efforts to update CoST with information from the analyses of the costs of potential measures to improve visibility in Class I areas in and near the Mid-Atlantic and Northeast region.

This report does not draw conclusions about which control measures are reasonable in any given state. The information presented in this report may be used by states as they develop policies and implementation plans to address reasonable progress goals.

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[1] See: http://www.marama.org/technical-center/regional-haze-planning/reasonable-progress-analysis

CHAPTER 2

SOURCE CATEGORY ANALYSIS: ELECTRIC GENERATING UNITS

SOURCE CATEGORY DESCRIPTION

The MANE-VU contribution assessment demonstrated that sulfur dioxide (SO_2) emissions from electric generating units (EGUs) are the principal contributor to visibility impairment in Class I MANE-VU areas (NESCAUM, 2006). Emissions of oxides of nitrogen (NO_x) may also contribute to visibility impairment and EGUs are important sources of NO_x emissions. MANE-VU previously developed an assessment (MACTEC, 2007) of SO_2 control technologies to achieve reasonable progress goals with respect to the four factors listed in Section 169A of the Clean Air Act. The information presented in this Chapter is an update to some parts of the MACTEC report and now includes NO_x control technologies.

Types of EGUs

Electricity is generated at most power plants by using mechanical energy to rotate the shaft of electromechanical generators. The energy needed to rotate the generator shaft can be produced by burning fossil fuels; from nuclear fission; from the conversion of kinetic energy from flowing water, wind, or tides; or from the conversion of thermal energy from geothermal wells or concentrated solar energy. Electricity also can be produced directly from sunlight using photovoltaic cells or by using a fuel cell to electrochemically convert chemical energy into an electric current. The focus of this Chapter is on EGUs that burn fossil fuels.

Key characteristics of fossil fuel-fired EGUs include (based on LADCO, 2005):

- **Fuel type and quality**. Fossil fuels include (coal, natural gas, and petroleum liquids). Historically, more than half of the electricity generated in the U.S. was from burning of coal. Coal is broadly classified into one of four types (anthracite, bituminous, subbituminous, or lignite) based on differences in heating values and amounts of fixed carbon, volatile matter, ash, sulfur, and moisture. Recent changes in energy markets have increased the role of natural gas in power generation. Petroleum liquids – residual oil and distillate oil – are used to a much lesser extent for generating electricity.
- **Combustion type**. The combustion of a fossil fuel to generate electricity can be either in: 1) a steam generating unit (also referred to as a "boiler") to feed a steam turbine that, in turn, spins an electric generator: or 2) a combustion turbine or a reciprocating internal combustion engine that directly drives the generator. Some modern power plants use a "combined cycle" electric power generation process, in which a gaseous or liquid fuel is burned in a combustion turbine that both drives electrical generators and provides heat to produce steam in a heat recovery steam generator (HRSG). The steam produced by the HRSG is then fed to a steam turbine that drives a second electric generator.
- **Unit size**. The electric-generating capacity of units ranges from approximately 15 to 1,300 MW. Given a typical efficiency of about 33 percent for steam generating units, this corresponds to a heat input range of 150 to 13,400 MMBTU/hr.
- **Unit age**. New boilers tend to be more efficient than older ones. Many boilers over 40 years old are still in service. Newer combined cycle plants that drive both a combustion

turbine generator set and a stream turbine generator significantly increases the overall efficiency of the electric power generation process.

- **Load**. Depending on utility needs, units may be operated somewhat differently. Baseload units are run continuously at a constant, high fraction of maximum rated load. Cycling units are run at a load that varies with demand. Peaking units run only during periods of high demand, which in some cases may be limited to the few hottest days of the summer or coldest days of the winter.
- **Type of control technologies employed**. Nearly all EGUs already employ some level of air pollution control technology to meet regulatory requirements. Some facilities have switched coal supply regions to use low sulfur coal to meet regulatory requirements, or have switched from coal to natural gas for economic or environmental reasons.

All of these factors affect the rate of emissions for a specific EGU.

Clean Air Act Regulations Controlling EGUs

EGUs are currently governed by multiple State and federal regulations under Titles I, III, and IV of the Clean Air Act. Each of these programs is discussed in the following paragraphs.

Title I imposes New Source Performance Standards (NSPS) on certain specified categories of new and modified large stationary sources. The NSPS apply to brand new sources or to an existing unit that meets certain, specific conditions described in the Clean Air Act and implementing regulations for being “modified” or “reconstructed.” The original NSPS applied to coal-fired units that were constructed or modified after 1971. EPA periodically revises the NSPS to reflect improvements in control methods for the reduction of emissions. The latest revision to the NSPS occurred in 2015 and established carbon pollution standards for new or modified power plants. Previously, the NSPS only applied to SO_2, NO_x and particulate matter emissions.

Title I subjects new and modified large stationary sources that increase their emissions to permitting requirements (known as New Source Review, or NSR). NSR requires evaluation of control technologies for new plants and for plant modifications that result in a significant increase in emissions, subjecting them to Best Available Control Technology (BACT) in attainment areas and to the Lowest Achievable Emission Rate (LAER) in nonattainment areas. Control strategies that constitute BACT and LAER evolve over time and are reviewed on a case by case basis in State permitting proceedings. Since 1999, EPA and some states have pursued a coordinated, integrated compliance and enforcement strategy to address NSR compliance issues at the nation's coal-fired power plants. Many of these cases have resulted in settlements requiring facilities to install state-of-the-art air pollution controls.

Title I regulates criteria pollutants by requiring local governments to adopt State Implementation Plans (SIPs) that set forth their strategy for achieving reductions in the particular criteria pollutant(s) for which they are out of attainment. The SIP requirements include Reasonably Available Control Technology (RACT) requirements, but more stringent requirements may be imposed depending on the locale's degree of non-attainment with ambient air quality standards.

Title I addresses the regional haze issue. In 1999, EPA published a final rule to address a type of visibility impairment known as regional haze. The regional haze rule required States to submit implementation plans to address regional haze visibility impairment in 156 Federally-protected parks and wilderness areas. As required by the CAA, EPA included in the final regional haze rule a requirement for best available retrofit technology (BART) for certain large stationary sources, including EGUs, that were built between 1962 and 1977.

Title I addresses the interstate transport of air pollution. Various allowance trading programs came into effect to address transport. The Ozone Transport Commission (OTC) NO_x Budget Program began in 1999 in the northeastern U.S. to reduce summertime NO_x emissions that contributed to ozone nonattainment. It was effectively replaced by the NO_x Budget Trading Program under the NO_x SIP Call in 2003, which was designed to reduce the transport of ground-level ozone in the larger eastern region of the U.S. The NO_x Budget Trading Program was effectively replaced by the Clean Air Interstate Rule (CAIR) in 2009 and capped emissions of SO_2 and NO_x in the eastern U.S. This program ended January 1, 2015. The current program is known as the Cross-State Air Pollution Rule (CSAPR) that requires 28 states to reduce power plant emissions that contribute to ozone and/or fine particle pollution in other states.

Title I establishes a mechanism for controlling air pollution from existing stationary sources that emit pollutants other than criteria or hazardous air pollutants. In 2015, EPA used its authority under Section 111(d) to address CO_2 emissions from power plants. This program is a state-based program for existing sources, where EPA establishes guidelines and the states then design programs that fit in those guidelines and get the needed reductions. While Section 111(d) does not directly address SO_2 and NO_x emissions, the state plans to address CO_2 emissions from power plants will likely impact the future emission of those pollutants.

Title III requires EPA to regulate emissions of hazardous air pollutants. The Mercury and Air Toxics (MATS) rule for power plants has a long history. In 2011, EPA finalized national standards to reduce mercury and other toxic air pollution from coal and oil-fired power plants. EPA estimates that 40% of older power plants do not have advanced air pollution control equipment to control emissions of air toxics. While the MATS rule does not directly address SO_2 and NO_x emissions, it will likely impact the future emission of those pollutants.

Title IV established the Acid Rain Program (ARP) in 1995 and required reductions in emissions of SO_2 and NO_x (the primary causes of acid rain) from power plants using market-based mechanisms. The SO_2 program set a permanent cap on the total amount of SO_2 that may be emitted by EGUs, with the final 2010 SO_2 cap set at 8.95 million tons, a level of one-half of the emissions from the power sector in 1980. NO_x reductions under the ARP are achieved through a program that applies to a subset of coal-fired EGUs. Since the program began in 1995, the ARP has achieved significant emission reductions.

The regulation of EGUs by various CAA programs has resulted in a variety of unit level emission limits that vary greatly and depend on boiler age, size, fuel type and location.

Emission and Fuel Consumption Trends

Unit level emissions, generation, primary fuel type and primary control information were obtained from EPA's Air Market Program Data tool (EPA, 2015). The primary fuel type was grouped into four bins (coal, oil, gas and wood). Primary control information was grouped into logical bins based on the pollutant. The EPA data do not explicitly list the use of low-sulfur coal as a SO_2 control, so some of the units listed as "no control" may actually use low-sulfur coal as a compliance strategy.

Tables 2.1 to 2.6 show trends in EGU SO_2 and NO_x emissions and electric generation in MANE-VU, the Midwest Regional Planning Organization (MRPO), and the Visibility Improvement State and Tribal Association of the Southeast (VISTAS) states. In general, emissions have declined significantly while generation has remained relatively constant. The following trends were observed in each RPO:

- **SO_2 Emissions in MANE-VU States**. Emissions in 2014 were 80% less than in 2002, while generation was only 8% less. Generation from coal-fired units decreased by 44%, while generation from gas-fired units increased by 106%. Generation from gas-fired units now exceeds generation of coal-fired units. Generation from coal-fired units with no add-on control devices decreased by 88% from 2002 to 2014. Only 14% of coal-fired generation was from units with no add-on control devices.
- **SO_2 Emissions in MRPO States**. Emissions in 2014 were 68% less than in 2002, while generation was only 4% less. Generation from gas-fired units increased significantly, but coal-fired generation still accounts for 87% of total generation. Generation from coal-fired units with no add-on control devices decreased by 66% from 2002 to 2014. But 32% of coal-fired generation in 2014 was from units with no add-on control devices.
- **SO_2 Emissions in VISTAS States**. Emissions in 2014 were 78% less than in 2002, while generation was 5% more. Generation from gas-fired units increased significantly, and now accounts for 40% of total generation with coal-fired generation accounting for 60%. Generation from coal-fired units with no add-on control devices decreased by 85% from 2002 to 2014. Only 14% of coal-fired generation in 2014 was from units with no add-on control devices.
- **NO_x Emissions in MANE-VU States**. Emissions in 2014 were 62% less than in 2002. Generation from coal-fired units equipped with SCR increased by 83% over that timeframe, and 67% of coal-fired generation in 2014 was from units equipped with SCR. Generation from gas-fired units equipped with SCR increased by 200% over that timeframe, and 79% of gas-fired generation in 2014 was from units equipped with SCR.
- **NO_x Emissions in MRPO States**. Emissions in 2014 were 69% less than in 2002. Generation from coal- and gas-fired units equipped with SCR increased dramatically. However, only 58% of coal-fired generation in 2014 was from units equipped with SCR.
- **NO_x Emission in VISTAS States**. Emissions in 2014 were 70% less than in 2002. Generation from coal- and gas-fired units equipped with SCR increased dramatically. However, only 74% of coal-fired generation in 2014 was from units equipped with SCR.

There are many other state- or facility-specific reasons that would also help explain the decrease in SO_2 and NO_x emissions and the shift in generation from coal to gas. It is beyond the scope of this project to identify all possible reasons.

Emission projections for future years are currently being developed ERTAC Electric Generation Unit (EGU) Forecasting Tool. Please check the MARAMA website (www.marama.org) for the latest emission projection results.

Table 2.1 Trends in SO_2 Emissions (tons/year) from EGUs in the MANE-VU Region

Primary Fuel	Primary Control	2002		2005		2008		2011		2014	
		Emissions (tpy)	Generation (10^9 BTU)	Emissions (tpy)	Generation (10^9 BTU)	Emissions (tpy)	Generation (10^9 BTU)	Emissions (tpy)	Generation (10^9 BTU)	Emissions (tpy)	Generation (10^9 BTU)
COAL	No Control	1,413,962	137,592	1,436,809	143,160	1,131,578	120,381	227,534	23,684	182,739	16,004
COAL	Dry FGD	0	946	0	2,921	19,177	5,536	22,667	6,814	8,559	6,559
COAL	Wet Lime FGD	36,848	21,122	37,853	23,553	57,262	32,608	137,381	60,472	75,876	52,142
COAL	Wet Limestone FGD	30,497	25,369	27,086	28,616	16,597	25,287	47,622	48,396	27,060	32,488
COAL	Other	9,181	10,718	18,411	8,267	17,959	7,464	25,031	4,691	19,134	3,278
		1,490,488	**195,747**	**1,520,159**	**206,517**	**1,242,573**	**191,276**	**460,234**	**144,056**	**313,366**	**110,471**
OIL	No Control	110,132	37,955	144,898	44,804	20,890	16,415	6,336	9,489	7,356	9,881
OIL	Dry FGD	0	0	0	0	0	0	0	0	0	0
OIL	Wet Lime FGD	0	0	0	0	0	0	0	0	0	0
OIL	Wet Limestone FGD	0	0	0	0	0	0	0	0	0	0
OIL	Other	0	0	0	0	0	0	0	0	0	0
		110,132	**37,955**	**144,898**	**44,804**	**20,890**	**16,415**	**6,336**	**9,489**	**7,356**	**9,881**
GAS	No Control	5,605	82,963	9,710	102,069	1,681	114,998	830	159,814	2,700	171,093
GAS	Dry FGD	0	0	0	0	0	0	0	0	0	0
GAS	Wet Lime FGD	0	0	0	0	0	0	0	0	0	0
GAS	Wet Limestone FGD	0	0	0	0	0	0	0	0	0	0
GAS	Other	0	0	0	0	0	0	0	0	0	0
		5,605	**82,963**	**9,710**	**102,069**	**1,681**	**114,998**	**830**	**159,814**	**2,700**	**171,093**
WOOD	No Control	6	201	10	264	2	284	1	259	260	326
WOOD	Dry FGD	0	0	0	0	0	0	0	0	0	0
WOOD	Wet Lime FGD	0	0	0	0	0	0	0	0	0	0
WOOD	Wet Limestone FGD	0	0	0	0	0	0	0	0	0	0
WOOD	Other	0	0	0	0	927	692	2	332	23	615
		6	**201**	**10**	**264**	**929**	**976**	**4**	**591**	**283**	**941**
		1,606,230	**316,865**	**1,674,776**	**353,655**	**1,266,072**	**323,666**	**467,404**	**313,950**	**323,704**	**292,386**

Source: EPA, 2015a

Table 2.2 Trends in SO_2 Emissions (tons/year) from EGUs in the MRPO Region

Primary Fuel	Primary Control	2002		2005		2008		2011		2014	
		Emissions (tpy)	Generation (10^9 BTU)	Emissions (tpy)	Generation (10^9 BTU)	Emissions (tpy)	Generation (10^9 BTU)	Emissions (tpy)	Generation (10^9 BTU)	Emissions (tpy)	Generation (10^9 BTU)
COAL	No Control	2,575,134	370,970	2,575,616	388,520	1,670,614	315,565	1,175,633	224,716	576,289	124,755
COAL	Dry FGD	1,798	517	1,478	496	4,578	1,920	16,960	14,855	19,631	27,472
COAL	Wet Lime FGD	64,672	32,047	63,543	37,478	150,972	63,122	162,533	72,627	118,736	87,587
COAL	Wet Limestone FGD	134,943	40,804	133,317	42,175	168,253	90,460	96,799	103,573	148,596	129,585
COAL	Other	10,108	3,317	21,618	5,044	20,252	4,749	13,556	3,711	31,241	19,259
		2,786,655	**447,654**	**2,795,573**	**473,713**	**2,014,668**	**475,816**	**1,465,481**	**419,483**	**894,493**	**388,658**
OIL	No Control	4,756	1,047	3,103	755	679	167	17	125	136	66
OIL	Dry FGD	2,790	0	2,686	0	0	0	0	0	0	0
OIL	Wet Lime FGD	57	0	3	0	0	0	0	0	0	0
OIL	Wet Limestone FGD	0	0	0	0	0	0	0	0	0	0
OIL	Other	0	0	0	0	0	0	0	0	0	0
		7,603	**1,047**	**5,792**	**755**	**679**	**167**	**17**	**125**	**136**	**66**
GAS	No Control	3,495	15,026	2,323	43,400	3,009	21,009	590	42,538	601	54,280
GAS	Dry FGD	0	0	0	0	0	0	0	0	0	57
GAS	Wet Lime FGD	0	0	0	0	0	0	0	0	0	0
GAS	Wet Limestone FGD	0	0	0	0	0	0	0	0	0	0
GAS	Other	999	0	380	0	414	0	267	62	386	1,320
		4,493	**15,026**	**2,703**	**43,400**	**3,424**	**21,009**	**856**	**42,599**	**988**	**55,657**
WOOD	No Control	139	181	554	214	191	571	716	751	501	778
WOOD	Dry FGD	0	0	0	0	0	0	0	0	0	0
WOOD	Wet Lime FGD	0	0	0	0	0	0	0	0	0	0
WOOD	Wet Limestone FGD	0	0	0	0	0	0	0	0	0	0
WOOD	Other	0	0	0	0	0	0	0	0	0	0
		139	**181**	**554**	**214**	**191**	**571**	**716**	**751**	**501**	**778**
		2,798,891	**463,909**	**2,804,622**	**518,082**	**2,018,963**	**497,563**	**1,467,070**	**462,958**	**896,117**	**445,159**

Source: EPA, 2015a

Table 2.3 Trends in SO_2 Emissions (tons/year) from EGUs in the VISTAS Region

Primary Fuel	Primary Control	2002		2005		2008		2011		2014	
		Emissions (tpy)	**Generation (10^9 BTU)**	**Emissions (tpy)**	**Generation (10^9 BTU)**	**Emissions (tpy)**	**Generation (10^9 BTU)**	**Emissions (tpy)**	**Generation (10^9 BTU)**	**Emissions (tpy)**	**Generation (10^9 BTU)**
COAL	No Control	3,147,982	453,588	3,114,055	461,624	2,032,556	328,550	786,147	122,318	477,290	66,549
COAL	Dry FGD	6,090	4,945	7,586	9,235	12,130	10,804	14,638	11,000	14,341	13,421
COAL	Wet Lime FGD	107,245	45,056	166,351	53,362	186,923	97,734	129,185	124,425	104,130	137,626
COAL	Wet Limestone FGD	235,104	109,318	207,285	116,905	256,628	189,316	213,505	253,569	196,775	238,378
COAL	Other	26,321	10,909	33,620	11,427	14,823	11,144	22,553	8,818	26,646	11,759
		3,522,743	**623,816**	**3,528,898**	**652,553**	**2,503,060**	**637,547**	**1,166,027**	**520,130**	**819,181**	**467,733**
OIL	No Control	145,925	31,700	137,052	26,328	42,461	14,258	5,516	8,879	2,633	3,582
OIL	Dry FGD	0	0	0	0	0	0	0	0	0	0
OIL	Wet Lime FGD	0	0	0	0	0	0	0	0	0	0
OIL	Wet Limestone FGD	0	0	0	0	0	0	0	0	0	0
OIL	Other	1	64	0	6	0	14	0	14	0	43
		145,926	**31,764**	**137,052**	**26,334**	**42,461**	**14,272**	**5,516**	**8,893**	**2,633**	**3,626**
GAS	No Control	44,593	91,018	59,246	119,781	20,826	149,178	3,781	251,643	3,335	307,965
GAS	Dry FGD	0	0	0	0	0	0	0	0	0	0
GAS	Wet Lime FGD	0	0	0	0	0	0	0	0	0	0
GAS	Wet Limestone FGD	0	0	0	0	0	0	0	0	0	0
GAS	Other	0	32	0	5	0	5	0	7	0	46
		44,594	**91,050**	**59,246**	**119,786**	**20,826**	**149,183**	**3,781**	**251,650**	**3,336**	**308,010**
WOOD	No Control	0	0	0	0	77	403	3,436	325	5,820	389
WOOD	Dry FGD	0	0	0	0	0	0	0	0	82	151
WOOD	Wet Lime FGD	0	0	0	0	0	0	0	0	0	0
WOOD	Wet Limestone FGD	0	0	0	0	0	0	0	0	0	0
WOOD	Other	0	0	0	0	0	0	0	0	17	649
		0	**0**	**0**	**0**	**77**	**403**	**3,436**	**325**	**5,919**	**1,189**
		3,713,263	**746,629**	**3,725,196**	**798,673**	**2,566,424**	**801,405**	**1,178,760**	**780,998**	**831,069**	**780,558**

Source: EPA, 2015a

Table 2.4 Trends in NO_x Emissions (tons/year) from EGUs in the MANE-VU Region

Primary Fuel	Primary Control	2002		2005		2008		2011		2014	
		Emissions (tpy)	Generation (10^9 BTU)	Emissions (tpy)	Generation (10^9 BTU)	Emissions (tpy)	Generation (10^9 BTU)	Emissions (tpy)	Generation (10^9 BTU)	Emissions (tpy)	Generation (10^9 BTU)
COAL	No Control	15,059	6,643	9,696	4,600	4,911	1,286	2,188	978	1,917	939
COAL	OFA	512	298	1,252	0	189	0	211	0	222	0
COAL	Comb Mod	15,689	2,942	12,605	2,265	8,931	2,420	4,876	1,410	2,854	534
COAL	Low NO_x	235,422	122,236	138,601	87,984	107,623	74,831	76,126	55,147	22,587	23,823
COAL	SNCR	54,883	20,781	67,128	32,659	54,786	27,606	35,142	16,625	19,606	9,132
COAL	SCR	65,776	40,469	90,330	76,845	102,531	82,667	74,283	67,395	101,710	74,115
COAL	Other	2,961	2,377	7,697	2,164	7,091	2,466	7,244	2,500	2,176	1,928
		390,303	**195,747**	**327,308**	**206,517**	**286,062**	**191,276**	**200,070**	**144,056**	**151,073**	**110,471**
OIL	No Control	20,392	10,231	19,761	11,631	5,397	3,512	3,496	1,395	4,434	2,550
OIL	OFA	11,359	12,017	14,346	13,620	4,195	6,358	1,352	1,952	444	554
OIL	Comb Mod	980	349	1,117	667	692	141	493	72	258	228
OIL	Low NO_x	14,234	11,468	12,574	11,940	3,672	4,651	2,076	3,821	2,538	4,411
OIL	SNCR	993	758	1,357	1,102	501	406	151	139	31	11
OIL	SCR	832	504	580	584	105	514	120	1,445	121	1,332
OIL	Other	4,286	2,627	5,892	5,261	856	833	664	664	1,012	796
		53,076	**37,955**	**55,628**	**44,804**	**15,418**	**16,415**	**8,352**	**9,489**	**8,838**	**9,881**
GAS	No Control	9,183	9,969	10,775	7,518	7,352	4,996	4,787	8,352	5,040	8,460
GAS	OFA	1,985	4,501	2,721	4,050	834	2,107	741	2,120	1,002	2,786
GAS	Comb Mod	1,403	1,086	980	907	831	891	283	274	474	263
GAS	Low NO_x	5,482	7,706	3,987	11,020	3,293	12,272	2,341	12,332	3,621	14,212
GAS	SNCR	2	0	1	0	2	0	116	276	538	366
GAS	SCR	6,354	45,429	4,913	69,465	4,761	88,365	5,810	129,292	6,167	135,909
GAS	Other	9,177	14,272	5,202	9,110	3,378	6,367	3,559	7,168	4,344	9,097
		33,586	**82,963**	**28,579**	**102,069**	**20,450**	**114,998**	**17,638**	**159,814**	**21,186**	**171,093**
WOOD	SNCR	0	0	0	0	515	692	149	332	167	349
WOOD	SCR	0	0	0	0	0	0	0	0	202	266
WOOD	Other	230	201	297	264	296	284	117	259	161	326
		230	**201**	**297**	**264**	**810**	**976**	**266**	**591**	**807**	**941**
		477,195	**316,865**	**411,812**	**353,655**	**322,740**	**323,666**	**226,327**	**313,950**	**181,904**	**292,386**

Source: EPA, 2015a

Table 2.5 Trends in NO_x Emissions (tons/year) from EGUs in the MRPO Region

Primary Fuel	Primary Control	2002		2005		2008		2011		2014	
		Emissions (tpy)	Generation (10^9 BTU)	Emissions (tpy)	Generation (10^9 BTU)	Emissions (tpy)	Generation (10^9 BTU)	Emissions (tpy)	Generation (10^9 BTU)	Emissions (tpy)	Generation (10^9 BTU)
MRPO											
COAL	No Control	254,978	80,185	75,593	31,920	46,090	20,840	21,882	11,602	12,089	5,825
COAL	OFA	149,978	46,354	72,854	27,471	75,307	28,744	34,925	21,349	6,546	4,382
COAL	Comb Mod	4,002	1,901	7,153	2,578	5,709	2,610	2,982	1,939	97	0
COAL	Low NO_x	501,333	264,896	274,250	203,233	233,119	188,340	180,163	161,181	138,523	120,527
COAL	SNCR	11,854	4,898	32,416	16,415	37,962	23,413	23,107	15,761	25,237	30,794
COAL	SCR	104,930	46,079	307,201	191,868	306,820	211,869	126,852	207,651	131,761	227,130
COAL	Other	9,740	3,341	4,198	229	2,116	0	2,338	0	3,001	0
		1,036,815	**447,654**	**773,665**	**473,713**	**707,123**	**475,816**	**392,250**	**419,483**	**317,253**	**388,658**
OIL	No Control	95	1	538	25	244	19	70	7	378	20
OIL	OFA	741	0	681	0	17	0	6	0	0	0
OIL	Comb Mod	0	0	0	0	0	0	0	0	0	0
OIL	Low NO_x	1,513	1,023	899	697	205	147	15	118	43	46
OIL	SNCR	63	0	1	0	0	0	0	0	0	0
OIL	SCR	0	0	0	0	0	0	0	0	0	0
OIL	Other	37	23	59	33	3	2	0	0	0	0
		2,448	**1,047**	**2,178**	**755**	**468**	**167**	**91**	**125**	**421**	**66**
GAS	No Control	2,135	1,924	3,492	20,960	2,190	1,801	1,707	546	1,923	834
GAS	OFA	170	205	219	135	30	16	0	0	5	0
GAS	Comb Mod	0	0	253	121	290	152	0	0	0	0
GAS	Low NO_x	3,403	7,530	1,941	7,089	1,720	4,164	1,959	6,238	1,767	6,126
GAS	SNCR	0	0	0	0	0	0	0	0	0	0
GAS	SCR	349	2,990	903	10,366	889	10,416	1,561	31,651	2,058	43,814
GAS	Other	1,631	2,378	2,995	4,729	3,209	4,459	2,940	4,165	2,570	4,883
		7,688	**15,026**	**9,804**	**43,400**	**8,328**	**21,009**	**8,168**	**42,599**	**8,323**	**55,657**
WOOD	SNCR	0	0	0	0	759	372	1,315	751	1,429	778
WOOD	Other	532	181	730	214	496	199	0	0	0	0
		532	**181**	**730**	**214**	**1,256**	**571**	**1,315**	**751**	**1,429**	**778**
		1,047,484	**463,909**	**786,377**	**518,082**	**717,175**	**497,563**	**401,824**	**462,958**	**327,426**	**445,159**

Source: EPA, 2015a

Table 2.6 Trends in NO$_x$ Emissions (tons/year) from EGUs in the VISTAS Region

Primary Fuel	Primary Control	2002		2005		2008		2011		2014	
		Emissions (tpy)	Generation (10^9 BTU)	Emissions (tpy)	Generation (10^9 BTU)	Emissions (tpy)	Generation (10^9 BTU)	Emissions (tpy)	Generation (10^9 BTU)	Emissions (tpy)	Generation (10^9 BTU)
COAL	No Control	206,027	74,111	88,672	39,548	58,630	22,811	20,486	8,602	21,905	8,808
COAL	OFA	67,409	19,581	42,925	14,102	29,665	9,107	16,747	4,544	8,392	1,925
COAL	Comb Mod	9,170	3,610	3,725	1,441	771	360	0	0	0	0
COAL	Low NO$_x$	861,782	394,564	409,563	215,660	309,081	173,303	165,960	102,160	110,156	69,744
COAL	SNCR	8,357	5,222	43,893	29,272	70,722	54,941	56,294	43,341	40,379	31,132
COAL	SCR	155,382	81,961	423,522	313,602	350,958	337,900	165,153	333,690	212,978	345,228
COAL	Other	82,085	44,768	60,270	38,927	54,025	39,125	26,059	27,794	9,823	10,896
		1,390,213	**623,816**	**1,072,570**	**652,553**	**873,852**	**637,547**	**450,700**	**520,130**	**403,634**	**467,733**
OIL	No Control	33,174	16,258	24,349	11,503	10,435	6,522	2,415	2,911	1,636	1,070
OIL	OFA	1,096	1,017	1,771	1,763	409	362	77	80	235	213
OIL	Comb Mod	4,164	1,794	4,094	1,143	2,663	1,197	2,690	1,482	23	37
OIL	Low NO$_x$	12,672	9,002	13,585	9,122	4,909	5,169	2,136	3,577	680	1,595
OIL	SNCR	0	0	0	0	0	0	0	0	0	0
OIL	SCR	0	0	0	0	0	0	0	0	0	0
OIL	Other	4,690	3,693	3,766	2,804	999	1,023	663	842	640	712
		55,795	**31,764**	**47,565**	**26,334**	**19,414**	**14,272**	**7,980**	**8,893**	**3,213**	**3,626**
GAS	No Control	14,581	9,423	9,198	4,965	5,495	4,879	7,739	4,721	5,233	5,135
GAS	OFA	599	655	756	683	2,771	1,292	1,599	1,561	77	63
GAS	Comb Mod	27	98	6	30	9	55	5	27	81	197
GAS	Low NO$_x$	29,219	44,495	27,973	48,994	16,030	41,598	10,564	48,485	8,356	44,974
GAS	SNCR	0	0	0	0	0	0	0	0	0	0
GAS	SCR	3,053	28,554	5,372	57,141	6,030	91,355	8,827	183,987	12,026	245,419
GAS	Other	4,696	7,826	4,984	7,972	5,786	10,004	6,303	12,870	6,257	12,223
		52,175	**91,050**	**48,290**	**119,786**	**36,120**	**149,183**	**35,036**	**251,650**	**32,030**	**308,010**
WOOD	No Control	0	0	0	0	574	403	947	325	755	389
WOOD	OFA	0	0	306	0	0	0	1,592	0	1,655	0
WOOD	SCR	0	0	0	0	0	0	0	0	465	800
		0	**0**	**306**	**0**	**574**	**403**	**2,539**	**325**	**3,521**	**1,189**
		1,498,183	**746,629**	**1,168,731**	**798,673**	**929,961**	**801,405**	**496,254**	**780,998**	**442,399**	**780,558**

Source: EPA, 2015a

FACTOR 1 – COST OF COMPLIANCE

Air pollution control technologies for EGUs have advanced substantially over the last several decades. As described in the previous section, state and federal clean air rules to address acid rain and ground-level smog led to power plant owners successfully deploying a range of advanced pollution control systems at hundreds of facilities across the country, providing valuable experience with the installation and operation of these technologies. This has provided regulators and industry with a working knowledge of a suite of cost-effective air pollution control options.

Pollutant emission controls are generally divided into three major types, as follows:

- Pre-combustion controls, in which fuel substitutions are made or fuel pre-processing is performed to reduce pollutant formation in the combustion unit.
- Combustion controls, in which operating and equipment modifications are made to reduce the amount of pollutants formed during the combustion process; or in which a material is introduced into the combustion unit along with the fuel to capture the pollutants formed before the combustion gases exit the unit.
- Post-combustion controls, in which one or more air pollution control devices are used at a point downstream of the furnace combustion zone to remove the pollutants from the post-combustion gases.

The following sections provide a brief summary of SO_2 and NO_x control options and costs, drawing heavily on recent work sponsored by EPA and regional planning organizations. More detailed descriptions of the options can be found in the literature cited in the list of references.

Identification of Available SO_2 Control Options

SO_2 is an undesirable by-product of the combustion of sulfur-bearing fossil fuels. Coal deposits contain sulfur in amounts ranging from trace quantities to as high as 8% or more. Untreated distillate oils typically have sulfur contents less than 0.5% while residual oil can have 1-2% sulfur by weight. Pipeline quality natural gas contains virtually no sulfur. Essentially all of the sulfur in the fuel is oxidized to form SO_2 (a very small percentage is further oxidized to SO_3 depending on fuel and boiler characteristics).

Since the relationship between sulfur content in the fuel and SO_2 emissions is essentially linear, the emission reduction benefits of fuel switching (for example from higher- to lower-sulfur coal, or from coal/oil to natural gas) are directly proportional to the difference in sulfur contents of fuels. Therefore, changing fuels is the principal means of reducing sulfur emissions without adding flue gas treatment methods. Major issues associated with fuel substitution include price, availability, transportation, and suitability of the boiler or plant to accommodate the new fuel.

Over the past decade, some EGUs have reduced the amount of SO_2 created through changes in fuel; however, in many cases such changes may be uneconomical or impractical. For this reason, gas treatment methods that capture the SO_2 that is formed from these industrial sources may be the most effective form of controlling SO_2 emissions. Post-combustion controls reduce SO_2 emissions by reacting the SO_2 in the flue gas with a reagent (usually calcium- or sodium-based) and removing the resulting product (a sulfate/sulfite) for disposal or commercial use, depending on the technology used. Post-combustion SO_2 reduction technologies are commonly referred to as Flue Gas Desulfurization (FGD) or SO_2 "scrubbers", broadly grouped into wet FGD, dry FGD, and dry sorbent injection (DSI) technologies.

A summary of available SO_2 control technology options are shown in Table 2.7. The method of SO_2 control appropriate for any individual EGU is dependent upon the type of boiler, type of fuel, capacity utilization, and the types and staging of other air pollution control devices. However, cost effective emissions reduction technologies for SO_2 are available and have proven effective in reducing emissions from the exhaust gas stream of EGU boilers.

Table 2.7 SO_2 Control Options for Coal-fired EGU Boilers

Technology	Description	Applicability	Performance
Switch to Low Sulfur Coal (generally <1% Sulfur)	Replace high sulfur bituminous coal with lower sulfur coal	Potential control measure for all coal-fired EGUs using coal with a high sulfur content	50-80% reduction in SO_2 emissions
Switch to natural gas (virtually 0% sulfur)	Replace coal combustion with natural gas	Potential control measure for all coal-fired EGUs	Virtually eliminate SO_2 emissions by switching to natural gas
Coal Cleaning	Coal is washed to remove some of the sulfur and ash prior to combustion	Potential control measure for all coal-fired EGUs	20-25% reduction in SO_2 emissions
Flue Gas Desulfurization (FGD) - Wet	SO_2 is removed from flue gas by dissolving it in a lime or limestone slurry. (Other alkaline chemicals are sometimes used)	Applicable to all coal-fired EGUs	30-95%+ reduction in SO_2 emissions
Flue Gas Desulfurization (FGD) – Spray Dry	A fine mist containing lime or other suitable sorbent is injected directly into flue gas	Applicable primarily for boilers currently firing low to medium sulfur fuels	60-95%+ reduction in SO_2 emissions
Flue Gas Desulfurization (FGD) –Dry Sorbent Injection	Powdered lime or other suitable sorbent is injected directly into flue gas	Applicable primarily for boilers currently firing low to medium sulfur fuels	40-60% reduction in SO_2 emissions

Table references: MACTEC, 2007; STAPPA-ALAPCO, 2006; NESCAUM, 2011; EPA, 2013.

Cost of Compliance – SO_2 Control Options

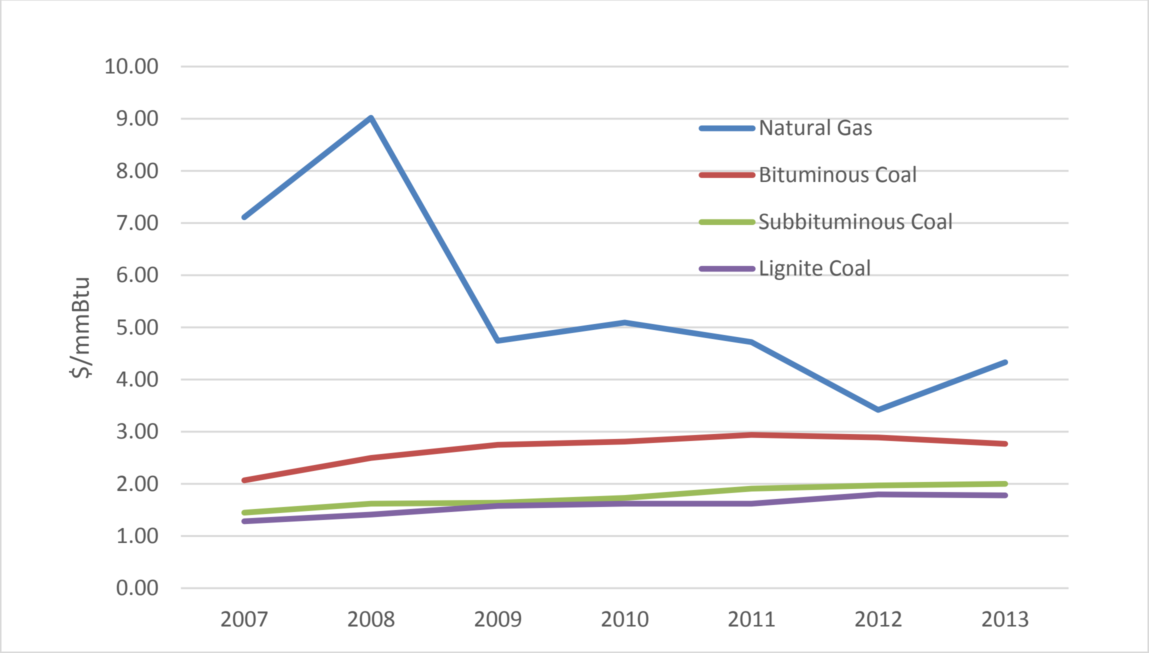
To compare the various control options, information has been compiled on the cost-effectiveness of fuel switching and retrofitting controls. In general, cost-effectiveness increases as boiler size and capacity factor (a measure of boiler utilization) increases.

Cost of Switching from Coal to Natural Gas

In many cases, switching to lower sulfur fuels is one of the most straightforward and technologically feasible strategies for reducing emissions, but it is not a trivial undertaking (NACAA, 2015). For any existing EGU, there are reasons the current fuels are used and other fuels are not used. Similarly, there are reasons the primary fuel is primary and the backup fuels are backups. These decisions are influenced by many different factors, such as delivered fuel costs, fuel handling system design, boiler design, availability of natural gas pipeline capacity, and so forth. Switching fuels will be most feasible from a technological perspective where a boiler is already designed to combust more than one type of fuel.

The original Four Factors Analysis (MACTEC, 2007) found that coal to natural gas conversion was uneconomical at the time due to the fuel price disparity between the two fuels. The price of natural gas was approximately four times higher than coal according to average monthly costs of fuel delivered to electricity producers (January 2007 data from EIA). Therefore there was no additional cost analysis in the report. The price of natural gas has decreased considerably since then, conversion to natural gas is viable economically, and a large number of coal-fired EGUs have converted or are in the process of converting. Information collected by EPA through October 2014 indicates that 70 coal fired units with a capacity of 12,400 MWs will have converted to natural gas between 2011 through 2015 (EPA, 2015a).

Figure 2.1 U.S. Delivered Coal and Natural Gas Prices for Electric Generation Average Cost by Fuel $/MMBTU



Source: Table 7.4; EIA, 2015.

EPA developed conversion cost and performance assumptions for use with the IPM® model (EPA, 2013). Capital cost components include the costs of boiler modifications and the cost of extending natural gas lateral pipeline spurs to a natural gas main pipeline. Operating and maintenance costs, fixed and variable, are less after the conversion due to lower costs of operating a gas boiler versus a coal boiler (e.g., fewer maintenance materials and less waste disposal). There is a heat rate penalty due to lower stack temperature and higher moisture loss.

Table 2.8 IPM v5.13 Cost and Performance Assumptions for Coal to Gas Conversions

Factor	Assumption	Description
Heat Rate Penalty	+5%	Lower stack temperature and higher moisture loss reduces efficiency
Incremental Capital Cost	PC Unit: \$/kW = 267*(75/MW)^0.35 Cyclone Unit: : \$/kW = 374*(75/MW)^0.35	New gas burners, piping, air heater upgrade, gas recirculating fans, and control system modifications.
Incremental Fixed O&M	-33% of the FOM cost of the existing coal unit	Reduced need for maintenance materials and labor.
Incremental Variable O&M	-25% of the VOM cost of the existing coal unit	Reduced waste disposal and other miscellaneous costs.

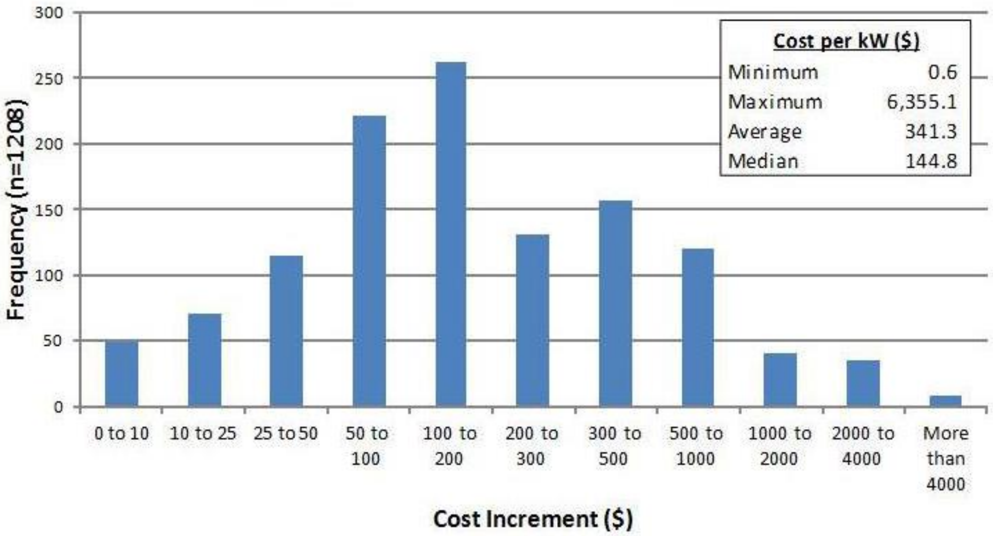
Table reference: Table 5-21, EPA, 2013.

EPA also developed estimates of the cost of extending pipeline laterals from each coal-fired boiler to the interstate national gas pipeline system. Their analysis included a number of factors including:

- Mainline pipeline flow capacity
- Required lateral capacity based on heat rate and boiler capacity
- Diameter of each lateral (calculated using the Weymouth equation)
- Cost per lateral ($90,000 per inch-mile based on recently completed projects)

Based on data for 1,208 coal-fired units EPA calculated an average cost per boiler of $341/kW of capacity. The distribution of lateral costs is shown in Figure 2.2.

Figure 2.2 Lateral Pipeline Costs per kW of Boiler Capacity



Source: Figure 5-7; EPA, 2013.

Cost of Switching from High to Low Sulfur Coal

Switching to a low-sulfur coal or blending a lower sulfur coal can impact cost due to the following main reasons:

- The cost of low-sulfur coal compared to higher sulfur coal
- The cost of transporting low-sulfur coal from the west to the east
- The cost of necessary boiler or coal handling equipment modifications
- The lower heating value of most low-sulfur coal requires more coal to be consumed to produce an equivalent amount of electricity.

Recent data from the Energy Information Administration show the average price of coals from various locations together with estimated heating values and sulfur content. The prices of coal indicated in Tables 2.4 and 2.5 do not include the cost of delivery.

The sulfur content, heating values and prices of coals mined in various regions of the country vary considerably (See Table 2.9). Central Appalachian coals, which are lower in sulfur than Illinois Basin or Northern Appalachian coals, generally have high heating value and are more accessible than low-sulfur western coal.

Table 2.9 Average Weekly Coal Commodity Spot Priced ($2014 per ton)

Week Ended	Central Appalachia 12,500 BTU, 1.2 lbs SO_2 / MMBTU	Northern Appalachia 13,000 BTU, <3.0 lbs SO_2 / MMBTU	Illinois Basin 11,800 BTU, 5.0 lbs SO_2 / MMBTU	Powder River Basin 8,800 BTU, 0.8 lbs SO_2 / MMBTU	Uinta Basin 11,700 BTU, 0.8 lbs SO_2 / MMBTU
23-Oct-15	$49.00	$52.00	$32.75	$11.55	$40.55
30-Oct-15	$49.00	$52.00	$32.75	$11.55	$40.55
6-Nov-15	$49.00	$52.00	$32.75	$11.55	$40.55
13-Nov-15	$43.50	$48.95	$32.60	$11.55	$40.65
20-Nov-15	$43.50	$48.95	$32.60	$11.55	$40.65

Source: http://www.eia.gov/coal/news_markets/

Note: The historical data file of spot prices is proprietary and cannot be released by EIA

Powder River Basin coal has a significantly lower heating value than the other four varieties of coal, but on an energy basis, it is still approximately one third the cost of the other coals listed. Since Powder River Basin coal contains significantly less sulfur, it would seem that this coal would be the best fuel for boilers trying to incorporate a lower sulfur coal. Unfortunately, due to the lower heating value of the coal, boilers that are configured to burn coal with a higher heating value can only use a small percentage of this low-sulfur coal (no higher than 15% Powder River Basin coal). The only way to burn higher percentages of the Powder River Basin coal would be to extensively retrofit the boilers or suffer from poor boiler performance and other operating difficulties (MACTEC, 2007). Such retrofits should be reviewed in light of current Prevention of Significant Deterioration (PSD) permitting regulations to ensure that all such requirements are met and that emissions do not increase. The coal prices included in Table 2.9 do not reflect the cost of boiler retrofits required to combust low sulfur coal.

Once coal is mined, it must be transported to where it will be consumed. Transportation costs add to the delivered price of coal. In some cases, like in long-distance shipments of Powder River Basin coal to power plants in the East, transportation costs can be more than the price of coal at the mine. Most coal is transported by train, barge, truck, or a combination of these modes. All of these transportation modes use diesel fuel. Increases in oil prices can significantly affect the cost of transportation and thereby affect the final delivered price of coal. In 2013, the average sales price of coal at the mine was \$37.24 per ton, and the average delivered price to the electric power sector was \$45.21 per ton, resulting in an average transportation cost of \$7.97 per ton, or 18% of the total delivered price (EIA, .

Cost of Coal Cleaning

Coal cleaning may be an economically viable approach for reducing coal sulfur compared to the purchase of lower sulfur coals from western states (Staudt, 2012). Sulfur may be removed from the coal through cleaning measures that remove rock and pyrite (including pyritic sulfur). Most coals experience some form of cleaning prior to shipment in order to remove impurities and increase the heating value of the delivered coal. To the extent that sulfur may be in these impurities, such as in pyrites, sulfur can be removed as well; however, some sulfur is organically bound to the coal and cannot be removed, at least through physical separation. Physical cleaning measures rely on the difference in density between the impurities and the coal. Chemical cleaning measures chemically remove impurities.

Up to 60% sulfur (on a heating value basis) is removed through physical cleaning methods from uncleaned coal depending upon the coal and the practice used (Staudt, 2012). However, 60% represents the best potential technology while common commercial practice reduces coal sulfur by about 40%. Higher sulfur reductions are possible if chemical cleaning methods are considered. Current data was unavailable for the cost of coal cleaning. However, because it has been used in practice, it is certainly an approach that is available and feasible, and is likely to be economically viable for many industrial facilities.

Cost of Post-Combustion Gas Treatment Technologies

While many EGUs can accommodate fuel changes to reduce the amount of SO_2 emitted, such changes may be uneconomical or impractical for other units. For this reason, gas treatment methods that capture and control the SO_2 that is formed may be the most effective form of control. Post-combustion SO_2 control is accomplished by reacting the SO_2 in the gas with a reagent (usually calcium- or sodium-based) and removing the resulting product (a sulfate/sulfite) for disposal or commercial use depending on the technology used. More detailed descriptions of these technologies can be found in recent literature (NESCAUM, 2011; EPA, 2013.)

The estimates previously used in the 2007 Assessment (MACTEC, 2007) were not used in this analysis because the EPA publications that served as the basis for those cost estimates are dated, and more recent cost factors are available. Instead, cost models developed by the engineering firm Sargent and Lundy LLC (S&L) were used to update SO_2 post-combustion control cost. Under a contract with EPA, SRA issued a subcontract to S&L to update and add to the retrofit emission control models previously developed for EPA and used in the Integrated Planning

Model (IPM®). The detailed reports and example calculation worksheets for S&L retrofit emission control models used by EPA are available in Attachments 5-1 through 5-7 of the IPM documentation for EPA Base Case v5.13 (EPA, 2013). Sargent & Lundy relied on several published sources for their cost models, which were significantly augmented by the S&L in-house database of recent FGD projects.

The two critical factors common across most all of the control device cost estimates are the volume of air treated (unit size) and the amount of pollutant to be removed. The exception is the Dry Sorbent Injection control for SO_2 where the prime cost is for the sorbent, and therefore unit size is not as important as the amount of pollutant removed. The S&L models also include a retrofit factor that can be changed based on the size of the site. Retrofits at smaller older plants can be more expensive on plant sites that have little room for the control equipment. Applicability, performance and cost factors for each control device are discussed briefly below.

- Limestone Forced Oxidation (LSFO): Typically not used on applications smaller than 100 MW. SO_2 emission control above 95%. The lowest manufacturer SO_2 emission guarantee is 0.04 lb/MMBTU. Base capital cost estimates include minor physical and chemical wastewater treatment.
- Lime Spray Dryer (LSD): This device is also called a Spray Dryer Absorber (SDA). Typically not used on applications smaller than 50 MW, and limited to coals with sulfur content less than 3.0 lbs SO_2/MMBTU. Can meet 95% SO_2 mission control. The lowest manufacturer emission guarantee is 0. 06 lb/MMBTU.
- Dry Sorbent Injection (DSI): Should not be used when coal sulfur content is greater than 2.0 lbs/MMBTU. SO_2 emission control dependent on the downstream particulate control device and amount of sorbent injected (Normalized Stoichiometric Ratio). Trona injection followed by an electrostatic precipitator can achieve 40 to 50% SO_2 reduction, and 70 to 75% reduction when injection is followed by a fabric filter. Cost estimates do not include particulate control device costs.

Tables 2.10 to 2.12 show SO_2 add-on control cost estimates for a number of boiler and control scenarios from the IPM documentation. These examples were used to calculate a cost effectiveness in $/ton using the same methodology as in the *2007 Assessment* which used a capital recovery factor of 0.15 and capacity factor of 0.85. The IPM documentation did not provide SO_2 control cost estimates for DSI. Table 2.13 provides a cost effectiveness estimate for DSI based on a 500 MW example from the S&L report.

Table 2.10 Examples of SO_2 Add-On Control Costs from EPA Base Case v5.13 (2011$)

FGD Type	**Heat Rate (BTU/kWh)**	**Capacity Penalty (%)**	**Heat Rate Penalty (%)**	**Variable O&M ($/MWh)**	**Capacity (MW)**									
					100		**300**		**500**		**700**		**1000**	
					Capital Cost ($/kW)	**Fixed O&M ($/kW-yr)**	**Capital Cost ($/kW)**	**Fixed O&M ($/kW-yr)**	**Capital Cost ($/kW)**	**Fixed O&M ($/kW-yr)**	**Capital Cost ($/kW)**	**Fixed O&M ($/kW-yr)**	**Capital Cost ($/kW)**	**Fixed O&M ($/kW-yr)**
LSFO	9,000	-1.5	1.53	2.203	819	23.7	600	11.2	519	8.3	471	7.7	426	6.4
	10,000	-1.67	1.7	2.26	860	24.2	629	11.5	544	8.6	495	8	447	6.6
	11,000	-1.84	1.87	2.49	899	24.6	658	11.8	569	8.9	517	8.2	467	6.8
LSD	9,000	-1.18	1.2	2.51	701	17.3	513	8.6	444	6.5	422	5.7	422	5.3
	10,000	-1.32	1.33	2.79	734	17.7	538	8.9	465	6.8	442	5.9	442	5.5
	11,000	-1.45	1.47	3.07	766	18	561	9.1	485	7	461	6.1	461	5.7

Notes:

1. The LSFO estimates are based on 3.0 lbs SO_2/MMBTU coal, and 96% removal. LSD estimates are based on 2.0 lbs SO_2/MMBTU coal and 92% removal.
2. The capacity penalty and heat rate penalty are not used in calculating cost effectiveness in $/ton removed. The penalties represent the electricity demand of the FGD. The capacity penalty equals the percent of unit generation required for the control device. The heat rate penalty is based on the capacity penalty and is a modeling procedure to capture the effect of the control device on fuel use and generation. It does not represent an actual increase in the unit heat rate.
3. Table Reference: Table 5-3, Documentation for EPA Base Case v.5.13 Using the Integrated Planning Model. U.S. EPA #450R13002, November 2013.

Table 2.11 SO_2 LSFO Control Cost Effectiveness for EPA Base Case v5.13 Examples (2011$)

FGD Type	Capacity (MW)	Heat Rate (BTU/kWh)	Assumed Capital Recovery Factor	Assumed Capacity Factor	Assumed Coal Sulfur lb/MMBTU	Assumed Percent Reduction	Total Annual Cost ($/kW-yr)	SO_2 Reduction (tons/kW-yr)	2011$/ton Reduction
LSFO	100	9,000	0.15	0.85	3	96%	163.0	0.097	1,689
LSFO	100	10,000	0.15	0.85	3	96%	170.0	0.107	1,586
LSFO	100	11,000	0.15	0.85	3	96%	178.0	0.118	1,509
LSFO	300	9,000	0.15	0.85	3	96%	117.6	0.097	1,219
LSFO	300	10,000	0.15	0.85	3	96%	122.7	0.107	1,144
LSFO	300	11,000	0.15	0.85	3	96%	129.0	0.118	1,094
LSFO	500	9,000	0.15	0.85	3	96%	102.6	0.097	1,063
LSFO	500	10,000	0.15	0.85	3	96%	107.0	0.107	998
LSFO	500	11,000	0.15	0.85	3	96%	112.8	0.118	956
LSFO	700	9,000	0.15	0.85	3	96%	94.8	0.097	982
LSFO	700	10,000	0.15	0.85	3	96%	99.1	0.107	924
LSFO	700	11,000	0.15	0.85	3	96%	104.3	0.118	884
LSFO	1000	9,000	0.15	0.85	3	96%	86.7	0.097	898
LSFO	1000	10,000	0.15	0.85	3	96%	90.5	0.107	844
LSFO	1000	11,000	0.15	0.85	3	96%	95.4	0.118	809

Notes:

The cost effectiveness calculation methodology, capital recovery factor, and capacity factor are the same as used in the *2007 Assessment* (MACTEC, 2007)

Table 2.12 SO_2 LSD Control Cost Effectiveness for EPA Base Case v5.13 Examples (2011$)

FGD Type	Capacity (MW)	Heat Rate (BTU/kWh)	Assumed Capital Recovery Factor	Assumed Capacity Factor	Assumed Coal Sulfur lb/MMBTU	Assumed Percent Reduction	Total Annual Cost ($/kW-yr)	SO_2 Reduction (tons/kW-yr)	2011$/ton Reduction
LSD	100	9,000	0.15	0.85	2	92%	141.1	0.062	2,289
LSD	100	10,000	0.15	0.85	2	92%	148.6	0.069	2,169
LSD	100	11,000	0.15	0.85	2	92%	155.8	0.075	2,067
LSD	300	9,000	0.15	0.85	2	92%	104.2	0.062	1,691
LSD	300	10,000	0.15	0.85	2	92%	110.4	0.069	1,611
LSD	300	11,000	0.15	0.85	2	92%	116.1	0.075	1,541
LSD	500	9,000	0.15	0.85	2	92%	91.8	0.062	1,489
LSD	500	10,000	0.15	0.85	2	92%	97.3	0.069	1,421
LSD	500	11,000	0.15	0.85	2	92%	102.6	0.075	1,362
LSD	700	9,000	0.15	0.85	2	92%	87.7	0.062	1,422
LSD	700	10,000	0.15	0.85	2	92%	93.0	0.069	1,357
LSD	700	11,000	0.15	0.85	2	92%	98.1	0.075	1,302
LSD	1000	9,000	0.15	0.85	2	92%	87.3	0.062	1,416
LSD	1000	10,000	0.15	0.85	2	92%	92.6	0.069	1,351
LSD	1000	11,000	0.15	0.85	2	92%	97.7	0.075	1,297

Notes:

The cost effectiveness calculation methodology, capital recovery factor, and capacity factor are the same as used in the 2*007 Assessment* (MACTEC, 2007).

Table 2.13 SO_2 DSI Control Costs and Cost Effectiveness Based on Sargent and Lundy Model Example ($2012)

FGD Type	Capacity (MW)	Heat Rate (BTU/kWh)	Variable O&M ($/MWh)	Capital Cost ($/kW)	Fixed O&M ($/kW-yr)	Assumed Capital Recovery Factor	Assumed Capacity Factor	Assumed Coal Sulfur lb/MMBTU	Assumed Percent Reduction	Total Annual Cost ($/kW-yr)	SO_2 Reduction (tons/kW-yr)	2012$/ton Reduction
DSI	500	9,500	9.18	44	0.89	0.15	0.85	2	50%	75.8	0.035	2,144

Notes:

1. The DSI generation based cost estimates assume 2.0 lbs SO_2/MMBTU coal and 50% removal. Downstream particulate control by an Electrostatic Precipitator.
2. The cost effectiveness calculation methodology, capital recovery factor, and capacity factor are the same as used in the *2007 Assessment* (MACTEC, 2007).
3. Table Reference: Attachment 5-3 of the IPM documentation for EPA Base Case v5.13

Identification of NO_x Control Options

The formation of NO_x is a byproduct of the combustion of fossil fuels. Most of the NO_x formed during the combustion process is the result of two oxidation mechanisms: (1) reaction of nitrogen in the combustion air with excess oxygen at elevated temperatures, referred to as thermal NO_x; and (2) oxidation of nitrogen that is chemically bound in the fuel, referred to as fuel NO_x. The degree to which this formation evolves depends on many factors including both the combustion process itself and the properties of the particular fuel being burned. This is why similar boilers firing different fuels or similar fuels burned in different boilers can yield different NO_x emissions.

A variety of approaches to minimize or reduce NO_x emissions into the atmosphere have been and continue to be developed (NESCAUM, 2011). A relatively simple way of understanding the many technologies available for NO_x emission control is to divide them into two major categories: (1) those that minimize the formation of NO_x itself during the combustion process (e.g., smaller quantities of NO_x are formed during combustion); and (2) those that reduce the amount of NO_x after it is formed during combustion, but prior to exiting the stack into the atmosphere. It is common to refer to the first approach as combustion modifications, whereas technologies in the second category are termed post-combustion controls. Combinations of some of these technologies are not only possible, but also often desirable as they may produce more effective NO_x control than the application of a stand-alone technology.

A summary of available NO_x control technology options is shown in Table 2.14. Combustion modifications can vary from simple "tuning" or optimization efforts to the deployment of dedicated technologies such as Low NO_x Burners (LNB), Overfire Air (OFA) or Flue Gas Recirculation~~s~~ (FGR). Conventional, commercial post-combustion NO_x controls include Selective Non-Catalytic Reduction (SNCR) and Selective Catalytic Reduction (SCR). They are fundamentally similar, in that they use an ammonia-containing reagent to react with the NO_x produced in the boiler to convert the NO_x to harmless nitrogen and water. SNCR accomplishes this at higher temperatures (1700ºF-2000ºF) in the upper furnace region of the boiler, while SCR operates at lower temperatures (about 700ºF) and hence, needs a catalyst to produce the desired reaction between ammonia and NO_x.

Table 2.14 NO_x Control Options for Coal-fired EGU Boilers

Technology	Description	Applicability	Performance
Switch to natural gas	Replace coal combustion with natural gas. Natural gas contains low fuel-bound nitrogen content and requires lower excess air for combustion than coal, resulting in lower uncontrolled NO_x emissions.	Potential control measure for all coal-fired EGUs	50 to 80% reduction in NO_x emissions. Will still require NO_x combustion and or post-combustion controls.
Combustion Controls	Modifications to the boiler furnace burners and combustion air systems to lower flame temperatures and oxygen concentrations to reduce thermal NO_x formation.	Potential control measure for most types of coal-fired EGU boilers. Dependent on boiler and coal type.	10 to 60% reduction in NO_x emissions.

Technology	Description	Applicability	Performance
Selective Noncatalytic Reduction (SNCR)	Ammonia or urea reagent is injected into the flue gas stream and reduces NO_x in to N_2 and H_2O without a catalyst.	Potential control measure for all coal-fired EGUs. Costs per ton of NO_x controlled for retrofitting a plant smaller than 100 MW increase rapidly due to the lack of economy of size. Also, older power plants in the 50 MW range tend to have compact plant sites with limited room for retrofit equipment.	25% reduction in NO_x emissions from pulverized coal boilers. 50% reduction from fluidized bed boilers.
Selective Catalytic Reduction (SCR)	Ammonia vapor injected into the flue gas stream upstream of a catalyst that assists the reduction reaction of NO_x to nitrogen gas (N_2) and water (H_2O)	Potential control measure for all coal-fired EGUs (≥ 25MW). Costs per ton of NO_x reduced for retrofitting a plant smaller than 100 MW increase rapidly due to the lack of economy of size.	90% reduction in NO_x emissions
Return Partially Operating SCR and SNCR Systems to Full Operation	Depressed NO_x allowance costs have resulted in some units to be able to comply by purchasing allowances rather than running existing emission control systems	Potential control measures for units that do not continuously run existing emission control systems	Highly variable based on fluctuations in allowance costs

Table references: NESCAUM, 2011; EPA, 2013; EPA, 2015b; EPA, 2015c; EPA, 2015d.

Cost of Compliance – NO_x Control Options

Cost of Combustion Controls

Information on NO_x combustion control costs emission reduction rates and for coal-fired EGUs are also available in the EPA's IPM v5.13 documentation (EPA 2013). Control cost and performance vary by boiler and coal types. Table 2.15 shows the NO_x combustion control costs used in IPM v5.13. The costs shown are for a 300 MW coal-fired boiler of different common types. EPA uses scaling factors to estimate the capital and fixed O&M costs of combustion controls for boilers smaller and larger than 300 MW. Variable O&M costs were assumed constant.

Table 2.16 shows the range of NO_x emission rates for boilers with combustion controls by boiler and coal types used by the model. The low rate in the range is the floor rate for reduction, and the high rate is a cut-off rate that indicates the use of combustion controls. Table 2.17 shows the fractional reduction for different combustion control configurations when adding new combustion controls.

Table 2.15 NO_x Combustion Control Cost Factors for Coal Fired Boilers (2011$)

Boiler Type	Technology	Capital Costs ($/kW)	Fixed O&M ($/kW-yr)	Variable O&M ($/MWh)
Dry Bottom Wall-fired	Low NO_x Burner without Overfire Air (LNB without OFA)	48	0.3	0.07
	Low NO_x Burner with Overfire Air (LNB with OFA)	65	0.5	0.09
Tangentially-fired	Low NO_x Coal-and-Air Nozzles with Close-Coupled Overfire Air (LNC1)	26	0.2	0
	Low NO_x Coal-and-Air Nozzles with Separated Overfire Air (LNC2)	35	0.2	0.03
	Low NO_x Coal-and-Air Nozzles with Close-Coupled and Separated Overfire Air (LNC3)	41	0.3	0.03
Vertically-Fired	NO_x Combustion Control	31	0.2	0.06
Scaling Factors: • LNB without OFA and LNB with OFA = ($/kW for 300 MW Unit) x $(300/X)^{0.359}$ • LNC1, LNC2, and LNC3 = ($/kW for 300 MW Unit) x $(300/X)^{0.359}$ • Vertically –Fired ($/kW for 300 MW Unit) x $(300/X)^{0.553}$ Where ($kW for 300 MW Unit) is from the above Capital Costs or Fixed O&M Costs, and X is the capacity in MW of the unit.				

Table Reference: EPA, 2013

Table 2.16 Range of NO_x Emission Rates for Coal-fired EGUs with Combustion Controls

Boiler Type	NO_x Rate lb/MMBTU		
	Bituminous	Subbituminous	Lignite
Dry Bottom Wall-fired	0.43-0.32	0.33-0.18	0.29-0.18
Tangentially-fired	0.34-0.24	0.24-0.12	0.22-0.17
Cell Burners	0.43-0.32	0.24-0.12	0.22-0.17
Cyclones	0.62-0.47	0.67-0.49	0.67-0.49
Vertically-Fired	0.57-0.49	0.44-0.25	0.44-0.25

Table Reference: EPA, 2013

Table 2.17 Fractional NO_x Reduction for Different Combustion Control Configurations

Boiler Type	Coal Type	Combustion Control	Fraction of Removal	Default Removal
Dry Bottom Wall-fired	Bituminous	LNB	0.163 + 0.272*Base NO_x	0.568
		LNB and OFA	0.313 + 0.272*Base NO_x	0.718
	Subbituminous/Lignite	LNB	0.135 + 541*Base NO_x	0.574
		LNB and OFA	0.285 + 541*Base NO_x	0.724
Tangentially-fired	Bituminous	LNC1	0.162 + 336*Base NO_x	0.42
		LNC2	0.212 + 336*Base NO_x	0.47
		LNC3	0.362 + 336*Base NO_x	0.62
	Subbituminous/Lignite	LNC1	0.20 + 717*Base NO_x	0.563
		LNC2	0.25 + 717*Base NO_x	0.613
		LNC3	0.35 + 717*Base NO_x	0.713

Table Reference: EPA, 2013

Most operating coal-fired EGUs already have NO_x combustion controls. Only about 10% of the EGUs in the current version of the IPM modeling inventory (National Electric Energy Data System v5.15) show no combustion controls or add-on controls. Of these only 20 have a capacity greater than 25 MW (EPA, 2013). Table 2.18 provides an example cost effectiveness for combustion control installations on four of the uncontrolled EGUs from the modeling inventory.

Cost of Post-Combustion Gas Treatment Technologies

Cost models developed by S&L were used to update NO_x post-combustion control costs (EPA, 2013). S&L updated and added to the retrofit emission control models previously developed for EPA and used in earlier versions of the IPM.

- Selective Catalytic Reduction (SCR): Removal efficiency is affected by the type of coal and costs for SCR catalyst, reagent and steam. SCR can achieve NO_x rate floor of 0.07 lbs NO_x/MMBTU for bituminous coal and 0.05 lbs NO_x /MMBTU for subbituminous and lignite. The fuel type (sulfur content) also affects the air pre-heater costs if ammonium bisulfate or sulfuric acid deposition poses a problem (coal sulfur content greater than 3.0 lbs SO_2/MMBTU).
- Selective Non-Catalytic Reduction (SNCR): NO_x removal efficiencies range from 25 to 50% based on boiler type. Like SCRs, the fuel type affects cost with air preheater modifications required for coals with sulfur content greater than 3.0 lbs SO_2/MMBTU.

Tables 2.19 to 2.22 show NO_x add-on control cost estimates for coal plants for a number of boiler and control scenarios from the IPM documentation. These examples were used to calculate a cost effectiveness in $/ton using the same methodology as in the *2007 Assessment* (MACTEC, 2007) which used a capital recovery factor of 0.15 and capacity factor of 0.85.

Table 2.18 Combustion Control Cost Effectiveness Examples for Uncontrolled EGUs in EPA Base Case v5.13 (2011$)

NOx Control Type	Boiler Type	Coal Type	Capacity MW	Heat Rate BTU/kWh	Variable O&M $/MWh	Capital Cost $/kW	Assumed NO_x Rate lb/MMBTU	Assumed Percent Reduction	Total Annual Cost $/kW-yr	NO_x Reduction tons/kW-yr	2011$/ton Reduction
LNC2	Tangential	Bituminous	40	12,000	0.03	72	0.465	47%	11.4	0.010	1,170
LNC1	Tangential	Subbituminous	77	10,900	0.03	42	0.332	58%	6.8	0.008	873
LNC1	Tangential	Subbituminous	138	10,800	0.03	34	0.321	58%	5.6	0.007	751
LNB	Wall Dry	Subbituminous	36	9,900	0.03	103	0.535	57%	16.3	0.011	1,448

Notes:

The cost effectiveness calculation methodology, capital recovery factor (0.15), and capacity factor (0.85) are the same as used in the 2*007 Assessment* (MACTEC, 2013).

Table 2.19 Examples of NO_x Add-On Control Costs for Coal Plants from EPA Base Case v5.13

Scrubber Type	Heat Rate (BTU/kWh)	Capacity Penalty (%)	Heat Rate Penalty (%)	Variable O&M ($/MWh)	Capacity (MW)									
					100		300		500		700		1000	
					Capital Cost ($/kW)	Fixed O&M ($/kW-yr)	Capital Cost ($/kW)	Fixed O&M ($/kW-yr)	Capital Cost ($/kW)	Fixed O&M ($/kW-yr)	Capital Cost ($/kW)	Fixed O&M ($/kW-yr)	Capital Cost ($/kW)	Fixed O&M ($/kW-yr)
SCR	9,000	-0.54	0.54	1.23	321	1.76	263	0.76	243	0.64	232	0.58	222	0.53
	10,000	-0.56	0.56	1.32	349	1.86	287	0.81	266	0.69	255	0.63	244	0.57
	11,000	-0.58	0.59	1.41	377	1.96	311	0.87	289	0.73	277	0.67	265	0.62
SNCR Tangential	9,000	-0.05	0.78	1.04	55	0.48	30	0.26	22	0.2	18	0.16	15	0.13
	10,000	-0.05	0.78	1.15	56	0.5	30	0.27	23	0.2	19	0.17	15	0.14
	11,000	-0.05	0.78	1.27	57	0.51	31	0.27	23	0.21	19	0.17	16	0.14
SNCR Fluidized Bed	9,000	-0.05	0.78	1.04	41	0.36	22	0.2	17	0.15	14	0.12	11	0.1
	10,000	-0.05	0.78	1.15	42	0.37	23	0.2	17	0.15	14	0.12	12	0.1
	11,000	-0.05	0.78	1.27	43	0.38	23	0.21	17	0.15	14	0.13	12	0.1

Notes:

1. The estimates are based on a boiler burning bituminous coal with NO_x inlet rate of 0.5 lb NO_x/MMBTU.
2. The SCR removal efficiency is assumed to be 90%. SNCR removal efficiency for tangential fired unit is assumed to be 25%, and 50% for a fluidized bed unit.
3. The capacity penalty and heat rate penalty are not used in calculating cost effectiveness in $/ton removed. The penalties represent the electricity demand of the FGD. The capacity penalty equals the percent of unit generation required for the control device. The heat rate penalty is based on the capacity penalty and is a modeling procedure to capture the effect of the control device on fuel use and generation. It does not represent an actual increase in the unit heat rate.
4. Table Reference: Table 5-6, Documentation for EPA Base Case v.5.13, Using the Integrated Planning Model. U.S. EPA #450R13002, November 2013.

Table 2.20 NO_x SCR Control Cost Effectiveness for Coal Plants for EPA Base Case v5.13 Examples (2011$)

NOx Control Type	Capacity (MW)	Heat Rate (BTU/kWh)	Assumed Capital Recovery Factor	Assumed Capacity Factor	Assumed Inlet NO_x Rate lb/MMBTU	Assumed Percent Reduction	Total Annual Cost ($/kW-yr)	NO_x Reduction (tons/kW-yr)	2011$/ton Reduction
SCR	100	9,000	0.15	0.85	0.5	90%	59.1	0.015	3,917
SCR	100	10,000	0.15	0.85	0.5	90%	64.0	0.017	3,822
SCR	100	11,000	0.15	0.85	0.5	90%	69.0	0.018	3,745
SCR	300	9,000	0.15	0.85	0.5	90%	49.4	0.015	3,274
SCR	300	10,000	0.15	0.85	0.5	90%	53.7	0.017	3,205
SCR	300	11,000	0.15	0.85	0.5	90%	58.0	0.018	3,148
SCR	500	9,000	0.15	0.85	0.5	90%	46.2	0.015	3,067
SCR	500	10,000	0.15	0.85	0.5	90%	50.4	0.017	3,009
SCR	500	11,000	0.15	0.85	0.5	90%	54.6	0.018	2,962
SCR	700	9,000	0.15	0.85	0.5	90%	44.5	0.015	2,954
SCR	700	10,000	0.15	0.85	0.5	90%	48.7	0.017	2,907
SCR	700	11,000	0.15	0.85	0.5	90%	52.7	0.018	2,861
SCR	1000	9,000	0.15	0.85	0.5	90%	43.0	0.015	2,851
SCR	1000	10,000	0.15	0.85	0.5	90%	47.0	0.017	2,805
SCR	1000	11,000	0.15	0.85	0.5	90%	50.9	0.018	2,760

Notes:

The cost effectiveness calculation methodology, capital recovery factor, and capacity factor are the same as used in the *2007 Assessment* (MACTEC, 2007).

Table 2.21 NO_x SNCR (Tangential Boiler) Control Cost Effectiveness for Coal Plants for EPA Base Case v5.13 Examples (2011$)

NOx Control Type	Capacity (MW)	Heat Rate (BTU/kWh)	Assumed Capital Recovery Factor	Assumed Capacity Factor	Assumed Inlet NO_x Rate lb/MMBTU	Assumed Percent Reduction	Total Annual Cost ($/kW-yr)	NO_x Reduction (tons/kW-yr)	2011$/ton Reduction
SNCR	100	9,000	0.15	0.85	0.5	25%	16.5	0.004	3,933
SNCR	100	10,000	0.15	0.85	0.5	25%	17.5	0.005	3,752
SNCR	100	11,000	0.15	0.85	0.5	25%	18.5	0.005	3,617
SNCR	300	9,000	0.15	0.85	0.5	25%	12.5	0.004	2,985
SNCR	300	10,000	0.15	0.85	0.5	25%	13.3	0.005	2,865
SNCR	300	11,000	0.15	0.85	0.5	25%	14.4	0.005	2,808
SNCR	500	9,000	0.15	0.85	0.5	25%	11.2	0.004	2,685
SNCR	500	10,000	0.15	0.85	0.5	25%	12.2	0.005	2,624
SNCR	500	11,000	0.15	0.85	0.5	25%	13.1	0.005	2,562
SNCR	700	9,000	0.15	0.85	0.5	25%	10.6	0.004	2,532
SNCR	700	10,000	0.15	0.85	0.5	25%	11.6	0.005	2,489
SNCR	700	11,000	0.15	0.85	0.5	25%	12.5	0.005	2,437
SNCR	1000	9,000	0.15	0.85	0.5	25%	10.1	0.004	2,417
SNCR	1000	10,000	0.15	0.85	0.5	25%	11.0	0.005	2,354
SNCR	1000	11,000	0.15	0.85	0.5	25%	12.0	0.005	2,343

Notes:
The cost effectiveness calculation methodology, capital recovery factor, and capacity factor are the same as used in the *2007 Assessment* (MACTEC, 2007).

Table 2.22 NO_x SNCR (Fluidized Bed Boiler) Control Cost Effectiveness for Coal Plants for EPA Base Case v5.13 Examples (2011$)

NOx Control Type	Capacity (MW)	Heat Rate (BTU/kWh)	Assumed Capital Recovery Factor	Assumed Capacity Factor	Assumed Inlet NO_x Rate lb/MMBTU	Assumed Percent Reduction	Total Annual Cost ($/kW-yr)	NO_x Reduction (tons/kW-yr)	2011$/ton Reduction
SNCR	100	9,000	0.15	0.85	0.5	50%	14.3	0.008	1,702
SNCR	100	10,000	0.15	0.85	0.5	50%	15.2	0.009	1,637
SNCR	100	11,000	0.15	0.85	0.5	50%	16.3	0.010	1,591
SNCR	300	9,000	0.15	0.85	0.5	50%	11.2	0.008	1,342
SNCR	300	10,000	0.15	0.85	0.5	50%	12.2	0.009	1,312
SNCR	300	11,000	0.15	0.85	0.5	50%	13.1	0.010	1,281
SNCR	500	9,000	0.15	0.85	0.5	50%	10.4	0.008	1,247
SNCR	500	10,000	0.15	0.85	0.5	50%	11.3	0.009	1,210
SNCR	500	11,000	0.15	0.85	0.5	50%	12.2	0.010	1,187
SNCR	700	9,000	0.15	0.85	0.5	50%	10.0	0.008	1,189
SNCR	700	10,000	0.15	0.85	0.5	50%	10.8	0.009	1,159
SNCR	700	11,000	0.15	0.85	0.5	50%	11.7	0.010	1,141
SNCR	1000	9,000	0.15	0.85	0.5	50%	9.5	0.008	1,133
SNCR	1000	10,000	0.15	0.85	0.5	50%	10.5	0.009	1,124
SNCR	1000	11,000	0.15	0.85	0.5	50%	11.5	0.010	1,114

Notes:

The cost effectiveness calculation methodology, capital recovery factor, and capacity factor are the same as used in the *2007 Assessment* (MACTEC, 2007).

The cost calculations for SCR discussed above apply to coal units. For SCR on oil/gas steam units, S&L developed the following cost parameters (EPA, 2013):

- Capital costs - $80/kW (2011$)
- Fixed O&M – $1.16/kW-hr
- Variable O&M – $0.13/MWh
- Percent removal – 80%

S&L also developed scaling factors for capital and fixed O&M costs to determine costs for various sized units using the above parameters.

Cost of Switching from Coal to Natural Gas

Switching from coal to natural gas may be a cost-effective strategy for reducing both SO_2 and NO_x emissions. The per BTU NO_x emissions for coal are about double those of natural gas (e.g., uncontrolled NO_x emissions for coal are generally 0.4 - 0.8 lbs/MMBTU, and 0.1 - 0.2 lbs/MMBTU for distillate oil and natural gas). Thus, a switch from coal to natural gas will a NO_x reduction co-benefit in addition to reducing SO_2 emissions. Fuel switching costs were discussed previously in the SO_2 section.

Cost of Returning Partially Operating SCRs and SNCRs to Full Operation

Since units that are partially running their SCR or SNCR system have already incurred the fixed operating costs (which are associated with having the controls functioning at any level), the remaining cost to achieve full design capability is the cost of additional reagent (EPA, 2015d). Changing NO_x removal rates following commencement of operations does not affect fixed operation and maintenance costs; likewise, the variable operation and maintenance components of catalyst replacement and auxiliary power are indifferent to reagent consumption or NO_x removal. In short, for SCRs and SNCRs, the marginal cost to increase from partial operation to full operation reflects the cost of additional reagent.

EPA estimated the reagent portion of operations costs $503 per ton NO_x removed (EPA, 2015d). This represents a reasonable estimate of the cost for operating these post combustion controls based on current market ammonia prices. The OTC also completed an analysis of the cost of full-time operation of SCRs versus the price of NO_x allowances (OTC, 2015). OTC estimated the costs to be in the range of $439 to $2,188 per ton of NO_x removed.

FACTOR 2 – COMPLIANCE TIME FRAME

Generally, sources are given a 2-4 year phase-in period to comply with new rules. Under the previous Phase I of the NOx SIP Call, EPA provided a compliance date of about 3½ years from the SIP submittal date. Most MACT standards allow a 3-year compliance period. Under Phase I of the NOx SIP Call, EPA provided a 2-year period after the SIP submittal date for compliance. States generally provided a 2-year period for compliance with RACT rules. For the purposes of this review, we have assumed that a maximum of 2 years after SIP submittal is adequate for pre-combustion controls (fuel switching) and a maximum of 3 years is adequate for the installation of post combustion controls.

For post-combustion controls, site-specific information must be supplied to vendors in order to determine the actual time needed for installation of a given control. Large scale implementation of control devices within the EGU sector, particularly in a short time period, may require consideration of impacts on regional electricity demands. Integrated Planning Model (IPM®) has allowed for these and other impacts in determining the least cost approach to emission reductions, however, there is a great deal of uncertainty associated with modeled results in comparison to real-world applications of control strategies.

For BART control measures, the proposed BART guidelines require States to establish enforceable limits and require compliance with the BART emission limitations no later than 5 years after EPA approves the regional haze SIP.

FACTOR 3 - ENERGY AND NON-AIR QUALITY IMPACTS

Fuel switching from coal to natural gas will have a small negative impact on heat rates, as can some NO_x combustion control measures. Fuel switching may increase energy costs in other sectors, and add to transportation issues and secondary environmental impacts from shifts in fuel extraction and fuel delivery.

Electricity demand to operate post-combustion controls will also negatively impact net heat rate or reduce the amount of electricity delivered to the grid. FGD systems typically operate with high pressure drops across the control equipment, resulting in a significant amount of electricity required to operate blowers and circulation pumps. In addition, some combinations of FGD technology and plant configuration may require flue gas reheating to prevent physical damage to equipment, resulting in higher fuel usage.

The primary environmental impact of FGD systems is the generation of wastewater and sludge from the SO_2 removal process. When the exhaust gas from the boiler enters the FGD the SO_2, metals, and other solids are removed from the exhaust and collected in the FGD liquid. The liquid slurry collects in the bottom of the FGD in a reaction tank. The slurry is then dewatered and a portion of the contaminant-laden water is removed from the system as wastewater. Waste from the FGD systems will increase sulfate, metals, and solids loading in a facility’s wastewater, potentially impacting community wastewater treatment facilities for smaller units that do not have self-contained water treatment systems.

In some cases FGD operation necessitates installation of a clarifier on site to remove excessive pollutants from wastewater. This places additional burdens on a facility or community wastewater treatment and solid waste management capabilities. These impacts will need to be analyzed on a site-specific basis. If lime or limestone scrubbing is used to produce calcium sulfite sludge, the sludge must be stabilized prior to land filling. If a calcium sulfate sludge is produced, dewatering alone is necessary before land filling, however, SO_2 removal costs are higher due to increased equipment costs for this type of control system. In some cases calcium sulfate sludge can be sold for use in cement manufacturing.

With wet FGD technologies a significant visible plume is present from the source due to condensation of water vapor as it exits the smoke stack. Although the water eventually evaporates and the plume disappears, community impact may be significant.

FACTOR 4 – REMAINING USEFUL LIFE

Available information for remaining useful life estimates of EGU boilers indicates a wide range of operating lifetimes, depending on size of the unit, capacity factor, and level of maintenance performed. Typical life expectancies are 50 years or more. Additionally, implementation of regulations over the years has resulted in retrofitting that has ultimately increased the expected life span of many EGUs. The lifetime of an EGU may be extended through repair, repowering, or other strategies if the unit is more economical to run than to replace with power from other sources. This may be particularly likely if the unit serves an area which has limited transmission capacity available to bring in other power.

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CHAPTER 4

SOURCE CATEGORY ANALYSIS: INDUSTRIAL, COMMERCIAL, AND INSTITUTIONAL BOILERS

SOURCE CATEGORY DESCRIPTION

The MANE-VU contribution assessment demonstrated that SO_2 emissions are the principal contributor to visibility impairment in Class I areas in the northeast. After electric generation units (EGUs), Industrial, Commercial, and Institutional (ICI) boilers and heaters are the next largest class of pollution sources that contribute to SO_2 emissions. NO_x emissions may also contribute to visibility impairment and ICI boilers are an important contributor to NO_x emissions inventory (NESCAUM, 2006). MANE-VU previously developed an assessment (MACTEC, 2007) of SO_2 control technologies to achieve reasonable progress goals with respect to the four factors listed in Section 169A of the Clean Air Act. The information presented in this Chapter is an update to some parts of the MACTEC report and now includes NO_x control technologies.

Types of ICI Boilers

Typical industrial applications include chemical, refining, manufacturing, metals, paper, petroleum, food production and a wide variety of other small industries. Commercial and institutional boilers are normally used to produce steam and hot water for space heating in office buildings, hotels, apartment buildings, hospitals, universities, and similar facilities. A fairly wide range of fuels are used by ICI boilers, ranging from coal, petroleum coke, distillate and residual fuel oils, natural gas, wood waste or other classes of waste products. Boilers aggregated under the ICI classification are generally smaller than boilers in the electric power industry, and typically have a heat input in the 10 to 250 MMBTU/hr range; however, ICI boilers can be as large as 1,000 MMBTU/hr or as small as 0.5 MMBTU/hour.

The process that a particular unit serves strongly influences the boiler fuel choice. For example, the iron and steel industry uses coal to generate blast furnace gas or coke oven gas that is used in boilers, resulting in sulfur emissions. Pulp and paper processing may use biomass as a fuel. Units with short duty cycles may utilize oil or natural gas as a fuel. The use of a wide variety of fuels is an important characteristic of the ICI boiler category. While many boilers are capable of co-firing liquid or gaseous fuels in conjunction with solid fuels, boilers are usually designed for optimum combustion of a single, specific fuel. Changes to the fuel type may, therefore, reduce the capacity, duty cycle, or efficiency of the boiler.

Boiler design also plays a role in the uncontrolled emission rate. Most ICI boilers are of three basic designs: water tube, fire tube, or cast iron. The fuel-firing configuration is a second major identifier of boiler design for solid fuels. Stoker boilers are the oldest technology and are still widely used for solid-fueled boilers. Pulverized coal boilers succeeded stokers as a more efficient method of burning coal and are used in larger boiler designs. Circulating fluidized bed (CFB) boilers are the most recent type of boiler for solid fuel combustion and are becoming more commonplace. CFB boilers are capable of burning a variety of fuels, and are more efficient and less polluting than stoker or pulverized coal boilers. Combined heat and power (CHP) or cogeneration technologies are also used to produce electricity and steam or hot water from a single unit. Some ICI boilers are used only in the colder months for space heating, while others have high capacity utilization year round.

Clean Air Act Regulations Controlling ICI Boilers

Emissions from ICI boilers are currently governed by multiple State and federal regulations under Titles I, III, and IV of the Clean Air Act (CAA). Each of these regulatory programs is discussed in the following paragraphs.

Title I regulates criteria pollutants by requiring local governments to adopt State Implementation Plans (SIPs) that set forth their strategy for achieving reductions in the particular criteria pollutant(s) for which they are out of attainment. The SIP requirements include Reasonably Available Control Technology (RACT) requirements, but more stringent requirements may be imposed depending on the locale's degree of non-attainment with ambient air standards.

Title I also imposes New Source Performance Standards (NSPS) on certain specified categories of new and modified large stationary sources. In 1986, EPA codified the NSPS for industrial boilers (40 CFR part 60, subparts Db and Dc). Subpart Db applies to fossil fuel-fired ICI units greater than 100 MMBTU per hour that were constructed or modified after June 19, 1984. Subpart Dc applies to fossil fuel-fired ICI units from 10 to 100 MMBTU per hour that were constructed or modified after June 9, 1989. EPA revises the NSPS from time to time to reflect improvements in control methods. The EPA promulgated revised NSPS for $SO_{2,}$ NO_x, and PM for subparts Db and Dc on February 27, 2006. In 2012, EPA promulgated several minor amendments, technical clarifications, and corrections to existing NSPS provisions for large and small ICI boilers.

In addition, Title I subjects new and modified large stationary sources that increase their emissions to permitting requirements that impose control technologies of varying levels of stringency (known as New Source Review, or NSR). NSR prescribes control technologies for new plants and for plant modifications that result in a significant increase in emissions, subjecting them to Best Available Control Technology (BACT) in attainment areas and to the Lowest Achievable Emission Rate (LAER) in nonattainment areas. Control strategies that constitute BACT and LAER evolve over time and are reviewed on a case by case basis in State permitting proceedings.

In 1999, EPA published a final rule to address a type of visibility impairment known as regional haze. The regional haze rule required States to submit implementation plans to address regional haze visibility impairment in 156 Federally-protected parks and wilderness areas. As required by the CAA, EPA included in the final regional haze rule a requirement for best available retrofit technology (BART) for certain large stationary sources, including ICI boilers, that were built between 1962 and 1977.

The Boiler MACT (Maximum Achievable Control Technology) rule under Title III of the CAA has a long history. EPA published the first Boiler MACT rule in 2004. Litigation forced the rule to be vacated just before the compliance deadline in 2007. The EPA finalized a revised version of the rule in March 2011 to meet a court-ordered deadline. On November 5, 2015, EPA issued the final reconsideration rule. The Boiler MACT rule is intended to substantially reduce emissions of toxic air pollutants from ICI boilers. These MACT standards apply to ICI boilers located at major sources of hazardous air pollutants (HAPs). There are many options for complying with the MACT standards, ranging from continued use of existing control systems to fuel switching to the installation of a fabric filter and wet scrubber technologies. Thus, the control technologies used to reduce the level of HAPs emitted from affected sources are also expected to reduce emissions of PM, and to a lesser extent, SO_2 and NO_x emissions.

Title IV of the CAA addresses acid rain by focusing primarily on power plant emissions of SO_2. Title IV includes an Opt-in Program that allows sources not required to participate in the Acid Rain Program the opportunity to enter the program on a voluntary basis and receive their own acid rain allowances. The Opt-in Program offers sources such as ICI boilers a financial incentive to voluntarily reduce its SO_2 emissions. By reducing emissions below allowance allocation, an opt-in source will have unused allowances, which it can sell in the SO_2 allowance market.

The regulation of ICI boilers by various CAA programs has resulted in a variety of unit level emission limits resulting from SIP, NSPS, NSR, BART or MACT requirements. Thus, the specific emission limits and control requirements for an existing ICI boiler vary greatly and depend on boiler age, size, fuel type and geographic location.

Emission and Fuel Consumption Trends

Tables 4.1 and 4.2 show trends in point source SO_2 and NO_x emissions from ICI boilers for the MANE-VU, Midwest Regional Planning Organization (MRPO), and the Visibility Improvement State and Tribal Association of the Southeast (VISTAS) states. Emissions have declined since 2002 in all three RPOs. SO_2 emissions from ICI boilers have decreased by about 62% in the MANE-VU region between 2002 and 2011, by 33% in the MRPO region, and by 52% in the VISTAS region. NO_x emissions from ICI boilers have decreased by about 42% in the MANE-VU region between 2002 and 2011, by 46% in the MRPO region, and by 38% in the VISTAS region. Note that emission estimates for 2014 are currently be quality assured and are not available for analysis.

There are several factors likely contributing to the emission reductions between 2002 and 2011:

- Industrial and commercial fuel consumption data from the Energy Information Administration (EIA) shows a transition from sulfur containing fuels (coal, residual oil) to natural gas. This transition is driven by both environmental and economic concerns. Nationally, residual oil consumption by industrial and commercial sources has decreased by 74% between 2002 and 2013, while coal consumption was 16% less in 2011 than in 2002. Natural gas consumption in 2014 was about 4% higher than in 2002.

- New or improved pollution controls have been installed. For example, the EPA petroleum refinery enforcement initiative (EPA, 2015d) settlements cover 109 refineries in 32 states and territories. These settlements have required significant reductions in SO_2 and NO_x emissions from refinery boilers.

Table 4.1 Trends in SO_2 Emissions (tons/year) from ICI Boilers

Primary Fuel	2002	2007/2008	2011	2014	2018
MANE-VU (CT, DC, DE, MA, MD, ME, NH, NJ, NY, PA, RI, VT)					
Coal	88,092	72,820	50,893	Not Available	23,045
Oil	48,509	35,010	9,859	Not Available	4,659
Gas	35,049	3,595	306	Not Available	253
Wood	1,048	1,680	1,102	Not Available	538
Other	1,436	561	3,319	Not Available	385
Total	**174,134**	**113,667**	**65,479**	Not Available	**28,880**
MRPO (IL, IN, OH, MI, WI)					
Coal	223,986	242,909	157,445	Not Available	71,853
Oil	17,421	5,575	1,057	Not Available	305
Gas	21,842	16,662	344	Not Available	339
Wood	304	384	806	Not Available	540
Other	2,606	2,413	19,309	Not Available	12,035
Total	**266,159**	**267,942**	**178,961**	Not Available	**85,072**
VISTAS (AL, FL, GA, KY, MS, NC, SC, TN, VA, WV)					
Coal	193,645	150,211	100,258	Not Available	19,953
Oil	47,869	22,514	6,064	Not Available	1,991
Gas	21,125	13,868	3,429	Not Available	3,377
Wood	14,951	15,690	8,980	Not Available	1,867
Other	5,378	3,952	9,672	Not Available	3,404
Total	**282,968**	**206,234**	**128,403**	Not Available	**30,592**

MANE-VU emissions obtained from 2002, 2007 and 2011 inventories prepared by MARAMA
MRPO and VISTAS emissions obtained from 2002, 2008 and 2011 EPA national emission inventories
Based on point source inventory with Source Classification Codes in the 1-02-xxx-xx and 1-03-xxx-xx series.
2014 emissions are currently being quality assured and are not available for this analysis.
2018 emissions are projections from the MARAMA ALPHA2 regional emission inventory.

Table 4.2 Trends in NO_x Emissions (tons/year) from ICI Boilers

Primary Fuel	**2002**	**2007/2008**	**2011**	**2014**	**2018**
MANE-VU (CT, DC, DE, MA, MD, ME, NH, NJ, NY, PA, RI, and VT)					
Coal	21,785	18,205	12,918	Not Available	6,600
Oil	17,816	14,694	5,193	Not Available	4,701
Gas	23,812	17,196	14,467	Not Available	12,941
Wood	4,117	4,616	4,526	Not Available	4,383
Other	547	761	2,405	Not Available	2,489
Total	**68,077**	**55,472**	**39,509**	Not Available	**31,114**
MRPO (IL, IN, OH, MI, WI)					
Coal	61,558	54,454	37,793	Not Available	30,804
Oil	8,533	1,597	390	Not Available	314
Gas	61,558	32,612	23,544	Not Available	22,990
Wood	3,974	4,264	4,134	Not Available	3,951
Other	1,249	1,481	7,553	Not Available	6,468
Total	**136,872**	**94,408**	**73,414**	Not Available	**64,527**
VISTAS (AL, FL, GA, KY, MS, NC, SC, TN, VA, WV)					
Coal	90,470	64,100	50,733	Not Available	36,175
Oil	13,571	6,793	2,943	Not Available	2,962
Gas	40,660	21,255	17,295	Not Available	17,074
Wood	32,471	32,980	27,009	Not Available	25,387
Other	8,779	7,720	8,018	Not Available	6,930
Total	**185,950**	**132,848**	**105,997**	Not Available	**88,529**

MANE-VU emissions obtained from 2002, 2007 and 2011 inventories prepared by MARAMA
MRPO and VISTAS emissions obtained from 2002, 2008 and 2011 EPA national emission inventories
Based on point source inventory with Source Classification Codes in the 1-02-xxx-xx and 1-03-xxx-xx series.
2014 emissions are currently being quality assured and are not available for this analysis.
2018 emissions are projections from the MARAMA ALPHA2 regional emission inventory.

- Energy efficiency has improved. Faced with steadily increasing energy bills, many companies and institutions have implemented energy saving measures. It is estimated that basic boiler tune-up procedures can add up savings of up to 5% or more of energy use with little or no costs, while more formal energy management schemes can reduce consumption by 20 to 30% or more (ABB, 2012).
- Some facilities and/or emission units have shut down due to the general decline in U.S. manufacturing. According to the Bureau of Labor Statistics, manufacturing employment in the U.S. declined by 20% between 2002 and 2014 (BLS, 2015).

There are many other state- or facility-specific reasons that would also help explain the decrease in SO_2 and NO_x emissions from ICI boilers. It is beyond the scope of this project to identify all possible reasons.

Also shown in Tables 4.1 and 4.2 are emission projections for 2018 (MARAMA, 2015). These projections take into account forecasted growth (both positive and negative) in energy consumption, as well as the impact of on-the-books regulatory programs that will result in emission reductions after 2011. Emissions of both SO_2 and NO_x are projected to continue to decline in all three RPOs.

FACTOR 1 – COST OF COMPLIANCE

Air pollution control technologies for ICI boilers have advanced substantially over the past 25 years. Changes in energy markets have affected the availability and price of different types of fuels used by ICI boilers, resulting in changes in emission levels. In addition, advances in power generation technologies, energy efficiency and renewable energy have the potential to further reduce emissions from these facilities. The focus of this evaluation is on the first two categories mentioned above - emission control technologies and cleaner fuels. The timing and magnitude of reductions from the other strategies – improved technologies, demand reduction/energy efficiency, and renewable power should be considered as part of a longer-term solution.

Pollutant emission controls are generally divided into three major types, as follows:

- Pre-combustion controls, in which fuel substitutions are made or fuel pre-processing is performed to reduce pollutant formation in the combustion unit.
- Combustion controls, in which operating and equipment modifications are made to reduce the amount of pollutants formed during the combustion process; or in which a material is introduced into the combustion unit along with the fuel to capture the pollutants formed before the combustion gases exit the unit.
- Post-combustion controls, in which one or more air pollution control devices are used at a point downstream of the furnace combustion zone to remove the pollutants from the post-combustion gases.

The following sections provide a brief summary of SO_2 and NO_x control options and costs, drawing heavily on recent work sponsored by regional planning organizations. More detailed descriptions of the options can be found in the literature cited in the list of references.

Identification of Available SO_2 Control Options

SO_2 is an undesirable by-product of the combustion sulfur-bearing fossil fuels. Coal deposits contain sulfur in amounts ranging from trace quantities to as high as 8% or more. Untreated distillate oils typically have sulfur contents less than 0.5% while residual oil can have 1-2% sulfur by weight. Petroleum coke, a byproduct of the oil refining process, may have as much as 6% sulfur. Process gases, such as coke oven gas or refinery fuel gas, if not desulfurized, can result in substantial levels of SO_2 when burned. Pipeline quality natural gas contains virtually no sulfur, while landfill gas may contain varying amounts of sulfur depending on the materials contained in the landfill. Essentially all of the sulfur in the fuel is oxidized to form SO_2 (a very small percentage is further oxidized to sulfur trioxide (SO_3) depending on fuel and boiler characteristics).

Since the relationship between sulfur content in the fuel and SO_2 emissions is essentially linear the emission reduction benefits of fuel switching (for example from higher- to lower-sulfur coal, from higher-sulfur oils to lower-sulfur oils, or from coal/oil to natural gas) are directly proportional to the difference in sulfur contents of fuels. Therefore, changing fuels, or cleaning fuels in the case of process gases or some coals, are the principal means of reducing sulfur emissions without adding flue gas treatment methods. Major issues associated with fuel substitution include price, availability, transportation, and suitability of the boiler or plant to accommodate the new fuel.

Many industrial and commercial sources can reduce the amount of SO_2 created through changes in fuel; however, in many cases such changes may be uneconomical or impractical. For this reason, gas treatment methods that capture the SO_2 that is formed from these industrial sources may be the most effective form of controlling SO_2 emissions. Post-combustion controls reduce SO_2 emissions by reacting the SO_2 in the flue gas with a reagent (usually calcium- or sodium-based) and removing the resulting product (a sulfate/sulfite) for disposal or commercial use, depending on the technology used. Post-combustion SO_2 reduction technologies are commonly referred to as Flue Gas Desulfurization (FGD) or SO_2 "scrubbers", broadly grouped into wet FGD, dry FGD, and dry sorbent injection (DSI) technologies.

A summary of available SO_2 control technology options are shown in Table 4.3. The method of SO_2 control appropriate for any individual ICI boiler is dependent upon the type of boiler, type of fuel, capacity utilization, and the types and staging of other air pollution control devices. However, cost effective emissions reduction technologies for SO_2 are available and have proven effective in reducing emissions from the exhaust gas stream of ICI boilers.

Cost of Compliance – SO_2 Control Options

To compare the various control options, information has been compiled on the cost-effectiveness of fuel switching and retrofitting controls. In general, cost-effectiveness improves as boiler size and capacity factor (a measure of boiler utilization) increases. All costs estimates for years other than 2014 were converted to 2014 dollars using the Chemical Engineering Plant Index, except where noted.

Table 4.3 Available SO_2 Control Options for ICI Boilers

Technology	Description	Applicability	Performance
Switch to Natural Gas (virtually 0% sulfur)	Replace coal combustion with natural gas	Potential control measure for all coal-,oil-, and process-gas fired ICI boilers	Virtually eliminate SO_2 emissions by switching to natural gas
Switch to a Lower Sulfur Oil	Replace higher-sulfur residual oil with lower-sulfur oil; replace high sulfur distillate oil with ultra-low sulfur distillate oil	Potential control measure for all oil-fired ICI boilers currently using higher sulfur content residual or distillate oils	50-80% reduction in SO_2 emissions by switching to a lower-sulfur oil
Switch to a Low Sulfur Coal (generally <1% sulfur)	Replace high-sulfur bituminous coal combustion with lower-sulfur coal	Potential control measure for all coal-fired ICI boilers currently using coal with high sulfur content	50-80% reduction in SO_2 emissions by switching to a lower-sulfur coal
Coal Cleaning	Coal is washed to remove some of the sulfur and ash prior to combustion	Potential control measure for all coal-fired ICI boilers	20-25% reduction in SO_2 emissions
Combustion Control	Introduce a reactive material, such as limestone or bi-carbonate, into combustion chamber along with the fuel	Applicable to pulverized coal-fired boilers and circulating fluidized bed boilers	40%-85% reductions in SO_2 emissions
Flue Gas Desulfurization (FGD) – Wet	Remove SO_2 from flue gas by dissolving it in a lime or limestone slurry or other alkaline chemicals	Applicable to all coal-fired ICI boilers	30-95%+ reduction in SO_2 emissions
Flue Gas Desulfurization (FGD) – Dry	A fine mist containing lime or other suitable sorbent is injected directly into flue gas	Applicable primarily for boilers currently firing low to medium sulfur fuels	60-95%+ reduction in SO_2 emissions
Flue Gas Desulfurization (FGD) – Dry Sorbent Injection	Powdered lime or other suitable sorbent is injected directly into flue gas	Applicable primarily for boilers currently firing low to medium sulfur fuels	40-60% reduction in SO_2 emissions

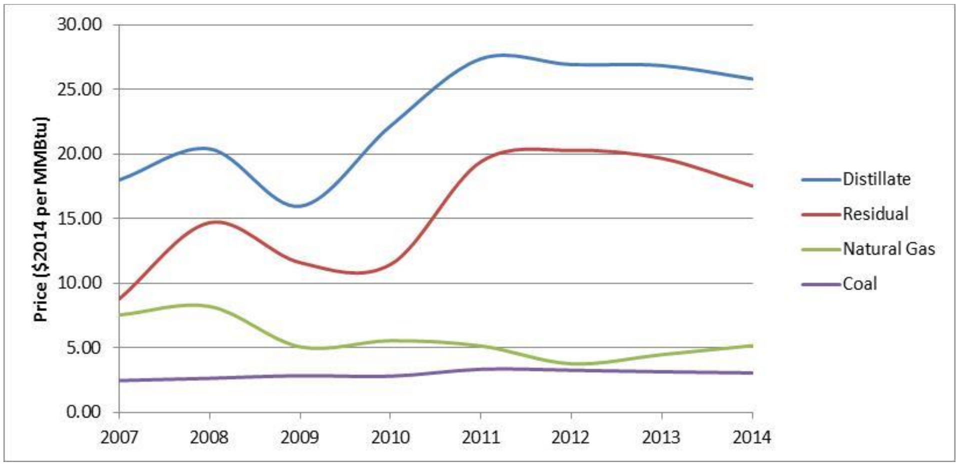
Table references: Staudt, 2012; NESCAUM 2009; OTC/LADCO 2010; STAPPA/ALAPCO 2006.

Cost of Switching to Lower Sulfur Fuels

In many cases, switching to lower sulfur fuels is one of the most straightforward and technologically feasible strategies for reducing emissions, but it is not a trivial undertaking (NACAA, 2015). For any existing ICI boiler, there are reasons the current fuels are used and other fuels are not used. Similarly, there are reasons the primary fuel is primary and the backup fuels are backups. These decisions are influenced by many different factors, such as delivered fuel costs, fuel handling system design, boiler design, availability of natural gas pipeline capacity, and so forth. Switching fuels will be most feasible from a technological perspective where a boiler is already designed to combust more than one type of fuel.

Many ICI boilers that are not already using low-emitting fuels as a primary energy source are using higher-emitting fuels for economic reasons. However, the underlying changes in the relative costs of different fuels can determine if fuel switching is an emission control option. Figure 4.1 shows the relative changes in the real price of fossil fuels used by industrial sources between 2007 and 2014 (EIA, 2015e). Fuel prices in the figure are all presented in terms of price per MMBTU to make the prices comparable.

Figure 4.1 Real Prices of Fossil Fuels for Industrial Sources



Source: EIA, 2015e

National average natural gas prices are significantly lower today than they were a decade ago. The real price of natural gas for industrial sources is 31% lower in 2014 than it was in 2007. Coal prices have risen by 25% during the same period. Natural gas is significantly cheaper than either distillate or residual oil, and is becoming more competitive with coal. Beginning in 2006, natural gas became less expensive on a BTU basis when compared to residual fuel oil. Beginning in 2009, that difference grew so that high sulfur residual fuel oil was more than 3-4 times the cost of natural gas on a BTU basis.

Conversion from coal or oil to natural gas, or co-firing natural gas, may be a viable option for some facilities that have adequate supply of gas to their site. Natural gas will virtually eliminate SO_2 emissions and will be beneficial to emissions of other pollutants, such as CO_2, NO_x, mercury, and particulate matter. A natural gas conversion will require modification of the burners; however, this is often much less expensive than other options such as flue gas desulfurization. Capital cost will also be impacted by the cost of any needed modifications to the natural gas supply (Staudt, 2012).

For those ICI boilers capable of burning multiple fuels, the cost of switching from oil to natural gas can be largely determined by the price of natural gas relative to oil prices. Through 2005, natural gas prices were generally higher than oil prices (dollars per MMBTU). But beginning in 2006 and continuing to the present, natural gas prices have been lower than oil prices. Thus, switching from oil to natural gas would result in fuel cost savings where natural gas is available.

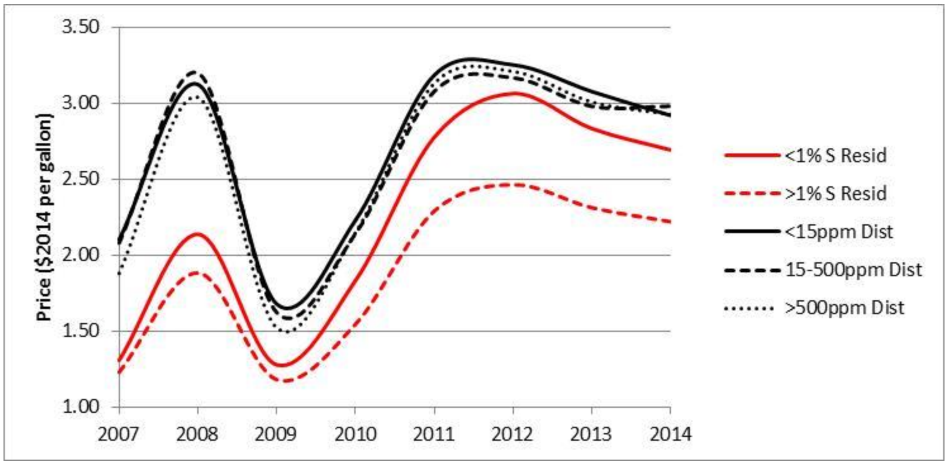
The real price gap between natural gas and coal decreased between 2007 and 2014, with natural gas costing $5.09 per MMBTU more than coal in 2007. The price gap dropped to as low as $0.50 in 2012 and $2.11 in 2014. With these price differentials, the cost effectiveness of switching from 1% sulfur coal to natural gas would range from $600 – 2,600 per ton, and from $1,200 – 5,200 for 0.5% sulfur coal, assuming that an existing boiler is capable for firing either fuel.

Switching fuels from one distillate oil to another will entail minimal capital cost. Changing from a residual fuel or other heavy fuel to distillate may require some changes to atomizers to adjust for the lighter fuel, but this is a relatively small cost. The primary cost associated with switching from high-sulfur to low-sulfur fuel oil is the differential in fuel prices.

Figure 4.2 shows the national real prices per gallon for residual oil and distillate oil from 2007 through 2014 (EIA, 2015e). The differential between low (less than 1 percent sulfur) and high (greater than 1 percent sulfur) sulfur residual oil has been increasing in recent years (note: the EIA prices for residual oil do not include a breakdown for very low sulfur residual oil {less than 0.31 percent sulfur}). The price of ultra-low sulfur (<15 ppm sulfur) distillate oil in recent years has been at times about 30% higher than the price of high sulfur residual oil. The EIA prices for No. 2 (distillate) oil are broken out by ultra-low (<15 ppm sulfur), low-sulfur (15-500 ppm sulfur), and high-sulfur (>500 ppm sulfur). These prices do not show much difference in price as a function of sulfur content of No. 2 oil.

Figure 4.3 shows the national stocks of residual oil and distillate oil from 2004 through 2014 (EIA, 2015e). Stocks of low sulfur distillate oil have risen dramatically over the past few years, while stocks of low sulfur residual oil have been decreasing but remain substantial.

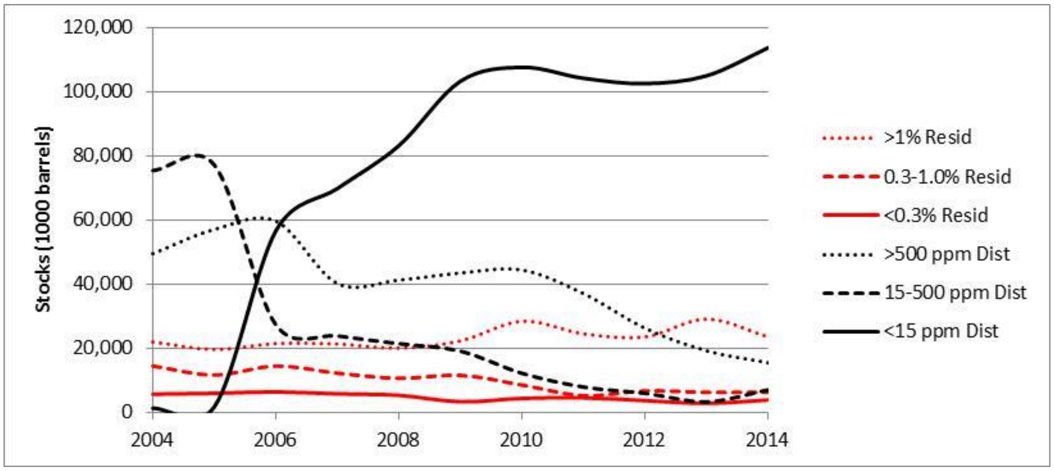
Figure 4.2 National Prices for High and Low Sulfur Residual and Distillate Fuel Oil



Source: EIA, 2015e

The potential increased costs (in fuel only) for switching to lower-sulfur fuel oil can be estimated as shown in the following example for a 250 MMBTU boiler in which average 2011-2014 fuel prices are used. If the high-sulfur residual oil is assumed to be 2 percent S, the low-sulfur residual oil is assumed to be 0.5 percent S, the high sulfur distillate oil is 3000 ppm, and the ultra-low sulfur distillate oil is assumed to be 15 ppm S, then the cost for fuel switching is as follows:

Figure 4.3 National Stocks of High and Low Sulfur Residual and Distillate Fuel Oil



Source: EIA, 2015e

Table 4.4 Example of Costs of Switching to Low-Sulfur Fuel Oil

Fuel Switch	SO_2 Reduction (tons)	\$2014/ton SO_2 Removed
From 2% S to 0.5% Residual Oil	1,135	4,400
From 2% S Residual to 15 ppm S Distillate	1,512	5,000
From 3000 ppm S to 15 ppm S Distillate	219	1,900

These costs are only fuel costs, and do not include any equipment costs needed to switch fuels (for example, burner changes when switching from residual to distillate oil).

The cost estimates in Table 4-4 suggest that for the sample boiler described above, switching from a 2.0 percent sulfur residual fuel oil to a low-sulfur residual oil (0.5 percent S) would provide a cost-effective sulfur removal strategy at about $4,400 per ton of SO_2 removed. The cost-effectiveness of switching to ultra-low sulfur distillate oil is estimated to be about $5,000 per ton. The cost effectiveness of switching from high sulfur to ultra-low sulfur distillate is estimated to be about $1,900 per ton.

Some ICI boilers may be able to switch from high-sulfur to low-sulfur coal without serious capital investment. The sulfur content, heating values and prices of coals mined in various regions of the country vary considerably (See Table 4.6). Central Appalachian coals, which are lower in sulfur than Illinois Basin or Northern Appalachian coals, generally have high heating value and are more accessible than low-sulfur western coal. The use of low-sulfur western coals may incur substantial transportation costs that would increase the cost of the delivered coal over local coal that is higher in sulfur. Even if such a fuel is available, use of the lower-sulfur coal that must be transported long distances from the supplier may not be cost competitive with burning higher sulfur fuel supplied by near-by suppliers. Thus, the cost-effectiveness of switching from high-sulfur to low-sulfur coal is very much dependent on the transportation costs which vary greatly by geographic location of the boiler.

Table 4.6 Average Weekly Coal Commodity Spot Priced ($2014 per ton)

Week Ended	Central Appalachia 12,500 Btu, 1.2 lbs SO_2 / MMBTU	Northern Appalachia 13,000 Btu, <3.0 lbs SO_2 / MMBTU	Illinois Basin 11,800 Btu, 5.0 lbs SO_2 / MMBTU	Powder River Basin 8,800 lbs SO_2 / MMBTU	Uinta Basin 11,700 Btu, 0.8 lbs SO_2 / MMBTU
23-Oct-15	$49.00	$52.00	$32.75	$11.55	$40.55
30-Oct-15	$49.00	$52.00	$32.75	$11.55	$40.55
6-Nov-15	$49.00	$52.00	$32.75	$11.55	$40.55
13-Nov-15	$43.50	$48.95	$32.60	$11.55	$40.65
20-Nov-15	$43.50	$48.95	$32.60	$11.55	$40.65

Source: http://www.eia.gov/coal/news_markets/
Note: The historical data file of spot prices is proprietary and cannot be released by EIA

Because industrial boilers are more likely to use local coals, for many industrial boiler owners coal cleaning may be a more economically viable approach for reducing coal sulfur than purchase of lower sulfur coals from western states (Staudt, 2012). Sulfur may be removed from l through cleaning measures that remove rock and pyrite (including pyritic sulfur). Most coals experience some form of cleaning prior to shipment in order to remove impurities and increase the heating value of the delivered coal. To the extent that sulfur may be in these impurities, sulfur can be removed as well; however, some sulfur is organically bound to the coal and cannot be removed through physical separation. Chemical cleaning measures chemically remove impurities.

Up to 60% sulfur (on a heating value basis) is removed through physical cleaning methods from uncleaned coal depending upon the coal and the practice used (Staudt, 2012). However, 60% represents the best potential technology while common commercial practice reduces coal sulfur by about 40%. Higher sulfur reductions are possible if chemical cleaning methods are considered. Current data was unavailable for the cost of coal cleaning. However, because it has been used in practice, it is certainly an approach that is available and feasible, and is likely to be economically viable for many industrial facilities.

Table 4.7 summarizes the cost-effectiveness of options for replacing high-sulfur fuels with low-sulfur alternatives.

Table 4.7 Summary of Cost-Effectiveness of Low Sulfur Fuel Options

Control Technology	Fuel Type	Cost Effectiveness ($/ton removed) 2014$
Switch to natural gas	Distillate/Residual Oil	Likely cost savings given current price trends
Switch from coal to gas	Coal	600 to 5,200, depending of sulfur content of the coal (for boilers already designed to use multiple fuels)
Switch from high to low sulfur oil	Residual Oil	4,000 to 5,100 (fuel costs only)
Switch from high sulfur residual to ultra-low sulfur distillate	Residual Oil	4,500 to 5,700 (fuel costs only)
Switch from high to ultra-low sulfur	Distillate Oil	0 to 3,300 (fuel costs only)
Convert from high to low sulfur coal	Coal	Not estimated due to variability in availability of low sulfur coal and facility-specific transportation costs
Coal Cleaning	Coal	Currently not available

Cost of Post-Combustion Gas Treatment Technologies

While many ICI boilers can accommodate fuel changes to reduce the amount of SO_2 emitted, in many other cases such changes may be uneconomical or impractical. For this reason, gas treatment methods that capture and control the SO_2 that is formed may be the most effective form of control. Post-combustion SO_2 control is accomplished by reacting the SO_2 in the gas with a reagent (usually calcium- or sodium-based) and removing the resulting product (a sulfate/sulfite) for disposal or commercial use, depending on the technology used. The types of flue gas SO_2 treatment methods are generally grouped into three categories:

- Wet scrubbers (or FGD) combine a mixture of lime or limestone and water with boiler flue gases to remove SO_2 and acid gases. The mixture is either injected into the scrubber with the flue gas, or the flue gas bubbles up through the mixture. The SO_2 is absorbed into the slurry and reacts with limestone to form an insoluble sludge. The sludge is disposed of in a pond specifically constructed for the purpose or is recovered as a salable byproduct. Wet scrubbers achieve SO_2 removal efficiencies of 90 to 98%.
- Dry scrubbers spray very finely powdered lime or other absorbents into a vessel where they combine with boiler flue gases to remove SO_2 and acid gases. The SO_2 is absorbed in the slurry and reacts with the hydrated lime reagent to form solid calcium sulfite and calcium sulfate as in a wet scrubber. The resulting sorbent is captured with a particulate control device such as an electrostatic precipitator or baghouse. Dry scrubbers general achieve removal efficiencies of 90 to 93%.
- Dry sorbent injection (DSI) systems inject sorbents, such as Trona (a naturally-occurring mineral), into the boiler flue gas ductwork to remove SO_2 and acid gases. The sorbent is then captured in the particulate matter removal system (either an electrostatic precipitator or a baghouse). DSI systems achieve 40 to 75% removal.

More detailed descriptions of these technologies can be found in recent literature cited below.

Estimates of the SO_2 post-combustion control costs for ICI boilers were obtained from published values in recent literature. The estimates previously used in the *2007 Assessment* (MACTEC, 2007) were not used because the EPA publications that served as the basis for those cost estimates are dated, and more recent cost factors are available. A brief summary of the key elements of these studies is provided below.

- In December 2005, environmental commissioners from Northeast and Midwest States initiated a state collaborative process. A staff-level workgroup was formed in 2006 to evaluate control options ICI boilers. To develop improved control cost estimates for ICI boilers, the workgroup assembled detailed information on direct capital equipment costs, direct installation costs, indirect capital costs and direct and indirect operating costs. These data were used in cost estimation algorithms that were originally modeled after the factor cost estimate methodology found in the EPA *Air Pollution Control Cost Manual*. Factor cost estimates are based on empirical factors that are used to estimate the cost of various elements. The algorithms were coded in a user friendly format (Excel spreadsheets) and account for the key variables that impact the cost analysis, including: boiler type and size, type of fuel combusted, type of emission control, uncontrolled and controlled emission rates, capital cost of control equipment (e.g., purchased equipment cost), financial costs (e.g., interest rates), unit capacity factor (hours/year), flue gas flow rates, and commodity prices (e.g., lime, water). For further information on the cost estimation methodology, see: Bodnarik, 2009 and OTC/LADCO, 2010.

- MARAMA and the Institute of Clean Air Companies (ICAC) sponsored the Advances in Air Pollution Control Technologies Workshop to provide state/local agency staff with the latest information on current and emerging emission control technologies. Cost estimates for several control technologies were developed by Dr. James Staudt using proprietary algorithms or algorithms developed for others (EPA). All cost data was benchmarked against independent data. See: Staudt, 2011.
- The Lake Michigan Air Directors Consortium (LADCO) sponsored a report that examined the inventory of SO_2 emissions and the candidate SO_2 control measures in the LADCO Region for industrial sources. The costs were developed from several references and therefore cover a wide range of situations and time periods. See: Staudt, 2012.

These studies provided valuable information on control options and cost effectiveness estimates for ICI boilers. Literature values of capital costs have been reported for different base years. The calculated capital cost values from the literature were normalized to a base year of 2014 using the Chemical Engineering Plant Cost Index values. Table 4.8 summarizes the published SO_2 control costs for a number of SO_2 control technologies.

Table 4.8 Summary of Cost-Effectiveness of SO_2 Post-Combustion Control Options

Control Option	Fuel Type	Emission Reduction	Boiler Size (MMBTU/hr)	Cost-Effectiveness ($2014 / ton of SO_2 Removed	Reference
Dry FDG	Wall-fired Coal	85% from 5.0 to 0.75 lb MMBTUSO_2/MMBTU	100 250 750	1,785 – 7,711 1,655 – 4,021 1,594 – 2,387	Bodnarik, 2009
Dry FDG	Coal	90% from 5.75 to 0.58 lb SO_2/MMBTU	210 420 630	1,106 774 663	Staudt, 2011,
Dry FDG	Coal	90% from 2.59 to 0.26 lb SO_2/MMBTU	210 420 630	2,211 1,548 1,327	Staudt, 2011
Dry FDG	Coal	90% from 1.15 to 0.12 lb SO_2/MMBTU	210 420 630	4,643 3,206 2,653	Staudt, 2011
Dry FDG	Coal	90% from 0.5 to 0.05 lb SO_2/MMBTU	210 420 630	10,503 7,297 5,970	Staudt, 2011
Dry FDG	Wall-fired Coal	95% from 5.0 to 0.25 lb SO_2/MMBTU	100 250 750	1,594 – 6,899 1,484 – 3,600 1,424 – 2,136	Bodnarik, 2009
Wet FGD	Wall-fired Coal	85% from 5.0 to 0.75 lb SO_2/MMBTU	100 250 750	1,845 – 7,531 1,574 – 3,841 1,444 – 2,226	Bodnarik, 2009
Wet FGD	Coal	90% from 5.75 to 0.58 lb SO_2/MMBTU	210 420 630	884 697 663	Staudt, 2011

Control Option	Fuel Type	Emission Reduction	Boiler Size (MMBTU/hr)	Cost-Effectiveness ($2014 / ton of SO_2 Removed	Reference
Wet FGD	Coal	90% from 2.59 to 0.26 lb SO_2/MMBTU	210 420 630	1,249 984 918	Staudt, 2011
Wet FGD	Coal	90% from 1.15 to 0.12 lb SO_2/MMBTU	210 420 630	1,979 1,548 1,404	Staudt, 2011
Wet FGD	Coal	90% from 0.5 to 0.05 lb SO_2/MMBTU	210 420 630	4,168 3,250 2,874	Staudt, 2011
Wet FGD	Wall-fired Coal	95% from 5.0 to 0.25 lb SO_2/MMBTU	100 250 750	1,655 – 6,739 1,404 – 3,440 1,294 – 1,875	Bodnarik, 2009
Dry Sorbent Injection with Existing ESP	Coal	90% from 2.59 to 0.26 lb SO_2/MMBTU	210 420 630	4,422 3,925 3,814	Staudt, 2011
Dry Sorbent Injection with Existing ESP	Coal	90% from 1.15 to 0.12 lb SO_2/MMBTU	210 420 630	3,206 3,040 2,985	Staudt, 2011
Dry Sorbent Injection with Existing ESP	Coal	90% from 0.5 to 0.05 lb SO_2/MMBTU	210 420 630	2,792 2,736 2,681	Staudt, 2011
Dry Sorbent Injection with New Baghouse	Coal	90% from 2.59 to 0.26 lb SO_2/MMBTU	210 420 630	9,950 6,633 5,528	Staudt, 2011
Dry Sorbent Injection with New Baghouse	Coal	90% from 1.15 to 0.12 lb SO_2/MMBTU	210 420 630	4,754 3,427 3,206	Staudt, 2011
Dry Sorbent Injection with New Baghouse	Coal	90% from 0.5 to 0.05 lb SO_2/MMBTU	210 420 630	3,206 2,322 2,211	Staudt, 2011

As can be seen in Table 4.8 above, there are several factors that impact cost-effectiveness:

- Uncontrolled SO_2 level – lower initial SO_2 levels will result in higher costs represented in $/ton of SO_2 removed.
- Boiler size – Larger boilers tend to benefit from economies of scale in terms of capital cost.
- Technology type – The capital costs of wet scrubbers are higher than those for dry scrubbers, although the cost effectiveness values of wet and dry processes are similar.

The cost effectiveness values for post-combustion SO_2 control options for ICI boilers are higher than those for EGUs because of the above reasons. See Chapter 2 for additional information on the cost effectiveness values for post-combustion SO_2 control options for EGUs.

Identification of NO_x Control Options

The formation of NO_x is a byproduct of the combustion of fossil fuels. Nitrogen contained in the fuels, as well as the nitrogen in the air, will react with oxygen during combustion to form NO_x. The degree to which this formation evolves depends on many factors including both the combustion process itself and the properties of the particular fuel being burned. This is why similar boilers firing different fuels or similar fuels burned in different boilers can yield different NO_x emissions.

A variety of approaches to minimize or reduce NO_x emissions into the atmosphere have been and continue to be developed (NESCAUM, 2009). A relatively simple way of understanding the many technologies available for NO_x emission control is to divide them into two major categories: (1) those that minimize the formation of NO_x itself during the combustion process (e.g., smaller quantities of NO_x are formed during combustion); and (2) those that reduce the amount of NO_x after it is formed during combustion, but prior to exiting the stack into the atmosphere. It is common to refer to the first approach as combustion modifications, whereas technologies in the second category are termed post-combustion controls. Combinations of some of these technologies are not only possible, but are also often desirable as they may produce more effective NO_x control than the application of a stand-alone technology.

A summary of available NO_x control technology options are shown in Table 4.9. Combustion modifications can vary from simple “tuning” or optimization efforts to the deployment of dedicated technologies such as Low NO_x Burners (LNB), Overfire Air (OFA) or Flue Gas Recirculations (FGR). Conventional, commercial post-combustion NO_x controls include Selective Non-Catalytic Reduction (SNCR) and Selective Catalytic Reduction (SCR). They are fundamentally similar, in that they use an ammonia-containing reagent to react with the NO_x produced in the boiler to convert the NO_x to harmless nitrogen and water. SNCR accomplishes this at higher temperatures (1,700ºF-2,000ºF) in the upper furnace region of the boiler, while SCR operates at lower temperatures (about 700ºF) and hence, needs a catalyst to produce the desired reaction between ammonia and NO_x.

Cost of Compliance – NO_x Control Options

To compare the various control options, information has been compiled on the cost-effectiveness of fuel switching and retrofitting controls. In general, cost-effectiveness increases as boiler size and capacity factor (a measure of boiler utilization) increases. All costs estimates for years other than 2014 were converted to 2014 dollars using the Chemical Engineering Plant Index, except where noted.

Reducing the amount of fuel used by boilers is one of the most cost effective ways to control NO_x emissions. Tuning-up a boiler optimizes the air-fuel mixture for the operating range of the boiler which ensures less fuel is wasted, and reduces emissions produced by inefficient combustion. Conducting an energy assessment of the systems and processes that the boiler supports helps to identify opportunities to improve boiler system efficiencies and reduce fuel use. EPA has estimated that the initial set-up for a boiler tune-up ranges from $3,000 to $7,000 per boiler, and thereafter, an annual tune-up costs $1,000 per boiler per year (EPA, 2013).

Table 4.9 Available NO_x Control Options For ICI Boilers

Technology	Description	Applicability	Performance
Boiler Tuning or Optimization	Adjusting the fuel/air ratio to operate the boiler more efficiently	Applicable to all ICI boilers	5 to 15% reduction in NO_x emissions
Low Excess Air	Involves limiting the amount of excess air in order to limit the amount of extra nitrogen and oxygen that enters the flame	Applicable to most ICI boiler types	5 to 10% reduction in NO_x emissions
Low-NO_x Burners	Involves changing the design of a standard burner in order to create a larger flame to lower flame temperatures and lower thermal NO_x formation which, in turn, results in lower overall NO_x emissions.	Applicable to most ICI boiler types	~ 50% for traditional LNB ~ 65% for ultra LNB ~ 85% for next generation ultra LNB
Overfire Air	Combustion air is diverted from the burners to create a fuel rich zone in the lower furnace. Peak flame temperatures are reduced to limit thermal NO_x formation.	Applicable to most ICI boiler types	5 to 15% reduction in NO_x emissions
Flue Gas Recirculation	Recirculates a portion of relatively cool exhaust gases back into the combustion zone in order to lower the flame temperature and reduce NO_x formation.	Applicable to most ICI boiler types	30 to 60% reduction in NO_x emissions
Selective Noncatalytic Reduction	Involves injection of a NO_x reducing agent, such as ammonia or urea, in the boiler exhaust gases at temperatures of approximately 1400-2000°F	ICI boilers operating at higher temperatures	25 to 50% reduction in NO_x emissions
Selective Catalytic Reduction	Involves injection of ammonia or urea into the exhaust gases in the presence of a catalyst at temperatures between 500° and 1200°F	ICI boilers operating at lower temperatures	90% reduction in NO_x emissions
Technology Combinations	Combination of a combustion modifications such as LNB/OFA with a post-combustion technology such as SCR or SNCR	Applicable to most ICI boiler types	Can exceed 90% reduction in NO_x emissions

Table references: NESCAUM 2009; EPA 2015e; EPA 2015f

EPA estimated that the tune-up will achieve at least a 1% improvement in efficiency which will result in fuel savings costs that will offset the tune-up costs. EPA also estimated that the one-time cost of an energy assessment ranges from $2,500 to $75,000 depending on the size of the facility. Energy assessments at selected manufacturing facilities shows that facilities can reduce fuel/energy use by 10 to 15%, with the fuel savings costs offsetting the cost of the energy assessment.

As mentioned in the previous section, switching from high sulfur fuels (coal, residual oil) to low sulfur fuels (ultra-low-sulfur distillate, natural gas) may be a cost-effective strategy for reducing SO_2 emissions. The per Btu NO_x emissions for high sulfur fuels are higher than for low-sulfur fuels (e.g., uncontrolled NO_x emissions for coal are generally 0.4 – 0.8 lbs/MMBTU, 0.2 – 0.4 lbs/MMBTUMMBTU for residual oil, and 0.1 – 0.2 lbs/MMBTUMMBTU for distillate oil and natural gas). The switch from high-sulfur fuels to low- or no-sulfur fuels will also have a NO_x reduction co-benefit.

Estimates of the NO_x combustion modification and post-combustion control costs for ICI boilers were obtained from published values in recent literature. The estimates previously used in the *2007 Assessment* (MACTEC, 2007) were not used here because the EPA publications that served as the basis for those cost estimates are dated, and more recent cost factors are available. A brief summary of the key elements of these studies is provided below.

- In December 2005, environmental commissioners from Northeast and Midwest States initiated a state collaborative process. A staff-level workgroup was formed in 2006 to evaluate control options ICI boilers. To develop improved control cost estimates for ICI boilers, the workgroup assembled detailed information on direct capital equipment costs, direct installation costs, indirect capital costs and direct and indirect operating costs. These data were used in cost estimation algorithms that were originally modeled after the factor cost estimate methodology found in the US EPA *Air Pollution Control Cost Manual*. Factor cost estimates are based on empirical factors that are used to estimate the cost of various elements. The algorithms were coded in a user friendly format (Excel spreadsheets) and account for the key variables that impact the cost analysis, including: boiler type and size, type of fuel combusted, type of emission control, uncontrolled and controlled emission rates, capital cost of control equipment (e.g., purchased equipment cost), financial costs (e.g., interest rates), unit capacity factor (hours/year), flue gas flow rates, and commodity prices (e.g., lime, water). See: Bodnarik, 2009 and OTC/LADCO, 2010.
- MARAMA and the Institute of Clean Air Companies (ICAC) sponsored Advances in Air Pollution Control Technologies Workshop to provide state/local agency staff with the latest information on current and emerging emission control technologies. Cost estimates for several control technologies were developed by Dr. James Staudt using proprietary algorithms or algorithms developed for others (EPA). All cost data was benchmarked against independent data. See: Staudt, 2011.
- The Ontario Ministry of Environment sponsored a study air pollution control options at six refineries in Ontario. The study included the development of the sizing and costing algorithms (SCAs) for the 24 emission reduction technologies, including refinery boilers and heaters. The SCAs were modeled after the factor cost estimate methodology found in

> the US EPA *Air Pollution Control Cost Manual*, included independent purchased equipment costs from current vendor data for Ontario locations. Equations were developed to fit the vendor data for cost of equipment of different sizes found at individual facilities. Factors were developed to estimate cost of auxiliary equipment, direct costs, indirect costs, and operating costs. Since this project used confidential business information, the algorithms were applied for this study for fictitious installations generally representative of the industry sector. See: EHS, 2014.

These studies provided valuable information on control options and cost effectiveness estimates for ICI boilers.

In theory, most of the technologies described above can be used together (NESCAUM, 2009). However, NO_x reductions are not necessarily additive, and more importantly, the economics of the combined technologies may or may not be cost-effective. Such analyses are highly specific to the site and strategy. However, several such technology combinations are considered attractive and have gained acceptance. For example, the combination of LNB/OFA with either SCR or SNCR is more prevalent than the application of the post-combustion technologies alone. The economics of this approach are justified by the reduced chemical (SNCR) and capital costs (SCR – smaller reactor/catalyst) due to lower NO_x levels entering the SCR/SNCR system.

Literature values of capital costs have been reported for different base years. The calculated capital cost values from the literature were normalized to a base year of 2014 using the Chemical Engineering Plant Cost Index values. Table 4-9 summarizes the published NO_x control costs for a number of NO_x control technologies and combinations of control technologies.

Table 4.9 Summary of Cost-Effectiveness of NO_x Control Options

Control Option	**Fuel Type**	**Emission Reduction**	**Boiler Size (MMBTU/hr)**	**Cost-Effectiveness ($2014 / ton of NO_x Removed**	**Reference**
Overfire Air	Natural Gas	25% from 0.20 to 0.15 lb NO_x/MMBTU	100 200 300 400	4,533 2,709 1,990 1,685	Staudt, 2011
Low NO_x Burners	Natural Gas	50% from 0.20 to 0.10 lb NO_x /MMBTU	100 200 300 400 500	2,764 1,714 1,327 1,161 1,050	Staudt, 2011
Low NO_x Burners	Natural Gas, Distillate Oil	50% from 0.20 to 0.10 lb NO_x /MMBTU	50 100 250 750	10,930 – 43,721 5,475 – 21,861 2,196 – 8.744 730 – 2,918	Bodnarik, 2009
Ultra-low NO_x Burners	Natural Gas	70% from 0.20 to 0.05 lb NO_x /MMBTU	100 200 300 400 500	2,211 1,548 1,161 1,050 995	Staudt, 2011
Ultra-low NO_x Burners	Refinery Fuel Gas and/or Oil	70% from 0.14 to 0.03 lb NO_x /MMBTU	50 - 500	1,357	EHS, 2014

Control Option	Fuel Type	Emission Reduction	Boiler Size (MMBTU/hr)	Cost-Effectiveness ($2014 / ton of NO_x Removed	Reference
Overfire Air	Residual Oil	25% from 0.37 to 0.28 lb NO_x /MMBTU	100 200 300 400 500	2,018 1,050 691 553 442	Staudt, 2011
Low NO_x Burners	Residual Oil	50% from 0.4 to 0.2 lb NO_x /MMBTU	50 100 250 750	5,475 – 21,861 2,738 – 10,930 1,093 – 4,372 365 – 1,454	Bodnarik, 2009
Low NO_x Burners	Residual Oil	50% from 0.37 to 0.185 lb NO_x /MMBTU	100 200 300 400 500	1,271 691 470 415 331	Staudt, 2011
Low NO_x Burners plus Flue Gas Recirculation	Residual Oil	60% from 0.4 to 0.16 lb NO_x /MMBTU	50 100 250 750	13,237 – 26,875 6,618 – 13,437 2,647 – 5,375 882 – 1,795	Bodnarik, 2009
Low NO_x Burners plus Overfire Air	Residual Oil	65% from 0.37 to 0.13 lb NO_x /MMBTU	100 200 300 400 500	912 498 415 276 221	Staudt, 2011
Overfire Air	Coal	25% from 0.7 to 0.52 lb NO_x /MMBTU	100 200 300 400 500	1,493 896 674 608 498	Staudt, 2011
Low NO_x Burners	Wall-fired Coal	50% from 0.7 to 0.35 lb NO_x /MMBTU	50 100 250 750	3,129 – 12,495 1,564 – 6,247 626 – 2,497 209 - 833	Bodnarik, 2009
Low NO_x Burners	Coal	65% from 0.7 to 0.25 lb NO_x /MMBTU	100 200 300 400 500	1,050 691 652 553 470	Staudt, 2011
SNCR	Not specified	25 to 65%, depending on fuel and type of industry	50 100 250 750	12,000 7,500 5,000 2,500	EPA, 2015e
SNCR	Residual Oil	50% from 0.4 to 0.2 lb NO_x /MMBTU	50 100 250 750	10,579 – 14,881 5,916 – 8,062 3,119 – 3,981 1,875 – 2,156	Bodnarik, 2009
SNCR	Wall-fired Coal	45% from 0.7 to 0.39 lb NO_x /MMBTU	50 100 250 750	7,230 – 9,958 4,272 – 5,636 2,487 – 3,038 1,695 – 1,885	Bodnarik, 2009

Control Option	**Fuel Type**	**Emission Reduction**	**Boiler Size (MMBTU/hr)**	**Cost-Effectiveness ($2014 / ton of NO_x Removed**	**Reference**
SNCR plus Low NO_x Burners plus Overfire Air	Coal	75% from 0.7 to 0.18 lb NO_x /MMBTU	100 200 300 400 500	2,018 1,327 1,050 940 829	Staudt, 2011
SCR	Refinery Fuel Gas and/or Oil	90%	100 250 500 750	12,704 8,662 7,507 5,775	EHS, 2014
SCR	Residual Oil	85% from 0.4 to 0.0.675 lb NO_x /MMBTU	50 100 250 750	11,251 – 39,911 5,856 – 20,156 2,627 – 8,353 1,183 – 3, 089	Bodnarik, 2009
SCR	Wall-fired Coal	85% from 0.7 to 0.11 lb NO_x /MMBTU	50 100 250 750	6,518 – 22,904 3,440 – 11,632 1,594 – 4,874 772 – 1,865	Bodnarik, 2009

FACTOR 2 – COMPLIANCE TIMEFRAME

States typically need 2-3 years to develop new regulations, and sources generally are given a 2-4 year phase-in period to comply with new rules. Most MACT standards allow a 3-year compliance period. States generally provided a 2-year period for compliance with RACT rules. For the purposes of this review, we have assumed that a 2-year period after SIP submittal is adequate for pre-combustion controls (fuel switching or cleaning) and a three year period for the installation of post combustion controls.

For BART control measures, the BART guidelines required States to establish enforceable limits and require compliance with the BART emission limitations no later than 5 years after EPA approves the regional haze SIP.

Refiners in the United States are already producing ultra-low sulfur distillate oil which may be marketed as diesel fuel in accordance with EPA on-road and off-road fuel sulfur content standards. ICI boilers would not have to retrofit or install expensive control technology to burn ultra-low sulfur distillate oil, and compliance with the standard is simply driven by supply and demand.

For combustion based and post-combustion based engineering and construction leads times will vary between 2 and 5 years depending on the size of the facility and specific control technology selected.

FACTOR 3 – ENERGY AND NON-ENVIRONMENTAL IMPACTS

Fuel switching and cleaning do not significantly affect the efficiency of the boiler but may add to transportation issues and secondary environmental impacts from waste disposal and material handling operations (e.g. fugitive dust). FGD systems typically operate with high pressure drops across the control equipment, resulting in a significant amount of electricity required to operate blowers and circulation pumps. In addition, some combinations of FGD technology and plant configuration may require flue gas reheating to prevent physical damage to equipment, resulting in higher fuel usage.

The primary environmental impact of FGD systems is the generation of wastewater and sludge from the SO_2 removal process. When the exhaust gas from the boiler enters the FGD the SO_2, metals, and other solids are removed from the exhaust and collected in the FGD liquid. The liquid slurry collects in the bottom of the FGD in a reaction tank. The slurry is then dewatered and a portion of the contaminant-laden water is removed from the system as wastewater. Waste from the FGD systems will increase sulfate, metals, and solids loading in a facility's wastewater, potentially impacting community wastewater treatment facilities for smaller units that do not have self-contained water treatment systems. In some cases FGD operation necessitates installation of a clarifier on site to remove excessive pollutants from wastewater. This places additional burdens on a facility or community wastewater treatment and solid waste management capabilities. These impacts will need to be analyzed on a site-specific basis. If lime or limestone scrubbing is used to produce calcium sulfite sludge, the sludge must be stabilized prior to landfilling. If a calcium sulfate sludge is produced, dewatering alone is necessary before land filling, however, SO_2 removal costs are higher due to increased equipment costs for this type of control system. In some cases calcium sulfate sludge can be sold for use in cement manufacturing.

With wet FGD technologies a significant visible plume is present from the source due to condensation of water vapor as it exits the smoke stack. Although the water eventually evaporates and the plume disappears, community impact may be significant.

Reducing the sulfur contents of distillate fuel oil has a variety of beneficial consequences for ICI boilers. Low sulfur distillate fuel is cleaner burning and emits less particulate matter which reduces the rate of fouling of heating units substantially and permits longer time intervals between cleanings. According to a study conducted by the New York State Energy Research and Development Authority (NYSERDA), boiler deposits are reduced by a factor of two by lowering the fuel sulfur content from 1,400 ppm to 500 ppm. These reductions in buildup of deposits result in longer service intervals between cleanings. (NYSERDA, 2005)

FACTOR 4 – REMAINING USEFUL LIFE

The remaining useful life of the source depends primarily on the age of the boiler, which must be evaluated on a source-by-source basis. Other source-specific factors affecting remaining useful life estimates of ICI boilers include average operating hours, capacity factors, size of the unit, capacity factor, and level of maintenance performed. Typical life expectancies range from about 10 years up to over 30 years.

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CHAPTER 8

SOURCE CATEGORY ANALYSIS: HEATING OIL

BACKGROUND

Source Category Description

Americans use many different energy sources to heat their homes, including heating oil, natural gas, electricity, bottled propane, and kerosene. Renewable sources, including wood combustion and solar photovoltaic installations, are becoming more common. Energy prices, availability of supplies, age of the residence and climate play a big role in the type and amount of fuel used.

Heating oil (alternatively referred to as fuel oil or #2 distillate heating oil) is a middle-distillate refined petroleum product comparable to diesel fuel (except for additives and sulfur content). Heating oil burners emit a variety of air pollutants that: contribute to the formation of ozone and fine particulate matter, regional haze; play a part in acid deposition and nitrification of water bodies; add to the global mercury pool; and factor in the build-up of greenhouse gasses in the atmosphere (NESCAUM, 2005). Of primary concern for this analysis, the combustion of heating oil is a significant source of sulfur dioxide (SO_2) emissions in the MANE-VU region.

Heating oil is particularly important in the MANE-VU region. The 2009 Residential Energy Consumption Survey (EIA, 2013) determined that about 42% of homes in New England reported heating oil as the main heating energy source. In the southern part of the MANE-VU region, 22% of homes used oil for home heating. Nationally, only 6% of homes used oil. Natural gas is the most widely used energy source for home heating in the southern part of the MANE-VU region, electricity is most prevalent in the Southeastern U.S. and natural gas dominates in the Midwest.

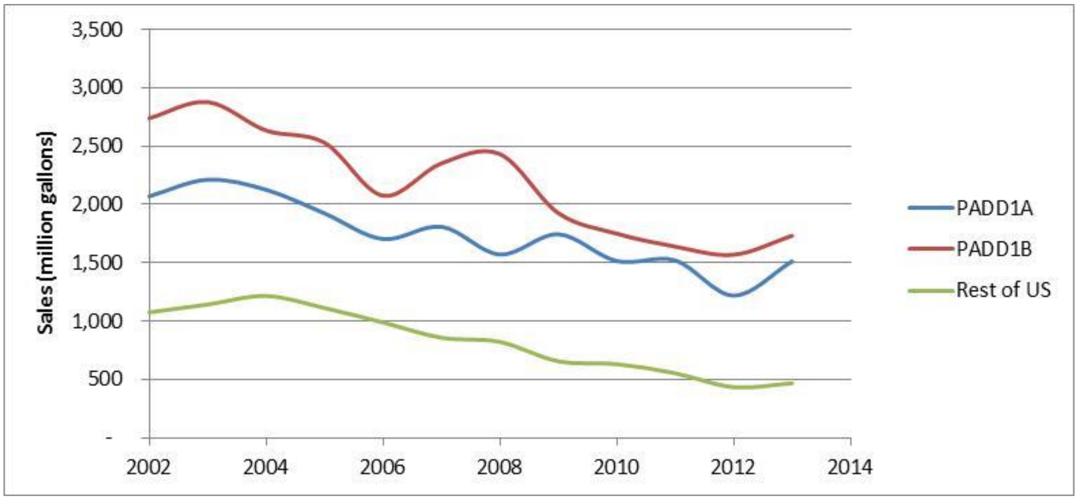
Consumption and Emission Trends

For decades, space heating and cooling has accounted for more than half of all residential energy consumption. Estimates show that 48% of energy consumption in U.S. homes in 2009 was for heating and cooling, down from 58% in 1993 (EIA, 2012). Factors underpinning this trend are increased adoption of more efficient equipment, better insulation, more efficient windows, and population shifts to warmer climates.

The demand for heating oil in the U.S. has been declining over the last decade. Figure 8.1 shows the trends in residential heating oil sales for the New England states, the other MANE-VU states, and the remainder of the U.S. (EIA, 2015). In New England, heating oil consumption decreased from 2.1 billion gallons in 2002 to 1.5 billion gallons in 2013, a decrease of about 27%. The decreases in consumption over this period were even larger in the other MANE-VU states (37% decrease) and nationally (56% decrease).

A recent study by the Congressional Research Service identified some of the reasons for declining heating oil demand (CRS, 2014). According to the CRS, no single factor explains the

Figure 8.1 Trends in Residential Heating Oil Sales



PADD 1A (New England: CT, ME, MA, NH, RI, and VT)
PADD 1B (Central Atlantic: DE, DC, MD, NJ, NY, and PA)
Source: EIA, 2015

Northeast's declining demand for heating oil. Steady price increases for heating oil appear to correlate with declining demand and consumers may have responded by using less heating oil (heating oil price trends are discussed in greater detail later in this Chapter). Some residential consumers may have switched to electricity, natural gas, bottled gas, or kerosene. More energy-efficient and better-insulated new houses could have replaced older units. Newer, more efficient oil-heat furnaces could have replaced older units.

In addition, a recent EIA study shows that wood as the main heating source in homes has gained popularity in many areas of the country in recent years. The increase is most notable in the Northeast, where there was at least a 50% increase from 2005 to 2012 in the number of households that rely on wood as the main heating source (EIA, 2014). As discussed later in this Chapter, heating oil prices have declined dramatically since 2014 and are forecasted to remain low for the next few years, which may lead to increased demand as consumers choose heating oil over other fuels.

As heating oil sales have decreased, so too have the emissions of SO_2 from the combustion of heating oil. Table 8.1 shows the trends in SO_2 emissions from residential heating oil combustion for the MANE-VU states and states in the neighboring RPOs. SO_2 emissions are directly proportional to amount of fuel consumed and fuel oil sulfur content. While consumption has decreased, the sulfur content has remained about the same from 2002 to 2012, ranging from 2,000 to 3,000 parts per million.

As discussed in the next section, some MANE-VU states began restricting the sulfur content heating oil in 2012, and most states will have heating oil sulfur restriction in place by 2018. Preliminary projections estimate that SO_2 emissions from heating oil combustion may decrease by as much as 95-99% by 2018 in the MANE-VU region. Final projections are not available for this report.

Table 8.1 Trends in SO_2 Emissions from Residential Heating Oil Combustion

RPO	**2002**	**2007/2008**	**2011**	**2014**
MANE-VU	130,736	95,864	71,429	Not yet available
MRPO	8,750	7,458	3,848	Not yet available
VISTAS	9,947	8,814	5,843	Not yet available

MANE-VU (CT, DC, DE, MA, MD, ME, NH, NJ, NY, PA, RI, and VT)
MRPO (IL, IN, OH, MI, WI)
VISTAS (AL, FL, GA, KY, MS, NC, SC, TN, VA, WV)
MANE-VU emissions obtained from 2002, 2007 and 2011 inventories prepared by MARAMA
MRPO and VISTAS emissions obtained from 2002, 2008 and 2011 EPA national emission inventories

Regulatory History

MANE-VU developed a low sulfur heating oil strategy to help states develop Regional Haze State Implementation Plans (MANE-VU, 2007):

- A strategy in the inner zone States (New Jersey, New York, Delaware, and Pennsylvania, or portion thereof) to reduce the sulfur content of heating oil to 500 ppm by no later than 2012 and to further the reduce the sulfur content to 15 ppm by 2016;
- A strategy in the outer zone States (remainder of MANE-VU region) to reduce the sulfur content heating oil to 500 ppm by no later than 2014 and to further reduce the sulfur content to 15 ppm by 2018.

The status of the heating oil sulfur in fuel rules in each state is summarized in Table 8.2.

Table 8.2 Sulfur Limits for Heating Oil in the MANE-VU Region (as of January 15, 2016)

Jurisdiction	Sulfur Restriction	Regulatory Citation
CT	500 ppm July 1, 2014 through June 30, 2018 15 ppm after July 1, 2018	Connecticut General Statutes section 16a-21a – Sulfur content of home heating oil and off-road diesel fuel.
DE	3000 ppm prior to July 1, 2016 15 ppm after July 1, 2016	DE Admin Code - 1108 - Sulfur Dioxide Emissions from Fuel Burning Equipment
DC	500 ppm July 1, 2016 through June 30, 2018 15 ppm after July 1, 2018	Section 801, Sulfur Content of Fuel Oils
MA	500 ppm July 1, 2014 through June 30, 2018 15 ppm after July 1, 2018	310 CMR 7.05 (1)(a)1: Table 1 : Sulfur Content Limit of Liquid Fossil Fuel
MD	500 ppm beginning July 2016; working on a new regulation in 2016 for a 15 ppm limit by July 2018	26.11.09.07 Control of Sulfur Oxides From Fuel Burning Equipment.
ME	15 ppm after July 1, 2018	An Act to Achieve Regional Uniformity in Sulfur Standards for Heating Oil (Chapter 106 rulemaking underway to make it consistent with statute)
NH	4000 ppm; legislative actions expected in 2016 for a 15 ppm limit by July 2018	Part Env-A 1603 Sulfur Content Limitation for Liquid Fuels
NJ	500 ppm July 1, 2014 through June 30, 2016 15 ppm after July 1, 2016	Title 7, Chapter 27, Subchapter 9 Sulfur in Fuels

Jurisdiction	Sulfur Restriction	Regulatory Citation
NY	15 ppm after July 1, 2012	Subpart 225-1 Fuel Composition and Use - Sulfur Limitations
PA	2000 to 5000 ppm through June 30, 2016, depending on air basin 500 ppm after July 1, 2016	§ 123.22. Combustion units
Philadelphia	2000 ppm until June 30, 2015 15 ppm after July 1, 2015	Regulation III – Control of Sulfur Compound Emissions
RI	500 ppm July 1, 2014 through June 30, 2018 15 ppm after July 1, 2018	Air Pollution Control Regulations No. 8 Sulfur Content of Fuels
VT	500 ppm July 1, 2014 through June 30, 2018 15 ppm after July 1, 2018	5-221(1) Sulfur Limitations in Fuel

FOUR FACTOR ANALYSIS OF POTENTIAL CONTROL SCENARIOS FOR EMISSIONS FROM HEATING OIL COMBUSTION

The remainder of this memorandum presents the four factor analysis that was applied to the heating oil sulfur reduction regulations. The four factors are: cost of compliance, time necessary for compliance, energy and non-air impacts, and remaining useful life of the sources. This document primarily focuses on reducing the sulfur content of heating oil to 15 ppm.

Costs of Compliance

This section first summarizes the costs for retrofitting refineries so that they could supply 15 ppm heating oil in sufficient quantities to meet MANE-VU heating oil demands. This is followed by a discussion of the price impacts for consumers.

Domestic oil refiners have already made extensive capital investments to produce lower sulfur distillate fuels to comply with EPA's national ultra-low sulfur diesel (ULSD) requirements for transportation fuels. Beginning in September 2006, the permissible level of sulfur in highway diesel fuel was 15 ppm. Prior to that, highway low sulfur diesel fuel was refined to contain 500 ppm sulfur. By 2010, all highway diesel fuel was to meet the 15 ppm sulfur requirement. Diesel fuel intended for locomotive, marine and non-road engines and equipment was required to meet the low sulfur diesel fuel maximum specification of 500 ppm sulfur in 2007. By June 2010, the ULSD fuel standard of 15 ppm sulfur applied to all non-road diesel fuel production. Beginning in 2012, locomotive and marine diesel fuel was required to meet the ULSD fuel standard of 15 ppm sulfur.

In its highway and nonroad diesel fuel rulemakings, EPA developed cost estimates for the deployment and implementation of desulfurization technologies at refineries (EPA, 2000; EPA, 2004). Table 8.3 summarizes EPA's cost estimates. For the highway ULSD rule, EPA estimated that it would cost existing refineries an average of $47.8 million (2002 dollars) per refinery to install desulfurization technologies to meet the highway ULSD requirements. EPA estimated that the total capital costs were $5.45 billion.

Table 8.3 EPA Estimated Costs of Desulfurizing Highway and Nonroad Diesel Fuel to Meet a 15 ppm Standard (2002 Dollars)

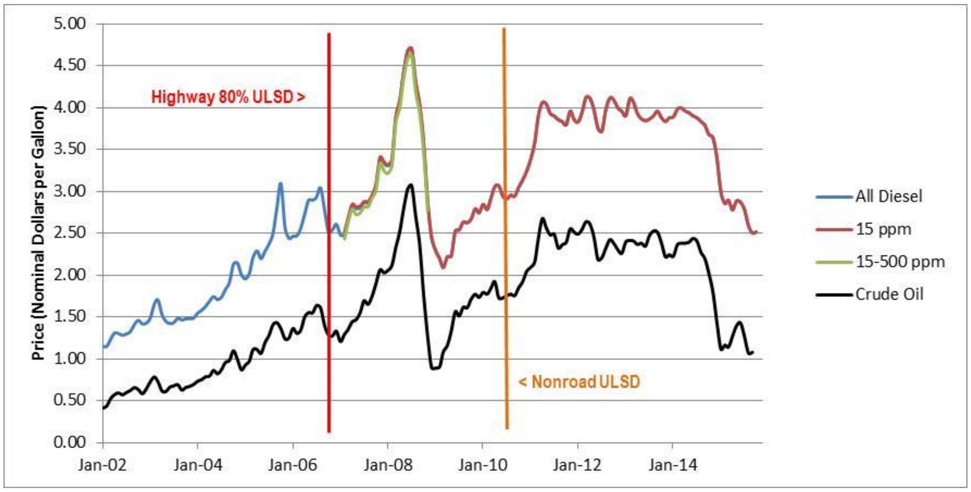
	Highway ULSD Rule	Nonroad ULSD Rule
Total Capital Cost ($million)	5,450	2,730
Average Capital Cost per Refinery ($million)	47.8	42.7
Average Operating Cost per Refinery ($million per year)	9.0	10.6
Per Gallon Cost (cents/gallon)	3.6	7.1

Source: EPA, 2000; EPA, 2004.

For complying with the 15 ppm sulfur cap standards applicable to nonroad diesel fuel in 2010 and to locomotive and marine diesel fuel in 2012, refiners were able to use the experience gained from complying with the 15 ppm highway diesel fuel standard. EPA projected that some refiners will utilize lower cost advanced desulfurization technologies recently commercialized. Others would rely on extensions of conventional hydrotreating technology which most refiners were already using to comply with the 15 ppm cap for highway diesel fuel in 2006. For the nonroad ULSD, EPA estimated that it would cost existing refineries an average of $42.7 million (2002 dollars) per refinery to install desulfurization technologies to meet the nonroad ULSD requirements. Total capital costs were estimated to be $2.73 billion. EPA estimated the average costs for 15 ppm sulfur nonroad fuel to be an additional 7.1 cents per gallon in 2014.

How have the EPA low sulfur highway and nonroad requirements affected diesel prices? Figure 8.2 shows that the shift to ULSD was relatively small in terms of the absolute price of diesel fuel compared to the magnitude of volatility in crude oil prices (EIA, 2015). The petroleum refining industry has a long history of cyclical performance. Cycles in the industry have been historically related to movements in the price of crude oil, which is the primary cost element in refinery operations, and this will likely remain true in the future. About 60 % of the price of a gallon of diesel fuel is contained in the raw crude oil. The remaining cost of producing diesel fuel is found in refining, marketing, taxes and other expenses. As a result, the price for 15 ppm sulfur diesel in 2015 is about the same as higher sulfur diesel before the EPA requirements took effect.

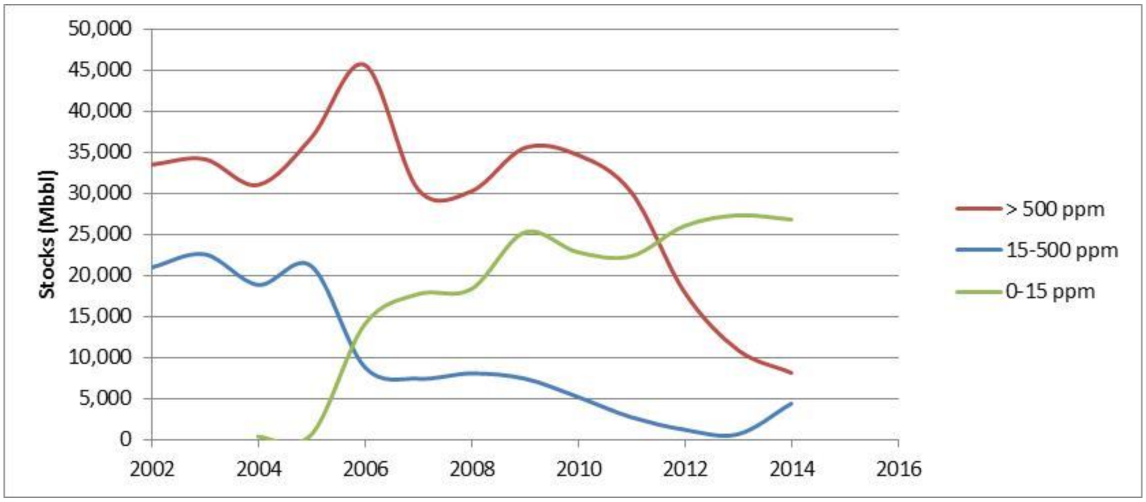
Figure 8.2 Comparison of Refiner Cost of Oil to Diesel Retail Prices



Source of Cost Data: EIA, 2015.

As a result of these EPA rulemakings, technologies are currently available to achieve significant reductions in heating oil sulfur as many refiners are already meeting a 15 ppm average for transportation fuels. Refineries have already made significant capital investments required for the production of LSD and ULSD fuel oil. EIA reported that total ULSD production progress has been good and has been able to meet the demand. Distillate stocks of ULSD have risen significantly in the East Coast over the past few years, as shown in Figure 8.3.

Figure 8.3 Trends in Distillate Stocks in PADD 1 (East Coast)



Source: EIA, 2015.

As a result of state actions to implement the MANE-VU low sulfur heating oil strategy, refiners are continuing to make further upgrades to produce ultra-low sulfur heating oil. These capital investments are expected to be considerably lower than those needed to meet the highway and nonroad sulfur requirements. Heating oil is only 11% of the total distillate production in the region and just over 3% of total refinery output.

Since refiners are already producing 15 ppm heating oil to meet New York's requirement for 15 ppm heating oil, how have heating oil prices been affected? Figure 8.4 shows the trends in heating oil prices in New York (NYSERDA, 2015). The maximum weekly heating oil price for the 2011/2012 heating season (before the 15 ppm requirements took effect) was $4.17 per gallon, and the maximum price for the 2012/2013 heating season was $4.25 per gallon, or 8 cents higher than the previous heating season. With the recent drop in crude oil prices, the weekly price per gallon for the 2014/2015 season dropped from $3.81 in September 2014 to $3.02 in February 2015. The price at the beginning of the 2015/2016 heating season was about $2.50 per gallon.

Thus, the anticipated cost increase from a shift to ULSD will be relatively small in terms of the absolute price of heating oil compared to the magnitude of volatility in crude oil prices. The price of heating oil once a complete shift to ULSD occurs will be set by the larger oil market.

Finally, according to the Consumer Energy Council of America (CECA, 2015), research indicates that the slight fuel price premium is more than compensated by cost savings associated with longer equipment life, greater fuel stability, and reduced maintenance and cleanings of the heating equipment.

Figure 8.4 Trends in Heating Oil Prices in New York State

Source: NYSERDA, 2015.

Time Necessary for Compliance

Refiners have demonstrated that they have been able to meet ULSD specifications for highway vehicles and nonroad equipment given sufficient lead time for the necessary investments. Past experience suggests at least 5 years will be needed for the industry to make the necessary investments for the heating oil market. Refiners in the U.S. have already made the switch to producing low sulfur fuel for highway vehicles, nonroad equipment, and the New York residential heating oil market. This same fuel can be marketed as heating oil since it is very similar to the highway/nonroad diesel fuel already produced.

The capacity for producing ULSD already exists among U.S. refiners, and 15 ppm heating oil is already being supplied for the extensive New York market. Some time may be required to allow petroleum marketers to adjust to distributing ULSD to heating oil customers, however, the distribution network for motor fuels and heating oil are already in place. With the phased-in timing for the remaining states, there appears to be sufficient time to allow refiners to add any additional heating oil capacity that may be required.

Small refiners may need more time to comply with a low sulfur control program. Small refiners generally have a more difficult time in obtaining funding for capital projects, and must plan further in advance of when the funds are needed. In EPA’s nonroad ULSD rulemaking, small refiners were provided additional time (up to three years) to provide enough time to select the most advantageous desulfurization equipment, and for securing capital funds to purchase and construct the desulfurization equipment.

Existing stocks of heating oil with higher than 15 ppm sulfur content may be in existence for several months after the date for refineries to produce only 15 ppm sulfur content heating oil. It may take several months for the full benefits of any ultra-low sulfur in fuel standard to be observed as the blending of varying sulfur content fuels will be occurring during this transition period. Therefore, the fuel oil that is actually stored within a tank and eventually combusted may not initially meet the 15 ppm standard, but will eventually be blended down to be below the 15 ppm sulfur content standard after repeated tank refills.

Finally, existing residential furnaces and boilers do not need to be retrofitted or modified to combust heating oil with a 15 ppm sulfur content. Consequently, the time necessary for compliance does not hinge on the replacement of existing heating oil furnaces or boilers to newer models.

Energy and Non-Air Environmental Impacts

Reducing the sulfur contents of heating oil has a variety of beneficial consequences for residential furnaces and boilers. Low sulfur distillate fuel is cleaner burning and emits less particulate matter which reduces the rate of fouling of heating units substantially and permits longer time intervals between cleanings.

The decreased sulfur levels would enable manufacturers to develop more efficient furnaces and boilers by using more advanced condensing furnaces and boilers. These boilers recoup energy that is normally lost to the heating of water vapor in the exhaust gases. Historically, the use of high sulfur fuels prevented this due to the corrosion of the furnace/boiler due to the creation of sulfuric acid in the exhaust gases. The increased efficiency results in a decrease in the amount of heating oil a heating unit uses, therefore, this would make a switch to lower sulfur heating oil more attractive and cost effective.

Remaining Useful Life of the Source

Residential furnaces and boilers have finite life times, but they do not need to be replaced to burn low or ultra-low sulfur fuel. Taking sulfur out of fuel causes no problems for oil heating equipment or storage tanks. On the contrary there is a great benefit to reducing sulfur because sulfur when burned will cause sooting and scaling and reduce efficiency. Reducing the amount of sulfur prolongs the life of heat exchangers, particularly those in condensing boilers and furnaces (Irving, 2016).

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CHAPTER 9

SOURCE CATEGORY ANALYSIS: RESIDENTIAL WOOD COMBUSTION

BACKGROUND

The MANE-VU Contribution Assessment and other MANE-VU reports have documented that visibility impairment in this region is primarily due to regional secondary sulfate (NESCAUM 2006). In addition, biomass combustion as a contributor to visibility impairment in MANE-VU Class I areas. Biomass combustion emissions due to human activity primarily derive from residential wood combustion. While some biomass burning occurs throughout the year, residential wood combustion occurs predominantly in the winter months, potentially contributing to wintertime peaks in PM concentrations.

MANE-VU previously developed an assessment (MACTEC, 2007) of control technologies to achieve reasonable progress goals with respect to the four factors listed in Section 169A of the Clean Air Act. The information presented in this Chapter is an update to some parts of the MACTEC report.

Source Category Description

Wood heating devices embody a variety of products that provide heat for residential consumers by burning wood or other solid biomass fuel. Indoor wood-burning devices can provide space heating for a single room or can be central heaters for a residential home. Indoor heating devices include freestanding wood stoves, pellet stoves, fireplace inserts, and forced-air furnaces. Outdoor wood heating devices, also known as outdoor wood boilers (OWBs) or hydronic heaters, are typically located adjacent to the home they heat in small sheds with short smoke stacks. OWBs are discussed in Chapter 10. Other wood-burning devices include low-mass fireplaces, open masonry fireplaces, fireplaces, fire pits, chimineas, cook stoves, masonry heaters, and pizza ovens. Campfires also generate air pollution, but are not considered in this analysis due to lack of available data. Table 9.1 provides a summary of the key characteristics of the types of devices included in this category.

Table 9.1 Types of Residential Wood Combustion Devices

Device Type	Description	Emission Characteristics
Indoor and Outdoor Fireplaces	Combustion air is drawn from the natural draft created by fire, and that same draft vents the exhaust gases through the chimney.	Typically have low efficiencies due to the large amount of heated room air that is exhausted out of the chimney; considered more of an aesthetic feature than a functional heating device
Fireplace Inserts	A type of heater/stove that is designed to fit inside the firebox of an existing wood-burning fireplace	Closed-door system, improves combustion by slowing down the fire, decreasing the excess air, and increasing the fire's temperature
Woodstoves - Conventional	Enclosed combustion devices that provide direct space heating for a specific room or area of a home	Units manufactured before 1990, do not have any emission reduction technology or design features
Woodstoves – EPA-certified, non-catalytic	Enclosed combustion devices that provide direct space heating for a	Relies on high temperatures (>1,000°F) within the fire box to fully combust the combustible gases

Device Type	Description	Emission Characteristics
	specific room or area of a home	and particles in the wood smoke
Woodstoves - EPA-certified, catalytic	Enclosed combustion devices that provide direct space heating for a specific room or area of a home	Presence of a catalytic element lowers the temperature at which wood smoke chemical compounds combust.
Wood Pellet Stoves	Uses tightly compacted pellets of wood or sawdust as fuel; a feed device regulates the amount of fuel that is released from a hopper into the heating chamber, which is where the combustion takes place	Typically more efficient in terms of combustion and heating than standard wood stoves but require electricity to operate the fans, controls, and pellet feeders
Masonry Heaters	Similar in appearance to fireplace, but are used primarily to generate heat, whereas fireplaces typically serve a more aesthetic purpose.	Cleaner-burning and more heat-efficient form of primary and supplemental radiative heat than a traditional fireplace
Force-Air Furnaces	Typically located inside a house and provides controlled heat throughout a home using a network of air ducts	PM emissions 7-8 times higher compared to woodstoves or pellet stoves
Fire Pits, Chimineas, Cook Stoves, Pizza Ovens, Campfires	Outdoor appliances involve using wood fuel for cooking or heating.	Used primarily for recreational purposes

Source: EPA, 2015a.

Thermal output, typically expressed in British thermal units per hour (BTU/hr), is the heat output measure that tells the amount of heat produced each hour. A higher BTU/hr rate suggests that a stove will produce more heat per hour than a stove with a lower rating. Depending on design and size characteristics, a space heating device heat output rating ranges between 8,000 and 90,000 BTU/hr. Larger heating systems designed to provide whole home heating have heat output ratings that range from 100,000 to greater than one million BTU/hr.

Emission and Consumption Trends

Table 9.2 shows the CO, $PM_{2.5}$ and VOC emissions in 2011 from residential wood combustion for the MANE-VU, MRPO, and VISTAS RPO states. The emission estimates were developed by EPA using the Residential Wood Combustion Tool. This tool computes county-and SCC-level emissions of criteria air pollutants for the entire country. EPA updated the inputs to the tool for the 2011 National Emission Inventory in partnership with the Eastern Regional Technical Advisory Committee (ERTAC). Emission trends over the past decade are not available due to improvements in emission factors and emission estimation methodologies. The new Residential Wood Combustion Tool used a new suite of source categories, new emission factors and new calculation methodology. Thus, the resulting emissions for this sub-category of area emissions are not comparable between older and newer inventories.

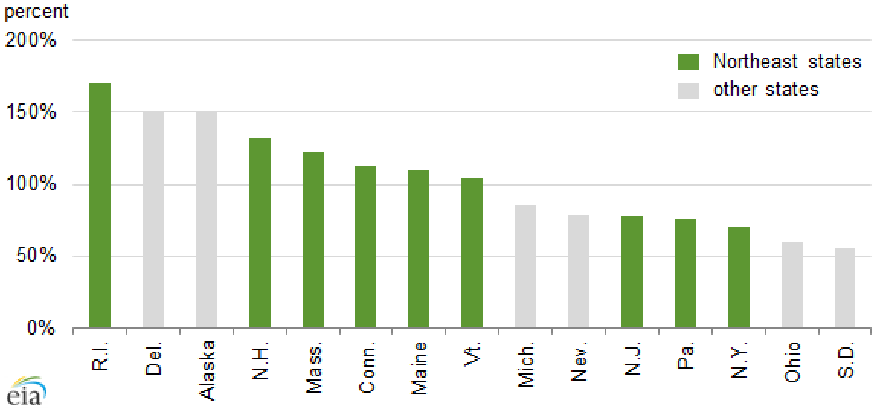
Wood as a main heating source in homes has gained popularity in many areas of the country in recent years, but the increase is most notable in the Northeast (EIA, 2014). As shown in Figure 9.1, most states in the MANE-VU RPO saw at least a 50% increase from 2005 to 2012 in the number of households that rely on wood as the main heating source. As the price of fuel oil and kerosene in this region increased during that period, fuel oil and kerosene use has declined in recent years as many households have turned to lower-cost alternatives, including wood.

Table 9.2 Residential Wood Combustion Emissions (tons/year)

SCC	Description	CO	PM$_{2.5}$	VOC
MANE-VU (CT, DC, DE, MA, MD, ME, NH, NJ, NY, PA, RI, VT)				
2104008100	Fireplace: general	51,945	8,228	6,589
2104008210	Woodstove: fireplace inserts; non-EPA certified	108,528	14,389	24,922
2104008220	Woodstove: fireplace inserts; EPA certified; non-catalytic	21,437	2,984	1,827
2104008230	Woodstove: fireplace inserts; EPA certified; catalytic	5,387	1,053	774
2104008310	Woodstove: freestanding, non-EPA certified	237,219	31,451	54,474
2104008320	Woodstove: freestanding, EPA certified, non-catalytic	45,572	6,344	3,884
2104008330	Woodstove: freestanding, EPA certified, catalytic	12,234	2,391	1,758
2104008400	Woodstove: pellet-fired, general (freestanding or insert)	3,859	743	10
2104008510	Furnace: Indoor, cordwood-fired, non-EPA certified	43,894	6,599	2,821
2104008700	Outdoor wood burning device (fire-pits, chimineas, etc.)	17,503	2,772	2,220
2104009000	Total: All Combustor Types	5,541	1,299	1,752
	TOTAL	**553,119**	**78,253**	**101,031**
MRPO (IL, IN, OH, MI, WI)				
2104008100	Fireplace: general	43,425	6,878	5,508
2104008210	Woodstove: fireplace inserts; non-EPA certified	52,583	6,972	12,075
2104008220	Woodstove: fireplace inserts; EPA certified; non-catalytic	11,581	1,612	987
2104008230	Woodstove: fireplace inserts; EPA certified; catalytic	2,821	551	405
2104008310	Woodstove: freestanding, non-EPA certified	127,979	16,968	29,389
2104008320	Woodstove: freestanding, EPA certified, non-catalytic	24,787	3,450	2,113
2104008330	Woodstove: freestanding, EPA certified, catalytic	16,139	3,154	2,319
2104008400	Woodstove: pellet-fired, general (freestanding or insert)	1,548	298	4
2104008510	Furnace: Indoor, cordwood-fired, non-EPA certified	91,898	13,815	5,906
2104008700	Outdoor wood burning device (fire-pits, chimineas, etc.)	48,581	7,695	6,162
2104009000	Total: All Combustor Types	6,115	1,433	1,934
	TOTAL	**427,457**	**62,826**	**66,802**
VISTAS (AL, FL, GA, KY, MS, NC, SC, TN, VA, WV)				
2104008100	Fireplace: general	58,045	9,194	7,363
2104008210	Woodstove: fireplace inserts; non-EPA certified	63,043	8,358	14,477
2104008220	Woodstove: fireplace inserts; EPA certified; non-catalytic	12,302	1,712	1,048
2104008230	Woodstove: fireplace inserts; EPA certified; catalytic	3,039	594	437
2104008310	Woodstove: freestanding, non-EPA certified	59,788	7,927	13,729
2104008320	Woodstove: freestanding, EPA certified, non-catalytic	11,663	1,624	994
2104008330	Woodstove: freestanding, EPA certified, catalytic	2,882	563	414
2104008400	Woodstove: pellet-fired, general (freestanding or insert)	227	44	1
2104008510	Furnace: Indoor, cordwood-fired, non-EPA certified	4,216	634	271
2104008700	Outdoor wood burning device (fire-pits, chimineas, etc.)	763	121	97
2104009000	Total: All Combustor Types	4,565	1,070	1,444
	TOTAL	**220,533**	**31,841**	**40,275**

Source: EPA, 2014

Figure 9.1



Source: EIA, 2014. Note: EIA excludes DE, MD, and DC from “Northeast states”

The American Community Survey (ACS) shows similar trends in the recent increase in the use of wood as the primary home heating fuel (Census, 2015). The number of households using wood as the primary home heating energy sources increased from 436,365 in 2010 to 542,851 in 2014 in the Northeast Census region (includes all MANE-VU jurisdictions except DC, DE, and MD). This is an increase of about 6% annual growth rate for a 25% increase over the five year period. In 2014, the ACS showed that 2.6% of all households in the Northeast used wood as the primary heating energy source. For the South Census region (which includes DC, DE, and MD), the ACS reported only a 4% increase over the five year period and that 1.3% of households used wood as the primary heating energy source.

Clean Air Act Programs Controlling Residential Wood Combustion

EPA adopted a Residential Wood Burning Heaters New Source Performance Standard (NSPS) in 1988. It placed limits on indoor wood stoves, but explicitly exempted other wood burning devices. In addition to the NSPS exemptions, the different types of unregulated residential wood burning devices have greatly expanded since 1988. The 1988 NSPS set no emission limits for many types of devices now on the market, such as OWBs and pellet stoves.

On February 3, 2015, EPA updated the NSPS for residential wood heaters to make new heaters significantly cleaner. The 1988 rule applied to adjustable burn-rate woodstoves (designed to allow the owner to adjust the airflow to change the rate at which wood burns), including a type of adjustable burn-rate woodstove known as a fireplace insert. Since that time, the technology for reducing emissions from wood heaters has significantly improved and now is available to make a range of wood heaters more efficient and less polluting. The 2015 NSPS updates PM emissions limits for newly manufactured adjustable-rate woodstoves and set the first federal air standards for pellet stoves and a type of previously unregulated woodstove known as a “single burn-rate” stove (designed so the owner cannot adjust the airflow). EPA is phasing in requirements over five years to allow manufacturers time to adapt emission control technologies to their particular model lines.

EPA does not regulate the manufacture and use of wood-burning fireplaces. Rather, EPA manages a Voluntary Wood-Burning Fireplace Program to encourage the development and sale of lower-emitting wood-burning fireplaces. EPA's fireplace program covers new masonry and prefabricated (low-mass) fireplaces and retrofit devices for existing fireplaces. Fireplace retrofits can reduce pollution up to 70 percent if installed properly. Manufacturers may apply to become program partners. To participate, manufacturers have fireplaces or retrofit devices tested and certified by an independent laboratory. EPA reviews the test results and determines whether a fireplace or retrofit device meets the program emission level. EPA-qualified units are marked with a hangtag and included in a list on the Burn Wise website (EPA, 2015g).

Several MANE-VU states have implemented voluntary wood stove change-out programs. Qualifying residents often receive incentives such as rebates, low/no interest loans and discounts to replace their old, conventional wood stoves and fireplace inserts with cleaner-burning, more efficient EPA-certified gas, pellet, electric or wood stoves and fireplaces. Households that participate in change-outs must surrender their old wood stoves to be recycled.

FACTOR 1 – COST OF COMPLIANCE

There are several strategies for reducing emissions from residential wood combustion: (1) regulatory approaches to reducing wood smoke, (2) voluntary programs to replace old, inefficient wood stoves and fireplaces, and (3) education and outreach tools to promote cleaner burning.

Compliance Costs – Regulatory Approaches

The primary regulatory approach is the establishment of performance standards for new wood heaters. For 2015 NSPS revisions, EPA made estimates of the cost-effectiveness of the new standards (EPA, 2015b). Table 9.3 is a snapshot of EPA's final cost-effectiveness calculation for pellet stoves assuming a 2.5% growth rate. The cost components consisted of capital costs per model (R&D, engineering labor, tooling, equipment integration, preliminary testing, and other costs to design and manufacture the modified wood stove model) and other fixed costs per model (certification testing and safety testing, roll-out of the modified products including store display models and burn programs, brochures, user manuals, training and product discounts).

Table 9.3 $PM_{2.5}$ Cost Effectiveness of NSPS for Pellet Stoves

			Annual Snapshots				Emission Reduction Cumulative per Year		
Year[3]	Nationwide Annual Cost[1] ($)	Nationwide Average Annual Cost ($)	Baseline $PM_{2.5}$ Emissions[2] (tons)	NSPS $PM_{2.5}$ Emissions[2] (tons)	Emission Reduction (tons)	CE based on nationwide average annual cost ($/ton)	Baseline $PM_{2.5}$ Emissions (tons)	NSPS $PM_{2.5}$ Emissions[2] (tons)	Emission Reduction[6] (tons)
2015 [4]	1,484,192	857,473	58	58	0	N/A	58	58	0
2016	1,484,192	857,473	59	59	0	N/A	117	117	0
2017	1,484,192	857,473	61	61	0	N/A	177	177	0
2018	1,564,285	857,473	62	62	0	N/A	239	239	0
2019	1,564,285	857,473	64	64	0	N/A	303	*303*	0
2020 [4]	1,564,285	857,473	65	29	36	23,667	368	332	36
2021	412,963	857,473	67	30	37	23,090	435	362	73
2022	412,963	857,473	69	30	38	22,526	504	392	111
2023	412,963	857,473	70	31	39	21,977	574	423	150

Year[3]	Nationwide Annual Cost[1] ($)	Nationwide Average Annual Cost ($)	Annual Snapshots				Emission Reduction Cumulative per Year		
			Baseline $PM_{2.5}$ Emissions[2] (tons)	NSPS $PM_{2.5}$ Emissions[2] (tons)	Emission Reduction (tons)	CE based on nationwide average annual cost ($/ton)	Baseline $PM_{2.5}$ Emissions (tons)	NSPS $PM_{2.5}$ Emissions[2] (tons)	Emission Reduction[6] (tons)
2024	412,963	857,473	72	32	40	21,441	646	455	190
2025	412,963	857,473	74	33	41	20,918	720	488	231
2026	412,963	857,473	76	34	42	20,408	795	522	273
2027	412,963	857,473	78	34	43	19,910	873	556	317
2028	412,963	857,473	79	35	44	19,425	952	592	361
2029	412,963	857,473	81	36	45	18,951	1,034	628	406
2030							1,034	628	406
2031							1,034	628	406
2032							1,034	628	406
2033							1,034	628	406
2034							1,034	628	406
2035							976	570	406
2036							917	511	406
2037							856	450	406
2038							794	388	406
2039							731	325	406
2040							665	296	370
2041							599	266	333
2042							530	236	294
2043							460	204	255
2044							388	172	215
2045							314	140	174
2046							238	106	132
2047							161	72	89
2048							81	36	45

Nationwide cumulative cost[5] ($):	12,862,099
Cumulative Emission Reduction over 20-year stove lifespan (tons)	6,374
CE based on total cost & cumulative emission reduction over 20-year emitting lifespan ($ per ton)	2,018

[1] Estimated nationwide annual costs are in 2013 $ and are based on a 6-year amortization period of R&D costs at a 7% interest rate (during 2015-2020), plus annual certification and reporting & recordkeeping costs (ongoing through 2029, representing a 10 year model life). Years 2030 through 2048 are past the 10-year model design lifespan used in this analysis.

[2] Estimated annual emissions are based on a forecasted revenue growth rate (as a surrogate for shipments) of 2.5% from 2015 through 2029, for the purposes of a sensitivity analysis.

[3] These heaters have in-home emitting lifespans of 20 years; thus pellet stoves shipped in 2029 will be emitting through 2048.

[4] Estimated emissions assume Step 1 standard becomes effective in 2015 and Step 2 standard in 2020. For pellet stoves, estimates assume that most models already meet the Step 1 limit and that manufacturers will certify and sell existing models meeting Step 1 standard during 2015 through 2019. Therefore no emission reductions are estimated until Step 2 in 2020.

[5] The nationwide cumulative cost represents the cost to manufacturers resulting from the R&D re-design to meet the NSPS and the NSPS-caused certification and reporting & recordkeeping costs to bring these stoves to market from 2015 through 2029.

[6] In order to not overstate emission reductions caused by the NSPS, emissions are reduced to discount pellet stoves already meeting the Step 2 limit (i.e., 70% of pellet stoves already meet the Step 2 limit).

Source: EPA, 2015a

As shown in Table 9.3 above, EPA estimated a cost-effectiveness of $2,018 per ton of $PM_{2.5}$ removed. The cost-effectiveness was based on total cost and cumulative emission reduction over 20-year emitting lifespan. The final estimates were made based on 2013 dollars and a 7% interest rate applied to the amortized costs during the 6-year R&D period and a 2.5% annual growth rate.

EPA also prepared cost-effectiveness estimates for VOC and CO, although these pollutants do not have emission limits under the final NSPS. EPA prepared a sensitivity analysis in which they varied the growth rate from 2.0% to 2.1%, 2.5% and 3.0%, which caused the emission estimates and resulting cost-effectiveness to vary. Table 9.4 summarizes the range of cost-effectiveness results of EPA's analyses for four types of devices, three pollutants, two interest rates, and three growth rates.

Table 9.4 $PM_{2.5}$, CO, and VOC Cost Effectiveness of NSPS for Various New Wood Heaters

Device Type	Pollutant	Interest Rate for Amortized Costs (%)	Annual Growth Rate (%)	Cost-Effectiveness based on total cost & cumulative emission reduction over 20-year emitting lifespan ($2013 per ton)
Wood Stove	$PM_{2.5}$	7	2.0	519
Wood Stove	$PM_{2.5}$	3	2.0	456
Wood Stove	$PM_{2.5}$	7	2.5	501
Wood Stove	$PM_{2.5}$	7	3.0	483
Wood Stove	CO	7	3.0	30
Wood Stove	VOC	7	3.0	327
Pellet Stove	$PM_{2.5}$	7	2.0	2,174
Pellet Stove	$PM_{2.5}$	3	2.0	2,024
Pellet Stove	$PM_{2.5}$	7	2.5	2,018
Pellet Stove	$PM_{2.5}$	7	3.0	1,874
Pellet Stove	CO	7	3.0	390
Pellet Stove	VOC	7	3.0	151,080
Single Burn Rate Stoves	$PM_{2.5}$	7	2.0	34
Single Burn Rate Stoves	$PM_{2.5}$	3	2.0	30
Single Burn Rate Stoves	$PM_{2.5}$	7	2.5	32
Single Burn Rate Stoves	$PM_{2.5}$	7	3.0	30
Single Burn Rate Stoves	CO	7	3.0	5
Single Burn Rate Stoves	VOC	7	3.0	17
Force-air Furnaces	$PM_{2.5}$	7	2.0	69
Force-air Furnaces	$PM_{2.5}$	3	2.0	61
Force-air Furnaces	$PM_{2.5}$	7	2.5	64
Force-air Furnaces	$PM_{2.5}$	7	3.0	60
Force-air Furnaces	CO	7	3.0	11
Force-air Furnaces	VOC	7	3.0	58

Source: EPA, 2015b; EPA, 2015c; EPA, 2015d; EPA, 2015e; EPA, 2015f.

Other regulatory approaches have been developed primarily to address local air pollution episodes (EPA, 2013), including:

- **Wood-burning Curtailment Programs**. Implement a mandatory curtailment program, also known as "burn bans," when weather conditions lead to air inversions which can lead to locally unhealthy levels of air pollution. Although curtailment programs are not always popular with the public, this measure can be highly effective at reducing wood smoke and has been successfully implemented in a number of communities.
- **Opacity and Visible Emission Limits**. Implement a program that allows no visible wood smoke or establishing opacity limits that restrict the percentage of light that may be prevented from passing through the smoke plume. The no visible emission option is easier to enforce than an opacity program, which require personnel qualified as opacity readers to determine compliance.
- **Restrictions on Wood Moisture Content**. Wood that is not properly seasoned will burn less efficiently and release more harmful pollutants. Implement a program to allow only the sale and/or burning of dry seasoned wood (e.g., less than 20% moisture) in wood burning appliances. To increase the likelihood that stove owners will burn seasoned wood, some air pollution control agencies have encouraged the use of wood moisture meters, which cost less than $25.
- **Removal of Old Wood Stoves upon Resale of a Home**. Some local communities require the removal and destruction of old wood stoves upon the resale of a home. This requirement has proven effective in locations like Mammoth Lakes, CA; Washoe County, NV; and the State of Oregon.
- **Restrictions of Wood-Burning Devices in New Construction**. Banning the installation of any wood-burning hearth appliances in new construction, or restricting the number and density of new wood-burning appliances in a given area.

Cost data and the emission reduction potentials for these other regulatory approaches are not readily available.

Compliance Costs – Voluntary Approaches

In addition to regulatory programs, several state and local agencies have implemented wood stove and fireplace replacement programs to help address wood smoke issues (EPA, 2013). These programs are designed to motivate households to replace older technologies with safer, more efficient, cleaner burning technologies. These programs are most effective when they also include education and outreach to ensure that households burn wood more efficiently and cleanly.

EPA estimates that more than 24,000 wood stoves and fireplaces have been replaced or retrofitted in 50 communities, resulting in approximately 3,700 tons of fine particle emissions reduced each year. EPA developed a table that lists residential wood combustion control measures to reduce $PM_{2.5}$ and other pollutants. This table is presented as Table 9.5 and includes estimated control efficiency and cost effectiveness numbers along with additional information.

Table 9.5 $PM_{2.5}$ Control Efficiency and Cost Effectiveness of Certain Residential Wood Combustion Control Measures

Appliance	Control Measure	Control Efficiency	Estimated Cost Effectiveness ($2012/ton)	Description/Notes/Caveats
Fireplaces	Use EPA Phase 2 Qualified Units	70%	$9,500	If new fireplace construction is allowed, approve only EPA Phase 2 qualified models. Under the EPA Wood-burning Fireplace Program, cleaner wood-burning fireplaces are qualified when their $PM_{2.5}$ emissions are at or below the Phase 2 $PM_{2.5}$ emissions level.
Fireplaces	Use Gas Logs in Existing Wood-burning Fireplaces	100%	$11,000	Incentives by various air districts in CA have helped retrofit thousands of open fireplaces to gas log sets. In addition to vented gas log sets, the option exists to install vented gas stove inserts into a wood-burning fireplace. Unlike gas logs, which provide little heat, a gas stove insert can be an efficient and clean way to heat a room. The cost per ton of $PM_{2.5}$ reductions will likely be greater as gas stove inserts cost more than gas log sets.
Fireplaces	Install Retrofit Devices into Existing Wood-burning Fireplaces	75%	$9,500	Provide incentives to encourage use of fireplace retrofit devices. Under the EPA Wood-burning Fireplace Program, retrofit devices are qualified when their $PM_{2.5}$ emissions are at or below the program Phase 2 $PM_{2.5}$ emissions level.
Wood Stoves	Wood to Wood Replacement Program	60%	$9,900	Implement a program and provide incentives to replace old uncertified wood stoves with new EPA-certified wood stoves. Education on proper wood stove use (e.g., burn only dry wood) and maintenance is critical.
Wood Stoves	Wood to Gas Replacement Program	99%	$7,200	Implement an incentive program to replace old, uncertified wood stoves with new gas stoves or gas logs.

Source: EPA, 2013

CSRA (MARAMA's contractor for this effort) independently estimated the cost-effectiveness of replacing older technology wood-burning devices with devices that are compliant with the Step 2 emission limits contained in the 2015 NSPS revisions.

- First, CSRA calculated the annualized cost for an NSPS-compliance stove, which take into account the capital costs associated with the installation/replacement of each newer technology and the annual maintenance cost. For this analysis, CSRA assumed other annual costs (chimney cleaning, fuel costs) would remain the same after the replacement as before the replacement. Table 9.6 summarized these cost calculations.
- CSRA calculated the emission reductions associated with replacing existing devices with NSPS Step 2 compliance devices. CSRA did this for three annual consumption scenarios, since the average amount of wood burned varies from the colder northern region of MANE-VU to the southern region. The wood consumption scenarios represent the low, average, and high state-level annual consumption per device (OMNI, 2006).
- Finally, CSRA calculated the cost-effectiveness of each replacement scenario by dividing the annualized replacement cost by the emission reduction.

Table 9-6 Cost Calculations for Three Types of NSPS-compliant Wood Stoves

	Wood Stove noncatalytic		Wood Stove catalytic		Pellet Stove	
	Average	**High**	**Average**	**High**	**Average**	**High**
CAPITAL COSTS						
Equipment Cost[1] ($2014)	848	2,800	848	2,800	1,279	3,500
Installation Cost[1] ($2014)	500	500	500	500	300	300
Total Capital Investment	1,348	3,300	1,348	3,300	1,579	3,800
Annual interest rate (%)	7.0	7.0	7.0	7.0	7.0	7.0
System lifespan (years)	20	20	20	20	20	20
Capital recovery factor	0.0944	0.0944	0.0944	0.0944	0.0944	0.0944
Annualized Capital Cost ($2014)	**127**	**311**	**127**	**311**	**149**	**359**
OPERATING COSTS (not including the cost of wood)						
Catalyst Replacement[3] ($2014)	0	0	43	43	0	0
Power Usage[4] (kw)	0	0	0	0	0.38	0.38
Hours Used Annually (hrs)	0	0	0	0	1,368	1,368
Electricity cost[5] ($2014)/kw-hr)	0.1762	0.1762	0.1762	0.1762	0.1762	0.1762
Annual Electricity Cost ($2014)	0	0	0	0	97	97
Annual Operating Cost ($2014)	**0**	**0**	**43**	**43**	**97**	**97**
TOTAL ANNUALIZED COST ($2014)	**127**	**311**	**170**	**354**	**241**	**450**

(1) Source: EPA, 2015a; Table 3-13, 2008 costs escalated to 2014 using Chemical Engineering Plant Index

(2) Source: EPA, 2015a; Table 3-12, 2008 costs escalated to 2014 using Chemical Engineering Plant Index

(3) Source: OMNI, 2006; Catalyst replacement cost, relevant only to the certified catalytic cordwood stoves and inserts was annualized from the data provided by the hearth products retailers.

(4) Source: OMNI, 2006; Electricity costs are relevant for stoves that have electrical components. For example, pellet stoves require electricity to run their fan, auger, and other control components.

(5) Source: EIA, 2015; used a rate of $0.1762 per kw-hr (New England average residential rate, September 2014).

Tables 9.7, 9.8 and 9.9 summarize the emission reduction and cost-effectiveness calculations for $PM_{2.5}$, VOC, and CO, respectively. The tables allow for a direct comparison of the cost burden for each realistic mitigation option that would be shouldered by residential users.

Table 9.7 PM$_{2.5}$ Cost-Effectiveness for Several Woodstove Change-Out Options

Annual tons Burned	PM$_{2.5}$ Emission Factor (lbs/ton)		Annual PM$_{2.5}$ Emissions (lbs)		Emission Reduction (lbs)	Annualized Replacement Cost ($2014)	Cost Effectiveness ($2014/ton)
	Existing	NSPS Step 2	Existing	NSPS Step 2			
Replace Old non-EPA Certified Stove with NSPS Step 2 EPA Certified non-Catalytic Stove							
1.15	30.6	3.89	35.2	4.5	30.7	127	8,269
2.77	30.6	3.89	84.8	10.8	74.0	127	3,433
3.53	30.6	3.89	108.0	13.7	94.3	127	2,694
Replace Old non-EPA Certified Stove with NSPS Step 2 EPA Certified Catalytic Stove							
1.15	30.6	7.79	35.2	9.0	26.2	170	12,962
2.77	30.6	7.79	84.8	21.6	63.2	170	5,381
3.53	30.6	7.79	108.0	27.5	80.5	170	4,223
Replace Old non-EPA Certified Stove with NSPS Step 2 EPA Certified Pellet-fired Stove							
1.15	30.6	1.36	35.2	1.6	33.6	241	14,334
2.77	30.6	1.36	84.8	3.8	81.0	241	5,951
3.53	30.6	1.36	108.0	4.8	103.2	241	4,670
Replace Old EPA Certified non-Catalytic Stove with NSPS Step 2 EPA Certified non-Catalytic Stove							
1.15	8.76	3.89	10.1	4.5	5.6	127	45,353
2.77	8.76	3.89	24.3	10.8	13.5	127	18,829
3.53	8.76	3.89	30.9	13.7	17.2	127	14,775
Replace Old EPA Certified non-Catalytic Stove with NSPS Step 2 EPA Certified Catalytic Stove							
1.15	8.76	7.79	10.1	9.0	1.1	170	304,796
2.77	8.76	7.79	24.3	21.6	2.7	170	126,540
3.53	8.76	7.79	30.9	27.5	3.4	170	99,296
Replace Old EPA Certified non-Catalytic Stove with NSPS Step 2 EPA Certified Pellet-fired Stove							
1.15	8.76	1.36	10.1	1.6	8.5	241	56,639
2.77	8.76	1.36	24.3	3.8	20.5	241	23,514
3.53	8.76	1.36	30.9	4.8	26.1	241	18,452
Replace Old EPA Certified Catalytic Stove with NSPS Step 2 EPA Certified non-Catalytic Stove							
1.15	9.72	3.89	11.2	4.5	6.7	127	37,885
2.77	9.72	3.89	26.9	10.8	16.1	127	15,728
3.53	9.72	3.89	34.3	13.7	20.6	127	12,342
Replace Old EPA Certified Catalytic Stove with NSPS Step 2 EPA Certified Catalytic Stove							
1.15	9.72	7.79	11.2	9.0	2.2	170	153,188
2.77	9.72	7.79	26.9	21.6	5.3	170	63,598
3.53	9.72	7.79	34.3	27.5	6.8	170	49,905
Replace Old EPA Certified Catalytic Stove with NSPS Step 2 EPA Certified Pellet-fired Stove							
1.15	9.72	1.36	11.2	1.6	9.6	241	50,135
2.77	9.72	1.36	26.9	3.8	23.2	241	20,814
3.53	9.72	1.36	34.3	4.8	29.5	241	16,333
Replace Old Pellet-fired Stove with NSPS Step 2 EPA Certified Pellet-fired Stove							
1.15	3.06	1.36	3.5	1.6	2.0	241	246,547
2.77	3.06	1.36	8.5	3.8	4.7	241	102,357
3.53	3.06	1.36	10.8	4.8	6.0	241	80,320

Table 9.8 VOC Cost-Effectiveness for Several Woodstove Change-Out Options

Annual tons Burned	VOC Emission Factor (lbs/ton)		Annual VOC Emissions (lbs)		Emission Reduction (lbs)	Annualized Replacement Cost ($2014)	Cost Effectiveness ($2014/ton)
	Existing	NSPS Step 2	Existing	NSPS Step 2			
Replace Old non-EPA Certified Stove with NSPS Step 2 EPA Certified non-Catalytic Stove							
1.15	53.0	5.33	61.0	6.1	54.8	127	4,633
2.77	53.0	5.33	146.8	14.8	132.0	127	1,924
3.53	53.0	5.33	187.1	18.8	168.3	127	1,509
Replace Old non-EPA Certified Stove with NSPS Step 2 EPA Certified Catalytic Stove							
1.15	53.0	12.0	61.0	13.8	47.2	170	7,211
2.77	53.0	12.0	146.8	33.2	113.6	170	2,994
3.53	53.0	12.0	187.1	42.4	144.7	170	2,349
Replace Old non-EPA Certified Stove with NSPS Step 2 EPA Certified Pellet-fired Stove							
1.15	53.0	0.02	61.0	0.0	60.9	241	7,911
2.77	53.0	0.02	146.8	0.1	146.8	241	3,284
3.53	53.0	0.02	187.1	0.1	187.0	241	2,577
Replace Old EPA Certified non-Catalytic Stove with NSPS Step 2 EPA Certified non-Catalytic Stove							
1.15	12.0	5.33	13.8	6.1	7.7	127	33,114
2.77	12.0	5.33	33.2	14.8	18.5	127	13,748
3.53	12.0	5.33	42.4	18.8	23.5	127	10,788
Replace Old EPA Certified non-Catalytic Stove with NSPS Step 2 EPA Certified Catalytic Stove							
1.15	12.0	12.0	13.8	13.8	0.0	170	No reduction
2.77	12.0	12.0	33.2	33.2	0.0	170	No reduction
3.53	12.0	12.0	42.4	42.4	0.0	170	No reduction
Replace Old EPA Certified non-Catalytic Stove with NSPS Step 2 EPA Certified Pellet-fired Stove							
1.15	12.0	0.02	13.8	0.0	13.8	241	34,986
2.77	12.0	0.02	33.2	0.1	33.2	241	14,525
3.53	12.0	0.02	42.4	0.1	42.3	241	11,398
Replace Old EPA Certified Catalytic Stove with NSPS Step 2 EPA Certified non-Catalytic Stove							
1.15	15.0	5.33	17.3	6.1	11.1	127	22,841
2.77	15.0	5.33	41.6	14.8	26.8	127	9,483
3.53	15.0	5.33	53.0	18.8	34.1	127	7,441
Replace Old EPA Certified Catalytic Stove with NSPS Step 2 EPA Certified Catalytic Stove							
1.15	15.0	12.0	17.3	13.8	3.5	170	98,551
2.77	15.0	12.0	41.6	33.2	8.3	170	40,915
3.53	15.0	12.0	53.0	42.4	10.6	170	32,106
Replace Old EPA Certified Catalytic Stove with NSPS Step 2 EPA Certified Pellet-fired Stove							
1.15	15.0	0.02	17.3	0.0	17.2	241	27,979
2.77	15.0	0.02	41.6	0.1	41.5	241	11,616
3.53	15.0	0.02	53.0	0.1	52.9	241	9,115
Replace Old Pellet-fired Stove with NSPS Step 2 EPA Certified Pellet-fired Stove							
1.15	0.041	0.02	0.0	0.0	0.0	241	19,958,592
2.77	0.041	0.02	0.1	0.1	0.1	241	8,286,058
3.53	0.041	0.02	0.1	0.1	0.1	241	6,502,091

Table 9.9 CO Cost-Effectiveness for Several Woodstove Change-Out Options

Annual tons Burned	CO Emission Factor (lbs/ton)		Annual CO Emissions (lbs)		Emission Reduction (lbs)	Annualized Replacement Cost ($2014)	Cost Effectiveness ($2014/ton)
	Existing	NSPS Step 2	Existing	NSPS Step 2			
Replace Old non-EPA Certified Stove with NSPS Step 2 EPA Certified non-Catalytic Stove							
1.15	231	62.6	265.4	72.0	193.4	127	1,313
2.77	231	62.6	639.3	173.4	465.9	127	545
3.53	231	62.6	814.7	221.0	593.7	127	428
Replace Old non-EPA Certified Stove with NSPS Step 2 EPA Certified Catalytic Stove							
1.15	231	83.5	265.4	96.0	169.4	170	2,007
2.77	231	83.5	639.3	231.3	408.0	170	833
3.53	231	83.5	814.7	294.8	520.0	170	654
Replace Old non-EPA Certified Stove with NSPS Step 2 EPA Certified Pellet-fired Stove							
1.15	231	7.1	265.4	8.2	257.3	241	1,874
2.77	231	7.1	639.3	19.7	619.6	241	778
3.53	231	7.1	814.7	25.1	789.7	241	610
Replace Old EPA Certified non-Catalytic Stove with NSPS Step 2 EPA Certified non-Catalytic Stove							
1.15	141	62.6	161.9	72.0	89.9	127	2,824
2.77	141	62.6	390.0	173.4	216.6	127	1,173
3.53	141	62.6	497.0	221.0	276.0	127	920
Replace Old EPA Certified non-Catalytic Stove with NSPS Step 2 EPA Certified Catalytic Stove							
1.15	141	83.5	161.9	96.0	65.9	170	5,160
2.77	141	83.5	390.0	231.3	158.7	170	2,142
3.53	141	83.5	497.0	294.8	202.3	170	1,681
Replace Old EPA Certified non-Catalytic Stove with NSPS Step 2 EPA Certified Pellet-fired Stove							
1.15	141	7.1	161.9	8.2	153.8	241	3,135
2.77	141	7.1	390.0	19.7	370.3	241	1,301
3.53	141	7.1	497.0	25.1	472.0	241	1,021
Replace Old EPA Certified Catalytic Stove with NSPS Step 2 EPA Certified non-Catalytic Stove							
1.15	104	62.6	120.1	72.0	48.1	127	5,284
2.77	104	62.6	289.2	173.4	115.8	127	2,194
3.53	104	62.6	368.5	221.0	147.6	127	1,721
Replace Old EPA Certified Catalytic Stove with NSPS Step 2 EPA Certified Catalytic Stove							
1.15	104	83.5	120.1	96.0	24.0	170	14,146
2.77	104	83.5	289.2	231.3	57.9	170	5,873
3.53	104	83.5	368.5	294.8	73.8	170	4,608
Replace Old EPA Certified Catalytic Stove with NSPS Step 2 EPA Certified Pellet-fired Stove							
1.15	104	7.1	120.1	8.2	111.9	241	4,308
2.77	104	7.1	289.2	19.7	269.5	241	1,788
3.53	104	7.1	368.5	25.1	343.5	241	1,403
Replace Old Pellet-fired Stove with NSPS Step 2 EPA Certified Pellet-fired Stove							
1.15	15.9	7.1	18.3	8.2	10.1	241	47,628
2.77	15.9	7.1	44.0	19.7	24.4	241	19,774
3.53	15.9	7.1	56.1	25.1	31.1	241	15,516

Compliance Costs – Education and Outreach

Wood smoke education and outreach is an important part of reducing $PM_{2.5}$. Engaging the public and giving them the tools to make informed decisions about what they burn and how they burn have been in effect for many years and have been proven effective (EPA, 2013). With proper burning techniques and well-seasoned wood, emissions (even in older wood-burning appliances) can be significantly reduced. While a new wood stove, hydronic heater, or wood-burning fireplace will typically pollute less than older appliances when used properly, it is important to emphasize that how a user operates their appliance is equally important in maximizing energy efficiency and reducing emissions.

For example, EPA's Burn Wise program (EPA, 2015g) serves as a resource for states and communities. Burn Wise is a way to encourage the importance of burning the right wood, the right way, in the right wood-burning appliance. The program offers a website, outreach tools and information to help consumers make informed decisions about what it means to burn wise. Several MANE-VU states have already developed similar education and outreach programs in their states.

Information about the costs associated with developing and implementing education and outreach programs at the state level are currently not available.

FACTOR 2 – COMPLIANCE TIMEFRAME

New woodstoves meeting more stringent PM emissions standards would be phased in slowly as older woodstoves are replaced. EPA's Step 1 NSPS emissions limits became effective nationally in 2015. EPA's Step 2 NSPS PM emissions limits become effective nationally in 2020. Thus, full compliance is likely to be around 2040, at the earliest.

Replacement of wood-fired stoves manufactured before the state or EPA standards took effect will gradually occur over the assumed 20 year life span of the units. Since they are designed to last for approximately 20 years, woodstove operators would likely be reluctant to replace them immediately. It is possible for older outdoor wood-fired boilers to be replaced more quickly given the proper economic incentives.

FACTOR 3 – ENERGY AND NON-ENVIRONMENTAL IMPACTS

Other factors beyond $PM_{2.5}$ and regional haze (i.e., VOC and fine particles) should also influence RWC regulatory policy. The greenhouse gas benefits of biomass combustion and the minimal acid gas emissions (acid precipitation impacts) from wood combustion are strong environmental advantages. Further, the fact that wood is a domestic renewable energy source and the fact that the cost of natural gas, propane, and fuel oil have a history of rising together have been responsible for the increase in the use of RWC.

For example, Renewable Heat NY is a program to help the high-efficiency, low-emission biomass heating industry reach scale. It encourages quicker development of the industry, raises consumer awareness, support the development of New York-based advanced technology heating products, and develop local sustainable heating markets that use biomass as fuel. Renewable Heat NY also aims to reduce wood smoke, fine particles and carbon monoxide emissions.

EPA noted in its 2015 NSPS revisions that the final rule is not likely to have any significant adverse energy effects. In general, EPA expects the NSPS to improve technology, including energy efficiency. Reducing emissions and increasing efficiency might increase the use of wood fuel, which would relieve pressure on traditional coal or petroleum based energy sources (and greenhouse gas emissions). But it is difficult to determine the precise energy impacts because wood-fueled appliances compete with other biomass forms as well as more traditional oil, electricity and natural gas. Robust data are not available to determine the potential conversion to other types of fuels and their associated appliances if the consumer costs of wood-fueled appliances increase and at what level that increase would drive consumer choice.

The increased use of residential wood combustion devices may have a variety of non-air impacts on the environment, especially on forest and water resources (MACTEC, 2007). The potential impacts are outlined below.

<u>Nuisance Smoke</u>: Outdoor wood-fired boilers typically have very short stacks, and are prone to smoke. The short stacks oftentimes prevent proper mixing of the smoke and soot with the surrounding air, thereby creating nuisance smoke problems for surrounding houses or communities.

<u>Water</u>: Increased logging to satisfy the demand for firewood may increase runoff of silts and sediments into adjacent creeks and rivers. This increased sediment load in rivers can affect aquatic ecosystems that are integral to rivers and streams.

<u>Soils</u>: Increased logging may impact soils in many ways. For example, heavy machinery used to fell and process trees may lead to rutting and compaction of the soil, which in turn leads to higher erosion and/or altered vegetative regrowth.

<u>Wildlife</u>: Increased logging may put pressure on existing wildlife populations in the US Northeast by altering their critical habitat.

<u>Threatened and Endangered Species</u>: Increased logging in Northeast may impact threatened and endangered species through habitat destruction or alteration.

Any mandatory change out program should be mindful that even with assistance, woodstove change out programs will impact families that are least able to bear the burden of additional costs. Voluntary programs do not impose this economic burden on families less able to bear associated costs.

FACTOR 4 – REMAINING USEFUL LIFE

Most wood heaters in consumer homes emit for at least 20 years and often much longer (EPA, 2015a). However, in order to address industry comments, EPA used a 10-year model design lifespan for estimating costs and assumed a 20-year appliance emitting lifespan. This assumption was made to best characterize the actual use lifespan given that most stoves in consumer homes emit for at least 20 years and often much longer. EPA assumed that models do not come into compliance until the year they are required to, although some models will meet the NSPS Step 2 PM limit prior to the 2020 compliance year and will therefore be emitting less than baseline levels prior to that year.

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CHAPTER 10

SOURCE CATEGORY ANALYSIS: OUTDOOR WOOD-FIRED BOILERS

BACKGROUND

The MANE-VU Contribution Assessment and other MANE-VU reports have documented that visibility impairment in this region is primarily due to regional secondary sulfate (NESCAUM 2006a). In addition, biomass combustion as a contributor to visibility impairment in MANE-VU Class I areas. Biomass combustion emissions due to human activity primarily derive from residential wood combustion. While some biomass burning occurs throughout the year, residential wood combustion occurs predominantly in the winter months, potentially contributing to wintertime peaks in PM concentrations.

MANE-VU previously developed an assessment (MACTEC, 2007) of control technologies to achieve reasonable progress goals with respect to the four factors listed in Section 169A of the Clean Air Act. The information presented in this Chapter is an update to some parts of the MACTEC report.

Source Category Description

An outdoor wood heater, also often called an outdoor wood-fired boiler (OWB), is a type of hydronic heater that is designed to be the home's primary heating system. OWBs are located in structure detached from the home and have the appearance of a small shed with a smokestack. OWBs burn wood to heat a liquid contained in a closed-loop system. The heated liquid is then circulated to the house to provide heat and hot water. OWBs are typically sold in areas with cold climates where wood may be the most readily available fuel source. In addition to OWBs, there is an emerging market for indoor hydronic heaters. Currently, the indoor hydronic heater market is approximately 10% of the OWB market (EPA, 2015a).

Manufacturers design OWBs to burn large amounts of wood over long periods of time. OWBs vary in size ranging from 115,000 BTU/hr to 3.2 million BTU/hr, although residential OWBs tend to be less than 1 million BTU/hr. According to sales data, the size of the most commonly sold unit is 500,000 BTU/hr. OWBs heat buildings ranging in size from 1,800 square feet to 20,000 square feet (NESCAUM, 2006b).

Typically, the dimensions of an OWB are three to five feet wide, six to nine feet deep, and six to ten feet tall, including the height of the chimney. Inside the OWB is an oversized firebox that can accommodate extremely large loads. Firebox sizes will vary with each unit but tend to range in size from 20 cubic feet up to 150 cubic feet. Industry literature indicates that a commonly sized residential unit can easily accommodate wood pieces that are 30 inches in diameter and 72 inches long. Surrounding the firebox is a water jacket that can be heated to temperatures up to 190°F. The OWB cycles water through the jacket to deliver hot water to the building. Water pipes run underground to deliver hot water for both space heating and domestic use (EPA, 2015a).

Consumption and Emission Trends

Table 10.1 shows the CO, $PM_{2.5}$ and VOC emissions in 2011 from outdoor wood boilers for the MANE-VU, MRPO, and VISTAS RPO states. The emission estimates were developed by EPA using the Residential Wood Combustion Tool. This tool computes county-and SCC-level emissions of criteria and HAPs for the entire country. EPA updated the inputs to the tool for the 2011 National Emission Inventory in partnership with the Eastern Regional Technical Advisory Committee (ERTAC). Emission trends over the past decade are not available due to improvements in emission factors and emission estimation methodologies. The new Residential Wood Combustion Tool used a new suite of source categories, new emission factors and a new calculation methodology. Thus, the resulting emissions for this sub-category of area emissions are not comparable between older and newer inventories.

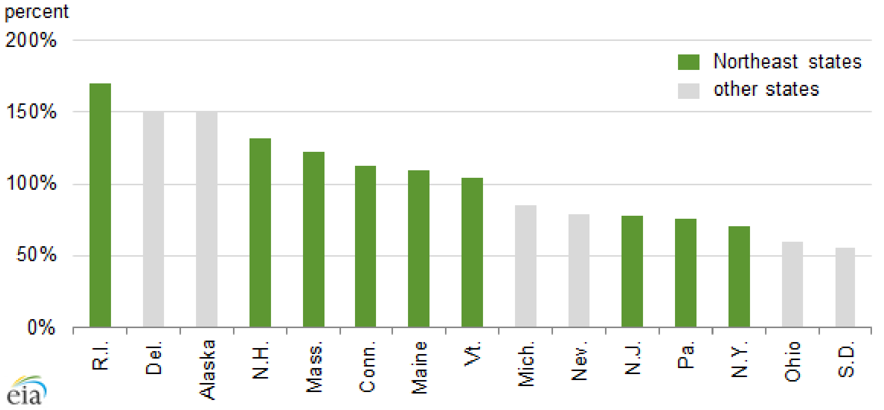
Table 10.1 2011 Emissions from Outdoor Wood Boilers (tons/year)
SCC = 21-04-008-610, Outdoor Hydronic Heaters

RPO	# of OWB	CO	$PM_{2.5}$	VOC
MANE-VU	63,150	107,468	19,105	20,120
MRPO	135,409	307,951	54,747	57,655
VISTAS	17,025	16,645	2,959	3,116

Source: EPA Residential Wood Combustion Tool (EPA 2014)
MANEVU (CT, DC, DE, MA, MD, ME, NH, NJ, NY, PA, RI, and VT)
MRPO (IL, IN, OH, MI, WI)
VISTAS (AL, FL, GA, KY, MS, NC, SC, TN, VA, WV)

Wood as a main heating source in homes has gained popularity in many areas of the country in recent years, but the increase is most notable in the Northeast (EIA, 2014). As shown Figure 10.1, most states in MANE-VU RPO saw at least a 50% jump from 2005 to 2012 in the number of households that rely on wood as the main heating source. As the price of fuel oil and kerosene in this region increased during that period, fuel oil and kerosene use has declined in recent years as many households have turned to lower-cost alternatives, including wood.

Figure 10.1



Source: EIA, 2014. EIA used the Census definition of “Northeast states,” which excludes DE, DC, and MD.

The American Community Survey (ACS) shows similar trends in the recent increase in the use of wood as the primary home heating fuel (Census, 2015). The number of households using wood as the primary home heating energy sources increased from 436,365 in 2010 to 542,851 in 2014 in the Northeast Census region (includes all MANE-VU jurisdictions except DC, DE, and MD). This is an increase of about 6% annual growth rate for a 25% increase over the five year period. In 2014, the ACS showed that 2.6% of all households in the Northeast used wood as the primary heating energy source. For the South Census region (which includes DC, DE, and MD), the ACS reported only a 4% increase over the five year period and that 1.3% of households used wood as the primary heating energy source.

Obviously not all of the growth in wood use will be for outdoor wood boilers. Future demand for outdoor wood boilers will be somewhat dependent on the price of wood fuel relative to electric, heating oil and gas heat, as well as consumer preferences. The recent drop in the price of heating oil over the past two years makes predictions of future growth subject to considerable uncertainty. Previous studies reported that over 155,000 outdoor wood boilers were in use in the United States in 2006 (NESCAUM, 2006). The NESCAUM report also estimated annual growth in sales of outdoor wood boilers of between 30 and 128%, resulting in a prediction that over 500,000 outdoor wood boilers would be in use before the end of 2010 if trends in annual sales continued to follow growth rates observed between 1990 and 2006. However, EPA estimated that there were only about 250,000 units for the 2011 NEI (EPA, 2014) using the Residential Wood Consumption Tool. EPA also estimated that 13,385 hydronic central heating systems were shipped in 2008 (EPA, 2015), and EPA projected an annual growth rate of 2-3%.

Regulatory History

EPA adopted a New Source Performance Standard (NSPS) for Residential Wood Burning Heaters in 1988. It placed limits on indoor wood stoves, but explicitly exempted other wood burning devices. In addition to the NSPS exemptions, the types of unregulated residential wood burning devices have greatly expanded since 1988. The 1988 NSPS does not limit emissions from many types of devices now in the market, such as OWBs and pellet stoves.

On January 29, 2007, NESCAUM made available its “Outdoor Hydronic Heater Model Regulation.” The model rule was designed to serve as a template to assist State and local agencies in adopting requirements that will reduce air pollution from OWBs. The model rule was developed in cooperation with a number of States and EPA. The model rule contains a single method for regulating new units with respect to the critical elements and contemplates that States may propose alternative approaches for other provisions. It also provides alternatives for states to consider for regulating previously installed units (NESCAUM 2007).

NESCAUM’s model rule sets standards for particulate matter (PM) emissions by phases for residential and commercial boilers. The PM standards for both boiler types are identical. Phase I calls for a PM emission limit of 0.44 pounds per million BTU heat input. This standard was to be met by March 31, 2008. Phase II calls for a PM emission standard of 0.32 lb/MMBTU which was to be met by March 31, 2010. Table 10.2 summarizes each of the MANE-VU states regulatory and voluntary efforts to control emissions from outdoor wood boilers. Most states have adopted regulations similar to the NESCAUM’s model rule.

In 2007, EPA launched a voluntary program to encourage manufacturers to make hydronic heaters cleaner. Through the voluntary Hydronic Heater Program, manufacturers have redesigned some models to make new units available to consumers that are 90 percent cleaner on average than unqualified models, based on laboratory testing (EPA, 2016).

Table 10.2 State Programs for Outdoor Wood Boilers in the MANE-VU Region (as of December10, 2015)

Jurisdiction	OWB Control Requirements	Regulatory Citation
CT	Setback and stack height requirements; voluntary purchase of new OWBs in accordance with EPA's voluntary Hydronic Heaters Program; Outdoor Wood-fired Furnace incentive program to replace older furnaces	Section 22a-174k of CT General Statutes
DE	Nothing specific to OWBs	
DC	Nothing specific to OWBs	
MA	PM limit of 0.32 lbs/MMBTU by December 26, 2008, for new units; setback and stack height requirements; visible emission limitations	310 CMR 7.26(50) Outdoor Hydronic Heaters
MD	PM limit of 0.32 lbs/MMBTU by April 1, 2010 for new units	Title 26, Subtitle 11, Section 26.11.09.11
ME	PM limit of 0.32 lbs/MMBTU by April 1, 2010 for new units; setback and stack height requirements; visible emission limitations	Chapter 150: Control of Emissions from Outdoor Wood Boilers
NH	PM limit of 0.32 lbs/MMBTU by April 1, 2010 for new units; setback and stack height requirements; visible emission limitations	Chapter 125-R Outdoor Wood-Fired Hydronic Heaters
NJ	Visible emission limitations	7:27-3.2 Smoke emissions from stationary indirect heat exchanges
NY	PM limit of 0.32 lbs/MMBTU by April 15, 2011 for new units; setback and stack height requirements; visible emission limitations	6 NYCRR Part 247 Outdoor Wood Boilers
PA	PM limit of 0.32 lbs/MMBTU by May 31, 2011 for new units; setback and stack height requirements	123.14. Outdoor wood-fired boilers
RI	PM limit of 0.32 lbs/MMBTU by July 1, 2011 for new units	Air Pollution Control Regulation No. 48 – Outdoor Wood Boilers
VT	PM limit of 0.32 lbs/MMBTU by March 31, 2010 for new units; setback and stack height requirements; visible emission limitations; voluntary OWB change out program with financial incentives to encourage replacement of older OWBs (suspended 9/30/2015)	5-204 Outdoor Wood Fired Boilers

On February 3, 2015, EPA revised the NSPS to include several types of previously unregulated new wood heaters, including outdoor and indoor wood-fired boilers (also known as hydronic heaters), and indoor wood-burning forced air furnaces. The revised NSPS has a 2-step approach to emission limits and compliance deadlines for newly manufactured units. The Step 1 PM emissions limit, effective in 2015, is identical to the current qualifying level for EPA's voluntary Hydronic Heater Program of 0.32 pounds per million BTU heat output (weighted average), with a cap of 18 grams per hour for individual test runs. The Step 2 emission limit is 0.10 pounds per million BTU heat output for each burn rate, with an alternative limit of 0.15 pounds per million BTU heat output for each burn rate is tested with cordwood. The Step 2 compliance date (2020) is 5 years after the final rule was published.

NESCAUM conducted tests on an OWB and reported in 2008 that it was technically feasible to add controls to existing OWB, but that no commercial retrofit products were available. NESCAUM indicated that significant emissions reductions could be achieved through add-on controls, and also that the species of wood and the moisture content of the wood burned strongly affected emissions (NESCAUM, 2008). This indicates that education on the proper use of OWB could reduce emissions from existing units.

FACTOR 1 – COST OF COMPLIANCE

There are several strategies for reducing emissions from outdoor wood boilers: (1) regulatory approaches to reducing wood smoke, (2) voluntary programs to replace old, inefficient wood stoves and fireplaces, and (3) education and outreach tools to promote cleaner burning.

Compliance Costs – Regulatory Approaches

The primary regulatory approach is the establishment of performance standards for new wood heaters. For new outdoor wood boilers under the 2015 NSPS revisions, EPA made estimates of the cost-effectiveness of the new standards (EPA, 2015b). Table 10.3 is a snapshot of EPA's final cost-effectiveness calculation for Force Air Furnaces and Hydronic Heating Systems.

Table 10.3 $PM_{2.5}$ Cost Effectiveness of NSPS for Hydronic Heating Systems

			Annual Snapshots				Emission Reduction Cumulative per Year		
Year[3]	Nationwide Annual Cost[1] ($)	Nationwide Average Annual Cost ($)	Baseline $PM_{2.5}$ Emissions[2] (tons)	NSPS $PM_{2.5}$ Emissions[2] (tons)	Emission Reduction (tons)	CE based on nationwide average annual cost ($/ton)	Baseline $PM_{2.5}$ Emissions (tons)	NSPS $PM_{2.5}$ Emissions[2] (tons)	Emission Reduction[6] (tons)
2015 [4]	24,855,398	10,321,500	3,710	371	3,339	3,091	3,710	371	3,339
2016	24,855,398	10,321,500	3,803	380	3,423	3,015	7,514	751	6,762
2017	24,855,398	10,321,500	3,898	390	3,508	2,942	11,412	1,141	10,271
2018	24,894,927	10,321,500	3,996	400	3,596	2,870	15,408	1,541	13,867
2019	24,894,927	10,321,500	4,096	410	3,686	2,800	19,503	1,950	17,553
2020 [4]	24,894,927	10,321,500	4,198	131	4,067	2,538	23,701	2,082	21,620
2021	619,059	10,321,500	4,303	134	4,168	2,476	28,004	2,216	25,788
2022	619,059	10,321,500	4,411	138	4,273	2,416	32,415	2,354	30,061
2023	619,059	10,321,500	4,521	141	4,380	2,357	36,936	2,495	34,440
2024	619,059	10,321,500	4,634	145	4,489	2,299	41,569	2,640	38,929
2025	619,059	10,321,500	4,750	148	4,601	2,243	46,319	2,788	43,531
2026	619,059	10,321,500	4,868	152	4,716	2,188	51,187	2,940	48,247
2027	619,059	10,321,500	4,990	156	4,834	2,135	56,178	3,096	53,081
2028	619,059	10,321,500	5,115	160	4,955	2,083	61,292	3,256	58,036
2029	619,059	10,321,500	5,243	164	5,079	2,032	66,535	3,420	63,115
2030							66,535	3,420	63,115
2031							66,535	3,420	63,115
2032							66,535	3,420	63,115
2033							66,535	3,420	63,115
2034							66,535	3,420	63,115
2035							62,825	3,049	59,776
2036							59,022	2,669	56,353
2037							55,123	2,279	52,844

Year[3]	Nationwide Annual Cost[1] ($)	Nationwide Average Annual Cost ($)	Annual Snapshots				Emission Reduction Cumulative per Year		
			Baseline $PM_{2.5}$ Emissions[2] (tons)	NSPS $PM_{2.5}$ Emissions[2] (tons)	Emission Reduction (tons)	CE based on nationwide average annual cost ($/ton)	Baseline $PM_{2.5}$ Emissions (tons)	NSPS $PM_{2.5}$ Emissions[2] (tons)	Emission Reduction[6] (tons)
2038							51,128	1,879	49,248
2039							47,032	1,470	45,562
2040							42,834	1,339	41,495
2041							38,531	1,204	37,327
2042							34,120	1,066	33,054
2043							29,600	925	28,675
2044							24,966	780	24,186
2045							20,216	632	19,584
2046							15,348	480	14,868
2047 [3]							10,358	324	10,034
2048 [3]							5,243	164	5,079
Nationwide cumulative cost[5] ($):	154,822,505								
Cumulative Emission Reduction over 20-year stove lifespan (tons)	856,776								
CE based on total cost & cumulative emission reduction over 20-year emitting lifespan ($ per ton)	181								

[1] Estimated nationwide annual costs are in 2013 $ and are based on a 6-year amortization period of R&D costs at a 7% interest rate (during 2015-2020), plus annual certification and reporting & recordkeeping costs (ongoing through 2029, representing a 10 year model life). Years 2030 through 2048 are past the 10-year model design lifespan used in this analysis.

[2] Except for an adjustment in year 2012 based on an industry projection (NERA), estimated annual emissions are based on a forecasted revenue growth rate (as a surrogate for shipments) of 2.5% from 2015 through 2029, for the purposes of a sensitivity analysis.

[3] These heaters have in-home emitting lifespans of at least 20 years; thus hydronic heaters shipped in 2029 will be emitting through 2048.

[4] Estimated emissions assume Step 1 standard becomes effective in 2015 and Step 2 standard in 2020.

[5] The nationwide cumulative cost represents the cost to manufacturers resulting from the R&D re-design to meet the NSPS and the NSPS-caused certification and reporting & recordkeeping costs to bring these heaters to market from 2014 through 2029.

[6] In order to not overstate emission reductions caused by the NSPS, emissions are reduced to discount hydronic heaters already meeting the Step 2 limit (i.e., 18% of hydronic heaters are estimated to already meet the Step 2 limit).

Source: EPA, 2015a

The cost components consisted of capital costs per model (R&D, engineering labor, tooling, equipment integration, preliminary testing, and other costs to design and manufacture the modified wood stove model) and other fixed costs per model (certification testing and safety testing, roll-out of the modified products including store display models and burn programs, brochures, user manuals, training and product discounts).

As shown in Table 10.3 above, EPA estimated a cost-effectiveness of $181 per ton of $PM_{2.5}$ removed. The cost-effectiveness was based on total cost and cumulative emission reduction over 20-year emitting lifespan. The final estimates were made based on 2013 dollars and a 7% interest rate applied to the amortized costs during the 6-year R&D period and a 2.5% annual growth rate.

EPA also prepared cost-effectiveness estimates for VOC and CO, although these pollutants do not have emission limits under the final NSPS. EPA also prepared a sensitivity analysis in which they varied the growth in shipments from 2.0% to 2.1%, 2.5% and 3.0%, which caused the emission estimates and resulting cost-effectiveness to vary. Table 10.4 summarizes the range of results of EPA's cost-effectiveness analyses for new hydronic heaters for three pollutants, two interest rates, and three growth rates.

Table 10.4 $PM_{2.5}$, CO, and VOC Cost Effectiveness of NSPS for New Hydronic Heaters

Pollutant	Interest Rate for Amortized Costs (%)	Annual Growth Rate (%)	Cost-Effectiveness based on total cost & cumulative emission reduction over 20-year emitting lifespan ($2013 per ton)
$PM_{2.5}$	7	2.0	192
$PM_{2.5}$	3	2.0	170
$PM_{2.5}$	7	2.5	181
$PM_{2.5}$	7	3.0	170
CO	7	3.0	30
VOC	7	3.0	161

Source: EPA, 2015b: EPA, 2015c; EPA, 2015d; EPA, 2015e; EPA, 2015f.

Compliance Costs – Voluntary Approaches

In addition to regulatory programs, several state and local agencies have implemented wood stove and fireplace replacement programs to help address wood smoke issues (EPA, 2013). These programs are designed to motivate households to replace older technologies with safer, more efficient, cleaner burning technologies. These programs are most effective when they also include education and outreach to ensure that households burn wood more efficiently and cleanly.

For outdoor wood furnaces manufactured before 2011 (before State-specific or EPA emission limits took effect), CSRA made a simple estimate of the cost-effectiveness of a change-out program in the MANE-VU region in the following manner:

- There were 63,150 OWBs in MANE-VU, and the 2011 $PM_{2.5}$, CO, and VOC emissions were previously shown in Table 10.1 (EPA, 2014);
- Individual NSPS-compliant OWBs retail for prices ranging from about $5,000 to $35,000, with the average of $7,433 (EPA, 2015a);
- Installation costs approximately $2,000 installed by a professional contractor, including all plumbing related to the set-up (EPA, 2015a);
- The annualized capital cost for replacement of an older OWB and installation of NSPS Step 2 OWB is $890 in 2014 dollars calculated assuming a 7% interest rate and 20 year lifespan.
- NSPS Step 2 compliant OWBs are 96.9% cleaner for $PM_{2.5}$ and CO, and 90% cleaner for VOC (EPA,2015a);

The estimated cost-effectiveness values are about \$3,070 per ton of $PM_{2.5}$ reduced, \$3,090 per ton of VOC reduced, and \$540 per ton of CO reduced.

Compliance Costs – Education and Outreach

Wood smoke education and outreach is an important part of reducing $PM_{2.5}$. Engaging the public and giving them the tools to make informed decisions about what they burn and how they burn have been in effect for many years and have been proven effective (EPA, 2013). With proper burning techniques and well-seasoned wood, emissions (even in older wood-burning appliances) can be significantly reduced. While a new hydronic heater will typically pollute less than older units when used properly, it is important to emphasize that how a user operates their units is equally important in maximizing energy efficiency and reducing emissions.

For example, EPA's Burn Wise program (EPA, 2015g) serves as a resource for states and communities. Burn Wise is a way to encourage the importance of burning the right wood, the right way, in the right wood-burning appliance. The program offers a website, outreach tools and information to help consumers make informed decisions about what it means to burn wise. Several MANE-VU states have already developed similar education and outreach programs in their states.

Information about the costs associated with developing and implementing education and outreach programs at the state level are currently not available.

FACTOR 2 – COMPLIANCE TIMEFRAME

New outdoor wood boilers meeting more stringent PM emissions standards are likely to be phased in slowly as older boilers are replaced. Many MANE-VU states adopted a PM limit of 0.32 lbs/MMBTU for new units that became effective in 2010-2011 time period. EPA's Step 1 NSPS PM emissions limit of 0.32 lbs/MMBTU became effective nationally in 2015, and is identical to the current qualifying level for EPA's voluntary Hydronic Heater Program and most MANE-VU state limits. EPA's Step 2 NSPS PM emissions limit of 0.10 lbs/MMBTU becomes effective nationally in 2020. Thus, full compliance is likely to be around 2040, at the earliest.

Replacement of wood-fired boilers manufactured before the state or EPA standards took effect will gradually occur over the assumed 20 year life span of the units. Since they are designed to last for approximately 20 years, operators of the outdoor wood-fired boilers would likely be reluctant to replace them immediately. It is possible for older outdoor wood-fired boilers to be replaced more quickly given the proper economic incentives.

For example, Connecticut's initial round of the Good Deals for Good Neighbors program funded awards totaling \$68,000 which resulted in the successful removal of a number of older, dirtier and improperly sited boilers. Under the Good Deals for Good Neighbors program, Connecticut will fund awards in the amounts of \$3,000 and \$6,000 for removal or removal and replacement of outdoor wood furnaces, respectively.

Vermont also offers a voluntary OWB Change-Out Program that provides financial incentives to encourage people to replace their old OWBs with cleaner, more efficient heating systems, including: (1) a Vermont-certified Phase II OWB that uses cordwood or wood pellets; (2) a natural gas or propane furnace with a thermal efficiency of 95% or better, (3) a natural gas or propane boiler with a thermal efficiency of 90% or better; (4) an indoor cordwood or wood pellet boiler; or (5) an alternative heating system such as a geothermal heat pump. Vermont issued rebate vouchers for up to $6,000 to replace eligible OWBs and $1,000 to match manufacturer rebates to replace eligible OWBs.

The rate of retirement will depend on the available funding for the change-out programs.

FACTOR 3 – ENERGY AND NON-ENVIRONMENTAL IMPACTS

EPA noted in its 2015 NSPS revisions that the final rule is not likely to have any significant adverse energy effects. In general, EPA expects the NSPS to improve technology, including energy efficiency. Reducing emissions and increasing efficiency might increase the use of wood fuel, which would relieve pressure on traditional coal or petroleum based energy sources (and greenhouse gas emissions). It is difficult to determine the precise energy impacts because wood-fueled appliances compete with other biomass forms as well as more traditional oil, electricity and natural gas. Robust data are not available to determine the potential conversion to other types of fuels and their associated appliances if the consumer costs of wood-fueled appliances increase and at what level that increase would drive consumer choice.

The increased use of residential wood combustion devices may have a variety of non-air impacts on the environment, especially on forest and water resources (MACTEC, 2007). The potential impacts are outlined below.

<u>Nuisance Smoke</u>: Outdoor wood-fired boilers typically have very short stacks, and are prone to smoke. The short stacks oftentimes prevent proper mixing of the smoke and soot with the surrounding air, thereby creating nuisance smoke problems for surrounding houses or communities.

<u>Water</u>: Increased logging to satisfy the demand for firewood may increase runoff of silts and sediments into adjacent creeks and rivers. This increased sediment load in rivers can affect aquatic ecosystems that are integral to rivers and streams.

<u>Soils</u>: Increased logging may impact soils in many ways. For example, heavy machinery used to fell and process trees may lead to rutting and compaction of the soil, which in turn leads to higher erosion and/or altered vegetative regrowth.

<u>Wildlife</u>: Increased logging may put pressure on existing wildlife populations in the US Northeast by altering their critical habitat.

<u>Threatened and Endangered Species</u>: Increased logging in Northeast may impact threatened and endangered species through habitat destruction or alteration.

FACTOR 4 – REMAINING USEFUL LIFE

Most wood heaters in consumer homes emit for at least 20 years and often much longer (EPA, 2015a). EPA assumed that models do not come into compliance until the year they are required to, although some models will meet the NSPS Step 2 PM limit prior to the 2020 compliance year and will therefore be emitting less than baseline levels prior to that year. Data on the remaining useful life of existing OWV in MANE-VU is not available. The 2007 Assessment estimated that most units in operation at that time had been installed within the past fifteen years, so replacements might have begun as early as 2012.

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DRAFT MEMORANDUM

TO: Susan Wierman, MARAMA
Joseph Jakuta, OTC

FROM: Ed Sabo, CSRA

DATE: January 29, 2016

SUBJECT: Updates to CoST Control Measure Database

BACKGROUND

MARAMA has developed the capability to run EPA's Control Strategy Tool (CoST) model. CoST allows users to estimate the emission reductions and costs associated with future-year emission control strategies, and then to generate emission inventories that reflect the effects of applying the control strategies. Some of the underlying control and cost information in CoST tool is dated and EPA's project to update this data has been delayed due to resource constraints. This memorandum documents CSRA's efforts to update CoST with information from the analyses of the costs of potential measures to improve visibility in Class I areas in and near the Mid-Atlantic and Northeast region.

OVERVIEW OF COST

CoST[2] is a relational database that contains information on an extensive set of control measure cost information and algorithms for calculating emission reductions and costs associated with potential control strategies. A key component of CoST is the Control Measures Database (CMDB), which consists of the following tables for stationary sources:

- **Summary** table with general information about the control measure;
- **Efficiency** table describing the reductions achieved by, and the costs required to apply, the measure for each affected pollutant;
- **Source classification code (SCC)** table that identify the SCCs to which the control measure applies;
- **Equation** table that contains parameters used to compute the results of cost equations for measures to which the equation applies;
- **Reference** table providing additional information on the control measure and how its control efficiency and cost information were derived.
- **Parameter** table with information that does not fit well within one of the five previous categories, especially parameters that are unique to a single control measure or a subset of control measures.

For many of the control measures in CoST, a simple cost factor in terms of dollars per ton of pollutant reduced is used to calculate the cost of the control measure when applied to a specific

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[2] Control Strategy Tool (CoST) software and documentation http://www3.epa.gov/ttn/ecas/cost.htm

source. However, a few control measures (especially those for EGUs and ICI boilers) use a more robust cost equation to determine engineering costs that take into account several variables for the source when those variables are available.

METHODOLOGY

CSRA used the following methodology to update the CoST CMDB:

- Review the existing CMDB control measures for electric generating units (EGUs); industrial, commercial and institutional (ICI) boilers; home heating oil; residential wood combustion; and outdoor wood boilers.
- Review the 2016 MANE-VU 4-factor analyses for the above categories and identify whether existing CMDB control measures should be updated or new control measures should be developed.
- Create new CMDB measures that uniquely identify the measure as representing the information contained in the MANE-VU 4-factor analyses. This was done by ending all CoST control measures abbreviations with "-MV." This allows the CoST user to easily select only those measures associated with the MANE-VU 4-factor analyses while not changing the original CoST data developed by EPA.
- Document the basis for developing the cost parameters using the COST_BASIS parameter field of the PROPS table. Where possible, CSRA updated the variables in the existing cost equations that take into account the variables that have the greatest impact on cost, in terms of both capital costs and operating and maintenance costs. If it is not possible to use a cost equation, CSRA calculated a cost-per-ton reduction factor.
- Review the source classification codes (SCCs) associated with each MANE-VU measure, and update the CoST SCC table as necessary.
- Update each of the six CMDB tables with the relevant information.
- Import the MANE-VU measures into the CMDB and verify that the information in the tables were correctly loaded into CoST.
- Test each MANE-VU control measure by running a CoST control strategy using a small subset of relevant inventory sources to verify the reasonableness of the resulting emission reduction and cost estimation calculations.

Table 1 summarizes the MANE-VU measures generated during this effort. Refer to the COST_BASIS parameter of the PROPS table to see the documentation of how each measure was developed.

Note that in testing the EGU control measures, CSRA identified two errors in the CoST model equations that result in anomalous results:

- CoST converts E6BTU/HR to MW using 1 MW = 3.412 MMBTU/hr. This conversion does not account for the 33% efficiency of a power plant that converts a fuel into electricity (e.g., the heat rate). The correct conversion factor should be 1 MW = 10.34 million BTU/hr (e.g., heat rate of 10,340 Btu/kw-hr). Of course, the precise heat rate is unit-specific, but for CoST purposes may not be needed although it can vary +/- 10%.
- CoST has an error in the code for calculating the scaling factor. The scaling factor used in calculating capitol cost in the code on page A-1 in the CoST Equations Document for design capacity < 500 MW is missing the design capacity in the denominator.

    - Incorrect: scaling_factor_model_size ^ scaling_factor_exponent
    - Correct: (scaling_factor_model_size/design_capacity)^scaling_factor_exponent

EPA acknowledged the error in the algorithm and indicated that they have not used the EGU control measure equations in CoST because they rely on IPM for control strategy information. EPA is currently reviewing and using the IPM documentation to update the EGU cost equations. When that effort is completed, EPA will revise the CoST code to implement the updates and ensure they are working error-free. EPA anticipates having the corrections completed. Until then, MARAMA should not use the control measures that utilize CoST equation 1 because of the erroneous results that it produces.

CSRA also conducted limited testing of all other CoST control measures (ICI boilers, heating oil, residential wood combustion, and outdoor wood boilers) developed for MANE-VU. Since these control measures use simple "cost per ton" factors instead of CoST equations, the application of the control measures to sample inventory sources is relatively straightforward. No anomalous results were observed during the testing for these source categories.

Table 1 – Control Measures Added to the CoST Control Measure Database

CMDB Abbreviation (cmabbreviation)	Major Pollutant	Control Technology	Source Group	Sector
PBBFPHHWDS_MV	PM25-PRI	Curtailment Program, aka Burn Ban	Fireplaces, Hydronic Heaters, Wood Stoves	nonpt
PCTGLGFPL_MV	PM25-PRI	Convert to Gas Logs	Fireplaces	nonpt
PEP2QUFPL_MV	PM25-PRI	EPA Phase 2 Qualified Units	Fireplaces	nonpt
PIRDVCFPL_MV	PM25-PRI	Install Retrofit Devices	Fireplaces	nonpt
PNGSTWDSTV_MV	PM25-PRI	New gas stove or gas logs	Wood Stoves	nonpt
PROC2CABR_MV	PM25-PRI	Replace Old Certified Catalytic with 2015 NSPS Step 2 Catalytic Average Burn Rate	Wood Stoves	nonpt
PROC2CHBR_MV	PM25-PRI	Replace Old Certified Catalytic with 2015 NSPS Step 2 Catalytic High Burn Rate	Wood Stoves	nonpt
PROC2CLBR_MV	PM25-PRI	Replace Old Certified Catalytic with 2015 NSPS Step 2 Catalytic Low Burn Rate	Wood Stoves	nonpt
PROC2NCABR_MV	PM25-PRI	Replace Old Certified Catalytic with 2015 NSPS Step 2 non-Catalytic Average Burn Rate	Wood Stoves	nonpt
PROC2NCHBR_MV	PM25-PRI	Replace Old Certified Catalytic with 2015 NSPS Step 2 non-Catalytic High Burn Rate	Wood Stoves	nonpt
PROC2NCLBR_MV	PM25-PRI	Replace Old Certified Catalytic with 2015 NSPS Step 2 non-Catalytic Low Burn Rate	Wood Stoves	nonpt
PROC2PABR_MV	PM25-PRI	Replace Old Certified Catalytic with 2015 NSPS Step 2 Pellet Average Burn Rate	Wood Stoves	nonpt
PROC2PHBR_MV	PM25-PRI	Replace Old Certified Catalytic with 2015 NSPS Step 2 Pellet High Burn Rate	Wood Stoves	nonpt

CMDB Abbreviation (cmabbreviation)	Major Pollutant	Control Technology	Source Group	Sector
PROC2PLBR_MV	PM25-PRI	Replace Old Certified Catalytic with 2015 NSPS Step 2 Pellet Low Burn Rate	Wood Stoves	nonpt
PRON2CABR_MV	PM25-PRI	Replace Old Non-cert with 2015 NSPS Step 2 Catalytic Average Burn Rate	Wood Stoves	nonpt
PRON2CHBR_MV	PM25-PRI	Replace Old Non-cert with 2015 NSPS Step 2 Catalytic High Burn Rate	Wood Stoves	nonpt
PRON2CLBR_MV	PM25-PRI	Replace Old Non-cert with 2015 NSPS Step 2 Catalytic Low Burn Rate	Wood Stoves	nonpt
PRON2NCABR_MV	PM25-PRI	Replace Old Non-cert with 2015 NSPS Step 2 non-Catalytic Average Burn Rate	Wood Stoves	nonpt
PRON2NCHBR_MV	PM25-PRI	Replace Old Non-cert with 2015 NSPS Step 2 non-Catalytic High Burn Rate	Wood Stoves	nonpt
PRON2NCLBR_MV	PM25-PRI	Replace Old Non-cert with 2015 NSPS Step 2 non-Catalytic Low Burn Rate	Wood Stoves	nonpt
PRON2PABR_MV	PM25-PRI	Replace Old Non-cert with 2015 NSPS Step 2 Pellet Average Burn Rate	Wood Stoves	nonpt
PRON2PHBR_MV	PM25-PRI	Replace Old Non-cert with 2015 NSPS Step 2 Pellet High Burn Rate	Wood Stoves	nonpt
PRON2PLBR_MV	PM25-PRI	Replace Old Non-cert with 2015 NSPS Step 2 Pellet Low Burn Rate	Wood Stoves	nonpt
PRONC2CABR_MV	PM25-PRI	Replace Old Certified Noncatalytic with 2015 NSPS Step 2 Catalytic Average Burn Rate	Wood Stoves	nonpt
PRONC2CHBR_MV	PM25-PRI	Replace Old Certified Noncatalytic with 2015 NSPS Step 2 Catalytic High Burn Rate	Wood Stoves	nonpt
PRONC2CLBR_MV	PM25-PRI	Replace Old Certified Noncatalytic with 2015 NSPS Step 2 Catalytic Low Burn Rate	Wood Stoves	nonpt
PRONC2NCABR_MV	PM25-PRI	Replace Old Certified Noncatalytic with 2015 NSPS Step 2 non-Catalytic Average Burn Rate	Wood Stoves	nonpt

CMDB Abbreviation (cmabbreviation)	Major Pollutant	Control Technology	Source Group	Sector
PRONC2NCHBR_MV	PM25-PRI	Replace Old Certified Noncatalytic with 2015 NSPS Step 2 non-Catalytic High Burn Rate	Wood Stoves	nonpt
PRONC2NCLBR_MV	PM25-PRI	Replace Old Certified Noncatalytic with 2015 NSPS Step 2 non-Catalytic Low Burn Rate	Wood Stoves	nonpt
PRONC2PABR_MV	PM25-PRI	Replace Old Certified Noncatalytic with 2015 NSPS Step 2 Pellet Average Burn Rate	Wood Stoves	nonpt
PRONC2PHBR_MV	PM25-PRI	Replace Old Certified Noncatalytic with 2015 NSPS Step 2 Pellet High Burn Rate	Wood Stoves	nonpt
PRONC2PLBR_MV	PM25-PRI	Replace Old Certified Noncatalytic with 2015 NSPS Step 2 Pellet Low Burn Rate	Wood Stoves	nonpt
PROP2PABR_MV	PM25-PRI	Replace Old Pellet with 2015 NSPS Step 2 Pellet Average Burn Rate	Wood Stoves	nonpt
PROP2PHBR_MV	PM25-PRI	Replace Old Pellet with 2015 NSPS Step 2 Pellet High Burn Rate	Wood Stoves	nonpt
PROP2PLBR_MV	PM25-PRI	Replace Old Pellet with 2015 NSPS Step 2 Pellet Low Burn Rate	Wood Stoves	nonpt
PROWB2HH_MV	PM25-PRI	Replace Old Outdoor Wood Boiler with 2015 NSPS Step 2 Hydronic Heater	Hydronic Heaters	nonpt
SULSFRESHETH$_MV	SO2	Ultra-Low Sulfur Fuel	Residential Heating	nonpt
SULSFRESHETL$_MV	SO2	Ultra-Low Sulfur Fuel	Residential Heating	nonpt
NLNBOUBCW_MV	NOX	Low NOx Burner and Over Fire Air	Utility Boiler - Coal/Wall	ptipm
NLNBOUBCW2_MV	NOX	Low NOx Burner and Over Fire Air	Utility Boiler - Coal/Wall2	ptipm
NLNBUUBCW_MV	NOX	Low NOx Burner	Utility Boiler - Coal/Wall	ptipm

CMDB Abbreviation (cmabbreviation)	Major Pollutant	Control Technology	Source Group	Sector
NLNBUUBCW2_MV	NOX	Low NOx Burner	Utility Boiler - Coal/Wall2	ptipm
NLNC1UBCT_MV	NOX	Low NOx Coal-and-Air Nozzles with cross-Coupled Overfire Air	Utility Boiler - Coal/Tangential	ptipm
NLNC1UBCT2_MV	NOX	Low NOx Coal-and-Air Nozzles with cross-Coupled Overfire Air	Utility Boiler - Coal/Tangential1	ptipm
NLNC2UBCT_MV	NOX	Low NOx Coal-and-Air Nozzles with separated Overfire Air	Utility Boiler - Coal/Tangential	ptipm
NLNC2UBCT2_MV	NOX	Low NOx Coal-and-Air Nozzles with separated Overfire Air	Utility Boiler - Coal/Tangential2	ptipm
NLNC3UBCT_MV	NOX	Low NOx Coal-and-Air Nozzles with Cross-Coupled and Separated Overfire Air	Utility Boiler - Coal/Tangential	ptipm
NLNC3UBCT2_MV	NOX	Low NOx Coal-and-Air Nozzles with Cross-Coupled and Separated Overfire Air	Utility Boiler - Coal/Tangential3	ptipm
NSCR_UBCT_MV	NOX	Selective Catalytic Reduction	Utility Boiler - Coal/Tangential	ptipm
NSCR_UBCW_MV	NOX	Selective Catalytic Reduction	Utility Boiler - Coal/Wall	ptipm
NSCR_UBCY_MV	NOX	Selective Catalytic Reduction	Utility Boiler - Cyclone	ptipm
NSCR_UBOT_MV	NOX	Selective Catalytic Reduction	Utility Boiler - Oil-Gas/Tangential	ptipm
NSCR_UBOW_MV	NOX	Selective Catalytic Reduction	Utility Boiler - Oil-Gas/Wall	ptipm
NSNCRUBCT_MV	NOX	Selective Non-Catalytic Reduction	Utility Boiler - Coal/Tangential	ptipm
NSNCRUBCW_MV	NOX	Selective Non-Catalytic Reduction	Utility Boiler - Coal/Wall	ptipm

CMDB Abbreviation (cmabbreviation)	Major Pollutant	Control Technology	Source Group	Sector
NSNCRUBCY_MV	NOX	Selective Non-Catalytic Reduction	Utility Boiler - Cyclone	ptipm
NSNCRUBOT_MV	NOX	Selective Non-Catalytic Reduction	Utility Boiler - Oil-Gas/Tangential	ptipm
NSNCRUBOW_MV	NOX	Selective Non-Catalytic Reduction	Utility Boiler - Oil-Gas/Wall	ptipm
SDSIUBC_MV	SO2	Dry Sorbent Injection	Utility Boilers - Bituminous/Subbituminous Coal	ptipm
SLSDUBC1_MV	SO2	Lime Spray Dryer	Utility Boilers - Bituminous/Subbituminous Coal (100 to 299 MW)	ptipm
SLSDUBC2_MV	SO2	Lime Spray Dryer	Utility Boilers - Bituminous/Subbituminous Coal (300 to 499 MW)	ptipm
SLSDUBC3_MV	SO2	Lime Spray Dryer	Utility Boilers - Bituminous/Subbituminous Coal (500 to 699 MW)	ptipm
SLSDUBC4_MV	SO2	Lime Spray Dryer	Utility Boilers - Bituminous/Subbituminous Coal (700 to 999 MW)	ptipm
SLSDUBC5_MV	SO2	Lime Spray Dryer	Utility Boilers - Bituminous/Subbituminous Coal (Over 1000 MW)	ptipm
SLSFOUBC1_MV	SO2	Limestone Forced Oxidation	Utility Boilers - Bituminous/Subbituminous Coal (100 to 299 MW)	ptipm
SLSFOUBC2_MV	SO2	Limestone Forced Oxidation	Utility Boilers - Bituminous/Subbituminous Coal (300 to 499 MW)	ptipm
SLSFOUBC3_MV	SO2	Limestone Forced Oxidation	Utility Boilers - Bituminous/Subbituminous Coal (500 to 699 MW)	ptipm
SLSFOUBC4_MV	SO2	Limestone Forced Oxidation	Utility Boilers - Bituminous/Subbituminous Coal (700 to 999 MW)	ptipm
SLSFOUBC5_MV	SO2	Limestone Forced Oxidation	Utility Boilers - Bituminous/Subbituminous Coal (Over 1000 MW)	ptipm
NLNBCH$_MV	NOX	Low NOx Burners High Cost	ICI2 Boilers - Coal	ptnonipm

CMDB Abbreviation (cmabbreviation)	Major Pollutant	Control Technology	Source Group	Sector
NLNBCL$_MV	NOX	Low NOx Burners Low Cost	ICI2 Boilers - Coal	ptnonipm
NLNBNGH$_MV	NOX	Low NOx Burners High Cost	ICI2 Boilers - Natural Gas	ptnonipm
NLNBNGL$_MV	NOX	Low NOx Burners Low Cost	ICI2 Boilers - Natural Gas	ptnonipm
NLNBOAROH$_MV	NOX	Low NOx Burners plus Overfire Air High Cost	ICI2 Boilers - Residual Oil	ptnonipm
NLNBOAROL$_MV	NOX	Low NOx Burners plus Overfire Air Low Cost	ICI2 Boilers - Residual Oil	ptnonipm
NLNBROH$_MV	NOX	Low NOx Burners High Cost	ICI2 Boilers - Residual Oil	ptnonipm
NLNBROL$_MV	NOX	Low NOx Burners Low Cost	ICI2 Boilers - Residual Oil	ptnonipm
NOACH$_MV	NOX	Overfire Air High Cost	ICI2 Boilers - Coal	ptnonipm
NOACL$_MV	NOX	Overfire Air Low Cost	ICI2 Boilers - Coal	ptnonipm
NOANGH$_MV	NOX	Overfire Air High Cost	ICI2 Boilers - Natural Gas	ptnonipm
NOANGL$_MV	NOX	Overfire Air Low Cost	ICI2 Boilers - Natural Gas	ptnonipm
NOAROH$_MV	NOX	Overfire Air High Cost	ICI2 Boilers - Residual Oil	ptnonipm
NOAROL$_MV	NOX	Overfire Air Low Cost	ICI2 Boilers - Residual Oil	ptnonipm
NSCRCH$_MV	NOX	Selective Catalytic Reduction High Cost	ICI2 Boilers - Coal	ptnonipm
NSCRCL$_MV	NOX	Selective Catalytic Reduction Low Cost	ICI2 Boilers - Coal	ptnonipm
NSCRNGH$_MV	NOX	Selective Catalytic Reduction High Cost	ICI2 Boilers - Gas	ptnonipm
NSCRNGL$_MV	NOX	Selective Catalytic Reduction Low Cost	ICI2 Boilers - Gas	ptnonipm
NSCRROH$_MV	NOX	Selective Catalytic Reduction High Cost	ICI2 Boilers - Residual Oil	ptnonipm
NSCRROL$_MV	NOX	Selective Catalytic Reduction Low Cost	ICI2 Boilers - Residual Oil	ptnonipm
NSNCRCHL$_MV	NOX	Selective non-Catalytic Reduction High Cost	ICI2 Boilers - Coal	ptnonipm
NSNCRCL$_MV	NOX	Selective non-Catalytic Reduction Low Cost	ICI2 Boilers - Coal	ptnonipm
NSNCRROH$_MV	NOX	Selective non-Catalytic Reduction High Cost	ICI2 Boilers - Residual Oil	ptnonipm
NSNCRROL$_MV	NOX	Selective non-Catalytic Reduction Low Cost	ICI2 Boilers - Residual Oil	ptnonipm
NULNBNGH$_MV	NOX	Ultra-Low NOx Burners High Cost	ICI2 Boilers - Natural Gas	ptnonipm
NULNBNGL$_MV	NOX	Ultra-Low NOx Burners Low Cost	ICI2 Boilers - Natural Gas	ptnonipm
SDFGDCH$_MV	SO2	Dry FGD High Cost	ICI2 Boilers - Coal	ptnonipm
SDFGDCL$_MV	SO2	Dry FGD Low Cost	ICI2 Boilers - Coal	ptnonipm
SDSICH$_MV	SO2	Dry Sorbent Injection High Cost	ICI2 Boilers - Coal	ptnonipm
SDSICL$_MV	SO2	Dry Sorbent Injection Low Cost	ICI2 Boilers - Coal	ptnonipm

CMDB Abbreviation (cmabbreviation)	**Major Pollutant**	**Control Technology**	**Source Group**	**Sector**
SFSC2GH$_MV	SO2	Fuel Switch Coal to Gas High $/ton	ICI2 Boilers - Coal	ptnonipm
SFSC2GL$_MV	SO2	Fuel Switch Coal to Gas Low $/ton	ICI2 Boilers - Coal	ptnonipm
SFSDOHS2ULSDH$_MV	SO2	Fuel Switch High Sulfur Distillate Oil to ULSD High Cost	ICI2 Boilers - Distillate Oil	ptnonipm
SFSDOHS2ULSDL$_MV	SO2	Fuel Switch High Sulfur Distillate Oil to ULSD Low Cost	ICI2 Boilers - Distillate Oil	ptnonipm
SFSO2G_MV	SO2	Fuel Switch Oil to Gas	ICI2 Boilers - Residual or Distillate Oil	ptnonipm
SFSROHS2LS_MV	SO2	Fuel Switch Residual Oil High to Low Sulfur	ICI2 Boilers - Residual Oil	ptnonipm
SFSROHS2ULSD_MV	SO2	Fuel Switch Residual Oil to ULSD	ICI2 Boilers - Residual Oil	ptnonipm
SWFGDCH$_MV	SO2	Wet FGD High Cost	ICI2 Boilers - Coal	ptnonipm
SWFGDCL$_MV	SO2	Wet FGD Low Cost	ICI2 Boilers - Coal	ptnonipm

APPENDIX M

Status of the Top 167 Electric Generating Units (EGUs) that Contributed to Visibility Impairment at MANE-VU Class I Areas during the 2008 Regional Haze Planning Period

Mid-Atlantic/Northeast Visibility Union
(MANE-VU)

July 25, 2016

The Mid-Atlantic/Northeast Visibility Union (MANE-VU) identified 167 Electric Generating Units (EGUs) as sources that most affected visibility in the MANE-VU Class I areas during the 2008 planning period. In establishing the reasonable progress goal for regional haze, MANE-VU Class I areas relied in part on implementation of emission reductions at the 167 EGU sources by 2018. These 167 EGU sources are located both within and outside MANE-VU.

The MANE-VU "Ask" requested a 90% or greater reduction in SO_2 emissions from 2002 levels at each of the 167 stacks identified by MANE-VU as contributing to visibility impairment at the MANE-VU Class I areas. If it is infeasible to achieve this level of reduction from a unit, the state could obtain the requested reduction from other units in the State.

The attached worksheets provide a summary of the status of controls at the 167 EGU units. New Jersey worked off of a previous analysis carried out by Maine to update the status of the controls at the units. Steps taken to update the worksheets are described as follows:

Step 1

The worksheet was updated with EGU control status from the National Electric Energy Data System (NEEDS) v5.14, and later NEEDS v5.15[1]. The worksheet previously had control status information from NEEDS v4.10. The worksheet was also updated with Environmental Protection Agency's (EPA) 2011 and 2015 Clean Air Markets Division (CAMD) Air Markets Program Data (AMPD),[2] updates from States (Georgia, Indiana, Massachusetts, Maryland, Maine, Michigan, New Hampshire, New Jersey, New York, North Carolina, Pennsylvania, and Virginia) and information from state SIPS (Ohio Regional Haze 5-Year Progress Report (January 2016)). "0" was assigned to units that had no values for SO_2 emissions in 2015 CAMD AMPD. Data from the Eastern Regional Technical Advisory Committee (ERTAC) was also reviewed to ensure consistency and accuracy.

Units with SO2 permit rates greater than 0.4lbs/mmBtu are highlighted in grey in the tables throughout the analysis. Note that some of the SO2 permit rates could be the permit rates at the units before controls were installed. For some of the units with SO2 permit rates greater than 0.4lbs/mmBtu, the actual amounts of SO2 emitted were less than 0.4lb/mmBtu. It is recommended that units with actual SO2 emissions greater than 0.4lbs/mmBtu be revisited in the future as resources allow.

Based on the information from the sources mentioned above, 46 out of the 167 units have been shut down, retired or decommissioned. The units eliminated are highlighted in grey in the tab "Retired_Shutdown_Decommissioned" in the spreadsheet "167 EGU Stacks that Impact MANE-VU Class I Areas" in Appendix X. These 46 units were eliminated in this step leaving 121 units.

Shawville is temporarily shut down to install equipment for burning natural gas. SO2 emissions are expected to be well below the 90% reduction expected at the Shawville units when they start burning natural gas. Shawville has retained its rights to burn coal, however, a federal regulation

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[1] http://www.epa.gov/airmarkets/power-sector-modeling-platform-v515 (Accessed February 22, 2016)

[2] http://ampd.epa.gov/ampd/ (Accessed February 25, 2016)

requires the installation of scrubbers before they can burn coal. The enforceability of the controls on these units should be investigated in the future as resources allow.

The 46 units that were eliminated in this step are listed in Table 1.

Table 1: Shut Down, Retired or Decommissioned Units (46 Units)

STATE	ORIS ID	PLANT NAME	UNIT ID
DELAWARE	594	INDIAN RIVER	1
			2
			3
GEORGIA	709	HARLLEE BRANCH	3,4
INDIANA	988	TANNER'S CREEK	U1,U2,U3
			4*
	1010	WABASH RIVER	2*,3*,4*,5*,6*
MASSACHUSETTS	1606	MOUNT TOM	1
	1613	SOMERSET	8
	1626	SALEM HARBOR	1
			3
			4
NEW JERSEY	2378	B L ENGLAND	1
NEW YORK	2526	GOUDEY	11,12,13
	2527	GREENIDGE	6
	2549	C R HUNTLEY	67*,68*
			63,64,65,66
	2554	DUNKIRK	3,4
	2594	OSWEGO	5
	2642	ROCHESTER 7	3,4
NORTH CAROLINA	2709	LEE	3
	2713	L V SUTTON	3
OHIO	2830	WALTER C BECKJORD	6
	2832	MIAMI FORT	5-1,5-2,6
	2837	EASTLAKE	5
	2840	CONESVILLE	1,2
	2864	R E BURGER	5 THRU 8
	2872	MUSKINGUM RIVER	1,2,3,4
			5*
	7253	RICHARD GORSUCH	1,2,3,4
PENNSYLVANIA	3113	PORTLAND	1
			2
	3148	MARTINS CREEK	1,2
	3178	ARMSTRONG	2
	2179	HATFIELD'S FERRY	1,2
	3131	SHAWVILLE	3,4

STATE	ORIS ID	PLANT NAME	UNIT ID
SOUTH CAROLINA	3319	JEFFERIES	3
			4
TENNESSEE	3405	JOHN SEVIER	3,4
VIRGINIA	3803	CHESAPEAKE	3
			4
WEST VIRGINIA	3936	KANAWHA RIVER	1,2
	3938	PHILIP SPORN	51
			11,21,31,41
	3942	ALBRIGHT	3
	3947	KAMMER	1,2,3

Note: Units with SO_2 permit rate greater than 0.4lbs/mmBtu are highlighted.
* Units with actual amount of SO_2 emitted greater than 0.4lbs/mmBtu.

Step 2

The remaining 121 units were reviewed for units that have 90% or greater SO_2 emission reductions from 2002 total SO_2 stack level emissions. The emission reduction was based on emissions reported as 2015 CAMD AMPD SO_2 stack level data. These units met the MANE-VU Ask at the stack level for a 90% or greater reduction. 83 units met this criterion, and were eliminated, leaving 38 units. The units eliminated are highlighted in light green in the tab "90%+Reduction" in the spreadsheet "167 EGU Stacks that Impact MANE-VU Class I Areas" in Appendix X. The 83 units that were eliminated are listed in Table 2.

Table 2: Units with 90% or Greater SO_2 Emission Reductions (2002-2015) (83 Units)

STATE	ORIS ID	PLANT NAME	UNIT ID
DELAWARE	593	EDGE MOOR	5
	594	INDIAN RIVER	4
GEORGIA	703	BOWEN	1BLR
			2BLR
			3BLR
			4BLR
ILLINOIS	861	COFFEEN	1,2
INDIANA	990	ELMER W STOUT	70
	1001	CAYUGA	1
			2
	1008	R GALLAGHER	1,2*
			3,4*
	6113	GIBSON	1,2
	6705	WARRICK	1,2
			4
KENTUCKY	1355	E W BROWN	2,3
	1378	PARADISE	3
	1384	COOPER	1,2*
	6041	H L SPURLOCK	1

STATE	ORIS ID	PLANT NAME	UNIT ID
			2
MARYLAND	602	BRANDON SHORES	1
			2
	1552	C P CRANE	1
			2
	1571	CHALK POINT	1,2*
	1572	DICKERSON	1,2,3
	1573	MORGANTOWN	1
			2
MASSACHUSETTS	1599	CANAL	1
			2
	1619	BRAYTON POINT	1
			2
			3
MICHIGAN	1702	DAN E KARN	3*,4*
	1733	MONROE	1,2
			3,4
NEW HAMPSHIRE	2364	MERRIMACK	1
			2
	8002	NEWINGTON	1
NEW JERSEY	2403	HUDSON	2
	2408	MERCER	1
			2
NEW YORK	2480	DANSKAMMER	4
	2516	NORTHPORT	3
	8006	ROSETON	1
NORTH CAROLINA	2712	ROXBORO	3A*,3B*
	2721	CLIFFSIDE	5
	2727	MARSHALL	3
			4
	6250	MAYO	1A,1B
	8042	BELEWS CREEK	1
			2
OHIO	2828	CARDINAL	3
	2832	MIAMI FORT	7
	2840	CONESVILLE	4
	2850	J M STUART	1
			2
			3
			4
	2866	W H SAMMIS	1*,2*
			3,4
			5

STATE	ORIS ID	PLANT NAME	UNIT ID
			6
			7
	2876	KYGER CREEK	1*,2*,3*,4*,5*
PENNSYLVANIA	3149	MONTOUR	1
	8226	CHESWICK	1
SOUTH CAROLINA	3297	WATEREE	WAT1
			WAT2
	3298	WILLIAMS	WIL1
	6249	WINYAH	1
TENNESSEE	3407	KINGSTON	1,2,3,4*,5
			6,7,8,9
VIRGINIA	3775	CLINCH RIVER	1,2
	3797	CHESTERFIELD	4
			5
			6
WEST VIRGINIA	3935	JOHN E AMOS	1*,2*
			3
	3943	FORT MARTIN	1
			2
	3948	MITCHELL	1,2
	6264	MOUNTAINEER	1

Note: Units with SO_2 permit rate greater than 0.4lbs/mmBtu are highlighted.
* Units with actual amount of SO_2 emitted greater than 0.4lbs/mmBtu.

Step 3

The remaining 38 units were further reviewed for units that have scrubbers with at least 90% scrubber control efficiency. This was done on a case by case basis. SO_2 emission reductions at these units were between 85 and 89% in 2015 compared to 2002 levels. Some of these units had over 90% SO_2 emission reductions in 2014 but could have differed because of variations in amount of the unit's operation between later years and the 2002 base year. Units with wet scrubbers that were installed prior to 2002 were also eliminated even though some of them have emission reductions less than 85% when the wet scrubbers reported scrubber control efficiency of well over 90%. This could be as a result of how the scrubber was used; scrubber shut downs or inactivity, or emission reductions that may have already taken place before 2002. It could also be due to meteorological changes. In this step, 13 Units were eliminated, leaving 25. The units eliminated are highlighted in purple in the tab "Scrubber90%+" in the spreadsheet "167 EGU Stacks that Impact MANE-VU Class I Areas" in Appendix X. The 13 units that were eliminated are listed in Table 3.

<u>Table 3</u>: Units with Scrubbers with 90% or Higher Scrubber Efficiency
SO_2 Emission Reductions: 85%-89% (2002-2015) (13 Units)

STATE	ORIS ID	PLANT NAME	UNIT ID
INDIANA	983	CLIFTY CREEK	1*,2*,3*
			4*,5,6*
	6113	GIBSON	3,4
KENTUCKY	1364	MILL CREEK	4
	6018	EAST BEND	2
NORTH CAROLINA	2712	ROXBORO	1
			2
			4A*,4B*
OHIO	2828	CARDINAL	1
PENNSYLVANIA	3136	KEYSTONE	1*
	3140	BRUNNER ISLAND	1*,2*
			3
	3149	MONTOUR	2

Note: Units with SO_2 permit rate greater than 0.4lbs/mmBtu are highlighted.
* Units with actual amount of SO_2 emitted greater than 0.4lbs/mmBtu.

Step 4

In this step, the remaining 25 units were reviewed for units that have scrubbers (both wet and dry) installed. Dry scrubbers are believed to be less efficient than wet ones (generally below 80% emission reduction), but according to a USEPA Air Pollution Control Technology fact sheet,[3] newer dry scrubbers are capable of higher control efficiencies, on the order of 90%. Some of the units that were eliminated in this step had scrubbers with 90% or higher efficiency but SO_2 emission reductions at these units in 2015 were less than 85% compared with 2002 levels. 14 units were eliminated in this step, leaving 11. 11 of these 14 units had wet scrubbers, while 3 had dry scrubbers. The units eliminated are highlighted in blue (wet scrubbers) and light blue (dry scrubbers) in the tab "Scrubbers" in the spreadsheet "167 EGU Stacks that Impact MANE-VU Class I Areas" in Appendix X. The 14 units that were eliminated are listed in Table 4.

<u>Table 4</u>: Units with Scrubbers (Wet and Dry)
SO_2 Emission Reductions: < 85% (2002-2015) (14 Units)

<u>Units with Wet Scrubbers</u>			
STATE	**ORIS ID**	**PLANT NAME**	**UNIT ID**
KENTUCKY	1356	GHENT	3,4
	1378	PARADISE	2
OHIO	2828	CARDINAL	2
	6019	W H ZIMMER	1
	6031	KILLEN STATION	2
	8102	GEN J M GAVIN	1

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[3] http://www3.epa.gov/ttncatc1/dir1/ffdg.pdf (Accessed March 3, 2016)

Units with Wet Scrubbers			
STATE	**ORIS ID**	**PLANT NAME**	**UNIT ID**
			2
PENNSYLVANIA	3136	KEYSTONE	2*
WEST VIRGINIA	3954	MT STORM	1,2
	6004	PLEASANTS	1
			2
Units with Dry Scrubbers			
STATE	**ORIS ID**	**PLANT NAME**	**UNIT ID***
PENNSYLVANIA	3122	HOMER CITY	1*
			2*
TENNESSEE	3403	GALLATIN	3*,4*

Note: Units with SO_2 permit rate greater than 0.4lbs/mmBtu are highlighted.
* Units with actual amount of SO_2 emitted greater than 0.4lbs/mmBtu.

It is recommended that the units in Table 4 be revisited to determine why their emissions are lower than expected.

Step 5

Units that have plans to retire or install newer controls by 2018 were eliminated in this step. Determinations were made based on updates from states and information from NEEDS v5.15. Six out of the remaining 11 units were eliminated, leaving 5 that will not meet the MANE-VU “Ask” by 2018. It is recommended that these units are reviewed again in the future to ensure that they either retired or installed controls. The units that were eliminated are highlighted in orange in the tab “Plans to Retire_Control” in the spreadsheet “167 EGU Stacks that Impact MANE-VU Class I Areas” in Appendix X. The 6 units that were eliminated in this step are listed in Table 5.

Table 5: Units with Plans to Retire or Install Newer Controls by 2018 (6 Units)

STATE	ORIS ID	PLANT NAME	UNIT ID
INDIANA	6166	ROCKPORT	MB1*,MB2*
KENTUCKY	1353	BIG SANDY	BSU1*, BSU2*
MAINE	1507	WILLIAM F WYMAN	4*
OHIO	2836	AVON LAKE	12*
TENNESSEE	3406	JOHNSONVILLE	1 THRU 10. 1*,2*,3*,4*
VIRGINIA	3809	YORKTOWN	1*,2

Note: Units with SO_2 permit rate greater than 0.4lbs/mmBtu are highlighted.
* Units with actual amount of SO_2 emitted greater than 0.4lbs/mmBtu.

Step 6

The remaining 5 units were further reviewed for the quantity of SO_2 in pounds (lbs.) burned per Heat Input in MMBtu. This analysis was done using 2015 CAMD AMPD data. 0.1 – 0.4 was chosen as the acceptable rate. 1 unit was eliminated, leaving 4 units having higher SO_2 emissions than others. The unit that was eliminated is highlighted in brown in the tab “Heat Input” in the spreadsheet “167 EGU Stacks that Impact MANE-VU Class I Areas” in Appendix X. The unit that was eliminated is listed in Table 6.

Table 6: Units with SO_2 (lbs) Burned per Heat Input (MMBtu) Between 0.1-0.4 (1 Unit)

STATE	ORIS ID	PLANT NAME	UNIT ID
NEW YORK	8006	ROSETON	2

Note: Units with SO_2 permit rate greater than 0.4lbs/mmBtu are highlighted.

Step 7

The remaining 4 units were ranked from highest to lowest based on total stack level SO_2 emissions using 2015 CAMD AMPD. These units do not seem to have sufficient SO_2 controls installed. These 7 units are listed in the tab “Rank” in the spreadsheet “167 EGU Stacks that Impact MANE-VU Class I Areas” in Appendix X, and are also listed in Table 7.

Table 7: Units with Insufficient SO2 Controls (4 Units)

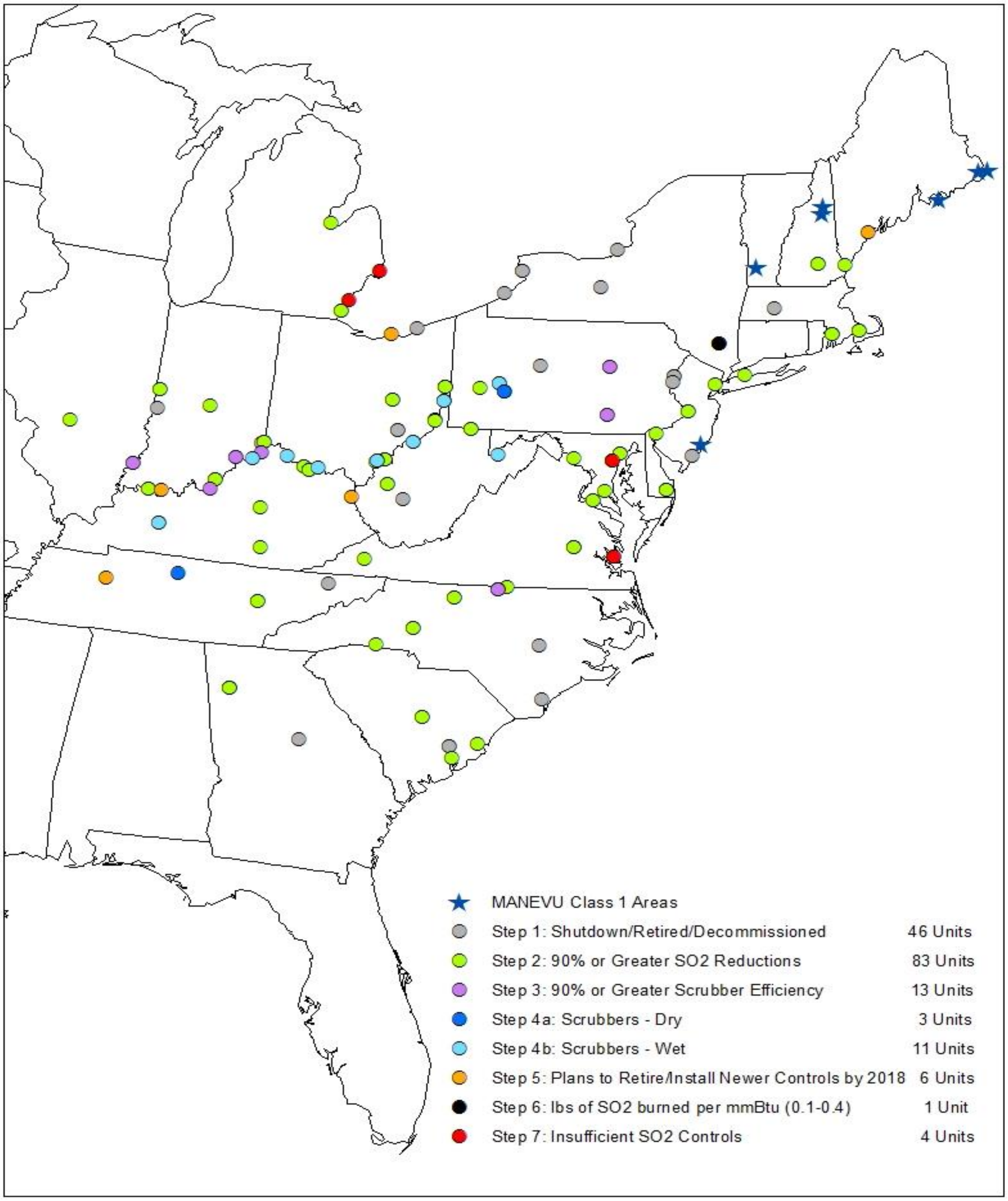
Plant	State	UNIT ID	ORIS ID	2015 CAMD SO_2 (tpy)	2002 CAMD SO_2 (tpy)	% Change 2002-2015
Trenton Channel	MI	9A*	1745	11,656	19,237	-39%
St. Clair	MI	7*	1743	8,938	15,980	-44%
Herbert A Wagner	MD	3*	1554	8,751	10,096	-13%
Yorktown	VA	3*	3809	2,070	10,567	-80%

Note: Units with SO_2 permit rate greater than 0.4lbs/mmBtu are highlighted.
* Units with actual amount of SO_2 emitted greater than 0.4lbs/mmBtu.

SO_2 emissions at Yorktown, Unit 3 has reduced in the past few years because utilization of the unit was reduced a lot. In addition, the unit falls under the Mercury and Air Toxics Standard (MATS) rule and is utilizing the annual capacity factor threshold in the MATS rule to comply. Yorktown, unit 3 does not have any scrubbers.

A map showing the locations of the 167 EGU units and their status is shown in Figure 1.

<u>Figure 1</u>: Status of Controls at Top 167 EGUs:
Contribution to Visibility Impairment
at MANE-VU Class I Areas



APPENDIX N

Mid-Atlantic/Northeast Visibility Union
MANE-VU

Reducing Regional Haze for
Improved Visibility and Health

Members
Connecticut
Delaware
District of Columbia
Maine
Maryland
Massachusetts
New Hampshire
New Jersey
New York
Pennsylvania
Penobscot Indian Nation
Rhode Island
St. Regis Mohawk Tribe
Vermont

Nonvoting Members
U.S. Environmental Protection Agency
National Park Service
U.S. Fish and Wildlife Service
U.S. Forest Service

MANE-VU Class I Areas
ACADIA NATIONAL PARK ME
BRIGANTINE WILDERNESS NJ
GREAT GULF WILDERNESS NH
LYE BROOK WILDERNESS VT
MOOSEHORN WILDERNESS ME
PRESIDENTIAL RANGE DRY RIVER WILDERNESS NH
ROOSEVELT CAMPOBELLO INTERNATIONAL PARK ME/NB, CANADA

STATEMENT OF THE MID-ATLANTIC/NORTHEAST VISIBILITY UNION (MANE-VU) STATES CONCERNING A COURSE OF ACTION WITHIN MANE-VU TOWARD ASSURING REASONABLE PROGRESS FOR THE SECOND REGIONAL HAZE IMPLEMENTATION PERIOD (2018-2028)

The federal Clean Air Act (CAA) and Regional Haze rule require States that are reasonably anticipated to cause or contribute to impairment of visibility in mandatory Class I Federal areas to implement reasonable measures to reduce visibility impairment within the national parks and wilderness areas designated as mandatory Class I Federal areas. Most pollutants that affect visibility also contribute to ozone, fine particulate and sulfur dioxide (SO_2) air pollution. In order to assure protection of public health and the environment, any additional air pollutant emission reduction measures necessary to meet the 2028 reasonable progress goal for regional haze should be implemented as soon as practicable but no later than 2028.

According to the federal Regional Haze rule (40 CFR 51.308 (f)(2)(i) through (iv)), all states must consider, in their Regional Haze SIPs, the emission reduction measures identified by Class I States as being necessary to make reasonable progress in any Class I area. These emission reduction measures are referred to as "Asks." If any State cannot agree with or complete a Class I State's "Asks," the State must describe the actions taken to resolve the disagreement in their Regional Haze SIP. This Ask by the MANE-VU Class I states, was developed through a collaborative process with all of the MANE-VU states. It is designed to identify reasonable emission reduction strategies which must be addressed by the states and tribal nations of MANE-VU through their regional haze SIP updates. This Ask has been developed and presented at this time so that SIPs may be developed and submitted between July of 2018 and July of 2021.

In addressing the emission reduction strategies in the Ask, the MANE-VU states will need to harmonize any activity on the strategies in the Ask with other federal or state requirements that affect the sources and pollutants covered by the Ask. These federal and state requirements include, but are not limited to:

- The 2010 SO_2 standard,
- The Regional Greenhouse Gas Initiative (RGGI), if applicable,
- The Mercury and Air Toxics Standards (MATS), and
- The new 2015 ozone standard.

Because of this need for cross-program harmonization and because of the formal public process required by the federal CAA and state rulemaking processes, it is expected that there will be opportunities for stakeholders and the public to comment on how states intend to address the measures in the Ask.

Many of the MANE-VU states are also members of RGGI. RGGI is a market based cap-and-invest program designed to cost effectively reduce greenhouse gas emissions from the energy sector while returning value to rate-payers. One of the co-benefits of RGGI is that it will also significantly reduce SO_2 and NOx emissions, the two most important haze precursors. Because of this, the RGGI states, regionally, will likely achieve greater emission reductions than those envisioned in this Ask.

To address the impact on mandatory Class I Federal areas within the MANE-VU region, the Mid-Atlantic and Northeast States will pursue a coordinated course of action designed to assure reasonable progress toward preventing any future, and remedying any existing impairment of visibility in mandatory Class I Federal areas and to leverage the multi-pollutant benefits that such measures may provide for the protection of public health and the environment. Per the Regional Haze rule, being on or below the uniform rate of progress for a given Class I area is not a factor in deciding if a State needs to undertake reasonable measures.

Therefore, the course of action for pursuing the adoption and implementation of measures necessary to meet the 2028 reasonable progress goal for regional haze include the following "emission management" strategies:

1. Electric Generating Units (EGUs) with a nameplate capacity larger than or equal to 25MW with already installed NOx and/or SO_2 controls - ensure the most effective use of control technologies on a year-round basis to consistently minimize emissions of haze precursors, or obtain equivalent alternative emission reductions;
2. Emission sources modeled by MANE-VU that have the potential for 3.0 Mm^{-1} or greater visibility impacts at any MANE-VU Class I area, as identified by MANE-VU contribution

analyses (see attached listing) - perform a four-factor analysis for reasonable installation or upgrade to emission controls;

3. Each MANE-VU State that has not yet fully adopted an ultra-low sulfur fuel oil standard as requested by MANE-VU in 2007 - pursue this standard as expeditiously as possible and before 2028, depending on supply availability, where the standards are as follows:
    a. distillate oil to 0.0015% sulfur by weight (15 ppm),
    b. #4 residual oil within a range of 0.25 to 0.5% sulfur by weight,
    c. #6 residual oil within a range of 0.3 to 0.5% sulfur by weight.
4. EGUs and other large point emission sources larger than 250 MMBTU per hour heat input that have switched operations to lower emitting fuels – pursue updating permits, enforceable agreements, and/or rules to lock-in lower emission rates for SO_2, NOx and PM. The permit, enforcement agreement, and/or rule can allow for suspension of the lower emission rate during natural gas curtailment;
5. Where emission rules have not been adopted, control NOx emissions for peaking combustion turbines that have the potential to operate on high electric demand days by:
    a. Striving to meet NOx emissions standard of no greater than 25 ppm at 15% O_2 for natural gas and 42 ppm at 15% O_2 for fuel oil but at a minimum meet NOx emissions standard of no greater than 42 ppm at 15% O_2 for natural gas and 96 ppm at 15% O_2 for fuel oil, or
    b. Performing a four-factor analysis for reasonable installation or upgrade to emission controls, or
    c. Obtaining equivalent alternative emission reductions on high electric demand days.

High electric demand days are days when higher than usual electrical demands bring additional generation units online, many of which are infrequently operated and may have significantly higher emission rates than the rest of the generation fleet. Peaking combustion turbine is defined for the purposes of this "Ask" as a turbine capable of generating 15 megawatts or more, that commenced operation prior to May 1, 2007, is used to generate electricity all or part of which is delivered to the electric power distribution grid for commercial sale and that operated less than or equal to an average of 1752 hours (or 20%) per year during 2014 to 2016;

(Note: SO_2 emissions for fuel oil units are addressed with Ask item 3.a. above)

6. Each State should consider and report in their SIP measures or programs to: a) decrease energy demand through the use of energy efficiency, and b) increase the use within their state of Combined Heat and Power (CHP) and other clean Distributed Generation technologies including fuel cells, wind, and solar.

This long-term strategy to reduce and prevent regional haze will allow each state up to 10 years to pursue adoption and implementation of reasonable and cost-effective NOx and SO_2 control measures.

Signed on behalf of the MANE-VU states and tribal nations:

David Foerter, Executive Director
MANE-VU/OTC

August 25, 2017

Listing of emission units that have the potential for 3.0 Mm^{-1} or greater visibility impacts at any MANE-VU Class I area using actual 2015 emissions for EGUs and 2011 for other emission sources). The complete contribution analyses report is available at http://www.otcair.org/manevu.

State	Facility Name	Facility/ ORIS ID	Unit IDs	Max Extinction
MA	Brayton Point	1619	4	4.3
MA	Canal Station	1599	1	3.0
MD	Herbert A Wagner	1554	3	3.8
MD	Luke Paper Company	7763811	001-0011-3-0018	6.0
MD	Luke Paper Company	7763811	001-0011-3-0019	5.9
ME	The Jackson Laboratory	7945211	7945211	10.2
ME	William F Wyman	1507	4	5.6
ME	Woodland Pulp LLC	5974211		7.5
NH	Merrimack	2364	2	3.3
NJ	B L England	2378	2,3	5.6
NY	Finch Paper LLC	8325211	12	5.9
NY	Lafarge Building Materials Inc	8105211	43101	8.1
PA	Brunner Island	3140	1,2	4.0
PA	Brunner Island	3140	3	3.8
PA	Homer City	3122	1	9.3
PA	Homer City	3122	2	8.1
PA	Homer City	3122	3	3.3
PA	Keystone	3136	1	3.2
PA	Keystone	3136	2	3.1
PA	Montour	3149	1	4.4
PA	Montour	3149	2	4.1
PA	Shawville	3131	3,4	3.6

APPENDIX O

Mid-Atlantic/Northeast Visibility Union
MANE-VU

Reducing Regional Haze for
Improved Visibility and Health

Members
Connecticut
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Maryland
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New Hampshire
New Jersey
New York
Pennsylvania
Penobscot Indian Nation
Rhode Island
St. Regis Mohawk Tribe
Vermont

Nonvoting Members
U.S. Environmental Protection Agency
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U.S. Forest Service

MANE-VU Class I Areas
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BRIGANTINE WILDERNESS NJ
GREAT GULF WILDERNESS NH
LYE BROOK WILDERNESS VT
MOOSEHORN WILDERNESS ME
PRESIDENTIAL RANGE DRY RIVER WILDERNESS NH
ROOSEVELT CAMPOBELLO INTERNATIONAL PARK ME/NB, CANADA

STATEMENT OF THE MID-ATLANTIC/NORTHEAST VISIBILITY UNION (MANE-VU) STATES CONCERNING A COURSE OF ACTION IN CONTRIBUTING STATES LOCATED UPWIND OF MANE-VU TOWARD ASSURING REASONABLE PROGRESS FOR THE SECOND REGIONAL HAZE IMPLEMENTATION PERIOD (2018-2028)

The federal Clean Air Act (CAA) and Regional Haze rule require States that are reasonably anticipated to cause or contribute to impairment of visibility in mandatory Class I Federal areas to implement reasonable measures to reduce visibility impairment within the national parks and wilderness areas designated as mandatory Class I Federal areas. Most pollutants that affect visibility also contribute to ozone, fine particulate and sulfur dioxide (SO_2) air pollution. In order to assure protection of public health and the environment, any additional air pollutant emission reduction measures necessary to meet the 2028 reasonable progress goal for regional haze should be implemented as soon as practicable but no later than 2028.

According to the federal Regional Haze rule (40 CFR 51.308 (f)(2)(i) through (iv)), all states must consider, in their Regional Haze SIPs, the emission reduction measures identified by Class I States as being necessary to make reasonable progress in any Class I area. These emission reduction measures are referred to as “Asks.” If any State cannot agree with or complete a Class I State’s “Asks,” the State must describe the actions taken to resolve the disagreement in their Regional Haze SIP. This Ask by the MANE-VU Class I states, was developed through a collaborative process with all of the MANE-VU states. It is designed to identify reasonable emission reduction strategies which must be addressed by the states and tribal nations through their regional haze SIP updates. This Ask has been developed and presented at this time so that SIPs may be developed and submitted between July of 2018 and July of 2021.

The following states identified by MANE-VU as contributing to visibility impairment at MANE-VU Class I areas should address this "Ask" in their regional haze SIP updates in addition to any other Class I area state "Ask"; Alabama, Florida, Illinois, Indiana, Kentucky, Louisiana, Michigan, Missouri, North Carolina, Ohio, Tennessee, Texas, Virginia, and West Virginia. There is a separate "Ask" to address visibility impairing emissions from MANE-VU states. Contributing state methodology is documented in a MANE-VU report; "Selection of States for MANE-VU Regional Haze Consultation (2018)", using actual 2015 emissions for EGUs and 2011 for other emission sources.

In addressing the emission reduction strategies in the Ask, states will need to harmonize any activity on the strategies in the Ask with other federal or state requirements that affect the sources and pollutants covered by the Ask. These federal and state requirements include, but are not limited to:

- The 2010 SO_2 standard,
- The Regional Greenhouse Gas Initiative (RGGI), if applicable,
- The Mercury and Air Toxics Standards (MATS), and
- The new 2015 ozone standard.

Because of this need for cross-program harmonization and because of the formal public process required by the federal CAA and state rulemaking processes, it is expected that there will be opportunities for stakeholders and the public to comment on how states intend to address the measures in the Ask.

To address the impact on mandatory Class I Federal areas within the MANE-VU region, the Mid-Atlantic and Northeast States will pursue a coordinated course of action designed to assure reasonable progress toward preventing any future, and remedying any existing impairment of visibility in mandatory Class I Federal areas and to leverage the multi-pollutant benefits that such measures may provide for the protection of public health and the environment. Per the Regional Haze rule, being on or below the uniform rate of progress for a given Class I area is not a factor in deciding if a State needs to undertake reasonable measures.

Therefore, the course of action for pursuing the adoption and implementation of measures necessary to meet the 2028 reasonable progress goal for regional haze include the following "emission management" strategies:

1. Electric Generating Units (EGUs) with a nameplate capacity larger than or equal to 25MW with already installed NOx and/or SO_2 controls - ensure the most effective use of control technologies on a year-round basis to consistently minimize emissions of haze precursors, or obtain equivalent alternative emission reductions;

2. Emission sources modeled by MANE-VU that have the potential for 3.0 Mm^{-1} or greater visibility impacts at any MANE-VU Class I area, as identified by MANE-VU contribution analyses (see attached listing) - perform a four-factor analysis for reasonable installation or upgrade to emission controls;

3. States should pursue an ultra-low sulfur fuel oil standard similar to the one adopted by MANE-VU states in 2007 as expeditiously as possible and before 2028, depending on supply availability, where the standards are as follows:
   a. distillate oil to 0.0015% sulfur by weight (15 ppm),
   b. #4 residual oil to 0.5% sulfur by weight,
   c. #6 residual oil to 0.5% sulfur by weight.

4. EGUs and other large point emission sources larger than 250 MMBTU per hour heat input that have switched operations to lower emitting fuels – pursue updating permits, enforceable agreements, and/or rules to lock-in lower emission rates for SO_2, NOx and PM. The permit, enforcement agreement, and/or rule can allow for suspension of the lower emission rate during natural gas curtailment;

5. Each State should consider and report in their SIP measures or programs to: a) decrease energy demand through the use of energy efficiency, and b) increase the use within their state of Combined Heat and Power (CHP) and other clean Distributed Generation technologies including fuel cells, wind, and solar.

This long-term strategy to reduce and prevent regional haze will allow each state up to 10 years to pursue adoption and implementation of reasonable and cost-effective NOx and SO_2 control measures.

Signed on behalf of the MANE-VU states and tribal nations:

David Foerter, Executive Director
MANE-VU/OTC

August 25, 2017

Listing of emission units that have the potential for 3.0 Mm^{-1} or greater visibility impacts at any MANE-VU Class I area using actual 2015 emissions for EGUs and 2011 for other emission sources). The complete contribution analyses report is available at http://www.otcair.org/manevu.

State	Facility Name	Facility/ ORIS ID	Unit IDs	Max Extinction
IN	Rockport	6166	MB1,MB2	3.8
KY	Big Sandy	1353	BSU1,BSU2	3.5
MI	Belle River		2	4.0
MI	Belle River		1	3.7
MI	St. Clair	1743	1,2,3,4,...6	3.1
NC	KapStone Kraft Paper Corporation	8048011	ST-1,2	6.0
OH	Avon Lake Power Plant	2836	12	9.2
OH	Gen J M Gavin	8102	1	3.3
OH	Gen J M Gavin	8102	2	3.1
OH	Muskingum River	2872	5	7.7
OH	Muskingum River	2872	1,2,3,4	4.4
VA	Yorktown Power Station	3809	3	10.9
VA	Yorktown Power Station	3809	1,2	7.0
WV	Harrison Power Station		1 (25%) 2 (20%)	7.0
WV	Kammer	3947	1,2,3	3.2

APPENDIX P

Mid-Atlantic/Northeast Visibility Union
MANE-VU

Reducing Regional Haze for
Improved Visibility and Health

Members
Connecticut
Delaware
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New Hampshire
New Jersey
New York
Pennsylvania
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Rhode Island
St. Regis Mohawk Tribe
Vermont

Nonvoting Members
U.S. Environmental Protection Agency
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U.S. Fish and Wildlife Service
U.S. Forest Service

MANE-VU Class I Areas

ACADIA NATIONAL PARK ME

BRIGANTINE WILDERNESS NJ

GREAT GULF WILDERNESS NH

LYE BROOK WILDERNESS VT

MOOSEHORN WILDERNESS ME

PRESIDENTIAL RANGE DRY RIVER WILDERNESS NH

ROOSEVELT CAMPOBELLO INTERNATIONAL PARK ME/NB, CANADA

STATEMENT OF THE MID-ATLANTIC/NORTHEAST VISIBILITY UNION (MANE-VU) STATES CONCERNING A COURSE OF ACTION BY THE ENVIRONMENTAL PROTECTION AGENCY AND FEDERAL LAND MANAGERS TOWARD ASSURING REASONABLE PROGRESS FOR THE SECOND REGIONAL HAZE IMPLEMENTATION PERIOD (2018-2028)

The federal Clean Air Act (CAA) and Regional Haze rule require States that are reasonably anticipated to cause or contribute to impairment of visibility in mandatory Class I Federal areas to implement reasonable measures to reduce visibility impairment within the national parks and wilderness areas designated as mandatory Class I Federal areas. Most pollutants that affect visibility also contribute to ozone, fine particulate and sulfur dioxide (SO_2) air pollution. In order to assure protection of public health and the environment, any additional air pollutant emission reduction measures necessary to meet the 2028 reasonable progress goal for regional haze should be implemented as soon as practicable but no later than 2028.

According to the federal Regional Haze rule (40 CFR 51.308 (f)(2)(i) through (iv)), all states must consider, in their Regional Haze SIP's, the emission reduction measures identified by Class I States as being necessary to make reasonable progress in any Class 1 area. These emission reduction measures are referred to as "Asks." If any State cannot agree with or complete a Class I State's "Asks," the State must describe the actions taken to resolve the disagreement in their Regional Haze SIP.

To address the impact on mandatory Class I Federal areas within the MANE-VU region, the Mid-Atlantic and Northeast States will pursue a coordinated course of action designed to assure reasonable progress toward preventing any future, and remedying any existing impairment of visibility in mandatory Class I Federal areas and to leverage the multi-pollutant benefits that such measures may provide for the protection of public health and the environment. Per the Regional Haze rule, being on or below the uniform rate of progress for a given Class I area is not a factor in deciding if a State needs to undertake reasonable measures.

The transport range of visibility impairing pollutants has been demonstrated to be extensive and well beyond the MANE-VU region. For example, a wildfire near Fort McMurray, Alberta in western Canada last year brought visibility impairing fine particulate matter and ozone over 2000 miles into the region at concentrations that contributed to exceedances of the health standard in some locations. Clearly, states located beyond those that MANE-VU chose to consult for regional haze, can play an active role in impairing visibility at the MANE-VU Class I areas. Further, despite that onroad vehicles produce a significant portion of the visibility impairing pollutants that affect our Class I areas they are beyond our states' ability to regulate. Therefore, the MANE-VU Class I area states need additional help from the Environmental Protection Agency and Federal Land Managers in pursuing important reasonable emission control measures. These include, but are not limited to:

1. Federal Land Managers to consult with MANE-VU Class I area states when scheduling prescribed burns and ensure that these burns do not impact nearby IMPROVE visibility measurements and do not impact potential 20 percent most and least visibility impaired days;

2. EPA to develop measures that will further reduce emissions from heavy-duty onroad vehicles; and

3. EPA to ensure that Class I Area state "Asks" are addressed in "contributing" state SIPs prior to approval. In the case of this "Ask", contributing states are defined as those that the MANE-VU Class I area states requested for consultation.

MANE-VU considers these measures as reasonable and would further visibility improvement in our region's Class I areas.

Signed on behalf of the MANE-VU states and tribal nations:

David Foerter, Executive Director
MANE-VU/OTC

August 25, 2017

APPENDIX Q

Impact of Wintertime SCR/SNCR Optimization on Visibility Impairing Nitrate Precursor Emissions

MANE-VU Technical Support Committee
November 20, 2017

MANE - VU
Mid-Atlantic/Northeast Visibility Union

Acknowledgements

The paper has been the effort of MANE-VU Technical Support Committee's Four-Factor Workgroup. Rob Sliwinski of New York Department of Environmental Conservation chaired the Technical Support Committee, who were responsible for review of the report. Kate Knight, and Kurt Kebschull from Connecticut Department of Energy and Environmental Protection; Mark Wert and Azin Kavian from Massachusetts Department of Environmental Protection; Mary Jane Rutkowski from Maryland Department of the Environment; Tom Downs, Tom Graham and Martha Webster from Maine Department of Environmental Protection; David Healy from New Hampshire Department of Environmental Services; Ray Papalski, Stella Oluwaseun-Apo, and Victoria Faranca from New Jersey Department of Environmental Protection; Scott Griffin and Amanda Chudow from New York Department of Environmental Conservation; Bryan Oshinski from Pennsylvania Department of Environmental Protection and Bennet Leon and Dan Riley of Vermont Department of Environmental Conservation provided valuable insights as the project progressed. Maine staff was particularly instrumental in the visibility data back trajectory analyses and Maryland staff provided the emission rates for the analysis. Joseph Jakuta managed the workgroup as MANE-VU staff and conducted the ERTAC runs.

Executive Summary

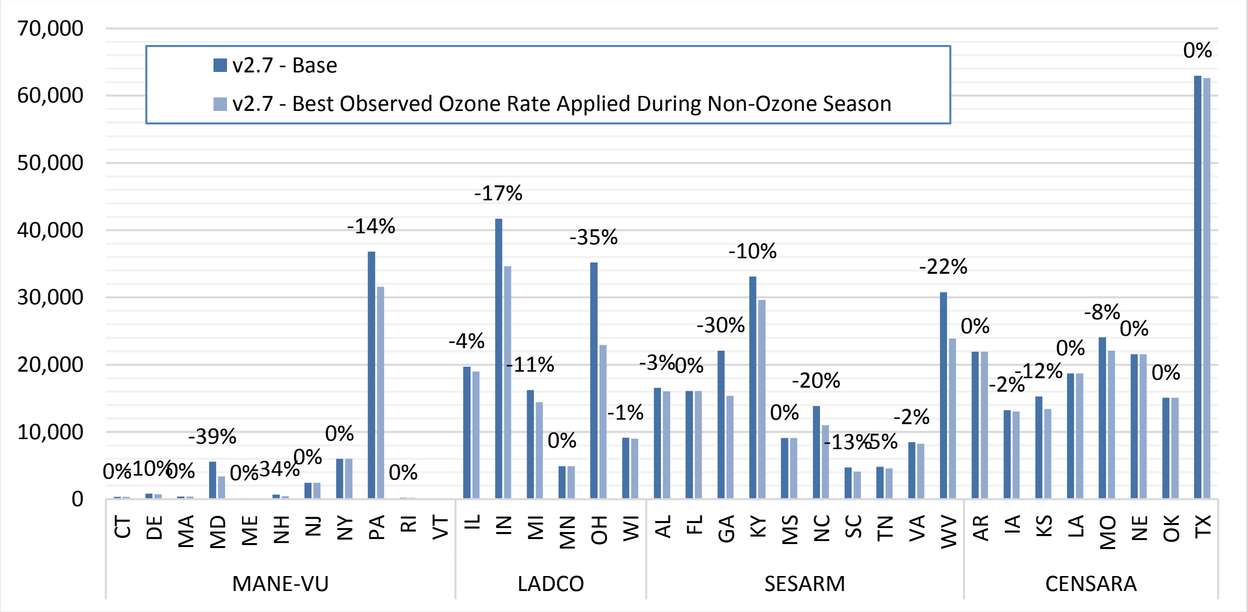
During the first planning phase for regional haze, programs that were put in place focused on reducing sulfur dioxide (SO_2) emissions. The reductions achieved led to improvements in visibility at the MANE-VU Federal Class I Areas due to reduced sulfates formed from SO_2 emissions. The reduction in visibility impairment from sulfates resulted in nitrates driving the visibility impairment rather than sulfates in some MANE-VU Class I Areas on the 20% most impaired days, in particular, during the winter months. Nitrogen oxide (NO_X) emissions are an important precursor to the formation of nitrates.

Often Electric Generating Units (EGUs) only run NO_X emission controls to comply with ozone season trading programs; consequently, emissions of NO_X are uncontrolled during the winter. Controlling winter-time NO_X emissions at EGUs using existing controls is generally more cost-effective compared to other sectors that would have to install and bear the capital costs of control equipment solely for improving visibility.

We looked at the visibility data and observed emission rates from EGUs with installed selective catalytic reduction (SCR) and selective non-catalytic reduction (SNCR) controls, and compared those rates to projected emissions using the ERTAC EGU tool, to show the potential NO_X emissions reductions from running existing SCR and SNCR during the winter months.

We found that the number of most impaired days occurring during the winter is increasing at all Class I areas, in particular Brigantine, and that Brigantine and Lye Brook are seeing nitrate impairment in high levels during those times. We also found that back trajectories from those sites during the winter often traverse MANE-VU and LADCO states with power plant emissions. We found that running existing installed controls is one of the most cost-effective ways to control NO_X emissions from EGUs and that running existing SCRs and SNCRs on EGUs could substantially reduce the NO_X emissions in many of the states upwind of Class I areas in MANE-VU that lead to visibility impairment during the winter from nitrates.

Total 2028 Projected NO_X Emissions from January 1-April 30 and November 1-December 31



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Introduction

During the first planning phase for regional haze, programs that were put in place focused on reducing sulfur dioxide (SO_2) emissions. The reductions achieved led to improvements in visibility at the MANE-VU Federal Class I Areas due to reduced sulfates formed from SO_2 emissions. The reduction in visibility impairment from sulfates resulted in nitrates driving the visibility impairment rather than sulfates in some MANE-VU Class I Areas on the 20% most impaired days, in particular, during the winter months. Nitrogen oxide (NO_X) emissions are an important precursor to the formation of nitrates.

Despite the progress made in the first planning period, additional progress is needed to continue to improve visibility. While many hazy days continue to be affected by high sulfate concentrations, many of the most impaired days are now dominated by nitrates, particularly on cooler days, when nitrogen emissions are more likely to contribute to the formation of nitrates rather than participating in the formation of ozone. Therefore, in addition to maintaining reductions already achieved, it is necessary to look closely at the sources of nitrates and the effectiveness of potential controls.

Often Electric Generating Units (EGUs) only run NO_X emission controls to comply with ozone season trading programs; consequently, emissions of NO_X are uncontrolled during the winter. Controlling winter-time NO_X emissions at EGUs using existing controls is generally more cost-effective compared to other sectors that would have to install and bear the capital costs of control equipment solely for improving visibility. We will look at the visibility data and observed emission rates from EGUs with installed selective catalytic reduction (SCR) and selective non-catalytic reduction (SNCR) controls, and compare those rates to projected emissions, to show the improvements that can be made to visibility impairment from running existing SCR and SNCR during the winter months.

Current Visibility Data

Figure 1 through Figure 5 show the variability in which meteorological seasons contained "20% most impaired days"[1] from 2000 to 2015. The 20% most impaired days metric was used because it aligns with the requirements for measuring progress as outlined in the Regional Haze Rule Update (82 FR 3078) and removes the impacts of natural sources of impairment, such as wild fires and sea salt, from consideration. The new metric also excludes some days that experience both high impairment from anthropogenic sulfate pollution and natural wildfires during the summer which leads to a greater focus on winter time nitrate impairment than would have occurred using the old "worst day" metric. However, the progress made in reducing SO_2 emissions and thus sulfate impairment has also lead to more impaired days being dominated by nitrates as we will see.

The Edwin B. Forsythe National Wildlife Refuge (hereafter Brigantine Wilderness) has the strongest increase in winter 20% most impaired days, followed by Acadia National Park and Great Gulf Wilderness Area. The only site that did not see an increase in the number of winter 20% most impaired days was Lye Brook, but this is likely due to the fact that the Lye Brook IMPROVE monitor was moved in 2012 and the 20% most impaired days were not calculated as of this writing for the new site. When you look at 20% most impaired days you also see an upward trend in the number of winter days. This shows that

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[1] 20% most impaired days are based on the draft IMPROVE AEROSOL, RHR III methodology used to calculate visibility impairment available in the Federal Land Manager Environmental Database (FED) database as of June 8, 2017 in accordance with the new definitions of impairment in regional haze regulatory framework

emissions that affect visibility during colder months are important to consider when developing control strategies, particularly for Brigantine.

Figure 1: Trends in seasonality of 20% most impaired days at Acadia National Park

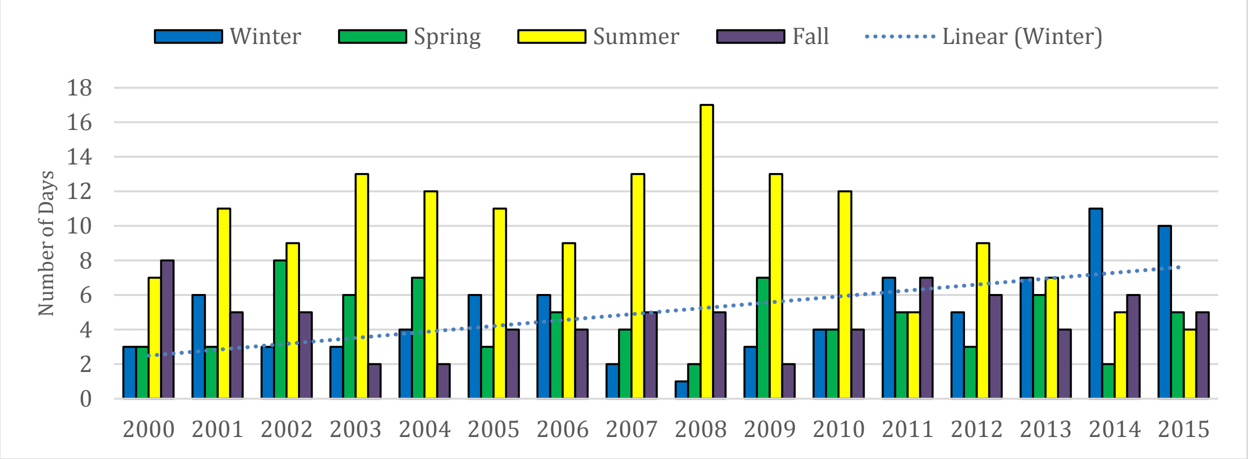


Figure 2: Trends in seasonality of 20% most impaired days at Moosehorn NWR

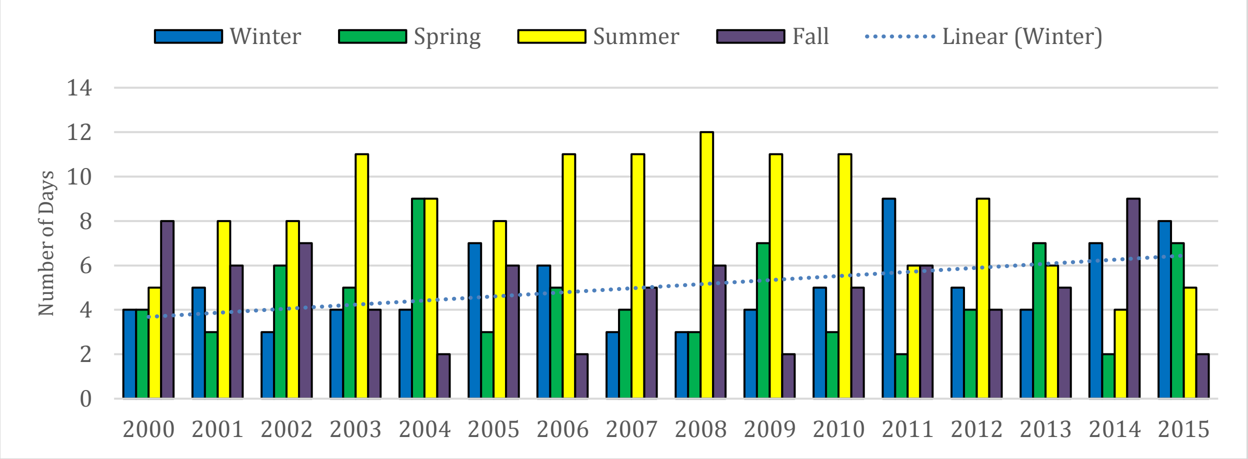


Figure 3: Trends in seasonality of 20% most impaired days at Lye Brook Wilderness

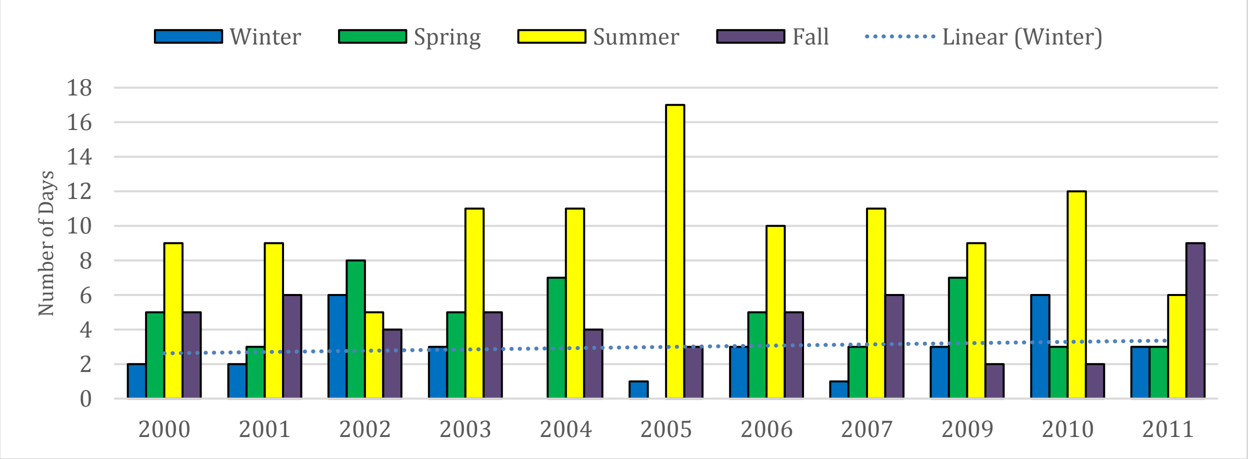


Figure 4: Trends in seasonality of 20% most impaired days at Great Gulf Wilderness

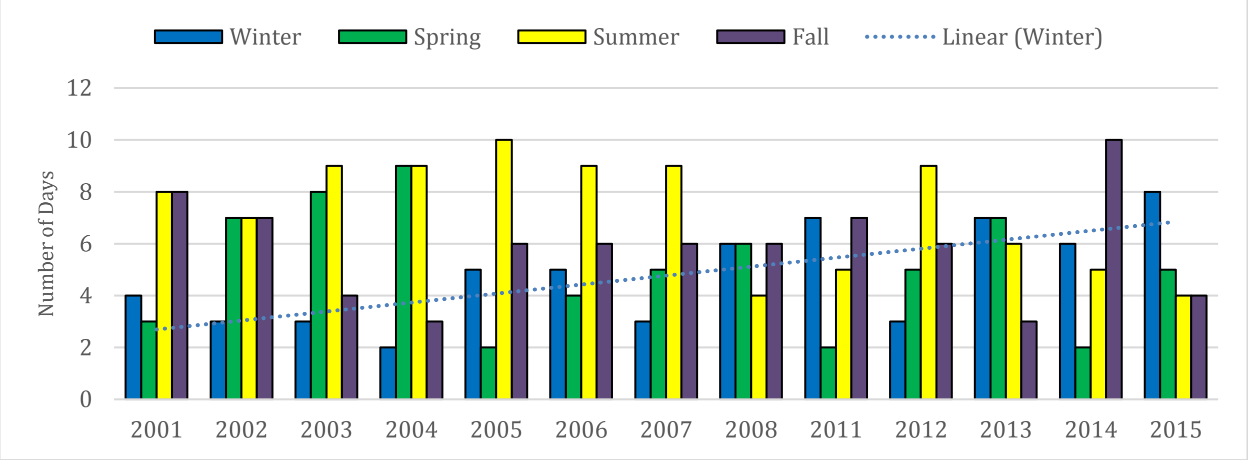
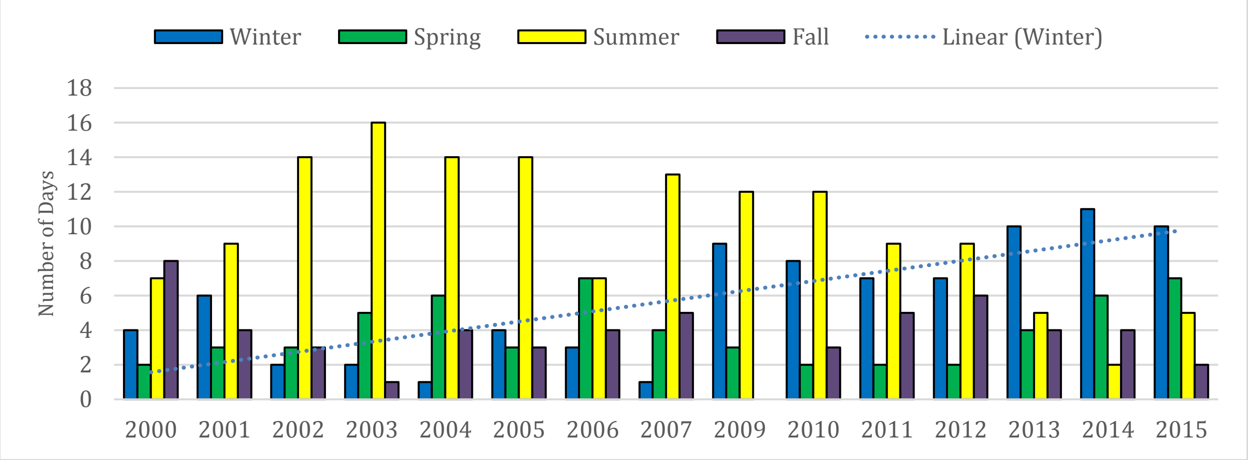


Figure 5: Trends in seasonality of 20% most impaired days at Brigantine Wilderness



Class I area plots were also created showing light extinction speciation for each day for 2002, 2011, and 2015 (Figure 6 through Figure 10). For all the Class I areas, there is a significant decrease in light extinction from 2002 to 2011 (especially from sulfates contribution) and a smaller decrease from 2011 to 2015. At Lye Brook and Brigantine, nitrates contribute to a greater percentage of visibility impairment on certain days.

Figure 6: Acadia National Park 2002/2011/2015 Speciation Comparison

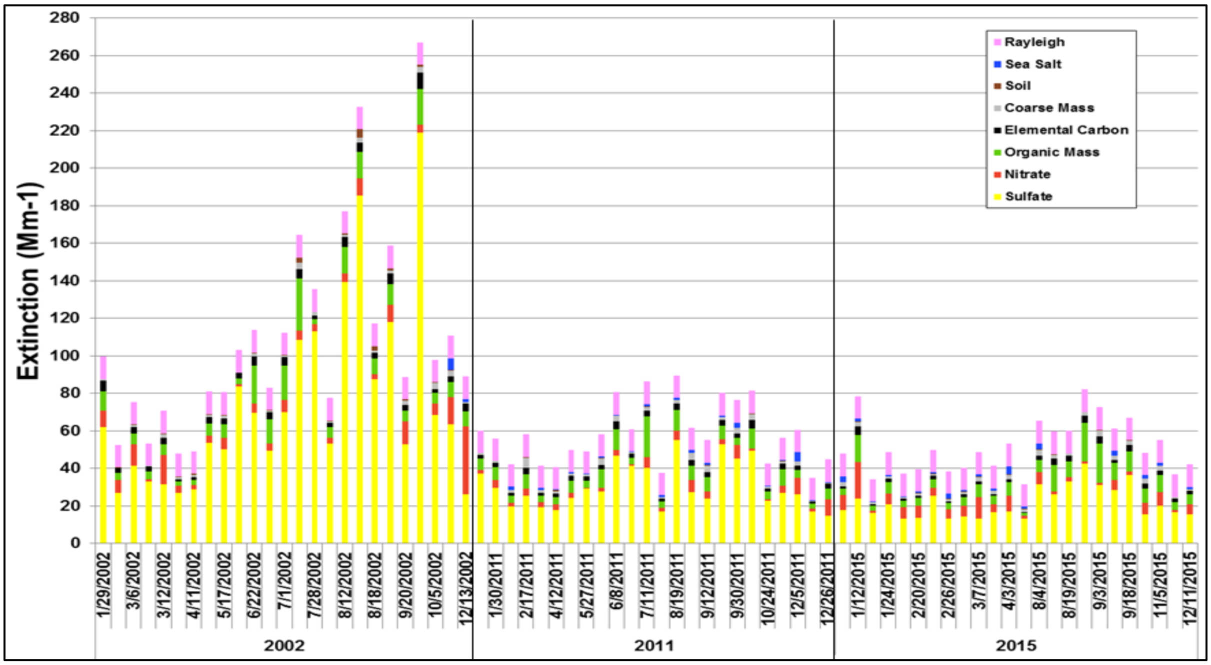


Figure 7: Moosehorn Wilderness 2002/2011/2015 Speciation Comparison

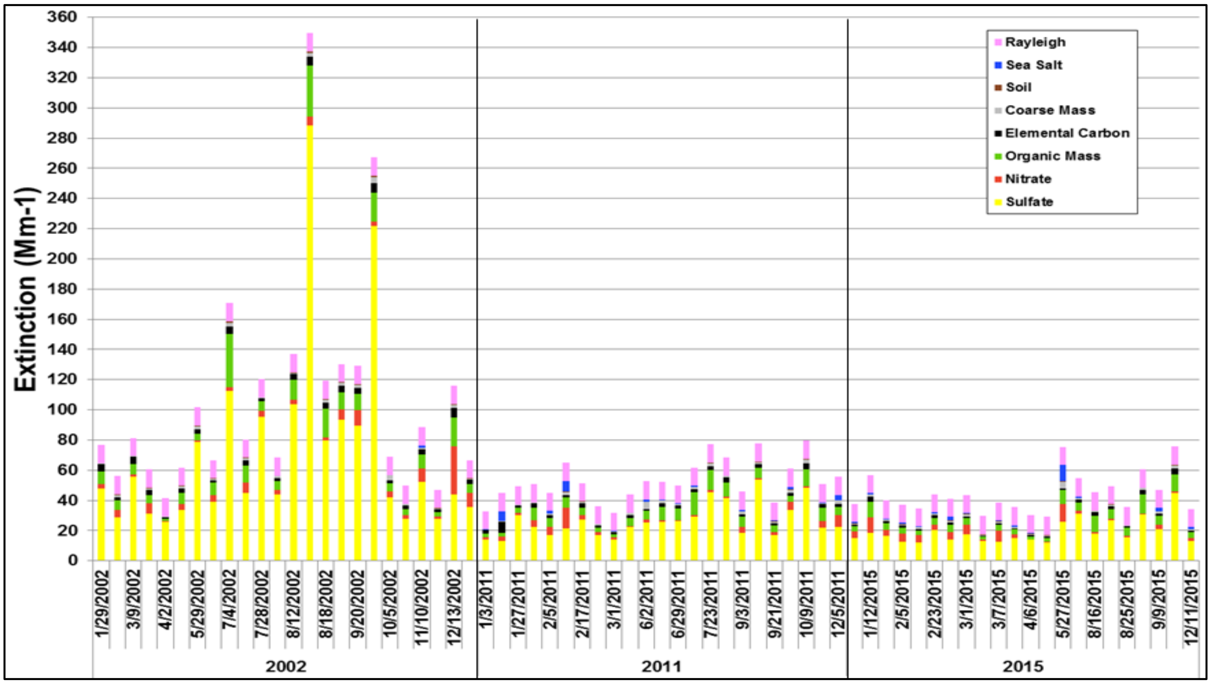


Figure 8: Great Gulf Wilderness 2002/2011/2015 Speciation Comparison

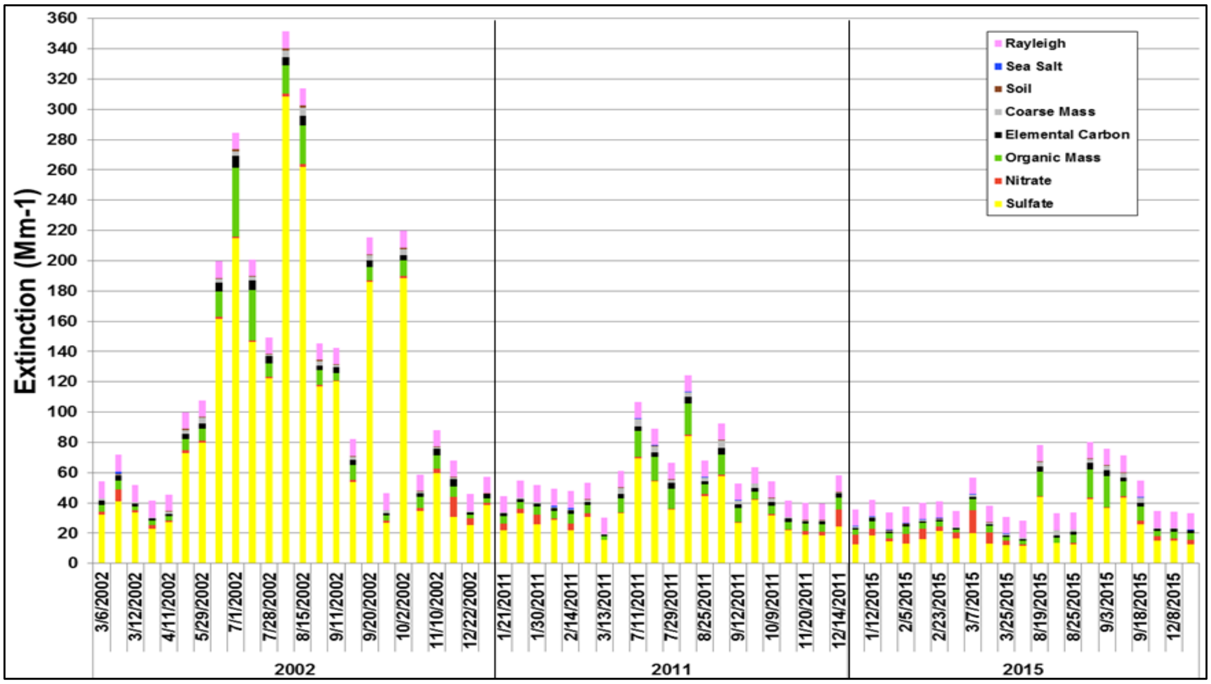


Figure 9: Lye Brook Wilderness 2011/2015 Speciation Comparison

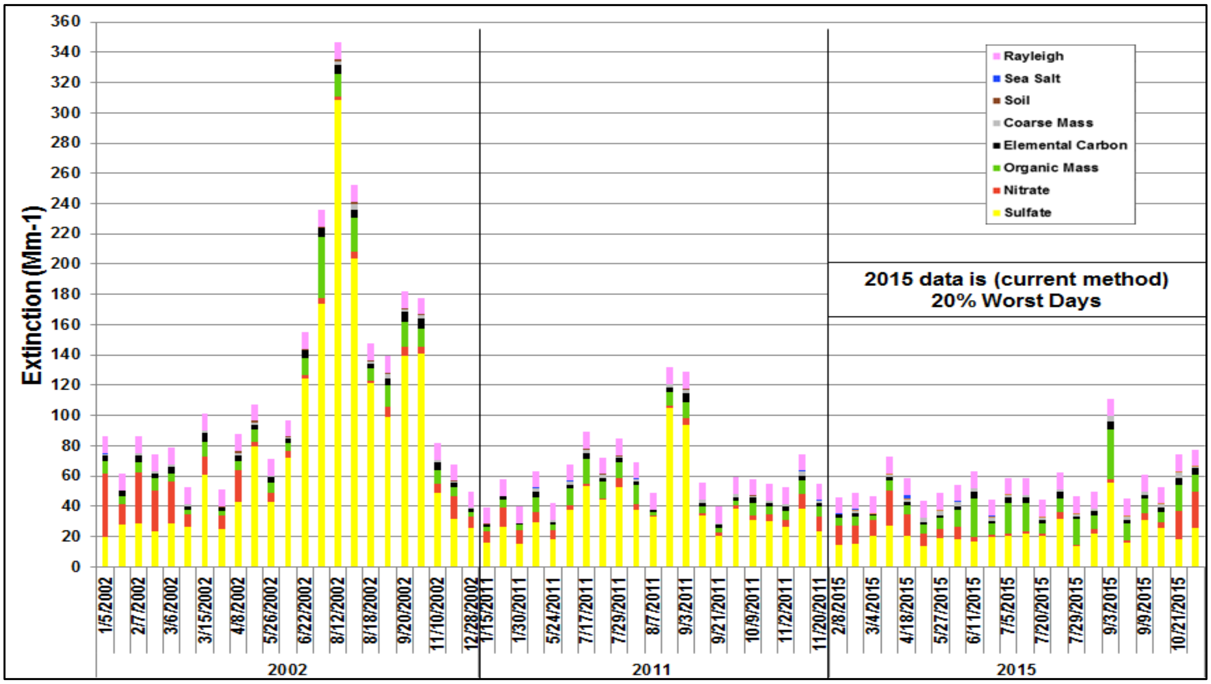


Figure 10: Brigantine Wilderness 2002/2011/2015 Speciation Comparison

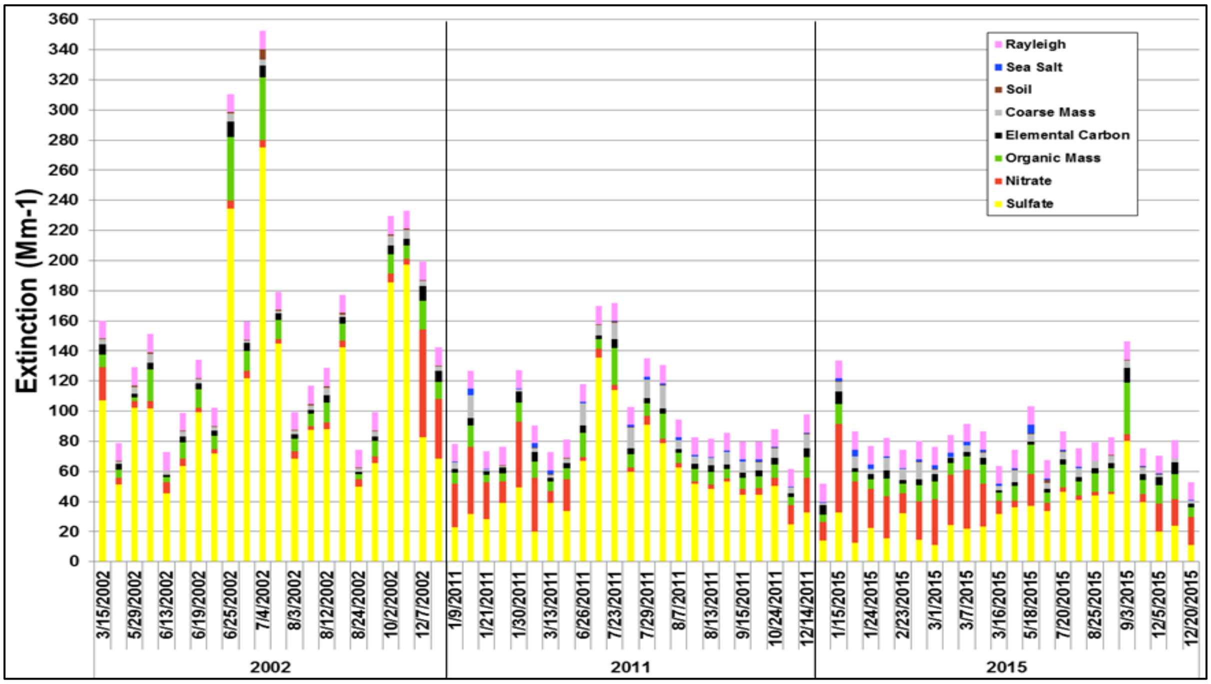


Table 1 demonstrates these trends between 2000 and 2015. At Brigantine, starting in 2007, at least half of the 20% most impaired days in each winter has had more extinction from nitrates than sulfates. In 11 winters out of 15 (73%) in the 2000-2015 period, Brigantine had days in which nitrates contributed more than sulfates to light extinction. At Lye Brook, in the same period, 6 winters (i.e., 43%) had some days in which nitrates contributed more than sulfates to light extinction, and more than half of the 20% most impaired days in 4 of these winters had more extinction from nitrates than sulfates. It is rare (less than 5%) for the other three Class I areas to have winter days where there is more extinction from nitrates than sulfates.

Focusing in on Lye Brook and Brigantine in more detail, one can see in Figure 11 and Figure 12 for Lye Brook and Figure 13 and Figure 14 for Brigantine that during the winter months the back trajectories on many of the 20% most impaired days traverse the southwestern states in MANE-VU, the states in LADCO and the northern most states in SESARM. Later we will see how this information compares with the locations of EGUs that could impact MANE-VU Class I Areas.

Table 1: Number of 20% most impaired winter days and winter days where nitrate extinction was greater than sulfate at each monitored Class I area*

Site	Year	Winter Days	NO_3 > SO_4	%
Acadia	2000	3	0	0%
	2001	6	0	0%
	2002	3	1	33%
	2003	3	0	0%
	2004	4	0	0%
	2005	6	0	0%
	2006	6	0	0%
	2007	2	0	0%
	2008	1	0	0%
	2009	3	0	0%
	2010	4	0	0%
	2011	7	0	0%
	2012	5	0	0%
	2013	7	0	0%
	2014	11	1	9%
	2015	10	0	0%
Brigantine	2000	4	1	25%
	2001	6	1	17%
	2002	2	0	0%
	2003	2	1	50%
	2004	1	1	100%
	2005	4	0	0%
	2006	3	0	0%
	2007	1	0	0%
	2009	9	3	33%
	2010	8	5	63%
	2011	7	3	43%
	2012	7	4	57%
	2013	10	5	50%
	2014	11	7	64%
	2015	10	6	60%
Great Gulf	2001	4	0	0%
	2002	3	0	0%
	2003	3	0	0%
	2004	2	0	0%
	2005	5	0	0%
	2006	5	0	0%
Great Gulf	2007	3	0	0%
	2008	6	0	0%
	2011	7	0	0%
	2012	3	0	0%
	2013	7	1	14%
	2014	6	0	0%
	2015	8	0	0%
Lye Brook	2000	2	0	0%
	2001	2	1	50%
	2002	6	3	50%
	2003	3	0	0%
	2005	0	0	0%
	2006	1	0	0%
	2007	3	0	0%
	2009	1	1	100%
	2010	3	0	0%
	2011	6	0	0%
	2012W	5	4	80%
	2013W	8	1	13%
	2014W	7	3	43%
	2015W	3	0	0%
Moosehorn	2000	4	0	0%
	2001	5	0	0%
	2002	3	0	0%
	2003	4	1	25%
	2004	4	0	0%
	2005	7	0	0%
	2006	6	0	0%
	2007	3	0	0%
	2008	3	0	0%
	2009	4	0	0%
	2010	5	0	0%
	2011	9	0	0%
	2012	5	0	0%
	2013	4	0	0%
	2014	7	0	0%
	2015	8	0	0%

*Notes

1. Data was not available for Great Gulf in 2000, 2009, 2010, or at Lye Brook in 2004

2. The location of the Lye Brook monitor changed from 2011 to 2012, though several months of contemporaneous monitoring results were collected for both sites and the measurements were found to be comparable. Also as a result, 20% most impaired days are not available from 2012 on so 20% worst days were used for those years and are marked with a W.

Figure 11: Trajectory analyses of Lye Brook Wilderness 20% most impaired days during Winter/Spring 2011

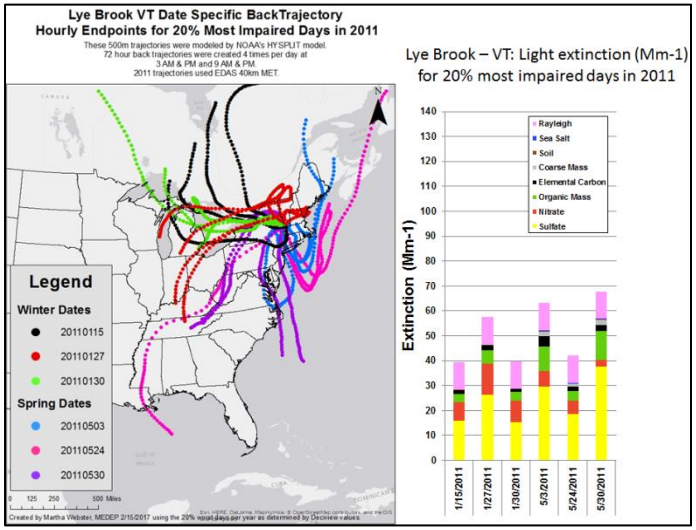


Figure 12: Trajectory analyses of Lye Brook Wilderness 20% most impaired days during Winter 2015

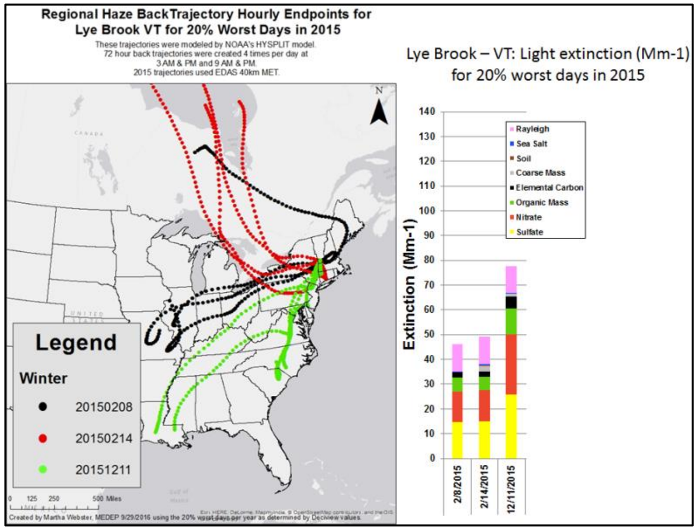


Figure 13: Trajectory analyses of Brigantine 20% most impaired days during Winter 2011

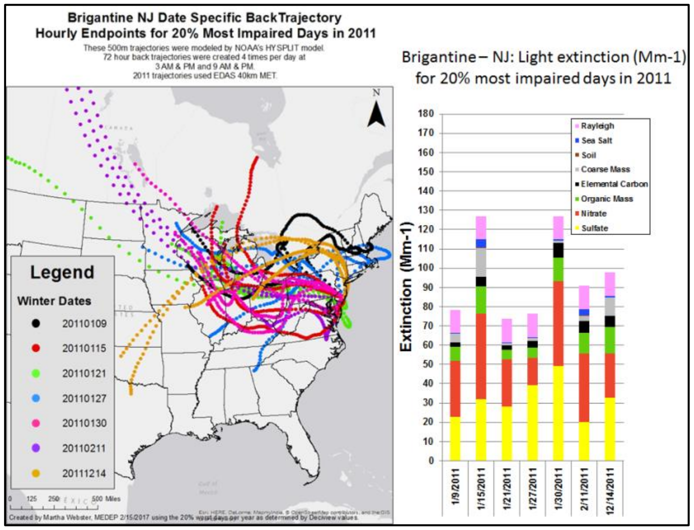


Figure 14: Trajectory analyses of Brigantine 20% most impaired days during Winter 2015

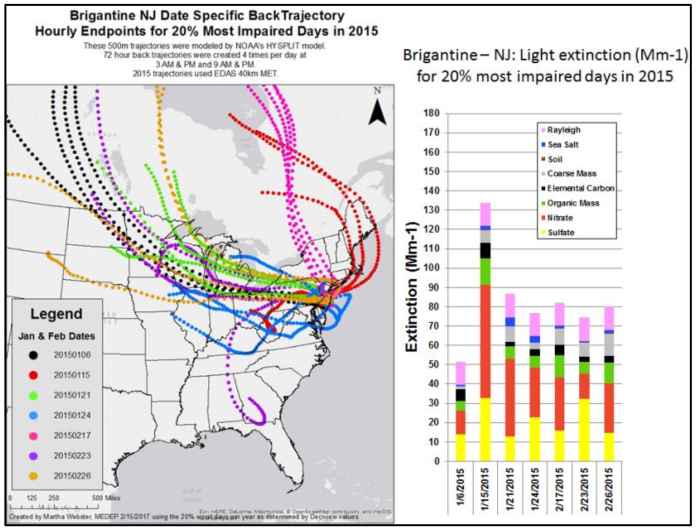
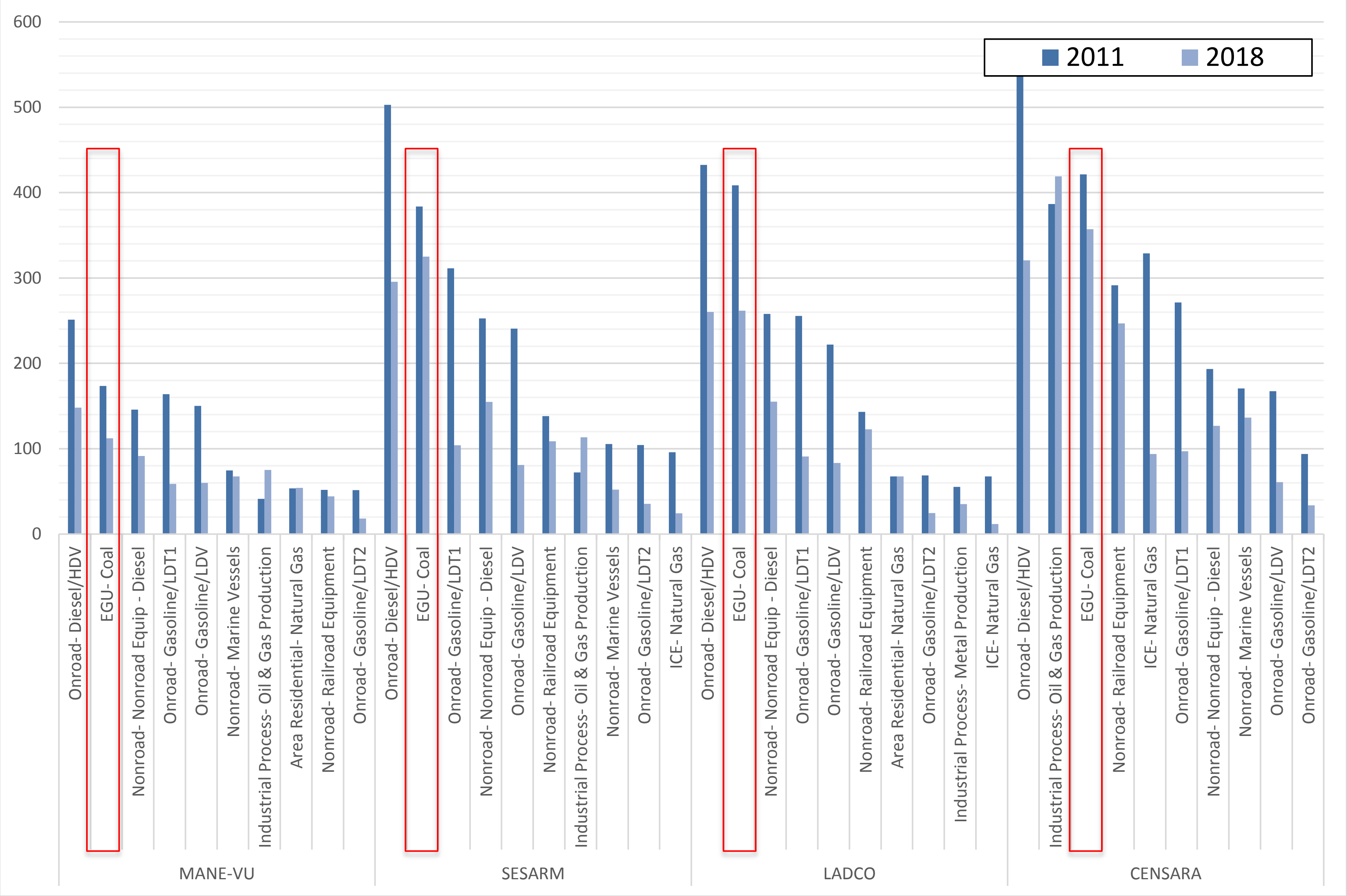


Figure 15: Sources of NO_X emissions in the Eastern United States based on 2011 and 2018 Alpha 2 inventory



Sources of Anthropogenic NO_X Emissions

Given that regulation of NO_X emission sources is typically the more cost-effective approach to reducing precursors of nitrates, the next step is to determine which sources produce the emissions that need to be reduced. When looking at the NO_X emissions inventory for both 2011 and 2018 (Figure 15) one sees that for each RPO in the Eastern United States, EGUs (highlighted) are among the top two most important NO_X–emitting source sectors.[2]

However, the focus of the analysis is not on heavy-duty vehicles or mobile sources in total, which do have a large overall contribution. As described below, the reasons for this are regulatory and scientific in nature.

First, states have very little regulatory authority to address mobile sources. The Clean Air Act under Section 209 preempts individual states outside of California from adopting emissions standards that differ from EPA's, and lower emissions standards are by far the most effective way to address NO_X emissions from mobile sources. Emissions standards for light duty vehicles were also recently lowered under the Tier 3 regulations[3] and many states in MANE-VU already have adopted the most recent California Low Emission Vehicle standards. Additionally, as of this writing, the most recent petition from the South Coast Air Quality Management District to tighten emission standards from heavy-duty vehicles, which many MANE-VU members have signed onto, has not yet been acted upon by EPA.[4]

Second, emissions from mobile and area sources are emitted close to ground level, which results in high levels of dry deposition and a lack of mixing and transport, whereas emissions from EGUs are released from tall stacks resulting in higher levels of vertical atmospheric mixing, a greater amount of pollution forming secondary organic aerosols, and more extensive pollution transport.[5,6] This implies that NO_X emissions from EGUs will likely have a wider range of impact on the formation of visibility impairing particulates in the mostly rural Class I areas in the eastern part of MANE-VU than NO_X emissions from other types of distant sources that emit at ground level, such as mobile sources. However, the exclusion of mobile sources in this analysis should not imply that locally emitted NO_X from mobile sources, particularly heavy-duty vehicles, should not be considered for analysis and control.

Third, running existing controls on EGUs has been found to be possibly the most cost effective way to control NO_X emissions. In particular, EPA found that a reasonable cost to restart an idled SCR on a coal-fired EGU would be $1,400 per ton of NO_X removed and $3,400 per ton of NO_X removed to restart an idled SNCR.[7,8] EPA found that retrofitting existing coal-fired EGUs with SCR would be $5,000 and SNCR would be $6,400 per ton of NO_X removed.[9]

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[2] Mid-Atlantic Northeast Visibility Union, "Contribution Assessment Preliminary Inventory Analysis."

[3] US EPA, "Control of Air Pollution from Motor Vehicles: Tier 3 Motor Vehicle Emission and Fuel Standards Final Rule."

[4] South Coast Air Quality Management District, "Petition to EPA for Rulemaking to Adopt Ultra-Low NOx Exhaust Emission Standards for On-Road Heavy-Duty Trucks and Engines."

[5] Fisher, "The Effect of Tall Stacks on the Long Range Transport of Air Pollutants."

[6] Trimble, "Air Quality: Information on Tall Smokestacks and Their Contribution to Interstate Transport of Air Pollution."

[7] US EPA, "EGU NOx Mitigation Strategies Final Rule TSD."

[8] Ibid.

[9] Ibid.

For all of these reasons, focusing on running controls on EGUs to reduce the impact of nitrates on visibility impairment during the colder months is the most reasonable approach that should be considered.

Emission Rate Processing

Maryland Department of the Environment conducted an ozone season analysis in order to determine the emission benefits that could be achieved if coal-fired EGUs ran their already installed NO_X controls at the best observed ozone season emission rates found by examining hourly emissions data from CAMD during the period 2005-2012.[10] Due to the fact that the primary factor in reducing the effectiveness of NO_X emission controls is flue gas temperature rather than the ambient temperature, any properly configured control system would not see a decrease in effectiveness during the winter months. Therefore, the best observed ozone season emission rates were assumed to be achievable during non-ozone season months as well. However, we determined it was not appropriate to use the best observed non-ozone season emissions rates in this analysis because the expectation was that controls would not necessarily be run to the same extent as during the ozone season since the same regulatory drivers, namely the ozone season NO_X trading programs, are not in place in the winter time.

We also compared the best observed ozone season rates that were being used in this analysis to Mode 4 NO_X emission rates from EPA's NEEDS v5.15. We found on average the 160 units analyzed had a Mode 4 NO_X emission rate that was 0.04 lb/MMBTU higher than the best observed rate being used in the analysis. While the emission rates used in this analysis are lower than the rates EPA uses they are well within the same magnitude that EPA relies on for its power sector modeling.

States have developed the ERTAC EGU projection tool[11] in order to project future year EGU emissions, and this tool is being used in development of base case 2011 and future case 2028 EGU emissions inventories for regional haze planning. The direct reliance of the ERTAC EGU projection tool on base year hourly data in developing future year hourly projections maintains changes in peak operations that could occur during the summer or winter, as well as downtime for maintenance activities or malfunctions.

In order to comply with the Mercury Air Toxic Standard (MATS) some units have opted to run SCR with less ammonia in order to remove mercury from the exhaust emissions. We also evaluated whether there could be an issue with best observed ozone season rates being applied inappropriately to such units. 41 of the 160 units considered had mercury controls installed, leaving 119 units that could be potentially using the appropriate rates. 15 of those units had SNCR, which is not used to remove mercury, leaving 104 units. 15 of the remaining units had their best observed ozone season rate in 2014 or 2015, which would imply that if they were using the SCR in such a fashion they are still achieving NO_X reductions. The remaining 89 units had a Mode 4 NOX emission rate that was on average 0.05 lb/MMbtu higher than the best observed rate implying that EPA does not expect the other units to be

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[10] Vinciguerra et al., "Expected Ozone Benefits of Reducing Nitrogen Oxide (NOx) Emissions from Coal-Fired Electricity Generating Units in the Eastern United States."

[11] AMEC, "Software Technical Documentation for Software to Estimate Future Activity and Air Emissions from Electric Generating Units (EGUs)."

using SCR controls to control mercury. This information was taken from NEEDS v5.15, which accounts for the MATS program.

One design feature of the ERTAC tool is that it won't shut down specific units permanently or even for several days unless the user specifies that the unit will behave in that manner in a given future year. This was intended since having a particular unit shutdown would result in ozone or haze benefits occurring in a particular region near to a unit that would not necessarily shutdown in that given year or hour. The error that would occur from incorrectly projecting particular units to shut down in a given hour is far worse from the perspective of air quality planning than using an optimistic emission rate when a particular unit may or may not be cycling on and off.

The version of future case regional haze modeling that is expected to be used in regional progress goal modeling is the Gamma inventory, which includes ERTAC EGU v2.7 projections for the EGU sector.

To estimate the impacts of optimizing controls during the winter, the best observed rates were processed for inclusion in the ERTAC EGU control file, and then, ERTAC EGU v2.7 was rerun with the new control file.[12] Full details of the creation of the control file and the data in the control file are found in Appendix A.

Results

NO_X emissions were projected using ERTAC and the emissions were compared for the time period from January 1 – April 30 and November 1 – December 31, the time period considered the non-ozone season. Results are being compared between the v2.7 base case results and the run where the best observed rates were applied.

We found that states in the four eastern RPOs would see a drop of NO_X emissions of ~55,000 tons (10%) when best observed rates were applied during non-ozone season i.e., which is approximately 307 tons per day respectively. Full state level data for the three scenarios are written out in Table 2 and depicted visually in Figure 16.

Table 2: Total 2028 Projected NO_X Emissions from January 1-April 30 and November 1-December 31

RPO	State	Base (Tons)	Non-OS Best Observed Rate Run (Tons)	% Change
MANE-VU	CT	327.03	327.03	0%
	DE	810.58	728.16	-10%
	MA	390.98	390.98	0%
	MD	5,563.30	3,388.78	-39%
	ME	133.37	133.37	0%
	NH	690.11	455.99	-34%
	NJ	2,463.72	2,463.72	0%
	NY	6,007.40	6,007.40	0%
	PA	36,794.01	31,570.49	-14%
	RI	201.99	201.99	0%
	VT	0.00	0.00	n/a
		53,382.49	**45,667.91**	-14%
LADCO	IL	19,718.14	18,992.34	-4%
	IN	41,709.04	34,635.87	-17%

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[12] All versions of the inputs were processed using v1.01 of the ERTAC EGU code.

RPO	**State**	**Base (Tons)**	**Non-OS Best Observed Rate Run (Tons)**	**% Change**
	MI	16,240.10	14,444.21	-11%
	MN	4,915.55	4,915.55	0%
	OH	35,210.31	22,931.80	-35%
	WI	9,129.28	9,024.42	-1%
		126,922.43	**104,944.19**	-17%
SESARM	AL	16,556.30	16,042.83	-3%
	FL	16,071.02	16,071.02	0%
	GA	22,085.39	15,355.41	-30%
	KY	33,095.90	29,643.16	-10%
	MS	9,099.17	9,099.17	0%
	NC	13,830.92	11,012.51	-20%
	SC	4,744.46	4,126.18	-13%
	TN	4,797.96	4,576.16	-5%
	VA	8,457.73	8,249.79	-2%
	WV	30,770.17	23,886.70	-22%
		159,509.02	**138,062.93**	-13%
CENSARA	AR	21,917.97	21,917.97	0%
	IA	13,249.45	13,038.43	-2%
	KS	15,293.89	13,405.27	-12%
	LA	18,714.47	18,714.47	0%
	MO	24,068.10	22,090.33	-8%
	NE	21,554.27	21,554.27	0%
	OK	15,081.12	15,081.12	0%
	TX	62,943.01	62,633.23	0%
		192,822.28	**188,435.10**	-2%
Grand Total		**532,636.21**	**477,110.12**	-10%

Figure 16: Total 2028 Projected NO$_X$ Emissions from January 1-April 30 and November 1-December 31

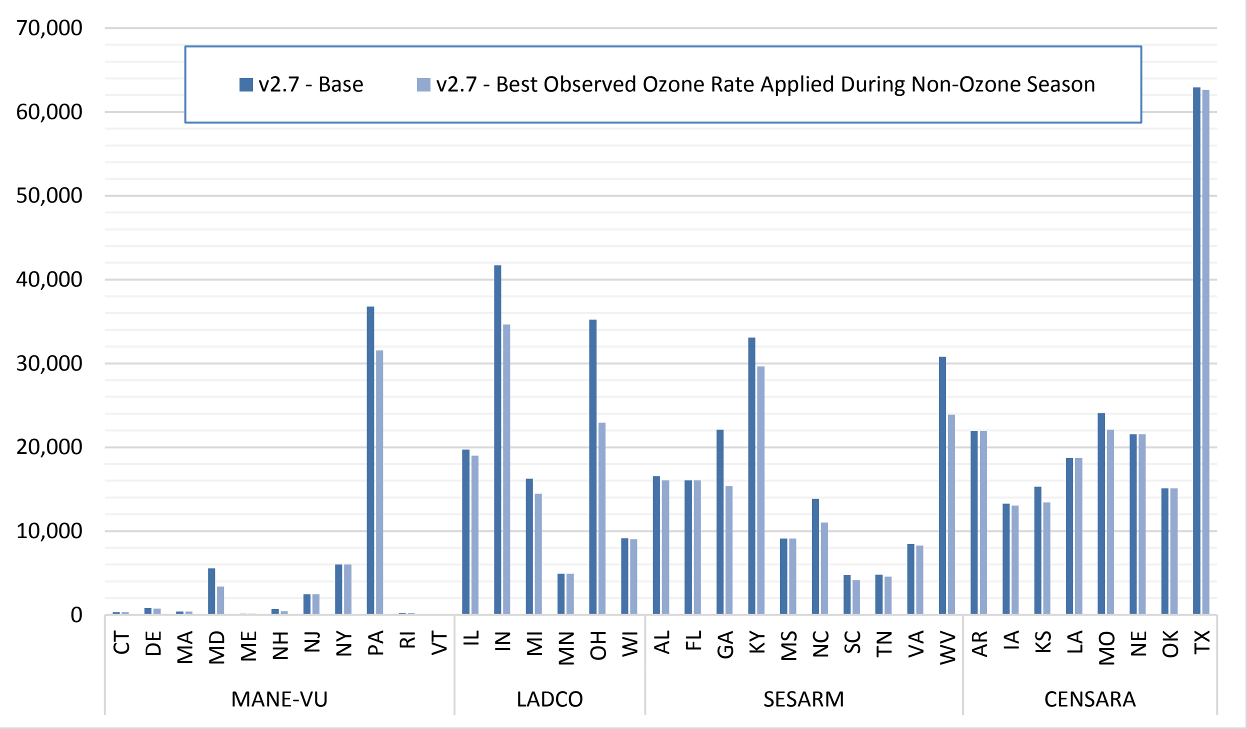
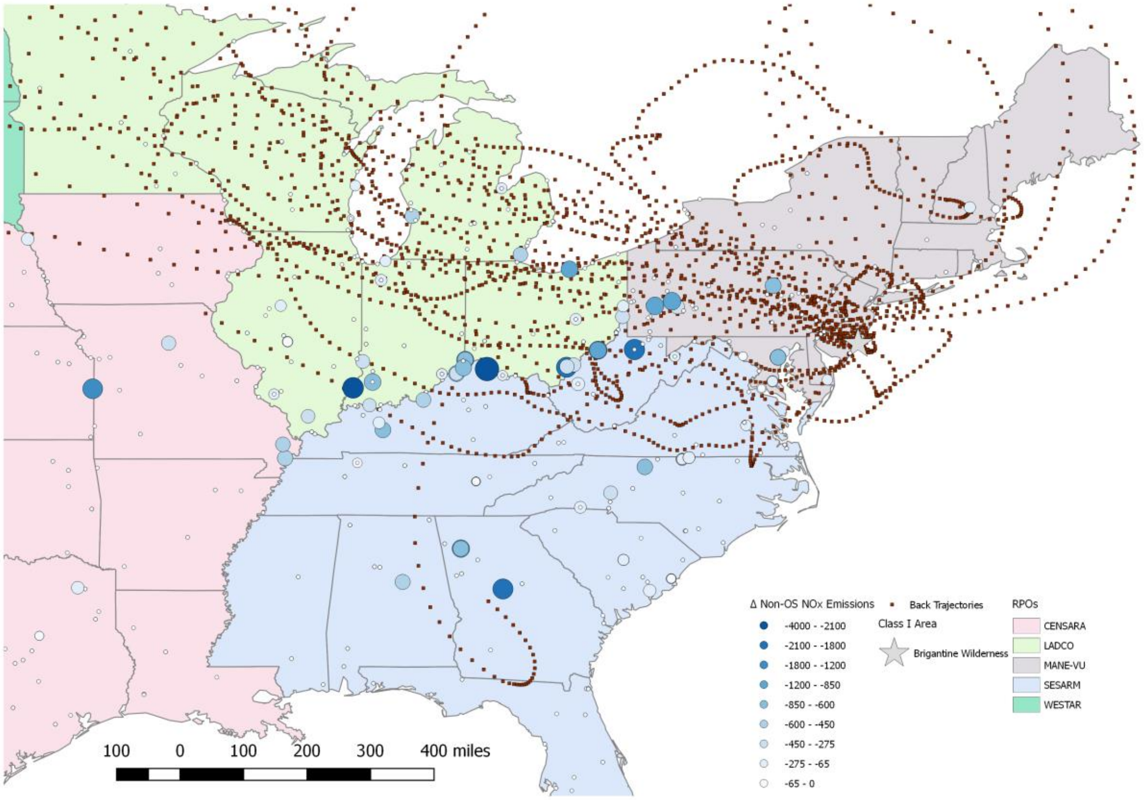


Figure 17 shows the change in non-ozone season emissions that occur when best observed rates are used during the non-ozone season months. It also shows which back trajectories occurred on days where nitrate impairment outweighs the sulfate impairment at Brigantine. Many of the back trajectories on the 20% most impaired days traverse the locations of the EGUs that are seeing some of the greatest reductions in emissions in the analysis. You can clearly see emission reductions occurring at power plants in Pennsylvania, Michigan, and along the Ohio River valley. Since the emissions from these power plants are released into air masses that are likely to travel to Brigantine, these emissions reductions should have a significant benefit at Brigantine. One should note that the back trajectories were not run at an elevation intended to evaluate against mobile and area sources and were not run for a long enough time period to demonstrate impacts from further away states such as Texas. The complete list of sources is provided in Appendix B.

Figure 17: Change in non-OS NO_X emissions (tons) due to optimization of non-OS emission rates and 2011 and 2015 back trajectories on 20% most impaired winter days where nitrates impacted visibility more than sulfates at Brigantine Wilderness



Summary

In recent years several MANE-VU Class I Areas have seen an increase in the relative visibility impairment from nitrates during the colder months. NO_X emissions are one of the main anthropogenic precursors to wintertime nitrate formation. Due to the higher elevation at which EGUs release emissions, NO_X emissions from EGUs have more potential to impact distant Class I Areas than other types of NO_X emission sources. Running existing installed controls is considered to be one of the most cost-effective ways to control NO_X emissions from EGUs. The analysis presented in this report demonstrates that running existing SCRs and SNCRs on EGUs would substantially reduce the NO_X emissions that lead to visibility impairment during the winter from nitrates.

Appendix A

In order to create the control file, the annual summary file and preprocessed control file files from the ERTAC v2.7and the best observed rate file were imported into Microsoft Access. The preprocessed control file was used since it included already processed seasonal controls, which are in a separate input file. Then, the best ozone season NO$_X$ emission rate was compared to the non-ozone season NO$_X$ emission rate from the annual summary file. In cases where the best observed ozone season NO$_X$ emission rate at a unit with an installed SCR or SNCR was lower than the non-ozone season NO$_X$ emission rate found in the annual summary an emission rate entry was added to the control file reflecting the best observed rate. Entries in the existing control emissions file for NO$_X$ emissions for units that met the criteria were removed (156 entries) and then new NO$_X$ emission rates were appended (291 entries). It should be noted that not all units have a control file entry since many units rely on the base year emission rates solely in ERTAC. The replacement ertac_control_emissions.csv file was then run through ERTAC EGU, using all other inputs directly from the 2028 projections for ERTAC v2.7, except ertac_seasonal_controls.csv, which was not needed for the run due to its inclusion in ertac_control_emissions.csv. The entries added to the final control file are in Table 3 below.

Table 3: Entries added to ERTAC Control File

ORISPL Code	Unit ID	Factor Start Date	Factor End Date	Pollutant	Emission Rate	Con. Eff.	Best Observed Rate Year
1241	1	2028-01-01	2028-04-30	NOX	0.081		2011
1241	1	2028-11-01	2028-12-31	NOX	0.081		2011
1241	2	2028-01-01	2028-04-30	NOX	0.0908		2015
1241	2	2028-11-01	2028-12-31	NOX	0.0908		2015
1356	1	2028-01-01	2028-04-30	NOX	0.0448		2005
1356	1	2028-11-01	2028-12-31	NOX	0.0448		2005
1356	3	2028-01-01	2028-04-30	NOX	0.0272		2005
1356	3	2028-11-01	2028-12-31	NOX	0.0272		2005
1356	4	2028-01-01	2028-04-30	NOX	0.0272		2005
1356	4	2028-11-01	2028-12-31	NOX	0.0272		2005
1364	3	2028-01-01	2028-04-30	NOX	0.045		2005
1364	3	2028-11-01	2028-12-31	NOX	0.045		2005
1364	4	2028-01-01	2028-04-30	NOX	0.0374		2007
1364	4	2028-11-01	2028-12-31	NOX	0.0374		2007
1378	3	2028-01-01	2028-04-30	NOX	0.1001		2005
1378	3	2028-11-01	2028-12-31	NOX	0.1001		2005
1552	1	2028-01-01	2028-04-30	NOX	0.2783		2015
1552	1	2028-11-01	2028-12-31	NOX	0.2783		2015
1552	2	2028-01-01	2028-04-30	NOX	0.2351		2015
1552	2	2028-11-01	2028-12-31	NOX	0.2351		2015
1554	2	2028-01-01	2028-04-30	NOX	0.2222		2015
1554	2	2028-11-01	2028-12-31	NOX	0.2222		2015
1554	3	2028-01-01	2028-04-30	NOX	0.0552		2015
1554	3	2028-11-01	2028-12-31	NOX	0.0552		2015
1571	1	2028-01-01	2028-04-30	NOX	0.104		2014
1571	1	2028-11-01	2028-12-31	NOX	0.104		2014
1571	2	2028-01-01	2028-04-30	NOX	0.1927		2009
1571	2	2028-11-01	2028-12-31	NOX	0.1927		2009
1572	1	2028-01-01	2028-04-30	NOX	0.2197		2015
1572	1	2028-11-01	2028-12-31	NOX	0.2197		2015
1572	2	2028-01-01	2028-04-30	NOX	0.2212		2015
1572	2	2028-11-01	2028-12-31	NOX	0.2212		2015
1572	3	2028-01-01	2028-04-30	NOX	0.2178		2015
1572	3	2028-11-01	2028-12-31	NOX	0.2178		2015
1573	1	2028-01-01	2028-04-30	NOX	0.0251		2013
1573	1	2028-11-01	2028-12-31	NOX	0.0251		2013
1573	2	2028-01-01	2028-04-30	NOX	0.0309		2011
1573	2	2028-11-01	2028-12-31	NOX	0.0309		2011
1702	1	2028-01-01	2028-04-30	NOX	0.0488		2015
1702	1	2028-11-01	2028-12-31	NOX	0.0488		2015
1702	2	2028-01-01	2028-04-30	NOX	0.0443		2015
1702	2	2028-11-01	2028-12-31	NOX	0.0443		2015
1710	2	2028-01-01	2028-04-30	NOX	0.0366		2015

Impact of Wintertime SCR/SNRC Optimization on Visibility Impairing Nitrate Precursor Emissions

ORISPL Code	Unit ID	Factor Start Date	Factor End Date	Pollutant	Emission Rate	Con. Eff.	Best Observed Rate Year
1710	2	2028-11-01	2028-12-31	NOX	0.0366		2015
1710	3	2028-01-01	2028-04-30	NOX	0.0414		2015
1710	3	2028-11-01	2028-12-31	NOX	0.0414		2015
1733	1	2028-01-01	2028-04-30	NOX	0.038		2014
1733	1	2028-11-01	2028-12-31	NOX	0.038		2014
1733	3	2028-01-01	2028-04-30	NOX	0.0573		2011
1733	3	2028-11-01	2028-12-31	NOX	0.0573		2011
1733	4	2028-01-01	2028-04-30	NOX	0.0408		2013
1733	4	2028-11-01	2028-12-31	NOX	0.0408		2013
2167	1	2028-01-01	2028-04-30	NOX	0.0895		2008
2167	1	2028-11-01	2028-12-31	NOX	0.0895		2008
2167	2	2028-01-01	2028-04-30	NOX	0.0941		2009
2167	2	2028-11-01	2028-12-31	NOX	0.0941		2009
2168	MB3	2028-01-01	2028-04-30	NOX	0.0961		2010
2168	MB3	2028-11-01	2028-12-31	NOX	0.0961		2010
2364	1	2028-01-01	2028-04-30	NOX	0.1613		2005
2364	1	2028-11-01	2028-12-31	NOX	0.1613		2005
2364	2	2028-01-01	2028-04-30	NOX	0.159		2006
2364	2	2028-11-01	2028-12-31	NOX	0.159		2006
2367	4	2028-01-01	2028-04-30	NOX	0.1811		2007
2367	4	2028-11-01	2028-12-31	NOX	0.1811		2007
2367	6	2028-01-01	2028-04-30	NOX	0.1896		2007
2367	6	2028-11-01	2028-12-31	NOX	0.1896		2007
26	5	2028-01-01	2028-04-30	NOX	0.076		2007
26	5	2028-11-01	2028-12-31	NOX	0.076		2007
2712	1	2028-01-01	2028-04-30	NOX	0.084		2005
2712	1	2028-11-01	2028-12-31	NOX	0.084		2005
2712	2	2028-01-01	2028-04-30	NOX	0.0575		2011
2712	2	2028-11-01	2028-12-31	NOX	0.0575		2011
2712	3A	2028-01-01	2028-04-30	NOX	0.0742		2005
2712	3A	2028-11-01	2028-12-31	NOX	0.0742		2005
2712	3B	2028-01-01	2028-04-30	NOX	0.0756		2005
2712	3B	2028-11-01	2028-12-31	NOX	0.0756		2005
2712	4A	2028-01-01	2028-04-30	NOX	0.0793		2009
2712	4A	2028-11-01	2028-12-31	NOX	0.0793		2009
2712	4B	2028-01-01	2028-04-30	NOX	0.0793		2009
2712	4B	2028-11-01	2028-12-31	NOX	0.0793		2009
2721	5	2028-01-01	2028-04-30	NOX	0.056		2011
2721	5	2028-11-01	2028-12-31	NOX	0.056		2011
2727	1	2028-01-01	2028-04-30	NOX	0.196		2010
2727	1	2028-11-01	2028-12-31	NOX	0.196		2010
2727	2	2028-01-01	2028-04-30	NOX	0.1956		2010
2727	2	2028-11-01	2028-12-31	NOX	0.1956		2010
2727	3	2028-01-01	2028-04-30	NOX	0.0679		2009
2727	3	2028-11-01	2028-12-31	NOX	0.0679		2009
2727	4	2028-01-01	2028-04-30	NOX	0.2008		2008
2727	4	2028-11-01	2028-12-31	NOX	0.2008		2008
2828	1	2028-01-01	2028-04-30	NOX	0.0348		2009
2828	1	2028-11-01	2028-12-31	NOX	0.0348		2009
2828	2	2028-01-01	2028-04-30	NOX	0.0426		2009
2828	2	2028-11-01	2028-12-31	NOX	0.0426		2009
2828	3	2028-01-01	2028-04-30	NOX	0.0226		2007
2828	3	2028-11-01	2028-12-31	NOX	0.0226		2007
2832	7	2028-01-01	2028-04-30	NOX	0.0536		2007
2832	7	2028-11-01	2028-12-31	NOX	0.0536		2007
2832	8	2028-01-01	2028-04-30	NOX	0.054		2007
2832	8	2028-11-01	2028-12-31	NOX	0.054		2007
2836	12	2028-01-01	2028-04-30	NOX	0.2842		2013
2836	12	2028-11-01	2028-12-31	NOX	0.2842		2013
2840	4	2028-01-01	2028-04-30	NOX	0.0546		2010
2840	4	2028-11-01	2028-12-31	NOX	0.0546		2010
2866	5	2028-01-01	2028-04-30	NOX	0.1058		2012
2866	5	2028-11-01	2028-12-31	NOX	0.1058		2012
2866	7	2028-01-01	2028-04-30	NOX	0.1019		2014
2866	7	2028-11-01	2028-12-31	NOX	0.1019		2014
2876	1	2028-01-01	2028-04-30	NOX	0.0788		2005
2876	1	2028-11-01	2028-12-31	NOX	0.0788		2005

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ORISPL Code	Unit ID	Factor Start Date	Factor End Date	Pollutant	Emission Rate	Con. Eff.	Best Observed Rate Year
2876	2	2028-01-01	2028-04-30	NOX	0.0792		2005
2876	2	2028-11-01	2028-12-31	NOX	0.0792		2005
2876	3	2028-01-01	2028-04-30	NOX	0.0787		2005
2876	3	2028-11-01	2028-12-31	NOX	0.0787		2005
2876	4	2028-01-01	2028-04-30	NOX	0.0786		2005
2876	4	2028-11-01	2028-12-31	NOX	0.0786		2005
2876	5	2028-01-01	2028-04-30	NOX	0.0785		2005
2876	5	2028-11-01	2028-12-31	NOX	0.0785		2005
3122	1	2028-01-01	2028-04-30	NOX	0.0667		2006
3122	1	2028-11-01	2028-12-31	NOX	0.0667		2006
3122	2	2028-01-01	2028-04-30	NOX	0.0826		2006
3122	2	2028-11-01	2028-12-31	NOX	0.0826		2006
3122	3	2028-01-01	2028-04-30	NOX	0.0872		2005
3122	3	2028-11-01	2028-12-31	NOX	0.0872		2005
3136	1	2028-01-01	2028-04-30	NOX	0.0431		2006
3136	1	2028-11-01	2028-12-31	NOX	0.0431		2006
3136	2	2028-01-01	2028-04-30	NOX	0.0433		2008
3136	2	2028-11-01	2028-12-31	NOX	0.0433		2008
3149	1	2028-01-01	2028-04-30	NOX	0.0581		2006
3149	1	2028-11-01	2028-12-31	NOX	0.0581		2006
3149	2	2028-01-01	2028-04-30	NOX	0.0578		2006
3149	2	2028-11-01	2028-12-31	NOX	0.0578		2006
3297	WAT1	2028-01-01	2028-04-30	NOX	0.0601		2007
3297	WAT1	2028-11-01	2028-12-31	NOX	0.0601		2007
3297	WAT2	2028-01-01	2028-04-30	NOX	0.0541		2006
3297	WAT2	2028-11-01	2028-12-31	NOX	0.0541		2006
3298	WIL1	2028-01-01	2028-04-30	NOX	0.0601		2005
3298	WIL1	2028-11-01	2028-12-31	NOX	0.0601		2005
3399	1	2028-01-01	2028-04-30	NOX	0.0588		2009
3399	1	2028-11-01	2028-12-31	NOX	0.0588		2009
3407	1	2028-01-01	2028-04-30	NOX	0.0498		2009
3407	1	2028-11-01	2028-12-31	NOX	0.0498		2009
3407	2	2028-01-01	2028-04-30	NOX	0.0501		2007
3407	2	2028-11-01	2028-12-31	NOX	0.0501		2007
3407	3	2028-01-01	2028-04-30	NOX	0.0504		2007
3407	3	2028-11-01	2028-12-31	NOX	0.0504		2007
3407	4	2028-01-01	2028-04-30	NOX	0.0501		2007
3407	4	2028-11-01	2028-12-31	NOX	0.0501		2007
3407	5	2028-01-01	2028-04-30	NOX	0.0486		2007
3407	5	2028-11-01	2028-12-31	NOX	0.0486		2007
3407	6	2028-01-01	2028-04-30	NOX	0.0448		2006
3407	6	2028-11-01	2028-12-31	NOX	0.0448		2006
3407	7	2028-01-01	2028-04-30	NOX	0.0447		2006
3407	7	2028-11-01	2028-12-31	NOX	0.0447		2006
3407	8	2028-01-01	2028-04-30	NOX	0.0448		2006
3407	8	2028-11-01	2028-12-31	NOX	0.0448		2006
3407	9	2028-01-01	2028-04-30	NOX	0.0449		2006
3407	9	2028-11-01	2028-12-31	NOX	0.0449		2006
3497	1	2028-01-01	2028-04-30	NOX	0.1261		2015
3497	1	2028-11-01	2028-12-31	NOX	0.1261		2015
3497	2	2028-01-01	2028-04-30	NOX	0.1305		2013
3497	2	2028-11-01	2028-12-31	NOX	0.1305		2013
3797	4	2028-01-01	2028-04-30	NOX	0.0487		2014
3797	4	2028-11-01	2028-12-31	NOX	0.0487		2014
3797	5	2028-01-01	2028-04-30	NOX	0.0309		2008
3797	5	2028-11-01	2028-12-31	NOX	0.0309		2008
3797	6	2028-01-01	2028-04-30	NOX	0.0326		2006
3797	6	2028-11-01	2028-12-31	NOX	0.0326		2006
3935	1	2028-01-01	2028-04-30	NOX	0.0317		2006
3935	1	2028-11-01	2028-12-31	NOX	0.0317		2006
3935	2	2028-01-01	2028-04-30	NOX	0.0312		2006
3935	2	2028-11-01	2028-12-31	NOX	0.0312		2006
3944	1	2028-01-01	2028-04-30	NOX	0.0634		2005
3944	1	2028-11-01	2028-12-31	NOX	0.0634		2005
3944	2	2028-01-01	2028-04-30	NOX	0.0662		2005
3944	2	2028-11-01	2028-12-31	NOX	0.0662		2005
3954	1	2028-01-01	2028-04-30	NOX	0.0539		2006

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ORISPL Code	Unit ID	Factor Start Date	Factor End Date	Pollutant	Emission Rate	Con. Eff.	Best Observed Rate Year
3954	1	2028-11-01	2028-12-31	NOX	0.0539		2006
3954	2	2028-01-01	2028-04-30	NOX	0.0485		2006
3954	2	2028-11-01	2028-12-31	NOX	0.0485		2006
4041	7	2028-01-01	2028-04-30	NOX	0.0603		2015
4041	7	2028-11-01	2028-12-31	NOX	0.0603		2015
4041	8	2028-01-01	2028-04-30	NOX	0.0608		2015
4041	8	2028-11-01	2028-12-31	NOX	0.0608		2015
4050	5	2028-01-01	2028-04-30	NOX	0.0361		2014
4050	5	2028-11-01	2028-12-31	NOX	0.0361		2014
594	4	2028-01-01	2028-04-30	NOX	0.0657		2012
594	4	2028-11-01	2028-12-31	NOX	0.0657		2012
6004	1	2028-01-01	2028-04-30	NOX	0.0394		2005
6004	1	2028-11-01	2028-12-31	NOX	0.0394		2005
6004	2	2028-01-01	2028-04-30	NOX	0.039		2005
6004	2	2028-11-01	2028-12-31	NOX	0.039		2005
6018	2	2028-01-01	2028-04-30	NOX	0.0518		2006
6018	2	2028-11-01	2028-12-31	NOX	0.0518		2006
6019	1	2028-01-01	2028-04-30	NOX	0.0562		2006
6019	1	2028-11-01	2028-12-31	NOX	0.0562		2006
602	1	2028-01-01	2028-04-30	NOX	0.0589		2007
602	1	2028-11-01	2028-12-31	NOX	0.0589		2007
602	2	2028-01-01	2028-04-30	NOX	0.0733		2015
602	2	2028-11-01	2028-12-31	NOX	0.0733		2015
6041	1	2028-01-01	2028-04-30	NOX	0.0829		2008
6041	1	2028-11-01	2028-12-31	NOX	0.0829		2008
6041	2	2028-01-01	2028-04-30	NOX	0.0729		2006
6041	2	2028-11-01	2028-12-31	NOX	0.0729		2006
6085	14	2028-01-01	2028-04-30	NOX	0.0979		2013
6085	14	2028-11-01	2028-12-31	NOX	0.0979		2013
6113	1	2028-01-01	2028-04-30	NOX	0.0343		2007
6113	1	2028-11-01	2028-12-31	NOX	0.0343		2007
6113	2	2028-01-01	2028-04-30	NOX	0.0672		2006
6113	2	2028-11-01	2028-12-31	NOX	0.0672		2006
6113	3	2028-01-01	2028-04-30	NOX	0.0659		2005
6113	3	2028-11-01	2028-12-31	NOX	0.0659		2005
6113	4	2028-01-01	2028-04-30	NOX	0.0632		2008
6113	4	2028-11-01	2028-12-31	NOX	0.0632		2008
6113	5	2028-01-01	2028-04-30	NOX	0.0597		2007
6113	5	2028-11-01	2028-12-31	NOX	0.0597		2007
6147	2	2028-01-01	2028-04-30	NOX	0.1187		2014
6147	2	2028-11-01	2028-12-31	NOX	0.1187		2014
6147	3	2028-01-01	2028-04-30	NOX	0.1485		2014
6147	3	2028-11-01	2028-12-31	NOX	0.1485		2014
6213	2SG1	2028-01-01	2028-04-30	NOX	0.0587		2015
6213	2SG1	2028-11-01	2028-12-31	NOX	0.0587		2015
6249	1	2028-01-01	2028-04-30	NOX	0.0623		2005
6249	1	2028-11-01	2028-12-31	NOX	0.0623		2005
6249	2	2028-01-01	2028-04-30	NOX	0.0679		2005
6249	2	2028-11-01	2028-12-31	NOX	0.0679		2005
6249	3	2028-01-01	2028-04-30	NOX	0.0812		2015
6249	3	2028-11-01	2028-12-31	NOX	0.0812		2015
6249	4	2028-01-01	2028-04-30	NOX	0.0869		2012
6249	4	2028-11-01	2028-12-31	NOX	0.0869		2012
6250	1A	2028-01-01	2028-04-30	NOX	0.061		2007
6250	1A	2028-11-01	2028-12-31	NOX	0.061		2007
6250	1B	2028-01-01	2028-04-30	NOX	0.0614		2007
6250	1B	2028-11-01	2028-12-31	NOX	0.0614		2007
6257	1	2028-01-01	2028-04-30	NOX	0.0613		2014
6257	1	2028-11-01	2028-12-31	NOX	0.0613		2014
6257	2	2028-01-01	2028-04-30	NOX	0.0606		2014
6257	2	2028-11-01	2028-12-31	NOX	0.0606		2014
6257	4	2028-01-01	2028-04-30	NOX	0.0627		2013
6257	4	2028-11-01	2028-12-31	NOX	0.0627		2013
6264	1	2028-01-01	2028-04-30	NOX	0.0387		2007
6264	1	2028-11-01	2028-12-31	NOX	0.0387		2007
6705	4	2028-01-01	2028-04-30	NOX	0.0948		2007
6705	4	2028-11-01	2028-12-31	NOX	0.0948		2007

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ORISPL Code	Unit ID	Factor Start Date	Factor End Date	Pollutant	Emission Rate	Con. Eff.	Best Observed Rate Year
6768	1	2028-01-01	2028-04-30	NOX	0.1046		2013
6768	1	2028-11-01	2028-12-31	NOX	0.1046		2013
6823	W1	2028-01-01	2028-04-30	NOX	0.0477		2006
6823	W1	2028-11-01	2028-12-31	NOX	0.0477		2006
703	1BLR	2028-01-01	2028-04-30	NOX	0.0547		2008
703	1BLR	2028-11-01	2028-12-31	NOX	0.0547		2008
703	2BLR	2028-01-01	2028-04-30	NOX	0.0543		2006
703	2BLR	2028-11-01	2028-12-31	NOX	0.0543		2006
703	3BLR	2028-01-01	2028-04-30	NOX	0.0553		2006
703	3BLR	2028-11-01	2028-12-31	NOX	0.0553		2006
703	4BLR	2028-01-01	2028-04-30	NOX	0.0525		2013
703	4BLR	2028-11-01	2028-12-31	NOX	0.0525		2013
7343	4	2028-01-01	2028-04-30	NOX	0.1873		2015
7343	4	2028-11-01	2028-12-31	NOX	0.1873		2015
8042	2	2028-01-01	2028-04-30	NOX	0.0382		2009
8042	2	2028-11-01	2028-12-31	NOX	0.0382		2009
8102	1	2028-01-01	2028-04-30	NOX	0.0686		2007
8102	1	2028-11-01	2028-12-31	NOX	0.0686		2007
8102	2	2028-01-01	2028-04-30	NOX	0.0553		2005
8102	2	2028-11-01	2028-12-31	NOX	0.0553		2005
8226	1	2028-01-01	2028-04-30	NOX	0.0901		2006
8226	1	2028-11-01	2028-12-31	NOX	0.0901		2006
876	1	2028-01-01	2028-04-30	NOX	0.0577		2013
876	1	2028-11-01	2028-12-31	NOX	0.0577		2013
876	2	2028-01-01	2028-04-30	NOX	0.06		2009
876	2	2028-11-01	2028-12-31	NOX	0.06		2009
879	51	2028-01-01	2028-04-30	NOX	0.0985		2013
879	51	2028-11-01	2028-12-31	NOX	0.0985		2013
879	52	2028-01-01	2028-04-30	NOX	0.0987		2015
879	52	2028-11-01	2028-12-31	NOX	0.0987		2015
879	61	2028-01-01	2028-04-30	NOX	0.0973		2013
879	61	2028-11-01	2028-12-31	NOX	0.0973		2013
879	62	2028-01-01	2028-04-30	NOX	0.0885		2015
879	62	2028-11-01	2028-12-31	NOX	0.0885		2015
889	2	2028-01-01	2028-04-30	NOX	0.0509		2010
889	2	2028-11-01	2028-12-31	NOX	0.0509		2010
976	4	2028-01-01	2028-04-30	NOX	0.0785		2015
976	4	2028-11-01	2028-12-31	NOX	0.0785		2015
983	1	2028-01-01	2028-04-30	NOX	0.0735		2005
983	1	2028-11-01	2028-12-31	NOX	0.0735		2005
983	2	2028-01-01	2028-04-30	NOX	0.075		2005
983	2	2028-11-01	2028-12-31	NOX	0.075		2005
983	3	2028-01-01	2028-04-30	NOX	0.0742		2005
983	3	2028-11-01	2028-12-31	NOX	0.0742		2005
994	2	2028-01-01	2028-04-30	NOX	0.051		2005
994	2	2028-11-01	2028-12-31	NOX	0.051		2005
994	3	2028-01-01	2028-04-30	NOX	0.0466		2005
994	3	2028-11-01	2028-12-31	NOX	0.0466		2005
997	12	2028-01-01	2028-04-30	NOX	0.092		2005
997	12	2028-11-01	2028-12-31	NOX	0.092		2005
1241	1	2028-01-01	2028-04-30	NOX	0.081		2011
1241	1	2028-11-01	2028-12-31	NOX	0.081		2011
1241	2	2028-01-01	2028-04-30	NOX	0.0908		2015
1241	2	2028-11-01	2028-12-31	NOX	0.0908		2015
1356	1	2028-01-01	2028-04-30	NOX	0.0448		2005
1356	1	2028-11-01	2028-12-31	NOX	0.0448		2005
1356	3	2028-01-01	2028-04-30	NOX	0.0272		2005
1356	3	2028-11-01	2028-12-31	NOX	0.0272		2005
1356	4	2028-01-01	2028-04-30	NOX	0.0272		2005
1356	4	2028-11-01	2028-12-31	NOX	0.0272		2005
1364	3	2028-01-01	2028-04-30	NOX	0.045		2005
1364	3	2028-11-01	2028-12-31	NOX	0.045		2005
1364	4	2028-01-01	2028-04-30	NOX	0.0374		2007
1364	4	2028-11-01	2028-12-31	NOX	0.0374		2007
1378	3	2028-01-01	2028-04-30	NOX	0.1001		2005
1378	3	2028-11-01	2028-12-31	NOX	0.1001		2005
1552	1	2028-01-01	2028-04-30	NOX	0.2783		2015

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ORISPL Code	Unit ID	Factor Start Date	Factor End Date	Pollutant	Emission Rate	Con. Eff.	Best Observed Rate Year
1552	1	2028-11-01	2028-12-31	NOX	0.2783		2015
1552	2	2028-01-01	2028-04-30	NOX	0.2351		2015
1552	2	2028-11-01	2028-12-31	NOX	0.2351		2015
1554	2	2028-01-01	2028-04-30	NOX	0.2222		2015
1554	2	2028-11-01	2028-12-31	NOX	0.2222		2015
1554	3	2028-01-01	2028-04-30	NOX	0.0552		2015
1554	3	2028-11-01	2028-12-31	NOX	0.0552		2015
1571	1	2028-01-01	2028-04-30	NOX	0.104		2014
1571	1	2028-11-01	2028-12-31	NOX	0.104		2014
1571	2	2028-01-01	2028-04-30	NOX	0.1927		2009
1571	2	2028-11-01	2028-12-31	NOX	0.1927		2009
1572	1	2028-01-01	2028-04-30	NOX	0.2197		2015
1572	1	2028-11-01	2028-12-31	NOX	0.2197		2015
1572	2	2028-01-01	2028-04-30	NOX	0.2212		2015
1572	2	2028-11-01	2028-12-31	NOX	0.2212		2015
1572	3	2028-01-01	2028-04-30	NOX	0.2178		2015
1572	3	2028-11-01	2028-12-31	NOX	0.2178		2015
1573	1	2028-01-01	2028-04-30	NOX	0.0251		2013
1573	1	2028-11-01	2028-12-31	NOX	0.0251		2013
1573	2	2028-01-01	2028-04-30	NOX	0.0309		2011
1573	2	2028-11-01	2028-12-31	NOX	0.0309		2011
1702	1	2028-01-01	2028-04-30	NOX	0.0488		2015
1702	1	2028-11-01	2028-12-31	NOX	0.0488		2015
1702	2	2028-01-01	2028-04-30	NOX	0.0443		2015
1702	2	2028-11-01	2028-12-31	NOX	0.0443		2015
1710	2	2028-01-01	2028-04-30	NOX	0.0366		2015
1710	2	2028-11-01	2028-12-31	NOX	0.0366		2015
1710	3	2028-01-01	2028-04-30	NOX	0.0414		2015
1710	3	2028-11-01	2028-12-31	NOX	0.0414		2015
1733	1	2028-01-01	2028-04-30	NOX	0.038		2014
1733	1	2028-11-01	2028-12-31	NOX	0.038		2014
1733	3	2028-01-01	2028-04-30	NOX	0.0573		2011
1733	3	2028-11-01	2028-12-31	NOX	0.0573		2011
1733	4	2028-01-01	2028-04-30	NOX	0.0408		2013
1733	4	2028-11-01	2028-12-31	NOX	0.0408		2013
2167	1	2028-01-01	2028-04-30	NOX	0.0895		2008
2167	1	2028-11-01	2028-12-31	NOX	0.0895		2008
2167	2	2028-01-01	2028-04-30	NOX	0.0941		2009
2167	2	2028-11-01	2028-12-31	NOX	0.0941		2009
2168	MB3	2028-01-01	2028-04-30	NOX	0.0961		2010
2168	MB3	2028-11-01	2028-12-31	NOX	0.0961		2010
2364	1	2028-01-01	2028-04-30	NOX	0.1613		2005
2364	1	2028-11-01	2028-12-31	NOX	0.1613		2005
2364	2	2028-01-01	2028-04-30	NOX	0.159		2006
2364	2	2028-11-01	2028-12-31	NOX	0.159		2006
2367	4	2028-01-01	2028-04-30	NOX	0.1811		2007
2367	4	2028-11-01	2028-12-31	NOX	0.1811		2007
2367	6	2028-01-01	2028-04-30	NOX	0.1896		2007
2367	6	2028-11-01	2028-12-31	NOX	0.1896		2007
26	5	2028-01-01	2028-04-30	NOX	0.076		2007
26	5	2028-11-01	2028-12-31	NOX	0.076		2007
2712	1	2028-01-01	2028-04-30	NOX	0.084		2005
2712	1	2028-11-01	2028-12-31	NOX	0.084		2005
2712	2	2028-01-01	2028-04-30	NOX	0.0575		2011
2712	2	2028-11-01	2028-12-31	NOX	0.0575		2011
2712	3A	2028-01-01	2028-04-30	NOX	0.0742		2005
2712	3A	2028-11-01	2028-12-31	NOX	0.0742		2005
2712	3B	2028-01-01	2028-04-30	NOX	0.0756		2005
2712	3B	2028-11-01	2028-12-31	NOX	0.0756		2005
2712	4A	2028-01-01	2028-04-30	NOX	0.0793		2009
2712	4A	2028-11-01	2028-12-31	NOX	0.0793		2009
2712	4B	2028-01-01	2028-04-30	NOX	0.0793		2009
2712	4B	2028-11-01	2028-12-31	NOX	0.0793		2009
2721	5	2028-01-01	2028-04-30	NOX	0.056		2011
2721	5	2028-11-01	2028-12-31	NOX	0.056		2011
2727	1	2028-01-01	2028-04-30	NOX	0.196		2010
2727	1	2028-11-01	2028-12-31	NOX	0.196		2010

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2727	2	2028-01-01	2028-04-30	NOX	0.1956		2010
2727	2	2028-11-01	2028-12-31	NOX	0.1956		2010
2727	3	2028-01-01	2028-04-30	NOX	0.0679		2009
2727	3	2028-11-01	2028-12-31	NOX	0.0679		2009
2727	4	2028-01-01	2028-04-30	NOX	0.2008		2008
2727	4	2028-11-01	2028-12-31	NOX	0.2008		2008
2828	1	2028-01-01	2028-04-30	NOX	0.0348		2009
2828	1	2028-11-01	2028-12-31	NOX	0.0348		2009
2828	2	2028-01-01	2028-04-30	NOX	0.0426		2009
2828	2	2028-11-01	2028-12-31	NOX	0.0426		2009
2828	3	2028-01-01	2028-04-30	NOX	0.0226		2007
2828	3	2028-11-01	2028-12-31	NOX	0.0226		2007
2832	7	2028-01-01	2028-04-30	NOX	0.0536		2007
2832	7	2028-11-01	2028-12-31	NOX	0.0536		2007
2832	8	2028-01-01	2028-04-30	NOX	0.054		2007
2832	8	2028-11-01	2028-12-31	NOX	0.054		2007
2836	12	2028-01-01	2028-04-30	NOX	0.2842		2013
2836	12	2028-11-01	2028-12-31	NOX	0.2842		2013
2840	4	2028-01-01	2028-04-30	NOX	0.0546		2010
2840	4	2028-11-01	2028-12-31	NOX	0.0546		2010
2866	5	2028-01-01	2028-04-30	NOX	0.1058		2012
2866	5	2028-11-01	2028-12-31	NOX	0.1058		2012
2866	7	2028-01-01	2028-04-30	NOX	0.1019		2014
2866	7	2028-11-01	2028-12-31	NOX	0.1019		2014
2876	1	2028-01-01	2028-04-30	NOX	0.0788		2005
2876	1	2028-11-01	2028-12-31	NOX	0.0788		2005
2876	2	2028-01-01	2028-04-30	NOX	0.0792		2005
2876	2	2028-11-01	2028-12-31	NOX	0.0792		2005
2876	3	2028-01-01	2028-04-30	NOX	0.0787		2005
2876	3	2028-11-01	2028-12-31	NOX	0.0787		2005
2876	4	2028-01-01	2028-04-30	NOX	0.0786		2005
2876	4	2028-11-01	2028-12-31	NOX	0.0786		2005
2876	5	2028-01-01	2028-04-30	NOX	0.0785		2005
2876	5	2028-11-01	2028-12-31	NOX	0.0785		2005
3122	1	2028-01-01	2028-04-30	NOX	0.0667		2006
3122	1	2028-11-01	2028-12-31	NOX	0.0667		2006
3122	2	2028-01-01	2028-04-30	NOX	0.0826		2006
3122	2	2028-11-01	2028-12-31	NOX	0.0826		2006
3122	3	2028-01-01	2028-04-30	NOX	0.0872		2005
3122	3	2028-11-01	2028-12-31	NOX	0.0872		2005
3136	1	2028-01-01	2028-04-30	NOX	0.0431		2006
3136	1	2028-11-01	2028-12-31	NOX	0.0431		2006
3136	2	2028-01-01	2028-04-30	NOX	0.0433		2008
3136	2	2028-11-01	2028-12-31	NOX	0.0433		2008
3149	1	2028-01-01	2028-04-30	NOX	0.0581		2006
3149	1	2028-11-01	2028-12-31	NOX	0.0581		2006
3149	2	2028-01-01	2028-04-30	NOX	0.0578		2006
3149	2	2028-11-01	2028-12-31	NOX	0.0578		2006
3297	WAT1	2028-01-01	2028-04-30	NOX	0.0601		2007
3297	WAT1	2028-11-01	2028-12-31	NOX	0.0601		2007
3297	WAT2	2028-01-01	2028-04-30	NOX	0.0541		2006
3297	WAT2	2028-11-01	2028-12-31	NOX	0.0541		2006
3298	WIL1	2028-01-01	2028-04-30	NOX	0.0601		2005
3298	WIL1	2028-11-01	2028-12-31	NOX	0.0601		2005
3399	1	2028-01-01	2028-04-30	NOX	0.0588		2009
3399	1	2028-11-01	2028-12-31	NOX	0.0588		2009
3407	1	2028-01-01	2028-04-30	NOX	0.0498		2009
3407	1	2028-11-01	2028-12-31	NOX	0.0498		2009
3407	2	2028-01-01	2028-04-30	NOX	0.0501		2007
3407	2	2028-11-01	2028-12-31	NOX	0.0501		2007
3407	3	2028-01-01	2028-04-30	NOX	0.0504		2007
3407	3	2028-11-01	2028-12-31	NOX	0.0504		2007
3407	4	2028-01-01	2028-04-30	NOX	0.0501		2007
3407	4	2028-11-01	2028-12-31	NOX	0.0501		2007
3407	5	2028-01-01	2028-04-30	NOX	0.0486		2007
3407	5	2028-11-01	2028-12-31	NOX	0.0486		2007
3407	6	2028-01-01	2028-04-30	NOX	0.0448		2006

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ORISPL Code	Unit ID	Factor Start Date	Factor End Date	Pollutant	Emission Rate	Con. Eff.	Best Observed Rate Year
3407	6	2028-11-01	2028-12-31	NOX	0.0448		2006
3407	7	2028-01-01	2028-04-30	NOX	0.0447		2006
3407	7	2028-11-01	2028-12-31	NOX	0.0447		2006
3407	8	2028-01-01	2028-04-30	NOX	0.0448		2006
3407	8	2028-11-01	2028-12-31	NOX	0.0448		2006
3407	9	2028-01-01	2028-04-30	NOX	0.0449		2006
3407	9	2028-11-01	2028-12-31	NOX	0.0449		2006
3497	1	2028-01-01	2028-04-30	NOX	0.1261		2015
3497	1	2028-11-01	2028-12-31	NOX	0.1261		2015
3497	2	2028-01-01	2028-04-30	NOX	0.1305		2013
3497	2	2028-11-01	2028-12-31	NOX	0.1305		2013
3797	4	2028-01-01	2028-04-30	NOX	0.0487		2014
3797	4	2028-11-01	2028-12-31	NOX	0.0487		2014
3797	5	2028-01-01	2028-04-30	NOX	0.0309		2008
3797	5	2028-11-01	2028-12-31	NOX	0.0309		2008
3797	6	2028-01-01	2028-04-30	NOX	0.0326		2006
3797	6	2028-11-01	2028-12-31	NOX	0.0326		2006
3935	1	2028-01-01	2028-04-30	NOX	0.0317		2006
3935	1	2028-11-01	2028-12-31	NOX	0.0317		2006
3935	2	2028-01-01	2028-04-30	NOX	0.0312		2006
3935	2	2028-11-01	2028-12-31	NOX	0.0312		2006
3944	1	2028-01-01	2028-04-30	NOX	0.0634		2005
3944	1	2028-11-01	2028-12-31	NOX	0.0634		2005
3944	2	2028-01-01	2028-04-30	NOX	0.0662		2005
3944	2	2028-11-01	2028-12-31	NOX	0.0662		2005
3954	1	2028-01-01	2028-04-30	NOX	0.0539		2006
3954	1	2028-11-01	2028-12-31	NOX	0.0539		2006
3954	2	2028-01-01	2028-04-30	NOX	0.0485		2006
3954	2	2028-11-01	2028-12-31	NOX	0.0485		2006
4041	7	2028-01-01	2028-04-30	NOX	0.0603		2015
4041	7	2028-11-01	2028-12-31	NOX	0.0603		2015
4041	8	2028-01-01	2028-04-30	NOX	0.0608		2015
4041	8	2028-11-01	2028-12-31	NOX	0.0608		2015
4050	5	2028-01-01	2028-04-30	NOX	0.0361		2014
4050	5	2028-11-01	2028-12-31	NOX	0.0361		2014
594	4	2028-01-01	2028-04-30	NOX	0.0657		2012
594	4	2028-11-01	2028-12-31	NOX	0.0657		2012
6004	1	2028-01-01	2028-04-30	NOX	0.0394		2005
6004	1	2028-11-01	2028-12-31	NOX	0.0394		2005
6004	2	2028-01-01	2028-04-30	NOX	0.039		2005
6004	2	2028-11-01	2028-12-31	NOX	0.039		2005
6018	2	2028-01-01	2028-04-30	NOX	0.0518		2006
6018	2	2028-11-01	2028-12-31	NOX	0.0518		2006
6019	1	2028-01-01	2028-04-30	NOX	0.0562		2006
6019	1	2028-11-01	2028-12-31	NOX	0.0562		2006
602	1	2028-01-01	2028-04-30	NOX	0.0589		2007
602	1	2028-11-01	2028-12-31	NOX	0.0589		2007
602	2	2028-01-01	2028-04-30	NOX	0.0733		2015
602	2	2028-11-01	2028-12-31	NOX	0.0733		2015
6041	1	2028-01-01	2028-04-30	NOX	0.0829		2008
6041	1	2028-11-01	2028-12-31	NOX	0.0829		2008
6041	2	2028-01-01	2028-04-30	NOX	0.0729		2006
6041	2	2028-11-01	2028-12-31	NOX	0.0729		2006
6085	14	2028-01-01	2028-04-30	NOX	0.0979		2013
6085	14	2028-11-01	2028-12-31	NOX	0.0979		2013
6113	1	2028-01-01	2028-04-30	NOX	0.0343		2007
6113	1	2028-11-01	2028-12-31	NOX	0.0343		2007
6113	2	2028-01-01	2028-04-30	NOX	0.0672		2006
6113	2	2028-11-01	2028-12-31	NOX	0.0672		2006
6113	3	2028-01-01	2028-04-30	NOX	0.0659		2005
6113	3	2028-11-01	2028-12-31	NOX	0.0659		2005
6113	4	2028-01-01	2028-04-30	NOX	0.0632		2008
6113	4	2028-11-01	2028-12-31	NOX	0.0632		2008
6113	5	2028-01-01	2028-04-30	NOX	0.0597		2007
6113	5	2028-11-01	2028-12-31	NOX	0.0597		2007
6147	2	2028-01-01	2028-04-30	NOX	0.1187		2014
6147	2	2028-11-01	2028-12-31	NOX	0.1187		2014

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6147	3	2028-01-01	2028-04-30	NOX	0.1485		2014
6147	3	2028-11-01	2028-12-31	NOX	0.1485		2014
6213	2SG1	2028-01-01	2028-04-30	NOX	0.0587		2015
6213	2SG1	2028-11-01	2028-12-31	NOX	0.0587		2015
6249	1	2028-01-01	2028-04-30	NOX	0.0623		2005
6249	1	2028-11-01	2028-12-31	NOX	0.0623		2005
6249	2	2028-01-01	2028-04-30	NOX	0.0679		2005
6249	2	2028-11-01	2028-12-31	NOX	0.0679		2005
6249	3	2028-01-01	2028-04-30	NOX	0.0812		2015
6249	3	2028-11-01	2028-12-31	NOX	0.0812		2015
6249	4	2028-01-01	2028-04-30	NOX	0.0869		2012
6249	4	2028-11-01	2028-12-31	NOX	0.0869		2012
6250	1A	2028-01-01	2028-04-30	NOX	0.061		2007
6250	1A	2028-11-01	2028-12-31	NOX	0.061		2007
6250	1B	2028-01-01	2028-04-30	NOX	0.0614		2007
6250	1B	2028-11-01	2028-12-31	NOX	0.0614		2007
6257	1	2028-01-01	2028-04-30	NOX	0.0613		2014
6257	1	2028-11-01	2028-12-31	NOX	0.0613		2014
6257	2	2028-01-01	2028-04-30	NOX	0.0606		2014
6257	2	2028-11-01	2028-12-31	NOX	0.0606		2014
6257	4	2028-01-01	2028-04-30	NOX	0.0627		2013
6257	4	2028-11-01	2028-12-31	NOX	0.0627		2013
6264	1	2028-01-01	2028-04-30	NOX	0.0387		2007
6264	1	2028-11-01	2028-12-31	NOX	0.0387		2007
6705	4	2028-01-01	2028-04-30	NOX	0.0948		2007
6705	4	2028-11-01	2028-12-31	NOX	0.0948		2007
6768	1	2028-01-01	2028-04-30	NOX	0.1046		2013
6768	1	2028-11-01	2028-12-31	NOX	0.1046		2013
6823	W1	2028-01-01	2028-04-30	NOX	0.0477		2006
6823	W1	2028-11-01	2028-12-31	NOX	0.0477		2006
703	1BLR	2028-01-01	2028-04-30	NOX	0.0547		2008
703	1BLR	2028-11-01	2028-12-31	NOX	0.0547		2008
703	2BLR	2028-01-01	2028-04-30	NOX	0.0543		2006
703	2BLR	2028-11-01	2028-12-31	NOX	0.0543		2006
703	3BLR	2028-01-01	2028-04-30	NOX	0.0553		2006
703	3BLR	2028-11-01	2028-12-31	NOX	0.0553		2006
703	4BLR	2028-01-01	2028-04-30	NOX	0.0525		2013
703	4BLR	2028-11-01	2028-12-31	NOX	0.0525		2013
7343	4	2028-01-01	2028-04-30	NOX	0.1873		2015
7343	4	2028-11-01	2028-12-31	NOX	0.1873		2015
8042	2	2028-01-01	2028-04-30	NOX	0.0382		2009
8042	2	2028-11-01	2028-12-31	NOX	0.0382		2009
8102	1	2028-01-01	2028-04-30	NOX	0.0686		2007
8102	1	2028-11-01	2028-12-31	NOX	0.0686		2007
8102	2	2028-01-01	2028-04-30	NOX	0.0553		2005
8102	2	2028-11-01	2028-12-31	NOX	0.0553		2005
8226	1	2028-01-01	2028-04-30	NOX	0.0901		2006
8226	1	2028-11-01	2028-12-31	NOX	0.0901		2006
876	1	2028-01-01	2028-04-30	NOX	0.0577		2013
876	1	2028-11-01	2028-12-31	NOX	0.0577		2013
876	2	2028-01-01	2028-04-30	NOX	0.06		2009
876	2	2028-11-01	2028-12-31	NOX	0.06		2009
879	51	2028-01-01	2028-04-30	NOX	0.0985		2013
879	51	2028-11-01	2028-12-31	NOX	0.0985		2013
879	52	2028-01-01	2028-04-30	NOX	0.0987		2015
879	52	2028-11-01	2028-12-31	NOX	0.0987		2015
879	61	2028-01-01	2028-04-30	NOX	0.0973		2013
879	61	2028-11-01	2028-12-31	NOX	0.0973		2013
879	62	2028-01-01	2028-04-30	NOX	0.0885		2015
879	62	2028-11-01	2028-12-31	NOX	0.0885		2015
889	2	2028-01-01	2028-04-30	NOX	0.0509		2010
889	2	2028-11-01	2028-12-31	NOX	0.0509		2010
976	4	2028-01-01	2028-04-30	NOX	0.0785		2015
976	4	2028-11-01	2028-12-31	NOX	0.0785		2015
983	1	2028-01-01	2028-04-30	NOX	0.0735		2005
983	1	2028-11-01	2028-12-31	NOX	0.0735		2005
983	2	2028-01-01	2028-04-30	NOX	0.075		2005

Impact of Wintertime SCR/SNRC Optimization on Visibility Impairing Nitrate Precursor Emissions

ORISPL Code	Unit ID	Factor Start Date	Factor End Date	Pollutant	Emission Rate	Con. Eff.	Best Observed Rate Year
983	2	2028-11-01	2028-12-31	NOX	0.075		2005
983	3	2028-01-01	2028-04-30	NOX	0.0742		2005
983	3	2028-11-01	2028-12-31	NOX	0.0742		2005
994	2	2028-01-01	2028-04-30	NOX	0.051		2005
994	2	2028-11-01	2028-12-31	NOX	0.051		2005
994	3	2028-01-01	2028-04-30	NOX	0.0466		2005
994	3	2028-11-01	2028-12-31	NOX	0.0466		2005
997	12	2028-01-01	2028-04-30	NOX	0.092		2005
997	12	2028-11-01	2028-12-31	NOX	0.092		2005

Appendix B

Table 4: Unit level results in total tons during non-ozone season from ERTAC v2.7, and the best observed rate (BOR) runs

RPO	St.	Facility Name	Orispl	Unit ID	Base	BOR	Difference
MANE-VU	CT	AES Thames	10675	UNITA	0.00	0.00	0
MANE-VU	CT	AES Thames	10675	UNITB	0.00	0.00	0
MANE-VU	CT	Bridgeport Harbor Station	568	BHB3	42.58	42.58	0
MANE-VU	DE	Indian River	594	1	0.00	0.00	0
MANE-VU	DE	Indian River	594	3	0.00	0.00	0
MANE-VU	DE	Indian River	594	4	242.09	159.66	-82.42
MANE-VU	MA	Brayton Point	1619	1	0.00	0.00	0
MANE-VU	MA	Brayton Point	1619	2	0.00	0.00	0
MANE-VU	MA	Brayton Point	1619	3	0.00	0.00	0
MANE-VU	MA	Mount Tom	1606	1	0.00	0.00	0
MANE-VU	MA	Salem Harbor	1626	1	0.00	0.00	0
MANE-VU	MA	Salem Harbor	1626	2	0.00	0.00	0
MANE-VU	MA	Salem Harbor	1626	3	0.00	0.00	0
MANE-VU	MD	AES Warrior Run	10678	001	472.61	472.61	0
MANE-VU	MD	Brandon Shores	602	1	1,139.49	463.48	-676.01
MANE-VU	MD	Brandon Shores	602	2	1,289.18	663.05	-626.13
MANE-VU	MD	C P Crane	1552	1	155.93	96.58	-59.34
MANE-VU	MD	C P Crane	1552	2	170.28	98.46	-71.82
MANE-VU	MD	Herbert A Wagner	1554	2	93.56	52.61	-40.96
MANE-VU	MD	Herbert A Wagner	1554	3	620.52	283.23	-337.29
MANE-VU	MD	Mirant Chalk Point	1571	1	283.29	154.41	-128.88
MANE-VU	MD	Mirant Chalk Point	1571	2	318.36	242.58	-75.78
MANE-VU	MD	Mirant Dickerson	1572	1	89.52	69.06	-20.46
MANE-VU	MD	Mirant Dickerson	1572	2	122.50	93.34	-29.16
MANE-VU	MD	Mirant Dickerson	1572	3	121.27	91.71	-29.56
MANE-VU	MD	Mirant Morgantown	1573	1	258.83	195.43	-63.41
MANE-VU	MD	Mirant Morgantown	1573	2	181.52	165.81	-15.71
MANE-VU	MD	R. Paul Smith Power Station	1570	11	0.00	0.00	0
MANE-VU	MD	R. Paul Smith Power Station	1570	9	0.00	0.00	0
MANE-VU	NH	Merrimack	2364	1	188.91	120.88	-68.04
MANE-VU	NH	Merrimack	2364	2	306.33	182.49	-123.83
MANE-VU	NH	Schiller	2367	4	53.76	32.83	-20.92
MANE-VU	NH	Schiller	2367	6	63.00	41.68	-21.33
MANE-VU	NJ	B L England	2378	1	0.00	0.00	0
MANE-VU	NJ	B L England	2378	2	0.00	0.00	0
MANE-VU	NJ	Carneys Point	10566	1001	247.22	247.22	0
MANE-VU	NJ	Carneys Point	10566	1002	251.41	251.41	0
MANE-VU	NJ	Deepwater	2384	8	0.00	0.00	0
MANE-VU	NJ	Hudson Generating Station	2403	2	0.00	0.00	0
MANE-VU	NJ	Logan Generating Plant	10043	1001	235.74	235.74	0
MANE-VU	NJ	Mercer Generating Station	2408	1	0.00	0.00	0
MANE-VU	NJ	Mercer Generating Station	2408	2	0.00	0.00	0
MANE-VU	NY	AES Cayuga, LLC	2535	1	135.83	135.83	0
MANE-VU	NY	AES Cayuga, LLC	2535	2	129.12	129.12	0
MANE-VU	NY	AES Greenidge	2527	6	0.00	0.00	0
MANE-VU	NY	AES Somerset (Kintigh)	6082	1	816.12	816.12	0
MANE-VU	NY	AES Westover (Goudey)	2526	13	0.00	0.00	0
MANE-VU	NY	Black River Generation, LLC	10464	E0001	0.00	0.00	0
MANE-VU	NY	Black River Generation, LLC	10464	E0002	0.00	0.00	0
MANE-VU	NY	Black River Generation, LLC	10464	E0003	0.00	0.00	0
MANE-VU	NY	Dunkirk	2554	1	51.57	51.57	0
MANE-VU	NY	Dunkirk	2554	2	62.46	62.46	0
MANE-VU	NY	Dunkirk	2554	3	166.83	166.83	0
MANE-VU	NY	Dunkirk	2554	4	134.83	134.83	0
MANE-VU	NY	Dynegy Danskammer	2480	3	0.00	0.00	0
MANE-VU	NY	Dynegy Danskammer	2480	4	0.00	0.00	0

Impact of Wintertime SCR/SNRC Optimization on Visibility Impairing Nitrate Precursor Emissions

RPO	St.	Facility Name	Orispl	Unit ID	Base	BOR	Difference
MANE-VU	**NY**	Huntley Power	**2549**	67	148.99	148.99	0
MANE-VU	**NY**	Huntley Power	**2549**	68	142.64	142.64	0
MANE-VU	**NY**	Niagara Generation, LLC	**50202**	1	0.00	0.00	0
MANE-VU	**NY**	S A Carlson	**2682**	10	0.00	0.00	0
MANE-VU	**NY**	S A Carlson	**2682**	12	0.00	0.00	0
MANE-VU	**NY**	S A Carlson	**2682**	9	0.00	0.00	0
MANE-VU	**NY**	Syracuse Energy Corporation	**50651**	BLR1	0.00	0.00	0
MANE-VU	**PA**	AES Beaver Valley LLC	**10676**	032	0.00	0.00	0
MANE-VU	**PA**	AES Beaver Valley LLC	**10676**	033	0.00	0.00	0
MANE-VU	**PA**	AES Beaver Valley LLC	**10676**	034	0.00	0.00	0
MANE-VU	**PA**	AES Beaver Valley LLC	**10676**	035	0.00	0.00	0
MANE-VU	**PA**	Armstrong Power Station	**3178**	1	0.00	0.00	0
MANE-VU	**PA**	Armstrong Power Station	**3178**	2	0.00	0.00	0
MANE-VU	**PA**	Bruce Mansfield	**6094**	1	2,223.60	2,223.60	0
MANE-VU	**PA**	Bruce Mansfield	**6094**	2	1,992.25	1,992.25	0
MANE-VU	**PA**	Bruce Mansfield	**6094**	3	3,888.10	3,888.10	0
MANE-VU	**PA**	Brunner Island	**3140**	1	477.43	477.43	0
MANE-VU	**PA**	Brunner Island	**3140**	2	441.12	441.12	0
MANE-VU	**PA**	Brunner Island	**3140**	3	1,001.39	1,001.39	0
MANE-VU	**PA**	Cambria Cogen	**10641**	1	222.21	222.21	0
MANE-VU	**PA**	Cambria Cogen	**10641**	2	241.91	241.91	0
MANE-VU	**PA**	Cheswick	**8226**	1	1,865.18	809.38	-1055.8
MANE-VU	**PA**	Colver Power Project	**10143**	AAB01	432.08	432.08	0
MANE-VU	**PA**	Conemaugh	**3118**	1	1,948.41	1,948.41	0
MANE-VU	**PA**	Conemaugh	**3118**	2	2,441.54	2,441.54	0
MANE-VU	**PA**	Cromby	**3159**	1	0.00	0.00	0
MANE-VU	**PA**	Ebensburg Power Company	**10603**	031	192.64	192.64	0
MANE-VU	**PA**	Eddystone Generating Station	**3161**	1	0.00	0.00	0
MANE-VU	**PA**	Eddystone Generating Station	**3161**	2	0.00	0.00	0
MANE-VU	**PA**	Elrama	**3098**	1	0.00	0.00	0
MANE-VU	**PA**	Elrama	**3098**	2	0.00	0.00	0
MANE-VU	**PA**	Elrama	**3098**	3	0.00	0.00	0
MANE-VU	**PA**	Elrama	**3098**	4	0.00	0.00	0
MANE-VU	**PA**	Gilberton Power Company	**10113**	031	57.72	57.72	0
MANE-VU	**PA**	Gilberton Power Company	**10113**	032	56.80	56.80	0
MANE-VU	**PA**	Hatfields Ferry Power Station	**3179**	1	0.00	0.00	0
MANE-VU	**PA**	Hatfields Ferry Power Station	**3179**	2	0.00	0.00	0
MANE-VU	**PA**	Hatfields Ferry Power Station	**3179**	3	0.00	0.00	0
MANE-VU	**PA**	Homer City	**3122**	1	961.99	679.48	-282.52
MANE-VU	**PA**	Homer City	**3122**	2	960.13	763.43	-196.7
MANE-VU	**PA**	Homer City	**3122**	3	1,633.78	1,253.56	-380.22
MANE-VU	**PA**	Keystone	**3136**	1	2,301.35	1,305.16	-996.2
MANE-VU	**PA**	Keystone	**3136**	2	2,405.67	1,339.26	-1066.4
MANE-VU	**PA**	Mitchell Power Station	**3181**	33	0.00	0.00	0
MANE-VU	**PA**	Montour	**3149**	1	1,581.95	1,028.22	-553.73
MANE-VU	**PA**	Montour	**3149**	2	1,892.79	1,200.83	-691.96
MANE-VU	**PA**	Mt. Carmel Cogeneration	**10343**	SG-101	238.76	238.76	0
MANE-VU	**PA**	New Castle	**3138**	3	42.51	42.51	0
MANE-VU	**PA**	New Castle	**3138**	4	68.66	68.66	0
MANE-VU	**PA**	New Castle	**3138**	5	48.74	48.74	0
MANE-VU	**PA**	Northampton Generating Plant	**50888**	NGC01	267.72	267.72	0
MANE-VU	**PA**	Northeastern Power Company	**50039**	031	83.74	83.74	0
MANE-VU	**PA**	Panther Creek Energy Facility	**50776**	1	171.66	171.66	0
MANE-VU	**PA**	Panther Creek Energy Facility	**50776**	2	158.60	158.60	0
MANE-VU	**PA**	Piney Creek Power Plant	**54144**	031	0.00	0.00	0
MANE-VU	**PA**	Portland	**3113**	1	0.00	0.00	0
MANE-VU	**PA**	Portland	**3113**	2	0.00	0.00	0
MANE-VU	**PA**	Scrubgrass Generating Plant	**50974**	1	226.34	226.34	0
MANE-VU	**PA**	Scrubgrass Generating Plant	**50974**	2	242.52	242.52	0
MANE-VU	**PA**	Seward	**3130**	1	739.24	739.24	0

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RPO	St.	Facility Name	Orispl	Unit ID	Base	BOR	Difference
MANE-VU	**PA**	Seward	**3130**	2	673.06	673.06	0
MANE-VU	**PA**	Shawville	**3131**	1	126.85	126.85	0
MANE-VU	**PA**	Shawville	**3131**	2	126.09	126.09	0
MANE-VU	**PA**	Shawville	**3131**	3	198.67	198.67	0
MANE-VU	**PA**	Shawville	**3131**	4	227.60	227.60	0
MANE-VU	**PA**	St. Nicholas Cogeneration Project	**54634**	1	131.46	131.46	0
MANE-VU	**PA**	Sunbury	**3152**	1A	0.00	0.00	0
MANE-VU	**PA**	Sunbury	**3152**	1B	0.00	0.00	0
MANE-VU	**PA**	Sunbury	**3152**	2A	0.00	0.00	0
MANE-VU	**PA**	Sunbury	**3152**	2B	0.00	0.00	0
MANE-VU	**PA**	Sunbury	**3152**	3	0.00	0.00	0
MANE-VU	**PA**	Sunbury	**3152**	4	0.00	0.00	0
MANE-VU	**PA**	Titus	**3115**	1	0.00	0.00	0
MANE-VU	**PA**	Titus	**3115**	2	0.00	0.00	0
MANE-VU	**PA**	Titus	**3115**	3	0.00	0.00	0
MANE-VU	**PA**	Wheelabrator - Frackville	**50879**	GEN1	266.12	266.12	0
MANE-VU	**PA**	WPS Westwood Generation, LLC	**50611**	031	158.44	158.44	0
LADCO	**IL**	Baldwin Energy Complex	**889**	1	0.00	0.00	0
LADCO	**IL**	Baldwin Energy Complex	**889**	2	737.62	653.32	-84.3
LADCO	**IL**	Baldwin Energy Complex	**889**	3	0.00	0.00	0
LADCO	**IL**	Coffeen	**861**	01	321.14	321.14	0
LADCO	**IL**	Coffeen	**861**	02	451.35	451.35	0
LADCO	**IL**	Crawford	**867**	7	0.00	0.00	0
LADCO	**IL**	Crawford	**867**	8	0.00	0.00	0
LADCO	**IL**	Dallman	**963**	31	136.06	136.06	0
LADCO	**IL**	Dallman	**963**	32	102.69	102.69	0
LADCO	**IL**	Dallman	**963**	33	177.83	177.83	0
LADCO	**IL**	Dallman	**963**	4	137.19	137.19	0
LADCO	**IL**	Duck Creek	**6016**	1	611.44	611.44	0
LADCO	**IL**	E D Edwards	**856**	1	0.00	0.00	0
LADCO	**IL**	E D Edwards	**856**	2	1,180.33	1,180.33	0
LADCO	**IL**	E D Edwards	**856**	3	347.71	347.71	0
LADCO	**IL**	Fisk	**886**	19	0.00	0.00	0
LADCO	**IL**	Havana	**891**	9	619.47	619.47	0
LADCO	**IL**	Hennepin Power Station	**892**	1	225.82	225.82	0
LADCO	**IL**	Hennepin Power Station	**892**	2	731.62	731.62	0
LADCO	**IL**	Hutsonville	**863**	05	0.00	0.00	0
LADCO	**IL**	Hutsonville	**863**	06	0.00	0.00	0
LADCO	**IL**	Joppa Steam	**887**	1	507.48	507.48	0
LADCO	**IL**	Joppa Steam	**887**	2	374.69	374.69	0
LADCO	**IL**	Joppa Steam	**887**	3	444.14	444.14	0
LADCO	**IL**	Joppa Steam	**887**	4	454.62	454.62	0
LADCO	**IL**	Joppa Steam	**887**	5	469.43	469.43	0
LADCO	**IL**	Joppa Steam	**887**	6	471.17	471.17	0
LADCO	**IL**	Kincaid Station	**876**	1	648.72	565.41	-83.31
LADCO	**IL**	Kincaid Station	**876**	2	558.30	502.55	-55.75
LADCO	**IL**	Marion	**976**	123	259.12	259.12	0
LADCO	**IL**	Marion	**976**	4	751.29	427.70	-323.59
LADCO	**IL**	Meredosia	**864**	01	0.00	0.00	0
LADCO	**IL**	Meredosia	**864**	02	0.00	0.00	0
LADCO	**IL**	Meredosia	**864**	03	0.00	0.00	0
LADCO	**IL**	Meredosia	**864**	04	0.00	0.00	0
LADCO	**IL**	Meredosia	**864**	05	0.00	0.00	0
LADCO	**IL**	Newton	**6017**	1	1,080.51	1,080.51	0
LADCO	**IL**	Newton	**6017**	2	0.00	0.00	0
LADCO	**IL**	Powerton	**879**	51	993.41	980.85	-12.56
LADCO	**IL**	Powerton	**879**	52	982.20	971.35	-10.86
LADCO	**IL**	Powerton	**879**	61	1,117.32	1,082.17	-35.15
LADCO	**IL**	Powerton	**879**	62	1,137.40	1,017.11	-120.3
LADCO	**IL**	Prairie State Generating Company	**55856**	01	666.89	666.89	0

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RPO	St.	Facility Name	Orispl	Unit ID	Base	BOR	Difference
LADCO	**IL**	Prairie State Generating Company	**55856**	02	648.72	648.72	0
LADCO	**IL**	Vermilion Power Station	**897**	1	0.00	0.00	0
LADCO	**IL**	Vermilion Power Station	**897**	2	0.00	0.00	0
LADCO	**IL**	Waukegan	**883**	7	583.21	583.21	0
LADCO	**IL**	Waukegan	**883**	8	1,004.16	1,004.16	0
LADCO	**IL**	Will County	**884**	4	533.73	533.73	0
LADCO	**IL**	Wood River Power Station	**898**	4	0.00	0.00	0
LADCO	**IL**	Wood River Power Station	**898**	5	0.00	0.00	0
LADCO	**IN**	A B Brown Generating Station	**6137**	1	462.13	462.13	0
LADCO	**IN**	A B Brown Generating Station	**6137**	2	667.26	667.26	0
LADCO	**IN**	Alcoa Allowance Management Inc	**6705**	4	1,129.40	832.93	-296.47
LADCO	**IN**	Bailly Generating Station	**995**	7	0.00	0.00	0
LADCO	**IN**	Bailly Generating Station	**995**	8	0.00	0.00	0
LADCO	**IN**	Cayuga	**1001**	1	2,173.73	2,173.73	0
LADCO	**IN**	Cayuga	**1001**	2	2,598.35	2,598.35	0
LADCO	**IN**	Clifty Creek	**983**	1	459.99	366.47	-93.52
LADCO	**IN**	Clifty Creek	**983**	2	456.71	366.73	-89.98
LADCO	**IN**	Clifty Creek	**983**	3	463.41	371.46	-91.96
LADCO	**IN**	Clifty Creek	**983**	4	490.57	490.57	0
LADCO	**IN**	Clifty Creek	**983**	5	319.32	319.32	0
LADCO	**IN**	Clifty Creek	**983**	6	1,765.98	1,765.98	0
LADCO	**IN**	Edwardsport	**1004**	7-1	0.00	0.00	0
LADCO	**IN**	Edwardsport	**1004**	7-2	0.00	0.00	0
LADCO	**IN**	Edwardsport	**1004**	8-1	0.00	0.00	0
LADCO	**IN**	Edwardsport	**1004**	CTG1	530.82	530.82	0
LADCO	**IN**	Edwardsport	**1004**	CTG2	534.98	534.98	0
LADCO	**IN**	F B Culley Generating Station	**1012**	2	61.39	61.39	0
LADCO	**IN**	F B Culley Generating Station	**1012**	3	527.25	527.25	0
LADCO	**IN**	Frank E Ratts	**1043**	1SG1	0.00	0.00	0
LADCO	**IN**	Frank E Ratts	**1043**	2SG1	0.00	0.00	0
LADCO	**IN**	Gibson	**6113**	1	1,472.87	844.98	-627.89
LADCO	**IN**	Gibson	**6113**	2	1,207.84	739.41	-468.43
LADCO	**IN**	Gibson	**6113**	3	1,032.98	584.10	-448.88
LADCO	**IN**	Gibson	**6113**	4	1,876.50	1,193.31	-683.19
LADCO	**IN**	Gibson	**6113**	5	3,707.17	1,538.64	-2168.53
LADCO	**IN**	IPL Eagle Valley Generating Station	**991**	3	0.00	0.00	0
LADCO	**IN**	IPL Eagle Valley Generating Station	**991**	4	0.00	0.00	0
LADCO	**IN**	IPL Eagle Valley Generating Station	**991**	5	0.00	0.00	0
LADCO	**IN**	IPL Eagle Valley Generating Station	**991**	6	0.00	0.00	0
LADCO	**IN**	Merom	**6213**	1SG1	1,194.38	1,194.38	0
LADCO	**IN**	Merom	**6213**	2SG1	1,278.50	919.54	-358.96
LADCO	**IN**	Michigan City Generating Station	**997**	12	1,080.74	974.13	-106.61
LADCO	**IN**	New Energy Corp	**880087**	U-4000	0.00	0.00	0
LADCO	**IN**	Petersburg	**994**	1	1,088.79	1,088.79	0
LADCO	**IN**	Petersburg	**994**	2	1,481.84	837.58	-644.26
LADCO	**IN**	Petersburg	**994**	3	1,856.94	1,008.22	-848.72
LADCO	**IN**	Petersburg	**994**	4	2,515.96	2,515.96	0
LADCO	**IN**	R Gallagher	**1008**	1	0.00	0.00	0
LADCO	**IN**	R Gallagher	**1008**	2	0.00	0.00	0
LADCO	**IN**	R Gallagher	**1008**	3	0.00	0.00	0
LADCO	**IN**	R Gallagher	**1008**	4	0.00	0.00	0
LADCO	**IN**	R M Schahfer Generating Station	**6085**	14	757.49	611.71	-145.78
LADCO	**IN**	R M Schahfer Generating Station	**6085**	15	1,500.69	1,500.69	0
LADCO	**IN**	R M Schahfer Generating Station	**6085**	17	0.00	0.00	0
LADCO	**IN**	R M Schahfer Generating Station	**6085**	18	0.00	0.00	0
LADCO	**IN**	Rockport	**6166**	MB1	2,684.10	2,684.10	0
LADCO	**IN**	Rockport	**6166**	MB2	3,604.33	3,604.33	0
LADCO	**IN**	State Line Generating Station (IN)	**981**	3	0.00	0.00	0
LADCO	**IN**	State Line Generating Station (IN)	**981**	4	0.00	0.00	0
LADCO	**IN**	Tanners Creek	**988**	U1	0.00	0.00	0

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RPO	St.	Facility Name	Orispl	Unit ID	Base	BOR	Difference
LADCO	**IN**	Tanners Creek	**988**	U2	0.00	0.00	0
LADCO	**IN**	Tanners Creek	**988**	U3	0.00	0.00	0
LADCO	**IN**	Tanners Creek	**988**	U4	0.00	0.00	0
LADCO	**IN**	Wabash River	**1010**	2	0.00	0.00	0
LADCO	**IN**	Wabash River	**1010**	3	0.00	0.00	0
LADCO	**IN**	Wabash River	**1010**	4	0.00	0.00	0
LADCO	**IN**	Wabash River	**1010**	5	0.00	0.00	0
LADCO	**IN**	Wabash River	**1010**	6	0.00	0.00	0
LADCO	**IN**	Whitewater Valley	**1040**	1	84.75	84.75	0
LADCO	**IN**	Whitewater Valley	**1040**	2	168.58	168.58	0
LADCO	**MI**	B C Cobb	**1695**	4	0.00	0.00	0
LADCO	**MI**	B C Cobb	**1695**	5	0.00	0.00	0
LADCO	**MI**	Belle River	**6034**	1	1,722.52	1,722.52	0
LADCO	**MI**	Belle River	**6034**	2	3,564.30	3,564.30	0
LADCO	**MI**	Cadillac Renewable Energy	**54415**	EUBLR	135.04	135.04	0
LADCO	**MI**	Dan E Karn	**1702**	1	314.63	220.75	-93.89
LADCO	**MI**	Dan E Karn	**1702**	2	342.69	238.12	-104.57
LADCO	**MI**	Eckert Station	**1831**	1	0.00	0.00	0
LADCO	**MI**	Eckert Station	**1831**	2	0.00	0.00	0
LADCO	**MI**	Eckert Station	**1831**	3	0.00	0.00	0
LADCO	**MI**	Eckert Station	**1831**	4	0.00	0.00	0
LADCO	**MI**	Eckert Station	**1831**	5	0.00	0.00	0
LADCO	**MI**	Eckert Station	**1831**	6	0.00	0.00	0
LADCO	**MI**	Endicott Generating	**4259**	1	0.00	0.00	0
LADCO	**MI**	Erickson	**1832**	1	755.04	755.04	0
LADCO	**MI**	Genesee Power Station	**54751**	01	76.58	76.58	0
LADCO	**MI**	Grayling Generating Station	**10822**	1	137.56	137.56	0
LADCO	**MI**	Harbor Beach	**1731**	1	0.00	0.00	0
LADCO	**MI**	J B Sims	**1825**	3	235.09	235.09	0
LADCO	**MI**	J C Weadock	**1720**	7	0.00	0.00	0
LADCO	**MI**	J C Weadock	**1720**	8	0.00	0.00	0
LADCO	**MI**	J H Campbell	**1710**	1	636.33	636.33	0
LADCO	**MI**	J H Campbell	**1710**	2	331.71	151.76	-179.95
LADCO	**MI**	J H Campbell	**1710**	3	1,453.42	977.64	-475.78
LADCO	**MI**	J R Whiting	**1723**	1	0.00	0.00	0
LADCO	**MI**	J R Whiting	**1723**	2	0.00	0.00	0
LADCO	**MI**	J R Whiting	**1723**	3	0.00	0.00	0
LADCO	**MI**	James De Young	**1830**	5	0.00	0.00	0
LADCO	**MI**	Monroe	**1733**	1	1,174.93	768.33	-406.6
LADCO	**MI**	Monroe	**1733**	2	1,043.18	1,043.18	0
LADCO	**MI**	Monroe	**1733**	3	590.40	512.56	-77.84
LADCO	**MI**	Monroe	**1733**	4	1,194.84	737.58	-457.26
LADCO	**MI**	Presque Isle	**1769**	5	0.00	0.00	0
LADCO	**MI**	Presque Isle	**1769**	6	0.00	0.00	0
LADCO	**MI**	Presque Isle	**1769**	7	0.00	0.00	0
LADCO	**MI**	Presque Isle	**1769**	8	0.00	0.00	0
LADCO	**MI**	Presque Isle	**1769**	9	0.00	0.00	0
LADCO	**MI**	River Rouge	**1740**	2	0.00	0.00	0
LADCO	**MI**	River Rouge	**1740**	3	0.00	0.00	0
LADCO	**MI**	Shiras	**1843**	3	163.18	163.18	0
LADCO	**MI**	St. Clair	**1743**	1	0.00	0.00	0
LADCO	**MI**	St. Clair	**1743**	2	0.00	0.00	0
LADCO	**MI**	St. Clair	**1743**	3	0.00	0.00	0
LADCO	**MI**	St. Clair	**1743**	4	0.00	0.00	0
LADCO	**MI**	St. Clair	**1743**	6	0.00	0.00	0
LADCO	**MI**	St. Clair	**1743**	7	0.00	0.00	0
LADCO	**MI**	TES Filer City Station	**50835**	1	339.06	339.06	0
LADCO	**MI**	TES Filer City Station	**50835**	2	328.21	328.21	0
LADCO	**MI**	Trenton Channel	**1745**	16	0.00	0.00	0
LADCO	**MI**	Trenton Channel	**1745**	17	0.00	0.00	0

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RPO	St.	Facility Name	Orispl	Unit ID	Base	BOR	Difference
LADCO	**MI**	Trenton Channel	**1745**	18	0.00	0.00	0
LADCO	**MI**	Trenton Channel	**1745**	19	0.00	0.00	0
LADCO	**MI**	Trenton Channel	**1745**	9A	0.00	0.00	0
LADCO	**MI**	Wyandotte	**1866**	7	90.20	90.20	0
LADCO	**MI**	Wyandotte	**1866**	8	123.15	123.15	0
LADCO	**MN**	Allen S King	**1915**	1	842.90	842.90	0
LADCO	**MN**	Black Dog	**1904**	3	0.00	0.00	0
LADCO	**MN**	Black Dog	**1904**	4	0.00	0.00	0
LADCO	**MN**	Boswell Energy Center	**1893**	1	0.00	0.00	0
LADCO	**MN**	Boswell Energy Center	**1893**	2	0.00	0.00	0
LADCO	**MN**	Boswell Energy Center	**1893**	3	446.71	446.71	0
LADCO	**MN**	Boswell Energy Center	**1893**	4	1,927.28	1,927.28	0
LADCO	**MN**	Hoot Lake	**1943**	2	0.00	0.00	0
LADCO	**MN**	Hoot Lake	**1943**	3	0.00	0.00	0
LADCO	**MN**	Northeast Station	**1961**	NEPP	0.00	0.00	0
LADCO	**MN**	Sherburne County	**6090**	1	0.00	0.00	0
LADCO	**MN**	Sherburne County	**6090**	2	0.00	0.00	0
LADCO	**MN**	Sherburne County	**6090**	3	1,490.50	1,490.50	0
LADCO	**MN**	Silver Lake	**2008**	4	0.00	0.00	0
LADCO	**MN**	Taconite Harbor Energy Center	**10075**	1	0.00	0.00	0
LADCO	**MN**	Taconite Harbor Energy Center	**10075**	2	0.00	0.00	0
LADCO	**MN**	Taconite Harbor Energy Center	**10075**	3	0.00	0.00	0
LADCO	**OH**	Ashtabula	**2835**	7	0.00	0.00	0
LADCO	**OH**	Avon Lake Power Plant	**2836**	10	6.48	6.48	0
LADCO	**OH**	Avon Lake Power Plant	**2836**	12	2,731.97	1,881.95	-850.02
LADCO	**OH**	Bay Shore	**2878**	1	566.74	566.74	0
LADCO	**OH**	Bay Shore	**2878**	2	0.00	0.00	0
LADCO	**OH**	Bay Shore	**2878**	3	0.00	0.00	0
LADCO	**OH**	Bay Shore	**2878**	4	0.00	0.00	0
LADCO	**OH**	Cardinal	**2828**	1	365.03	251.40	-113.63
LADCO	**OH**	Cardinal	**2828**	2	101.28	99.48	-1.81
LADCO	**OH**	Cardinal	**2828**	3	581.27	222.04	-359.23
LADCO	**OH**	Conesville	**2840**	3	0.00	0.00	0
LADCO	**OH**	Conesville	**2840**	4	676.83	540.88	-135.95
LADCO	**OH**	Conesville	**2840**	5	2,077.04	2,077.04	0
LADCO	**OH**	Conesville	**2840**	6	2,814.95	2,814.95	0
LADCO	**OH**	Eastlake	**2837**	1	0.00	0.00	0
LADCO	**OH**	Eastlake	**2837**	2	0.00	0.00	0
LADCO	**OH**	Eastlake	**2837**	3	0.00	0.00	0
LADCO	**OH**	Eastlake	**2837**	4	0.00	0.00	0
LADCO	**OH**	Eastlake	**2837**	5	0.00	0.00	0
LADCO	**OH**	Gen J M Gavin	**8102**	1	2,464.79	2,259.45	-205.34
LADCO	**OH**	Gen J M Gavin	**8102**	2	2,584.35	2,150.81	-433.53
LADCO	**OH**	Hamilton Municipal Power Plant	**2917**	9	3.90	3.90	0
LADCO	**OH**	J M Stuart	**2850**	1	0.00	0.00	0
LADCO	**OH**	J M Stuart	**2850**	2	0.00	0.00	0
LADCO	**OH**	J M Stuart	**2850**	3	0.00	0.00	0
LADCO	**OH**	J M Stuart	**2850**	4	0.00	0.00	0
LADCO	**OH**	Killen Station	**6031**	2	0.00	0.00	0
LADCO	**OH**	Kyger Creek	**2876**	1	831.43	497.83	-333.6
LADCO	**OH**	Kyger Creek	**2876**	2	821.61	493.75	-327.87
LADCO	**OH**	Kyger Creek	**2876**	3	2,734.85	969.08	-1765.77
LADCO	**OH**	Kyger Creek	**2876**	4	673.73	380.07	-293.66
LADCO	**OH**	Kyger Creek	**2876**	5	2,967.21	1,069.77	-1897.44
LADCO	**OH**	Lake Shore	**2838**	18	0.00	0.00	0
LADCO	**OH**	Miami Fort Generating Station	**2832**	6	0.00	0.00	0
LADCO	**OH**	Miami Fort Generating Station	**2832**	7	2,016.79	1,082.82	-933.97
LADCO	**OH**	Miami Fort Generating Station	**2832**	8	1,552.08	921.27	-630.81
LADCO	**OH**	Muskingum River	**2872**	1	0.00	0.00	0
LADCO	**OH**	Muskingum River	**2872**	2	0.00	0.00	0

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RPO	St.	Facility Name	Orispl	Unit ID	Base	BOR	Difference
LADCO	**OH**	Muskingum River	**2872**	3	0.00	0.00	0
LADCO	**OH**	Muskingum River	**2872**	4	0.00	0.00	0
LADCO	**OH**	Muskingum River	**2872**	5	0.00	0.00	0
LADCO	**OH**	Niles	**2861**	1	0.00	0.00	0
LADCO	**OH**	Niles	**2861**	2	0.00	0.00	0
LADCO	**OH**	O H Hutchings	**2848**	H-1	0.00	0.00	0
LADCO	**OH**	O H Hutchings	**2848**	H-2	0.00	0.00	0
LADCO	**OH**	O H Hutchings	**2848**	H-3	0.00	0.00	0
LADCO	**OH**	O H Hutchings	**2848**	H-4	0.00	0.00	0
LADCO	**OH**	O H Hutchings	**2848**	H-5	0.00	0.00	0
LADCO	**OH**	O H Hutchings	**2848**	H-6	0.00	0.00	0
LADCO	**OH**	Picway	**2843**	9	0.00	0.00	0
LADCO	**OH**	R E Burger	**2864**	5	0.00	0.00	0
LADCO	**OH**	R E Burger	**2864**	6	0.00	0.00	0
LADCO	**OH**	W H Sammis	**2866**	1	0.00	0.00	0
LADCO	**OH**	W H Sammis	**2866**	2	0.00	0.00	0
LADCO	**OH**	W H Sammis	**2866**	3	0.00	0.00	0
LADCO	**OH**	W H Sammis	**2866**	4	0.00	0.00	0
LADCO	**OH**	W H Sammis	**2866**	5	515.73	393.68	-122.06
LADCO	**OH**	W H Sammis	**2866**	6	411.49	411.49	0
LADCO	**OH**	W H Sammis	**2866**	7	1,493.46	1,357.04	-136.43
LADCO	**OH**	W H Zimmer Generating Station	**6019**	1	5,798.18	2,060.79	-3737.39
LADCO	**OH**	Walter C Beckjord Generating Station	**2830**	1	0.00	0.00	0
LADCO	**OH**	Walter C Beckjord Generating Station	**2830**	2	0.00	0.00	0
LADCO	**OH**	Walter C Beckjord Generating Station	**2830**	3	0.00	0.00	0
LADCO	**OH**	Walter C Beckjord Generating Station	**2830**	4	0.00	0.00	0
LADCO	**OH**	Walter C Beckjord Generating Station	**2830**	5	0.00	0.00	0
LADCO	**OH**	Walter C Beckjord Generating Station	**2830**	6	0.00	0.00	0
LADCO	**WI**	Alma	**4140**	B4	0.00	0.00	0
LADCO	**WI**	Alma	**4140**	B5	0.00	0.00	0
LADCO	**WI**	Bay Front	**3982**	1	64.30	64.30	0
LADCO	**WI**	Bay Front	**3982**	2	66.57	66.57	0
LADCO	**WI**	Blount Street	**3992**	7	0.00	0.00	0
LADCO	**WI**	Columbia	**8023**	1	1,151.23	1,151.23	0
LADCO	**WI**	Columbia	**8023**	2	694.36	694.36	0
LADCO	**WI**	Edgewater (4050)	**4050**	3	0.00	0.00	0
LADCO	**WI**	Edgewater (4050)	**4050**	5	351.29	261.46	-89.83
LADCO	**WI**	Elm Road Generating Station	**56068**	1	298.11	298.11	0
LADCO	**WI**	Elm Road Generating Station	**56068**	2	482.73	482.73	0
LADCO	**WI**	Genoa	**4143**	1	336.69	336.69	0
LADCO	**WI**	J P Madgett	**4271**	B1	463.11	463.11	0
LADCO	**WI**	Manitowoc	**4125**	8	14.77	14.77	0
LADCO	**WI**	Manitowoc	**4125**	9	87.07	87.07	0
LADCO	**WI**	Nelson Dewey	**4054**	1	0.00	0.00	0
LADCO	**WI**	Nelson Dewey	**4054**	2	0.00	0.00	0
LADCO	**WI**	Pleasant Prairie	**6170**	1	1,084.01	1,084.01	0
LADCO	**WI**	Pleasant Prairie	**6170**	2	653.60	653.60	0
LADCO	**WI**	Pulliam	**4072**	5	0.00	0.00	0
LADCO	**WI**	Pulliam	**4072**	6	0.00	0.00	0
LADCO	**WI**	Pulliam	**4072**	7	170.88	170.88	0
LADCO	**WI**	Pulliam	**4072**	8	433.42	433.42	0
LADCO	**WI**	South Oak Creek	**4041**	5	309.21	309.21	0
LADCO	**WI**	South Oak Creek	**4041**	6	295.56	295.56	0
LADCO	**WI**	South Oak Creek	**4041**	7	351.32	343.58	-7.74
LADCO	**WI**	South Oak Creek	**4041**	8	440.28	432.99	-7.29
LADCO	**WI**	Weston	**4078**	1	0.00	0.00	0
LADCO	**WI**	Weston	**4078**	3	559.48	559.48	0
LADCO	**WI**	Weston	**4078**	4	527.84	527.84	0
SESARM	**AL**	Barry	**3**	3	0.00	0.00	0
SESARM	**AL**	Barry	**3**	4	548.04	548.04	0

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RPO	St.	Facility Name	Orispl	Unit ID	Base	BOR	Difference
SESARM	**AL**	Barry	**3**	5	389.58	389.58	0
SESARM	**AL**	Charles R Lowman	**56**	1	266.75	266.75	0
SESARM	**AL**	Charles R Lowman	**56**	2	1,560.89	1,560.89	0
SESARM	**AL**	Charles R Lowman	**56**	3	346.75	346.75	0
SESARM	**AL**	Colbert	**47**	1	0.00	0.00	0
SESARM	**AL**	Colbert	**47**	2	0.00	0.00	0
SESARM	**AL**	Colbert	**47**	3	0.00	0.00	0
SESARM	**AL**	Colbert	**47**	4	0.00	0.00	0
SESARM	**AL**	Colbert	**47**	5	0.00	0.00	0
SESARM	**AL**	E C Gaston	**26**	5	1,727.18	1,213.71	-513.47
SESARM	**AL**	Gorgas	**8**	10	1,892.99	1,892.99	0
SESARM	**AL**	Gorgas	**8**	6	0.00	0.00	0
SESARM	**AL**	Gorgas	**8**	7	0.00	0.00	0
SESARM	**AL**	Gorgas	**8**	8	379.03	379.03	0
SESARM	**AL**	Gorgas	**8**	9	518.57	518.57	0
SESARM	**AL**	James H Miller Jr	**6002**	1	1,620.08	1,620.08	0
SESARM	**AL**	James H Miller Jr	**6002**	2	2,362.07	2,362.07	0
SESARM	**AL**	James H Miller Jr	**6002**	3	2,513.13	2,513.13	0
SESARM	**AL**	James H Miller Jr	**6002**	4	1,372.00	1,372.00	0
SESARM	**AL**	Widows Creek	**50**	1	0.00	0.00	0
SESARM	**AL**	Widows Creek	**50**	2	0.00	0.00	0
SESARM	**AL**	Widows Creek	**50**	3	0.00	0.00	0
SESARM	**AL**	Widows Creek	**50**	4	0.00	0.00	0
SESARM	**AL**	Widows Creek	**50**	5	0.00	0.00	0
SESARM	**AL**	Widows Creek	**50**	6	0.00	0.00	0
SESARM	**AL**	Widows Creek	**50**	7	0.00	0.00	0
SESARM	**AL**	Widows Creek	**50**	8	0.00	0.00	0
SESARM	**FL**	Big Bend	**645**	BB01	729.03	729.03	0
SESARM	**FL**	Big Bend	**645**	BB02	315.63	315.63	0
SESARM	**FL**	Big Bend	**645**	BB03	736.65	736.65	0
SESARM	**FL**	Big Bend	**645**	BB04	731.36	731.36	0
SESARM	**FL**	C D McIntosh Jr Power Plant	**676**	3	593.71	593.71	0
SESARM	**FL**	Cedar Bay Generating Co.	**10672**	CBA	0.00	0.00	0
SESARM	**FL**	Cedar Bay Generating Co.	**10672**	CBB	0.00	0.00	0
SESARM	**FL**	Cedar Bay Generating Co.	**10672**	CBC	0.00	0.00	0
SESARM	**FL**	Crist Electric Generating Plant	**641**	4	0.00	0.00	0
SESARM	**FL**	Crist Electric Generating Plant	**641**	5	0.00	0.00	0
SESARM	**FL**	Crist Electric Generating Plant	**641**	6	192.60	192.60	0
SESARM	**FL**	Crist Electric Generating Plant	**641**	7	1,242.66	1,242.66	0
SESARM	**FL**	Crystal River	**628**	1	0.00	0.00	0
SESARM	**FL**	Crystal River	**628**	2	0.00	0.00	0
SESARM	**FL**	Crystal River	**628**	4	522.10	522.10	0
SESARM	**FL**	Crystal River	**628**	5	675.09	675.09	0
SESARM	**FL**	Curtis H. Stanton Energy Center	**564**	1	1,531.30	1,531.30	0
SESARM	**FL**	Curtis H. Stanton Energy Center	**564**	2	1,128.11	1,128.11	0
SESARM	**FL**	Deerhaven	**663**	B2	160.85	160.85	0
SESARM	**FL**	Indiantown Cogeneration Facility	**50976**	01	528.35	528.35	0
SESARM	**FL**	Lansing Smith Generating Plant	**643**	1	0.00	0.00	0
SESARM	**FL**	Lansing Smith Generating Plant	**643**	2	0.00	0.00	0
SESARM	**FL**	Northside	**667**	1A	120.73	120.73	0
SESARM	**FL**	Northside	**667**	2A	190.12	190.12	0
SESARM	**FL**	Polk	**7242**	**1	218.08	218.08	0
SESARM	**FL**	Scholz Electric Generating Plant	**642**	1	0.00	0.00	0
SESARM	**FL**	Scholz Electric Generating Plant	**642**	2	0.00	0.00	0
SESARM	**FL**	Seminole (136)	**136**	1	614.96	614.96	0
SESARM	**FL**	Seminole (136)	**136**	2	622.70	622.70	0
SESARM	**FL**	St. Johns River Power	**207**	1	0.00	0.00	0
SESARM	**FL**	St. Johns River Power	**207**	2	0.00	0.00	0
SESARM	**GA**	Bowen	**703**	1BLR	2,128.78	1,104.38	-1024.41
SESARM	**GA**	Bowen	**703**	2BLR	1,365.23	867.92	-497.32

Impact of Wintertime SCR/SNRC Optimization on Visibility Impairing Nitrate Precursor Emissions

RPO	St.	Facility Name	Orispl	Unit ID	Base	BOR	Difference
SESARM	**GA**	Bowen	**703**	3BLR	960.53	594.27	-366.26
SESARM	**GA**	Bowen	**703**	4BLR	1,301.04	671.24	-629.8
SESARM	**GA**	Hammond	**708**	1	142.46	142.46	0
SESARM	**GA**	Hammond	**708**	2	220.14	220.14	0
SESARM	**GA**	Hammond	**708**	3	143.18	143.18	0
SESARM	**GA**	Hammond	**708**	4	1,146.75	1,146.75	0
SESARM	**GA**	Harllee Branch	**709**	1	0.00	0.00	0
SESARM	**GA**	Harllee Branch	**709**	2	0.00	0.00	0
SESARM	**GA**	Harllee Branch	**709**	3	0.00	0.00	0
SESARM	**GA**	Harllee Branch	**709**	4	0.00	0.00	0
SESARM	**GA**	Jack McDonough	**710**	MB1	0.00	0.00	0
SESARM	**GA**	Jack McDonough	**710**	MB2	0.00	0.00	0
SESARM	**GA**	Kraft	**733**	1	0.00	0.00	0
SESARM	**GA**	Kraft	**733**	2	0.00	0.00	0
SESARM	**GA**	Kraft	**733**	3	0.00	0.00	0
SESARM	**GA**	McIntosh (6124)	**6124**	1	61.18	61.18	0
SESARM	**GA**	Mitchell (GA)	**727**	3	0.00	0.00	0
SESARM	**GA**	Scherer	**6257**	1	2,233.25	809.96	-1423.29
SESARM	**GA**	Scherer	**6257**	2	2,316.44	1,429.08	-887.37
SESARM	**GA**	Scherer	**6257**	3	4,010.14	4,010.14	0
SESARM	**GA**	Scherer	**6257**	4	3,743.59	1,842.06	-1901.54
SESARM	**GA**	Wansley (6052)	**6052**	1	779.43	779.43	0
SESARM	**GA**	Wansley (6052)	**6052**	2	457.62	457.62	0
SESARM	**GA**	Yates	**728**	Y1BR	0.00	0.00	0
SESARM	**GA**	Yates	**728**	Y2BR	0.00	0.00	0
SESARM	**GA**	Yates	**728**	Y3BR	0.00	0.00	0
SESARM	**GA**	Yates	**728**	Y4BR	0.00	0.00	0
SESARM	**GA**	Yates	**728**	Y5BR	0.00	0.00	0
SESARM	**KY**	Big Sandy	**1353**	BSU2	0.00	0.00	0
SESARM	**KY**	Cane Run	**1363**	4	0.00	0.00	0
SESARM	**KY**	Cane Run	**1363**	5	0.00	0.00	0
SESARM	**KY**	Cane Run	**1363**	6	0.00	0.00	0
SESARM	**KY**	Coleman	**1381**	C1	0.00	0.00	0
SESARM	**KY**	Coleman	**1381**	C2	0.00	0.00	0
SESARM	**KY**	Coleman	**1381**	C3	0.00	0.00	0
SESARM	**KY**	D B Wilson	**6823**	W1	730.79	576.71	-154.07
SESARM	**KY**	E W Brown	**1355**	1	404.86	404.86	0
SESARM	**KY**	E W Brown	**1355**	2	709.79	709.79	0
SESARM	**KY**	E W Brown	**1355**	3	336.91	336.91	0
SESARM	**KY**	East Bend	**6018**	2	1,900.01	1,168.54	-731.47
SESARM	**KY**	Elmer Smith	**1374**	1	0.00	0.00	0
SESARM	**KY**	Elmer Smith	**1374**	2	0.00	0.00	0
SESARM	**KY**	Ghent	**1356**	1	985.80	696.23	-289.57
SESARM	**KY**	Ghent	**1356**	2	2,078.51	2,078.51	0
SESARM	**KY**	Ghent	**1356**	3	1,362.77	685.59	-677.18
SESARM	**KY**	Ghent	**1356**	4	746.53	400.64	-345.9
SESARM	**KY**	Green River	**1357**	4	0.00	0.00	0
SESARM	**KY**	Green River	**1357**	5	0.00	0.00	0
SESARM	**KY**	H L Spurlock	**6041**	1	495.17	453.13	-42.04
SESARM	**KY**	H L Spurlock	**6041**	2	972.64	904.88	-67.76
SESARM	**KY**	H L Spurlock	**6041**	3	436.73	436.73	0
SESARM	**KY**	H L Spurlock	**6041**	4	440.94	440.94	0
SESARM	**KY**	HMP&L Station 2	**1382**	H1	307.74	307.74	0
SESARM	**KY**	HMP&L Station 2	**1382**	H2	303.49	303.49	0
SESARM	**KY**	John S. Cooper	**1384**	1	883.13	883.13	0
SESARM	**KY**	John S. Cooper	**1384**	2	173.66	173.66	0
SESARM	**KY**	Mill Creek	**1364**	1	2,059.20	2,059.20	0
SESARM	**KY**	Mill Creek	**1364**	2	2,189.94	2,189.94	0
SESARM	**KY**	Mill Creek	**1364**	3	374.33	337.71	-36.62
SESARM	**KY**	Mill Creek	**1364**	4	1,152.91	670.94	-481.96

Impact of Wintertime SCR/SNRC Optimization on Visibility Impairing Nitrate Precursor Emissions

RPO	St.	Facility Name	Orispl	Unit ID	Base	BOR	Difference
SESARM	**KY**	Paradise	**1378**	1	0.00	0.00	0
SESARM	**KY**	Paradise	**1378**	2	0.00	0.00	0
SESARM	**KY**	Paradise	**1378**	3	2,227.15	1,600.97	-626.17
SESARM	**KY**	R D Green	**6639**	G1	1,391.02	1,391.02	0
SESARM	**KY**	R D Green	**6639**	G2	1,224.61	1,224.61	0
SESARM	**KY**	Robert Reid	**1383**	R1	0.00	0.00	0
SESARM	**KY**	Shawnee	**1379**	1	116.82	116.82	0
SESARM	**KY**	Shawnee	**1379**	10	0.00	0.00	0
SESARM	**KY**	Shawnee	**1379**	2	1,181.67	1,181.67	0
SESARM	**KY**	Shawnee	**1379**	3	1,181.41	1,181.41	0
SESARM	**KY**	Shawnee	**1379**	4	115.42	115.42	0
SESARM	**KY**	Shawnee	**1379**	5	1,313.23	1,313.23	0
SESARM	**KY**	Shawnee	**1379**	6	931.73	931.73	0
SESARM	**KY**	Shawnee	**1379**	7	1,007.34	1,007.34	0
SESARM	**KY**	Shawnee	**1379**	8	987.06	987.06	0
SESARM	**KY**	Shawnee	**1379**	9	882.42	882.42	0
SESARM	**KY**	Trimble County	**6071**	1	725.31	725.31	0
SESARM	**KY**	Trimble County	**6071**	2	633.49	633.49	0
SESARM	**KY**	Tyrone	**1361**	5	0.00	0.00	0
SESARM	**KY**	William C. Dale	**1385**	1	0.00	0.00	0
SESARM	**KY**	William C. Dale	**1385**	2	0.00	0.00	0
SESARM	**KY**	William C. Dale	**1385**	3	0.00	0.00	0
SESARM	**KY**	William C. Dale	**1385**	4	0.00	0.00	0
SESARM	**MS**	Daniel Electric Generating Plant	**6073**	1	984.49	984.49	0
SESARM	**MS**	Daniel Electric Generating Plant	**6073**	2	377.10	377.10	0
SESARM	**MS**	R D Morrow Senior Generating Plant	**6061**	1	848.49	848.49	0
SESARM	**MS**	R D Morrow Senior Generating Plant	**6061**	2	1,170.65	1,170.65	0
SESARM	**MS**	Red Hills Generation Facility	**55076**	AA001	560.95	560.95	0
SESARM	**MS**	Red Hills Generation Facility	**55076**	AA002	738.52	738.52	0
SESARM	**NC**	Asheville	**2706**	1	0.00	0.00	0
SESARM	**NC**	Asheville	**2706**	2	0.00	0.00	0
SESARM	**NC**	Belews Creek	**8042**	1	1,343.74	1,343.74	0
SESARM	**NC**	Belews Creek	**8042**	2	1,380.02	770.66	-609.36
SESARM	**NC**	Buck	**2720**	5	0.00	0.00	0
SESARM	**NC**	Buck	**2720**	6	0.00	0.00	0
SESARM	**NC**	Buck	**2720**	7	0.00	0.00	0
SESARM	**NC**	Buck	**2720**	8	0.00	0.00	0
SESARM	**NC**	Buck	**2720**	9	0.00	0.00	0
SESARM	**NC**	Cape Fear	**2708**	5	0.00	0.00	0
SESARM	**NC**	Cape Fear	**2708**	6	0.00	0.00	0
SESARM	**NC**	Cliffside	**2721**	1	0.00	0.00	0
SESARM	**NC**	Cliffside	**2721**	2	0.00	0.00	0
SESARM	**NC**	Cliffside	**2721**	3	0.00	0.00	0
SESARM	**NC**	Cliffside	**2721**	4	0.00	0.00	0
SESARM	**NC**	Cliffside	**2721**	5	249.50	90.73	-158.77
SESARM	**NC**	Cliffside	**2721**	6	698.96	698.96	0
SESARM	**NC**	Dan River	**2723**	1	0.00	0.00	0
SESARM	**NC**	Dan River	**2723**	2	0.00	0.00	0
SESARM	**NC**	Dan River	**2723**	3	0.00	0.00	0
SESARM	**NC**	Elizabethtown Power	**10380**	UNIT1	0.00	0.00	0
SESARM	**NC**	Elizabethtown Power	**10380**	UNIT2	0.00	0.00	0
SESARM	**NC**	G G Allen	**2718**	1	0.00	0.00	0
SESARM	**NC**	G G Allen	**2718**	2	0.00	0.00	0
SESARM	**NC**	G G Allen	**2718**	3	0.00	0.00	0
SESARM	**NC**	G G Allen	**2718**	4	176.36	176.36	0
SESARM	**NC**	G G Allen	**2718**	5	157.85	157.85	0
SESARM	**NC**	H F Lee Steam Electric Plant	**2709**	1	0.00	0.00	0
SESARM	**NC**	H F Lee Steam Electric Plant	**2709**	2	0.00	0.00	0
SESARM	**NC**	H F Lee Steam Electric Plant	**2709**	3	0.00	0.00	0
SESARM	**NC**	L V Sutton	**2713**	1	0.00	0.00	0

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RPO	St.	Facility Name	Orispl	Unit ID	Base	BOR	Difference
SESARM	**NC**	L V Sutton	**2713**	2	0.00	0.00	0
SESARM	**NC**	L V Sutton	**2713**	3	0.00	0.00	0
SESARM	**NC**	Lumberton Power	**10382**	UNIT1	0.00	0.00	0
SESARM	**NC**	Lumberton Power	**10382**	UNIT2	0.00	0.00	0
SESARM	**NC**	Marshall	**2727**	1	426.84	327.46	-99.38
SESARM	**NC**	Marshall	**2727**	2	662.70	530.22	-132.49
SESARM	**NC**	Marshall	**2727**	3	834.09	546.09	-288
SESARM	**NC**	Marshall	**2727**	4	1,707.68	1,366.79	-340.89
SESARM	**NC**	Mayo	**6250**	1A	357.36	186.40	-170.95
SESARM	**NC**	Mayo	**6250**	1B	323.74	167.64	-156.1
SESARM	**NC**	Riverbend	**2732**	10	0.00	0.00	0
SESARM	**NC**	Riverbend	**2732**	7	0.00	0.00	0
SESARM	**NC**	Riverbend	**2732**	8	0.00	0.00	0
SESARM	**NC**	Riverbend	**2732**	9	0.00	0.00	0
SESARM	**NC**	Roxboro	**2712**	1	398.83	235.36	-163.48
SESARM	**NC**	Roxboro	**2712**	2	570.97	416.97	-154
SESARM	**NC**	Roxboro	**2712**	3A	393.88	211.22	-182.67
SESARM	**NC**	Roxboro	**2712**	3B	368.67	195.42	-173.24
SESARM	**NC**	Roxboro	**2712**	4A	309.60	211.16	-98.44
SESARM	**NC**	Roxboro	**2712**	4B	279.95	189.31	-90.64
SESARM	**NC**	W H Weatherspoon	**2716**	1	0.00	0.00	0
SESARM	**NC**	W H Weatherspoon	**2716**	2	0.00	0.00	0
SESARM	**NC**	W H Weatherspoon	**2716**	3	0.00	0.00	0
SESARM	**NC**	Westmoreland Partners Roanoke Valley II	**54755**	2	45.55	45.55	0
SESARM	**NC**	Westmoreland-LG&E Roanoke Valley I	**54035**	1	217.14	217.14	0
SESARM	**SC**	Canadys Steam	**3280**	CAN1	0.00	0.00	0
SESARM	**SC**	Canadys Steam	**3280**	CAN2	0.00	0.00	0
SESARM	**SC**	Canadys Steam	**3280**	CAN3	0.00	0.00	0
SESARM	**SC**	Cope Station	**7210**	COP1	295.14	295.14	0
SESARM	**SC**	Cross	**130**	1	868.88	868.88	0
SESARM	**SC**	Cross	**130**	2	0.00	0.00	0
SESARM	**SC**	Cross	**130**	3	390.09	390.09	0
SESARM	**SC**	Cross	**130**	4	367.77	367.77	0
SESARM	**SC**	Dolphus M Grainger	**3317**	1	0.00	0.00	0
SESARM	**SC**	Dolphus M Grainger	**3317**	2	0.00	0.00	0
SESARM	**SC**	H B Robinson	**3251**	1	0.00	0.00	0
SESARM	**SC**	Jefferies	**3319**	3	0.00	0.00	0
SESARM	**SC**	Jefferies	**3319**	4	0.00	0.00	0
SESARM	**SC**	W S Lee	**3264**	1	0.00	0.00	0
SESARM	**SC**	W S Lee	**3264**	2	0.00	0.00	0
SESARM	**SC**	Wateree	**3297**	WAT1	306.91	184.37	-122.54
SESARM	**SC**	Wateree	**3297**	WAT2	297.80	190.26	-107.54
SESARM	**SC**	Williams	**3298**	WIL1	418.33	205.25	-213.09
SESARM	**SC**	Winyah	**6249**	1	215.45	155.75	-59.69
SESARM	**SC**	Winyah	**6249**	2	185.63	129.88	-55.75
SESARM	**SC**	Winyah	**6249**	3	181.78	156.98	-24.8
SESARM	**SC**	Winyah	**6249**	4	224.99	190.11	-34.88
SESARM	**TN**	Allen	**3393**	1	0.00	0.00	0
SESARM	**TN**	Allen	**3393**	2	0.00	0.00	0
SESARM	**TN**	Allen	**3393**	3	0.00	0.00	0
SESARM	**TN**	Bull Run	**3396**	1	174.44	174.44	0
SESARM	**TN**	Cumberland	**3399**	1	977.10	931.44	-45.66
SESARM	**TN**	Cumberland	**3399**	2	1,802.96	1,802.96	0
SESARM	**TN**	Gallatin	**3403**	1	166.83	166.83	0
SESARM	**TN**	Gallatin	**3403**	2	163.78	163.78	0
SESARM	**TN**	Gallatin	**3403**	3	199.77	199.77	0
SESARM	**TN**	Gallatin	**3403**	4	201.21	201.21	0
SESARM	**TN**	John Sevier	**3405**	1	0.00	0.00	0
SESARM	**TN**	John Sevier	**3405**	2	0.00	0.00	0
SESARM	**TN**	John Sevier	**3405**	3	0.00	0.00	0

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RPO	St.	Facility Name	Orispl	Unit ID	Base	BOR	Difference
SESARM	**TN**	John Sevier	**3405**	4	0.00	0.00	0
SESARM	**TN**	Johnsonville	**3406**	1	0.00	0.00	0
SESARM	**TN**	Johnsonville	**3406**	10	0.00	0.00	0
SESARM	**TN**	Johnsonville	**3406**	2	0.00	0.00	0
SESARM	**TN**	Johnsonville	**3406**	3	0.00	0.00	0
SESARM	**TN**	Johnsonville	**3406**	4	0.00	0.00	0
SESARM	**TN**	Johnsonville	**3406**	5	0.00	0.00	0
SESARM	**TN**	Johnsonville	**3406**	6	0.00	0.00	0
SESARM	**TN**	Johnsonville	**3406**	7	0.00	0.00	0
SESARM	**TN**	Johnsonville	**3406**	8	0.00	0.00	0
SESARM	**TN**	Johnsonville	**3406**	9	0.00	0.00	0
SESARM	**TN**	Kingston	**3407**	1	118.81	86.41	-32.4
SESARM	**TN**	Kingston	**3407**	2	50.75	41.21	-9.54
SESARM	**TN**	Kingston	**3407**	3	114.09	84.22	-29.86
SESARM	**TN**	Kingston	**3407**	4	112.40	88.25	-24.15
SESARM	**TN**	Kingston	**3407**	5	103.17	81.74	-21.43
SESARM	**TN**	Kingston	**3407**	6	46.43	37.19	-9.24
SESARM	**TN**	Kingston	**3407**	7	89.64	67.50	-22.14
SESARM	**TN**	Kingston	**3407**	8	45.47	36.96	-8.52
SESARM	**TN**	Kingston	**3407**	9	79.33	60.48	-18.85
SESARM	**VA**	Altavista Power Station	**10773**	1	0.00	0.00	0
SESARM	**VA**	Altavista Power Station	**10773**	2	0.00	0.00	0
SESARM	**VA**	Birchwood Power Facility	**54304**	001	79.66	79.66	0
SESARM	**VA**	Chesapeake Energy Center	**3803**	1	0.00	0.00	0
SESARM	**VA**	Chesapeake Energy Center	**3803**	2	0.00	0.00	0
SESARM	**VA**	Chesapeake Energy Center	**3803**	3	0.00	0.00	0
SESARM	**VA**	Chesapeake Energy Center	**3803**	4	0.00	0.00	0
SESARM	**VA**	Chesterfield Power Station	**3797**	3	95.37	95.37	0
SESARM	**VA**	Chesterfield Power Station	**3797**	4	87.54	44.17	-43.37
SESARM	**VA**	Chesterfield Power Station	**3797**	5	135.42	68.75	-66.67
SESARM	**VA**	Chesterfield Power Station	**3797**	6	253.58	155.69	-97.9
SESARM	**VA**	Clinch River	**3775**	3	0.00	0.00	0
SESARM	**VA**	Clover Power Station	**7213**	1	1,322.05	1,322.05	0
SESARM	**VA**	Clover Power Station	**7213**	2	1,401.33	1,401.33	0
SESARM	**VA**	Cogentrix-Hopewell	**10377**	BLR01A	75.41	75.41	0
SESARM	**VA**	Cogentrix-Hopewell	**10377**	BLR01B	57.17	57.17	0
SESARM	**VA**	Cogentrix-Hopewell	**10377**	BLR01C	74.40	74.40	0
SESARM	**VA**	Cogentrix-Hopewell	**10377**	BLR02A	65.68	65.68	0
SESARM	**VA**	Cogentrix-Hopewell	**10377**	BLR02B	45.00	45.00	0
SESARM	**VA**	Cogentrix-Hopewell	**10377**	BLR02C	44.80	44.80	0
SESARM	**VA**	Cogentrix-Portsmouth	**10071**	BLR01A	0.00	0.00	0
SESARM	**VA**	Cogentrix-Portsmouth	**10071**	BLR01B	0.00	0.00	0
SESARM	**VA**	Cogentrix-Portsmouth	**10071**	BLR01C	0.00	0.00	0
SESARM	**VA**	Cogentrix-Portsmouth	**10071**	BLR02A	0.00	0.00	0
SESARM	**VA**	Cogentrix-Portsmouth	**10071**	BLR02B	0.00	0.00	0
SESARM	**VA**	Cogentrix-Portsmouth	**10071**	BLR02C	0.00	0.00	0
SESARM	**VA**	Glen Lyn	**3776**	51	0.00	0.00	0
SESARM	**VA**	Glen Lyn	**3776**	52	0.00	0.00	0
SESARM	**VA**	Glen Lyn	**3776**	6	0.00	0.00	0
SESARM	**VA**	Hopewell Power Station	**10771**	1	0.00	0.00	0
SESARM	**VA**	Hopewell Power Station	**10771**	2	0.00	0.00	0
SESARM	**VA**	Mecklenburg Power Station	**52007**	1	52.71	52.71	0
SESARM	**VA**	Mecklenburg Power Station	**52007**	2	55.98	55.98	0
SESARM	**VA**	Mirant Potomac River	**3788**	1	0.00	0.00	0
SESARM	**VA**	Mirant Potomac River	**3788**	2	0.00	0.00	0
SESARM	**VA**	Mirant Potomac River	**3788**	3	0.00	0.00	0
SESARM	**VA**	Mirant Potomac River	**3788**	4	0.00	0.00	0
SESARM	**VA**	Mirant Potomac River	**3788**	5	0.00	0.00	0
SESARM	**VA**	Southampton Power Station	**10774**	1	0.00	0.00	0
SESARM	**VA**	Southampton Power Station	**10774**	2	0.00	0.00	0

Impact of Wintertime SCR/SNRC Optimization on Visibility Impairing Nitrate Precursor Emissions

RPO	St.	Facility Name	Orispl	Unit ID	Base	BOR	Difference
SESARM	VA	Spruance Genco, LLC	54081	BLR01A	109.61	109.61	0
SESARM	VA	Spruance Genco, LLC	54081	BLR01B	118.07	118.07	0
SESARM	VA	Spruance Genco, LLC	54081	BLR02A	119.63	119.63	0
SESARM	VA	Spruance Genco, LLC	54081	BLR02B	118.16	118.16	0
SESARM	VA	Spruance Genco, LLC	54081	BLR03A	116.16	116.16	0
SESARM	VA	Spruance Genco, LLC	54081	BLR03B	118.66	118.66	0
SESARM	VA	Spruance Genco, LLC	54081	BLR04A	98.24	98.24	0
SESARM	VA	Spruance Genco, LLC	54081	BLR04B	93.34	93.34	0
SESARM	VA	Virginia City Hybrid Energy Center	56808	1	453.23	453.23	0
SESARM	VA	Virginia City Hybrid Energy Center	56808	2	419.44	419.44	0
SESARM	VA	Yorktown Power Station	3809	1	0.00	0.00	0
SESARM	VA	Yorktown Power Station	3809	2	0.00	0.00	0
SESARM	WV	Albright Power Station	3942	1	0.00	0.00	0
SESARM	WV	Albright Power Station	3942	2	0.00	0.00	0
SESARM	WV	Albright Power Station	3942	3	0.00	0.00	0
SESARM	WV	Fort Martin Power Station	3943	1	3,856.71	3,856.71	0
SESARM	WV	Fort Martin Power Station	3943	2	3,964.71	3,964.71	0
SESARM	WV	Grant Town Power Plant	10151	1A	497.46	497.46	0
SESARM	WV	Grant Town Power Plant	10151	1B	488.67	488.67	0
SESARM	WV	Harrison Power Station	3944	1	3,275.75	1,438.23	-1837.52
SESARM	WV	Harrison Power Station	3944	2	3,299.07	1,272.83	-2026.23
SESARM	WV	Harrison Power Station	3944	3	3,266.44	3,266.44	0
SESARM	WV	John E Amos	3935	1	750.57	564.25	-186.32
SESARM	WV	John E Amos	3935	2	856.52	584.34	-272.18
SESARM	WV	John E Amos	3935	3	1,022.68	1,022.68	0
SESARM	WV	Kammer	3947	1	0.00	0.00	0
SESARM	WV	Kammer	3947	2	0.00	0.00	0
SESARM	WV	Kammer	3947	3	0.00	0.00	0
SESARM	WV	Kanawha River	3936	1	0.00	0.00	0
SESARM	WV	Kanawha River	3936	2	0.00	0.00	0
SESARM	WV	Longview Power	56671	001	915.48	915.48	0
SESARM	WV	Mitchell (WV)	3948	1	632.15	632.15	0
SESARM	WV	Mitchell (WV)	3948	2	925.19	925.19	0
SESARM	WV	Mount Storm Power Station	3954	1	391.08	315.83	-75.25
SESARM	WV	Mount Storm Power Station	3954	2	324.99	249.11	-75.87
SESARM	WV	Mount Storm Power Station	3954	3	334.85	334.85	0
SESARM	WV	Mountaineer (1301)	6264	1	1,421.90	1,052.13	-369.77
SESARM	WV	Phil Sporn	3938	11	0.00	0.00	0
SESARM	WV	Phil Sporn	3938	21	0.00	0.00	0
SESARM	WV	Phil Sporn	3938	31	0.00	0.00	0
SESARM	WV	Phil Sporn	3938	41	0.00	0.00	0
SESARM	WV	Phil Sporn	3938	51	0.00	0.00	0
SESARM	WV	Pleasants Power Station	6004	1	2,311.41	1,131.08	-1180.33
SESARM	WV	Pleasants Power Station	6004	2	1,795.10	935.11	-859.99
SESARM	WV	Rivesville Power Station	3945	7	0.00	0.00	0
SESARM	WV	Rivesville Power Station	3945	8	0.00	0.00	0
SESARM	WV	Willow Island Power Station	3946	1	0.00	0.00	0
SESARM	WV	Willow Island Power Station	3946	2	0.00	0.00	0
SESARM	WV	Morgantown Energy Associates	10743	CFB1	212.05	212.05	0
SESARM	WV	Morgantown Energy Associates	10743	CFB2	211.03	211.03	0
CENSARA	AR	Flint Creek Power Plant	6138	1	2,943.88	2,943.88	0
CENSARA	AR	Independence	6641	1	4,282.36	4,282.36	0
CENSARA	AR	Independence	6641	2	4,038.27	4,038.27	0
CENSARA	AR	John W. Turk Jr. Power Plant	56564	SN-01	547.45	547.45	0
CENSARA	AR	Plum Point Energy Station	56456	1	924.01	924.01	0
CENSARA	AR	White Bluff	6009	1	3,416.40	3,416.40	0
CENSARA	AR	White Bluff	6009	2	5,072.31	5,072.31	0
CENSARA	IA	Dubuque	1046	1	0.00	0.00	0
CENSARA	IA	Dubuque	1046	5	0.00	0.00	0
CENSARA	IA	Dubuque	1046	6	0.00	0.00	0

Impact of Wintertime SCR/SNRC Optimization on Visibility Impairing Nitrate Precursor Emissions

RPO	St.	Facility Name	Orispl	Unit ID	Base	BOR	Difference
CENSARA	IA	Fair Station	1218	2	0.00	0.00	0
CENSARA	IA	George Neal North	1091	1	0.00	0.00	0
CENSARA	IA	George Neal North	1091	2	0.00	0.00	0
CENSARA	IA	George Neal North	1091	3	1,798.19	1,798.19	0
CENSARA	IA	George Neal South	7343	4	2,601.58	2,390.56	-211.02
CENSARA	IA	Lansing	1047	3	0.00	0.00	0
CENSARA	IA	Lansing	1047	4	261.82	261.82	0
CENSARA	IA	Louisa	6664	101	1,800.13	1,800.13	0
CENSARA	IA	Muscatine	1167	8	1,581.79	1,581.79	0
CENSARA	IA	Muscatine	1167	9	297.99	297.99	0
CENSARA	IA	Ottumwa	6254	1	744.55	744.55	0
CENSARA	IA	Pella	1175	6	0.00	0.00	0
CENSARA	IA	Pella	1175	7	0.00	0.00	0
CENSARA	IA	Sutherland	1077	1	0.00	0.00	0
CENSARA	IA	Sutherland	1077	3	0.00	0.00	0
CENSARA	IA	Walter Scott Jr. Energy Center	1082	1	0.00	0.00	0
CENSARA	IA	Walter Scott Jr. Energy Center	1082	2	0.00	0.00	0
CENSARA	IA	Walter Scott Jr. Energy Center	1082	3	3,252.00	3,252.00	0
CENSARA	IA	Walter Scott Jr. Energy Center	1082	4	782.32	782.32	0
CENSARA	KS	Holcomb	108	SGU1	1,321.80	1,321.80	0
CENSARA	KS	Jeffrey Energy Center	6068	1	1,271.87	1,271.87	0
CENSARA	KS	Jeffrey Energy Center	6068	2	1,345.42	1,345.42	0
CENSARA	KS	Jeffrey Energy Center	6068	3	2,001.34	2,001.34	0
CENSARA	KS	La Cygne	1241	1	978.56	863.75	-114.81
CENSARA	KS	La Cygne	1241	2	3,729.42	1,955.61	-1773.81
CENSARA	KS	Lawrence Energy Center	1250	3	0.00	0.00	0
CENSARA	KS	Lawrence Energy Center	1250	4	417.12	417.12	0
CENSARA	KS	Lawrence Energy Center	1250	5	1,242.41	1,242.41	0
CENSARA	KS	Nearman Creek	6064	N1	1,527.45	1,527.45	0
CENSARA	KS	Riverton	1239	39	0.00	0.00	0
CENSARA	KS	Riverton	1239	40	0.00	0.00	0
CENSARA	KS	Tecumseh Energy Center	1252	10	0.00	0.00	0
CENSARA	KS	Tecumseh Energy Center	1252	9	237.74	237.74	0
CENSARA	LA	Big Cajun 2	6055	2B1	688.93	688.93	0
CENSARA	LA	Dolet Hills Power Station	51	1	2,775.43	2,775.43	0
CENSARA	LA	Nelson Industrial Steam Company	50030	1A	439.98	439.98	0
CENSARA	LA	Nelson Industrial Steam Company	50030	2A	438.61	438.61	0
CENSARA	LA	R S Nelson	1393	6	1,976.99	1,976.99	0
CENSARA	LA	Rodemacher Power Station (6190)	6190	2	1,302.62	1,302.62	0
CENSARA	LA	Rodemacher Power Station (6190)	6190	3-1	196.84	196.84	0
CENSARA	LA	Rodemacher Power Station (6190)	6190	3-2	256.72	256.72	0
CENSARA	MO	Asbury	2076	1	1,503.01	1,503.01	0
CENSARA	MO	Chamois Power Plant	2169	2	0.00	0.00	0
CENSARA	MO	Columbia	2123	6	60.53	60.53	0
CENSARA	MO	Columbia	2123	7	76.89	76.89	0
CENSARA	MO	Hawthorn	2079	5A	782.88	782.88	0
CENSARA	MO	Iatan	6065	1	836.76	836.76	0
CENSARA	MO	Iatan	6065	2	674.93	674.93	0
CENSARA	MO	John Twitty Energy Center	6195	1	333.36	333.36	0
CENSARA	MO	John Twitty Energy Center	6195	2	407.37	407.37	0
CENSARA	MO	Labadie	2103	1	1,334.89	1,334.89	0
CENSARA	MO	Labadie	2103	2	1,464.99	1,464.99	0
CENSARA	MO	Labadie	2103	3	1,386.43	1,386.43	0
CENSARA	MO	Labadie	2103	4	1,495.00	1,495.00	0
CENSARA	MO	Lake Road	2098	6	0.00	0.00	0
CENSARA	MO	Meramec	2104	1	0.00	0.00	0
CENSARA	MO	Meramec	2104	2	0.00	0.00	0
CENSARA	MO	Meramec	2104	3	0.00	0.00	0
CENSARA	MO	Meramec	2104	4	0.00	0.00	0
CENSARA	MO	Montrose	2080	1	0.00	0.00	0

Impact of Wintertime SCR/SNRC Optimization on Visibility Impairing Nitrate Precursor Emissions

RPO	St.	Facility Name	Orispl	Unit ID	Base	BOR	Difference
CENSARA	**MO**	New Madrid Power Plant	**2167**	1	1,852.79	1,302.74	-550.04
CENSARA	**MO**	New Madrid Power Plant	**2167**	2	1,412.25	831.80	-580.45
CENSARA	**MO**	Rush Island	**6155**	1	913.29	913.29	0
CENSARA	**MO**	Rush Island	**6155**	2	1,063.91	1,063.91	0
CENSARA	**MO**	Sibley	**2094**	3	0.00	0.00	0
CENSARA	**MO**	Sikeston	**6768**	1	1,283.04	831.71	-451.33
CENSARA	**MO**	Sioux	**2107**	1	1,347.62	1,347.62	0
CENSARA	**MO**	Sioux	**2107**	2	1,943.83	1,943.83	0
CENSARA	**MO**	Thomas Hill Energy Center	**2168**	MB1	595.07	595.07	0
CENSARA	**MO**	Thomas Hill Energy Center	**2168**	MB2	685.26	685.26	0
CENSARA	**MO**	Thomas Hill Energy Center	**2168**	MB3	2,238.46	1,842.51	-395.95
CENSARA	**NE**	Gerald Gentleman Station	**6077**	1	3,058.78	3,058.78	0
CENSARA	**NE**	Gerald Gentleman Station	**6077**	2	5,487.51	5,487.51	0
CENSARA	**NE**	Gerald Whelan Energy Center	**60**	1	561.32	561.32	0
CENSARA	**NE**	Gerald Whelan Energy Center	**60**	2	137.36	137.36	0
CENSARA	**NE**	Lon D Wright Power Plant	**2240**	8	268.93	268.93	0
CENSARA	**NE**	Nebraska City Station	**6096**	1	2,879.47	2,879.47	0
CENSARA	**NE**	Nebraska City Station	**6096**	2	867.72	867.72	0
CENSARA	**NE**	North Omaha Station	**2291**	1	515.34	515.34	0
CENSARA	**NE**	North Omaha Station	**2291**	2	560.14	560.14	0
CENSARA	**NE**	North Omaha Station	**2291**	3	594.70	594.70	0
CENSARA	**NE**	North Omaha Station	**2291**	4	718.39	718.39	0
CENSARA	**NE**	North Omaha Station	**2291**	5	1,359.35	1,359.35	0
CENSARA	**NE**	Platte	**59**	1	676.03	676.03	0
CENSARA	**NE**	Sheldon	**2277**	1	2,282.38	2,282.38	0
CENSARA	**NE**	Sheldon	**2277**	2	1,580.65	1,580.65	0
CENSARA	**OK**	AES Shady Point	**10671**	1A	246.32	246.32	0
CENSARA	**OK**	AES Shady Point	**10671**	1B	203.90	203.90	0
CENSARA	**OK**	AES Shady Point	**10671**	2A	222.77	222.77	0
CENSARA	**OK**	AES Shady Point	**10671**	2B	228.02	228.02	0
CENSARA	**OK**	Grand River Dam Authority	**165**	1	0.00	0.00	0
CENSARA	**OK**	Grand River Dam Authority	**165**	2	1,938.26	1,938.26	0
CENSARA	**OK**	Hugo	**6772**	1	1,464.79	1,464.79	0
CENSARA	**OK**	Muskogee	**2952**	6	2,731.91	2,731.91	0
CENSARA	**OK**	Northeastern	**2963**	3313	0.00	0.00	0
CENSARA	**OK**	Northeastern	**2963**	3314	0.00	0.00	0
CENSARA	**OK**	Sooner	**6095**	1	1,249.20	1,249.20	0
CENSARA	**OK**	Sooner	**6095**	2	1,328.20	1,328.20	0
CENSARA	**TX**	AES Deepwater, Inc.	**10670**	01001	0.00	0.00	0
CENSARA	**TX**	Big Brown	**3497**	1	1,130.75	1,092.26	-38.48
CENSARA	**TX**	Big Brown	**3497**	2	1,364.12	1,328.36	-35.76
CENSARA	**TX**	Coleto Creek	**6178**	1	974.29	974.29	0
CENSARA	**TX**	Gibbons Creek Steam Electric Station	**6136**	1	869.62	869.62	0
CENSARA	**TX**	H W Pirkey Power Plant	**7902**	1	2,310.08	2,310.08	0
CENSARA	**TX**	Harrington Station	**6193**	061B	815.91	815.91	0
CENSARA	**TX**	Harrington Station	**6193**	062B	794.94	794.94	0
CENSARA	**TX**	Harrington Station	**6193**	063B	780.59	780.59	0
CENSARA	**TX**	J K Spruce	**7097**	**1	1,218.22	1,218.22	0
CENSARA	**TX**	J K Spruce	**7097**	**2	563.83	563.83	0
CENSARA	**TX**	J T Deely	**6181**	1	0.00	0.00	0
CENSARA	**TX**	J T Deely	**6181**	2	0.00	0.00	0
CENSARA	**TX**	Limestone	**298**	LIM1	2,964.96	2,964.96	0
CENSARA	**TX**	Limestone	**298**	LIM2	3,358.46	3,358.46	0
CENSARA	**TX**	Martin Lake	**6146**	1	2,482.70	2,482.70	0
CENSARA	**TX**	Martin Lake	**6146**	2	2,289.96	2,289.96	0
CENSARA	**TX**	Martin Lake	**6146**	3	2,227.89	2,227.89	0
CENSARA	**TX**	Monticello	**6147**	1	1,220.42	1,220.42	0
CENSARA	**TX**	Monticello	**6147**	2	894.12	872.34	-21.78
CENSARA	**TX**	Monticello	**6147**	3	1,941.96	1,728.21	-213.75
CENSARA	**TX**	Oak Grove 1	**6180**	1	1,039.17	1,039.17	0

Impact of Wintertime SCR/SNRC Optimization on Visibility Impairing Nitrate Precursor Emissions

RPO	St.	Facility Name	Orispl	Unit ID	Base	BOR	Difference
CENSARA	**TX**	Oak Grove 2	**6180**	2	810.30	810.30	0
CENSARA	**TX**	Oklaunion Power Station	**127**	1	2,447.23	2,447.23	0
CENSARA	**TX**	Sam Seymour	**6179**	1	1,102.92	1,102.92	0
CENSARA	**TX**	Sam Seymour	**6179**	2	1,108.58	1,108.58	0
CENSARA	**TX**	Sam Seymour	**6179**	3	763.06	763.06	0
CENSARA	**TX**	San Miguel	**6183**	SM-1	1,393.96	1,393.96	0
CENSARA	**TX**	Sandow	**6648**	4	584.65	584.65	0
CENSARA	**TX**	Sandow 5	**52071**	5A	309.52	309.52	0
CENSARA	**TX**	Sandow 5	**52071**	5B	235.03	235.03	0
CENSARA	**TX**	Sandy Creek	**56611**	S01	440.75	440.75	0
CENSARA	**TX**	Tolk Station	**6194**	171B	2,307.83	2,307.83	0
CENSARA	**TX**	Tolk Station	**6194**	172B	1,333.66	1,333.66	0
CENSARA	**TX**	Twin Oaks Power, LP	**7030**	U1	428.13	428.13	0
CENSARA	**TX**	Twin Oaks Power, LP	**7030**	U2	600.46	600.46	0
CENSARA	**TX**	W A Parish	**3470**	WAP5	455.85	455.85	0
CENSARA	**TX**	W A Parish	**3470**	WAP6	626.05	626.05	0
CENSARA	**TX**	W A Parish	**3470**	WAP7	344.63	344.63	0
CENSARA	**TX**	W A Parish	**3470**	WAP8	457.92	457.92	0
CENSARA	**TX**	Welsh Power Plant	**6139**	1	2,397.10	2,397.10	0
CENSARA	**TX**	Welsh Power Plant	**6139**	2	0.00	0.00	0
CENSARA	**TX**	Welsh Power Plant	**6139**	3	2,132.07	2,132.07	0

APPENDIX R

High Electric Demand Days and Visibility Impairment in MANE-VU

MANE-VU Technical Support Committee
12/20/2017

MANE - VU
Mid-Atlantic/Northeast Visibility Union

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The paper has been the effort of MANE-VU Technical Support Committee's Four-Factor Workgroup. Rob Sliwinski of New York Department of Environmental Conservation chaired the Technical Support Committee, whom were responsible for review of the report. Claire Sickinger, Kate Knight, and Kurt Kebschull from Connecticut Department of Energy and Environmental Protection; Mark Wert and Azin Kavian from Massachusetts Department of Environmental Protection; Mary Jane Rutkowski from Maryland Department of the Environment; Tom Downs, Tom Graham and Martha Webster from Maine Department of Environmental Protection; David Healy from New Hampshire Department of Environmental Services; Ray Papalski, Stella Oluwaseun-Apo, and Victoria Faranca from New Jersey Department of Environmental Protection; Scott Griffin and Amanda Chudow from New York Department of Environmental Conservation; Bryan Oshinski from Pennsylvania Department of Environmental Protection and Bennet Leon and Dan Riley of Vermont Department of Environmental Conservation provided valuable insights as the project progressed. Maine staff was particularly instrumental in the visibility data back trajectory analyses, and Claire Sickinger, Stella Oluwaseun-Apo, and Amanda Chudnow each conducted independent analysis of ISO-NE, PJM, and ISO-NY respectively that made up the bulk of the energy demand analysis. Joseph Jakuta managed the workgroup as MANE-VU staff.

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Introduction

The Federal Clean Air Act and Regional Haze rule require States that are reasonably anticipated to cause or contribute to impairment of visibility in mandatory Class I Federal areas to implement reasonable measures to reduce visibility impairment within the national parks and wilderness areas designated as mandatory Class I Federal Areas. To address the impact on Class I Federal areas within the Mid-Atlantic /Northeast Visibility Union (MANE-VU) region, the MANE-VU States will pursue a coordinated course of action to assure reasonable progress toward preventing any future, and remedying any existing impairment of visibility in mandatory Class I Federal areas. This course of action includes pursuing the adoption and implementation of emission management strategies.

One of the emission management strategies that will be considered for adoption and implementation by the MANE-VU Class I States is for the MANE-VU States to perform a four-factor analysis for peaking combustion turbines that operate on high electric demand days to address and control oxides of Nitrogen (NOx) and sulfur dioxide (SO2) emissions, where:

a) “High Electric Demand Day or “HEDD” is defined as the day when higher than usual electrical demands bring additional generation units online, many of which are infrequently operated and may have significantly higher emission rates than the rest of the generation fleet and,

b) “Peaking combustion turbine” is defined for the purposes of the MANE-VU “Ask” as a turbine capable of generating 15 megawatts or more, that commenced operation prior to May 1, 2007, used to generate electricity all or part of which is delivered to the electric power distribution grid for commercial sale, and that operates less than or equal to an average of 1752 hours (or 20%) per year during 2014 to 2016.

This analysis reviews visibility and energy data to determine the impact electric load has on visibility impairment, specifically the impacts of HEDDs on the “20% most impaired visibility days,”[1] though it also looks at the older 20% worst day metric as well.

Scope and Domain

As discussed in the above, the purpose of this study is to review the impact of ISO-NE, ISO-NY, and PJM HEDD on the MANE-VU region’s visibility. Therefore, the analysis encompasses two domains: that of ISO-NE, ISO-NY, and PJM for the HEDD analysis and that of MANE-VU (plus some neighboring areas) for the visibility impairment analysis.

Specifically, the following figures depict the region analyzed for HEDD; the Independent System Operator (ISO) for the energy distribution in New England (Figure 1

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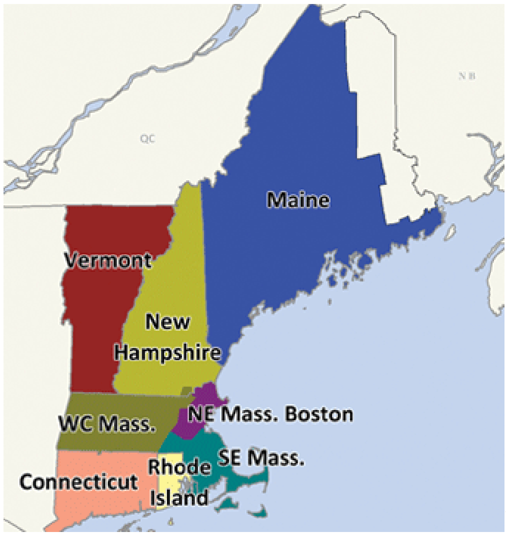
[1] 20% most impaired days are based on the draft IMPROVE AEROSOL, RHR III methodology used to calculate visibility impairment available in the Federal Land Manager Environmental Database (FED) database as of June 8, 2017 in accordance with the new definitions of impairment in regional haze regulatory framework



), the ISO for energy distribution in New York (Figure 2) and the Regional Transmission Organization (RTO) for the Mid-Atlantic, PJM (Figure 3). ISO-NE is responsible for administering the power plants, maintaining the electric grid, and operating the power market for the region.

Figure 1: ISO-NE region and load zones within the region

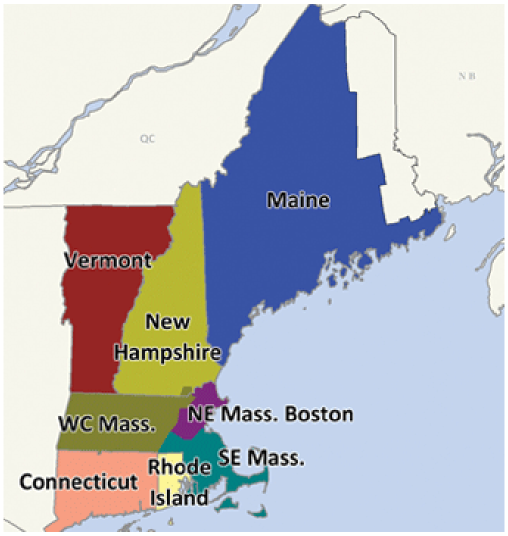


Figure 2: ISO-NY region and load zones within the region

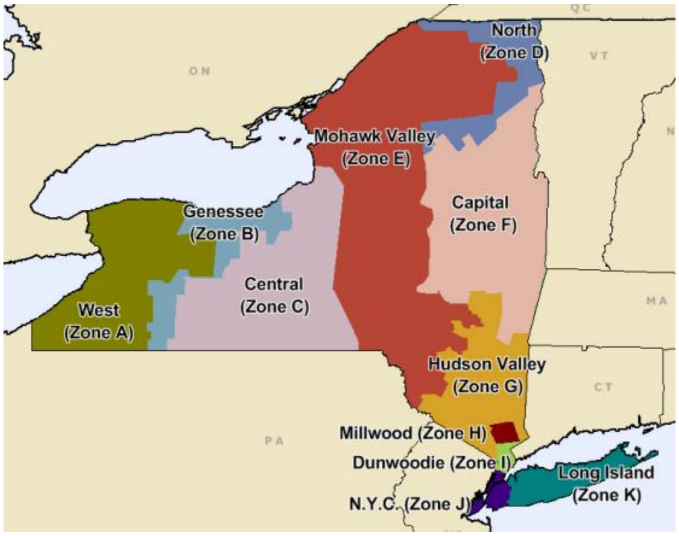
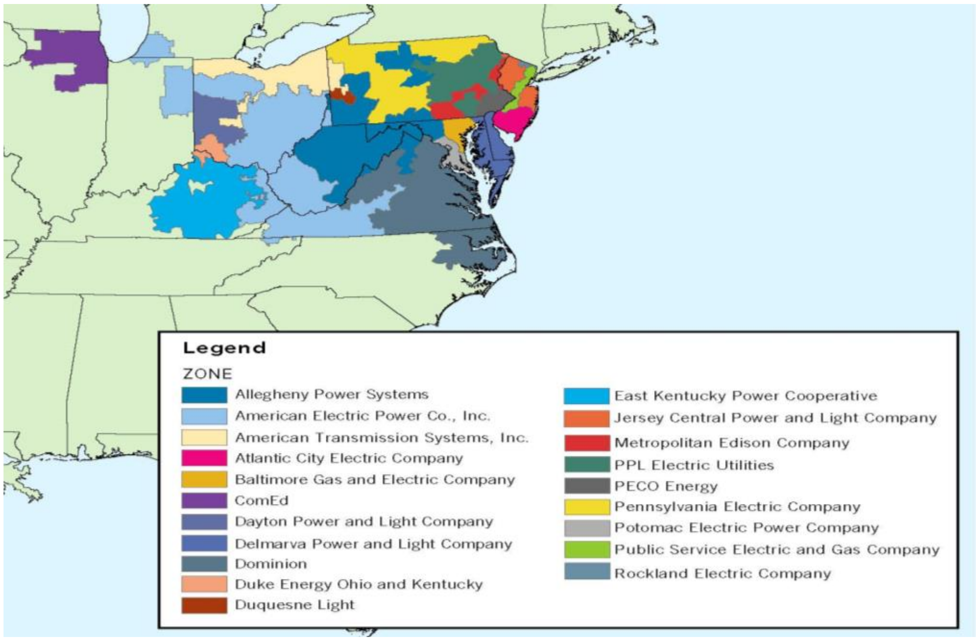


Figure 3: PJM region and load zones within the region



The region examined for the visibility impairment includes all of the MANE-VU. The states included in MANE-VU are Maine, New Hampshire, Vermont, Rhode Island, Massachusetts, Connecticut, New York, New Jersey, Delaware, Maryland, Pennsylvania, and the District of Columbia. Nearby states that are not in MANE-VU but frequently impact visibility in MANE-VU are also included in portions of the analysis, the extent of which was determined by the extent the air mass traveled in a 72-hour period. Within the MANE-VU region, the federally designated Class I areas are Brigantine Wilderness Area in the Edwin B. Forsythe National Wildlife Refuge (Brigantine), New Jersey; Lye Brook Wilderness (Lye Brook), Vermont; Great Gulf Wilderness and Presidential Range - Dry River Wilderness (Great Gulf), New Hampshire;

Acadia National Park (Acadia), and Moosehorn Wilderness (Moosehorn), Maine; and Roosevelt Campobello International Park, Maine/New Brunswick, Canada.

The scope of the analysis was originally intended to only review the most recent set of data that both IMPROVE (Interagency Monitoring of Protected Visual Environments) monitoring and HEDD data have available, 2015.

HEDD Analysis

HEDD are defined as the 85th percentile of the daily peak demand.[2] The 85th percentile was chosen to evaluate HEDD in part to be consistent with the analyses of the surrounding ISOs/RTOs and in part because it approximates the value which was determined to be an appropriate definition of HEDD for the New Jersey HEDD rule.[3] This section evaluated the daily peak demand data for 2015 to define the HEDDs to compare against visibility impairment in the following sections.

Electric Load Data

Electric load data was obtained from the ISO-NE, ISO-NY, and PJM Interconnection. ISO-NE covers the six New England states and ISO-NY solely covers New York. PJM Interconnection is a regional transmission organization (RTO) that coordinates the movement of wholesale electricity in all or parts of Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia and the District of Columbia.

As shown in Table 1, the two 85th percentile values for all three ISOs/RTOs are very close showing that we can rely on the 85th percentile on days monitored by IMPROVE.

Table 2 expands on this information by looking at the average peak generation on 20% most impaired days and HEDDs. There is a noticeable difference in the average maximum daily load between 20% most impaired days using all three ranking systems and the other days monitored by IMPROVE. The difference is even more noticeable between HEDDs and non HEDDs.

Table 1: Maximum, 85th Percentile, and 85th Percentile maximum daily generation (MWh) on IMPROVE monitored days

	ISO-NE	ISO-NY	PJM
Maximum	24,074	18,168	143,633
85th Percentile	19,331	11,432	122,756
85th Percentile on IMPROVE Days	19,261	11,515	122,252

Table 2: Average Generation (MWh) in each ISOs/RTOs on most impaired days and other monitored days ranked using three methods and on HEDDs and non-HEDDS on monitored days at each Class I Area.

	Old Ranking		Anthropogenic Ranking		Impairment Ranking		HEDD on Monitored Day		All Monitored
	Top 20%	Other Days	Top 20%	Other Days	Top 20%	Other Days	Y	N	Days
Acadia	48,866	41,975	47,617	42,284	47,617	42,284	55,363	41,102	**43,341**
ISO-NE	19,222	16,430	18,600	16,583	18,600	16,583	21,171	16,203	**16,983**
ISO-NY	10,915	8,368	9,918	8,615	9,918	8,615	13,617	7,990	**8,874**
PJM	116,461	101,126	114,332	101,653	114,332	101,653	131,301	99,113	**104,168**
Brigantine	48,448	42,078	47,601	42,288	47,601	42,288	55,363	41,102	**43,341**
ISO-NE	18,918	16,505	18,382	16,637	18,382	16,637	21,171	16,203	**16,983**

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[2] Data provided by ISO-NE, https://www.iso-ne.com/isoexpress/web/reports/load-and-demand/-/tree/zone-info

[3] N.J.A.C. 7:27-19

	Old Ranking		Anthropogenic Ranking		Impairment Ranking		HEDD on Monitored Day		All Monitored
	Top 20%	Other Days	Top 20%	Other Days	Top 20%	Other Days	Y	N	Days
ISO-NY	10,845	8,386	10,181	8,550	10,181	8,550	13,617	7,990	**8,874**
PJM	115,582	101,343	114,240	101,675	114,240	101,675	131,301	99,113	**104,168**
Great Gulf	50,842	41,371	47,410	42,146	47,410	42,146	57,504	40,418	**43,116**
ISO-NE	19,397	16,313	18,663	16,479	18,663	16,479	21,373	16,094	**16,881**
ISO-NY	11,787	8,194	10,026	8,592	10,026	8,592	13,732	7,942	**8,856**
PJM	121,342	99,605	113,541	101,367	113,541	101,367	131,301	98,071	**103,609**
Lye Brook	48,467	42,025	n/a	n/a	n/a	n/a	57,652	40,734	**43,279**
ISO-NE	18,796	16,470	n/a	n/a	n/a	n/a	21,089	16,185	**16,923**
ISO-NY	11,258	8,225	n/a	n/a	n/a	n/a	13,779	7,996	**8,815**
PJM	115,345	101,379	n/a	n/a	n/a	n/a	131,181	98,967	**104,098**
Moosehorn	48,936	42,367	48,271	42,533	48,271	42,533	55,363	41,242	**43,681**
ISO-NE	19,156	16,596	18,925	16,653	18,925	16,653	21,171	16,259	**17,108**
ISO-NY	10,816	8,575	10,233	8,721	10,233	8,721	13,617	8,064	**9,023**
PJM	116,835	101,930	115,656	102,225	115,656	102,225	131,301	99,401	**104,911**
Grand Total	**49,080**	**41,960**	**47,723**	**42,534**	**47,723**	**42,534**	**56,205**	**40,921**	**43,349**

Figure 4 shows the electric demand (dots) for 2015 for each ISOs/RTOs with blue being ISO-NE, orange being ISO-NY, and green being PJM. The lighter lines represent the 85th percentile of daily demand for the year, while the darker lines represent the 85th percentile of electric demand on IMPROVE days. There is a clear spike in electric demand during the summer months in all ISOs/RTOs, with a lesser spike during the winter months, with some of the lower demand values occurring in spring and fall.

Figure 4: Peak daily demand (GWh) in ISO-NE (blues, right scale), ISO-NY (oranges, right scale), and PJM (greens, left scale) 2015

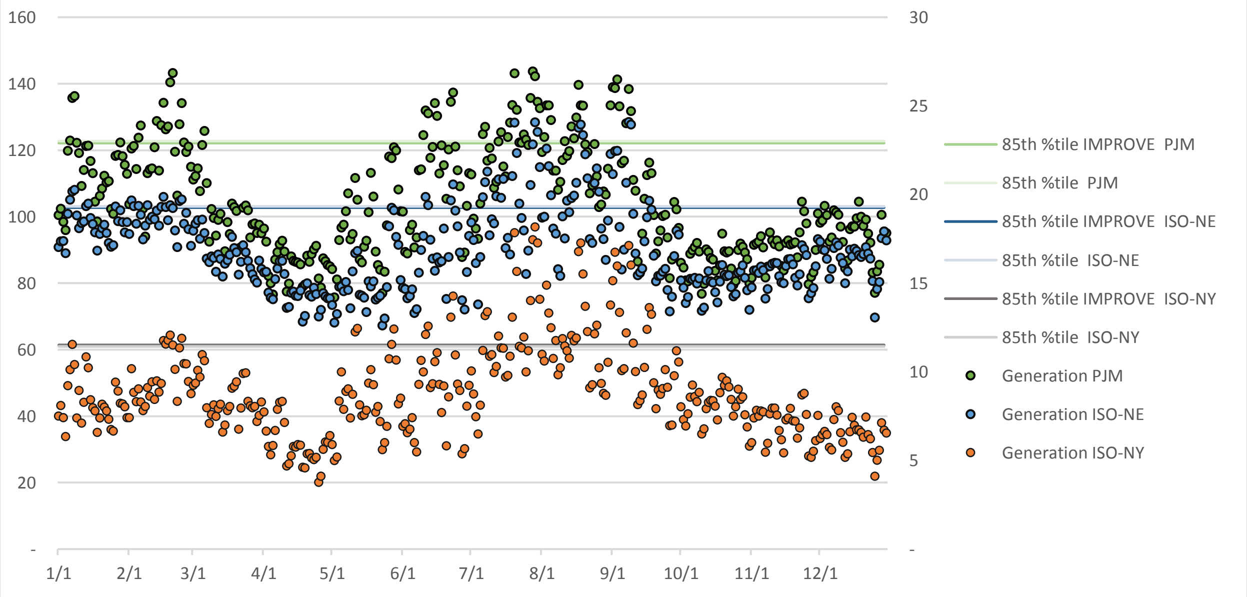

Figure 5, shows which IMPROVE monitored days occurred during 85th percentile days, 85th percentile IMPROVE monitored days, or both. In all of three ISOs/RTOs the HEDDs begin occurring in mid to late-May and extend throughout the summer ending in early to mid-September. In all three ISOs/RTOs there are also HEDDs that occur during January and February.

Figure 5: Peak daily demand (GWh) on IMPROVE sample days, 2015

Visibility Data Analysis

The following portion of the analysis reviews the visibility impairment at the MANE-VU and nearby Class I areas and evaluates any/if any correlation in the occurrence in impairment and HEDD. The full visibility analysis was prepared by Maine DEP for MANE-VU and will be released as a separate report.[4]

Best Visibility Days Analysis

A comparison of the visibility values against the HEDD were also evaluated. If the correlation was similar to the worst days, it might indicate that HEDD sources are not significant in the issue of visibility impairment. However, this analysis revealed that the occurrence of a HEDD day on the days deemed "best visibility" was in fact significantly rarer than the occurrence with impaired days as seen in Table 3. Great Gulf did not have a best day occur on the same day as a HEDD in any ISO/RTO. Acadia and Moosehorn had one best day occur on the same day as a HEDD in ISO-NE. Brigantine and Lye Brook both only had one best day occur during a HEDD in ISO-NY. Acadia and Moosehorn also had two best days occur during HEDDs in ISO-NY and PJM, respectively. It would be expected that HEDDs would not occur on best visibility days and that expectation appears correct.

Table 3: Number of HEDDs on Best Days

Site	Monitored Days	ISO-NE	ISO-NY	PJM
ACAD1	23	1	2	0
BRIG1	23	0	1	0
GRGU1	21	0	0	0
LYEB1	21	0	1	0
MOOS1	21	1	1	2

20% Most Impaired Visibility Day Analysis

The data shown in both Table 4 and Figure 6 demonstrate that poor visibility days often occur on HEDDs. Table 4 shows the counts of the number of 20% most impaired days using three different ranking techniques and find that between 57% and 29% of all HEDDs occur on the most impaired days depending on the ranking methodology and which ISO/RTO is being looked at. Since the impairment method can remove days from consideration that experience both high impact from fires and anthropogenic emissions that would go to explain that decrease in number of HEDDs seen on most impaired days.

Table 4: Number of HEDDs on 20% Most Impaired using three ranking techniques

		Old Rank			Anthropogenic			Impairment		
Site	**Monitored Days**	**ISO-NE**	**ISO-NY**	**PJM**	**ISO-NE**	**ISO-NY**	**PJM**	**ISO-NE**	**ISO-NY**	**PJM**
ACAD1	24	12	11	11	11	10	10	8	8	10
BRIG1	24	9	10	7	9	9	7	8	7	7
GRGU1	21	11	11	12	9	9	11	7	7	8
LYEB1	22	9	10	7	n/a	n/a	n/a	n/a	n/a	n/a
MOOS1	22	10	9	9	11	10	10	9	9	9

The middle quintile rankings were not available in data sets for the anthropogenic and impairment methods so we also looked strictly at the old "worst day" ranking to see when HEDDs occurred on other

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[4] 2017, Regional Haze Visibility Update, Tom Downs, Martha Webster and Rich Greves, Maine DEP

impairment days. Figure 6 shows that the 20% worst days clearly line up with HEDDs and decrease as visibility improves.

Figure 6: Total HEDDs in each ISO/RTO during each quintile of day using the old "worst day" method

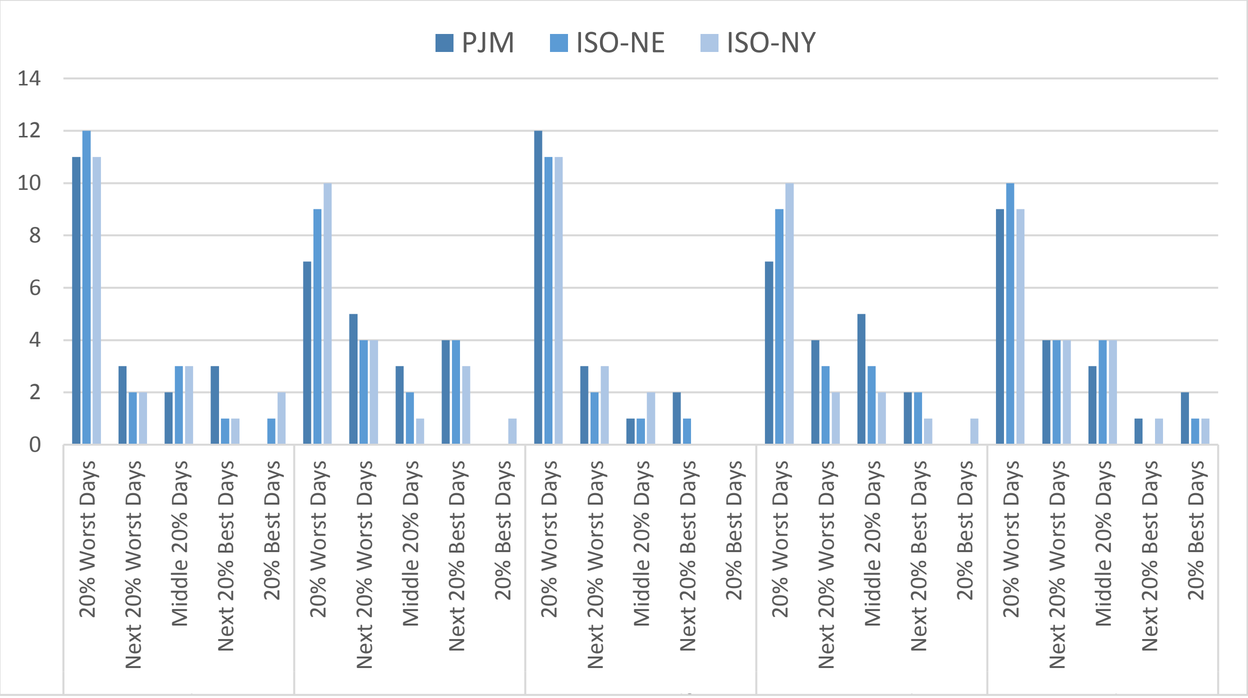


Figure 7 shows the speciation analyses for the 20% most impaired visibility days and Figure 8 shows the speciation analyses for the 20% most impaired visibility days at each MANE-VU Class I Area in 2015. We only looked at speciation on the 20% worst days and the 20% most impaired days using the impairment method, since all 20% most impaired days calculated using the anthropogenic method were included in one of the other sets of days. Lye Brook was not included since 20% most impaired data was not available for 2015.

The HEDD that occur on the most impaired days for each Class I Area are distinguished by the label with their percentile ranking. Ammonium sulfate has the highest extinction year-round at all Class I Areas except Brigantine, which showed multiple instances of ammonium nitrate extinction exceeding that of ammonium sulfate, however only one of those corresponded to a HEDD. At all Class I Areas, ammonium nitrate extinction was highest in the cooler months and lowest in the warmer months. Organic mass extinction was significant in all Class I Areas and elemental carbon only stood out as a significant contributor on a few days at Brigantine. Sea salt extinction was noticeable at Acadia and Brigantine, and on one day at Moosehorn, which was also a HEDD, however sea salt not a pollutant that would indicate energy sources were the cause. More than half of the 20% most impaired days occurred in the winter and summer for all areas in 2015.

Figure 7: Speciation (left axis) of the 20% most impaired days and the maximum daily load (GWh) (right axis) in ISO-NE, ISO-NY, and PJM with HEDDs noted in orange at each Class I Area.

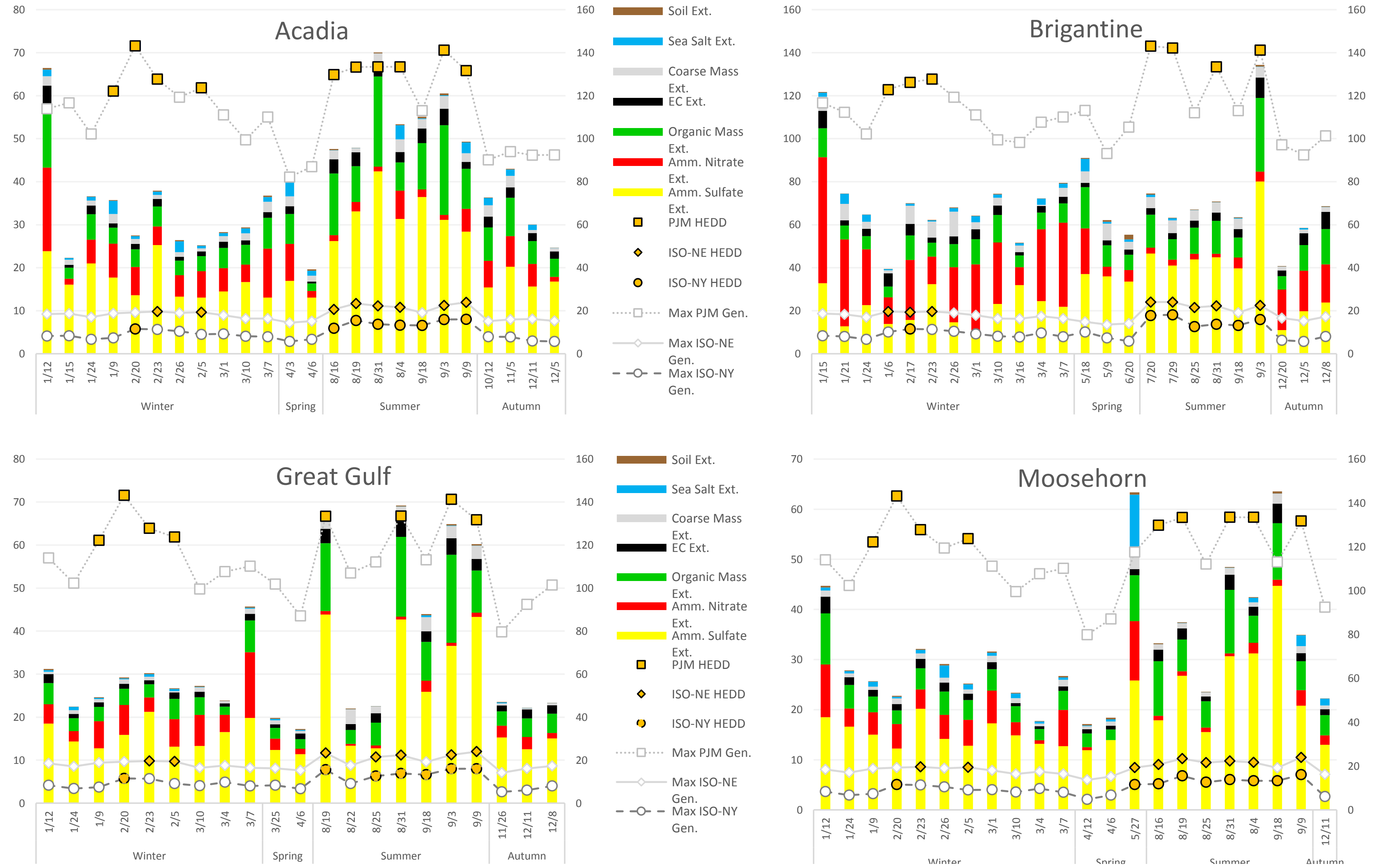
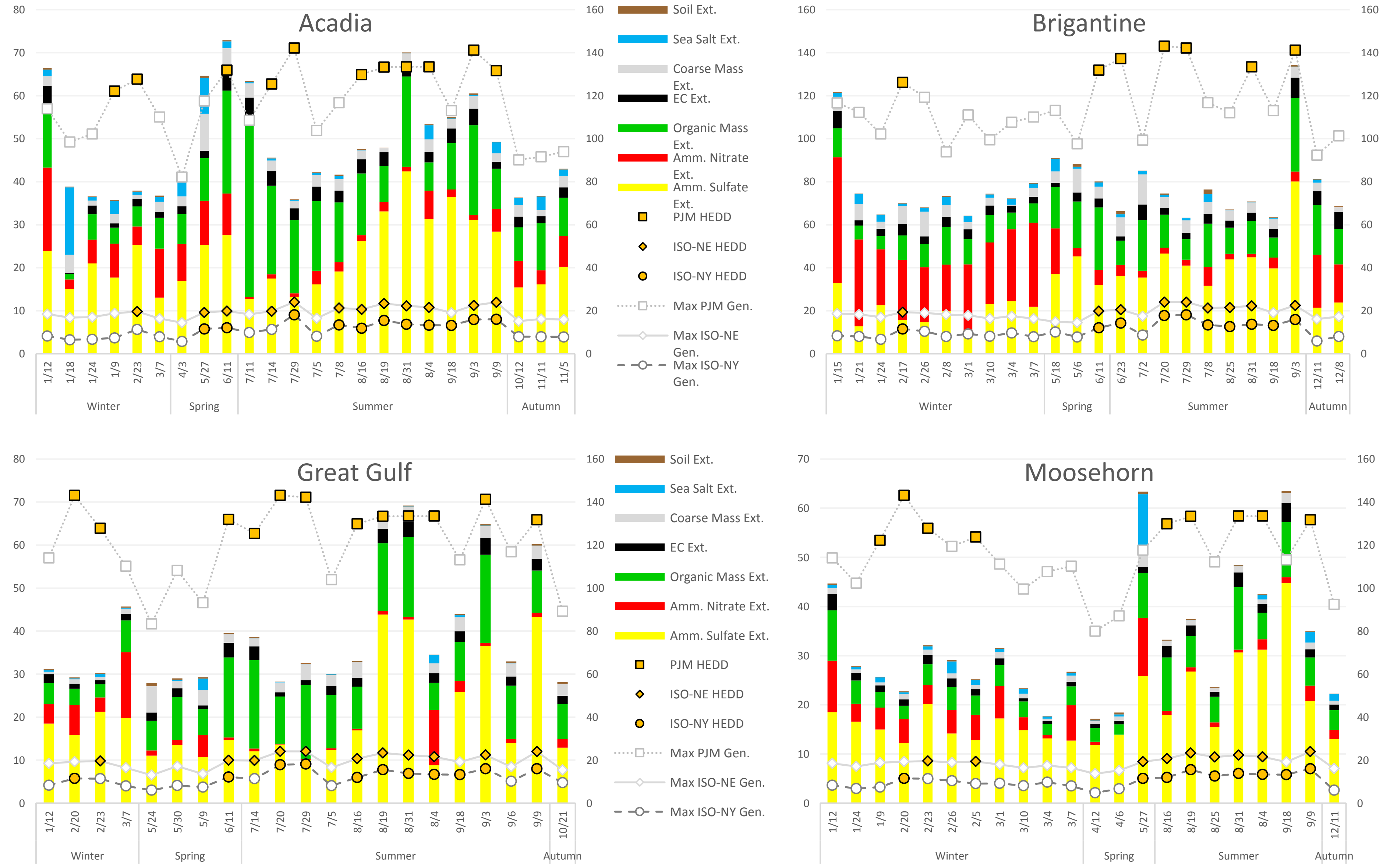


Figure 8: Speciation (left axis) of the 20% worst days and the maximum daily load (GWh) (right axis) in ISO-NE, ISO-NY, and PJM with HEDDs noted in orange at each Class I Area.

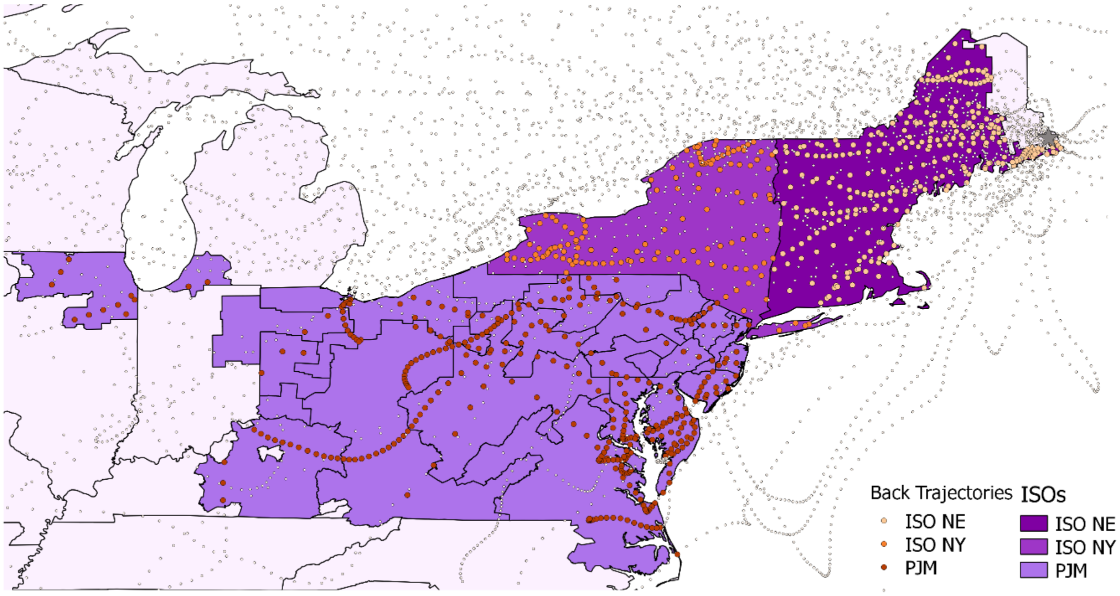


HYSPLIT Analysis of Most Impaired Visibility Days

The HYSPLIT model was used to develop 72-hour back trajectories at 500m four times per day (3 AM, 9 AM, 3 PM, and 9 PM) to determine the wind patterns on the most impaired days. These back trajectories were developed for a previous report by Maine DEP.[5] Back trajectories were not developed for the 20% worst days for this report so only the 20% most impaired days as ranked using the impairment method were used. The trajectories were overlaid on a map of the area covered by each of the ISOs/RTOs to graphically display how the wind patterns matched with the foot print of the ISOs/RTOs. The back trajectories that went over the geography of the ISO/RTO during the days that were a HEDD were highlighted.

Figure 9 shows the back trajectories during 20% most impaired days for Acadia, Great Gulf, and Moosehorn, respectively, which occurred during a HEDD in at least one ISO/RTO. The patterns in each map are similar with the most back trajectories in ISO-NE, and several crossing ISO-NY and PJM. It would be reasonable to expect that all three ISOs/RTOs analyzed could play a role in impacting visibility conditions in each of those Class I areas.

Figure 9: 72-hour back trajectories at 3 AM & PM and 9 AM & PM from Moosehorn during 20% most impaired days that were HEDDs in one analyzed ISO/RTO at 500m



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[5] Mid-Atlantic Northeast Visibility Union, *Regional Haze Metrics Trends and HYSPLIT Trajectory Analyses*.

Figure 10: 72-hour back trajectories at 3 AM & PM and 9 AM & PM from Acadia during 20% most impaired days that were HEDDs in one analyzed ISO at 500m

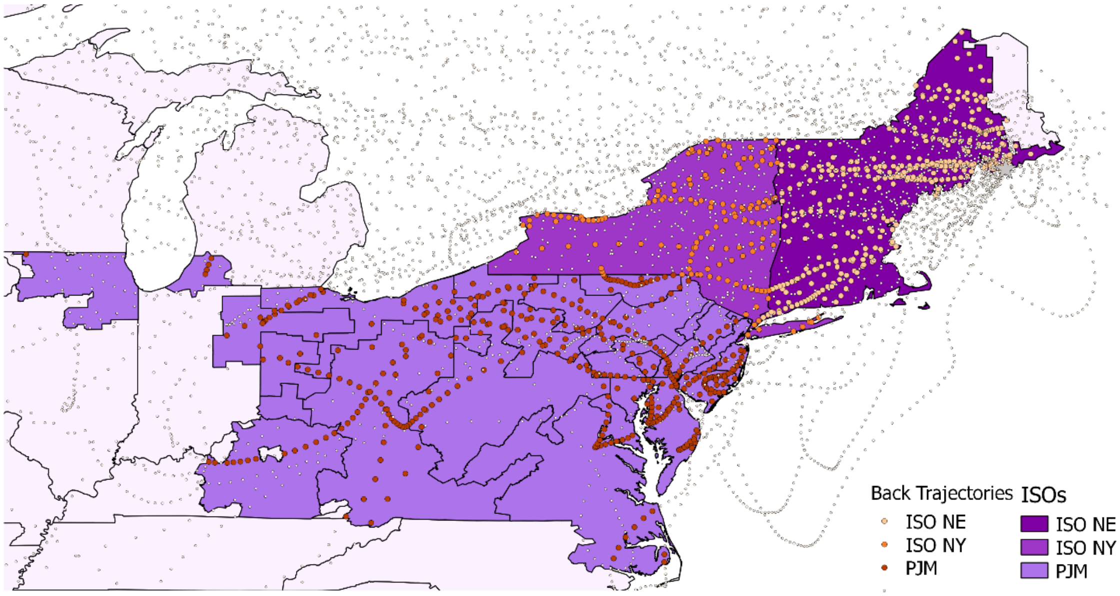


Figure 11: 72-hour back trajectories at 3 AM & PM and 9 AM & PM from Great Gulf during 20% most impaired days that were HEDDs in one analyzed ISO/RTO at 500m

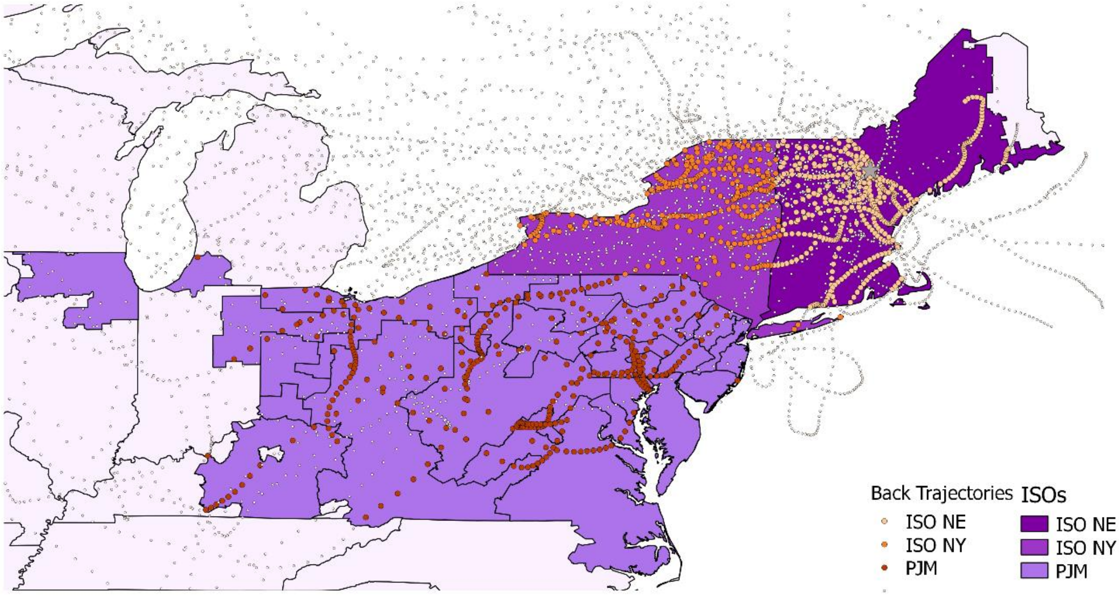


Figure 12 shows the back trajectories during 20% most impaired days for Lye Brook that occurred during a HEDD in at least one ISO/RTO. The pattern for Lye Brook is similar to that of the other New England Class I Areas, except due to it being on the western side of ISO-NE, the impact of ISO-NY would appear to be greater and that of ISO-NE to be minimal.

Figure 12: 72-hour back trajectories at 3 AM & PM and 9 AM & PM from Lye Brook during 20% most impaired days that were HEDDs in one analyzed ISO/RTO at 500m

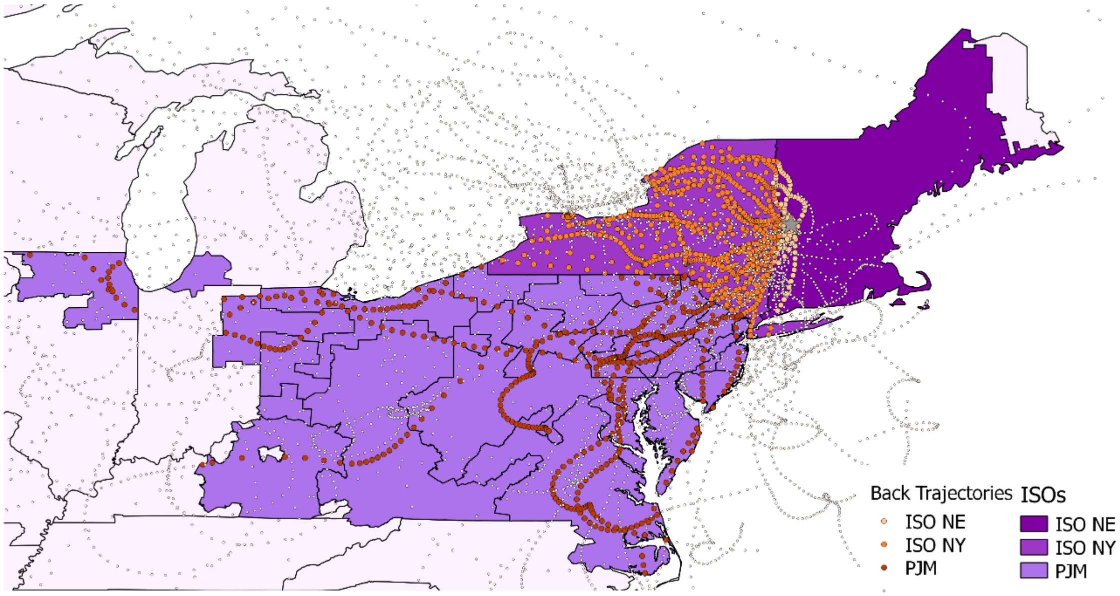
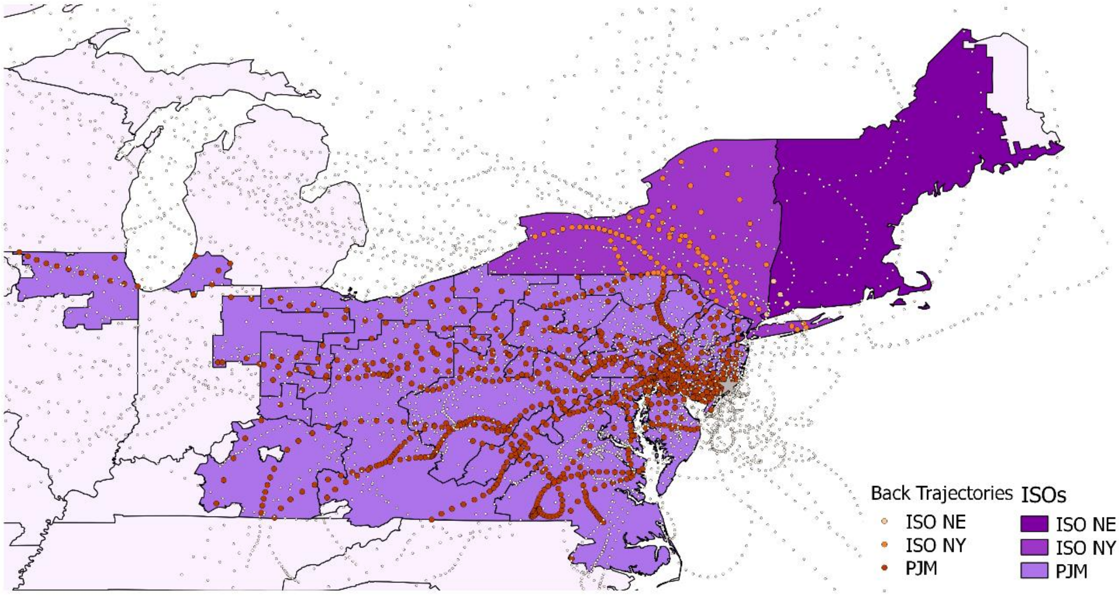


Figure 13 shows the back trajectories during 20% most impaired days for Brigantine that occurred during a HEDD in at least one ISO/RTO. It is clear from the trajectories that, in 2015, ISO-NE has little influence on poor visibility at Brigantine, but emissions from PJM are an important indicator of poor visibility during HEDDs. ISO-NY could potentially have an impact on visibility issues in Brigantine as well, especially from the western part of the ISO/RTO.

Figure 13: 72-hour back trajectories at 3 AM & PM and 9 AM & PM from Brigantine during 20% most impaired days that were HEDDs in one analyzed ISO/RTO at 500m



Meteorological Factors

Brigantine

Preliminary meteorological analysis shows that on HEDD and on the most impaired days, a common meteorological feature, called a low pressure surface trough or the Appalachian Lee-side Trough (APLT), exists that creates favorable conditions for poor visibility at Brigantine. This feature allows polluted air aloft to easily mix down to the surface and combine with local emissions. This feature is frequently seen west of New Jersey on days prior to as well as on the most impaired days. In addition, on days when extreme temperatures cause electricity generating units to operate at a higher capacity due to increased demand, increased pollutant levels is released into the atmosphere. As a result, downwind locations may see an increase in haze or pollutant concentrations on the next day.

Calm winds at the coast are also commonly seen on days of visibility impairment at Brigantine. Calm winds create poor atmospheric ventilation for pollutants to disperse in the atmosphere. Brigantine's unique location near the coast makes it an ideal downwind endpoint for pollutants to accumulate that travel from the west. If any units operate without controls on days prior to the most impaired days, a greater amount of pollution from upwind States travels eastward to Brigantine. Persistence can also be a factor, i.e., when there are several days of stagnation during prolonged hot or cold periods. Extended periods of extreme temperatures with little atmospheric ventilation can cause electric generating units to operate at higher levels of demand for several days in a row, during which pollutants accumulate in the same location when there is poor atmospheric ventilation. As a result, when finally the heavily polluted air mass is pushed downwind, it creates poor visibility in the downwind areas.

New England Class I Areas

Poor visibility can be associated with several weather patterns during winter and summer months at the New England Class I Areas. During the summer, high pressure moving from the Midwest to off the coast of the Mid-Atlantic States setting up a Bermuda High with west to southwest transport winds leads to impairment in New England's Class I areas. Another pattern that leads to the transport of visibility impairing pollution to New England Class I areas is the Lee-side Trough, which sets up resulting in Southwest flow of pollutants from large cities in the Northeast to New England's Class I areas. The Lee-side Trough also help turn the winds in the Gulf of Maine resulting in transported pollution to Maine's Class I areas by sea breezes. Finally, southerly winds can transport pollution from large cities in the Northeast to the New Hampshire and Vermont Class I areas.

Meteorological conditions that lead to visibility impairment in the winter differ from those in the summer at New England Class I areas. In some instances very cold air masses sit in place resulting in a HEDD with higher power plant emissions and higher residential heating emissions. Winds tend to be more from the Northwest in these events with emissions from Canada also contributing to the pollution at New England Class I areas. In other situations, a high pressure system moving into the Northeast from the Midwest and large cities in the Northeast will set up a subsidence inversion pushing aloft transported pollution closer to the surface. This type of event is much warmer than the HEDD events and are more polluted with a stalled or slow moving High Pressure system and can happen in any season of the year. Finally, nighttime inversions will trap pollutants near the surface. Pollution levels are higher during the winter during these inversions because they last longer than in any other season. Inland Class I areas are more impacted by this type of event.

Analysis of Days Preceding the Most Impaired Visibility Days

Electric load data from the three ISOs/RTOs were reviewed for two days preceding the most impaired days for two of the methods (anthropogenic was left off since all 20% most impaired days using that ranking were in the other two sets of days). The two methods showed similar characteristics.

As one can see in Table 5, 20% most impaired days are preceded in the day before and two days before by HEDDs only slightly less often than when they occur on the same day as HEDDs in the different ISOs. In the case of the worst ranking between 50% and 23% of most impaired days are preceded by a HEDD in a particular ISO/RTO and 43% and 17% of most impaired days are preceded by a HEDD two days before in a particular ISO/RTO. Brigantine shows the greatest drop off, likely because it is closer to the ISO/RTO than the other Class I areas so the air masses impacting it two days later are further west than the ISOs/RTOs being analyzed.

Table 5: Number of HEDDs on the day of, day before, and 2 days before 20% most impaired using two ranking techniques

			Old Rank			**Impairment**	
Site	**When was HEDD?**	**ISO-NE**	**ISO-NY**	**PJM**	**ISO-NE**	**ISO-NY**	**PJM**
Acadia	Day Of	12	11	11	8	8	10
	Day Before	10	9	10	9	7	8
	2 Days Before	8	7	8	8	8	8
Brigantine	Day Of	9	10	7	8	7	7
	Day Before	9	8	8	7	6	5

		Old Rank			Impairment		
Site	**When was HEDD?**	**ISO-NE**	**ISO-NY**	**PJM**	**ISO-NE**	**ISO-NY**	**PJM**
	2 Days Before	5	4	7	4	4	5
Great Gulf	Day Of	11	11	12	7	7	8
	Day Before	10	10	10	8	7	6
	2 Days Before	6	9	9	6	7	5
Lye Brook	Day Of	9	10	7	n/a	n/a	n/a
	Day Before	8	8	11	n/a	n/a	n/a
	2 Days Before	5	8	9	n/a	n/a	n/a
Moosehorn	Day Of	10	9	9	9	9	9
	Day Before	7	7	7	8	7	7
	2 Days Before	6	6	6	6	7	7

When looking at the 20% most impaired days using the impairment ranking a similar pattern holds up as did with HEDDS occurring on most impaired days, that there are slightly fewer. 38% and 21% of most impaired days are preceded by a HEDD in a particular ISO/RTO and 33% and 17% of most impaired days are preceded by a HEDD two days before in a particular ISO/RTO. Again this is likely due to summer days with high impairment from HEDD units, among other sources, being excluded from consideration since they coincided with days with high levels of impairment from fires. This of course doesn't clear up whether HEDDs are occurring directly in the lead up to a HEDD that is occurring during a 20% most impaired visibility day.

Table 6 and Table 7 help to answer the question of whether there are HEDDs occurring in the lead up to a HEDD that is occurring during a 20% most impaired visibility day when looking at the impairment method and the old "worst day" method, respectively. It is often that a HEDD occurring during a 20% most impaired day has HEDDs in the day or two days prior, particularly during the summer. There are also several instances where there is not a HEDD during the 20% most impaired day, but has HEDDs in the day or two days prior, particularly during the winter.

Table 6: Max daily load (MWh) on HEDDs in each ISO that occur the day of, the day before, and two days before a 20% most impaired day at each Class I Area

			ISO-NE			ISO-NY			PJM		
Site	Season	Date	Day Of	Day Before	2 Days Before	Day Of	Day Before	2 Days Before	Day Of	Day Before	2 Days Before
Acadia	Winter	1/9		20,255	20,162			11,534		136,197	135,639
		1/12									
		1/18									
		1/24									
		2/23	19,625						127,775		
		3/7								125,702	
	Spring	4/3									
		5/27				11,535					
		6/11	19,862			12,101			131,922	124,478	
	Summer	7/5									
		7/8	21,291	20,694	19,836	13,382	13,161			126,953	124,745
		7/11									
		7/14	19,806	20,854	19,888		12,009		125,399		
		7/29	24,065	22,810	20,524	18,168	17,443	14,008	142,225	143,633	135,699
		8/4	21,597	22,589		13,299	14,878		133,418	133,436	123,914
		8/16	20,658	19,932	19,783	11,899	11,729	12,047	129,803	123,513	127,063
		8/19	23,345	23,941	23,758	15,512	17,252	16,776	133,354	133,464	139,650
		8/31	22,269			13,764			133,453		
		9/3	22,465	22,445	21,139	15,955	16,744	15,123	141,210	138,664	138,975
		9/9	23,937	24,074	20,657	16,016	17,114	12,190	131,701	138,388	128,068
		9/18		19,636		13,235	13,614	12,384			

			ISO-NE			ISO-NY			PJM		
Site	Season	Date	Day Of	Day Before	2 Days Before	Day Of	Day Before	2 Days Before	Day Of	Day Before	2 Days Before
Brigantine	Autumn	10/12									
		11/5									
		11/11									
	Winter	1/15		19,486	19,332						
		1/21									
		1/24									
		2/8									127,381
		2/17		19,851		11,553	11,759		126,240	134,183	127,475
		2/26			19,723			11,881			134,132
		3/1									
		3/4									
		3/7								125,702	
		3/10									
	Spring	5/6									
		5/18									
		6/11	19,862			12,101			131,922	124,478	
	Summer	6/23	20,563	19,656		14,263	13,076		137,287	134,545	
		7/2									
		7/8	21,291	20,694	19,836	13,382	13,161			126,953	124,745
		7/20	24,055	21,037		17,842	13,081		143,065	133,567	128,265
		7/29	24,065	22,810	20,524	18,168	17,443	14,008	142,225	143,633	135,699
		8/25	21,473	20,643		12,613	12,127				
		8/31	22,269			13,764			133,453		
		9/3	22,465	22,445	21,139	15,955	16,744	15,123	141,210	138,664	138,975
		9/18		19,636		13,235	13,614	12,384			
	Autumn	12/8									
		12/11									
Great Gulf	Winter	1/12									
		2/20		19,382		11,506	12,061	11,781	143,129	140,386	127,107
		2/23	19,625						127,775		
		3/7								125,702	
	Spring	5/9									
		5/24									
		5/30						12,401			
		6/11	19,862			12,101			131,922	124,478	
	Summer	7/5									
		7/14	19,806	20,854	19,888		12,009		125,399		
		7/20	24,055	21,037		17,842	13,081		143,065	133,567	128,265
		7/29	24,065	22,810	20,524	18,168	17,443	14,008	142,225	143,633	135,699
		8/4	21,597	22,589		13,299	14,878		133,418	133,436	123,914
		8/16	20,658	19,932	19,783	11,899	11,729	12,047	129,803	123,513	127,063
		8/19	23,345	23,941	23,758	15,512	17,252	16,776	133,354	133,464	139,650
		8/31	22,269			13,764			133,453		
		9/3	22,465	22,445	21,139	15,955	16,744	15,123	141,210	138,664	138,975
		9/6						13,337			133,169
		9/9	23,937	24,074	20,657	16,016	17,114	12,190	131,701	138,388	128,068
		9/18		19,636		13,235	13,614	12,384			
	Autumn	10/21									
Moosehorn	Winter	2/8									127,381
		2/14								128,761	
		3/4									
		3/7								125,702	
	Spring	4/18									
		5/9									
		5/27				11,535					
		5/30						12,401			
		6/11	19,862			12,101			131,922	124,478	
	Summer	6/23	20,563	19,656		14,263	13,076		137,287	134,545	
		7/5									
		7/8	21,291	20,694	19,836	13,382	13,161			126,953	124,745

			ISO-NE			ISO-NY			PJM		
Site	Season	Date	Day Of	Day Before	2 Days Before	Day Of	Day Before	2 Days Before	Day Of	Day Before	2 Days Before
		7/20	24,055	21,037		17,842	13,081		143,065	133,567	128,265
		7/26						11,947		123,129	124,661
		7/29	24,065	22,810	20,524	18,168	17,443	14,008	142,225	143,633	135,699
		8/19	23,345	23,941	23,758	15,512	17,252	16,776	133,354	133,464	139,650
		9/3	22,465	22,445	21,139	15,955	16,744	15,123	141,210	138,664	138,975
		9/6						13,337			133,169
		9/9	23,937	24,074	20,657	16,016	17,114	12,190	131,701	138,388	128,068
		9/18		19,636		13,235	13,614	12,384			
	Autumn	10/21									
		12/11									

Table 7: Max Daily Load (MWh) on HEDDs in each ISO that occur the day of, the day before, and two days before a 20% worst day at each Class I Are

			ISO-NE			ISO-NY			PJM		
Site	Season	Date	Day Of	Day Before	2 Days Before	Day Of	Day Before	2 Days Before	Day Of	Day Before	2 Days Before
Acadia	Winter	1/9		20,255	20,162			11,534		136,197	135,639
		1/12									
		1/18									
		1/24									
		2/23	19,625						127,775		
		3/7								125,702	
	Spring	4/3									
		5/27				11,535					
		6/11	19,862			12,101			131,922	124,478	
	Summer	7/5									
		7/8	21,291	20,694	19,836	13,382	13,161			126,953	124,745
		7/11									
		7/14	19,806	20,854	19,888		12,009		125,399		
		7/29	24,065	22,810	20,524	18,168	17,443	14,008	142,225	143,633	135,699
		8/4	21,597	22,589		13,299	14,878		133,418	133,436	123,914
		8/16	20,658	19,932	19,783	11,899	11,729	12,047	129,803	123,513	127,063
		8/19	23,345	23,941	23,758	15,512	17,252	16,776	133,354	133,464	139,650
		8/31	22,269			13,764			133,453		
		9/3	22,465	22,445	21,139	15,955	16,744	15,123	141,210	138,664	138,975
		9/9	23,937	24,074	20,657	16,016	17,114	12,190	131,701	138,388	128,068
		9/18		19,636		13,235	13,614	12,384			
	Autumn	10/12									
		11/5									
		11/11									
Brigantine	Winter	1/15		19,486	19,332						
		1/21									
		1/24									
		2/8									127,381
		2/17		19,851		11,553	11,759		126,240	134,183	127,475
		2/26			19,723			11,881			134,132
		3/1									
		3/4									
		3/7								125,702	
		3/10									
	Spring	5/6									

			ISO-NE			ISO-NY			PJM		
Site	Season	Date	Day Of	Day Before	2 Days Before	Day Of	Day Before	2 Days Before	Day Of	Day Before	2 Days Before
		5/18									
		6/11	19,862			12,101			131,922	124,478	
	Summer	6/23	20,563	19,656		14,263	13,076		137,287	134,545	
		7/2									
		7/8	21,291	20,694	19,836	13,382	13,161			126,953	124,745
		7/20	24,055	21,037		17,842	13,081		143,065	133,567	128,265
		7/29	24,065	22,810	20,524	18,168	17,443	14,008	142,225	143,633	135,699
		8/25	21,473	20,643		12,613	12,127				
		8/31	22,269			13,764			133,453		
		9/3	22,465	22,445	21,139	15,955	16,744	15,123	141,210	138,664	138,975
		9/18		19,636		13,235	13,614	12,384			
	Autumn	12/8									
		12/11									
Great Gulf	Winter	1/12									
		2/20		19,382		11,506	12,061	11,781	143,129	140,386	127,107
		2/23	19,625						127,775		
		3/7								125,702	
	Spring	5/9									
		5/24									
		5/30						12,401			
		6/11	19,862			12,101			131,922	124,478	
	Summer	7/5									
		7/14	19,806	20,854	19,888		12,009		125,399		
		7/20	24,055	21,037		17,842	13,081		143,065	133,567	128,265
		7/29	24,065	22,810	20,524	18,168	17,443	14,008	142,225	143,633	135,699
		8/4	21,597	22,589		13,299	14,878		133,418	133,436	123,914
		8/16	20,658	19,932	19,783	11,899	11,729	12,047	129,803	123,513	127,063
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		8/31	22,269			13,764			133,453		
		9/3	22,465	22,445	21,139	15,955	16,744	15,123	141,210	138,664	138,975
		9/6						13,337			133,169
		9/9	23,937	24,074	20,657	16,016	17,114	12,190	131,701	138,388	128,068
		9/18		19,636		13,235	13,614	12,384			
	Autumn	10/21									
Lye Brook	Winter	2/8									127,381
		2/14								128,761	
		3/4									
		3/7								125,702	
	Spring	4/18									
		5/9									
		5/27				11,535					
		5/30						12,401			
		6/11	19,862			12,101			131,922	124,478	
	Summer	6/23	20,563	19,656		14,263	13,076		137,287	134,545	
		7/5									
		7/8	21,291	20,694	19,836	13,382	13,161			126,953	124,745
		7/20	24,055	21,037		17,842	13,081		143,065	133,567	128,265
		7/26						11,947		123,129	124,661
		7/29	24,065	22,810	20,524	18,168	17,443	14,008	142,225	143,633	135,699
		8/19	23,345	23,941	23,758	15,512	17,252	16,776	133,354	133,464	139,650
		9/3	22,465	22,445	21,139	15,955	16,744	15,123	141,210	138,664	138,975
		9/6						13,337			133,169
		9/9	23,937	24,074	20,657	16,016	17,114	12,190	131,701	138,388	128,068
		9/18		19,636		13,235	13,614	12,384			
	Autumn	10/21									
		12/11									
Moosehorn	Winter	1/12									
		1/18									
		1/27									
		2/14								128,761	

			ISO-NE			ISO-NY			PJM		
Site	Season	Date	Day Of	Day Before	2 Days Before	Day Of	Day Before	2 Days Before	Day Of	Day Before	2 Days Before
		2/23	19,625						127,775		
		2/26			19,723			11,881			134,132
		3/1									
	Spring	4/3									
		5/27				11,535					
		6/11	19,862			12,101			131,922	124,478	
	Summer	7/5									
		7/11									
		7/14	19,806	20,854	19,888		12,009		125,399		
		8/4	21,597	22,589		13,299	14,878		133,418	133,436	123,914
		8/16	20,658	19,932	19,783	11,899	11,729	12,047	129,803	123,513	127,063
		8/19	23,345	23,941	23,758	15,512	17,252	16,776	133,354	133,464	139,650
		8/31	22,269			13,764			133,453		
		9/3	22,465	22,445	21,139	15,955	16,744	15,123	141,210	138,664	138,975
		9/9	23,937	24,074	20,657	16,016	17,114	12,190	131,701	138,388	128,068
		9/18		19,636		13,235	13,614	12,384			
	Autumn	10/12									
		11/11									

Conclusions

Visibility impairment occurs year round at all of the Class I Areas in MANE-VU, though it is more predominate in the summer and, to a lesser extent the winter months – with Brigantine being the opposite having more impairment during the winter (it should be noted that the trend due to winter time nitrates is increasing as sulfate becomes more controlled which is discussed in “Impact of Wintertime SCR/SNCR Optimization on Visibility Impairing Nitrate Precursor Emissions”). HEDDs that occurred on days monitored by the IMPROVE system followed the same seasonal pattern for the three ISOs/RTOs we examined, with the most occurring during the summer, than during the winter, and a few in the spring (no HEDDs occurred during the autumn).

There are noticeable differences between the average peak generation on HEDDs and non-HEDDs and substantial increases in the levels of generation typically lead to increases of emissions of pollutants that impair visibility such as SO2 and NOX. When looking exclusively at HEDDs themselves, the highest of those typically occur during the summer months.

HEDDs more often occurred during the most impaired days in 2015, regardless of which method was being examined, though using the old “worst day” metric resulted in the most HEDDs and most impaired days occurring on the same day. It is also typical for these days, particular in the summer, to be preceded by one or two days which are HEDDs as well. HEDDs rarely occurred during best visibility days in 2015 and at Great Gulf they never occurred during the same days.

When the speciation data on HEDDs is examined there appears to be a strong relationship with high levels of sulfate impairment during the HEDD day, but when HEDDs occur during the winter there is a less clear relationship with either sulfate or nitrate impairment.

Examining back trajectories show that the air masses are moving over the geographies of ISO-NE, ISO-NY, and PJM during HEDDS. Air masses moving over all three ISOs/RTOs , in particular ISO-NE, are moving towards Acadia, Great Gulf, and Moosehorn on HEDDs that happen to also be days of poor visibility. For Lye Brook it is air masses that are moving over ISO-NY and to a lesser extent PJM that are leading to days with poor visibility. For Brigantine, it is air masses moving over predominately PJM that are leading to days with poor visibility.

Though the data presented is indicative of potential relationship between HEDDs, there are clearly other variables that contribute to impaired visibility, but since the goal of the Regional Haze program is to eliminate all anthropogenic influence on Class I Areas, reducing emissions from units that run on HEDDs should be considered as a control measure, in particular when implemented during the summer.

APPENDIX S

Benefits of Combined Heat and Power Systems for Reducing Pollutant Emissions in MANE-VU States

MANE-VU Technical Support Committee

3/9/2016

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Executive Summary

CHP, or cogeneration, is a general term that refers to converting systems that separately produce heat and electricity to integrated systems that produce both. A traditional system with separate power and heat production can achieve an efficiency of 45%, whereas CHP can achieve efficiencies of 80%. A more advanced type of system called trigeneration uses a single integrated process for heating, electricity, and cooling. In addition to the efficiency benefits associated with CHP, transmission losses are decreased since electricity is now produced closer to the end user. This report examines the benefits of installing cogeneration or trigeneration systems for different applications in the MANE-VU states.

This report incorporates an analysis conducted by ICF international that examined the technical and economic potential for CHP installations on a national basis. The ERTAC EGU tool was then used to estimate criteria pollutant benefits from reduced generation in the power sector.

With the CHP technologies discussed in the paper, increases in CHP penetration would lead to significant decreases in SO_2 pollution in MANE-VU due to displacement of current base load generation. Conversely, there was an increase in onsite NO_X emissions from CHP systems in some of the scenarios examined. Smaller CHP systems would need to meet the NO_X standards outlined in the OTC Stationary Generator Model Rule to have a benefit. Larger systems would have a NO_X emission benefit if lowest achievable emission rates (LAER) were applied.

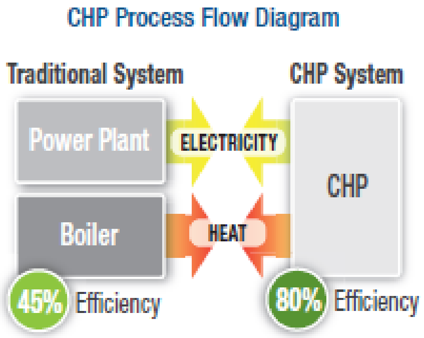
Overview

In November 2012, the Mid-Atlantic North East Visibility Union (MANE-VU) members charged the Technical Support Committee (TSC) with evaluating the potential for combined heat and power strategies to reduce ozone and fine particulate matter levels in MANE-VU states. The TSC was also charged with recommending an appropriate strategy or strategies. In February 2013, the TSC launched the Combined Heat & Power (CHP) Workgroup to fulfill MANE-VU's charge. The workgroup decided to initially focus on the reduction potential for installations and retrofits of commercial and industrial systems with CHP.

Purpose of this report: This report estimates the magnitude of oxides of Nitrogen (NO_X) and Sulfur Dioxide (SO_2) emission reductions possible in MANE-VU from installation and retrofit of commercial and industrial systems with CHP.

Background

CHP, or cogeneration, is a general term that refers to converting systems that separately produce heat and electricity to integrated systems that produce both. A traditional system with separate power and heat production can achieve an efficiency of 45%, whereas CHP can achieve efficiencies of 80% (note: efficiency is defined here as the conversion of fuel to useful energy). A more advanced type of system called trigeneration uses a single integrated process for heating, electricity, and cooling. In addition to the efficiency benefits associated with CHP, transmission losses are decreased since electricity is now produced closer to the end user.



Since CHP systems use the same fuel to produce heat and electricity rather than the traditional separated power plant/boiler system, they also produce fewer emissions. For example, with CHP, an institution would produce a similar level of emissions as it would with just a boiler used for heating, but power no longer needs to be generated elsewhere to meet the institution's electricity needs. So the overall system does not emit the same level of criteria, toxic, and greenhouse pollutants as traditional separate heat-producing and electricity-generating processes.

There are other benefits to the installation of CHP systems. CHP systems can be set up as distributed generation resources, to be called on during times of peak energy needs. In addition, CHP systems can continue to function and provide local power during electrical grid failures. This allows facilities with CHP systems to remain electrified at times when the grid fails due to acts of nature, voltage problems, or blackouts.

There are also challenges to implementation of CHP systems. In a report on CHP produced by Oak Ridge National Laboratory it was stated that "challenges include unfamiliarity with CHP, technology limitations, utility business practices, regulatory ambiguity, environmental permitting approaches that do not acknowledge and reward the energy efficiency and emissions benefits, uneven tax treatment, and interconnection requirements, processes, and enforcement.[1]" Additionally, since CHP systems are smaller than a conventional electrical generating unit (EGU), emissions from these systems could in some case outweigh the benefits of the reduced offsite electricity production from the grid. There are also many economic factors that could prevent CHP from being feasible. The interactions between fuel prices, electricity prices, potential capacity, physical constraints, and available capital, among other factors, could prevent some CHP capacity from being realized.   Regulations also play a role in reducing the amount of economically feasible CHP.

Criteria Pollutant Reduction Potential from Commercial and Industrial Installation & Retrofits of Heating Systems with CHP

Potential for CHP Installation in MANE-VU States

The first step in determining potential emission reductions from CHP installations is to determine how much potential there is for such installations, especially since many states in MANE-VU have existing installed CHP. A report by ICF International examined the technical potential for installation of CHP systems, beyond current installations, on a national basis. This report was relied on for determining the technical potential in the MANE-VU region. Table 1 shows the technical potential for CHP systems in the U.S.

An examination of the benefits of CHP systems in the MANE-VU region was performed by estimating the emissions associated with all technically feasible CHP in MANE-VU as listed in Table 2.

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[1] Oak Ridge National Laboratory. "COMBINED HEAT AND POWER Effective Energy Solutions for a Sustainable Future." http://www1.eere.energy.gov/manufacturing/distributedenergy/pdfs/chp_report_12-08.pdf. Accessed March 23, 2013.

Table 1: Technical potential (MW) for CHP systems in the U.S. by capacity and application[2]

Sector		Load Factor	Application	Technical Potential (MW)					
				.05-1 MW	1-5 MW	5-20 MW	>20 MW	Total	Class
Cogeneration	Industrial	High	Food & Beverage	2,744	3,250	1,330	697	8,021	63,823
			Textiles	586	751	726	176	2,239	
			Lumber and Wood	1,413	854	332	164	2,763	
			Paper	1,230	1,869	3,601	7,597	14,297	
			Printing/Publishing	2,306	5,875	8,165	8,223	24,569	
			Chemicals	424	897	697	1,941	3,959	
			Petroleum Refining	1,023	314	120	28	1,485	
			Rubber/Misc Plastics	88	122	53	0	263	
			Stone/Clay/Glass	406	532	953	1,214	3,105	
			Fabricated Metals	254	21	6	0	281	
			Transportation Equip.	681	469	725	304	2,179	
			Furniture	44	2	0	0	46	
			Chemicals	173	23	5	0	201	
			Machinery/Cptr Equip	74	62	17	0	153	
			Instruments	76	23	24	0	123	
			Misc Manufacturing	85	20	34	0	139	
	Comm/Inst	High	Waste Water Treatment	111	66	0	0	177	3,242
			Prisons	318	1,343	850	554	3,065	
		Low	Laundries	116	13	0	0	129	612
			Health Clubs	125	26	8	0	159	
			Golf/Country Clubs	235	28	15	0	278	
			Carwashes	43	3	0	0	46	
Trigeneration	Comm/Inst	High	Refrig Warehouses	67	33	9	7	116	21,188
			Data Centers	272	380	339	46	1,037	
			Nursing Homes	765	159	13	0	937	
			Hospitals	892	3,179	769	345	5,185	
			Colleges/Universities	641	1,648	1,669	1,471	5,429	
			Multi-Family Buildings	3,774	1,325	0	0	5,099	
			Hotels	1,330	1,386	460	209	3,385	
		Low	Airports	125	261	290	0	676	43,014
			Post Offices	29	11	0	0	40	
			Food Sales	1,079	65	41	0	1,185	
			Restaurants	1,179	62	15	0	1,256	
			Commercial Buildings	20,378	12,842	0	0	33,220	
			Movie Theaters	3	1	0	0	4	
			Schools	789	87	0	0	876	
			Museums	41	13	0	0	54	
			Government Facilities	1,276	1,334	955	170	3,735	
			Big Box Retail	1,662	251	25	30	1,968	

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[2] ICF International. "Effect of a 30 Percent Investment Tax Credit on the Economic Market Potential for Combined Heat and Power." October 2010. Accessed October 29, 2014.

Table 2: Existing and technical potential (MW) for CHP systems in MANE-VU states by capacity

State	Existing (MW)[3]	Technical Potential (MW)[2]				
		.05-1 MW	1-5 MW	5-20 MW	>20 MW	Total
CT	741	492	396	78	0	966
DC[4]	14	0	0	0	0	0
DE	231	104	59	21	0	184
ME	936	176	142	0	6	324
MD	705	682	457	0	75	1,214
MA	1,576	976	755	0	140	1,871
NH	47	184	130	9	0	323
NJ	3,049	1,133	875	421	28	2,457
NY	5,775	2,851	2,671	820	259	6,601
PA	3,269	1,631	1,442	233	155	3,461
RI	126	159	117	22	0	298
VT	24	85	61	19	0	165
Total	16,493	8,473	7,105	1,623	663	17,864

Table 1 examines various CHP applications and whether they: 1) would produce electricity, heating, and cooling (trigeneration) or just electricity and heating (cogeneration), 2) would be used for industrial purposes or commercial/institutional purposes, and 3) run only during business hours (low load factor) or closer to 24 hours a day (high load factor). Data from the ICF analyses was also used to estimate annual operating hours from for systems in each class.

Table 2 includes state level totals of both existing and technical potential by system capacity as found in the ICF report. The technical potential is the basis for the capacity estimates throughout this paper. Since ICF did not analyze Washington, DC, although it has 14 MW of existing CHP capacity, it was excluded from the remainder of the paper.

Since no information was available for technical potential for each class at the state level, it was assumed that each state had the same distribution of classes as was found nationally Equation 1 was used to estimate the technical potential for each class/state/capacity possibility. The resulting distribution that was used throughout the rest of this paper can be found in Table 3.

Equation 1: State/Class/Size Technical Potential

$$PercentageTechPotential_{Class/\ Size} = (TechPotential_{Class/Size}/TechPotential_{National/Size})$$

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[3] https://doe.icfwebservices.com/chpdb/. Accessed September 4, 2015.

[4] Since ICF did not analyze Washington, DC, although it has 14 MW of existing CHP capacity, it was excluded from the remainder of the paper.

Table 3: Percentage of technical potential for each class by capacity in the U.S.

Class	Op. Hours[2]	System Capacity			
		.05-1 MW	1-5 MW	5-20 MW	>20 MW
Cogen/Industrial/High Load	7,000	24.77%	38.09%	75.47%	87.78%
Cogen/Commercial/High Load	7,000	0.92%	3.56%	3.82%	2.39%
Cogen/Commercial/Low Load	4,000	1.11%	0.18%	0.10%	0.00%
Trigen/Commercial/High Load	7,000	16.52%	20.48%	14.65%	8.97%
Trigen/Commercial/Low Load	5,000	56.69%	37.69%	5.96%	0.86%

Additionally, only the CHP systems that are economically feasible were examined. ICF produced three scenarios looking at differing levels of the Investment Tax Credit (ITC) to determine what could be economically feasible (Table 4). Since this information was not available at the state level, it was assumed that each state had the same distribution of classes as was found nationally. The percentage of each size that was found to be economically feasible was applied to each state's technical feasibility for these scenarios.

Table 4: Economic feasibility of CHP at three levels of the ITC in the U.S.[2]

Class	National Capacity (MW)				
	.05-1 MW	1-5 MW	5-20 MW	>20 MW	Total
0% ITC	125 0.27%	371 0.94%	567 2.55%	1,547 6.68%	2,610
Expanded ITC (10% up to 25 MW)	181 0.39%	500 1.26%	674 3.03%	1,802 7.78%	3,157
30% ITC (30% up to 25 MW)	258 0.55%	681 1.72%	973 4.37%	2,284 9.86%	4,196
Technical Potential	46,857	39,600	22,246	23,176	131,879

Potential Emission Reductions

There are two ways in which installation of CHP can change emissions levels, onsite and offsite. The onsite emission changes would be due to retrofits and repowering necessary to convert a system to CHP (for example, a newly installed boiler or turbine that produces different emissions from the previous equipment). Offsite emissions changes would occur because CHP acts as a replacement for electricity produced elsewhere.

Calculations for Estimating Onsite Emission Changes

The breakouts in Table 3 were used to calculate emission reductions by capacity and the class of facility. For each state, emission reductions were calculated for NO_X and SO_2.

Using the same capacity breakout, an assessment conducted by NYSERDA contained emission reductions from replacing a subset of the boilers in their region with natural gas fired CHP systems[5]. Average annual emission rates for existing and replacement systems were calculated

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[5] NYSERDA. "Combined Heat and Power Market Potential for New York State." October 2002.

on a per MW basis for NO_X and SO_2 using the base case scenario found in the NYSERDA report (except NO_X emission rates for replacement systems, see below). Since emission rates are not available for systems sized .05-.5 MW in the NYSERDA report, it was assumed that they had the same emission rates as systems sized .5-1 MW.

Instead of relying on the NYSERDA report, several estimates of NO_X emission rates were used when calculating emissions from replacement systems. Systems smaller than 5 MW were assumed to employ Reciprocating Internal Combustion Engines (RICE). Systems larger than 5 MW were assumed to employ Combustion Turbines (CT). Microturbines and fuel cells were also considered for the smaller systems, but these technologies are still evolving and using RICE would result in a more conservative estimate. For systems sized less than 5 MW, Delaware's stationary generator rule was used for Delaware, the OTC 2010 stationary generator model rule was used for New Jersey, and the RICE NSPS was used for all other states.

For systems in the 5-15 MW range, it was assumed that the emission rates from the OTC Model Rule for Additional NO_X Control Measures applied, regardless of state. Also regardless of state, all systems greater than 20 MW used the New Source Performance Standard for CTs. Additionally, average emission rates for the 5-20 MW category were calculated by averaging regulatory values for systems sized 5-15 MW (given 2/3 weight) and 15-20 MW (given 1/3 weight).

However, the emission rates for systems 5 MW and greater would almost certainly trigger New Source Review (NSR) or Prevention of Significant Deterioration (PSD), which would in turn lead to requirements to install the Lowest Achievable Emission Rate (LAER) or Best Available Control Technology (BACT) respectively. In order two find an appropriate BACT emission rate, the workgroup searched the RACT/BACT/LAER Clearinghouse (RBLC) for CHP combustion turbines installed since 2005 that ran on natural gas and were less than 25 MW.

Three units were found in the RBLC that had an emission rate in the appropriate format and that met the criteria – Woodbridge Energy Center (.034 lb/MWh) and Hess Newark Energy Center (0.170 lb/MWh) in New Jersey and Wesleyan University (0.109 lb/MWh) in Connecticut. These units had an average emission rate of 0.105 lb/MWh, considered to be BACT, and a lowest emission rate of 0.034 lb/MWh, considered to be LAER. Given that there are several ozone nonattainment areas in MANE-VU, that many other areas have a history of ozone nonattainment, and that some states in MANE-VU require LAER in attainment areas, the LAER emission rate was applied to the CHP systems in this analysis.

Although units smaller than 5 MW could trigger NSR, the second scenario (which assumes all states have adopted the OTC Stationary Generator Model Rule) should be sufficient to address BACT. Therefore no further analysis was conducted with respect to BACT.

A second set of calculations was made showing what would happen if all MANE-VU states adopted the 2010 stationary generator rule for the replacement systems. This meant that all states, except Delaware, had NO_X emission rates equivalent to those used for New Jersey in the first scenario. Emission factors used in the onsite calculations are summarized in Table 5.

Table 5: Annual average emission rates (lb/MWh) for CHP replacement and existing heating only boilers

Capacity	NO_X				SO_2		***CHP Heat Rate (Btu/kWh)***[2]
	CHP - DE[6]	**CHP – OTC M.R.**[7]	**CHP – Fed.**[8]	**Existing**	**CHP**	**Existing**	
.05-.5 MW	0.60	0.88	2.96	-	-	-	10,800
.5-1 MW	0.60	0.88	2.96	0.6355	0.0062	0.0031	10,800
1-5 MW	0.60	0.88	2.96	0.8246	0.0070	0.0028	9,492
5-20 MW[9][10]	1.87/0.034	1.87/0. 034	1.87/0. 034	0.7750	0.0069	0.0027	11,765
> 20 MW[10]	1.20/0. 034	1.20/0. 034	1.20/0. 034	0.5546	0.0055	0.0022	9,220

The systems were assumed to run according the annual operating hours listed in Table 3. It should be noted that the replacement systems themselves produce more emissions than the original systems.

Calculations for Estimating Offsite Emission Changes

As discussed earlier, the other way in which CHP systems can reduce pollution is by reducing the amount of electricity that power plants need to produce.

Several assumptions were made in order to estimate the emission reductions from the power sector due to implementation of CHP:

- For each state, CHP systems would replace base load coal generation in the ERTAC region in which the state was predominately located. In regions where coal generation does not occur, the system would replace Combined Cycle Natural Gas units. The coal assumption in particular could lead to an overstatement of the benefits.
- Transmission loss would be the average in the Eastern Interconnection of 5.82%.
- Although CHP systems would undertake routine maintenance during shoulder months, this activity will have a negligible effect on emission estimates.
- New CHP systems will be operational by the modeled future year of 2018, which was chosen due to its importance for Ozone and Regional Haze planning.

To calculate the number of hours that the low load factor cogeneration CHP systems would run during the year, the number of heating degree days and cooling degree days were averaged from 2004-2013 for each of month of the year. The ratio of heating degree days to total degree days was used to approximate the number of hours in the month the heating system would run (heating hours).

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[6] DE 7 § 1144 3.2.2

[7] OTC Model Rule for Stationary Generator Control Measures.

[8] 40CFR60-JJJJ

[9] OTC Model Rule for Additional Nitrogen Oxides (NOx) Control Measures

[10] 40CFR60-KKKK

In order to estimate the start and end of the heating season, the shoulder months were examined to determine which had the clearest end date-and then the average annual heating hours were used to calculate the other date based on the assumption that the heating would run straight through. An overview of the heating/cooling degree days and heating hours are in Table 5, as well as the approximate dates used as the end and beginning of the heating season for each state.

Table 6: Average annual heating and cooling degree days, last and first date of heating season, and calculated hours for heating by state from 2004-2013[11]

State	Annual Average Degree Days		Heating Season		Heating Hours
	Heating	Cooling	Last Day	First Day	
CT	5,780	625	6/7	9/14	6,386
DE	4,414	1,210	5/17	9/27	5,545
MA	6,043	534	6/14	9/12	6,622
MD	4,497	1200	5/17	9/27	5,568
ME	7,622	236	7/22	8/19	7,563
NH	7,327	310	6/20	8/21	7,268
NJ	5,045	913	5/23	9/19	5,900
NY	5,909	647	6/7	9/14	6,405
PA	5,623	734	5/24	9/7	6,208
RI	5,682	585	6/15	9/18	6,488
VT	7,778	249	6/22	8/13	7,498

The ERTAC EGU tool was then used to estimate the emission reductions from reduced need for generation in the power sector. Version 2.3 of the ERTAC inputs was used as the basis for the runs and the runs were conducted using a modified copy of version 1.01 of the software. The modifications were made to limit the number of hours that units could be run based on the utilization factor.

To use ERTAC EGU to project CHP’s impacts on the grid, a “virtual CHP plant” was created for: 1) each state (three in the case of New York), 2) each class of facilities, 3) the four tiers of capacities, and 4) in the case of the CHP low load class, each season. This resulted in a total of 364 “virtual CHP plants.” The scenario in which all of the technically feasible CHP systems are built will be henceforth called “Technical Potential Scenario”. In addition, the benefits of only installing larger systems (those greater than or equal to 5 MW) and of only installing smaller systems (those less than 5 MW) were examined. These cases are henceforth called “Large Systems Scenario” and “Small Systems Scenario,” respectively. Finally, the three economic options, “0% ITC Scenario," “10% ITC Scenario,” and “30% ITC Scenario” were assessed.

ERTAC EGU distributes generation using geographic regions that are based on the regions used by the Energy Information Agency in their Annual Energy Outlook report. In most cases the

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[11] NCDC Climate Indicators. http://www7.ncdc.noaa.gov/CDO/CDODivisionalSelect.jsp. Accessed April 11, 2014.

entirety of the MANE-VU state is within the applicable ERTAC region so 100% of the virtual CHP systems are allocated to that region. Even though part of western Pennsylvania, and to a lesser extent part of western Maryland, is in the RFCW region, all of the CHP systems were allocated to the RFCE region since the RFCW region extends well beyond the MANE-VU region. New York has three regions. To allocate the CHP systems across those regions, the percentage of the population from 2010 US Census data in each region was used as a surrogate[12]. A map of all of the ERTAC regions is in Figure 1 and the list of regions analyzed is in Table 7.

Figure 1: Map of ERTAC Regions

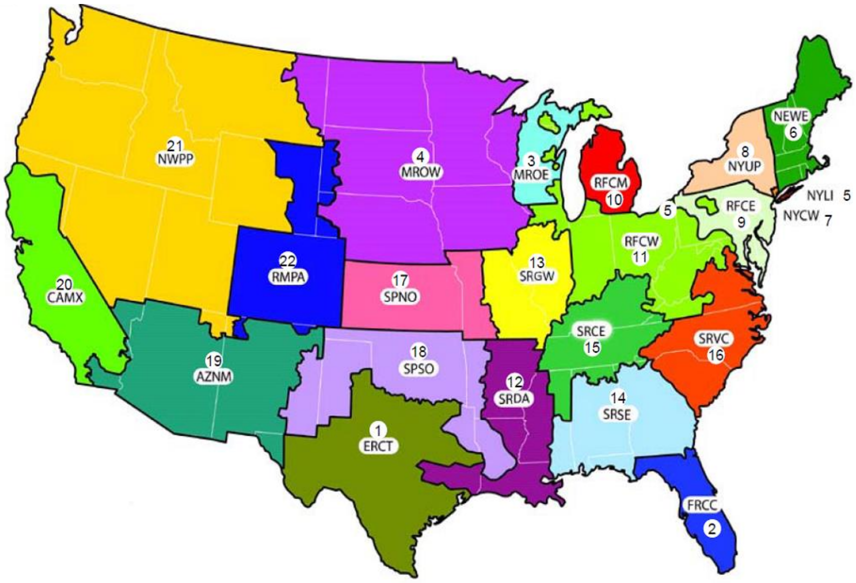

Table 7: List of ERTAC EGU regions analyzed and which states are allocated to the regions

ERTAC EGU Region	State Allocation
NEWE	100% of CT, ME, MA, ME, NH, RI, VT
NYCW	42% of NY
NYLI	15% of NY
NYUP	43% of NY
RFCE	100% of DE, MD, NJ, PA

The ERTAC EGU input files must contain several data elements to process the "virtual CHP plants":

1. Capacity: calculated using Equation 2 using the distributions from Table 3.
2. Annual heat rate: based on the capacity tier, obtained from the ICF report and listed in Table 5.

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[12] http://www.census.gov/popest/data/counties/totals/2014/CO-EST2014-01.html. Accessed August 6, 2015.

3. Utilization fraction (percentage of hours operating): The operating hours, based on the class obtained from the ICF report, are listed in Table 3. For the low load cogeneration class, the utilization fraction was the same as that used for low load trigeneration facilities for the non-summer months and was adjusted accordingly for the summer months using the length of the heating season defined in Table 5.
4. Maximum heat input: calculated using Equation 3.
5. NO_X and SO_2 emission rates: set to 0 since the onsite emissions were calculated separately.

Equation 2: "Virtual CHP plant" capacity

$$Capacity_{Virtual\ Plant} = PercentageTechPotential_{Class/Size}/TechPotential_{State/Size}/(1\text{-}TransLoss)$$

Equation 3: "Virtual CHP plant" maximum heat input

$$Maximum\ Heat\ Input = Annual\ Heat\ Rate * Capacity_{Class/State/Size}/1000$$

Additionally, to properly shutdown the "virtual CHP plants" during hours which they are not running, the ERTAC EGU code was altered so that systems do not run after the maximum number of hours was met. The maximum number of hours is based on the utilization fraction.

Results

When looking at the scenarios that examined technical potential only, the replacement of boilers in MANE-VU with CHP systems would yield substantial increases in onsite NO_X if the model rule is not adopted by all of the states. These emission increases outweigh the benefits of reduced power needed from the grid. Implementing the model rule would lead to regional NO_X benefits. Using BACT emission limits for the large systems, which are independent of the model rule, has a positive impact on NO_X emissions. In all situations the implementation of CHP systems has a clear SO_2 benefit. Table 8 summarizes the changes in onsite and offsite NO_X and SO_2 for all of the scenarios analyzed.

For the systems that ICF found to be economical at the various ITC levels, the emission changes increase at higher ITC levels. This is an expected trend. Having the model rule implemented throughout MANE-VU resulted in NO_X benefits at all levels of the ITC, whereas all of the scenarios without full implementation of the model rule resulted in NO_X increases. In all cases there was a benefit in reduced SO_2.

More details on the changes in emissions are in Table 9.

Table 8: Changes in NO_X and SO_2 annual emissions (tons) in the MANE-VU region as a result of CHP replacement

Scenario				Scenario			
		Pollutant	**Total**			**Pollutant**	**Total**
"Technical Potential"	**Onsite**	**NO_X - no Model Rule**	85,993	"30% ITC"	Onsite	NO_X - no Model Rule	686
		NO_X - w/ Model Rule	1,819			NO_X - w/ Model Rule	-246
		SO_2	201			SO_2	4
	Offsite	**NO_X**	-28,894		Offsite	NO_X	-295
		SO_2	-64,628			SO_2	-1,303
	Total	**NO_X - no Model Rule**	57,098		Total	NO_X - no Model Rule	390
		NO_X - w/ Model Rule	-27,075			NO_X - w/ Model Rule	-542
		SO_2	-64,427			SO_2	-1,299
	CHP Capacity (MW)		17,680		CHP Capacity (MW)		303
"Large Units"	**Onsite**	**NO_X**	-5,342	"10% ITC"	Onsite	NO_X - no Model Rule	495
						NO_X - w/ Model Rule	-181
		SO_2	31			SO_2	3
	Offsite	**NO_X**	-1,912		Offsite	NO_X	-211
		SO_2	-9,653			SO_2	-947
	Total	**NO_X**	-7,254		Total	NO_X - no Model Rule	284
						NO_X - w/ Model Rule	-392
		SO_2	-9,623			SO_2	-944
	CHP Capacity (MW)		2,265		CHP Capacity (MW)		221
"Small Units"	**Onsite**	**NO_X - no Model Rule**	91,334	"0% ITC"	Onsite	NO_X - no Model Rule	334
		NO_X - w/ Model Rule	7,160			NO_X - w/ Model Rule	-159
		SO_2	170			SO_2	2
	Offsite	**NO_X**	-12,804		Offsite	NO_X	-161
		SO_2	-58,066			SO_2	-737
	Total	**NO_X - no Model Rule**	78,230		Total	NO_X - no Model Rule	174
		NO_X - w/ Model Rule	-5,644			NO_X - w/ Model Rule	-319
		SO_2	-57,895			SO_2	-735
	CHP Capacity (MW)		15,415		CHP Capacity (MW)		173

Conclusions

With the CHP technologies discussed in this paper, increases in CHP penetration would lead to significant decreases in SO_2 emissions in MANE-VU due to displacement of current base load generation. The same is not true for NO_X emissions, given the increase in onsite NO_X emissions from CHP systems in the vast majority of the scenarios examined. When looking at smaller systems, the replacements need to meet the NO_X standards outlined in the OTC Stationary Generator Model Rule to have a benefit.

Although not specifically addressed in this paper, increased CHP penetration would likely produce the additional benefit of reduced SO_2 emissions. This is an additional consideration that decision-makers should examine when pursuing policies to encourage CHP installations. Finally, there are potential newer technologies on the horizon such as fuel cells. These technologies could reduce the onsite emissions footprint further which would result in more emissions reductions, in particular from NO_X.

Recommendations for Future Work

One limitation of using the ERTAC EGU tool is that economics is not considered on a unit by unit basis, which creates a challenge in ensuring that the CHP systems replace generation from economically marginal units. Additionally, ERTAC EGU segregates generation by fuel further adding to the challenges of only reducing generation from marginal units. Although the technique of creating the "virtual CHP plant" attempted to solve this problem, it would be advisable to attempt using other more appropriate tools in any future analysis. Work is underway to explore incorporating ERTAC EGU projections into the EPA's AVERT (AVoided Emissions and geneRation Tool) model, which is designed to show the impact of renewables and other unconventional generation on the grid. Once that work is complete, the AVERT tool could be very useful for examining the impact of CHP systems in MANE-VU replacing marginal units and peaking units.

Table 9: Changes in NO_X and SO_2 annual emissions (tons) in MANE-VU as a result of CHP replacement

Scenario			**Emission Changes**												
		Pollutant	**CT**	**DE**	**DC**	**ME**	**MD**	**MA**	**NH**	**NJ**	**NY**	**PA**	**RI**	**VT**	**Total**
"Technical Potential"	**Onsite**	**NO_X - no Model Rule**	5,792	-106	0	2,137	7,548	11,430	2,099	-162	34,665	19,843	1,807	939	85,993
		NO_X - w/ Model Rule	222	-106	0	140	430	576	132	-162	-57	542	78	23	1,819
		SO_2	11	2	0	4	13	20	4	28	76	39	3	2	201
	Offsite	**NO_X**	-388	-215	0	0	-6,230	-716	-2,677	-1,180	-4,626	-12,863	0	0	-28,894
		SO_2	-540	-561	0	0	-11,265	-1,508	-3,389	-1,315	-20,786	-25,262	0	0	-64,628
	Total	**NO_X - no Model Rule**	5,405	-320	0	2,137	1,318	10,713	-578	-1,342	30,040	6,980	1,807	939	57,098
		NO_X - w/ Model Rule	-166	-320	0	140	-5,799	-141	-2,545	-1,342	-4,682	-12,321	78	23	-27,075
		SO_2	-530	-559	0	4	-11,252	-1,488	-3,386	-1,287	-20,710	-25,223	3	2	-64,427
	Capacity (MW)		966	0	0	324	1,214	1,871	323	2,457	6,601	3,461	298	165	17,680
"Large Units"	**Onsite**	**NO_X**	-199	-54	0	-11	-136	-254	-23	-1,124	-2,561	-876	-56	-48	-5,342
		SO_2	1	0	0	0	1	2	0	6	15	5	0	0	31
	Offsite	**NO_X**	9	-14	0	1	-285	-235	240	-94	-565	-970	0	0	-1,912
		SO_2	108	-76	0	0	-1,519	-1,394	491	-237	-4,762	-2,265	0	0	-9,653
	Total	**NO_X**	-189	-68	0	-10	-421	-489	218	-1,218	-3,126	-1,846	-56	-48	-7,254
		SO_2	109	-75	0	0	-1,518	-1,392	491	-230	-4,748	-2,259	0	0	-9,623
	Capacity (MW)		78	0	0	6	75	140	9	449	1,079	388	22	19	2,265
"Small Units"	**Onsite**	**NO_X - no Model Rule**	5,991	-52	0	2,148	7,684	11,684	2,122	962	37,226	20,718	1,863	987	91,334
		NO_X - w/ Model Rule	421	-52	0	151	567	830	155	962	2,504	1,417	134	72	7,160
		SO_2	10	2	0	3	12	19	3	22	61	34	3	2	170
	Offsite	**NO_X**	-191	-102	0	1	-2,004	-256	-782	-514	-2,212	-6,744	0	0	-12,804
		SO_2	-540	-491	0	0	-9,892	-1,508	-3,390	-1,158	-19,257	-21,831	0	0	-58,066
	Total	**NO_X - no Model Rule**	5,800	-154	0	2,149	5,680	11,428	1,340	448	35,015	13,974	1,863	987	78,530
		NO_X - w/ Model Rule	230	-154	0	151	-1,437	574	-628	448	293	-5,326	134	72	-5,644
		SO_2	-531	-489	0	3	-9,880	-1,489	-3,386	-1,136	-19,196	-21,797	3	2	-57,895
	Capacity (MW)		888	0	0	318	1,139	1,731	314	2,008	5,522	3,073	276	146	15,415
"30% ITC"	**Onsite**	**NO_X - no Model Rule**	55	-3	0	22	64	98	21	-45	275	173	17	8	686
		NO_X - w/ Model Rule	-6	-3	0	0	-9	-19	0	-45	-119	-43	-1	-2	-246
		SO_2	0	0	0	0	0	0	0	1	2	1	0	0	4
	Offsite	**NO_X**	-7	-1	0	1	-40	-11	-47	-8	-63	-119	0	0	-295
		SO_2	-28	-11	0	0	-209	-71	-149	-35	-547	-254	0	0	-1,303
	Total	**NO_X - no Model Rule**	48	-4	0	22	25	87	-26	-53	212	54	17	8	390
		NO_X - w/ Model Rule	-13	-4	0	1	-49	-30	-47	-53	-182	-162	-2	-2	-542
		SO_2	-28	-10	0	0	-209	-71	-149	-34	-545	-253	0	0	-1,299
	Capacity (MW)		13	0	0	4	19	32	4	42	123	59	4	2	303
"10% ITC"	Onsite	**NO_X - no Model Rule**	40	-2	0	16	46	69	15	-31	200	124	12	6	495
		NO_X - w/ Model Rule	-4	-2	0	0	-8	-15	0	-31	-86	-32	-1	-1	-181
		SO_2	0	0	0	0	0	0	0	0	1	1	0	0	3
	Offsite	**NO_X**	-5	0	0	1	-29	-8	-34	-5	-46	-86	0	0	-211
		SO_2	-21	-8	0	0	-153	-51	-108	-25	-399	-183	0	0	-947
	Total	**NO_X - no Model Rule**	36	-2	0	16	17	62	-19	-36	154	38	12	6	284
		NO_X - w/ Model Rule	-9	-2	0	0	-37	-23	-34	-36	-132	-118	-1	-1	-392
		SO_2	-21	-8	0	0	-152	-51	-108	-25	-397	-182	0	0	-944
	Capacity (MW)		9	0	0	3	14	24	3	30	90	44	3	2	221
"0% ITC"	**Onsite**	**NO_X - no Model Rule**	29	-2	0	11	32	48	11	-27	134	86	9	4	334
		NO_X - w/ Model Rule	-3	-2	0	0	-7	-14	0	-27	-75	-28	-1	-1	-159
		SO_2	0	0	0	0	0	0	0	0	1	0	0	0	2
	Offsite	**NO_X**	-3	0	0	1	-23	-6	-26	-2	-36	-66	0	0	-161
		SO_2	-16	-6	0	0	-119	-38	-82	-20	-315	-141	0	0	-737
	Total	**NO_X - no Model Rule**	25	-2	0	12	9	42	-15	-30	98	20	9	4	174
		NO_X - w/ Model Rule	-7	-2	0	0	-30	-20	-26	-30	-111	-95	-1	-1	-319
		SO_2	-16	-6	0	0	-119	-38	-82	-20	-314	-141	0	0	-735
	Capacity (MW)		7	0	0	2	11	19	2	24	71	34	2	1	173

APPENDIX T

Public Service of New Hampshire

INTRA-COMPANY BUSINESS MEMO

Subject Merrimack Station Unit 2 NOx Control Technology Selection Date July 25, 1994

From B.J. Owens

To D.R. Brown Reference

R.G. Chevalier J.M. MacDonald
J.A. Philbrick J.B. Lander
H.E. Keyes

Title I of the 1990 Clean Air Act Amendments will require substantial reductions in the emission of Nitrogen Oxides (NOx) from each of the three, PSNH fossil fired generating stations, with the most significant reductions occurring at Merrimack Station. Unit 1 and Unit 2 at Merrimack utilize cyclone fired coal fuel boilers, designed and manufactured by Babcock & Wilcox Company. The cyclone furnace firing arrangement was popular from approximately 1940 to 1975 for a number of reasons. Because the cyclones burn crushed coal, approximately 1/4" maximum particle size, less fuel preparation than pulverized coal units is required, reducing capital costs of fuel preparation equipment and operating costs. Because the smaller quantity of flyash produced by the wet bottom units allowed smaller furnace volumes, tighter convection pass tube spacing, and lower precipitator capacities, initial capital cost of the cyclone units was lower than an equivilent capacity pulverized coal fired boiler. The intense temperature of the cyclone fired combustion process at Merrimack however, produces extremely high NOx emission levels, especially from the Unit 2 boiler.

The investigation and evaluation of NOx emission control technologies by PSNH began early in 1992, but has been more difficult at Merrimack Station due to a number of design and operating parameters unique to the cyclone fired boilers. For instance;

- The installation of Low NOx Burners (LNB) would require a complete conversion to pulverized coal, as well as the removal of the existing cyclone furnace burners. The removal of the cyclones and their replacement with conventional burner opening panels would require tremendous modification of both boilers fluid circuitry, especially in the case of the "once-thru" design of Unit 2. The Unit 2 cyclones and their water cooled barrel tubes make up approximately ten percent of the boilers steam generating surface, and their removal would result in an equivilent derating of the unit's generating capacity. Conversion of the boilers to a LNB pulverized coal firing arrangement would not retain the existing wet bottom furnace design, and would s ubstantially increase (by approximately 130%) the amount of particulate flyash loading. Because of the small furnace dimensions and tight convective surface spacing of the original cyclone fired design, additional reductions in each of the units firing rate and generating capacity would be required to avoid the detrimental effects of flyash erosion. *
- Combustion modification methods, such as staged firing or flue gas recirculation are not practical with the existing cyclone firing arrangement, due to the inherent sensitivity of the cyclone combustion process. The cyclones cannot be operated at sub-stoichiometric conditions, because the close proximity of the combustion chemistry to cyclone barrel tubes would allow severe tube corrosion in a reducing atmosphere. In addition, any

* Example: Overfire Air

decrease in the cyclone combustion temperature will adversely affect the fluididity of ash and the ability of the units to "tap" approximately seventy percent of their ash output in a liquid slag form. This tapping ability is essential to essential to the continued operation of both units at Merrimack.

- Pulverized coal reburning, demonstrated at Wisconsin Power and Light's Nelson Dewey Station, has been reviewed for possible application at Merrimack Station on several occasions by Babcock & Wilcox, the original designer and manufacturer of the boilers. The first review several years ago was a marketing effort by B&W, in hopes of finding potential sites for demonstration and application of the technology. More recently, at PSNH's request, Babcock & Wilcox engineers looked at applying pulverized coal reburning to the Merrimack units as a potential Title I NOx compliance strategy. The result of both reviews by B&W was that the furnace height available in both of the units was determined to be insufficient to provide the residence time required for complete fuel particle burnout.
- The use of natural gas as a fuel, either by completely converting the units to gas firing, or in a natural gas reburning application, is not feasible, since sufficient uninterruptible gas supplies are not currently available at the station. Natural gas suppliers have no plans to increase the capacity of the gas distribution system near the station in the immediate future.
- Conversion to other fuels such as oil is viewed as impractical, since the station's ability to burn coal makes it one of the most economical to operate in New England. NOx compliance would most likely not be achieveable with a fuel conversion alone, since compliance to the lower limit of the new fuel would be required.
- Operating the two units at Merrimack at reduced loads decreases NOx emissions from each. Compliance stratagies were examined that would include load reductions and revised outage schedules. These strategies were rejected when reviewed by the Environmental Protection Agency because load reduction was not considered a control technology.

The result of PSNH's review was that post-combustion NOx control technologies, while requiring high capital or operating cost expentitures, appeared to be the most viable means of reducing NOx emissions to the levels required for Clean Air Act compliance. Selective Catalytic Reduction (SCR), despite its widely accepted use with pulverized coal fired units in Europe, and on gas and oil fired units in California, was not initially considered a commercially proven technology for cyclone fired boiler compliance in 1995. Both Merrimack units reinject flyash into the combustion zone to minimize landfill requirements. The temperatures associated with the cylone boiler combustion, coupled with the concentrations of some elements of the reinjected ash have been known to cause early deactivation of conventional catalyst material. During earlier evaluations of potential technologies, this risk of "catalyst poisoning" was considered significant enough to rule out the use of SCR as the Merriamack Unit 2 compliance strategy in 1995. In addition, the high capital costs suggested by Accurex Environmental, EPRI, and others made SCR an economically poor choice. PSNH was hopeful however, that additional technology developments would make SCR a suitable choice for installation in time to meet 1999 compliance requirements.

Considering the relative success of the Selective Non-Catalytic Reduction (SNCR) system demonstration at the cyclone fired Unit 1 of Atlantic Electric's B.L. England Station, that technology was considered the only proven means of reducing NOx to the levels required in 1995, with some additional technology required for compliance with the proposed 1999 range of NOx limits. In February 1994, a Request for Quotation was issued by PSNH to five qualified bidders, for the design and supply of complete SNCR systems for Unit 1 and Unit 2 at Merrimack. Bids were received in March 1994, and during the bid review and evaluation process one vendor offered an unsolicited alternate proposal for a Unit 2 SCR system. This proposal suggested capital costs somewhat lower than earlier estimates, and more importantly, included guarantees of system performance and catalyst life over an extended time period. While SCR requires a significantly higher initial capital investment, the utilization of ammonia reagent is much better with SCR than with SNCR, resulting in a lower consumption and operating cost. In addition, the installation of SCR technology in 1995 will provide a much better framework for 1999 compliance, as additional catalyst is added based on 1995-1999 operating history. After substantial investigation, and evaluation of the available technologies on both a technical and economic basis, Selective Catalytic Reduction (SCR) appears to be the best NOx control strategy for Merrimack's Unit 2.

A Purchase Order has been issued to Noell, Inc., of Long Beach, California for preliminary engineering of an SCR system capable of achieving the proposed NOx limits. This action was initiated to help address the extremely tight schedule we are facing, while we determine the other regulatory implications of such a capital intensive solution.

If you have any quesitons or need additional information, feel free to call.

B.J. Owens

GSP MERRIMACK

431 River Road
Bow, NH 03304

May 25, 2018

Mr. Craig A. Wright
Director, Air Resources Division
NH Department of Environmental Services
29 Hazen Drive, PO Box 98
Concord, NH 03302-0095

Re: Proposed Nitrogen Oxide Reasonably Available Control Technology Limit for Merrimack Station, Bow, New Hampshire
N.H. Code Admin. R. Ch. Env-A 1300

Dear Director Wright:

GSP Merrimack LLC submits the enclosed comments in response to the New Hampshire Department of Environmental Services' proposed changes to the Nitrogen Oxide Reasonably Available Control Technology rule, N.H. Code Admin. R. Ch. Env-A 1300, dated April 19, 2018.

We look forward to discussing these comments with you. Please do not hesitate to call me or Melissa Cole, P.E., if we can provide any additional information.

Sincerely,

Elizabeth H. Tillotson

Elizabeth H. Tillotson

Executive Director of Administration & Regulatory Affairs
Granite Shore Power LLC

cc: Melissa Cole, P.E., Granite Shore Power LLC
Linda Landis, Esq., Balch & Bingham
Mary F. Samuels, Esq., Balch & Bingham
Julia B. Barber, Esq., Balch & Bingham

GSP Merrimack LLC's Comments on DES' Proposed Nitrogen Oxides Reasonably Available Control Technology Limit for Merrimack Station

I. Introduction

GSP Merrimack LLC ("GSP") submits these comments in response to the New Hampshire Department of Environmental Services' ("DES") proposed changes to the nitrogen oxides (NOx) reasonably available control technology ("RACT") rule, N.H. Code Admin. R. Ch. Env-A 1300, dated April 19, 2018.[1] As the owner and operator of Merrimack Station, GSP appreciates the opportunity to comment on DES' proposed revisions to the RACT limits, which directly affect two cyclone boilers at Merrimack Station. While GSP recognizes DES' responsibility to ensure that up-to-date RACT limits apply to sources in the State, DES' proposed limits for Merrimack Station exceed the requirements of RACT and are not technologically or economically feasible. As explained below, DES' proposed limits do not consider the unique boiler and equipment design or current dispatch of the units. In short, DES' proposed limits are more stringent than the designed and proven capability of the units.

For these reasons, GSP urges DES to consider GSP's proposed alternative limits and averaging times outlined below. Specifically, GSP encourages DES to establish a RACT limit for MK1 of 0.22 lb/mmBtu NOx on a 7-boiler operating day average, excluding hours when the selective catalytic reduction ("SCR") permissives are not met and a limit of 5.5 tons of NOx per day on a 24-calendar day average that applies at all times. For MK2, GSP encourages DES to establish a RACT limit of 0.25 lb/mmBtu NOx on a 7-boiler operating day average, excluding hours when the SCR permissives are not met and a limit of 15.4 tons of NOx per day on a 24-calendar day average that applies at all times. While such limits would still impose additional operational and cost burdens on GSP, they satisfy RACT and would achieve additional NOx reductions while providing the necessary operational flexibility for the units.

II. Background

A. Procedural History

On March 12, 2008, the Environmental Protection Agency ("EPA") revised the primary and secondary National Ambient Air Quality Standards ("NAAQS") for ozone, establishing an 8-hour standard.[2] In 2012, EPA designated all areas in New Hampshire as in attainment for the new 8-hour standard.[3] However, because New Hampshire is part of the Ozone Transport Region ("OTR"), it is subject to additional requirements as outlined in section 184(b) of the Clean Air Act ("CAA").[4] Specifically, New Hampshire must submit to EPA a revision to its State Implementation Plan ("SIP") demonstrating, pursuant to Section 182(f) of the CAA, that up-to-date NOx RACT

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[1] Vol. XXXVIII, No. 16 N.H. Rulemaking Reg. 3 (Apr. 19, 2018).

[2] 73 Fed. Reg. 16,436 (Mar. 27, 2008).

[3] 77 Fed. Reg. 30,088, 30,135 (May 21, 2012).

[4] The OTR is comprised of Connecticut, Delaware, the District of Columbia, Maine, Maryland, Massachusetts, New Hampshire, New Jersey, New York, Pennsylvania, Rhode Island, Vermont, and Virginia. These states are required to submit RACT SIP revisions and mandate certain levels of controls for pollutants that form ozone, even if they meet the ozone standards. 82 Fed. Reg. 9,158, 9,160 (Feb. 3, 2017).

requirements exist for all major stationary sources of NOx in the State, including Merrimack Station.[5]

Accordingly, in March 2014, DES submitted a draft RACT certification to EPA explaining why DES' existing regulatory provisions constitute RACT.[6] DES reasoned that, based on the State's attainment designation and monitored data, New Hampshire did not need additional emission reductions in order to attain and maintain the new 8-hour (2008) ozone standard.[7] On April 18, 2014, EPA responded to DES' draft certification and recommended, in part, that DES review its current NOx RACT requirements for electric generating units ("EGUs") to determine whether more stringent requirements are technologically and economically feasible.[8] With respect to Merrimack Station, EPA looked to the lowest annual average emission rate from historical data to support its recommendation. EPA also noted that reducing NOx emissions at Merrimack Station is expected to improve air quality in New England, and in particular, Maine.[9] Final RACT submissions were due to EPA by July 20, 2014.

On February 3, 2017, EPA issued findings of failure to submit to a number of states, including New Hampshire, due to the lack of required SIP submittals.[10] New Hampshire now must submit a completed SIP that includes an updated NOx RACT rule to EPA in advance of the 18 month sanctions clock, which is set to expire on September 6, 2018.[11]

On April 19, 2018, DES issued proposed amendments to the NOx RACT rule, which included lowering the NOx emissions standards for wet bottom utility boilers firing coal.[12] This rule directly impacts two units at Merrimack Station, referred to as "MK1" and "MK2." Specifically, DES proposed to lower the emission limit for MK1 from 0.92 lb/mmBtu based on a 24-hour calendar day average to 0.22 lb/mmBtu based on a 7-boiler operating day rolling average. For MK2, the proposed rule lowers emission limits from 1.4 lb/mmBtu based on a 24-hour calendar day average to 0.25 lb/mmBtu based on a 7-boiler operating day rolling average.[13] DES' proposed limits include all hours of operation, including startup, shutdown, and low-load conditions, when the SCR system, the pollution control technology for NOx, is not able to operate.

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[5] 40 C.F.R. § 51.1116; 80 Fed. Reg. 12,264 (Mar. 6, 2015).

[6] NHDES, *Revision to New Hampshire State Implementation Plan, Certification of Reasonably Available Control Technology for the 8-hour Ozone National Ambient Air Quality Standard*, Preliminary Draft (Mar. 13, 2014).

[7] *Id.* at 6.

[8] Letter from Anne Arnold, EPA Region 1 Air Quality Planning Unit, to Barbara Hoffman, NHDES SIP Planning Manager (Apr. 18, 2014) (transmitting EPA's Comments on New Hampshire's March 13, 2014 Draft RACT Certification for the 2008 Ozone Standard).

[9] EPA, *Comments on New Hampshire's March 13, 2014 Draft RACT Certification for the 2008 Ozone Standard* 2 (Apr. 18, 2014). Notably, on November 16, 2017, EPA designated all of New Hampshire and all of Maine as in attainment/unclassifiable with the 2015 ozone standard. 82 Fed. Reg. 54,232, 54,253, 54,263 (Nov. 16, 2017).

[10] 82 Fed. Reg. 9,158 (Feb. 3, 2017).

[11] *Id.* at 9,160-61. According to EPA, the RACT SIP requirements of the 2008 8-hour ozone NAAQS will be retained for the revised ozone standards EPA promulgated in 2015, and DES' RACT SIP amendment is intended to cover both standards. 81 Fed. Reg. 81,276 (Nov. 17, 2016).

[12] NHDES, Chapter Env-A 1300 Initial Proposal (Mar. 26, 2018), *available at* https://www.des.nh.gov/organization/commissioner/legal/rulemaking/documents/env-a1300-ip.pdf.

[13] Proposed N.H. Code Admin. R. Env-A 1303.5(b), (c).

Prior to DES' proposal, GSP participated in extensive discussions with DES regarding technologically and economically feasible limits for Merrimack Station. However, DES' proposal does not reflect all prior discussions between GSP and DES. Further, DES provided no technical or economic justification for the proposed limits. This is not only inconsistent with DES' customary practice of providing a justification document with proposed rulemakings, but it also presents a significant challenge in commenting on DES' proposed limits.[14]

On May 14, 2018, EPA Region 1 submitted comments on DES' proposed RACT limits.[15] While GSP appreciates EPA's input, GSP has significant concerns with EPA's recommended NOx limits and averaging period. As explained below, both DES' and EPA's proposed limits exceed the requirements for RACT and are not technologically or economically feasible for Merrimack Station.

B. Merrimack Station Is Unique From Other EGUs

Merrimack Station is a fossil fuel-fired electricity generating facility. The facility is comprised of two cyclone-fired utility boilers ("MK1" and "MK2") that burn bituminous coal. MK1 and MK2 are each equipped with SCR systems for the control of NOx emissions and electrostatic precipitators ("ESP") for the control of particulate matter ("PM"). In 2011, a wet limestone-based flue gas desulfurization ("FGD") system was installed to control the emissions of sulfur dioxide (SO_2), mercury, and hydrochloric acid from MK1 and MK2. Each unit is equipped with continuous emissions monitoring systems ("CEMS") and a continuous opacity monitoring system, and a CEMS is installed on the common stack.

Cyclone boilers such as MK1 and MK2 are specially engineered to utilize fuels containing mineral matter (ash) that have a very low melting temperature. Cyclone boilers use a cyclonic action to separate the slag from the flame, draining the slag to a collection tank. It is necessary for cyclone boilers to combust at higher temperatures than other coal units to ensure the slag properly drains and exits the boiler. One drawback of needing to maintain high combustion temperatures is the relatively high production of thermal NOx as compared to other coal combustion designs. As a result, the "uncontrolled"[16] NOx emissions at Merrimack Station are higher than at other coal facilities.

Merrimack Station currently implements the most effective technology available for maximum NOx reductions, SCRs. In fact, Merrimack Station was the first investor owned utility in the nation to install an SCR to achieve NOx reductions. MK2's SCR became operational in 1995, and MK1's SCR was added in 1999. Merrimack Station also implements an aggressive catalyst management plan that ensures optimal NOx removal efficiencies for the SCRs. Each SCR has four

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[14] Although DES submitted a Draft Technical Support Document for the proposed amendments to the RACT rule on December 28, 2017, that document contains no information on proposed limits for Merrimack Station, stating simply that Merrimack Station's permitted emission limits are still being reviewed. NHDES, *Changes to Chapter Env-A 1300 Nitrogen Oxides (NOx) Reasonably Available Control Technology (RACT) to Meet 2008 and 2015 Ozone Standards State Implementation Plan Requirements, Draft Technical Support Document* 8 (Dec. 28, 2017).

[15] Letter from Anne McWilliams, U.S. EPA Region 1, to Karla McManus, DES Air Res. Div. (May 14, 2018) (enclosing comments on DES' proposed revisions to Env-A 1300, NOx RACT).

[16] NOx emission rates for pre-NSPS units are often described as "uncontrolled" because these units were not designed to minimize NOx emissions. *See* EPA, *Alternative Control Techniques Document – NOx Emissions from Utility Boilers* 4-20 (Mar. 1994).

catalyst layers. Merrimack Station incorporates advances in technology each time a catalyst layer is replaced. Nevertheless, the SCRs on MK1 and MK2 are 19 and 23 years old, respectively. The four layers of catalyst in each system continuously degrade during their replacement cycle, thereby reducing efficiency. Additionally, the remaining SCR system components have typical wear associated with the age of the equipment. Thus, these SCRs are not capable of exceeding or continuously meeting the maximum reductions seen in the early years of their installation, as those maximum reductions were realized under an entirely different set of operating conditions. For example, in the early years the SCR had four new catalyst layers (each under 2 years old), which is not a scenario that would be repeated, as Merrimack Station implements a staggered catalyst replacement cycle. Additionally, the units at the time had consistent, steady-state operations and did not have to consider the complexity of balancing operations with respect to other pollution control equipment that has since been added.

C. Merrimack Station's Current Operations

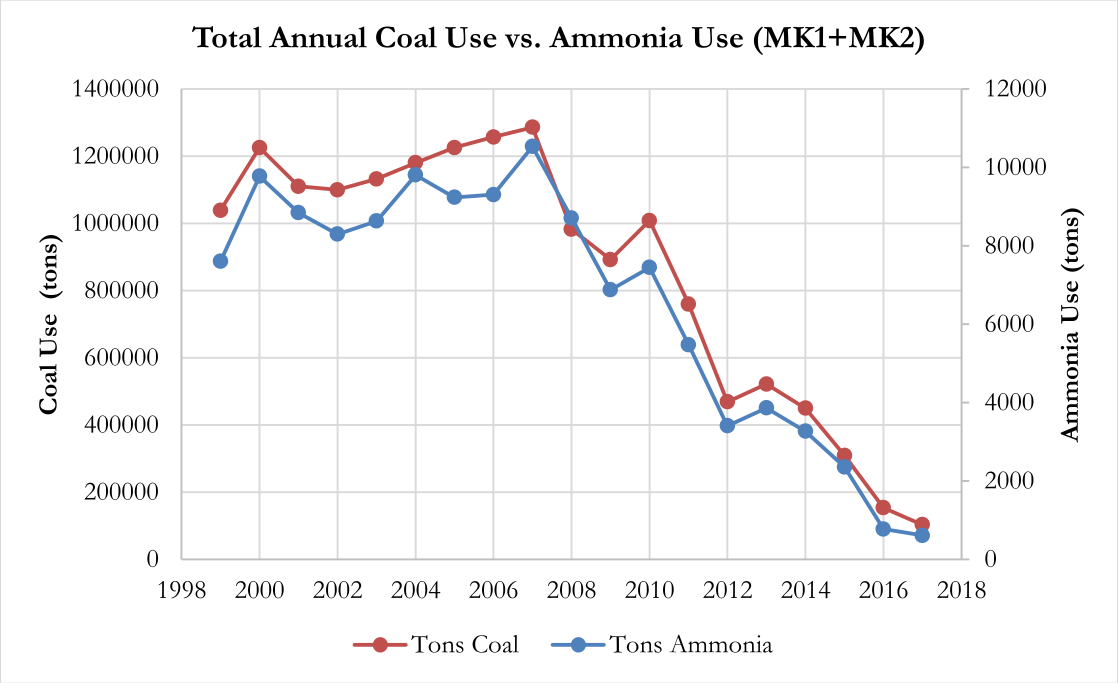
MK1 and MK2 were historically operated as base-loaded units in the early 2000s. In the last few years, due to the increased supply of natural gas to the region, the units have operated at significantly lower capacity factors annually. Therefore, the units operate significantly fewer hours annually with significantly fewer emissions. However, the ratio of startup/shutdown hours to steady-state/full load hours is much higher. This change in operation significantly impacts the annual average NOx emission rate (lb/mmBtu), particularly because the number of startup hours (when the SCR is not yet in operation) has increased and the number of hours of steady-state operation (when the SCR is in operation) has dramatically decreased. In its 2014 comments, EPA noted an upward trend in the annual average NOx emission rate (lb/mmBtu) from MK1 and MK2. However, as shown in the tables below, this trend is consistent with the changes in unit dispatch (i.e., more startups and less steady-state operation). Specifically, the capacity factor has decreased from 96% to 9% on MK1 and from 83% to 5% on MK2 between 2007 and 2017.

Capacity Factor (%)		
Unit	2007	2017
MK1	96	9
MK2	83	5

Therefore, the percentage of time the SCR permissives (i.e., the parameters necessary for the SCR to operate) are not met has increased by from 1% to 17% for MK1 and 2% to 27% for MK2, as shown below.

Comparison of SCR "Off" Time with Total Hours of Operation		MK1	MK2
2007	SCR On Hours (permissives met)	8469	7379
	SCR Off Hours (permissives not met)	87	145
	Total Hours	8556	7524
	% of Hours with SCR Off (permissives not met)	1%	2%
vs.			
2017	SCR On Hours (permissives met)	920	529
	SCR Off Hours (permissives not met)	193	191
	Total Hours	1113	720
	% of Hours with SCR Off (permissives not met)	17%	27%

As DES is aware, Merrimack Station has aggressively reduced NOx emissions for over 20 years. Merrimack Station has always operated the SCR year-round within its technical and cost-effective range. In fact, MK1 NOx emissions continue to be approximately 60% below the existing applicable NOx RACT limits. The graph below illustrates the correlation between coal use and ammonia use, which confirms that Merrimack Station utilizes its SCRs efficiently and that any increase in the NOx emissions rate is related to changes in operation rather than inefficient use of the SCR or reagent.[17]



Moreover, Merrimack Station's laudable effort to reduce NOx emissions is reflected by the significantly reduced total annual mass NOx emissions.

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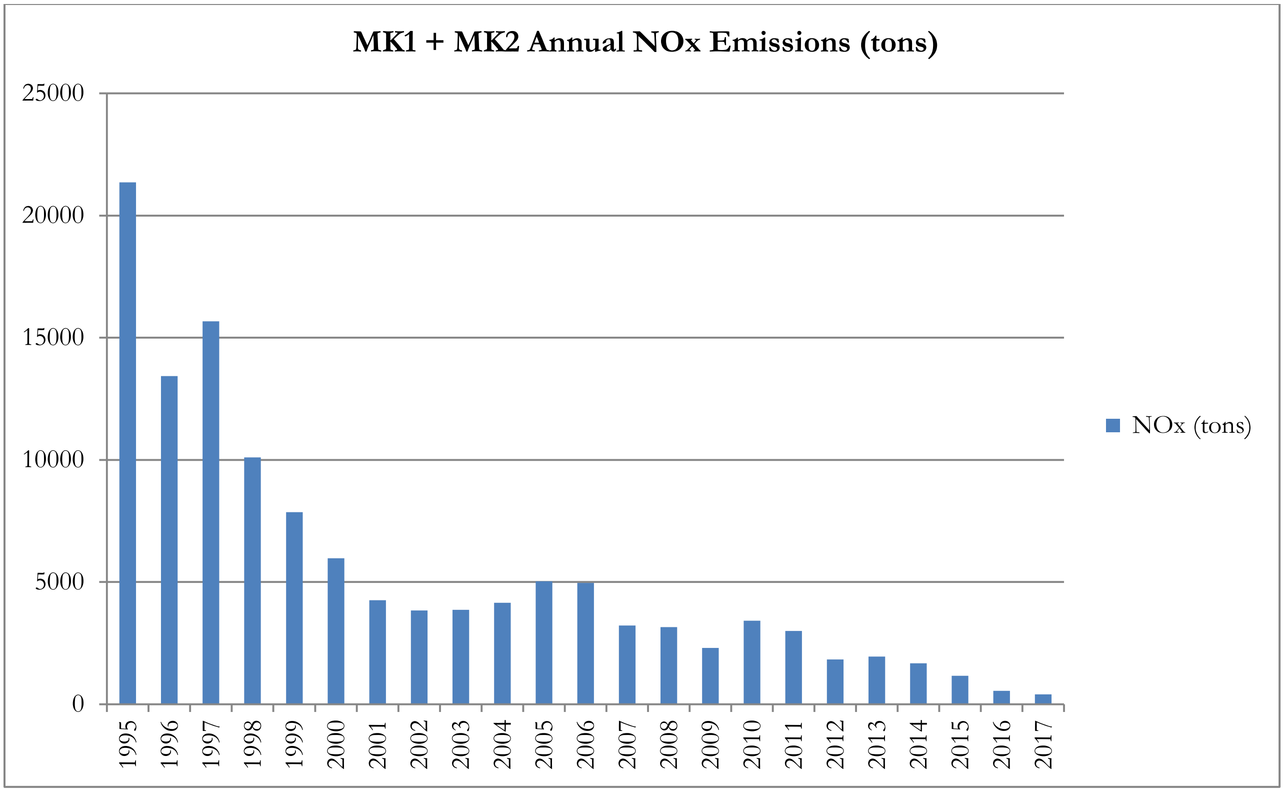
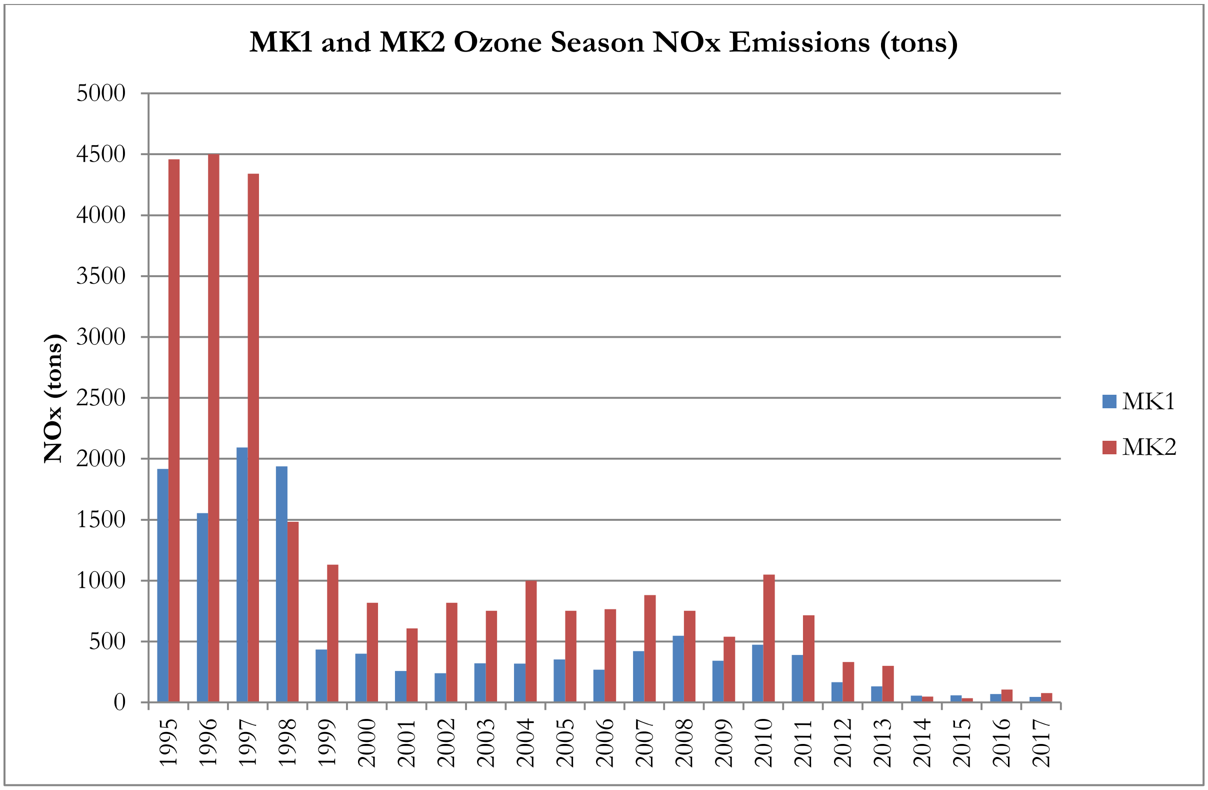
[17] Coal use is "as combusted" and ammonia use is from annual purchase records.



Notably, Merrimack Station's ozone season NOx emissions have decreased dramatically and are negligible in recent years.



Going forward, Merrimack Station anticipates continuing its NOx reduction efforts while providing reliable power. To do that successfully, operational flexibility is required. It is critical to understand that such operational flexibility is necessary to ensure consistent compliance with the NOx RACT emission limits.

III. The RACT Standard

RACT generally applies to areas in nonattainment with a NAAQS standard for a criteria pollutant. EPA has defined RACT as "the lowest emission limitation that a particular source is capable of meeting by the application of control technology that is reasonably available considering technological and economic feasibility."[18] RACT should include "only control technologies that advance attainment."[19] RACT does not dictate the form of the standard or how states must implement it. Instead, "RACT for a particular source is determined on a case-by-case basis, considering the technological and economic circumstances of the individual source."[20] And, although EPA has encouraged the use of presumptive norm levels of control for RACT when available, EPA has also recognized that the presumptive norm "[does] not take into account the unique circumstances of each facility," stating that, "[i]n many cases appropriate controls would be more or less stringent."[21] "The presumptive norm is only a recommendation. For any source or group of sources, regardless of whether they fall within the industry norm, the State may develop case-by-case RACT requirements independently of EPA's recommendation."[22]

Further, the OTR's advisory organization, the Ozone Transport Commission ("OTC"), has created recommended principles for RACT. In these principles, the OTC defines RACT as "levels of control, and emission rates, that are achieved in practice by existing similar sources [and] are technologically and economically feasible, *considering capacity, fuel, equipment design, control technology, age and site limitations*."[23]

Even though New Hampshire is in compliance with the 2008 and 2015 ozone NAAQS, DES is still required to submit a SIP with up-to-date NOx RACT limits because of its inclusion in the OTR. However, New Hampshire's inclusion in the OTR does not justify imposition of an unreasonable standard on the facility. EPA establishes ozone transport regions when it "has reason to believe that the interstate transport of air pollutants from one or more States *contributes significantly* to a violation of a [NAAQS] in one or more other States . . . ."[24] Congress established the northeast corridor OTR because "transport of ozone and its precursors ha[d] been clearly demonstrated" for those states, including New Hampshire.[25] Notably, in EPA's 2014 comments on DES' draft RACT

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[18] 44 Fed. Reg. 53,761, 53,762 (Sept. 17, 1979); 57 Fed. Reg. 55,620, 55,624 (Nov. 25, 1992).

[19] *See NRDC v. EPA*, 571 F.3d 1245, 1253 (D.C. Cir. 2009).

[20] 44 Fed. Reg. at 53,762.

[21] *Id.*

[22] *Id.* at 53,762-63.

[23] Ozone Transport Commission, *Statement of Reasonably Available Control Technology Principles*, June 11, 2014 (emphasis added).

[24] 42 U.S.C. § 7506a(a) (emphasis added).

[25] 136 Cong. Rec. S16895-01 (daily ed. Oct. 27, 1990).

certification, EPA expressed concern about Merrimack Station's impact on ozone levels in Maine. However, all areas in both New Hampshire and Maine have been designated attainment/unclassifiable with the 2008 and 2015 ozone NAAQS.[26]

There is simply no indication that emissions from Merrimack Station are "contributing significantly" to a violation of the ozone NAAQS in one or more other states. This was confirmed by EPA's 2016 Cross-State Air Pollution Rule ("CSAPR") Update, where EPA determined that emissions from New Hampshire "do not significantly contribute to nonattainment or interfere with maintenance of the 2008 ozone NAAQS in downwind states."[27] Accordingly, EPA did not require further reductions from sources in New Hampshire.[28] Therefore, the proposed limitations, which go beyond the confines of RACT, are not proper and cannot be justified for Merrimack Station.[29]

Moreover, RACT is generally less stringent than other control programs under the CAA. EPA has stated that "both BACT and [lowest achievable emission rate ("LAER")] require, in almost all cases, a more stringent . . . level of emissions control than RACT."[30] Because "RACT requires that sources adopt controls that are reasonably available . . . they may not be the most stringent controls that have been adopted for other similar sources."[31] RACT should certainly be no more stringent than BART, which analyzes *best* available *retrofit* technology, rather than *reasonably* available control technology. For Merrimack Station, DES' proposed RACT limit for MK2 is more stringent than its BART limit. Specifically, DES proposes a limit of 0.25 lb/mmBtu over a seven day average for RACT, as compared to the BART limit of 0.30 lb/mmBtu based on a 30-day average.[32] Not only is this RACT limit more stringent than the BART limit, but it also relies on a significantly shorter

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[26] 77 Fed. Reg. at 30,127, 30,135; 82 Fed. Reg. at 54, 253, 54,263. In fact, the State of Maine has been exempt from the OTR requirements related to the 8-hour ozone NAAQS because Maine's Department of Environmental Protection submitted a technical demonstration showing that "NOx emissions in Maine are not having a meaningful adverse impact on the ability of any nonattainment areas located in the [OTR] to attain the ozone standards during times when elevated ozone levels are monitored in those areas." 79 Fed. Reg. 43,945, 43,945-46 (July 29, 2014). Such similar exemption may be appropriate for New Hampshire.

[27] 81 Fed. Reg. 74,504, 74,506 (Oct. 26, 2016).

[28] *Id.*

[29] EPA has indicated that states may require NOx reductions that are "'beyond RACT" if such reductions are needed in order to provide for timely attainment of the ozone NAAQS." 78 Fed. Reg. 34,178, 34,193 (June 6, 2013). Because New Hampshire and Maine are both in attainment with the ozone NAAQS, additional reductions beyond RACT requirements are improper and cannot be justified for this facility.

[30] 79 Fed. Reg. 30,737, 30,739 (May 29, 2014); *see also* 66 Fed. Reg. 52,862, 52,866 (Oct. 18, 2001) (EPA noted that requirements such as BACT and LAER "are often more stringent than RACT.").

[31] 79 Fed. Reg. at 30,739 (quoting EPA, *RACT Qs & As – Reasonably Available Control Technology (RACT): Questions and Answers* (May 18, 2006)).

[32] Moreover, the D.C. Circuit has ruled that complying with the requirements of CSAPR satisfies BART. *Util. Air Regulatory Grp. v. EPA*, 885 F.3d 714 (Mar. 20, 2018). New Hampshire is in attainment with the 2008 and 2015 ozone NAAQS, and is not even subject to the CSAPR Update. Thus, a limit that is more stringent than BART is not necessary or reasonable for the facility. Of particular interest is EPA's cost analysis under CSAPR where EPA concluded that more costly NOx reductions from EGUs would provide little additional benefit and were not needed to address ozone NAAQS attainment and maintenance issues. 78 Fed. Reg. 48,208, 48,256 (Aug. 8, 2011).

averaging time. This is contrary to EPA's general permitting policy, whereby emission limits increase as the averaging period decreases.[33]

The proposed limits are also more stringent than RACT and BACT limits for other similar cyclone units. For example, Maryland's C.P. Crane's cyclone boilers are subject to Maryland's NOx RACT Averaging Plan. This requires the units to meet a limit of 0.70 lb/mmBtu from May 1 through September 30 (ozone season) and a limit of 1.50 lb/mmBtu from October 1 through April 30 (non-ozone season).[34] As another example, Minnkota Power's Milton R. Young is subject to BACT, and its NOx limits for Unit 1 include a 0.36 lb/mmBtu NOx limit on a 30-day rolling average, excluding startup, and a 2,070.2 lb/hr limit on a 24-hour rolling average during startup.[35] Similarly, Milton R. Young Unit 2 has a limit of 0.35 lb/mmBtu on a 30-day rolling average, excluding startup, and a 3,995.60 lb/hr 24-hour average limit during startup.[36] Although RACT must be determined on a case-by-case basis, and DES must take into account the unique attributes of each facility, the significant discrepancies between DES' proposed determination here and the RACT and BACT limits of other, similar sources highlight that the proposed NOx RACT for Merrimack Station is not technologically or economically feasible.

IV. The Proposed Limits Must Be Technologically Feasible

EPA has explained that "[f]or purposes of evaluating the technological feasibility of a potential control measure, the state may consider factors including but not limited to a source's processes and operating procedures, raw materials, physical plant layout, and potential environmental impacts such as increased water pollution, waste disposal, and energy requirements."[37] The proposed limits do not reflect the unique circumstances at Merrimack Station concerning its technological capabilities, including equipment design (i.e., cyclone boilers have inherently higher uncontrolled NOx emissions), control technology limitations (SCRs cannot operate to control NOx emissions during periods of startup, shutdown, or low load), early installation of the SCR technology , operations of multiple control devices (SCR, FGD, ESP) which must work collectively to reduce a variety of emissions, and operating schedule (primarily peaking with traditional operation in winter months and intermittent operation in the ozone season). Instead, they appear to be presumptive limits established for typical boilers operating in a continuous, steady state. Presumptive limits established for typical base load units are simply not achievable for peaking cyclone boilers.

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[33] EPA, *Guidance for 1-Hour SO2 Nonattainment Area SIP Submissions* 24 (Apr. 23, 2014) ("A limit based on the 30-day average of emissions, for example, at a particular level is likely to be a less stringent limit than a 1-hour limit at the same level since the control level needed to meet a 1-hour limit every hour is likely to be greater than the control level needed to achieve the same limit on a 30-day average basis."); *see also* Pat Foley, EPA, *Limit Setting: Averaging Times and Statistical Analysis* at Slide 26 (Mar. 2010), *available at* http://www.marama.org/calendar/events/presentations/2010_03Permit/Foley_PermitsAveragingPeriods_Mar10.pdf. ("EPA's Emissions Limit PowerPoint"). Although this presentation seems to be tailored to the petroleum refining industry, the same permitting principles should apply to any industry.

[34] State of Maryland Department of the Environment, C.P. Crane LLC Part 70 Operating Permit issued June 1, 2016, at 42-43.

[35] *See* RACT/BACT/LAER Clearinghouse for Minnkota Power Cooperative's M.R. Young Station.

[36] *Id.*

[37] 40 C.F.R. § 51.1009(a)(3)(i) (discussing RACT and Reasonably Available Control Measures ("RACM") for $PM_{2.5}$).

A. The existing SCRs are the only reasonably available NOx controls for Merrimack Station

The SCRs at Merrimack Station were installed over twenty years ago, and the proposed limits would require emissions reductions beyond the design efficiencies and capabilities of the SCRs as well as the capabilities of the units. Moreover, the necessity of having to maintain high combustion temperatures in the cyclone boilers restricts the operational changes available to the boilers to limit NOx formation. However, other possible control mechanisms, such as fuel switching or over-fire air ("OFA") cannot be technologically or economically justified, as the additional reductions achievable from these strategies are minimal when installed after the SCR. Moreover, these controls cannot be physically added to the units at Merrimack Station because they would cause operational issues and reduce the efficiency of other pollution control devices. For example, fuel switching for Merrimack Station would mean firing sub-bituminous coal. Although the units are not permitted to burn sub-bituminous coal, if this lower rank fuel was used, it would result in a loss of boiler efficiency and a probable increase in heat rate. This would require Merrimack Station to burn more fuel, causing an increase in emissions. It would also impact Merrimack Station's mercury capture and the efficiency of the precipitator. Overall, this fuel would not provide reliable unit operations and would not be considered a viable alternative to the current use of bituminous coal.

Over-fire air also poses several issues and is an unacceptable solution. The negative impacts include reduced boiler performance, potential boiler modifications to boiler surface areas, increased fouling, boiler tube erosion, and cyclone wear. Any installation is complicated by, if not impossible, due to the engineering and design challenges of the windbox configuration and screen tubes at Merrimack. While the negatives are many, an installation of an OFA system after the installation of an SCR is likely to produce little to no improvement in NOx reductions. Any of these changes would also have the potential to negatively impact the removal capability of the FGD and the collection capability of the ESPs. Since the proposed limits would require utilization of the SCRs at such high removal rates (i.e., high ammonia injection rates) that other operational problems could occur. For instance, since the SCRs are also used to oxidize elemental mercury to ionic mercury to facilitate mercury removal across wet FGD controls for the Mercury and Air Toxics ("MATS") rule, the beneficial effects of mercury oxidation could be reduced by the high ammonia injection rates. High ammonia injection rates could also cause opacity upsets due to the negative impact on the ESPs collection capability.

B. Separate limits must apply when the SCR permissives cannot be met

Numerous variables can affect the efficiency of the SCRs, and the emission limits must account for these constraints. As is true with any SCR system, several parameters must be met for the SCRs to operate. Most importantly, a permissive inlet gas temperature limit must be met for the SCRs to begin functioning and to continue to function. Thus, during startup, shutdown, low-load, testing, and malfunction periods, when the permissive limits are not met, the SCRs are not able to operate to control NOx emissions. Other required operational parameters that must be satisfied for the SCR to operate include average SCR catalyst temperature, ammonia mix air flow, and ammonia tank level. Furthermore, as shown in the table below, several events can reduce the effectiveness of an SCR system. Thus, although SCR systems are very effective at reducing NOx emissions, the systems can be influenced by a number of factors that can ultimately affect their removal efficiency.

Event	Details
Ammonia control system response issues	Delays in systems ability to adjust to fluctuations in load, gas flows, temperatures, mixing ratios, etc. to achieve new equilibrium
Accuracy of the feedback parameter	Inlet NOx concentration assumed (either using fixed value, or changed using manual inputs) in calculations to determine NH_3 flow and then corrected via feedback from NOx outlet analyzer Cannot over-inject, NH_3 slip minimized to prevent downstream equipment plugging
Ammonia injection distribution	Plugged nozzles Temperature profiles within ducts
Failure of a portion of the ammonia delivery system	Piping, valves, gauges, flow meters, vaporizers, mixers, injection grid (maintenance managed under OSHA PSM program) Mechanical issues or PLC faults
Catalyst Issues	Surface plugging (sootblowing used to prevent, vacuumed during outages) Deterioration of reaction sites due to combustion byproducts (sampling program used to determine catalyst activity and changeout schedule)

GSP supports EPA's recommendation that a separate limit apply during startup and shutdown events and is prepared to work with DES, as suggested by EPA, to determine the appropriate startup and shutdown metric for these units. However, as noted above, there are additional time periods when the SCRs are not operational and these periods should also be subject to alternative limits. In particular, DES must take into account the limitations on the SCR during low-load periods.[38] These low-load operations occur for discrete, short durations, and despite the inability of the SCR to operate, do not necessarily result in increased NOx emissions on a mass basis

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[38] Examples of low-load periods include, but are not limited to, the following:

- Forced and planned startups and shutdowns (separate limits contemplated by DES/EPA)
- Loss of one of any equipment pair. Both pieces are necessary for full load operation and the loss of one results in temporary half load operation (such as forced draft fans, condensate pumps, etc.);
- Loss of the main boiler feed pump;
- Loss of coal feeders, condenser waterbox cleaning, etc.; and
- Any condition which results in the flue gas temperatures to be below the SCR permissive temperature will result in the SCR not able to be put in service or remain in service.

because of the lower heat inputs at which these conditions occur. However, these scenarios would certainly exceed the overly stringent rate-based daily permit limits contemplated by EPA.

In its comments, EPA evaluated startup and shutdown data for the three-year period from 2015 to 2017 but did not review low-load operations during that period. Although GSP believes that operating temperatures provide a better indicator of when the SCR is able to operate, GSP performed a high-level analysis of low-load operations for MK1 using 90 MWg as the threshold for illustrative purposes only. The table below illustrates that low-load conditions occurred on up to 23 percent of operating days during this period. Even a single hour with low-load operation is enough to skew the daily average such that compliance with an aggressive daily limit cannot be met. GSP does not believe it is DES' or EPA's intention to set limits that would have less than an 80 percent chance at success.

MK1 Summary of "Low-Load" Operation
(when SCR cannot operate, excludes SU/SD)

Year	Total # of hours low-load	Total # of days (with at least 1 hr low-load)	Total Hours (non-startup/shutdown)	Total # days of operation (assume 24-hr days)	% of days with low-load operation
2015	49	14	2270	95	15%
2016	24	10	1451	60	17%
2017	30	9	950	40	23%

The need for operational flexibility that allows for infrequent, intermittent low-load operation exists for both MK1 and MK2.

For example, to meet the rate referenced by EPA of 0.2 lb/mmBtu on a 24-hour basis, MK2 would need to operate at a rate of 0.17 lb/mmBtu (93% efficiency) for 23 hours just to afford a single hour of partial load operation at 0.80 lb/mmBtu. This operational efficiency is beyond the design of the SCR and, most importantly, beyond the current realistic sustainable capability of the unit. If Merrimack Station were required to utilize the SCRs beyond their design efficiency at such high removal rates (i.e., high ammonia injection rates), other operational problems noted above would likely occur (e.g., plugging air heater, more frequent maintenance outages, fouled reagent distribution nozzles, accelerated catalyst deterioration, or loss of production). A NOx RACT emission limit must not be set at a level that is beyond what the reasonably available control technology is designed to achieve.

In addition, the units are required to perform multi-load Relative Accuracy Test Audits of the continuous emission monitoring systems ("CEMS") in accordance with 40 CFR Part 75. It would be contradictory for DES/EPA to require low-load operation for quality assurance testing when such operations would *guarantee* an exceedance of the facility's daily NOx emission limit. Low load operation is beneficial to grid stability, particularly during high demand periods, and limiting operational flexibility could result in the unnecessary shutdown of the unit. The proposed limits must not take away short-term, partial load capability.

C. The emission limits must provide operational flexibility

In setting emissions limits, a compliance margin or "safety factor" between the lowest possible emission rate and the permit limitation must be established to allow for normal operational events to occur. In discussing the best available control technology ("BACT") standard, which is generally more stringent than, and certainly no less stringent than, RACT, EPA's Environmental Appeals Board ("EAB") explained that BACT levels "do not necessarily reflect the highest possible control efficiencies but, rather, will allow permittees to achieve compliance on a consistent basis."[39] In fact, EPA has "approved the use of a so-called 'safety factor' in the calculation of [an emission] limit to account for variability and fluctuation in expected performance of the pollution control methods."[40] If an emission limit is set "to reflect the highest control efficiency, . . . violations of the permit [would be] unavoidable."[41] As the EAB previously explained:

> In essence, Agency guidance and [the EAB's] prior decisions recognize a distinction between, on the one hand, measured "emissions rates," which are necessarily data obtained from a particular facility at a specific time, and on the other hand, the "emissions limitation" determined to be BACT and set forth in the permit, which the facility is required to continuously meet throughout the facility's life. Stated simply, if there is uncontrollable fluctuation or variability in the measured emission rate, then the lowest measured emission rate will necessarily be more stringent than the "emissions limitation" that is "achievable" for that pollution control method over the life of the facility.[42]

Additional EPA guidance indicates that in order to account for process and emissions variability, different statistics are used to develop long-term vs. short-term limits.[43] Long-term limits are based on ranked 95th percentile and short-term limits (such as 24-hour or 7-day averages) are based on the less restrictive 99th percentile.[44] EPA also indicates that an evaluation should be performed on datasets representing at least 18 months of operation to ensure sufficient statistical analysis.[45] Neither DES nor EPA has provided any statistical analysis of the available historical data. Instead, EPA's comments refer to the historical performance of the SCRs and hypothesizes emission limitations based on a cursory review.

In evaluating daily emission limitations for MK1, EPA's comments point to brief, isolated periods of time that represent a small fraction of the long history of SCR operation. Specifically, EPA inappropriately based its evaluation of acceptable RACT permit limits on data from two specific ozone periods (May 1 to September 30) in 2001 and 2005 when the SCR was new (installed in 1999) and operating with four new catalyst layers (layers 1, 2, 3 in 1999 and layer 4 in April 2001) during summer months. This is a short-term, highly-optimized scenario and is not representative of

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[39] *In re Steel Dynamics*, 9 E.A.D. 165, 188 (EAB 2000).

[40] *In re Vulcan Const. Mat., LP*, 15 E.A.D. 163 (EAB 2011).

[41] *Id.*

[42] *Id.*

[43] EPA's Emissions Limit PowerPoint at Slide 26.

[44] *Id.*

[45] *Id.* at Slide 19.

sustained operation or the full scope of challenges associated with winter operation. The catalyst management program for Merrimack Station does not include any scenario where the unit would again have 4 catalyst layers all less than 2 years old as it did in the initial years after installation of the SCR. Merrimack Station's SCRs are 19 to 23 years into the 30 year lifespan typical of the control technology. In addition, in 2001, the SCR did not have the additional burden of maintaining operational balance with the FGD system, which was installed in 2011. It is widely accepted that increased ammonia flow can cause reduced FGD efficiency because the excess ammonia takes up catalyst area that then becomes unavailable for other reactions to take place (e.g., oxidation of mercury or conversion of SO_2 to SO_3). EPA does not factor in the age of the SCR or the catalyst management program.

Importantly, EPA's discussion of 0.1 lb/mmBtu and 0.15 lb/mmBtu as representative of emission rates during "most of" the 2001 and 2005 ozone seasons, respectively, fails to mention that these rates would not have even been achievable *permit limits* during these peak performance time periods. The graphs below show the average daily steady-state NOx emissions during the ozone season from 2000-2009, which covers the time period EPA references. The graphs depict the range of percentiles for the dataset that was filtered to represent peak performance of the SCR. The data was filtered to show only ozone-season operation when the SCRs were being operated at design capacity (corresponding to June 2000 through September 2007 for MK1, and May 2000 through September 2009 for MK2). Then, any day with less than 24 hours of operation was removed from the dataset as well as any days with less than 2160 MWh for MK1 or 4320 MWh for MK2, to ensure that the remaining data is representative of "steady-state" operations.[46]

As shown below, daily NOx emissions from MK1 exceeded 0.1 lb/mmBtu and 0.15 lb/mmBtu numerous times in 2001 and 2005 during "steady-state" operations. In fact, the 0.15 limit was only met 50 percent of the operational time during these time periods. According to EPA's permitting guidance, the proper 24-hour steady-state limit for MK1 would be 0.32 lb/mmBtu, which represents the 99th percentile.[47]

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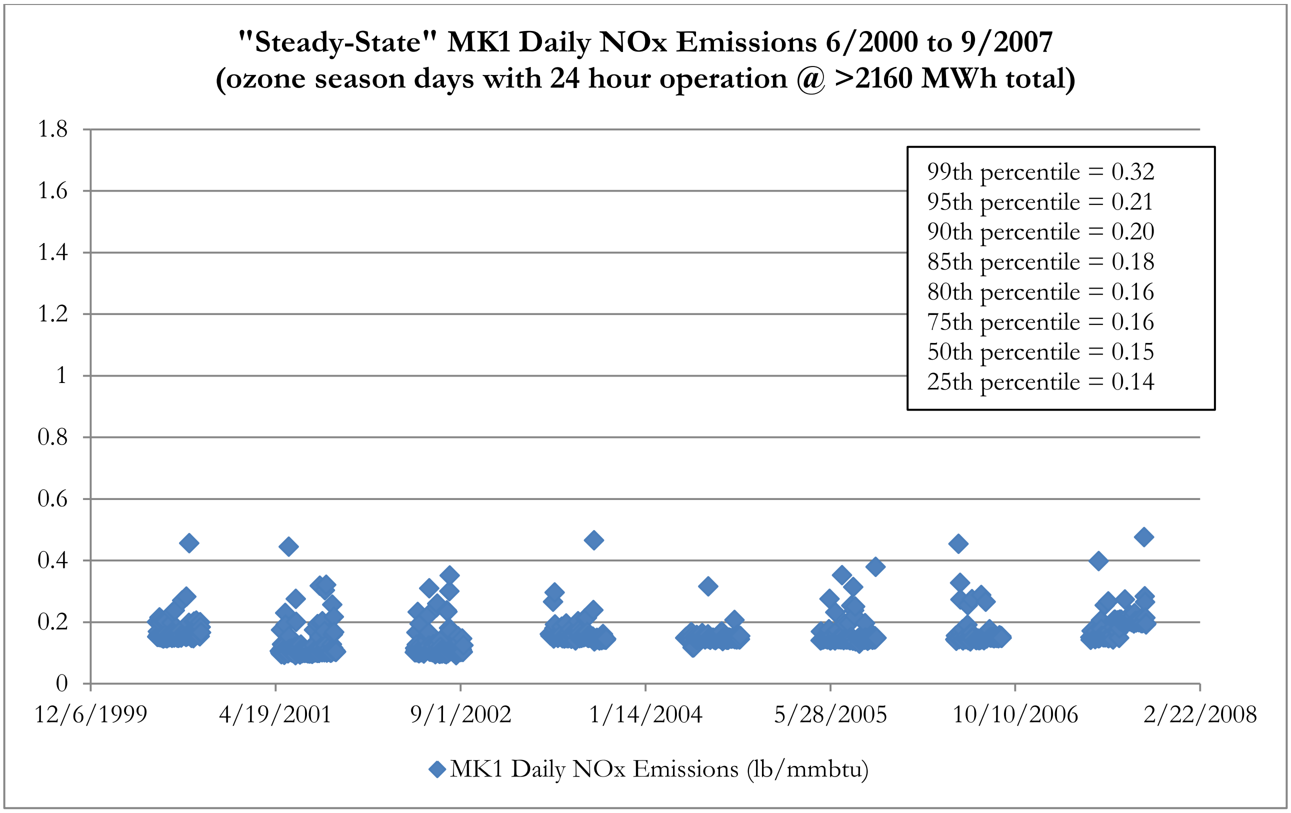
[46] Note that these numbers, 2160 MWh for MK1 and 4320 MWh for MK2, were used for illustrative purposes only and should not be used for permitting purposes. The MK1 threshold was determined using 90 MW x 24 hrs = 2160 MWh, and the MK2 threshold was determined using 180 MW x 24 hrs = 4230 MWh.

[47] EPA's Emissions Limit PowerPoint at Slide 26.



More specifically, an analysis of the historical data indicates that MK1 would have experienced 22 permit deviations in the 2001 ozone season and 22 in the 2005 ozone season if the limit had been set at EPA's suggested limit 0.15 lb/mmBtu.

MK1 NOx Emissions from 2001 Ozone Season (May 1-Sept. 30)			
Number of Days with 24 hours of operation	Days with NOx emissions > 0.15 lb/mmBtu	Days with NOx emissions > 0.20 lb/mm Btu	Days with NOx emissions > 0.30 lb/mmBtu
151	22	12	6

MK1 NOx Emissions from 2005 Ozone Season (May 1-Sept. 30)			
Number of Days with 24 hours of operation	Days with NOx emissions > 0.15 lb/mmBtu	Days with NOx emissions > 0.20 lb/mm Btu	Days with NOx emissions > 0.30 lb/mmBtu
146	22	12	4

Similarly, with respect to MK2, the graph below shows that the limit referenced by EPA of 0.20 lb/mmBtu cannot reasonably be met.[48] MK2 exceeded this limit numerous times, even directly after the SCR was installed. MK2 would only comply with such a limit 85 percent of the time. According to EPA's permitting guidance, the proper 24-hour steady-state limit for MK2 would be 0.40

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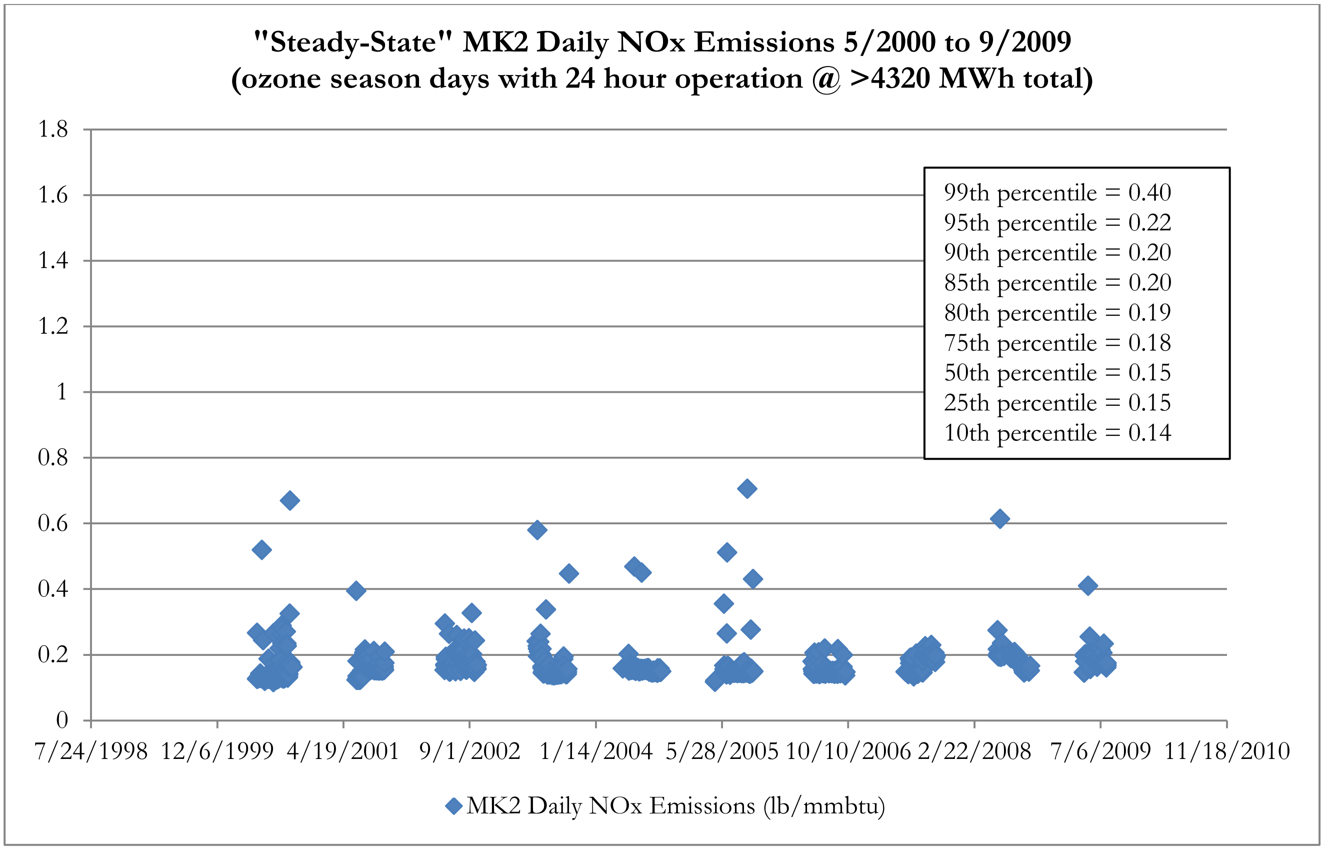
[48] As noted earlier, this graph was limited to only operation representing maximum efficiency of the SCR.

lb/mmBtu, which represents the 99th percentile.[49] Even this number would then need to be adjusted to reflect current operational conditions.



Although EPA did not point to any specific historical data for MK2, the unit would have had similar permit deviations during the ozone seasons soon after the SCR was installed. Specifically, MK2 would have violation the limit referenced by EPA of 0.2 lb/mmBtu 10 times in the 2001 ozone season and 6 times in the 2005 ozone season.

MK2 NOx Emissions from 2001 Ozone Season (May 1-Sept. 30)			
Number of Days with 24 hours of operation	Days with NOx emissions > 0.15 lb/mmBtu	Days with NOx emissions > 0.20 lb/mm Btu	Days with NOx emissions > 0.30 lb/mmBtu
89	43	10	1

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[49] EPA's Emissions Limit PowerPoint at Slide 26.

MK2 NOx Emissions from 2005 Ozone Season (May 1-Sept. 30)			
Number of Days with 24 hours of operation	Days with NOx emissions > 0.15 lb/mmBtu	Days with NOx emissions > 0.20 lb/mm Btu	Days with NOx emissions > 0.30 lb/mmBtu
115	18	6	4

In sum, EPA's suggested limits are not achievable and have never been achievable, even during the time period when the SCRs were able to produce results consistent with their maximum design capacity. DES must set a limit that reasonably represents the current sustainable performance capabilities of the SCRs and should not base that determination on the decades-old short-term peak performance of the control technology.

D. DES' proposed limits are based on flawed assumptions

The assumptions DES made in calculating its proposed limits are flawed for many reasons. First, DES assumed a flawed emission rate for startup conditions. In establishing a 7-boiler operating day emissions limitation for NOx that was inclusive of both startup conditions and "normal" steady-state operation, DES assumed three days of startup and four days of normal operation. DES determined a NOx emissions rate for "startup" days using near "maximum" mass emissions of 5.5 tons and 13.0 tons per day for MK1 and MK2, respectively, as selected through DES' review of recent data. DES then converted these mass values to a rate basis using incorrect heat input assumptions. That is, DES incorrectly used maximum heat input for MK1 (1,238 mmBtu/hr) and MK2 (3,473 mmBtu/hr) in converting the mass emissions to units of pounds per million Btu. When the unit is in startup, it is not operating at maximum heat input. Based on our understanding, DES used the below calculations to arrive at an emission rate for startup days to use in determining its proposed limits:

MK1 - DES Calculation of NOx emission rate for startup days:

$$\frac{5.5\ tons\ NOx}{day}\ x\ \frac{1\ day}{24\ hour} \div \frac{1{,}238\ mmbtu}{hour}\ x\ \frac{2{,}000\ lb}{ton} = 0.37\frac{lb}{mmbtu}NOx$$

MK2 – DES Calculation of NOx emission rate for startup days:

$$\frac{13.0\ tons\ NOx}{day}\ x\ \frac{1\ day}{24\ hour} \div \frac{3{,}473\ mmbtu}{hour}\ x\ \frac{2{,}000\ lb}{ton} = 0.31\frac{lb}{mmbtu}NOx$$

However, the heat input used in the calculation should be representative of the average daily heat input on startup days. When the NOx mass emission limits are divided by a lower heat input which is more representative of startup conditions, the resulting pound per million Btu rate is much higher. For example, the average actual NOx emission rate during startup periods in 2017 (defined as first firing of fuel until first full hour of ammonia flow) was 0.6 lb/mmBtu and 0.8 lb/mmBtu for MK1 and MK2, respectively.

DES then presumably determined the lb/mmBtu rate for "normal steady-state" days by back-calculating from a pre-determined 7-day limit. Stated differently, DES seemingly knew what final 7-day limit it wanted and determined the 4-day steady-state emission rate based off of that 7-day limit. As shown in the equation below, this results in a required steady-state emission rate for normal operation days of 0.11 lb/mmBtu for MK1 and 0.21 lb/mmBtu for MK2. These numbers are arbitrary and represent unachievable NOx reductions.

MK1 – DES Calculation of 7-day NOx emission rate:

$$\frac{\left(0.37\frac{lb}{mmbtu}\ x\ 3\ days\right)+(0.11\frac{lb}{mmbtu}x\ 4\ days)}{7\ days}=0.22\frac{lb}{mmbtu}$$

MK2 – DES Calculation of 7-day NOx emission rate:

$$\frac{\left(0.31\frac{lb}{mmbtu}\ x\ 3\ days\right)+(0.21\frac{lb}{mmbtu}x\ 4\ days)}{7\ days}=0.25\frac{lb}{mmbtu}$$

The NOx emission rates selected by DES for normal steady-state operating days are arbitrary and represent greater than achievable NOx reductions. Both rates would require >91% emissions reduction, which is greater than the design efficiency and capability of the SCRs. These steady-state NOx emission rates are combined with equally unachievable startup NOx emission rates, resulting in a proposed permit limit that would be impossible to meet. If DES' intention was to provide a 7-day NOx emission limit that was representative of 3 days of startup and 4 days of normal operation, the following is a more accurate representation:

MK1 – Calculation of 7-day NOx emission rate using actual representative startup data:

$$\frac{\left(0.64\frac{lb}{mmbtu}\ x\ 45\ hours\right)+(0.2\frac{lb}{mmbtu}x\ 123)}{168\ hours}=0.3\frac{lb}{mmbtu}$$

Where,

0.64 lb/mmBtu = actual average NOx rate for MK1 in 2017 during the startup hours preceding SCR operation (i.e., prior to first full hour with ammonia flow)

45 hours = average number of hours per start (i.e., 15 hours) for MK1 in 2017 multiplied by 3 to account for 3 starts in a 7-day period

0.2 lb/mmBtu = average target rate for days with normal operation (SCR on)

123 hours = remaining hours available in 7-day period for normal operation (i.e., 168 hours less 45 hours for startup)

MK2 – Calculation of 7-day NOx emission rate using actual representative startup data:

$$\frac{\left(0.8\frac{lb}{mmbtu}\ x\ 39\ hours\right)+(0.2\frac{lb}{mmbtu}x\ 129)}{168\ hours}=0.34\frac{lb}{mmbtu}$$

Where,

0.8 lb/mmBtu = actual average NOx rate for MK2 in 2017 during the startup hours preceding SCR operation (i.e., prior to first full hour with ammonia flow)

39 hours = average number of hours per start (i.e., 13 hours) for MK2 in 2017 multiplied by 3 to account for 3 starts in a 7-day period

0.2 lb/mmBtu = average target rate for days with normal operation (SCR on)

129 hours = remaining hours available in 7-day period for normal operation (i.e., 168 hours less 39 hours for startup)

V. The Proposed Limits Are Not Economically Feasible

EPA has previously explained that "[f]or purposes of evaluating the economic feasibility of a potential control measure, the state may consider factors including but not limited to capital costs, operating and maintenance costs, and cost effectiveness of the measure" (i.e., cost per ton of pollutant reduced by that technology).[50] Additionally, EPA has historically interpreted the term "economic feasibility" for RACT to "include[] a presumption that it is reasonable for similar sources to bear similar costs of emissions reductions . . . ."[51] In implementing the 2008 ozone NAAQS SIP requirements, EPA recognized that "[i]n cases where controls were applied due to the 1-hour or 1997 NAAQS ozone RACT requirement, [it] expect[s] that any incremental emissions reductions from application of a second round of RACT controls may be small and, therefore, the cost of advancing that small additional increment of reduction may not be reasonable."[52] Furthermore, with respect to SCRs, EPA has stated that an "SCR is capable of NOx reduction efficiencies in the range of 70% to 90% . . . . Higher reductions are possible, but generally are not cost-effective."[53]

A full economic analysis was not performed to assess feasibility of the proposed limits since the limits are not technologically feasible. However, several factors that contribute to the increased financial burden associated with achieving aggressive NOx permit limits. For example, there would also be significant operating costs associated with procuring additional volumes of reagent. Anhydrous ammonia pricing experiences fluctuations based on market volatility typically associated

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[50] 40 C.F.R. § 51.1009(a)(3)(ii) (discussing RACT and RACM for $PM_{2.5}$); 81 Fed. Reg. 58,010, 58,042 (Aug. 24, 2016) ("The EPA believes that it is appropriate for states to give substantial weight to cost effectiveness in evaluating the economic feasibility of an emission reduction measure or technology.").

[51] 81 Fed. Reg. at 58,041 (discussing fine particulate matter NAAQS SIP requirements).

[52] 80 Fed. Reg. at 12,279. Indeed, EPA has recognized the principle that the RACT rules "should enable, if not encourage, the adoption of emission reduction strategies that will be the most effective, *and* the most cost effective, at reducing ozone levels" 78 Fed. Reg. at 34,192 (emphasis added).

[53] EPA, *Air Pollution Control Technology Fact Sheet* 1, *available at* https://www3.epa.gov/ttncatc1/dir1/fscr.pdf.

with natural gas pricing. In addition, suppliers of anhydrous ammonia can charge premiums during high demand periods. Given Merrimack Station's current unit dispatch in the range of 5 to 30 percent capacity factor, it is becoming increasingly difficult to obtain a high volume of anhydrous ammonia on short notice from suppliers (i.e., 10-15 tank trucks per week) since that level of usage is intermittent and not sustained throughout the year.

Additional contributors to the financial burden associated with increased incremental NOx reductions include, but are not limited to, potential anhydrous ammonia storage and delivery system capacity upgrades, reagent storage fees (daily fee for railcars on-site), catalyst replacement costs (catalyst testing, material, labor, crane equipment, temporary storage, hazardous waste management and disposal fees), electricity cost, additional air heater and ESP inspections and maintenance cleaning events.

As Merrimack Station is no longer in the regulated utility sector, GSP bears the full or a very high degree of market risk as the price at which electricity can be sold is dependent on what the short-term markets will bear. Therefore, the ability to take on this financial burden is dependent on the state of the economy and on commodity prices. Since MK1 and MK2 maintain such a low capacity factor, the financial burden of fixed operational and maintenance costs associated with aggressive operation of the SCR are not proportional to other EGUs experiencing similar costs while operating at full capacity. These costs certainly do not justify the marginal emission reductions that would result from DES' proposed limit. As a result, DES' proposed NOx RACT is not economically feasible.

VI. GSP's NOx RACT Analysis and Proposed Limits

GSP maintains that a 7-boiler operating day limit that is only applicable to hours when the SCR operating parameters are met offers reasonable operational flexibility while providing the stringency required of NOx RACT emission limits when paired with a daily mass emission limit. GSP proposed the following limits for MK1 and MK2 in technical discussions with DES:

- **MK1**:
    - 0.22 lb/mmBtu NOx, 7-boiler operating day average, excluding hours when SCR permissives are not met
    - 5.5 ton NOx per day, 24-hour calendar day average, applies at all times
- **MK2**:
    - 0.25 lb/mmBtu NOx, 7-boiler operating day average, excluding hours when SCR permissives are not met
    - 15.4 tons NOx per day, 24-hour calendar day average, applies at all times

The rate-based limits proposed above would force more aggressive operation of the SCRs, as GSP would need to operate MK1 and MK2 as far below these values as possible to create even a small margin of operational flexibility. Moreover, these rate-based limits force consistent, year-round operation of the SCRs at their design capacities, while accounting for variability typical of the equipment. In addition, the daily mass limits that apply at all times would provide sufficient means to restrict duration of startup events or other low-load operations on a short-term basis. EPA's own website stresses the importance of providing operational flexibility, stating that, "[i]n designing clean air programs, EPA strives to provide companies with flexibility on ways to comply while ensuring accountability for environmental performance."[54]

Although there are many SCR permissive parameters that must be met before the SCR inlet dampers can be opened and ammonia flow can initiate, for the purpose of permitting, GSP considers temperature (SCR inlet and catalyst) to be the parameter most indicative of the beginning of SCR operation.

If DES nevertheless proceeds to establish a 24-hour limit, it must be higher than 0.20 lb/mmBtu in order to have a statistical expectation of success. For instance, the steady-state percentile graphs included above depict the range of percentiles for the dataset that was filtered to represent peak performance of the SCRs. The resulting percentiles illustrate that even during peak performance periods, the SCR for MK2 only achieved NOx emission rates of 0.15 lb/mmBtu or less 50 percent of the time. Even an emission rate of 0.20 lb/mmBtu, as proposed by DES, was only achieved 85 to 90 percent of the time. As noted earlier, EPA's guidance for setting permit limits recommends the use of different statistics to develop long-term vs. short-term limits. Long-term limits are based on ranked 95th percentile and short-term limits (such as 24-hour or 7-day averages) are based on the less restrictive 99th percentile. An emission rate of 0.20 lb/mmBtu is significantly more stringent than the rate that would result from applying EPA's guidance.

GSP's statistical analysis of historical data indicates that the 99th percentile representative of "steady-state" conditions on a 24-hour calendar day basis is 0.32 lb/mmBtu for MK1 and 0.40 lb/mmBtu for MK2. Even so, this statistical analysis represents peak performance of the SCR and must be further adjusted to reach a sustainable limit that accounts for year-round operations (challenges associated with winter operation), the current age of the SCR, and increased variability in process operations. In addition, if limits were to be proposed on a 24-hour basis, GSP expects that they would be higher than the emission limits proposed above by GSP on a 7-operating day average basis to account for the reduced averaging period, as supported by the above statistical analysis. GSP would also expect that the same exclusions apply for periods when the SCR permissives are not met and that the same daily mass NOx emission limits stated above would apply at all times to restrict emissions during periods when the SCR cannot operate.

Furthermore, if DES establishes an emission limit on a 24-hour calendar day basis, the valid averaging period provisions of Env-A 808.17e must apply, requiring at least 18 valid hours of data for comparison to the emission limit. GSP would interpret this to mean 18 valid hours of data with the SCR operating.

Finally, GSP does not support EPA's recommendation to establish permit emission limits that apply on a 24-hour rolling basis instead of a 24-hour calendar day basis. This would be that much more restrictive, in that a new 24-hour average would be calculated at the end of each operating hour. For example, for a 24-hour limit on a calendar day basis, GSP would have the entire calendar day to manage emission rates, and would be "tested" against a permit limit at the end of each day for a maximum of 365 "tests" per year. For the 24-hour rolling average, however, there is

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[54] EPA, *Building Flexibility and Accountability into Clean Air Programs*, https://www.epa.gov/clean-air-act-overview/building-flexibility-accountability-clean-air-programs (last updated Feb. 16, 2017).

no opportunity to manage emission rates throughout the day, as the 24-hour emission rate is a moving target subject to change each hour, with a maximum of 8,760 “tests” that the unit must pass per year. Additionally, EPA’s proposal to pair a 24-hour rolling average NOx emission rate with mass limits that apply to the specific hours that the boilers are in startup and shutdown would be difficult to manage in practice and would make compliance demonstrations unnecessarily complicated.

In sum, the limit contemplated by DES does not align with RACT, which EPA defines as the lowest emission limit that a source is “capable of meeting”, by the application of reasonably available control technology (in this case, the existing SCR). While the SCR can outperform its design capabilities on some occasions when the optimum conditions exist, this performance level is certainly not attainable every hour of every day, which is what would be required to meet the emission limitations contemplated by DES. The emission limit must not be equal to or more stringent than the designed or proven capability of the units.

VII. Conclusion

GSP appreciates the opportunity to provide comments on DES’ proposed NOx RACT limits. As explained above, DES’ and EPA’s proposed limits are not technologically or economically feasible for Merrimack Station and would result in frequent, unnecessary permit deviations with minimal overall mass NOx reductions. GSP strongly encourages DES to adopt GSP’s proposed limits as outlined above. Thank you for your consideration of our comments.

GRANITE SHORE POWER

August 30, 2018

Mr. Craig Wright, Director
NHDES Air Resources Department
29 Hazen Drive, Concord, NH

GSP's Response to DES' Request for Information on MANE-VU "Ask" Associated with the Regional Haze Rule

I. Introduction

Granite Shore Power LLC (GSP) submits this response to the New Hampshire Department of Environmental Services' (DES) Request for Information (RFI) related to the Mid-Atlantic Northeast Visibility Union (MANE-VU) "Ask" associated with the regional haze rule. While GSP understands that the MANE-VU "Ask" is directed at member states, GSP appreciates the opportunity to be engaged in the process of reviewing emission control strategies at each of its operating facilities. DES submitted the comprehensive RFI to GSP on May 3, 2018. The deadlines in the original RFI were revised, as confirmed on June 15, 2018 via email from Ms. Catherine Beahm, Air Permits Program Manager. On June 25, 2018, GSP submitted a NOx RACT analysis for Schiller Station to satisfy a portion of the RFI. This current submittal satisfies the remaining portion of the RFI (MANE-VU "Ask") and is being submitted by the revised deadline of August 31, 2018.

II. Background

The Clean Air Act and Regional Haze rule (40 CFR 51.308 (f)(2)(i) through (iv) requires states that are reasonably anticipated to cause or contribute to impairment of visibility in mandatory Class I Federal areas to implement reasonable measures to reduce visibility impairment. As part of the New Hampshire regional Haze State Implementation Plan (SIP), NH must consider emission reduction measures identified by Class I States as being necessary to make reasonable progress in any Class I area. DES is part of the MANE-VU, in which the member states work collaboratively to develop emission control strategies to address visibility impairment in Class I areas. On August 25, 2017, MANE-VU issued a statement in which six emission management strategies were proposed in order to meet the 2028 reasonable progress goal for regional haze.

III. Schiller Station

Schiller Station is a wood and fossil fuel-fired electricity generating facility owned and operated by GSP Schiller LLC, a wholly owned subsidiary of Granite Shore Power. The facility includes three utility boilers: one wood and fossil fuel-fired boiler (designated as Unit 5) and two fossil fuel-fired (residual oil and coal) boilers (designated as Unit 4 and Unit 6). All three boilers are equipped with oxygen trim systems. Each boiler stack is equipped with a continuous emissions monitoring system (CEMS) and a continuous opacity monitoring system (COMS). The facility also includes one combustion turbine (designated as emission unit SRCT).

A. NOx Control Strategies

DES has requested that GSP evaluate the most effective use of the current NOx control strategies for Units 4, 5, and 6 and to perform a four factor analysis for reasonable installation or upgrade to emission controls for the combustion turbine (SRCT).

i. Unit 4 and Unit 6

Units 4 and 6 are equipped with low-NOx burners, selective non-catalytic reduction ("SNCR") systems, and overfire air systems ("OFA") to control NOx emissions. The SNCR systems for units 4, 5, and 6 are fed from a common reagent storage tank system containing a 50 percent solution (as received) of urea.

Unit 4 and Unit 6 are dry-bottom wall-fired boilers that began operation in the 1950's rated at approximately 48 MW each. The boilers were retrofitted in mid-1999 with RJM Corporation's low NOx burner modifications. Baseline NOx levels prior to the burner modifications were up to 1.0 lb/MMBtu[1]. The burner modifications reduced NOx emissions by approximately 50 percent to 0.4 to 0.5 lb/MMBtu. The former owner, Public Service Company of New Hampshire (PSNH), sold NOx allowances to fund the installation of a NOxOUT™ SNCR system on Units 4, 5, and 6 in late 1999. The SNCR system was designed to achieve an additional 30 to 35 percent NOx reduction to 0.33 lb/MMBtu at loads of 80 to 100 percent. In the early 2000s, OFA systems were installed to further reduce NOx emissions. The OFA systems are comprised of ports, ducts, and dampers that allow up to 15 percent of the combustion airflow to be diverted from the top of the windbox through ports located above the top elevation of burners.

Units 4 and 6 were historically operated as base-loaded units. In the last few years, due to the increased supply of natural gas to the region, the units have operated at significantly lower capacity factors annually. Therefore, the units operate significantly fewer hours annually with significantly fewer emissions. Specifically, the capacity factor has decreased from 84% to 8% on Unit 4 and from 75% to 7% on Unit 6 between 2007 and 2017.

As DES is aware, Schiller Station has aggressively reduced NOx emissions for over 20 years. Schiller Station currently implements cost-effective combustion control technologies (low NOx burners, OFA) that achieve cumulative NOx reductions of up to 70 percent from baseline (see footnote 1) NOx levels. In fact, Unit 4 and 6 NOx emissions continue to be approximately 40 percent below the existing applicable daily NOx RACT limits of 0.5 lb/MMBtu.

At the request of DES, GSP performed a NOx RACT analysis to evaluate the technical and economic feasibility of achieving certain levels of NOx reduction while operating the SNCR on Units 4 and 6. The results of the analysis were submitted to DES on June 25, 2018. The analysis demonstrated that NOx emission limits more stringent than 0.25 lb/MMBtu are not technologically or economically feasible for Units 4 and 6 and would result in a high cost despite minimal overall mass NOx reductions. As a result, DES proposed NOx RACT Order (RO-003) on July 13, 2018 for Units 4 and 6. The proposed NOx RACT Order contains a NOx emission limit of 0.25 lb/MMBtu on a 24-hour calendar day average, including all hours of operation for Unit 4 and Unit 6. The NOx RACT Order will become effective upon final issuance by DES, pending public comments. GSP intends to maintain NOx emissions below these limits through use of low NOx burners, OFA, and cost-effective SNCR use on an as-needed basis.

The pending NOx RACT Order will establish limits consistent with the most-effective use of the NOx controls for Units 4 and 6.

ii. Unit 5

Unit 5 is a circulating fluidized bed (CFB) wood-fired boiler equipped with a SNCR system to control NOx emissions. Unit 5's NOx emissions are limited to 0.075 lb/MMBtu on a 24-hour calendar day basis pursuant to NOx RACT Order ARD-06-001 issued by DES on August 4, 2006. The limit was established as a result of a NOx RACT analysis of the technological and economic feasibility of NOx control techniques, including low NOx burners, OFA, flue gas recirculation, natural gas reburn, burners out of service, use of alternative fuels, SCR and SNCR. The former owner, PSNH, ultimately proposed the use of SNCR paired with CFB technology, which is recognized as a low emission, advanced solid fuel combustion technology. The formation of NOx in the CFB boiler is reduced as a result of the low combustion temperatures and low excess air within the fluidized bed.

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[1] Based on several references to the baseline NOx rates of 0.8 to 1.0 lb/MMBtu in internal historical documents. Also noted in July 28, 1992 version of NOx RACT Emission Limits Part Env-A 1210 as baseline NOx 0.675 to 0.990 lb/MMBtu based on single test points July 6 to 8, 1992.

The only other technologically feasible option, SCR, was not economically feasible because of increased costs that would be associated with pretreatment of particulate matter.

Unit 5's NOx limit was ultimately established based on design specifications and emission data provided by the boiler manufacturer. The limit is representative of emissions during normal or stable operations, however the limit is not suitable for periods of startup or shutdown, as SNCR systems will not be allowed to operate until the defined minimum boiler load and temperature are reached[2]. As such, PSNH and DES reviewed actual emissions data for a period of at least one year to determine an emission limit that could reasonably be achieved during startup and shutdown periods. The current NOx limit for startup and shutdown periods is 0.15 lb/MMBtu for up to two calendar days per event.

The existing limits represent the most effective use of the control technology, as assessed by PSNH and DES following commissioning of the Unit 5 boiler and SNCR system. The current limits require year-round use of the SNCR.

A summary of RACT/BACT/LAER Clearinghouse data is provided in Attachment A for NOx control on wood-fired boilers. The summary illustrates that Unit 5's NOx limit of 0.075 lb/MMBtu is the lowest emissions limit listed for similar sized units. Not only does it compare (or supersede) the limits of equivalent size wood boilers (two being explicitly called out as circulating fluidized beds) being controlled by SNCR, but it is also equivalent to one of similar size, being controlled with an SCR.

iii. SRCT

A four-factor analysis for reasonable installation or upgrade to NOx emission controls was performed for SRCT. The analysis is included as Attachment B. The analysis indicated that there were no technologically and economically feasible control options available for the combustion turbine. Alternatively, GSP will continue to look for opportunities to employ good combustion practices, such as the recently upgraded control system with improved fuel control valve and routine inspections in accordance with manufacturer recommendations.

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[2] https://cdn.ymaws.com/www.icac.com/resource/resmgr/MATS_decision/MATS_SS_Guidance_Document_Fi.pdf

B. Acid Gas Control Strategies

DES has requested that GSP evaluate the most effective use of the current acid gas control strategies for Units 4, 5, and 6.

i. Unit 4 and Unit 6

Units 4 and 6 are equipped with dry sorbent injection (DSI) systems to control emissions of acid gases. The DSI systems were installed for the purpose of complying with 40 CFR 63 Subpart UUUUU, National Emission Standards for Hazardous Air Pollutants: Coal- and Oil-fired Electric Utility Steam Generating Units (Mercury and Air Toxics Standards or MATS). The DSI systems are intended to reduce concentrations of hydrochloric acid (HCl). As a co-benefit, the DSI system reduces concentrations of sulfur oxides including SO2.

GSP currently performs quarterly stack testing for HCl as required by the MATS rule. GSP must operate the DSI system year-round at or above the average injection rate observed during the most recent stack test for HCl. Less frequent performance testing is required of units that achieve Low Emitting EGU (LEE) status. LEE status is achieved after 3 consecutive years of required quarterly tests are performed with resulting emissions less than 50 percent of the allowable emission rate of 0.002 lb/MMBtu. All stack tests performed to date on Units 4 and 6 have resulted in HCl emissions less than 50 percent of the emission limit and both units are nearing completion of the 3 year period that would qualify them for LEE status with reduced test frequency.

Additionally, in 2016 as a result of the 2010 1-hour SO2 National Ambient Air Quality Standard (NAAQS), Schiller Station submitted to DES modeling of actual existing emissions and proposed potential emissions showing compliance with the 1-hr SO2 standard. Existing local monitoring data also provided abundant evidence that the existing limits were adequate to prevent significant deterioration and to maintain the NAAQS in both New Hampshire and Maine. DES ultimately proposed a new daily SO2 limit for Schiller Station Units 4 and 6 of 0.83 lb/MMBtu. This current SO2 limit is achieved through a combination of low sulfur coal and operation of the DSI system.

Since the DSI system is already required to operate at a set minimum rate to reduce HCl emissions, the SO2 emissions are managed by automatically injecting incremental additional sorbent using emissions feedback from the SO2 CEMS.

Units 4 and 6 comply with the most current and strict federal standards for acid gases: MATS HCl limit and 1-hr SO2 NAAQS. Schiller station implements the most effective use of the existing control technology, which is year-round operation of the DSI system, as applicable, targeting reduction of multiple acid gases. Due to operational and cost considerations, the DSI system is operated effectively, to comply with strict federal standards without over-injecting sorbent material. For instance, Schiller Station works diligently to balance operation of the DSI system with operation of other emission controls to avoid adverse impacts on mercury capture or overloading the electrostatic precipitator with particulate matter.

ii. Unit 5

Unit 5 was converted to a wood-fired boiler in 2006. Since Unit 5 is also permitted to burn coal, DES has requested that GSP evaluate the most effective use of limestone injection to reduce SO2 emissions from coal combustion. Unit 5 has only fired coal for the purpose of collecting performance test data in 2006 during commissioning of the boiler. Since the initial testing was limited and Unit 5 has not fired coal for approximately 12 years, GSP is unable to evaluate the most effective use of the limestone injection system for SO2 emission reductions from coal combustion.

However, GSP does assert that the current daily permit limit of 0.12 lb SO2/MMBtu for coal firing based on New Source Performance Standards for EGU's (40 CFR 60.43Da(a)) is sufficiently stringent to assist DES with meeting the state's reasonable progress goals for regional haze in the event of coal firing on Unit 5. The existing limit is even more stringent than other current federal standards for acid gases from coal-fired EGUs (i.e., MATS 0.2 lb/MMBtu SO2 proxy for HCl limit).

IV. Merrimack Station

Merrimack Station is a fossil fuel-fired electricity generating facility owned and operated by GSP Merrimack LLC, a wholly owned subsidiary of Granite Shore Power. Merrimack Station is comprised of two bituminous coal-fired utility boilers (designated as Unit 1 and Unit 2) and two combustion turbines operating as load shaving units. Each boiler duct is equipped with a CEM system to measure NOx, SO2, CO2, stack flow, and opacity. The common stack (for Units 1 and 2) is equipped with a CEM system to measure NOx, SO2, CO2, stack flow, and also a sorbent trap monitoring system to measure Hg.

A. NOx Control Strategies

DES has requested that GSP evaluate the most effective use of the current NOx control strategies for Unit 1 and to perform a four-factor analysis for reasonable installation or upgrade to emission controls for Unit 2 and the two combustion turbines (MKCT1 and MKCT2).

i. Unit 1

Unit 1 is equipped with a selective catalytic reduction ("SCR") system to control NOx emissions. DES recently reviewed historical performance data for Unit 1 and revised the NOx RACT rules in Env-A 1300 with more stringent daily NOx emission limits on both a rate basis and a mass basis. The new daily NOx limits, effective August 15, 2018, for Unit 1 are 0.22 lb/MMBtu when SCR temperature permissive parameters are met for all operating time in the day, or 4.0 tons per day when any startup, shutdown, or low-load conditions occur in the day (flue gas temperatures below SCR operating temperature). These recently revised NOx RACT limits represent the most effective use of the SCR, given that the system must be operated year-round at or above its design capacity to demonstrate compliance.

ii. Unit 2

Unit 2 is equipped with a selective catalytic reduction ("SCR") system to control NOx emissions. DES recently reviewed historical performance data for Unit 2 and revised the NOx RACT rules in Env-A 1300 with more stringent daily NOx emission limits on both a rate basis and a mass basis. The new daily NOx limits, effective August 15, 2018, for Unit 2 are 0.22 lb/MMBtu when SCR temperature permissive parameters are met for all operating time in the day, or 11.5 tons per day when any startup, shutdown, or low-load conditions occur in the day.

Unit 2 is also still subject to the provisions of Env-A 2300 for the mitigation of regional haze, which established a Best Available Retrofit Technology (BART) control strategy to limit NOx to 0.30 lb/MMBtu on a 30-day rolling average basis for all hours of operation. BART is defined as "an emission limitation based on the degree of reduction achievable through the application of the best system of continuous emission reduction for each pollutant which is emitted by an existing stationary facility." The BART emission limitation was established on a case-by-case basis, taking into consideration the technology available, the costs of compliance, the energy and non-air quality environmental impacts of compliance, pollution control equipment in use or in existence at the source, the remaining useful life of the source, and the degree of improvement in visibility which may reasonably be anticipated to result from the use of such technology.

The BART control strategy combined with recently revised NOx RACT limits represent the most effective use of the SCR, given that the system must be operated year-round at or above its design capacity to demonstrate compliance.

Further, a four-factor analysis for installation or upgrade to emission controls is unnecessary because Unit 2 has been operating the most effective control technology for nearly 20 years. GSP has already stated in its May 25, 2018 comment letter on the proposed NOx RACT rule revisions that Unit 2 would not be a viable candidate for retrofit with additional NOx controls. Control mechanisms, such as fuel switching or over-fire air cannot be technologically or economically justified, as the additional reductions achievable from these strategies are minimal when installed after the SCR. Moreover, these controls cannot be physically added to the units at Merrimack Station because they would cause operational issues and reduce the efficiency of other pollution control devices. For example, fuel switching for Merrimack Station would mean firing sub-bituminous coal. Although the units are not permitted to burn sub-bituminous coal, if this lower rank fuel was used, it would result in a loss of boiler efficiency and a probable increase in heat rate. This would require Merrimack Station to burn more fuel, causing an increase in emissions. It would also impact Merrimack Station's mercury capture and the efficiency of the precipitator. Overall, this fuel would not provide reliable unit operations and would not be considered a viable alternative to the current use of bituminous coal.

Over-fire air also poses several issues and is an unacceptable solution. The negative impacts include reduced boiler performance, potential boiler modifications to boiler surface areas, increased fouling, boiler tube erosion, and cyclone wear. Any installation is complicated by, if not impossible, due to the engineering and design challenges of the windbox configuration and screen tubes at Merrimack. In addition, the installation of an OFA system after the installation of an SCR is likely to produce little to no improvement in NOx reductions. Any of these changes would also have the potential to negatively impact the removal capability of the FGD and the collection capability of the ESPs.

iii. MKCT1

A four-factor analysis for reasonable installation or upgrade to NOx emission controls was performed for MKCT1. The analysis is included as Attachment B. The analysis indicated that there were no technologically and economically feasible control options available for the combustion turbine. Alternatively, GSP will continue to look for opportunities to employ good combustion practices, such as the recently upgraded control system with improved fuel control valve and routine inspections in accordance with manufacturer recommendations.

iv. MKCT2

A four-factor analysis for reasonable installation or upgrade to NOx emission controls was performed for MKCT2. The analysis is included as Attachment B. The analysis indicated that there were no technologically and economically feasible control options available for the combustion turbine. Alternatively, GSP will continue to look for opportunities to employ good combustion practices, such as the recently upgraded control system with improved fuel control valve and routine inspections in accordance with manufacturer recommendations.

B. SO2 Control Strategies

DES has requested that GSP evaluate the most effective use of the current SO2 control strategies for Unit 1 and to perform a four-factor analysis for reasonable installation or upgrade to emission controls for Unit 2.

v. Unit 1 and Unit 2 (common SO2 control)

A common wet limestone-based flue gas desulfurization (FGD) system controls mercury with a co-benefit of acid gas emissions reductions from Unit 1 and Unit 2. The FGD system is equipped with an emergency cooling pump engine which powers a cooling water pump to provide cooling water to the FGD system during emergency situations such as loss of station power or circulating water system failure.

DES indicated in its response to Federal Land Managers' June 26, 2009 Comments on NH's draft final Regional Haze SIP, that the wet FGD is currently being optimized for mercury emission reductions required by state law and that it is unreasonable to require state-of-the-art performance for SO2 removal as if it were the only pollutant of interest.

The temporary permit (TP-0008) for installation of the FGD required a minimum of 90 percent SO2 reduction. The permit also included provisions to reset the required SO2 percent reduction to the maximum sustainable rate after an initial operating period.

On September 1, 2016, DES issued Temporary Permit TP-0189 which established the maximum sustainable rate of SO2 reduction from the FGD. The rate was established based on a comprehensive review of actual FGD performance data. TP-0189 also established additional SO2 emission rates to ensure compliance with the 2010 1-hour SO2

NAAQS. These emission limitations established in TP-0189 represent the maximum performance of the state-of-the-art FGD system and compliance with strict federal standards for SO2. Therefore, year-round use of the FGD is considered the most-effective use of controls for SO2 on Units 1 and 2.

C. Particulate Matter Control Strategies

DES has requested that GSP evaluate the most effective use of the current particulate matter (PM) control strategies for Unit 1 and to perform a four-factor analysis for reasonable installation or upgrade to emission controls for Unit 2.

vi. Units 1 and 2

Units 1 and 2 are each equipped with two electrostatic precipitators in series for the control of PM. Both the original and supplemental electrostatic precipitators are operated year-round in accordance with permit conditions to control PM emissions. The Title V permit (TV-0053) requires a minimum number of ESP sections in service during startup and normal operation of both Units 1 and 2. It is suspected that the wet FGD provides additional PM control, though PM reductions from the FGD have not been quantified.

Units 1 and 2 are subject to a BART emission control strategy established in Env-A 2300 for Mitigation of Regional Haze. EPA's June 26, 2009 Comments on NH's draft final Regional Haze SIP indicated that it is reasonable to consider the use of two currently installed ESPs as BART for Unit 2. EPA also indicated that the MANE-VU recommended level of BART control for non-CAIR EGUs is 0.02-0.04 lb/MMBtu. In response, DES established by rule a sustainable performance level of 0.08 lb/MMBtu for TSP emissions for both Unit 1 and Unit 2 even though Unit 1 was not a BART-eligible unit. By including Unit 1 in the rule, DES reduced allowable combined TSP emissions from the two coal-fired units at Merrimack Station to less than the total emissions that would be allowed if Unit 2 were set at the MANE-VU recommended level of 0.04 lb/MMBtu and the Unit 1 emission limit was unchanged.

DES indicated in its response to Federal Land Managers' June 26, 2009 Comments on NH's draft final Regional Haze SIP, that "the existing ESPs were previously upgraded to include state-of-the-art electronic controls and that further upgrading would require either major equipment substitutions or the addition of a third ESP in series with the two existing units. Adding a third ESP might be physically impossible because of sever spatial limitations following past improvements to emission control systems. To undertake either major equipment replacement or installation of a third ESP, if it could be done at all, would require a major capital expenditure. Typical equipment replacement costs for ESP upgrades may be in the range of $10,000 to $30,000 per MW. For Unit 2, additional costs of this magnitude are not easily justified when weighed against the visibility improvement (less than 0.01 dv on the 20 percent worst visibility days) that would be realized."

Subsequent to establishing BART emission limits for TSP in Env-A 2300, Units 1 and 2 became subject to a MATS PM emission limit of 0.03 lb/MMBtu, which is even less than the MANE-VU recommendation for BART-eligible sources. GSP performed 3 years of quarterly stack testing for PM as required by the rule in order to achieve Low Emitting EGU (LEE) status. LEE status is achieved after 3 consecutive years of required quarterly tests are performed with resulting emissions less than 50 percent of the allowable emission rate of 0.03 lb/MMBtu. Units 1 and 2 have completed all quarterly testing required to demonstrate LEE status and are now subject to reduced stack testing frequency.

The current control strategy is considered the most-effective use of controls for PM emissions, given the year-round operation of ESPs on Units 1 and 2 and the magnitude of emissions (consistently less than 50 percent of the stringent federal 0.03 lb/MMBtu MATS limit).

V. Newington Station

Newington Station is a fossil fuel-fired electricity generating facility owned and operated by GSP Newington LLC, a wholly owned subsidiary of Granite Shore Power. The facility is comprised of one oil- and natural gas-fired EGU designated as Unit 1.

A. NOx Control Strategies

DES has requested that GSP evaluate the most effective use of the current NOx control strategies for Unit 1.

i. Unit 1

Newington Station already reduces its NOx emissions with combustion control technologies. Unit 1 is equipped with low NOx burners for oil combustion and an overfire air system for use during oil and natural gas combustion. These controls are used year-round in accordance with manufacturers recommendations. The overfire air system is separately optimized for oil and gas operation to meet daily NOx RACT limits of 0.35 lb/MMBtu for oil combustion and 0.25 lb/MMBtu for oil and gas combustion.

Unit 1 is subject to MATS as an existing EGU. Based on historical operating data, Unit 1 qualifies as a "limited-use liquid oil-fired EGU". Limited-use units are subject to tune-up requirements only. In the event that the annual capacity factor when burning oil exceeds 8 percent as averaged on a 24-month block period, Unit 1 would no longer qualify as a limited-use EGU, and instead be considered a "continental liquid oil-fired EGU" subject to emission limits. DES has included in Newington Station's Title V Permit (TV-0054) a requirement to conduct a NOx RACT analysis pursuant to Env-A 1315 within six months of submitting the notification of a MATS subcategory switch. At such time, Newington Station would evaluate technical and economic feasibility of additional NOx controls.

DES indicated in its response to EPA's June 26, 2009 comments on NH's draft final Regional Haze SIP Revision that the MANE-VU BART Workgroup draft presumptive control levels found in Appendix C of NESCAUM's "Five-Factor Analysis of BART Eligible Sources: Survey of Options for Conducting BART Determinations" are generally applicable to BART facilities having greater than 750 MW capacity and may not be representative of smaller EGUs like Newington Station Unit 1. DES also indicated that the workgroup's draft recommendations for EGUs do not take into account the effects of scale when a facility operates at very low utilization rates and capacity factors. DES went on to specifically state that the capital costs associated with SCR or SNCR to achieve a control level of 0.1 to 0.25 lb/MMBtu cannot be justified for Unit 1, especially on a visibility benefit basis. DES ultimately found that the existing NOx RACT limits reasonably represent the sustainable performance capabilities of this unit and are sufficient as BART control levels for NOX on a 30-day averaging basis.

VI. White Lake Station

The White Lake Combustion Turbine is located in the town of Tamworth, New Hampshire. White Lake serves primarily as a peaking unit, operating during the periods of highest seasonal peak demand. Additionally, this unit is called upon when a quick response is needed for additional generation to maintain electrical system stability.

A. NOx Control Strategies

DES has requested that GSP perform a four-factor analysis for reasonable installation or upgrade to NOx emission controls for the combustion turbine (WLCT).

i. WLCT

A four-factor analysis for reasonable installation or upgrade to NOx emission controls was performed for WLCT. The analysis is included as Attachment B. The analysis indicated that there were no technologically and economically feasible control options available for the combustion turbine. Alternatively, GSP will continue to look for opportunities to employ good combustion practices, such as the recently upgraded control system with improved fuel control valve and routine inspections in accordance with manufacturer recommendations.

VII. Lost Nation Station

The Lost Nation Combustion Turbine is located in the town of Northumberland, New Hampshire. Lost Nation serves primarily as a peaking unit, operating during the periods of highest seasonal peak demand. Additionally, this unit is called upon when a quick response is needed for additional generation to maintain electrical system stability.

A. NOx Control Strategies

DES has requested that GSP perform a four-factor analysis for reasonable installation or upgrade to NOx emission controls for the combustion turbine (LNCT).

i. LNCT

A four-factor analysis for reasonable installation or upgrade to NOx emission controls was performed for LNCT. The analysis is included as Attachment B. The analysis indicated that there were no technologically and economically feasible control options available for the combustion turbine. Alternatively, GSP will continue to look for opportunities to employ good combustion practices, such as the recently upgraded control system with improved fuel control valve and routine inspections in accordance with manufacturer recommendations.

VIII. Conclusion

GSP appreciates the opportunity to provide this discussion to inform DES' response to the MANE-VU "Ask" and support its reasonable progress goals for regional haze. As explained above, GSP already operates its existing control technologies in the most effective manner to reduce emissions as required by stringent federal emission standards. Separately, a four-factor analysis for the addition of NOx controls on the combustion turbines revealed that only SCR technology is technically feasible, however SCRs are not economically feasible given the high installation and maintenance costs for units with limited opportunity for NOx reduction.

ATTACHMENT A

RACT/BACT/LAER CLEARINGHOUSE DATABASE REVIEW

CEC

Granite Shore Power
183-110
EPA Database Review[1]

Facility	NOX Control	Primary Fuel(s)	Unit Rating	Units	First Emissions Limit			Second Emissions Limit			Conversion to lb/MMBtu	
BOISE WHITE PAPER	LOW NOX BURNERS	WOOD	435	MMBtu/hr	0.3	LB/MMBTU	3 H	130.5	LB/H	3 H	0.3	lb/MMBtu
DEL TIN FIBER LLC	LOW NOX COMBUSTORS AND SNCR	WOOD WASTE	291	MMBtu/hr	87.2	LB/H		386.1	T/YR		0.3	lb/MMBtu
SIERRA PACIFIC INDUSTRIES-LOYALTON	SELECTIVE NON-CATALYTIC REDUCTION (SNCR)	WOOD	335.7	MMBtu/hr	102	PPM	@12% CO2, 8-HR ROLLING AVG	65	LB/H	8-HR ROLLING AVG	0.19	lb/MMBtu
SIERRA PACIFIC INDUSTRIES-LOYALTON	SELECTIVE NON-CATALYTIC REDUCTION (SNCR)	WOOD	335.7	MMBtu/hr	80	PPM	@12% CO2, 8-HR ROLLING AVG	50.75	LB/H	8-HR ROLLING AVG	0.15	lb/MMBtu
PLAINFIELD RENEWABLE ENERGY, LLC	SNCR	Wood	523.1	MMBtu/hr	0.075	LB/MMBTU		45.3	PPMVD @7% O2	24 HR BLOCK	0.075	lb/MMBtu
WHEELABRATOR SHERMAN ENERGY COMPANY	GOOD COMBUSTION PRACTICES	WOOD	315	MMBtu/hr	0.25	LB/MMBTU	30 day avg	345.8	T/YR		0.25	lb/MMBtu
DISTRICT ENERGY ST. PAUL, INC	SELECTIVE, NON-CATALYTIC REDUCTION, SNCR	WOOD	550	MMBtu/hr	0.15	LB/MMBTU		0.11	LB/MMBTU, GAS		0.15	lb/MMBtu
SOUTH POINT BIOMASS GENERATION	SELECTIVE CATALYTIC REDUCTION	WOOD	318	MMBtu/hr	27.98	LB/H		122.55	T/YR	PER ROLLING 12 MONTHS	0.09	lb/MMBtu
GP ALLENDALE LP	NOX EMISSIONS CONTROLLED THROUGH A COMBINATION OF STAGED COMBUSTION AND FLUE GAS RECIRCULATION.	WOOD	334	MMBtu/hr	119.28	LB/H		408.95	T/YR		0.36	lb/MMBtu
GP ALLENDALE LP	NOX EMISSIONS CONTROLLED THROUGH A COMBINATION OF STAGED COMBUSTION AND FLUE GAS RECIRCULATION.	WOOD	334	MMBtu/hr	119.28	LB/H		408.95	T/YR		0.36	lb/MMBtu
GP ALLENDALE LP	NOX EMISSIONS CONTROLLED THROUGH A COMBINATION OF STAGED COMBUSTION AND FLUE GAS RECIRCULATION.	WOOD	197	MMBtu/hr	119.28	LB/H		408.95	T/YR		0.61	lb/MMBtu
GP CLARENDON LP	NOX EMISSIONS CONTROLLED THROUGH A COMBINATION OF STAGED COMBUSTION AND FLUE GAS RECIRCULATION.	WOOD	334	MMBtu/hr	119.28	LB/H		408.95	T/YR		0.36	lb/MMBtu
GP CLARENDON LP	NOX EMISSIONS CONTROLLED THROUGH A COMBINATION OF STAGED COMBUSTION AND FLUE GAS RECIRCULATION.	WOOD	197	MMBtu/hr	119.28	LB/H		408.95	T/YR		0.61	lb/MMBtu
GP CLARENDON LP	NOX EMISSIONS CONTROLLED THROUGH A COMBINATION OF STAGED COMBUSTION AND FLUE GAS RECIRCULATION.	WOOD	334	MMBtu/hr	119.28	LB/H		408.95	T/YR		0.36	lb/MMBtu
LUFKIN GENERATING PLANT	Selective Catalytic Reduction	wood	693	MMBtu/hr	0.075	LB/MMBTU	ROLLING 30-DAY AVERAGE	0			0.075	lb/MMBtu
DARRINGTON ENERGY COGENERATION POWER PLANT	SNCR	WOOD WASTE	403	MMBtu/hr	0.12	LB/MMBTU	24-HR	0			0.12	lb/MMBtu
SIMPSON TACOMA KRAFT COMPANY, LLC	PROPER COMBUSTION CONTROLS WITH OVERFIRE AIR	WOOD WASTE	595	MMBtu/hr	0.2	LB/MMBTU	30 DAY ROLLING AVERAGE	522	T	12 MONTH ROLLING	0.2	lb/MMBtu
BOISE WHITE PAPER LLC	OVERFIRE AIR SYSTEM ADDED TO IMPROVE BOILER COMBUSTION SYSTEM. BOILER HAS AN ESP.	WOOD/BARK	343	MMBtu/hr	0.3	LB/MMBTU	30 DAY ROLLING	0			0.3	lb/MMBtu
RIPLEY HEATING PLANT	SELECTIVE NON-CATALYTIC REDUCTION (SNCR) FOR OXIDES OF NITROGEN	WOOD & COAL	185	MMBTU/H	0.1	LB/MMBTU		89.8	T/YR		0.1	LB/MMBTU

1 - Technology Transfer Network, Clean Air Technology Center, RACT/BACT/LAER Clearinghouse database review - Utility and Large Industrial-Size (>250 MMBtu/hr) and Industry Boilers (>100 MMBtu/hr) firing biomass, dated August 27, 2018

🟨	Identified as CFBs
🟦	Wood boiler w/SCR control

ATTACHMENT B

FOUR-FACTOR ANALYSIS FOR REASONABLE INSTALLATION OR UPGRADE TO EMISSION CONTROLS

REASONABLE PROGRESS REPORT

WHITE LAKE GENERATING STATION – TAMWORTH, NEW HAMPSHIRE
LOST NATION GENERATION STATION – NORTHUMBERLAND, NEW HAMPSHIRE
MERRIMACK STATION – BOW, NES HAMPSHIRE
SCHILLER STATION – PORTSMOUTH, NEW HAMPSHIRE

PREPARED FOR:
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CEC PROJECT 183-110

AUGUST 2018

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APPENDICES

Appendix A Summary of NO_X Control Technologies
Appendix B SCR Cost Effectiveness at 73 Hours Per Year

1.0 INTRODUCTION

Granite Shore Power LLC ("GSP") submits the following in response to the Mid-Atlantic/Northeast Visibility Union's (MANE-VU) *Statement of MANE-VU States Concerning a Course of Action Within MANE-VU Toward Assuring Reasonable Progress For the Second Regional Haze Implementation Period (2018-2028)*, dated August 25, 2017. As the owner and operator of four generating stations with five peaking combustion turbines in New Hampshire: White Lake Generating Station, Lost Nation Generating Station, Merrimack Station, and Schiller Station; GSP appreciates the opportunity to be involved in the response to MANE-VU.

Based on the results of the analyses for reasonable installation or upgrade to emissions controls conducted, GSP anticipates that the current requirements and nitrogen oxide (NO_X) emissions levels will be retained for each of the five peaking combustion turbines.

2.0 BACKGROUND

In accordance with the MANE-VU statement:

> The federal Clean Air Act (CAA) and Regional Haze rule requires States that are reasonably anticipated to cause or contribute to impairment of visibility in mandatory Class I Federal areas to implement reasonable measures to reduce visibility impairment within the national parks and wilderness areas designated as mandatory Class I Federal areas.

Furthermore:

> According to the Regional Haze rule (40 CFR 51.308 (f)(2)(i) through (iv)), all states must consider, in their Regional Haze SIPs, the emission reduction measures identified by Class I States as being necessary to make reasonable progress in any Class I area. These emission reduction measures are referred to as "Asks." If any State cannot agree with or complete a Class I State's "Ask," the State must describe the action taken to resolve the disagreement in their Regional Haze SIP…
>
> To address the impact on mandatory Class I Federal areas within the MANE-VU region, the Mid-Atlantic and Northeast State will pursue a coordinated course of action designated to assume reasonable progress toward preventing any future, and remedying any existing impairment of visibility in mandatory Class I Federal areas and to leverage the multi-pollutant benefits that such measure may provide for the protection of public health and the environment…

SIPs are to be submitted between July 2018 and July 2021. With the objective of meeting the 2028 reasonable progress goal for regional haze, five different "emission management" strategies were developed. Strategy 5 applies to the five peaking combustion turbines operated by GSP.

5. Where emission rules have not been adopted, control NOx emissions for peaking combustion turbines that have the potential to operate on high electric demand days by:
    a. Striving to meet NOx emission standard of no greater than 25 ppm at 15% O_2 for natural gas and 42 ppm at 15% O_2 for fuel oil but at a minimum meet NOx emissions standard of no greater than 42 ppm at 15% O_2 for natural gas and 96 ppm at 15% O_2 for fuel oil, or
    b. Performing a four-factor analysis for reasonable installation or upgrade to emission controls, or
    c. Obtaining equivalent alternative emission reductions on high electric demand days.

3.0 DESCRIPTION OF GENERATING STATIONS

GSP owns and operates five peaking combustion turbines at their four generating stations in New Hampshire that are associated with this Ask. The combustion turbines are all classified as small turbines (<25 megawatts, MW) and given their vintage (1968-1970), there are no existing NOx controls other than good combustion practices.

3.1 WHITE LAKE GENERATING STATION

The White Lake Generating Station is located in Tamworth, New Hampshire, and is operated under State-Only Operating Permit No. SP-0216. Emission Unit EU01 is a Pratt & Whitney simple-cycle combustion turbine, installed in 1968. Its maximum heat input is 300 million British Thermal Units per hour (MMBtu/hr), which is equivalent to 2,222 gallons per hour (gal/hr), based on a heating value of 135,000 Btu/gal of kerosene-1 fuel. Fuel consumption is permit-limited to 908,270 gallons of kerosene in any consecutive 12-month period and emissions are subject to a facility-wide emissions limit of 50 tons per year (tpy) of NOx. Based on stack testing conducted in 2015, the average NOx emission rate for EU01 is 0.642 lb/MMBtu.

3.2 LOST NATION GENERATING STATION

The Lost Nation Generating Station is located in Northumberland, New Hampshire, and is operated under State-Only Operating Permit No. SP-0217. Emission Unit EU01 is a General Electric simple-cycle combustion turbine, installed in 1969. Its maximum heat input is 315 MMBtu, which is equivalent to 2,250 gal/hr, based on a heating value of 140,000 British Thermal units per gallon (Btu/gal) of #2 fuel oil. Fuel consumption is permit-limited to 981,100 gallons of No. 2 fuel oil in any consecutive 12-month period and emissions are subject to a facility-wide emissions limit of 50 tpy of NOx. Lost Nation is also permitted to operate a starter engine with 4 MMBtu/hr rated heat input. Based on stack testing conducted in 2015, the average NOx emission rate for EU01 is 0.641 lb/MMBtu.

3.3 MERRIMACK STATION

The Merrimack Station is located in Bow, New Hampshire, and is operated under Title V Operating Permit No. TV-0055. Emission Units MKCT1 and MKCT2 are both Pratt & Whitney simple-cycle combustion turbines, installed in 1968 and 1969, respectively. Each combustion turbine has a maximum fuel consumption permit limit of 2,279 gal/hr (19.96 million gallons during any 12-month consecutive period) based on a fuel heating value of 140,000 Btu/gal. The combustion turbines can fire either No. 1 fuel oil or jet fuel (JP-4). The combustion turbines are subject to a NO_X limit of 0.09 pounds per million British Thermal unit (lb/MMBtu) on an hourly average, which is the existing Reasonably Available Control Technology (RACT) limit. Based on stack testing conducted in 2016, the average NO_X emission rate for MKCT1 is 0.827 lb/MMBtu and MKCT2 is 0.857 lb/MMBtu.

Merrimack is also permitted to operate two steam generating units, a primary coal crusher, a secondary coal crusher, an emergency generator, an emergency boiler, and an emergency cooling pump.

3.4 SCHILLER STATION

The Schiller Station is located in Portsmouth, New Hampshire, and is operated under Title V Operating Permit No. TV-0053. Emission Unit SRCT is a Pratt & Whitney simple-cycle combustion turbine, installed in 1970. Its maximum heat input is 290 MMBtu, which is equivalent to 2,070 gal/hr of distillate fuel (#2 fuel oil, JP-4, kerosene) or 290,000 cubic feet per hour (cf/hr) of natural gas. Fuel oil consumption is limited to 13,900,000 gallons in any consecutive 12-month period. The fuel consumption rates are based on the following assumed heating values: 12,700 Btu/lb (bituminous coal), 150,000 Btu/gal (No. 6 fuel oil), 140,000 Btu/gal (distillate oil), 4,275 Btu/lb (wood), 1,000 Btu/ft^3 (natural gas), and 94,000 Btu/gal (propane). The combustion turbine is subject to a NO_X limit of 0.09 lb/MMBtu on an hourly average, which is the existing RACT limit. Based on stack testing conducted in 2016, the average NO_X emission rate for SRCT is 0.8 lb/MMBtu.

Schiller is also permitted to operate two steam generating units, a fluidized bed boiler, a primary coal crusher, a secondary coal crusher, an emergency generator, and a heating system boiler.

4.0 REASONABLE PROGRESS EVALUATION PROCESS

The reasonable progress evaluation requested for the five peaking combustion turbines is an assessment of the applicable control technologies capable of reducing emissions of a pollutant and is conducted using a "top-down" approach taking into account feasibility and cost effectiveness, as well as, economic, environmental, and energy impacts. These assessments are conducted on a case-by-case basis using site-specific information, as available. The result of the analysis may not result in emissions of a pollutant which would exceed the emissions allowed by any applicable standard under 40 CFR Part 60 or 61.

The reasonable progress evaluation generally follows U.S. EPA-developed guidance for Best Available Control Technology (BACT) as outlined in Chapters B and G of the U.S. EPA Draft *New Source Review Workshop Manual* (OAQPS, October 1990). The five-step process includes:

Step 1: Identify Available Control Technologies;
Step 2: Eliminate Technically Infeasible Options;
Step 3: Rank Remaining Control Technologies by Control Effectiveness;
Step 4: Evaluate Economic, Environmental, and Energy Impacts of Technically Feasible Control Technologies; and
Step 5: Select BACT.

However, the reasonable progress evaluation essentially combines steps 4 and 5 into one – "Evaluate Factors and Present Determination." The four factors to be evaluated are: the cost of compliance, the time necessary for compliance, energy and non-air quality impacts, and the remaining useful life. The reasonable progress evaluation also incorporates guidance provided by the New Hampshire Department of Environmental Services (DES).

4.1 STEP 1 – IDENTIFY AVAILABLE CONTROL TECHNOLOGIES

The first step in the reasonable progress evaluation analysis is to identify "available" control options. Available control options are those air pollution control technologies or techniques (including lower-emitting processes and practices) that have the potential for practical application to the emissions unit and pollutant under evaluation, with a focus on technologies that have been demonstrated to achieve the highest levels of control for the pollutant in question, regardless of the source type in which the demonstration has occurred.

4.2 STEP 2 – ELIMINATE TECHNICALLY INFEASIBLE OPTIONS

In the second step of the reasonable progress evaluation, any available control technique listed in Step 1 may be eliminated from further consideration if it is not technically feasible for the specific source under review. A demonstration of technical infeasibility must be documented and show, based on physical, chemical, or engineering principles, that technical difficulty would preclude the successful use of the control option on the emissions unit under review. U.S. EPA generally considers a technology to be technically feasible if it has been demonstrated and operated successfully on the same type of emissions unit under review or is available and applicable to the emissions unit type under review. If a technology has been operated on the same type of emissions unit, it is presumed to be technically feasible. An available technology from Step 1, however, cannot be eliminated as infeasible simply because it has not been used on the same type of source that is under review. If the technology has not been operated successfully on the type of source under review, then questions regarding "availability" and "applicability" to the particular source type under review should be considered for the technology to be eliminated as technically infeasible.

4.3 STEP 3 – RANK REMAINING CONTROL TECHNOLOGIES BY CONTROL EFFECTIVENESS

Step 3 of the reasonable progress evaluation calls for the remaining control technologies to be listed in order of overall control effectiveness for the pollutant under review. The most effective control alternative (i.e., the option that achieves the lowest emissions level) should be listed at the top and the remaining technologies ranked in descending order of control effectiveness. The ranking of control options in Step 3 determines where to start the "top-down" selection process in Step 4. In determining and ranking technologies based on control effectiveness, facilities should include information on each technology's control efficiency (e.g., percent pollutant removed, emissions per unit product), expected emission rate (e.g., tpy, pounds per hour [lb/hr], pounds per unit of product, pounds per unit of input, parts per million [ppm]), and expected emissions reduction (e.g., tpy). The metrics chosen for ranking should best represent the array of control technology alternatives under consideration.

4.4 STEP 4 – EVALUATE FACTORS AND PRESENT DETERMINATION

Under Step 4 of the reasonable progress evaluation, facilities must consider the cost of compliance, time necessary for compliance, energy and non-air quality impacts, and remaining useful life of each option remaining options under consideration. Accordingly, after available and technically feasible control options have been ranked in terms of control effectiveness (Step 3), facilities should consider these four factors when presenting the determination for reasonable installation or upgrade of emission controls. If the most stringent control option (based on the ranking of controls under Step 3) is eliminated from further consideration for reasonable installation, then the next most stringent alternative is considered, and so on, until a final determination of all controls is completed.

5.0 REASONABLE PROGRESS EVALUATION FOR NO_X

NO_X is primarily formed by two mechanisms: the combination of elemental nitrogen and O_2 in the combustion air within the high temperature environment of the combustor (thermal NO_X) and the oxidation of nitrogen contained in the fuel (fuel NO_X). NO_X emissions from combustion turbines when firing fuel originate primarily as thermal NO_X. The rate of formation of thermal NO_X is a function of residence time and free oxygen, and is exponential with peak flame temperature. Fuel oil has a higher flame temperature and produces more NO_X than natural gas.

5.1 STEP 1 - IDENTIFY AVAILABLE CONTROL TECHNOLOGIES

The scope of potentially applicable control options was determined based on a review of the U.S. EPA RACT/BACT/LAER Clearinghouse (RBLC) database for entries within the last 10 years for simple-cycle combustion turbines, as well as other publically available information such as the Air Pollution Training Institute[1] or other recently permitted combustion turbines. RBLC entries that were not representative of the emissions unit, proposed fuel, or operating condition were excluded

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[1] https://www.apti-learn.net/lms/register/display_document.aspx?dID=39

from further consideration. In addition, entries that were proven to not meet an emissions limit were also excluded from further consideration. A summary table is presented in Appendix A. Given there are essentially two ways to reduce NO_X emissions—primary (or in-combustor) methods that minimize the production of NO_X in the turbine and secondary methods (or add-on controls) that reduce the NO_X that has been formed—controls have been identified as such. In addition, while not a technology per se, use of good combustion practices is a common baseline approach to optimizing the emissions profile for combustion turbines so it has been included here as well.

5.1.1 Primary Controls - Water or Steam Injection

Water or steam injection is an example of an "in-combustor" NO_X control technology. The addition of an inert diluent, such as water or steam, into the high temperature region of the combustion turbine flame controls NO_X formation by quenching peak flame temperatures.

5.1.2 Primary Controls - Dry Low-NO_X/Dry Low-Emission (DLN/DLE) Combustors

DLN/DLE combustors are also an example of an "in-combustor" NO_X control technology. The combustors limit peak flame temperature and excess oxygen with lean, pre-mix flames that achieve NO_X control equal to or better than water or steam injection. Each combustion turbine vendor has their own version of this technology—Siemens (ULN), General Electric (DNL 2.6+), Pratt & Whitney (TALON X, previously known as rich burn quick mix, lean burn (RQL) [2]), etc. These combustors are generally built into the original design of the combustion turbine, but can be retrofitted for certain models.

5.1.3 Secondary Controls - XONON™ Catalytic Combustor

The XONON™ catalytic combustor system is a NO^X control technology developed by Catalytica Energy Systems, Inc. It works by avoiding high temperatures caused by combustion. By integrating a catalyst into the combustor, XONON™ limits combustion temperatures to below the level where NO_X is formed. The XONON™ catalytic combustor system is a module that is installed inside the main component of the combustor. The module consists of a channel where pre-mixed fuel and air passes through the catalyst. It eliminates the fuel being combusted in a flame by combusting it using a catalyst at a lower temperature. Thus, NO_X formation is reduced. The XONON™ catalytic combustor system is now owned by Kawasaki Heavy Industries, Ltd. which is in the process of making the control technology available for gas turbine generators in the 1-1.4 MW range.

5.1.4 Secondary Controls - SCONOX™ Process (aka EMx™)

The SCONOX™ process is a NO_X control technology developed by Goal Line Environmental Technologies (GLET). It uses a coated oxidation catalyst to oxidize and remove NO_X (as well as carbon monoxide, CO) without using a reagent such as NH_3 or NH_3(aq). The technology is now

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[2] https://www.researchgate.net/publication/266595753_Rich_Burn_Quick-_Mix_Lean_Burn_RQL_Combustor

on its second generation, called EMx™, and is distributed by EmeraChem (formerly GLET). The technology is made of a platinum-based catalyst coated with potassium carbonate (K_2CO_3) and works by oxidizing CO to carbon dioxide (CO_2) and nitrogen oxide (NO) to nitrogen dioxide (NO_2). The CO_2 is then exhausted from the system and the NO_2 absorbs onto the K_2CO_3 catalyst to form potassium nitrite (KNO_2) and potassium nitrate (KNO_3). The K_2CO_3 is regenerated by running hydrogen gas (H_2) across the catalyst. Consistent operations can be maintained using four out of five catalyst modules in a rotating fashion while the fifth module is regenerated.

A pitfall of the control technology is its potential to deactivate when exposed to sulfur oxides (SO_X). In order to prevent this issue, an additional catalytic oxidation/absorption system known as SCOSOX™ is installed upstream of the SCONOX™ catalyst to first oxidize sulfur dioxide (SO_2) to sulfur trioxide (SO_3). Also, both the SCONOX™ and SCOSOX™ catalysts are required to be washed every six to 12 months, which involves removing the catalysts from the modules. Using a fuel with low sulfur content decreases the frequency of washes required.

5.1.5 Secondary Controls - Selective Catalytic Reduction

Selective catalytic reduction (SCR) is a control technology used to convert NO_X into diatomic nitrogen (N_2) and water (H_2O) using a catalyst. The reduction reactions used by SCR require oxygen, so it is most effective at oxygen levels above 2-3%. Base metals such as vanadium or titanium are often used for the catalyst due to their effectiveness as a control technology for NO_X and cost-effectiveness for use with natural gas combustion. In addition, a gaseous reductant such as anhydrous ammonia (NH_3) or aqueous ammonia ($NH_3(aq)$) is added to the flue gas and absorbed onto the catalyst. The optimal temperature range for most SCT catalyst range from 600 degrees Fahrenheit (°F) to 800°F.

5.1.6 Secondary Controls - Selective Non-Catalytic Reduction

Selective non-catalytic reduction (SNCR) is a post-combustion control technology for NO_X emissions that uses a reduction-oxidation reaction to convert NO_X into nitrogen (N_2), water (H_2O), and carbon dioxide (CO_2). Like SCR, SNCR involves injecting ammonia (or urea) into the flue gas stream, which must be between approximately 1,400 and 2,000°F for the chemical reaction to occur. SNCR is more economically desirable due to the lack of catalyst required and, in theory, SNCR can control NO_X emissions with an efficiency similar to that of SCR (i.e., 90%). However, operating constraints on temperature, reaction time, and mixing often lead to less effective results when using SNCR in practice.

5.1.7 Alternative Controls - Good Combustion Practices

Good combustion practices are a method of controlling NO_X emissions from a combustion turbine. Maintaining optimum combustion efficiency or implementing appropriate maintenance procedures are examples of good combustion practices.

5.2 STEP 2 - ELIMINATE TECHNICALLY INFEASIBLE OPTIONS

5.2.1 Primary Controls

GSP contacted Turner EnviroLogic, Inc.[3], a reputable provider of air pollution control equipment and systems for industrial and power generation businesses. It is their opinion that only the original manufacturer would be in the position to retrofit combustion turbines of this vintage with primary controls. GSP then contacted Pratt & Whitney (P&W) engineering to discuss the potential for retrofitting this vintage (1968-1970) combustion turbine with their low emissions combustor, TALON X (formerly known as Rich-Quench Lean (RQL) combustion. P&W said that they no longer support these model combustion turbines. GSP also contacted General Electric (GE) engineering to discuss the potential to retrofit a 1969 model combustion turbine with their DLN 2.6+ technology, but as of the date of this report, there has not been a response. However, research conducted on-line regarding DLN 2.6+ indicates that it is only available for newer model combustion engines. Based on the on-line research and discussions with P&W, it has been determined that retrofitting with primary controls should not be considered technically feasible for these combustion turbines. Therefore, water or steam injection and DLN/DLE combustors have been eliminated from further analysis.

5.2.2 Secondary Controls - XONON™ Catalytic Combustor

Although developments to the XONON™ control technology are underway for gas turbines, such that it may become effective in gas turbine generators in the 1-1.4 MW range, this technology has not yet become available for application to larger turbine units. The current XONON™ catalytic combustor system has not been used on larger (i.e., greater than 1.4 MW) combined-cycle turbines and therefore, it is not considered technically feasible.

5.2.3 Secondary Controls - SCONOX™ Process (aka EMx™)

Although there have been developments to the SCONOX™ control technology, the current process has not been used on larger (i.e., greater than 1.4 MW) combustion turbines and therefore, it is not considered technically feasible.

5.2.4 Secondary Controls - Selective Catalytic Reduction

SCR has been used historically on combustion turbines and is considered technically feasible, and therefore is considered further in the evaluation.

5.2.5 Secondary Controls - Selective Non-Catalytic Reduction

SNCR is considered technically infeasible for the proposed combustion turbines due to the temperature at which the turbines will operate, the residence time of the technology, and the lack of historical use of SNCR on combustion turbines. Therefore, SNCR is not considered technically feasible.

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[3] http://tenviro.com/

5.2.6 Alternative Controls - Good Combustion Practices

Good combustion practices are considered technically feasible, and therefore are considered further in the evaluation.

5.3 STEP 3 - RANK REMAINING CONTROL TECHNOLOGIES BY CONTROL EFFECTIVENESS

Control Type	Control Efficiency	Ranking
SCR	90%	1
Good Combustion Practices	10%	2

5.4 STEP 4 - EVALUATE FACTORS AND PRESENT DETERMINATION

Good combustion practices are already being employed by GSP for each of the combustion turbines; consequently, no cost of compliance analysis was conducted for this type of control. Therefore, presented below is the four-factor analysis (cost of compliance) for SCR.

5.4.1 Factor 1: Cost of Compliance

The cost of compliance, measured in terms of annual control costs (dollars) per air emissions reduced (tons), was calculated according to the U.S. EPA Air Pollution Control Cost Manual, sixth edition. The capital cost was provided by an air pollution control vendor (Turner EnviroLogic[4]) and annualized using a capital recovery factor. The annual operating and maintenance costs were estimated using EPA default values and site-specific data, as available. These two costs were then summed and divided by the tons of pollutant anticipated to be removed.

GSP's five combustion turbines are of the same vintage (installed 1968-1970), have similar unit ratings (290 MMBtu/hr - 319 MMBtu/hr), are operated in the similar manner (operate less 1% of the number of hours in a given year), and have similar NO_X emissions (ranging from 0.7 lb/MMBtu to 0.9lb/MMBtu). Therefore, a representative cost of compliance analysis was conducted for the unit at Schiller Station.

Since the combustion turbines are peaking units, the annual capacity factor is typically less than 1%. In fact, when GSP conducted a lookback of combustion turbine operation over the last ten years at Schiller Station, it was found that the year with highest hours of operations was 2010. In 2010, the combustion turbine operated a total of 73 hours, which equated to 3.4 tons of NO_X emissions for the year. Accordingly, the representative cost of compliance analysis was conservatively based on data from 2010. Results indicate that the average cost of compliance (dollar per ton reduced) would be in excess of $197,000 (see Table 1 below). The detailed cost of compliance is provides in Appendix B.

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[4] http://tenviro.com/

Table 1. Cost of Compliance – Schiller Station Combustion Turbine

Control Type	NOx Potential Emissions (tpy)	NOx Reduced via Controls (tpy)[(a)]	Total Annualized Cost ($)	Average Cost of Compliance ($/ton reduced)
SCR @ 73 hours	3.4	3.1	604,428	197,525

(a) Assumes 90% control.

5.4.2 Factor 2: Time Necessary for Compliance

The minimal time necessary to install an SCR would be approximately 6 months.

5.4.3 Factor 3: Energy and Non-Air Quality Impacts

SCR catalysts must be disposed of properly. If not, non-air quality impacts could be realized. In addition, concerns related to the transportation, storage and use of ammonia should be considered as non-air quality impacts.

5.4.4 Factor 4: Remaining Useful Life

Based on the PSNH Generation Asset and PPA Valuation Report prepared for the New Hampshire Public Utilities Commission[5], dated March 31, 2014, the remaining useful life of each of the combustion turbines is 15 years. Please note this is a conservative assumption as the report stated a 15-year book life in March 2014.

6.0 CONCLUSION

GSP appreciates the opportunity to provide input in response to the MANE-VU Ask. As indicated by the results of the four-factor analysis for reasonable installation or upgrade to emission controls presented above, there are no additional NOx controls that GSP could employ on the combustion turbines that are both technically and economically feasible. GSP already employs good combustion practices to optimize their NOx emissions profile. Therefore, the current requirements and NOx emissions levels will be retained for each of the five peaking combustion turbines.

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[5] http://www.puc.state.nh.us/Electric/PUBLIC%20VERSION%20PSNH%20Asset%20Valuation%20Report_FINAL.pdf

APPENDIX A
SUMMARY OF NO_X CONTROL TECHNOLOGIES

Appendix A
Summary of NOx Control Technologies as Reported in the RBLC Database
Granite Shore Power LLC
183-110

Natural Gas

Facility Name	Process Name	Fuel	Throughput	Units	Pollutant	Control(s)	Emission Limit	Units	Averging Period
KENAI NITROGEN OPERATIONS	Five (5) Natural Gas Fired Combustion Turbines	Natural Gas	37.6	MMBTU/H	Nitrogen Oxides (NOx)	Selective Catalytic Reduction	7	PPMV	3-HR AVG @ 15 % O2
HILLABEE ENERGY CENTER	COMBUSTION TURBINE	Natural Gas	2142	MMBTU/H	Nitrogen Oxides (NOx)	LOW-NOX BURNER, SCR	24.6	LB/H	
STERLINGTON COMPRESSOR STATION	COMPRESSOR TURBINE NO. 1	Natural Gas	79.1	MMBTU/H	Nitrogen Oxides (NOx)	DRY LOW NOX BURNERS AND GOOD COMBUSTION PRACTICES	0.057	LB/MMBTU	
STERLINGTON COMPRESSOR STATION	COMPRESSOR TURBINE NO. 2	Natural Gas	79.1	MMBTU/H	Nitrogen Oxides (NOx)	DRY LOW NOX BURNERS AND GOOD COMBUSTION PRACTICES	0.057	LB/MMBTU	
THETFORD GENERATING STATION	FGCCA or FGCCB--4 nat. gas fired CTG w/ DB for HRSG	Natural Gas	2587	MMBTU/H	Nitrogen Oxides (NOx)	Low NOx burners and selective catalytic reduction.	3	PPMV	24-H ROLLING AVERAGE
THETFORD GENERATING STATION	FGCCA or FGCCB: 4 nat gas fired CTG with DB for HRSG: Startup/shutdown events	Natural Gas	2587	MMBTU/H	Nitrogen Oxides (NOx)	Low NOx burners and selective catalytic reduction.	78.4	T/YR	12-MO ROLL TIME PERIOD FOR STARTUP/SHUTD
DTE GAS COMPANY--MILFORD COMPRESSOR STATION	FG-TURBINES	Natural Gas	10504	HP	Nitrogen Oxides (NOx)	Dry ultra-low NOx burners	15	PPM	TEST PROTOCOL
DTE GAS COMPANY - MILFORD COMPRESSOR STATION	FGTURNBINES (5 Simple Cycle CTs: EUTURBINE1, EUTURBINE2, EUTURBINE3, EUTURBINE4, EUTURBINE5)	Natural Gas	10504	HP	Nitrogen Oxides (NOx)	Dry ultra-low NOx burners.	15	PPM	
MGM MIRAGE	TURBINE GENERATORS - UNITS CC007 AND CC008 AT CITY CENTER	Natural Gas	4.6	MMBTU/H	Nitrogen Oxides (NOx)	LEAN PRE-MIX TECHNOLOGY AND LIMITING THE FUEL TO NATURAL GAS ONLY	0.178	LB/MMBTU	
BUFFALO CREEK PROCESSING PLANT	Small Combustion Turbines (<25MW)	Natural Gas	10179	Horsepower	Nitrogen Oxides (NOx)	Dry-Low NOx Combustion	15	PPMVD@15%O2	1-HR
ROSE VALLEY PLANT	TURBINES 9,443-HP SIEMENS SGT-200-2S	Natural Gas	9443	HP	Nitrogen Oxides (NOx)	DRY LOW-NOx COMBUSTION.	15	PPMVD @15% O2	1-HR
GUADALUPE GENERATING STATION	(2) simple cycle turbines	Natural Gas	190	MW	Nitrogen Oxides (NOx)	DLN burners, limited operation	9	PPMVD	@15% O2, 3 HOUR ROLLING AVG
ECHO SPRINGS GAS PLANT	TURBINES S35-S36	Natural Gas	12555	HP	Nitrogen Oxides (NOx)	SOLONOX	15	PPMV	
ECHO SPRINGS GAS PLANT	TURBINE S37	Natural Gas	16162	HP	Nitrogen Oxides (NOx)	GOOD COMBUSTION PRACTICES	15	PPMV	
ECHO SPRINGS GAS PLANT	TURBINE S34	Natural Gas	3856	HP	Nitrogen Oxides (NOx)	SOLONOX	25	PPMV	

Fuel Oil

Facility Name	Process Name	Fuel	Throughput	Units	Pollutant	Control(s)	Emission Limit	Units	Averging Period
POINT THOMSON PRODUCTION FACILITY	Turbines	Fuel Gas	7520	kW	Nitrogen Oxides (NOx)	Dry Low NOx and SoLoNOx	15	PPMV	15% OXYGEN

APPENDIX B
SCR COST EFFECTIVENESS AT 73 HOURS PER YEAR

CEC

Granite Shore Power - Schiller Station
Portsmouth, New Hampshire
Cost Effectiveness - Selective Catalytic Reduction - Combustion Turbine (SRCT)
73 hours per year
CEC Project #183-110

Prepared By: JLF
Date Prepared: 8/27/2018
Reviewed By: JG
Date Reviewed: 8/28/2018

Item	Value	Basis[1]
Direct Costs		
Purchased Equipment Cost		
Equipment cost + auxiliaries[2] [A]	$2,000,000	A
Instrumentation	$200,000	0.10 x A
Freight	$160,000	0.08 x A
Total Purchased Equipment Cost [B]	**$2,360,000**	B = 1.18 x A
Direct Installation Costs		
Foundations and supports	$188,800	0.08 x B
Handling and erection	$330,400	0.14 x B
Electrical	$94,400	0.04 x B
Piping	$47,200	0.02 x B
Insulation for ductwork	$23,600	0.01 x B
Painting	$23,600	0.01 x B
Total Direct Installation Cost	**$708,000**	0.30 x B
Buildings (Bldg.)	**$118,000**	As required (5-18% B)
Total Direct Cost (DC)	**$3,186,000**	1.35 x B
Indirect Costs (Installation)		
Engineering	$236,000	0.10 x B
Construction and field expenses	$118,000	0.05 x B
Contractor fees	$236,000	0.10 x B
Start-up	$47,200	0.02 x B
Performance test	$23,600	0.01 x B
Contingencies	$70,800	0.03 x B
CEMs	$70,000	Assumption to purchase & install
PSD Permit	$75,000	Assumption to prepare application & review draft permit
Other	$0	As required
Construction period	0.5	Years
Interest Rate	7%	Percent
Interest during construction (Int.)	$111,510	DC * i *n
Total Indirect Cost (IC)	**$988,110**	0.31 x B + Int + PSD
Total Capital Investment (TCI) = DC + IC	**$4,174,110**	1.61 x B + Bldg. + Int. + CEMs + PSD

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1 - EPA's OAQPS Cost Control Manual, Sixth Edition unless otherwise noted

2 - Estimate provided by Tom Turner, P.E. of Turner EnviroLogic, Inc., dated August 23, 2018.

Granite Shore Power - Schiller Station
Portsmouth, New Hampshire
Cost Effectiveness - Selective Catalytic Reduction - Combustion Turbine (SRCT)
73 hours per year
CEC Project #183-110

Prepared By: JLF
Date Prepared: 8/27/2018
Reviewed By:
Date Reviewed:

	Item	Value	Basis[1]
Direct Annual Costs (DC)			
Electricity			
	Pressure Drop (in WC)	5	Pressure drop - catalyst bed
	Power Output of Turbine (kW)	20,400	ISO Rating
	Power Loss Due to Pressure Drop (%)	0.50%	0.1% for every 1" pressure drop
	Power Loss Due to Pressure Drop (kW)	102	
	Unit cost ($/kW)	$0.039	Estimated market value
Cost of Power Loss ($/yr)		**$290**	Based on operation of 73 hours/year
Operating Labor			
	Catalyst labor req.	821	1/2 hr/shift of operation @ $60/hr
	Ammonia delivery requirement (SCR)	1,440	24 hr/yr (3 deliveries per year) @ $60/hr
	Ammonia recordkeeping and reporting (SCR)	2,400	40 hours per year @ $60/hr
	Catalyst cleaning	2,400	40 hours per year @ $60/hr
	Supervisor	123	15% Operating labor
Total Cost ($/yr)		**7,184**	
Ammonia			
	Requirement (gal/hr)	51.3	19% aqueous ammonia
	Hours of operation (per year)	73	hours/year
	Unit Cost ($/gal)	$3.56	Default
Total cost ($/ton)		**13,344**	
Catalyst Maintenance			
	Catalyst system maintenance labor	274	1/2 hr/operating day @ $60/hr
	Ammonia system maintenance labor	21,900	1 hr/day @ $60/hr
	Material	$22,174	100% x maintenance labor
Total cost ($/yr)		**44,348**	
Catalyst Replacement			
	Catalyst Cost ($)	$193,282	Catalyst modules
	Catalyst Disposal Cost ($)	-	Included in catalyst cost
	Catalyst replacement labor	19,200	8 workers, 40hr, every 3 years @ $60/hr
	Catalyst life (yrs)	3	n
	Interest Rate (%)	7%	i
	CRF	0.381	Amoritization of catalyst over 3 years
Total Cost ($/yr)		**80,967**	(Material + Labor Cost) * CRF
Indirect Annual Costs (IC)			
	Overhead	$0	OAQPS SCR Assumption
	Administrative charges	$0	OAQPS SCR Assumption
	Annual Contingency	$0	OAQPS SCR Assumption
	Property taxes	$0	OAQPS SCR Assumption
	Insurance	$0	OAQPS SCR Assumption
	Capital Recovery	$458,295	CRF * TCI (15 year life[3] @ 7% interest)
Total Indirect Costs ($/yr)		**458,295**	
Total Annualized Costs (TAC) ($)		**604,428**	
Total Pollutant Controlled (tons/yr) Natural Gas		**3.1**	Assume maximum of 3.4 tpy @ 90% reduction
Cost Effectiveness ($/ton)		**197,525**	

3 - *PSNH Generation Asset and PPA Valuation Report*, La Capra Associates, Inc, dated March 31, 2014

GRANITE SHORE POWER

January 17, 2020

Mr. Craig Wright, Director
NHDES Air Resources Department
29 Hazen Drive, Concord, NH

GSP's Supplemental Response to DES' Request for Information on MANE-VU "Ask" Associated with the Regional Haze Rule

Granite Shore Power LLC (GSP) submits this supplemental response to the New Hampshire Department of Environmental Services' (DES) Request for Information (RFI) related to the Mid-Atlantic Northeast Visibility Union (MANE-VU) "Ask" associated with the regional haze rule. While GSP understands that the MANE-VU "Ask" is directed at member states, GSP appreciates the opportunity to be engaged in the process of reviewing emission control strategies at each of its operating facilities. GSP submitted information on June 25, 2018 and August 31, 2018 to satisfy the RFI. This current submittal is to provide supplemental information in response to questions that NHDES received on its draft State Implementation Plan (SIP) related to the MANE-VU "Ask".

Specifically, NHDES requested that GSP provide additional information related to Merrimack Station's NOx control strategy and feasibility of additional or alternate controls. Information on the feasibility and effectiveness of NOx controls at Merrimack Station has been previously provided to NHDES in the following submittals:

- Merrimack Station Unit 2 NOx Control Technology Selection Memo, July 25, 1994
- GSP Comments on Proposed NOx RACT Limit (Env-A 1300), p.10, May 25, 2018
- GSP Response to NHDES RFI on MANE-VU "Ask", p.8, August 31, 2018

The following is a summary of the information provided in the above submittals with some additional details included as specifically requested.

Merrimack Station Unit 1 and Unit 2 are each equipped with a selective catalytic reduction ("SCR") system to control NOx emissions. DES reviewed historical performance data for Unit 1 and Unit 2 and revised the NOx RACT rules in Env-A 1300 with more stringent daily NOx emission limits on both a rate basis and a mass basis. The new daily NOx limit, effective August 15, 2018, for both units is 0.22 lb/MMBtu when SCR temperature permissive parameters are met for all operating time in the day. Alternately, the NOx limits are 4.0 (Unit 1) or 11.5 (Unit 2) tons per day when any startup, shutdown, or low-load conditions occur in the day (flue gas temperatures below SCR operating temperature). These recently revised NOx RACT limits represent the most effective use of the SCR, given that the system must be operated year-round at or above its design capacity to demonstrate compliance.

The installation of SCRs on Units 1 and 2 were among the first of its kind over 20 years ago and continue to be the best available technology for NOx control. These units are not viable candidates for retrofit with additional NOx controls. The installation of additional control mechanisms cannot be justified, as the incremental reductions achievable from such a strategy are minimal, at best, when installed later than the SCR.

Specifically, the following emission control mechanisms have been investigated and evaluated at Merrimack Station: combustion modification methods (including overfire air), reburn, fuel switching, SNCR and SCR. Early investigations began in 1992 and ultimately resulted in installation of the SCRs as the best available control technology for Unit 1[1] and Unit 2. Subsequent to the early investigations, a preliminary engineering feasibility study of potential further NOx emissions reductions was performed by an internal engineering team in 2012. The study was completed over a four-week period and included visits to other power plants. Details from the study are provided below.

Overfire Air (OFA)

OFA is a staged combustion process that works by bypassing a portion of the combustion air that would normally go to the cyclones and injects it into an area in the radiant section of the boiler above the cyclones. By doing so, the stoichiometry in the cyclone is reduced to about 0.9 thus creating a fuel rich combustion zone and subsequent reduction in thermal and fuel NOx generation. As part of the incomplete combustion process, significant amounts of CO are produced. The CO then leaves the cyclone and completes the combustion process as it meets up with the overfire air.

The engineering study team visited other cyclone boiler electric generating facilities which had installed OFA. In each case, the OFA was installed prior to installation of the SCR, not after. Upon installation, the SCR became the primary NOx compliance strategy. From these field visits and additional discussions with industry experts, it was learned that OFA technology was developed to meet the requirements of Title IV while avoiding the high capital cost of installing SCR. Because of the significant technical challenges associated with OFA (discussed below) and the marginal increase in NOx capture that would result, the industry experts indicated they were not aware of any cyclone boiler in the United States that had installed OFA after an SCR was in service, and questioned the feasibility and merits of doing so.

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[1] Unit 1 first installed SNCR which was ineffective and was replaced by SCR technology.

Expected OFA challenges include:

- Engineering challenges due to existing boiler configuration, including the cyclone locations, windbox design, and screen tubes
    - Merrimack Station has split windbox designs which create difficulties since the OFA must be pulled off and balanced from two or more different locations increasing the complexity of the controls and ducting design.
    - Unit 1's configuration with screen tubes directly in front of the cyclones' re-entrant throats is a significant problem that was not a factor at any of the sites that were visited or contacted as part of the study.
- Required replacement of existing parts and equipment as part of initial OFA implementation
    - One of the visited facilities required a cyclone replacement (which was reported to cost $8 million) per the recommendation of the boiler manufacturer. The existing cyclone would not have survived the reducing conditions of staged combustion.
    - All facilities visited had to replace their original gas recirculation fans to implement OFA.
- Damage to existing parts and equipment through routine operation of OFA
    - Potential for significantly increasing corrosion damage to the boiler tubes. Boilers normally operate with an excess of oxygen, i.e., more oxygen than is needed to support combustion, in order to ensure that there are no "reducing zones" in the furnace. OFA purposely introduces reducing zones. Particularly, in the areas above the burners where the air required to complete combustion is injected, boilers have experienced significant increases in corrosion with increases in boiler tube failures after adding OFA.
- Significant loss in boiler performance due to OFA installation
    - When implementing OFA, the mapping of heat release throughout the boiler is changed from the initial design point resulting in higher heat releases where they should be lower, and lower heat releases where they should be higher. One of the visited facilities cited need for installation of additional reheat surface area and high "k-factor" refractory to return boiler performance to its prior conditions, with limited success.
    - Another facility cited costly re-orificing of the boiler to help maintain hydraulic performance, thermal performance, and prevent water wall damage.

- Other performance issues reported included low slag viscosity, boiler tube corrosion, over temperature conditions in the upper gas passes, and increased fly ash production. All units visited reported experiencing increased fouling the convection section of the boiler since the installation of the OFA.

The potential ash handling issues, increases in boiler tube failures due to corrosion, fouling of convective sections of the boiler, performance impacts on the precipitator, and changes in heat release patterns throughout the boiler could lead to increased forced outages and adversely impact the reliability of the Merrimack units. In addition, purposely creating zones with high concentrations of carbon monoxide creates a safety risk for plant employees that would need to be managed.

The facilities visited by the engineering team reported being able to achieve 0.50 to 0.67 lb NOx/MMBtu with OFA only, and 0.15 to 0.35 lb NOx/MMBtu with OFA and SCR under optimal conditions for a total of 83 to 90 percent reduction. With the new NOx RACT limits, under optimal conditions, Units 1 and 2 achieve nearly identical NOx reductions of 83 to 91 percent with SCR alone. This confirms that there is limited to no opportunity to see increased NOx removal with addition of OFA, especially since SCR is already installed and was designed for a specific NOx inlet concentration. Any decrease in the NOx inlet concentration realized from introduction of OFA is not likely to decrease the final NOx emission rate, but will decrease the NOx removal percentage of the SCR. Said differently, the overall percent removal from OFA/SCR is expected to be the same or similar to the SCR operating alone.

Reburn

Reburn technology utilizes a secondary fuel to stage the combustion in the boiler. By using a secondary fuel to create a reducing zone (no oxygen) in the boiler, fuel NOx and thermal NOx formed in the cyclone burners is reduced to N2. Additionally, this staging effectively reduces the firing temperature and subsequent thermal NOx production. There are typically three types of fuel used for reburn; micronized coal, liquid fuels such as oil, and gaseous fuels. Babcock and Wilcox determined that both units are too short for micronized coal, the cost of oil is uneconomical with minimal, uncertain NOx reductions without modeling and engineering evaluations, and the lack of availability of gaseous fuel on the site eliminates it as an option. Also, the re-burn process reduces thermal NOx production by reduces firing temperature, which creates reducing zones, where ash removal problems and corrosion related issues can occur. Overall, reburn technology is not a viable option for Merrimack Station.

Fuel Switching

Fuel Switching is not a viable option due to the requirement to fire subbituminous coal, either as a blend with the existing fuel or as the primary fuel. Merrimack Station's Unit is designed to burn high volatile bituminous coal with specific ash properties and energy densities. Introducing sub-bituminous coal would mean a reduction of boiler effectiveness and efficiency with a probable loss of capacity and increase in heat rate. These impacts would require the burning of more fuel, causing an increase in emissions and potentially requiring modification of systems such as precipitators, material handling equipment, and boiler heat transfer surfaces to handle the additional throughput. Overall, this fuel would not provide reliable unit operations and would not be considered a viable alternative to the current use of bituminous coal.

SNCR

SNCR was tried and proved unsuccessful at Merrimack Station. It was deployed on Unit 1 and only achieved a 15 percent NOx reduction which is much less than the reductions currently observed on both units with SCR technology. This is not a viable control option at Merrimack Station.

In conclusion, Merrimack Station already operates the most effective NOx control technology year-round. Some facilities have implemented multiple NOx controls, however, in all known cases the less effective controls were implemented first and the SCR installation followed later, presumably due to more stringent requirements requiring best available controls. Merrimack Station made the capital investment for SCR controls early-on and therefore avoided the layered control approach that other facilities implemented to avoid or delay significant capital expenditures. Adding a lesser control at this juncture would create substantial technical challenges with negligible environmental return on investment.

If you have any questions regarding this submittal please contact Melissa A. Cole, P.E., Environmental Engineer at 603-230-7917 or Melissa.Cole@graniteshorepower.com.

Sincerely,

GRANITE SHORE POWER

Elizabeth H. Tillotson

Elizabeth H. Tillotson
Executive Director of Administration & Regulatory Affairs

GRANITE SHORE POWER

October 18, 2021

Mr. Craig Wright, Director
NHDES Air Resources Department
29 Hazen Drive, Concord, NH

Response to DES' Request for Information Related to the Regional Haze Rule Four-Factor Analysis

Granite Shore Power LLC (GSP) submits this response to the New Hampshire Department of Environmental Services' (DES) Request for Information (RFI) dated September 2, 2021. The DES RFI requested that GSP provide the following information associated with the Regional Haze Rule:

1. A Four-Factor Analysis for SO2 and NOx for Energy Generating Units (EGUs) MK1 and MK2; and

2. A revised selective catalytic reduction (SCR) cost effectiveness estimate for GSP's five peaking units, which used the current bank prime rate instead of the assumed interest rate of 7%.

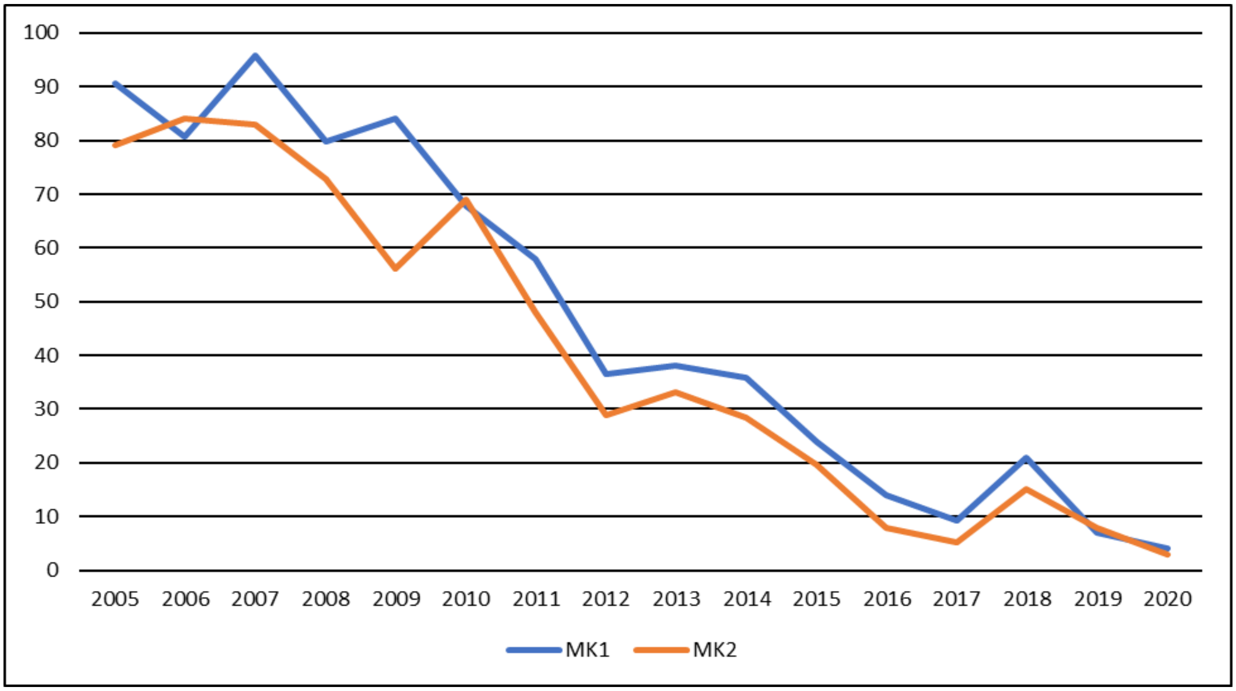
Four-Factor Analyses for SO2 and NOx are included in Attachment A. The Four-Factor Analysis for each confirms no feasible control technologies are available and effective emission controls are already in operation. A discussion regarding our review of emission control technologies is provided below. The revised SCR cost effectiveness estimate is included in Attachment B.

BACKGROUND

Merrimack Station is comprised of two cyclone-fired utility boilers (MK1 and MK2) that burn bituminous coal. MK1 and MK2 are each equipped with SCR systems for the control of NOx emissions, electrostatic precipitators (ESP) for the control of particulate matter (PM), and a wet limestone flue gas desulfurization (FGD) system for the control of sulfur dioxide emissions (SO2), mercury, and hydrochloric acid. These controls are operated year-round and are engaged prior to combustion of fuel in the boiler, with the exception of the SCRs, which by design are engaged when the proper operating temperatures are reached during the startup sequence.

When evaluating the feasibility of additional controls, it is important for perspective to consider the changes in the operation of MK1 and MK2 over time. MK1 and MK2 were historically operated as base-loaded units in the early 2000s. Over the last decade, due to the increased supply of natural gas to the region, the units have shifted to operation as "peaking units" to supply power to the electrical grid during periods of high demand or to provide for grid reliability. Due to this change in energy markets and the resulting change in the function of Merrimack Station, MK1 and MK2 have operated at significantly lower capacity factors annually as illustrated below in Figure 1.

Figure 1. MK1 and MK2 Capacity Factor (%)



The more intermittent use of MK1 and MK2 has increased the number of annual startup and shutdown hours, which has resulted in short-term increases in emission rates during periods of startup/shutdown. However, there has been a dramatic decrease in total SO2 and NOx emissions due to the decrease in annual operating hours combined with the operation of technologically advanced emission control systems as illustrated in Figures 2 and 3, below. Although the permit does not limit operation, market conditions and forecasts suggest that the units will maintain their status as peaking units for the foreseeable future. Therefore, targeting small capacity factor units for additional controls has a low probability of demonstrating actual state-wide progress in visibility impairment criteria.

Figure 2. MK1 and MK2 Annual SO2 Emissions (Tons)

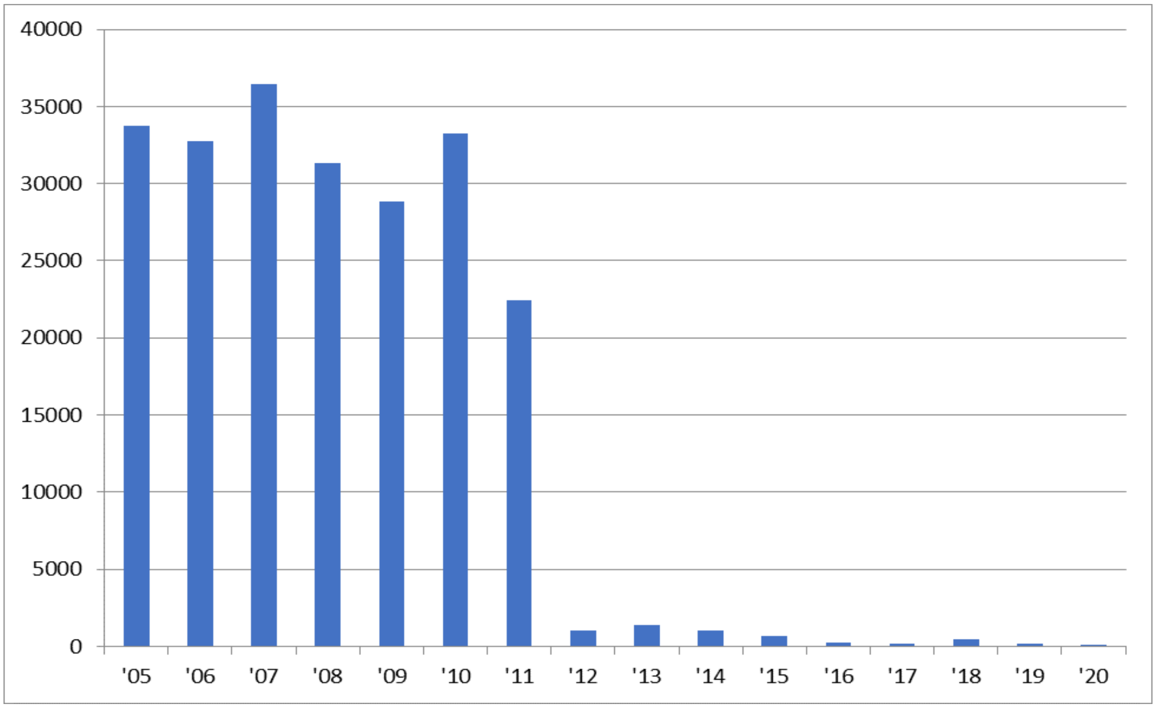
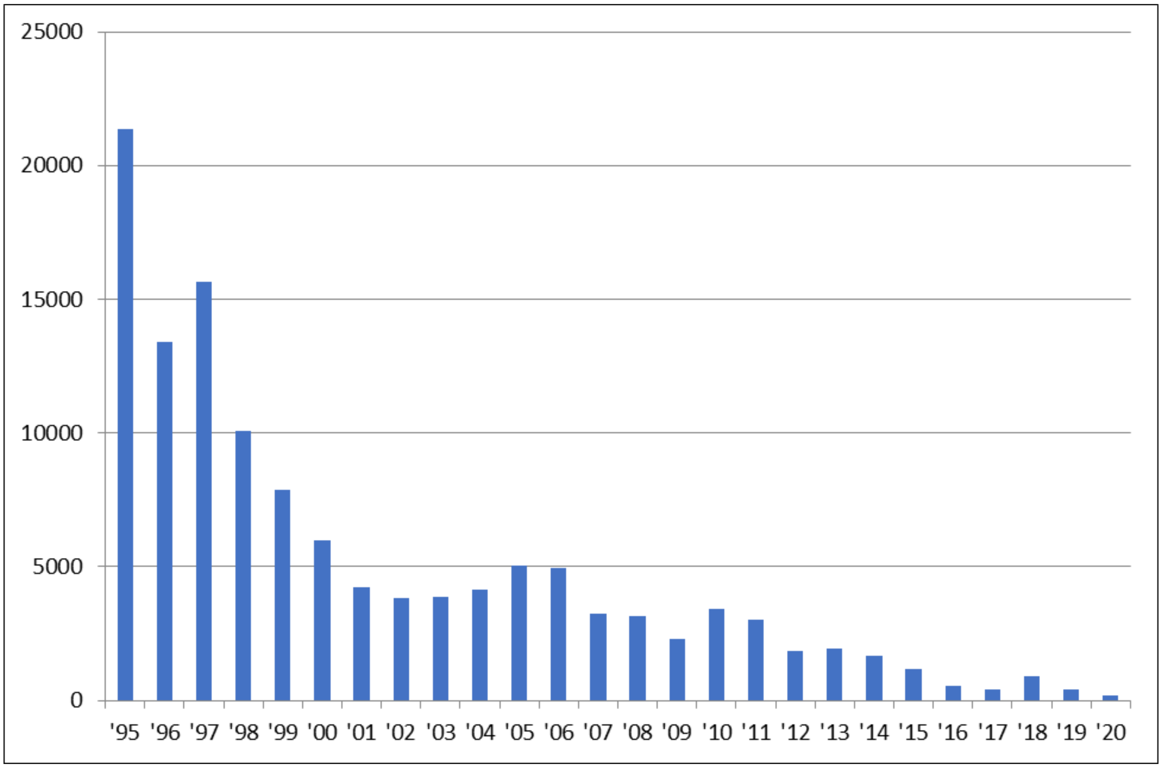


Figure 3. MK1 and MK2 Annual NOx Emissions (Tons)



FOUR FACTOR ANALYSIS – SO2

GSP operates a wet limestone FGD system that was commissioned in September 2011. It was the most effective and technologically advanced system at the time and is still current technology that achieves a 95% reduction in SO2 emissions. In the attached Four Factor Analysis for SO2, we reviewed the feasibility of various control technologies including:

- Upgrades to the existing FGD;
- Coal cleaning;
- Dry FGD;
- FGD combined with Dry Sorbent Injection; and
- Fuel Switching.

Based on our review, the above technologies are not feasible as described in Attachment A. In addition, U.S. EPA's document titled *Guidance on Regional Haze State Implementation Plans for the Second Implementation Period* (EPA RHG) dated August 2019, provides example scenarios for sources that they consider "effectively controlled". In certain circumstances, EPA believes it may be reasonable for a state not to select a particular source for further analysis because it "may be reasonable to assume for the purposes of efficiency and prioritization that a full four-factor analysis would likely result in the conclusion that no further controls are necessary." An example scenario identified by EPA that is pertinent to GSP includes the following:

> "For the purposes of SO2 and NOx control measures, a combustion source (e.g., an EGU or industrial boiler or process heater) that, during the first implementation period, installed a FGD system that operates year-round with an effectiveness of at least 90 percent or by the installation of a selective catalytic reduction system that operates year-round with an overall effectiveness of at least 90 percent (in both cases calculating the effectiveness as the total for the system, including any bypassed flue gas), on a pollutant-specific basis."

Two related footnotes add that:

> "For purposes of this consideration, the first regional haze implementation period started when SIPs were due on December 17, 2007."

and;

> "While a 90 percent control effectiveness is used in this example, we expect that any FGD system installed to meet CAA requirements since 2007 would have an effectiveness of 95 percent or higher. This does not apply to a source that has recently achieved a higher level of control efficiency without the installation of a control system, for example if it has merely

> increased the flow rate of a reagent. In such a situation, the four factors should be fully considered. The outcome may still be that the current level of control is the measure that is necessary to make reasonable progress."

The FGD system was installed after the first implementation period of 2007 and achieves a SO2 removal efficiency of 95%. GSP interprets that the SO2 emissions from MK1 and MK2 are "effectively controlled" by the FGD system in accordance with the EPA RHG, and that a full Four Factor Analysis is not necessary because "it is reasonable to assume for the purposes of efficiency and prioritization that a full four-factor analysis would likely result in the conclusion that no further controls are necessary."

FOUR FACTOR ANALYSIS – NOx

Merrimack Station currently implements the most effective technology available for maximum NOx reductions, SCRs. In fact, Merrimack Station was the first investor-owned utility in the nation to install an SCR to achieve NOx reductions. MK2's SCR became operational in 1995 and MK1's SCR was added in 1999.

The SCR system achieves an overall NOx control efficiency of 80 to 90%. As indicated in the EPA's cost control manual dated June 2019, SCR systems are often designed to meet control targets of 90 percent or higher. However, SCR system design is a proprietary technology and the design is highly site-specific. Therefore, the actual control efficiency will depend upon many site-specific features, including, but not limited to, inlet NOx concentration, space constraints, and operational function. While the SCRs remain highly effective during normal operations, as described previously, the higher ratio of startup/shutdown hours to operational hours as MK1 and MK2 have transitioned to peaking units, has slightly decreased the overall efficiency of the system. However, this transition has resulted in a significant net benefit in the reduction of total NOx (and SO2) emissions from MK1 and MK2. The SCR systems at Merrimack Station have been optimized for unit specific parameters and based upon catalyst monitoring and ammonia slip data, the systems are operating efficiently and as designed. As summarized in Attachment A, we did not identify additional feasible NOx control technologies for MK1 and MK2 and the system is already effectively controlled.

If you have any questions regarding this submittal please contact Luke Sanborn at (603) 230-7959 or Melissa A. Cole at (603) 230-7917.

Sincerely,

GRANITE SHORE POWER

Elizabeth H. Tillotson

Elizabeth H. Tillotson
Vice President

ATTACHMENT A

FOUR FACTOR ANALYSES

Four-Factor Analysis Summary for SO2

Operating Parameters – Baseline Year

Parameter		
Emission Sources	2 cyclone-fired utility boilers – MK1 & MK2	Fuel: Bituminous coal
Power Output	108 (U1) + 330 (U2) = 438	MW (net)
Annual Heat Input (2017)	1,053,780 (U1) + 1,686,970 (U2) = 2,740,750	MMBtu/yr
Annual Capacity Factor (2017)	5-9	%
SO2 Emissions (limit)	0.39 94%	lb/MMBtu, (7-day rolling) % reduction (30-day rolling)
Existing SO2 Controls	Wet Limestone FGD	94% minimum

Table 1: Feasible Control Options and Cost

Control Technology	Technically Feasible (Y/N)	Brief Justification of Feasibility	Removal Efficiency (%)	Incremental Cost ($/ton SO2 removed)
1) Upgrades to existing FGD	N	• Technologically advanced wet limestone FGD commenced operation in September 2011. • Existing FGD system designed with sufficient capacity and redundancy. • SO_2 Permit Limit of 94% reduction. FGD has reliably achieved 95% reduction (30-day average basis). • Per EPA Regional Haze Guidance (Page 24)[1], 95% control efficiency is already considered “Effectively Controlled”.	95%	N/A
2) Coal cleaning	N	• FGD system was designed and optimized to control contaminant loading of bituminous coal. • Changes in the characteristics of the fuel may reduce the efficiency of the system and upset the balance with other control devices.	N/A	N/A

		- FGD considered “Effectively Controlled” as described in #1, above.		
3) Dry FGD	N	- A $422 million investment was made in a technologically advanced LSFO FGD that commenced operation in September 2011. - Dry FGD is a less effective technology than the existing wet FGD system. - Existing FGD considered “Effectively Controlled” as described in #1, above.	N/A	N/A
3) FGD + Dry Sorbent Injection	N	- FGD system was optimized to control designed contaminant loading. - Adding a DSI system would change contaminant loading to FGD and decrease efficiency. - Existing FGD considered “Effectively Controlled” as described in #1, above.	N/A	N/A
4)Fuel Switching	N	- Cyclone boilers are not designed or able to burn sub-bituminous coal. - Burning sub-bituminous coal would decrease efficiency of boilers and emission controls. - Sub-bituminous coal has lower heat content, which would increase fuel use and emissions. - Would reduce efficiency of Hg and PM controls. - Natural gas supply not available at the Facility.	N/A	N/A

1. USEPA; “Guidance on Regional Haze State Implementation Plans for the Second Implementation Period,” August 2019, Page 24.

Table 2: Four-Factor Analysis for Feasible Technologies

Control Technology	Factor 1: Cost of Compliance ($/ton SO2 removed)	Factor 2: Time Necessary for Compliance (months)	Factor 3:Energy and Non-Air Quality Environmental Impacts	Factor 4: Remaining Useful Life (years)
1) Feasible alternative emissions controls not identified and existing emission controls are considered “Effectively Controlled”.				
2)				

Four-Factor Analysis Summary for NOx

Operating Parameters – Baseline Year

Parameter		
Emission Sources	2 cyclone-fired utility boilers – MK1 & MK2	Fuel: Bituminous coal
Power Output	108 (U1) + 330 (U2) = 438	MW (net)
Annual Heat Input (2017)	1,053,780 (U1) + 1,686,970 (U2) = 2,740,750	MMBtu/yr
Annual Capacity Factor (2017)	5-9	%
NOx Emissions (limit)	0.22	lb/MMBtu
Existing NOx Controls	Type: SCR, 4 catalyst layers	Removal Efficiency: 80 to 90%

Table 1: Feasible Control Options and Cost

Control Technology	Technically Feasible (Y/N)	Brief Justification of Feasibility	Removal Efficiency (%)	Incremental Cost ($/ton NOx removed)
1)Fuel Switching	N	• Cyclone boilers are not designed or able to burn sub-bituminous coal. • Burning sub-bituminous coal would decrease efficiency of boilers and emission controls. • Sub-bituminous coal has lower heat content, which would increase fuel use and emissions. • Would reduce efficiency of Hg and PM controls. • Natural gas supply not available at the Facility.	N/A	N/A
2) Over-fire air	N	• Not compatible with existing cyclone or split windbox designs. • Has not been installed as a retrofit after installation of existing SCR. • Increased corrosion and damage to boiler tubes. • Loss in boiler performance and potential need to re-orifice the boiler to maintain performance and prevent water wall damage. • Negative impact on performance of FGD and ESP.	N/A	N/A

Control Technology	Technically Feasible (Y/N)	Brief Justification of Feasibility	Removal Efficiency (%)	Incremental Cost ($/ton NOx removed)
3) SNCR	N	• Has been tried on MK1 and was proven unsuccessful with only 15% NOx reduction.	N/A	N/A
4)Reburn	N	• 3 fuel options: -Units too short for micronized coal. -Oil will have insignificant NOx reduction. -Gaseous fuel unavailable onsite. • Reduction in firing temperature creates reducing zones, which would cause increased corrosion and damage to boiler tubes as well as ash removal issues.	N/A	N/A
5) Upgrade to Existing SCR	N	• SCR for Unit 1 installed in 1999 and Unit 2 installed in 1995. Facility was early adopter of technology compared to other facilities that staged improvements. Technology is still current and effective. • SCRs already achieve 80 to 90% control efficiency, maintained through catalyst sampling and technology advancements available during catalyst replacement events.	80 to 90%	N/A

Table 2: Four-Factor Analysis for Feasible Technologies

Control Technology	Factor 1: Cost of Compliance ($/ton SO2 removed)	Factor 2: Time Necessary for Compliance (months)	Factor 3:Energy and Non-Air Quality Environmental Impacts	Factor 4: Remaining Useful Life (years)
1)	**Feasible alternative emissions controls not identified. We interpret that existing emission controls are considered "Effectively Controlled".**			
2)				

ATTACHMENT B

REVISED SCR COST EFFECTIVENESS ESTIMATE

REASONABLE PROGRESS REPORT

WHITE LAKE GENERATING STATION – TAMWORTH, NEW HAMPSHIRE
LOST NATION GENERATION STATION – NORTHUMBERLAND, NEW HAMPSHIRE
MERRIMACK STATION – BOW, NES HAMPSHIRE
SCHILLER STATION – PORTSMOUTH, NEW HAMPSHIRE

PREPARED FOR:
GRANITE SHORE POWER LLC

PREPARED BY:
CIVIL & ENVIRONMENTAL CONSULTANTS, INC.

CEC PROJECT 183-110/310-770

AUGUST 2018/OCTOBER 2021

Civil & Environmental Consultants, Inc.

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APPENDICES

Appendix A	Summary of NO_X Control Technologies
Appendix B	SCR Cost Effectiveness at 73 Hours Per Year

1.0 INTRODUCTION

Granite Shore Power LLC ("GSP") submits the following in response to the Mid-Atlantic/Northeast Visibility Union's (MANE-VU) *Statement of MANE-VU States Concerning a Course of Action Within MANE-VU Toward Assuring Reasonable Progress For the Second Regional Haze Implementation Period (2018-2028)*, dated August 25, 2017. As the owner and operator of four generating stations with five peaking combustion turbines in New Hampshire: White Lake Generating Station, Lost Nation Generating Station, Merrimack Station, and Schiller Station; GSP appreciates the opportunity to be involved in the response to MANE-VU.

Based on the results of the analyses for reasonable installation or upgrade to emissions controls conducted, GSP anticipates that the current requirements and nitrogen oxide (NO_X) emissions levels will be retained for each of the five peaking combustion turbines.

2.0 BACKGROUND

In accordance with the MANE-VU statement:

> The federal Clean Air Act (CAA) and Regional Haze rule requires States that are reasonably anticipated to cause or contribute to impairment of visibility in mandatory Class I Federal areas to implement reasonable measures to reduce visibility impairment within the national parks and wilderness areas designated as mandatory Class I Federal areas.

Furthermore:

> According to the Regional Haze rule (40 CFR 51.308 (f)(2)(i) through (iv)), all states must consider, in their Regional Haze SIPs, the emission reduction measures identified by Class I States as being necessary to make reasonable progress in any Class I area. These emission reduction measures are referred to as "Asks." If any State cannot agree with or complete a Class I State's "Ask," the State must describe the action taken to resolve the disagreement in their Regional Haze SIP…
>
> To address the impact on mandatory Class I Federal areas within the MANE-VU region, the Mid-Atlantic and Northeast State will pursue a coordinated course of action designated to assume reasonable progress toward preventing any future, and remedying any existing impairment of visibility in mandatory Class I Federal areas and to leverage the multi-pollutant benefits that such measure may provide for the protection of public health and the environment…

SIPs are to be submitted between July 2018 and July 2021. With the objective of meeting the 2028 reasonable progress goal for regional haze, five different "emission management" strategies were developed. Strategy 5 applies to the five peaking combustion turbines operated by GSP.

5. Where emission rules have not been adopted, control NO_X emissions for peaking combustion turbines that have the potential to operate on high electric demand days by:

   a. Striving to meet NO_X emission standard of no greater than 25 ppm at 15% O_2 for natural gas and 42 ppm at 15% O_2 for fuel oil but at a minimum meet NO_X emissions standard of no greater than 42 ppm at 15% O_2 for natural gas and 96 ppm at 15% O_2 for fuel oil, or

   b. Performing a four-factor analysis for reasonable installation or upgrade to emission controls, or

   c. Obtaining equivalent alternative emission reductions on high electric demand days.

3.0 DESCRIPTION OF GENERATING STATIONS

GSP owns and operates five peaking combustion turbines at their four generating stations in New Hampshire that are associated with this Ask. The combustion turbines are all classified as small turbines (<25 megawatts, MW) and given their vintage (1968-1970), there are no existing NO_X controls other than good combustion practices.

3.1 WHITE LAKE GENERATING STATION

The White Lake Generating Station is located in Tamworth, New Hampshire, and is operated under State-Only Operating Permit No. SP-0216. Emission Unit EU01 is a Pratt & Whitney simple-cycle combustion turbine, installed in 1968. Its maximum heat input is 300 million British Thermal Units per hour (MMBtu/hr), which is equivalent to 2,222 gallons per hour (gal/hr), based on a heating value of 135,000 Btu/gal of kerosene-1 fuel. Fuel consumption is permit-limited to 908,270 gallons of kerosene in any consecutive 12-month period and emissions are subject to a facility-wide emissions limit of 50 tons per year (tpy) of NO_X. Based on stack testing conducted in 2015, the average NO_X emission rate for EU01 is 0.642 lb/MMBtu.

3.2 LOST NATION GENERATING STATION

The Lost Nation Generating Station is located in Northumberland, New Hampshire, and is operated under State-Only Operating Permit No. SP-0217. Emission Unit EU01 is a General Electric simple-cycle combustion turbine, installed in 1969. Its maximum heat input is 315 MMBtu, which is equivalent to 2,250 gal/hr, based on a heating value of 140,000 British Thermal units per gallon (Btu/gal) of #2 fuel oil. Fuel consumption is permit-limited to 981,100 gallons of No. 2 fuel oil in any consecutive 12-month period and emissions are subject to a facility-wide emissions limit of 50 tpy of NO_X. Lost Nation is also permitted to operate a starter engine with 4 MMBtu/hr rated heat input. Based on stack testing conducted in 2015, the average NO_X emission rate for EU01 is 0.641 lb/MMBtu.

3.3 MERRIMACK STATION

The Merrimack Station is located in Bow, New Hampshire, and is operated under Title V Operating Permit No. TV-0055. Emission Units MKCT1 and MKCT2 are both Pratt & Whitney simple-cycle combustion turbines, installed in 1968 and 1969, respectively. Each combustion turbine has a maximum fuel consumption permit limit of 2,279 gal/hr (19.96 million gallons during any 12-month consecutive period) based on a fuel heating value of 140,000 Btu/gal. The combustion turbines can fire either No. 1 fuel oil or jet fuel (JP-4). The combustion turbines are subject to a NO_X limit of 0.09 pounds per million British Thermal unit (lb/MMBtu) on an hourly average, which is the existing Reasonably Available Control Technology (RACT) limit. Based on stack testing conducted in 2016, the average NO_X emission rate for MKCT1 is 0.827 lb/MMBtu and MKCT2 is 0.857 lb/MMBtu.

Merrimack is also permitted to operate two steam generating units, a primary coal crusher, a secondary coal crusher, an emergency generator, an emergency boiler, and an emergency cooling pump.

3.4 SCHILLER STATION

The Schiller Station is located in Portsmouth, New Hampshire, and is operated under Title V Operating Permit No. TV-0053. Emission Unit SRCT is a Pratt & Whitney simple-cycle combustion turbine, installed in 1970. Its maximum heat input is 290 MMBtu, which is equivalent to 2,070 gal/hr of distillate fuel (#2 fuel oil, JP-4, kerosene) or 290,000 cubic feet per hour (cf/hr) of natural gas. Fuel oil consumption is limited to 13,900,000 gallons in any consecutive 12-month period. The fuel consumption rates are based on the following assumed heating values: 12,700 Btu/lb (bituminous coal), 150,000 Btu/gal (No. 6 fuel oil), 140,000 Btu/gal (distillate oil), 4,275 Btu/lb (wood), 1,000 Btu/ft^3 (natural gas), and 94,000 Btu/gal (propane). The combustion turbine is subject to a NO_X limit of 0.09 lb/MMBtu on an hourly average, which is the existing RACT limit. Based on stack testing conducted in 2016, the average NO_X emission rate for SRCT is 0.8 lb/MMBtu.

Schiller is also permitted to operate two steam generating units, a fluidized bed boiler, a primary coal crusher, a secondary coal crusher, an emergency generator, and a heating system boiler.

4.0 REASONABLE PROGRESS EVALUATION PROCESS

The reasonable progress evaluation requested for the five peaking combustion turbines is an assessment of the applicable control technologies capable of reducing emissions of a pollutant and is conducted using a “top-down” approach taking into account feasibility and cost effectiveness, as well as, economic, environmental, and energy impacts. These assessments are conducted on a case-by-case basis using site-specific information, as available. The result of the analysis may not result in emissions of a pollutant which would exceed the emissions allowed by any applicable standard under 40 CFR Part 60 or 61.

The reasonable progress evaluation generally follows U.S. EPA-developed guidance for Best Available Control Technology (BACT) as outlined in Chapters B and G of the U.S. EPA Draft *New Source Review Workshop Manual* (OAQPS, October 1990). The five-step process includes:

Step 1: Identify Available Control Technologies;

Step 2: Eliminate Technically Infeasible Options;

Step 3: Rank Remaining Control Technologies by Control Effectiveness;

Step 4: Evaluate Economic, Environmental, and Energy Impacts of Technically Feasible Control Technologies; and

Step 5: Select BACT.

However, the reasonable progress evaluation essentially combines steps 4 and 5 into one – "Evaluate Factors and Present Determination." The four factors to be evaluated are: the cost of compliance, the time necessary for compliance, energy and non-air quality impacts, and the remaining useful life. The reasonable progress evaluation also incorporates guidance provided by the New Hampshire Department of Environmental Services (DES).

4.1 STEP 1 – IDENTIFY AVAILABLE CONTROL TECHNOLOGIES

The first step in the reasonable progress evaluation analysis is to identify "available" control options. Available control options are those air pollution control technologies or techniques (including lower-emitting processes and practices) that have the potential for practical application to the emissions unit and pollutant under evaluation, with a focus on technologies that have been demonstrated to achieve the highest levels of control for the pollutant in question, regardless of the source type in which the demonstration has occurred.

4.2 STEP 2 – ELIMINATE TECHNICALLY INFEASIBLE OPTIONS

In the second step of the reasonable progress evaluation, any available control technique listed in Step 1 may be eliminated from further consideration if it is not technically feasible for the specific source under review. A demonstration of technical infeasibility must be documented and show, based on physical, chemical, or engineering principles, that technical difficulty would preclude the successful use of the control option on the emissions unit under review. U.S. EPA generally considers a technology to be technically feasible if it has been demonstrated and operated successfully on the same type of emissions unit under review or is available and applicable to the emissions unit type under review. If a technology has been operated on the same type of emissions unit, it is presumed to be technically feasible. An available technology from Step 1, however, cannot be eliminated as infeasible simply because it has not been used on the same type of source that is under review. If the technology has not been operated successfully on the type of source under review, then questions regarding "availability" and "applicability" to the particular source type under review should be considered for the technology to be eliminated as technically infeasible.

4.3 STEP 3 – RANK REMAINING CONTROL TECHNOLOGIES BY CONTROL EFFECTIVENESS

Step 3 of the reasonable progress evaluation calls for the remaining control technologies to be listed in order of overall control effectiveness for the pollutant under review. The most effective control alternative (i.e., the option that achieves the lowest emissions level) should be listed at the top and the remaining technologies ranked in descending order of control effectiveness. The ranking of control options in Step 3 determines where to start the "top-down" selection process in Step 4. In determining and ranking technologies based on control effectiveness, facilities should include information on each technology's control efficiency (e.g., percent pollutant removed, emissions per unit product), expected emission rate (e.g., tpy, pounds per hour [lb/hr], pounds per unit of product, pounds per unit of input, parts per million [ppm]), and expected emissions reduction (e.g., tpy). The metrics chosen for ranking should best represent the array of control technology alternatives under consideration.

4.4 STEP 4 – EVALUATE FACTORS AND PRESENT DETERMINATION

Under Step 4 of the reasonable progress evaluation, facilities must consider the cost of compliance, time necessary for compliance, energy and non-air quality impacts, and remaining useful life of each option remaining options under consideration. Accordingly, after available and technically feasible control options have been ranked in terms of control effectiveness (Step 3), facilities should consider these four factors when presenting the determination for reasonable installation or upgrade of emission controls. If the most stringent control option (based on the ranking of controls under Step 3) is eliminated from further consideration for reasonable installation, then the next most stringent alternative is considered, and so on, until a final determination of all controls is completed.

5.0 REASONABLE PROGRESS EVALUATION FOR NO_X

NO_X is primarily formed by two mechanisms: the combination of elemental nitrogen and O_2 in the combustion air within the high temperature environment of the combustor (thermal NO_X) and the oxidation of nitrogen contained in the fuel (fuel NO_X). NO_X emissions from combustion turbines when firing fuel originate primarily as thermal NO_X. The rate of formation of thermal NO_X is a function of residence time and free oxygen, and is exponential with peak flame temperature. Fuel oil has a higher flame temperature and produces more NO_X than natural gas.

5.1 STEP 1 - IDENTIFY AVAILABLE CONTROL TECHNOLOGIES

The scope of potentially applicable control options was determined based on a review of the U.S. EPA RACT/BACT/LAER Clearinghouse (RBLC) database for entries within the last 10 years for simple-cycle combustion turbines, as well as other publically available information such as the Air Pollution Training Institute[1] or other recently permitted combustion turbines. RBLC entries that were not representative of the emissions unit, proposed fuel, or operating condition were excluded

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[1] https://www.apti-learn.net/lms/register/display_document.aspx?dID=39

from further consideration. In addition, entries that were proven to not meet an emissions limit were also excluded from further consideration. A summary table is presented in Appendix A. Given there are essentially two ways to reduce NO_X emissions—primary (or in-combustor) methods that minimize the production of NO_X in the turbine and secondary methods (or add-on controls) that reduce the NO_X that has been formed—controls have been identified as such. In addition, while not a technology per se, use of good combustion practices is a common baseline approach to optimizing the emissions profile for combustion turbines so it has been included here as well.

5.1.1 Primary Controls - Water or Steam Injection

Water or steam injection is an example of an "in-combustor" NO_X control technology. The addition of an inert diluent, such as water or steam, into the high temperature region of the combustion turbine flame controls NO_X formation by quenching peak flame temperatures.

5.1.2 Primary Controls - Dry Low-NO_X/Dry Low-Emission (DLN/DLE) Combustors

DLN/DLE combustors are also an example of an "in-combustor" NO_X control technology. The combustors limit peak flame temperature and excess oxygen with lean, pre-mix flames that achieve NO_X control equal to or better than water or steam injection. Each combustion turbine vendor has their own version of this technology—Siemens (ULN), General Electric (DNL 2.6+), Pratt & Whitney (TALON X, previously known as rich burn quick mix, lean burn (RQL) [2]), etc. These combustors are generally built into the original design of the combustion turbine, but can be retrofitted for certain models.

5.1.3 Secondary Controls - XONON™ Catalytic Combustor

The XONON™ catalytic combustor system is a NO^X control technology developed by Catalytica Energy Systems, Inc. It works by avoiding high temperatures caused by combustion. By integrating a catalyst into the combustor, XONON™ limits combustion temperatures to below the level where NO_X is formed. The XONON™ catalytic combustor system is a module that is installed inside the main component of the combustor. The module consists of a channel where pre-mixed fuel and air passes through the catalyst. It eliminates the fuel being combusted in a flame by combusting it using a catalyst at a lower temperature. Thus, NO_X formation is reduced. The XONON™ catalytic combustor system is now owned by Kawasaki Heavy Industries, Ltd. which is in the process of making the control technology available for gas turbine generators in the 1-1.4 MW range.

5.1.4 Secondary Controls - SCONOX™ Process (aka EMx™)

The SCONOX™ process is a NO_X control technology developed by Goal Line Environmental Technologies (GLET). It uses a coated oxidation catalyst to oxidize and remove NO_X (as well as carbon monoxide, CO) without using a reagent such as NH_3 or NH_3(aq). The technology is now

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[2] https://www.researchgate.net/publication/266595753_Rich_Burn_Quick-_Mix_Lean_Burn_RQL_Combustor

on its second generation, called EMx™, and is distributed by EmeraChem (formerly GLET). The technology is made of a platinum-based catalyst coated with potassium carbonate (K_2CO_3) and works by oxidizing CO to carbon dioxide (CO_2) and nitrogen oxide (NO) to nitrogen dioxide (NO_2). The CO_2 is then exhausted from the system and the NO_2 absorbs onto the K_2CO_3 catalyst to form potassium nitrite (KNO_2) and potassium nitrate (KNO_3). The K_2CO_3 is regenerated by running hydrogen gas (H_2) across the catalyst. Consistent operations can be maintained using four out of five catalyst modules in a rotating fashion while the fifth module is regenerated.

A pitfall of the control technology is its potential to deactivate when exposed to sulfur oxides (SO_X). In order to prevent this issue, an additional catalytic oxidation/absorption system known as SCOSOX™ is installed upstream of the SCONOX™ catalyst to first oxidize sulfur dioxide (SO_2) to sulfur trioxide (SO_3). Also, both the SCONOX™ and SCOSOX™ catalysts are required to be washed every six to 12 months, which involves removing the catalysts from the modules. Using a fuel with low sulfur content decreases the frequency of washes required.

5.1.5 Secondary Controls - Selective Catalytic Reduction

Selective catalytic reduction (SCR) is a control technology used to convert NO_X into diatomic nitrogen (N_2) and water (H_2O) using a catalyst. The reduction reactions used by SCR require oxygen, so it is most effective at oxygen levels above 2-3%. Base metals such as vanadium or titanium are often used for the catalyst due to their effectiveness as a control technology for NO_X and cost-effectiveness for use with natural gas combustion. In addition, a gaseous reductant such as anhydrous ammonia (NH_3) or aqueous ammonia ($NH_3(aq)$) is added to the flue gas and absorbed onto the catalyst. The optimal temperature range for most SCT catalyst range from 600 degrees Fahrenheit (°F) to 800°F.

5.1.6 Secondary Controls - Selective Non-Catalytic Reduction

Selective non-catalytic reduction (SNCR) is a post-combustion control technology for NO_X emissions that uses a reduction-oxidation reaction to convert NO_X into nitrogen (N_2), water (H_2O), and carbon dioxide (CO_2). Like SCR, SNCR involves injecting ammonia (or urea) into the flue gas stream, which must be between approximately 1,400 and 2,000°F for the chemical reaction to occur. SNCR is more economically desirable due to the lack of catalyst required and, in theory, SNCR can control NO_X emissions with an efficiency similar to that of SCR (i.e., 90%). However, operating constraints on temperature, reaction time, and mixing often lead to less effective results when using SNCR in practice.

5.1.7 Alternative Controls - Good Combustion Practices

Good combustion practices are a method of controlling NO_X emissions from a combustion turbine. Maintaining optimum combustion efficiency or implementing appropriate maintenance procedures are examples of good combustion practices.

5.2 STEP 2 - ELIMINATE TECHNICALLY INFEASIBLE OPTIONS

5.2.1 Primary Controls

GSP contacted Turner EnviroLogic, Inc.[3], a reputable provider of air pollution control equipment and systems for industrial and power generation businesses. It is their opinion that only the original manufacturer would be in the position to retrofit combustion turbines of this vintage with primary controls. GSP then contacted Pratt & Whitney (P&W) engineering to discuss the potential for retrofitting this vintage (1968-1970) combustion turbine with their low emissions combustor, TALON X (formerly known as Rich-Quench Lean (RQL) combustion. P&W said that they no longer support these model combustion turbines. GSP also contacted General Electric (GE) engineering to discuss the potential to retrofit a 1969 model combustion turbine with their DLN 2.6+ technology, but as of the date of this report, there has not been a response. However, research conducted on-line regarding DLN 2.6+ indicates that it is only available for newer model combustion engines. Based on the on-line research and discussions with P&W, it has been determined that retrofitting with primary controls should not be considered technically feasible for these combustion turbines. Therefore, water or steam injection and DLN/DLE combustors have been eliminated from further analysis.

5.2.2 Secondary Controls - XONON™ Catalytic Combustor

Although developments to the XONON™ control technology are underway for gas turbines, such that it may become effective in gas turbine generators in the 1-1.4 MW range, this technology has not yet become available for application to larger turbine units. The current XONON™ catalytic combustor system has not been used on larger (i.e., greater than 1.4 MW) combined-cycle turbines and therefore, it is not considered technically feasible.

5.2.3 Secondary Controls - SCONOX™ Process (aka EMx™)

Although there have been developments to the SCONOX™ control technology, the current process has not been used on larger (i.e., greater than 1.4 MW) combustion turbines and therefore, it is not considered technically feasible.

5.2.4 Secondary Controls - Selective Catalytic Reduction

SCR has been used historically on combustion turbines and is considered technically feasible, and therefore is considered further in the evaluation.

5.2.5 Secondary Controls - Selective Non-Catalytic Reduction

SNCR is considered technically infeasible for the proposed combustion turbines due to the temperature at which the turbines will operate, the residence time of the technology, and the lack of historical use of SNCR on combustion turbines. Therefore, SNCR is not considered technically feasible.

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[3] http://tenviro.com/

5.2.6 Alternative Controls - Good Combustion Practices

Good combustion practices are considered technically feasible, and therefore are considered further in the evaluation.

5.3 STEP 3 - RANK REMAINING CONTROL TECHNOLOGIES BY CONTROL EFFECTIVENESS

Control Type	Control Efficiency	Ranking
SCR	90%	1
Good Combustion Practices	10%	2

5.4 STEP 4 - EVALUATE FACTORS AND PRESENT DETERMINATION

Good combustion practices are already being employed by GSP for each of the combustion turbines; consequently, no cost of compliance analysis was conducted for this type of control. Therefore, presented below is the four-factor analysis (cost of compliance) for SCR.

5.4.1 Factor 1: Cost of Compliance

The cost of compliance, measured in terms of annual control costs (dollars) per air emissions reduced (tons), was calculated according to the U.S. EPA Air Pollution Control Cost Manual, sixth edition. The capital cost was provided by an air pollution control vendor (Turner EnviroLogic[4]) and annualized using a capital recovery factor. The annual operating and maintenance costs were estimated using EPA default values and site-specific data, as available. These two costs were then summed and divided by the tons of pollutant anticipated to be removed.

GSP's five combustion turbines are of the same vintage (installed 1968-1970), have similar unit ratings (290 MMBtu/hr - 319 MMBtu/hr), are operated in the similar manner (operate less 1% of the number of hours in a given year), and have similar NO_X emissions (ranging from 0.7 lb/MMBtu to 0.9lb/MMBtu). Therefore, a representative cost of compliance analysis was conducted for the unit at Schiller Station.

Since the combustion turbines are peaking units, the annual capacity factor is typically less than 1%. In fact, when GSP conducted a lookback of combustion turbine operation over the last ten years at Schiller Station, it was found that the year with highest hours of operations was 2010. In 2010, the combustion turbine operated a total of 73 hours, which equated to 3.4 tons of NO_X emissions for the year. Accordingly, the representative cost of compliance analysis was conservatively based on data from 2010. Results indicate that the average cost of compliance (dollar per ton reduced) would be in excess of $175,000 (see Table 1 below). The detailed cost of compliance is provides in Appendix B.

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[4] http://tenviro.com/

Table 1. Cost of Compliance – Schiller Station Combustion Turbine

Control Type	NO_X Potential Emissions (tpy)	NO_X Reduced via Controls (tpy)[(a)]	Total Annualized Cost ($)	Average Cost of Compliance ($/ton reduced)
SCR @ 73 hours	3.4	3.1	546,021	178,438

(a) Assumes 90% control.

5.4.2 Factor 2: Time Necessary for Compliance

The minimal time necessary to install an SCR would be approximately 6 months.

5.4.3 Factor 3: Energy and Non-Air Quality Impacts

SCR catalysts must be disposed of properly. If not, non-air quality impacts could be realized. In addition, concerns related to the transportation, storage and use of ammonia should be considered as non-air quality impacts.

5.4.4 Factor 4: Remaining Useful Life

Based on the PSNH Generation Asset and PPA Valuation Report prepared for the New Hampshire Public Utilities Commission[5], dated March 31, 2014, the remaining useful life of each of the combustion turbines is 15 years. Please note this is a conservative assumption as the report stated a 15-year book life in March 2014.

6.0 CONCLUSION

GSP appreciates the opportunity to provide input in response to the MANE-VU Ask. As indicated by the results of the four-factor analysis for reasonable installation or upgrade to emission controls presented above, there are no additional NO_X controls that GSP could employ on the combustion turbines that are both technically and economically feasible. GSP already employs good combustion practices to optimize their NO_X emissions profile. Therefore, the current requirements and NO_X emissions levels will be retained for each of the five peaking combustion turbines.

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[5] http://www.puc.state.nh.us/Electric/PUBLIC%20VERSION%20PSNH%20Asset%20Valuation%20Report_FINAL.pdf

APPENDIX A
SUMMARY OF NO_X CONTROL TECHNOLOGIES

Appendix A
Summary of NOx Control Technologies as Reported in the RBLC Database
Granite Shore Power LLC
183-110

Natural Gas

Facility Name	Process Name	Fuel	Throughput	Units	Pollutant	Control(s)	Emission Limit	Units	Averging Period
KENAI NITROGEN OPERATIONS	Five (5) Natural Gas Fired Combustion Turbines	Natural Gas	37.6	MMBTU/H	Nitrogen Oxides (NOx)	Selective Catalytic Reduction	7	PPMV	3-HR AVG @ 15 % O2
HILLABEE ENERGY CENTER	COMBUSTION TURBINE	Natural Gas	2142	MMBTU/H	Nitrogen Oxides (NOx)	LOW-NOX BURNER, SCR	24.6	LB/H	
STERLINGTON COMPRESSOR STATION	COMPRESSOR TURBINE NO. 1	Natural Gas	79.1	MMBTU/H	Nitrogen Oxides (NOx)	DRY LOW NOX BURNERS AND GOOD COMBUSTION PRACTICES	0.057	LB/MMBTU	
STERLINGTON COMPRESSOR STATION	COMPRESSOR TURBINE NO. 2	Natural Gas	79.1	MMBTU/H	Nitrogen Oxides (NOx)	DRY LOW NOX BURNERS AND GOOD COMBUSTION PRACTICES	0.057	LB/MMBTU	
THETFORD GENERATING STATION	FGCCA or FGCCB--4 nat. gas fired CTG w/ DB for HRSG	Natural Gas	2587	MMBTU/H	Nitrogen Oxides (NOx)	Low NOx burners and selective catalytic reduction.	3	PPMV	24-H ROLLING AVERAGE
THETFORD GENERATING STATION	FGCCA or FGCCB: 4 nat gas fired CTG with DB for HRSG: Startup/shutdown events	Natural Gas	2587	MMBTU/H	Nitrogen Oxides (NOx)	Low NOx burners and selective catalytic reduction.	78.4	T/YR	12-MO ROLL TIME PERIOD FOR STARTUP/SHUTD
DTE GAS COMPANY--MILFORD COMPRESSOR STATION	FG-TURBINES	Natural Gas	10504	HP	Nitrogen Oxides (NOx)	Dry ultra-low NOx burners	15	PPM	TEST PROTOCOL
DTE GAS COMPANY - MILFORD COMPRESSOR STATION	FGTURNBINES (5 Simple Cycle CTs: EUTURBINE1, EUTURBINE2, EUTURBINE3, EUTURBINE4, EUTURBINE5)	Natural Gas	10504	HP	Nitrogen Oxides (NOx)	Dry ultra-low NOx burners.	15	PPM	
MGM MIRAGE	TURBINE GENERATORS - UNITS CC007 AND CC008 AT CITY CENTER	Natural Gas	4.6	MMBTU/H	Nitrogen Oxides (NOx)	LEAN PRE-MIX TECHNOLOGY AND LIMITING THE FUEL TO NATURAL GAS ONLY	0.178	LB/MMBTU	
BUFFALO CREEK PROCESSING PLANT	Small Combustion Turbines (<25MW)	Natural Gas	10179	Horsepower	Nitrogen Oxides (NOx)	Dry-Low NOx Combustion	15	PPMVD@15%O2	1-HR
ROSE VALLEY PLANT	TURBINES 9,443-HP SIEMENS SGT-200-2S	Natural Gas	9443	HP	Nitrogen Oxides (NOx)	DRY LOW-NOx COMBUSTION.	15	PPMVD @15% O2	1-HR
GUADALUPE GENERATING STATION	(2) simple cycle turbines	Natural Gas	190	MW	Nitrogen Oxides (NOx)	DLN burners, limited operation	9	PPMVD	@15% O2, 3 HOUR ROLLING AVG
ECHO SPRINGS GAS PLANT	TURBINES S35-S36	Natural Gas	12555	HP	Nitrogen Oxides (NOx)	SOLONOX	15	PPMV	
ECHO SPRINGS GAS PLANT	TURBINE S37	Natural Gas	16162	HP	Nitrogen Oxides (NOx)	GOOD COMBUSTION PRACTICES	15	PPMV	
ECHO SPRINGS GAS PLANT	TURBINE S34	Natural Gas	3856	HP	Nitrogen Oxides (NOx)	SOLONOX	25	PPMV	

Fuel Oil

Facility Name	Process Name	Fuel	Throughput	Units	Pollutant	Control(s)	Emission Limit	Units	Averging Period
POINT THOMSON PRODUCTION FACILITY	Turbines	Fuel Gas	7520	kW	Nitrogen Oxides (NOx)	Dry Low NOx and SoLoNOx.	15	PPMV	15% OXYGEN

APPENDIX B
SCR COST EFFECTIVENESS AT 73 HOURS PER YEAR

Granite Shore Power - Schiller Station
Portsmouth, New Hampshire
Cost Effectiveness - Selective Catalytic Reduction - Combustion Turbine (SRCT)
73 hours per year
CEC Project #183-110/310-770

Prepared By: JLF
Date Prepared: 8/27/2018
Reviewed By: JG
Date Reviewed: 8/28/2018

Item	**Value**	**Basis**[1]
Direct Costs		
Purchased Equipment Cost		
Equipment cost + auxiliaries[2] **[A]**	$2,000,000	**A**
Instrumentation	$200,000	0.10 x A
Freight	$160,000	0.08 x A
Total Purchased Equipment Cost **[B]**	**$2,360,000**	**B** = 1.18 x A
Direct Installation Costs		
Foundations and supports	$188,800	0.08 x B
Handling and erection	$330,400	0.14 x B
Electrical	$94,400	0.04 x B
Piping	$47,200	0.02 x B
Insulation for ductwork	$23,600	0.01 x B
Painting	$23,600	0.01 x B
Total Direct Installation Cost	**$708,000**	0.30 x B
Buildings (Bldg.)	**$118,000**	As required (5-18% B)
Total Direct Cost (DC)	**$3,186,000**	1.35 x B
Indirect Costs (Installation)		
Engineering	$236,000	0.10 x B
Construction and field expenses	$118,000	0.05 x B
Contractor fees	$236,000	0.10 x B
Start-up	$47,200	0.02 x B
Performance test	$23,600	0.01 x B
Contingencies	$70,800	0.03 x B
CEMs	$70,000	Assumption to purchase & install
PSD Permit	$75,000	Assumption to prepare application & review draft permit
Other	$0	As required
Construction period	0.5	Years
Interest Rate	5%	Percent
Interest during construction (Int.)	$81,641	DC * i *n
Total Indirect Cost (IC)	**$958,241**	0.31 x B + Int + PSD
Total Capital Investment (TCI) = DC + IC	**$4,144,241**	1.61 x B + Bldg. + Int. + CEMs + PSD

1 - EPA's OAQPS Cost Control Manual, Sixth Edition unless otherwise noted
2 - Estimate provided by Tom Turner, P.E. of Turner EnviroLogic, Inc., dated August 23, 2018.

Granite Shore Power - Schiller Station
Portsmouth, New Hampshire
Cost Effectiveness - Selective Catalytic Reduction - Combustion Turbine (SRCT)
73 hours per year
CEC Project #183-110/310-770

Prepared By: JLF **Reviewed By:** JG/KW
Date Prepared: 8/27/2018/Rev. 10/15/2021 **Date Reviewed:** 8/28/2018/Rev. 10/15/2021

	Item	Value	Basis[1]
Direct Annual Costs (DC)			
Electricity			
	Pressure Drop (in WC)	5	Pressure drop - catalyst bed
	Power Output of Turbine (kW)	20,400	ISO Rating
	Power Loss Due to Pressure Drop (%)	0.50%	0.1% for every 1" pressure drop
	Power Loss Due to Pressure Drop (kW)	102	
	Unit cost ($/kW)	$0.039	Estimated market value
Cost of Power Loss ($/yr)		**$290**	Based on operation of 73 hours/year
Operating Labor			
	Catalyst labor req.	821	1/2 hr/shift of operation @ $60/hr
	Ammonia delivery requirement (SCR)	1,440	24 hr/yr (3 deliveries per year) @ $60/hr
	Ammonia recordkeeping and reporting (SCR)	2,400	40 hours per year @ $60/hr
	Catalyst cleaning	2,400	40 hours per year @ $60/hr
	Supervisor	123	15% Operating labor
Total Cost ($/yr)		**7,184**	
Ammonia			
	Requirement (gal/hr)	51.3	19% aqueous ammonia
	Hours of operation (per year)	73	hours/year
	Unit Cost ($/gal)	$3.56	Default
Total cost ($/ton)		**13,344**	
Catalyst Maintenance			
	Catalyst system maintenance labor	274	1/2 hr/operating day @ $60/hr
	Ammonia system maintenance labor	21,900	1 hr/day @ $60/hr
	Material	$22,174	100% x maintenance labor
Total cost ($/yr)		**44,348**	
Catalyst Replacement			
	Catalyst Cost ($)	$193,282	Catalyst modules
	Catalyst Disposal Cost ($)	-	Included in catalyst cost
	Catalyst replacement labor	19,200	8 workers, 40hr, every 3 years @ $60/hr
	Catalyst life (yrs)	3	n
	Interest Rate (%)	5%	i
	CRF	0.368	Amoritization of catalyst over 3 years
Total Cost ($/yr)		**78,208**	(Material + Labor Cost) * CRF
Indirect Annual Costs (IC)			
	Overhead	$0	OAQPS SCR Assumption
	Administrative charges	$0	OAQPS SCR Assumption
	Annual Contingency	$0	OAQPS SCR Assumption
	Property taxes	$0	OAQPS SCR Assumption
	Insurance	$0	OAQPS SCR Assumption
	Capital Recovery	$402,646	CRF * TCI (15 year life[3] @ 5.125% interest)
Total Indirect Costs ($/yr)		**402,646**	
Total Annualized Costs (TAC) ($)		**546,021**	
Total Pollutant Controlled (tons/yr) Natural Gas		**3.1**	Assume maximum of 3.4 tpy @ 90% reduction
Cost Effectiveness ($/ton)		**178,438**	

3 - *PSNH Generation Asset and PPA Valuation Report* , La Capra Associates, Inc, dated March 31, 2014