Documentation of 2018 Emissions from Electric Generating Units in the Eastern United States for MANE-VU's Regional Haze Modeling

Final Report

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This report was prepared for use by the MANE-VU States and does not necessarily represent the position of the U.S. Environmental Protection Agency.

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1 INTRODUCTION

1.1 Purpose

Development of an emissions inventory is an important foundation for performing regional scale atmospheric modeling for regulatory air quality management. The accuracy of the atmospheric model's prediction of air quality depends, in part, on the accurate representation of emissions from a variety of source sectors including point, area, non-road, on-road and biogenic sources. Electric generating units (EGUs) are an important point source sector and are often considered for controls to meet air quality objectives. Therefore, it is especially important to accurately represent and document EGU emissions and associated characteristics in a regulatory modeling application.

This report describes the development of future year EGU emission estimates for use in Mid-Atlantic/Northeast Visibility Union (MANE-VU) 2018 regional haze modeling.

This document synthesizes information from several documents that already describe parts of the process of preparing emissions estimates and provides information not yet included in other documents. It covers the following major steps in that process: preparation of the inter-Regional Planning Organization (RPO) Integrated Planning Model® (IPM) runs commonly referred to as the Visibility Improvement State and Tribal Association of the Southeast (VISTAS) IPM runs, the post-processing of those runs to create Sparse Matrix Operator Kernel Emissions (SMOKE) input files, the modification of those files to reflect state estimates of emissions, and the adjustments made by MANE-VU modelers to maintain the Clean Air Interstate Rule (CAIR) cap. It also provides background information about preparing EGU forecasts and related work by the U.S. Environmental Protection Agency (EPA).

1.2 Background on Emissions Projections

Emission projections for point sources depend on changes in source level activity, the emission factors or installed controls. The approach taken to project point source emissions depends on the level of detail necessary in the projection. Changes in point source emissions are accounted for by a combination of growth, control, and retirement rates. Growth rates are applied to estimate the overall change in activity, while retirement rates are applied to estimate the decrease in emissions activity from existing sources. Retirement (and replacement of these sources with new sources) must be considered because regulations affecting new sources may differ from those affecting existing sources.

The projection year control factor accounts for both changes in emission factors due to technology improvements and new levels of control required by regulations. The control factor accounts for three variables: regulation control, rule effectiveness, and rule penetration.

Control factors are closely linked to the type of emission process (identified by Source Classification Code (SCC)) and secondarily to the type of industry identified by Standard Industrial Classification (SIC). Point source projections should account for Federal, State, and local regulations affecting these categories.

A complicating factor is the requirement for emission offsets in nonattainment areas through New Source Review requirements. This may be accounted for by 1) restricting growth under the assumption that it will be offset; 2) applying reductions to selected source categories to account for the emission growth which must be offset; or 3) selecting the individual sources, based on a cost analysis, from which offsets are likely to come.

1.3 Factors Causing Variation in EGU Emissions Forecasts

There are various sources of uncertainty in estimating future EGU emissions. These include the relative prices of various fuels (especially coal, oil, and natural gas), predictions of which plants will be shut down, the size, type, and location of new plants, the total demand for electricity, and requirements imposed by state-specific or plant-specific regulations or orders. Emissions estimates based on the methods described in this report represent the MANE-VU states' best effort to forecast future emissions in light of these and other uncertainties.

When projecting Electricity Generating Unit (EGU) emissions in the Eastern United States, emission trading should be considered. There are three general approaches to performing projections while accounting for such trading schemes. The first option is to optimize control levels across the domain based on the cost of alternative controls. The second option is to survey individual sources to determine how they will comply (will they apply controls and sell or buy allowances) and use this as the basis for the future year control level. The third option is to apply the control level used to establish the budget to all affected sources and ignore which sources may choose to buy or sell credits/allowances.

Other factors which must be considered include programs, such as fuel switching, designed to provide source flexibility in meeting future air quality requirements. Fuel switching refers to instances where a unit historically burned one primary fuel, such as coal, and under a "fuel switching" program the unit would burn an alternate fuel, such as natural gas, during a certain period of time and may switch back to the "historic" fuel for some or all of the year. Fuel switching is often done in cases where sources average their emissions to meet federal mandates. Fuel switching may also be used as a seasonal compliance strategy (e.g., switching from residual fuel oil to natural gas in order to reduce NOx emissions during the ozone season. The variation in emissions over the course of the year caused by fuels switching must be calculated properly in projections.

Repowering is another example of a planned change in emission rates which should be considered. In this case, the unit may be switching entirely from coal to natural gas or may be completing a major modification which would lower the emission rate.

Spatial allocation is another factor which must be considered, particularly if air quality modeling will be performed using the projection. For point sources, important questions are which facilities will retire and where new growth will occur. Changes in land use patterns may also impact the location of point source emissions. As undeveloped and rural areas become suburban and urban areas, the number of point sources in that area will increase.

As can be seen from the discussion above, any number of complicating issues can lead to emission forecasts which may differ from user to user. An inconsistent decision made between two parties can lead to significant differences in growth, control, or placement of emissions from point source forecasts. For this reason, the Regional Planning Organizations (RPOs) in the Eastern U.S. made a decision to utilize consistent forecasting methods for EGU emissions, as they are one of the most significant contributors to regional haze in the United States. This decision, to coordinate on the projection of EGU source emissions, led to the preparation of an EGU forecast methods document from which a coordinated decision was made on methods to develop EGU emissions in future years. Each RPO ends up using somewhat different estimates, as discussed below, but there was a great deal of cooperation and data sharing throughout the process.

2 PREPARATION OF EGU FORECASTS

2.1 Decision to Use the IPM Model

Early in the planning process there was a joint agreement by the RPOs to work together to develop future year EGU emissions estimates based on the use of the Integrated Planning Model® (IPM). The decision to use IPM modeling resulted in part from a study of EGU forecast methods prepared by E.H. Pechan and Associates, Inc. (Pechan) for the Midwest Regional Planning Organization (MRPO) (Pechan, 2004), which recommended IPM as a viable methodology. Although IPM results were available from work conducted by EPA to support their rulemaking for the Clean Air Interstate Rule (CAIR), the RPOs concluded that certain model inputs needed to be revised. Thus, the RPOs decided to work together to hire contractors to conduct new IPM modeling and to post-process the IPM results. This section describes the recommendation to use IPM.

The Lake Michigan Air Directors Consortium (LADCO) sought contractor assistance in reviewing emissions inventory growth for existing and new EGUs (Pechan, 2004). Because the results of EGU emission forecasts are used in urban or regional scale air quality modeling exercises to estimate future year air pollutant concentrations, growth methods are needed to supply model-ready emission model inputs. The purpose of LADCO's project was to begin to examine EGU growth methods.

The primary pollutants of interest were sulfur dioxide (SO_2), oxides of nitrogen (NO_x), particulate matter (PM), ammonia (NH_3), and mercury (Hg). Projection years of interest included 2009 (the approximate time for ozone and $PM_{2.5}$ attainment) and 2018 (a longer term regional haze planning horizon). The geographic area of interest was the eastern half of the United States (to capture the trading issues affecting the Midwest States).

This 2004 Pechan report provided a detailed evaluation of three EGU growth modeling methods of interest to the LADCO States for consideration in developing its own approach. These evaluations addressed the following attributes of each modeling approach:

- Description of primary analytical modeling methods;
- Geographic areas of application;
- Advantages; and
- Disadvantages.

The material in this evaluation was intended to be used to determine which of the currently available modeling approaches might be best suited for use by the LADCO States (and other RPOs) for future state implementation plan (SIP) and air dispersion modeling work. The models evaluated in this report included the Integrated Planning Model® (IPM), the National Energy Modeling System (NEMS), and the Electric Power Market Model (EPMM).

Based on the conclusions and summary of the report (Pechan, 2004), the four participating RPOs (MANE-VU, MRPO, VISTAS, and the Central Regional Air Planning Association, CENRAP) decided to use IPM as the tool for forecasting EGU emissions.

2.2 The Integrated Planning Model (IPM)

IPM was developed by ICF Consulting, Inc. (ICF) and used to support public and private sector clients. This model is a proprietary, multi-regional, dynamic, deterministic linear programming model of the U.S. electric power sector. It provides forecasts of least-cost capacity expansion, electricity dispatch, and emission control strategies for meeting energy demand and environmental, transmission, dispatch, and reliability constraints. It can be used to evaluate the cost and emissions impacts of proposed policies to limit emissions of SO_2, NO_x, carbon dioxide (CO_2), and Hg from the electric power sector. The IPM model was a key analytical tool used by EPA in developing the Clean Air Interstate Rule (CAIR) and the Clean Air Mercury Rule (CAMR).

Among the factors that make IPM particularly well suited to model multi-emissions control programs are (1) its ability to capture complex interactions among the electric power, fuel, and environmental markets; (2) its detail-rich representation of emission control options encompassing a broad array of retrofit technologies along with emission reductions through fuel switching, changes in capacity mix and electricity dispatch strategies; and (3) its capability to model a variety of environmental market mechanisms, such as emissions caps, allowances, trading, and banking. The model's ability to capture the dynamics of the allowance market and its provision of a wide range of emissions reduction options are particularly important for assessing the impact of multi-emissions environmental policies like CAIR and CAMR.

2.3 U.S. EPA Use of IPM

The U.S. EPA uses IPM to analyze the projected impact of environmental policies on the electric power sector in the 48 contiguous states and the District of Columbia. The next two sections describe EPA modeling results available to the RPOs early in the planning process. Then Section 2.3.3 reviews the limitations of the EPA results that led the RPOs to conduct additional IPM modeling.

2.3.1 EPA's Base Case 2004

The EPA's Base Case 2004 (EPA, 2005a) served as the starting point against which EPA compared various policy scenarios. It is a projection of electricity sector activity that takes into account federal and state air emission laws and regulations whose provisions were either in effect or enacted and clearly delineated at the time the base case was finalized in August 2004. Regulations mandated under the Clean Air Act Amendments of 1990 (CAAA), but whose provisions have not yet been finalized, were <u>not included in the base case</u>. These include:

- <u>Measures to Implement Ozone and Particulate Matter (PM) Standards</u>: EPA Base Case 2004 predates and so does not include the provisions of CAIR, the primary federal regulatory measure for achieving the National Ambient Air Quality Standards (NAAQS) for ozone (8-hour standard of 0.08 ppm) and fine particles (24-hour average of 65 ug/m3 or less and annual mean of 15 ug/m3 for particles of diameter 2.5 micrometers or less, i.e., $PM_{2.5}$). EPA Base Case 2004 was used to evaluate policy alternatives which ultimately resulted in CAIR. The final CAIR was issued on March 10, 2005. EPA Base Case 2004 includes measures to implement ozone and particulate matter standards to the extent that some of the state regulations included in EPA Base Case 2004 contain measures to bring non-attainment areas into attainment. Individual permits issued by states in response to ozone and particulate matter standards are not captured in the base case.

• Mercury Regulations on Electric Steam Generating Units: EPA Base Case 2004 predates both CAMR, which was issued by EPA on March 15, 2005 and the "Maximum Achievable Control Technology" (MACT) standards that were scheduled to be promulgated by December 15, 2004, but, pending litigation, were superseded by CAMR. Consequently, this base case did not include any federal regulatory measures for mercury control. (CAMR was vacated in 2008.)

• Clean Air Visibility Rules: On July 1, 1999, EPA issued Regional Haze Regulations to meet the national goal for visibility established in Section 169A of the CAAA, which calls for "prevention of any future, and the remedying of any existing, impairment of visibility in Class I areas [156 national parks and wilderness areas], which impairment results from manmade air pollution." The regulations required states to submit revised SIPs that (1) establish goals that provide for reasonable progress towards achieving natural visibility conditions at Class I areas, (2) adopt a long-term control strategy that includes such measures as are necessary to achieve the reasonable progress goals, and (3) require Best Available Retrofit Technology (BART) for sources in listed source categories placed in operation between 1962 and 1977.

In effect, EPA Base Case 2004 offered a snapshot projection of the electric sector assuming that the only future environmental regulations were those with provisions known at the time that the base case assumptions were finalized. While not necessarily an accurate reflection of what would actually occur, this assumption ensured that the base case was policy neutral with respect to future environmental policies.

2.3.2 EPA CAIR Case

On January 30, 2004, EPA proposed CAIR, which set emission reduction requirements for 29 States and the District of Columbia. Those emission reduction requirements were based on achieving highly cost-effective emission reductions from large electricity generating units.

While EPA believed that the modeling it initially performed for the January 2004 proposal provided a reasonable estimate of the impact of requiring highly cost-effective emission reductions from electricity generating units, it did not exactly model the proposed control region. For both SO_2 and NO_x, EPA used modeling assumptions that differed slightly from the January 2004 CAIR proposal. For SO_2 in particular, EPA modeled the program assuming a cap on national emissions rather than in the 29 States proposed. Although EPA believed the modeling done at that time provided a reasonable approximation of the impacts of the original CAIR, because 92 percent of the SO_2 emissions in the 48 contiguous States occur in the 28 States that were covered by the proposal, EPA completed additional analysis. This additional analysis examined the effect of covering the geographic region proposed in the January 30, 2004 proposal using the NO_x emissions cap and a close approximation of the SO_2 cap proposed for CAIR (EPA, 2005a).

For the supplemental proposal, EPA performed refined modeling of the emission reduction requirements proposed on January 30, 2004. In this refined modeling, EPA modeled the exact control regions for both SO_2 and NO_x, as proposed.

2.3.3 EPA's CAIR Modeling Limitations

The U.S. EPA's modeling was based on its best judgment for various input assumptions that were uncertain, particularly assumptions for future fuel prices and electricity demand growth (EPA, 2004). In addition, EPA's modeling using IPM did not take into account the potential for advancements in the capabilities of pollution control technologies for SO_2 and NO_x removal as well as reductions in their costs over time.

Retirement Ratios: EPA issued a CAIR supplemental notice of proposed rulemaking that proposed two alternatives for how the SO_2 reduction target would be achieved. The proposal took comment on implementing the reduction requirements in the second phase either by using a 2.86 to 1 ratio (which would match the 65 percent SO_2 reduction target) of acid rain allowances to emissions, or alternatively, by implementing the reductions using a 3 to 1 ratio (for administrative simplicity) and then letting States create and distribute additional allowances equal to the surplus created by the 3 to 1 ratio to achieve the proposed 65 percent reduction. In either case, the effective cap on SO_2 emissions from the power sector would be the same.

Modelers assumed a 3 to 1 Title IV allowance retirement ratio for 2015 and beyond to implement the reductions in the proposed control region. The model did not add back the 130,000 tons of SO_2 from over-compliance that would result from this ratio. Therefore, in this modeling, EPA analyzed slightly greater SO_2 emission reductions than required by the proposal. This assumption was made for modeling simplicity and was expected to result in a slight overestimate of costs for the proposal and of the emissions reductions achieved.

BART: The EPA did not incorporate any best achievable retrofit technology (BART) modeling in this analysis. BART would achieve reductions in non-CAIR States and had the potential to mitigate leakage issues.

Demand Response: EPA's 2004 CAIR case includes a demand response to increased natural gas prices but not electricity prices. In the model, increased gas prices would prompt the public to curtail their use of gas and encourage them to seek substitutes. However, no provision for demand response was included for electricity prices. If demand had been allowed to change in response to increasing prices of electricity, one can assume that consumers would have reduced their demand for electricity, lowering electricity prices and reducing generation and emissions to some extent.

State Rules: Only some State-adopted rules were incorporated into EPA's modeling framework. A list of the State Multi-pollutant regulations used in IPM 2.1, IPM 2.1.6, and IPM 2.1.9 can be located in Appendix 3-2 of EPA's Standalone Documentation for EPA Base Case 2004 (v.2.1.9) Using the Integrated Planning Model (EPA, 2005a).

Because of the limitations noted above, the RPOs decided to initiate their own IPM modeling based on the EPA's latest update of the IPM input framework, called IPM 2.1.9. EPA completed the input framework for IPM 2.1.9 in March of 2003.

2.4 RPO Use of IPM – Phase I

In August 2004, VISTAS contracted with ICF to run IPM to provide revised utility forecasts for 2009 and 2018 under two future scenarios – Base Case and CAIR Case (ICF, 2004). The Base Case represented the current operation of the power system under laws and regulations as known at the time the run was made, including those that come into force in the study horizon. The CAIR Case was the Base Case with the proposed CAIR rule superimposed. Run results were parsed at the unit level for the 2009 and 2018 run years. [1]

In August 2004, MRPO contracted with Pechan to post-process the VISTAS' IPM outputs to provide the (National Emission Inventory Input Format) NIF formatted emission files needed for the regional inventory. The IPM output files were delivered by ICF to VISTAS in November 2004 and the post-processed data files were delivered by Pechan to the MRPO in December 2004.

These IPM runs (VISTAS_CAIR_2) and the NIF files that were generated from the parsed data sets are commonly referred to as the Phase I Inter-RPO runs. The Phase I runs were ultimately not used in RPO modeling of regional haze, as further revisions to the inputs were necessary once the final version of CAIR was adopted.

2.5 RPO Use of IPM – Phase II

On March 10, 2005, EPA issued the final CAIR. A consortium of RPOs, (MANE-VU, VISTAS, MRPO, and CENRAP) conducted another round of IPM modeling which reflected changes to control assumptions based on the final CAIR as well as additional changes to model inputs based on state and local agency and stakeholder comments. Several conference calls were conducted in the spring of 2005 among the participating RPOs to discuss and provide comments on IPM assumptions related to six main topics: power system operation, generating resources, emission control technologies, set-up parameters, financial assumptions, and fuel assumptions. Based on these discussions, VISTAS sponsored a new set of IPM runs to reflect the final CAIR

[1] "Parsing" results refers to allocating emissions estimates to individual units. Results may be analyzed in aggregate form but must be parsed in order to be used in air quality modeling. (See Section 3.2)

requirements as well as certain changes to IPM assumptions that were agreed to by the RPOs. ICF performed the following four runs using IPM during the summer of 2005. This set of IPM runs is referred to as the VISTAS Phase II analysis or Inter-RPO v.2.1.9 runs.

- Base Case with EPA 2.1.9 coal, gas, and oil price assumptions (VISTASII_BC_1Z1).
- Base Case with EPA 2.1.9 coal and gas supply curves adjusted for the U.S. Energy Information Administration's most recent Annual Energy Outlook (AEO 2005) reference case price and volume relationships (VISTASII_BC_2Y).
- Strategy Case with EPA 2.1.9 coal, gas and oil price assumptions (VISTASII_PC_1f).
- Strategy Case with EPA 2.1.9 coal and gas supply curves adjusted for AEO 2005 reference case price and volume relationships (VISTASII_PC_2C).

The above runs were parsed for 2009 and 2018 run years. The output taken from the Strategy Case with EPA 2.1.9 coal, gas, and oil price assumptions (VISTASII_PC_1f) is also referred to as the Inter-RPO CAIR Case IPM 2.1.9 or RPO 2.1.9 IPM and is the basis for discussion in the remainder of this report. That run was also parsed for 2012. The RPO 2.1.9 IPM parsed results were post-processed for 2009, 2012, 2018, as described in Section 3.2.1

The Phase II scenarios were based on VISTAS Phase I and EPA IPM 2.1.9 assumptions (EPA, 2005b). Additional changes that were implemented in the above four runs are summarized below and in associated documentation (ICF, 2007):

- Unadjusted AEO 2005 electricity demand projections were used. (U.S. EPA runs were adjusted to reflect reduced demand due to voluntary conservation projects sponsored by U.S. EPA)
- Gas supply curves were adjusted for AEO 2005 reference case price and volume relationships. The EPA 2.1.9 gas supply curves were scaled such that IPM solved for AEO 2005 gas prices when the power sector gas demand in IPM is consistent with AEO 2005 power sector gas demand projections.
- The coal supply curves used in EPA 2.1.9 were scaled such that the average mine mouth coal prices that the IPM was solving in aggregated coal supply regions were comparable to AEO 2005. Coal grades and supply regions contained in AEO 2005 and EPA 2.1.9 were not directly comparable. An iterative approach was used to obtain comparable results. The coal transportation matrix was not updated with Energy Information Administration (EIA) assumptions due to significant differences between the EPA 2.1.9 and EIA AEO 2005 coal supply and coal demand region configurations.
- The cost and performance of new units were updated to AEO 2005 reference case levels.
- The run years 2008, 2009, 2012, 2015, 2018, 2020 and 2026 were modeled.
- The AEO 2005 life extension costs for fossil and nuclear units were incorporated.
- The extensive NEEDS comments provided by VISTAS, MRPO, CENRAP and MANE-VU were incorporated into the Phase I NEEDS input file.
- MANE-VU's comments in regards to the northeast state regulations were incorporated.
- Northeast Renewable Portfolio Standards (RPS) were modeled based on the Regional Greenhouse Gas Initiative analysis. A single RPS cap was modeled for MA, RI, NY, NJ, MD, and CT. These states could buy credits from NY or from the PJM Interconnection and New England model regions.

- Selective Catalytic Reduction (SCR) and Scrubber Feasibility Limits: No limits were applied in 2008, 2009 and 2010 to the capacity for installing these emissions controls.
- The Clean Air Visibility Rule (CAVR) was not modeled.
- Modelers assumed a Title IV SO_2 Bank for 2007 of 4.98 million tons.
- The investments required under the Illinois Power, Mirant and First Energy NSR settlements (as identified during spring 2005) were incorporated in the above runs.

For the Phase II inter-RPO set of IPM runs, ICF generated two different parsed files for each of the two strategy case scenarios (VISTAS II_PC_1f and VISTAS II_PC_2c). One file includes all fuel burning units (fossil, biomass, landfill gas) as well as non-fuel burning units (hydro, wind, etc.). The second file contains just the fossil-fuel burning units (e.g., emissions from biomass and landfill gas are omitted). In all RPOs the fossil-only file was used for modeling. This is consistent with EPA, since EPA used the fossil only results for CAIR analyses.

2.6 State Results – Phase II

Table 1 presents unmodified State level fuel use and emission results from the 2018 Inter-RPO CAIR Case IPM v. 2.1.9 fossil-only parsed file (VISTASII_PC_1f). Note that IPM produces only NO_x and SO_2 emissions estimates.

2.7 MANE-VU Sponsored CAIR Plus IPM Modeling

Using the IPM Phase II RPO modeling platform MANE-VU contracted with ICF to evaluate the impact of both tightening the SO_2 and NO_x CAIR caps and expanding the CAIR region to include the electricity generating sector in additional states the Eastern United States. As part of this analysis, ICF developed a new Base Case that implemented EPA's CAIR, CAMR and CAVR policies and a Policy Case with lower SO_2 and NO_x CAIR caps in an extended region. The new Base Case was developed for comparison to the Policy Case. The model assumptions and data used in this analysis are somewhat different than those in the RPO Phase II analysis and are described in Section B of the project report (ICF, 2007). Neither the base or policy cases from the CAIR Plus project were used in subsequent SIP modeling.

Table 1. State Level Fuel Use and Emission Summary; 2018 VISTASII_PC_1f.xls. (fossil only)

		Fuel Use (TBtu)		Emissions (Tons)		
State	**RPO**	**Summer**	**Annual**	**Summer NOx**	**Annual NOx**	**Annual SO2**
Connecticut	MANE-VU	62.1572	142.7141	1,521	3,418	6,697
Delaware	MANE-VU	41.9472	92.7542	5,485	12,341	35,442
District Of Columbia	MANE-VU	2.0774	4.8716	49	103	83
Maine	MANE-VU	21.8494	49.8748	804	1,827	5,436
Maryland	MANE-VU	195.3393	437.8991	6,832	14,709	28,065
Massachusetts	MANE-VU	188.0653	433.3227	8,004	18,157	17,486
New Hampshire	MANE-VU	32.4638	73.8699	1,393	3,089	7,469
New Jersey	MANE-VU	140.8000	304.7240	6,432	13,636	32,495
New York	MANE-VU	282.4272	669.0821	10,926	24,376	51,445
Pennsylvania	MANE-VU	687.1446	1,540.1322	36,329	82,881	135,946
Rhode Island	MANE-VU	15.1701	40.0407	244	576	55
Vermont	MANE-VU	1.3677	3.0597	74	105	35
	MANE-VU Total	**1,670.8093**	**3,792.3450**	**78,093**	**175,219**	**320,651**
Alabama	VISTAS	605.2513	1,329.1117	19,416	41,715	190,029
Florida	VISTAS	831.5942	1,813.5433	26,620	56,506	139,526
Georgia	VISTAS	687.9659	1,530.2279	26,228	56,180	178,196
Kentucky	VISTAS	494.6026	1,121.9188	27,904	64,099	229,596
Mississippi	VISTAS	211.7079	443.3923	4,269	8,895	27,226
North Carolina	VISTAS	431.1262	984.5996	25,412	57,774	102,217
South Carolina	VISTAS	326.3757	749.2039	20,240	46,318	118,584
Tennessee	VISTAS	300.8087	672.6405	13,348	29,873	112,343
Virginia	VISTAS	305.6546	710.9991	18,443	43,144	80,602
West Virginia	VISTAS	477.7910	1,080.9570	22,556	51,208	124,464
	VISTAS Total	**4,672.8781**	**10,436.5940**	**204,435**	**455,711**	**1,302,784**
Illinois	MRPO	564.3359	1,281.6624	31,214	71,234	241,136
Indiana	MRPO	665.8976	1,534.4126	40,820	95,376	376,864
Michigan	MRPO	537.6731	1,257.6784	42,629	98,685	398,562
Ohio	MRPO	773.6334	1,785.3989	35,888	83,129	215,501
Wisconsin	MRPO	303.7451	691.5260	19,794	45,701	155,369
	MRPO Total	**2,845.2851**	**6,550.6783**	**170,345**	**394,124**	**1,387,433**
Arkansas	CENRAP	211.9455	479.1864	14,836	33,097	82,605
Iowa	CENRAP	238.7101	548.7369	22,252	51,119	147,305
Kansas	CENRAP	213.4288	465.8685	37,207	83,333	81,486
Louisiana	CENRAP	225.6282	481.9880	14,240	30,432	74,263
Minnesota	CENRAP	175.6582	388.8279	17,940	41,029	85,847
Missouri	CENRAP	416.5504	918.5720	34,350	77,660	280,887
Nebraska	CENRAP	113.8064	255.2901	22,524	50,781	73,629
Oklahoma	CENRAP	357.5522	745.1097	36,695	76,048	113,680
Texas	CENRAP	1,710.8244	3,236.6605	79,449	153,837	339,433
	CENRAP Total	**3,664.1040**	**7,520.2400**	**279,493**	**597,336**	**1,279,135**
Arizona	WRAP	442.6160	1,022.0551	36,168	81,858	60,640
California	WRAP	602.8505	1,403.6297	10,464	23,767	5,447
Colorado	WRAP	215.1782	486.7281	31,074	70,171	87,163
Idaho	WRAP	14.5575	34.1372	309	718	0
Montana	WRAP	88.4363	200.1442	17,034	38,504	22,066
Nevada	WRAP	179.3334	408.0758	20,978	47,404	31,172
New Mexico	WRAP	155.2294	344.7868	32,965	74,010	52,917
North Dakota	WRAP	131.5025	297.0199	31,745	71,711	108,645
Oregon	WRAP	109.6842	255.3128	4,968	11,330	10,034
South Dakota	WRAP	16.3929	36.8730	6,457	14,574	12,085
Utah	WRAP	146.1278	330.1164	26,905	60,782	37,819
Washington	WRAP	155.7190	362.9219	11,625	26,379	12,236
Wyoming	WRAP	202.3566	457.1643	35,935	81,182	40,265
	WRAP Total	**2,459.9843**	**5,638.9652**	**266,628**	**602,390**	**480,488**
National Total		**15,313.0609**	**33,938.8226**	**998,994**	**2,224,779**	**4,770,490**

3 POST PROCESSING OF IPM OUTPUT

3.1 Use of SMOKE Emissions Processing Model

On behalf of MANE-VU, modelers from The Northeast States for Coordinated Air Use Management (NESCAUM) used an emissions processing model to prepare data produced by the IPM model for use in air quality and visibility modeling. The Sparse Matrix Operator Kernel Emissions (SMOKE) Modeling System is an emissions processing system designed to create gridded, speciated, hourly emissions for input into a variety of air quality models, such as EPA's Community Multi-Scale Air Quality (CMAQ) model and Regional Modeling System for Aerosols and Deposition (REMSAD) (Houyoux, et. al., 2000). SMOKE supports area, biogenic, mobile (both onroad and nonroad), and point source emissions processing for criteria, particulate, and toxic pollutants. For biogenic emissions modeling, SMOKE uses the Biogenic Emission Inventory System, version 2.3 (BEIS2) and version 3.09 and 3.12 (BEIS3). SMOKE is also integrated with the onroad emissions model MOBILE6.

The sparse matrix approach used throughout SMOKE permits rapid and flexible processing of emissions data. Flexible processing comes from splitting the processing steps of inventory growth, controls, chemical speciation, temporal allocation, and spatial allocation into independent steps whenever possible. The results from these steps are merged together in the final stage of processing using vector-matrix multiplication. It allows individual steps (such as adding a new control strategy, or processing for a different grid) to be performed and merged without having to redo all of the other processing steps. Individual emission scenarios were simulated for MANE-VU using the SMOKE Modeling System.

NESCAUM, on behalf of MANE-VU and its participating States, conducted regional air quality simulations for calendar year 2002 and several future periods (NESCAUM, 2008). This work was directed at satisfying a number of goals under the Haze State Implementation Plan (SIP), including a contribution assessment, a pollution apportionment for 2018, and the evaluation of visibility benefits of control measures being considered for achieving reasonable progress goals and establishing a long-term emissions management strategy for MANE-VU Class I areas. The modeling tools utilized for these analyses include the Fifth-Generation NCAR / Penn State Mesoscale Model (MM5), SMOKE, CMAQ and REMSAD, and incorporate tagging features that allow for the tracking of individual source regions or measures. These tools have been evaluated and found to perform adequately relative to U.S. EPA modeling guidance.

As described below, in order for NESCAUM to process the EGU emissions generated by the IPM® procedures noted above, a series of intermediate steps were required to get the activity and emission data into the appropriate format for SMOKE processing.

3.2 Preparing IPM Output for Use in SMOKE Model

IPM can produce projections at the regional, state, plant, or unit level. Data must be parsed to provide the unit level information required for chemical transport modeling. Parsing involves developing detailed unit level information from the model's projections at the model plant level. ICF parsed the VISTASII_PC_1f data for use by the RPOs.

Further post-processing of IPM parsed output is needed to prepare the files for use by the SMOKE emissions processing model. The following sections describe the intermediate steps necessary to make these conversions. The first step is the augmentation of the IPM parsed output files to include additional unit level characteristics and pollutant estimates necessary for one atmosphere modeling. This step converts the IPM parsed data files into EPA's National Emission Inventory Input Format (NIF). The second step is the additional conversion of these NIF files into the Inventory Data Analyzer (IDA) format required by the SMOKE emissions processor.

3.2.1 IPM to NIF

After running IPM, ICF provided an initial spreadsheet file containing unit-level records for both:

(1) "existing" units (those currently in operation during the modeled base year) and

(2) committed/planned or new generic aggregates (new generic units expected to come online or identified as needed to meet electric generation demand in a geographic area).

IPM parsed file records include unit and fuel type data; existing, retrofit (for SO_2 and NO_x), and separate NO_x control information; annual SO_2 and NO_x emissions and heat input; summer season (May-September) NO_x and heat input; July day NO_x and heat input; coal heat input by coal type; nameplate capacity megawatt (MW), and State FIPS codes (Federal Information Processing codes used to identify geographic areas). Existing units also had county FIPS codes, a unique plant identifier (ORISPL) and unit ID (also called boiler ID) (BLRID); generic units did not have these data.

The processing of IPM parsed data to NIF format included estimating emissions of pollutants not generated by IPM and adding control efficiencies, stack parameters, latitude-longitude coordinates, and State identifiers (plant ID, point ID, stack ID, process ID) from a series of lookup tables or by matching to individual units as configured in base year 2002 emission files (Pechan, 2005). Additionally, new generic units created by IPM were sited in a county and given appropriate IDs. This processing is described in more detail below.

Generic Units: The new generic units and associated data were prepared by transforming the generic aggregates into units similar in size and fuel to existing units in terms of the available data. Generic aggregates were split into smaller generic units based on their unit types and capacity. Each generic unit was provided a dummy ORIS unique plant and boiler ID, and was given a county FIPS code based on an algorithm that sited each generic unit by assigning a sister plant that is in a county based on its attainment/nonattainment status. Within a State, existing plants (in county then ORIS plant code order) in attainment counties were used first as sister sites to new generic units (to obtain county location), followed by existing plants in PM nonattainment counties, followed by existing plants in 8-hour ozone nonattainment counties. No States identified counties that should not be considered when siting new generic units, so this process was identical to the one used for EPA IPM post-processing under CAIR.

SCCs were assigned to existing units using unit/fuel/firing/bottom type data. SCCs were assigned to generic units using unit and fuel type information. Latitude-longitude coordinates were assigned, first using the EPA-provided data files, secondly using an in-house contractor developed latitude-longitude file, and lastly using county centroids. These additional location files were only used when the data were not provided in the original 2002 base year files. Stack parameters were then assigned to each unit, first using the EPA-provided data files, secondly using an in-house stack parameter file based on previous EIA-767 data, and lastly using an EPA June 2003 SCC-based default stack parameter file. These data were only used when the data were not provided in the 2002 base year files.

IPM does not calculate emissions for all pollutants necessary for regional haze modeling. Therefore additional data were required to estimate VOC, CO, filterable primary PM_{10} and $PM_{2.5}$, PM condensable, and NH_3 emissions. Thus, ash and sulfur contents were assigned by first using 2002 EIA-767 values for existing units or SCC-based defaults; filterable PM_{10} and $PM_{2.5}$ efficiencies were obtained from the 2002 EGU NEI that were based on 2002 EIA-767 control data and the PM Calculator program (a default of 99.2 percent is used for coal units if necessary); fuel use was back calculated from the given heat input and a default SCC-based heat content; and emission factors were obtained from an EPA-approved emission factor file based on AP-42 emission factors. Table 2 presents the SCC-based default heat content and stack parameters used when actual data were not available. Table 3 (worksheet sccemfac100704 from MRPOpostprocdatafiles.xls, Pechan 2005) reflects emission factors used to develop emission estimates of CO, VOC, filterable PM, and NH_3.

Table 2. SCC Default Heat Content and Stack Parameters from IPM to NIF Conversion.

			Stack Parameters			
SCC	Fuel	Heat Content (Btu/SCC Unit)	Height (ft)	Diameter (ft)	Temp (degrees F)	Velocity (ft/s)
10100201	Bituminous Coal	23.4286	603.2	19.8	281.2	76.5
10100202	Bituminous Coal	23.4286	509.7	14.6	226.0	62.0
10100203	Bituminous Coal	23.4286	491.6	16.6	278.4	80.5
10100204	Bituminous Coal	23.4286	225.0	0.6	67.2	2.4
10100211	Bituminous Coal	23.4286	0.0	0.0	0.0	0.0
10100212	Bituminous Coal	23.4286	445.6	17.4	275.2	77.6
10100217	Bituminous Coal	23.4286	399.3	10.8	245.6	40.1
10100221	Subbituminous Coal	17.8870	983.0	22.8	350.0	110.0
10100222	Subbituminous Coal	17.8870	468.5	16.0	254.7	65.6
10100223	Subbituminous Coal	17.8870	446.8	15.9	308.0	93.6
10100224	Subbituminous Coal	17.8870	255.5	10.0	251.3	15.3
10100226	Subbituminous Coal	17.8870	495.8	18.9	259.2	91.2
10100238	Subbituminous Coal	17.8870	600.0	22.5	315.0	78.0
10100301	Lignite Coal	12.9149	427.5	22.3	232.8	74.2
10100302	Lignite Coal	12.9149	483.5	21.0	229.4	92.4
10100303	Lignite Coal	12.9149	462.0	21.7	271.3	72.5
10100317	Lignite Coal	12.9149	326.7	12.3	326.7	74.7
10100601	Natural Gas	1023.8846	263.9	10.3	236.0	46.9
10100801	Coke	27.4376	371.3	5.5	122.4	20.4
10102018	Waste Coal	12.0929	0.0	0.0	0.0	0.0
20100201	Natural Gas	1023.8846	62.0	10.0	585.3	61.3
20100301	Gasified Coal	1023.8846	62.0	10.0	585.3	61.3

Table 3. EPA-Approved Emission Factor File for CO, VOC, filterable PM, and NH_3.

SCC	FUEL	COEF	VOCEF	PM10EF	PM25EF	NH3EF	PMFLAG
10100201	BIT	0.5000	0.0400	2.6000	1.4800	0.030	A
10100202	BIT	0.5000	0.0600	2.3000	0.6000	0.030	A
10100203	BIT	0.5000	0.1100	0.2600	0.1100	0.030	A
10100204	BIT	5.0000	0.0500	13.2000	4.6000	0.030	
10100211	BIT	0.5000	0.0400	2.6000	1.4800	0.030	A
10100212	BIT	0.5000	0.0600	2.3000	0.6000	0.030	A
10100217	BIT	18.0000	0.0500	12.4000	1.3640	0.030	
10100221	SUB	0.5000	0.0400	2.6000	1.4800	0.030	A
10100222	SUB	0.5000	0.0600	2.3000	0.6000	0.030	A
10100223	SUB	0.5000	0.1100	0.2600	0.1100	0.030	A
10100224	SUB	5.0000	0.0500	13.2000	4.6000	0.030	
10100226	SUB	0.5000	0.0600	2.3000	0.6000	0.030	A
10100238	SUB	18.0000	0.0500	16.1000	4.2000	0.030	
10100301	LIG	0.2500	0.0700	1.8170	0.5214	0.030	A
10100302	LIG	0.6000	0.0700	2.3000	0.6600	0.030	A
10100303	LIG	0.6000	0.0700	0.8710	0.3690	0.030	A
10100317	LIG	0.1500	0.0300	12.0000	1.4000	0.030	
10100601	NG	84.0000	5.5000	1.9000	1.9000	3.200	
10100801	PC	0.6000	0.0700	7.9000	4.5000	0.397	A
10102018	WC	0.1500	0.0300	12.0000	1.4000	0.030	
20100201	NG	83.8628	2.1477	1.9380	1.9380	6.560	
20100301	IGCC	34.6500	2.2050	11.5500	11.5500	6.560	

Notes:

1. SCCs beginning with 101002 (coal), 101003 (coal), 101008 (coke), or 101020 (waste coal), emission factors in LB/TON; SCCs beginning with 101006 (natural gas), 201002 (natural gas), or 201003 (IGCC), emission factors are in LB/E6FT3.
2. If PMFLAG = 'A', then multiply ash content with PM emission factor.

Source: Table derived from worksheet sccemfac100704 from MRPOpostprocdatafiles.xls, Pechan 2005.

Condensable PM: To estimate total primary PM emissions, additional calculations were conducted to derive condensable PM emissions from these sources. In MANE VU and VISTAS PM condensable emissions were calculated based on factors derived from AP-42 defaults. In MRPO no condensable emissions were estimated or included in the inventory. (Janssen, 2008) Table 4 (worksheet pmcdef from MRPOpostprocdatafiles.xls, Pechan 2005) shows these PM condensable emission factors and SCC assignments.

Table 4. EPA-Approved Condensable PM Emission Factor Assignment.

SCC	PMCDEF (LB/E6BTU)
10100201, 10100202, 10100203, 10100211, 10100212, 10100221, 10100222, 10100223, 10100226, 10100301, 10100302, 10100303	0.0200[2]
10100201, 10100202, 10100203, 10100211, 10100212, 10100221, 10100222, 10100223, 10100226, 10100301, 10100302, 10100303 [1]	(0.1 * sulfur content - 0.03)[3]
10100204, 10100224	0.0400
10100217, 10100238, 10100317, 10102018	0.0100
10100601	0.0057
10100801	0.0100
20100201, 20100301	0.0047
Notes:	
1. If the emission factor is less than 0.01, then it is set equal to 0.01.	
2. AND there is either an SO_2 FGD or a PM scrubber (for MRPO post-processing); or AND there is an SO_2 wet FGD (for EPA post-processing).	
3. AND there is any PM control other than a scrubber and there is no SO_2 control (for MRPO post-processing); or AND there is any control other than an SO_2 wet FGD (for EPA post-processing).	

Source: Table derived from worksheet pmcdef from MRPOpostprocdatafiles.xls, Pechan 2005.

Additional Pollutants: As noted above, in processing IPM parsed data to convert it to NIF format, emissions of additional pollutants were estimated. Emissions for 28 temporal-pollutant combinations were estimated since there are seven pollutants (VOC, CO, primary PM_{10} and $PM_{2.5}$, NH_3, SO_2 and NO_x) and four temporal periods (annual, summer season, winter season, and July day).

Crosswalk Match to 2002 Inventory: The final step in the IPM to NIF conversion process was to match the IPM unit IDs with the identifiers in the base year 2002 inventory for existing EGUs. A crosswalk file was used to obtain FIPS State and county, plant ID (within State and county), and point ID. If the FIPS State and county, plant ID and point ID were in the 2002 base year NIF tables, then the process ID and stack ID were obtained from the NIF; otherwise, defaults, described above, were used.

The post-processed files were then provided in NIF 3.0 format. Two sets of tables were developed : “NIF files” for IPM units that had a crosswalk match and were in the 2002 base year inventory, and “NoNIF files” for IPM units that were not in the 2002 base year inventory (which included existing units with or without a crosswalk match as well as generic units). Two special cases relating to the crosswalk match were handled as follows:

1. One-to-many match: At a given plant, if one IPM boiler ID was matched to more than one point ID, the boiler data were put on the first point ID records; records from the other point IDs were deleted from the relevant tables.

2. Many-to-one match: At a given plant, if more than one IPM boiler ID was matched to one point ID, all the boilers’ emissions (tons), throughput (really heat input in MMBtu), and capacity (MW) were summed (“summed boiler”) and put on that point

ID's records in the relevant tables. The values for stack parameters and latitude-longitude values were those from the first record summed.

3.3 State Results – Phase II Augmented

Summarizing the results of the estimation of additional pollutants, Table 5 presents additional pollutant augmented State level emission results from the 2018 Inter-RPO CAIR Case IPM v. 2.1.9 fossil-only parsed file (VISTASII_PC_1f with pollutant augmentation; found in modeling file *ida_egu_18_basef_2453605.txt* from VISTAS BaseF). A comparison of RPO totals for SO_2 and NO_x shows that these are the same as presented in Table 1.

3.4 NIF to IDA

The main purpose of the SMOKE conversion task was to convert EGU emission inventories provided in NIF format into the IDA format required by the SMOKE model for the criteria pollutants VOC, NO_x, CO, SO_2, PM_{10}, $PM_{2.5}$, and NH_3. Annual and seasonal emissions were taken directly from the NIF structured inventories with no alternate temporal calculations performed (e.g., estimate seasonal emissions from annual or annual from seasonal). The temporal allocation module of the SMOKE emissions processor was intended to be used to further define temporal distribution of these emissions.

No quality assurance (QA) related to the reported values in the NIF files was conducted (e.g., it was assumed that reported emission levels were correct) and therefore the QA focus was to maintain the integrity of the mass files in the conversion to IDA.

Each set of NIF structured data had a unique set of relational tables necessary to maintain the information required in each source sector based on its reporting requirements. Conversion scripts to read the information from each of these relational data sets and convert them to the IDA structures required by this task were implemented by Alpine (Alpine, 2006). Prior to and after the conversion from NIF to IDA, a list of emission summary reports was developed to check that the emissions input into the conversion process were the same as output into the IDA formatted files.

Table 5. State Level Emission Summary; 2018 VISTASII_PC_1f with Pollutant Augmentation. Modeling file *ida_egu_18_basef_2453605.txt* from VISTAS Base F. (fossil-only)

		Annual Emissions (Tons)						
		IPM Generated		Augmented Pollutants				
State	**RPO**	**NOx**	**SO2**	**VOC**	**CO**	**PM-10**	**PM-2.5**	**NH3**
Connecticut	MANE-VU	3,418	6,697	145	9,837	959	927	341
Delaware	MANE-VU	12,341	35,442	117	1,183	2,950	2,438	76
District Of Columbia	MANE-VU	103	83	5	154	104	99	12
Maine	MANE-VU	1,827	5,436	53	4,057	296	279	139
Maryland	MANE-VU	14,709	28,065	575	11,831	8,253	6,433	435
Massachusetts	MANE-VU	18,157	17,486	484	13,860	3,918	3,233	1,059
New Hampshire	MANE-VU	3,089	7,469	73	1,697	2,268	2,156	124
New Jersey	MANE-VU	13,636	32,495	352	7,611	4,017	3,515	564
New York	MANE-VU	24,376	51,445	758	22,242	11,031	9,343	1,472
Pennsylvania	MANE-VU	82,881	135,946	1,920	41,445	31,580	23,756	1,790
Rhode Island	MANE-VU	576	55	42	1,627	157	156	127
Vermont	MANE-VU	105	35	3	117	26	25	9
	MANE-VU Total	**175,218**	**320,651**	**4,528**	**115,659**	**65,558**	**52,360**	**6,148**
Alabama	VISTAS	41,714	190,029	1,599	27,888	20,401	15,936	2,009
Florida	VISTAS	56,506	139,526	2,027	58,982	24,804	18,403	3,948
Georgia	VISTAS	56,180	178,196	1,940	33,040	25,929	19,087	2,374
Kentucky	VISTAS	64,099	229,596	1,623	17,103	24,659	18,813	782
Mississippi	VISTAS	8,895	27,226	511	12,228	7,270	4,358	918
North Carolina	VISTAS	57,774	102,217	1,232	14,386	31,797	26,551	847
South Carolina	VISTAS	46,318	118,584	932	11,263	26,740	22,629	793
Tennessee	VISTAS	29,873	112,343	922	7,391	15,008	12,988	449
Virginia	VISTAS	43,144	80,602	863	16,482	19,652	17,300	881
West Virginia	VISTAS	51,208	124,464	1,447	12,946	23,538	16,968	721
	VISTAS Total	**455,711**	**1,302,784**	**13,096**	**211,709**	**219,798**	**173,034**	**13,722**
Illinois	MRPO	71,233	241,136	2,229	17,868	32,650	30,132	1,152
Indiana	MRPO	95,376	376,864	2,105	19,416	35,082	27,835	1,274
Michigan	MRPO	98,685	398,562	1,623	17,522	38,902	34,276	1,091
Ohio	MRPO	83,129	215,501	2,254	23,832	42,754	33,323	1,773
Wisconsin	MRPO	45,701	155,369	1,101	11,901	15,629	14,246	626
	MRPO Total	**394,124**	**1,387,432**	**9,312**	**90,539**	**165,016**	**139,813**	**5,915**
Arkansas	CENRAP	33,097	82,605	696	11,429	3,897	3,326	814
Iowa	CENRAP	51,119	147,305	770	8,759	10,033	8,615	569
Kansas	CENRAP	83,333	81,486	798	7,203	8,520	6,807	461
Louisiana	CENRAP	30,432	74,263	660	11,043	3,966	3,590	919
Minnesota	CENRAP	41,029	85,847	674	5,563	8,162	7,034	343
Missouri	CENRAP	77,660	280,887	1,579	13,165	18,456	16,769	800
Nebraska	CENRAP	50,781	73,629	450	3,590	2,296	1,915	217
Oklahoma	CENRAP	76,048	113,680	1,008	28,182	5,561	4,840	1,355
Texas	CENRAP	153,837	339,433	4,988	102,583	38,952	31,631	6,424
	CENRAP Total	**597,336**	**1,279,135**	**11,622**	**191,518**	**99,842**	**84,528**	**11,902**
Arizona	WRAP	81,858	60,640	1,170	29,037	11,515	9,644	2,189
California	WRAP	23,767	5,447	1,496	56,188	5,442	5,337	4,402
Colorado	WRAP	70,171	87,163	667	12,139	4,751	4,166	609
Idaho	WRAP	718	0	36	1,398	113	113	109
Montana	WRAP	38,504	22,066	326	3,035	7,217	4,636	193
Nevada	WRAP	47,404	31,172	479	9,862	5,244	4,315	750
New Mexico	WRAP	74,010	52,916	554	5,991	13,435	7,637	388
North Dakota	WRAP	71,711	108,645	784	9,937	5,670	4,757	324
Oregon	WRAP	11,330	10,034	276	9,322	1,311	1,305	722
South Dakota	WRAP	14,574	12,085	110	536	362	297	33
Utah	WRAP	60,782	37,819	423	3,523	6,459	4,881	211
Washington	WRAP	26,379	12,236	451	11,848	3,780	3,192	898
Wyoming	WRAP	81,182	40,265	678	5,672	8,537	7,116	341
	WRAP Total	**602,389**	**480,488**	**7,449**	**158,487**	**73,834**	**57,395**	**11,170**
National Total		**2,224,778**	**4,770,490**	**46,007**	**767,912**	**624,049**	**507,129**	**48,857**

4 MODIFICATIONS BY OTHER REGIONS

4.1 Emission Control Modifications within VISTAS, MRPO, and CENRAP

State and local agencies and invited stakeholders from VISTAS, MRPO, and CENRAP reviewed the results of the Inter-RPO Phase II set of IPM runs. These stakeholders primarily reviewed and commented on the IPM results with respect to IPM decisions on NO_x post-combustion controls and SO_2 scrubbers and provided additional information on when and where new SO_2 and NO_x controls were planned to come online based on the best available data from state rules, enforcement agreements, compliance plans, permits, and discussions/commitments from individual companies. They also reviewed the IPM results to verify that known and existing controls and emission rates were properly reflected in the IPM runs. After considering comments, those RPOs adjusted the IPM results for specific units using new information they had as part of the permitting process or other contact with the industry that indicated which units would install controls as a result of CAIR and when these new controls would come on-line (MACTEC, 2007; MRPO 2006; ENVIRON 2007).

As described in the following section, some entities specified changes to the controls assigned by IPM to reflect their best estimates of emission control levels. These changes typically involved either 1) adding selective catalytic reduction (SCR) or scrubber controls to units where IPM did not predict SCR or scrubber controls, or 2) removing IPM-assigned SCR or scrubber controls at units where the commenting entity indicated there were no firm plans for controls at those units.

At this point in the process MANE-VU decided not to make any changes to the northeastern state IPM output regardless of state knowledge of discrepancies with actual conditions. MANE-VU determined that IPM provided a reasonable estimate of the impact of the CAIR cap and trade program consistent with methods used by EPA, and planners were concerned that adjustments would not reflect the allocation of all allowed emissions under CAIR.

In MANE-VU's final modeling, many of the changes made by the other RPOs were included, but due to the timing of the release of revised data, the location with respect to the modeling domain, and need to progress with modeling, MANE-VU did not incorporate changes reflected in the final CENRAP EGU files.

4.2 Emission Factor and Control Modifications for VISTAS Emission Sources

VISTAS reviewed the PM and NH_3 emissions from its States' EGUs provided after the original IPM to NIF conversation conducted for the RPOs and identified significantly higher emissions in 2009/2018 than in 2002. VISTAS determined this conversion used a set of PM and NH_3 emission factors that were "the most recent EPA approved uncontrolled emission factors" for estimating 2009/2018 EGU emissions but were most likely not the same emission factors used by States for estimating these emissions in 2002. Thus, the emission increase from 2002 to 2009/2018 was simply an artifact of the change in emission factors, not anything to do with changes in activity or control technology application. During this review, VISTAS additionally identified an inconsistent use of SCCs for determining emission factors between the base and future years.

Documentation (Alpine, 2005a, b) indicates that VISTAS adjusted the 2002 base year emissions inventory to account for these discrepancies in base year and future year PM and NH_3 emission factor use. Using the latest "EPA-approved" uncontrolled emission factors by SCC, Alpine utilized data collected under EPA's Consolidated Emissions Reporting Rule (CERR) or data reported by VISTAS. Alpine used reported annual heat input, fuel throughput, heat, ash, and sulfur content to estimate annual uncontrolled 2002 emissions for units identified as having corresponding output from IPM. This step was conducted for non-CEM pollutants (CO, VOC, PM, and NH_3) only. For PM emissions, the condensable component of emissions was calculated and added to the resulting PM primary estimations. The resulting 2002 emissions were then adjusted by any control efficiency factors reported in the CERR or VISTAS data collection effort. The second adjustment was to the future year inventories. Alpine updated the SCCs in the future year inventory to assign the same SCC used in the base year. Using the same methods as described for the 2002 revisions, those non-IPM generated pollutants were estimated using IPM predicted fuel characteristics and base year 2002 SCC assignments.

In addition to the changes to the emission factor assignments, SCC, and IPM-assigned controls, VISTAS also specified other changes to the IPM results or converted IPM to NIF files. Comments on changes in stack parameters from the 2002 inventory were implemented in the converted files for the 2018 inventory. Changes to stack parameters were also made in cases where new controls were scheduled to be installed. In cases where an emission unit was projected to have an SO_2 scrubber by 2018, some States were able to provide revised stack parameters for some units based on design features for the new control system. Other units projected to install scrubbers by 2018 were not far enough along in the design process to have specific design details. For those units, VISTAS made the following assumptions: 1) the scrubber is a wet scrubber; 2) keep the current stack height the same; 3) keep the current flow rate the same, and 4) change the stack exit temperature to 169 degrees F (this is the virtual temperature derived from a wet temperature of 130 degrees F) (MACTEC, 2007). VISTAS determined that exit temperature (wet) of 130 degrees F +/- 5 degrees F is representative of different size units and wet scrubber technology.

4.3 Emission Inventory Replacement by Western States

During the development of their EGU emission forecast, the Western Regional Air Partnership (WRAP) conducted an exercise where IPM was not used to prepare emission estimates from EGU sources. Using capacity factor adjustments and emission control assumptions, WRAP developed a forecast of EGU emissions based on its initial 2002 base year inventory (ERG, 2006). This revised forecast was used by some of the other RPOs and replaced the emissions generated for the domain by IPM. This change by WRAP is reflected in the difference in State emission totals between Tables 5 and 6. As WRAP is outside the MANE VU modeling domain, this change was not reflected in MANE-VU modeling. MANE-VU did not change its boundary conditions to reflect this change.

4.4 Eliminating Double Counting of EGU Units

An additional set of procedures was used by MANE-VU and VISTAS to avoid double counting of EGU emissions in the 2018 point source inventory (MACTEC, 2006, 2007). Since each

RPO's 2002 emissions inventory file contained both EGUs and non-EGU point sources, and EGU emissions were projected using IPM, it was necessary to split the 2002 point source file into two components. The first component contained those emission units accounted for in the IPM forecasts. The second component contained all other point sources not accounted for in IPM.

As described in the previous section, 2018 NIF files for EGUs were prepared from the IPM parsed files. All IPM matched units were initially removed from the 2018 point source inventory to create the non-EGU inventory (which was projected to 2018 using non-EGU growth and control factors). This was done on a unit-by-unit basis based on a cross-reference table that matched IPM emission unit identifiers (ORISPL plant code and BLRID emission unit code) to NIF emission unit identifiers (FIPSST state code, FIPSCNTY county code, State Plant ID, State Point ID). When there was a match between the IPM ORISPL/BLRID and the emission unit ID, the unit was assigned to the EGU inventory; all other emission units were assigned to the non-EGU inventory.

If an emission unit was contained in the NIF files created from the IPM output, the corresponding unit was removed from the initial 2018 point source inventory. For VISTAS, the NIF 2018 EGU files from the IPM parsed files were then merged with the non-EGU 2018 files to create a complete 2018 point source scenario.

Next, several ad-hoc QA/QC queries were done to verify that there was no double-counting of emissions in the EGU and non-EGU inventories:

- The IPM parsed files were reviewed to identify EGUs accounted for in IPM. This list of emission units was compared to the non-EGU inventory derived from the IPM-NIF cross-reference table to verify that units accounted for in IPM were not double-counted in the non-EGU inventory. As a result of this comparison, a few adjustments were made in the cross-reference table to add emission units for plants to ensure these units accounted for in IPM were moved to the EGU inventory.

- The non-EGU inventory was further reviewed to identify remaining emission units with an Standard Industrial Classification (SIC) code of "4911 Electrical Services" or Source Classification Code of "1-01-xxx-xx External Combustion Boiler, Electric Generation". The list of sources meeting these selection criteria were compared to the IPM parsed file to ensure that these units were not double-counted.

- VISTAS invited various stakeholder groups to review the 2018 point source inventory to verify whether there was any double counting of EGU emissions. In some instances, corrections were provided where an emission unit was double counted.

4.5 Preliminary Results from Phase II Additional Modifications

Table 6 summarizes the Base G emissions inventory for EGUs, presenting State level emission results from the 2018 Inter-RPO CAIR Case IPM v. 2.1.9 parsed file modified by VISTAS, MRPO, and WRAP per the methods noted in the above sections. Note that no changes occurred to the MANE-VU state emissions as a result of these changes.

Table 6. State Level Emission Summary; 2018 VISTAS Base G Modeling file ptinv_egu_2018_11sep2006.txt. Based on 2018 VISTASII_PC_1f (fossil-only) with adjustments from VISTAS, MRPO, and WRAP.

		Annual Emissions (Tons)						
State	**RPO**	**NOx**	**SO2**	**VOC**	**CO**	**PM-10**	**PM-2.5**	**NH3**
Connecticut	MANE-VU	3,418	6,697	145	9,836	959	927	341
Delaware	MANE-VU	12,341	35,442	117	1,183	2,950	2,438	76
District Of Columbia	MANE-VU	103	83	5	154	104	99	12
Maine	MANE-VU	1,827	5,436	53	4,057	296	279	139
Maryland	MANE-VU	14,709	28,065	575	11,831	8,253	6,433	435
Massachusetts	MANE-VU	18,157	17,486	484	13,860	3,917	3,233	1,059
New Hampshire	MANE-VU	3,089	7,469	73	1,697	2,268	2,156	124
New Jersey	MANE-VU	13,636	32,495	352	7,611	4,017	3,515	564
New York	MANE-VU	24,376	51,445	758	22,242	11,031	9,343	1,471
Pennsylvania	MANE-VU	82,881	135,946	1,919	41,446	31,580	23,756	1,790
Rhode Island	MANE-VU	576	55	42	1,627	157	156	127
Vermont	MANE-VU	105	35	3	117	26	25	9
	MANE-VU Total	**175,219**	**320,651**	**4,528**	**115,660**	**65,558**	**52,360**	**6,148**
Alabama	VISTAS	62,860	135,782	1,620	21,611	7,385	4,380	1,033
Florida	VISTAS	56,827	133,037	1,857	42,573	9,287	6,288	2,665
Georgia	VISTAS	69,308	226,477	1,805	35,584	18,217	11,319	1,676
Kentucky	VISTAS	59,740	211,225	1,344	12,125	6,194	4,067	436
Mississippi	VISTAS	10,455	15,143	1,055	11,822	7,007	6,853	545
North Carolina	VISTAS	56,526	96,402	1,147	16,376	32,676	26,014	608
South Carolina	VISTAS	50,068	87,202	860	13,078	28,110	24,454	578
Tennessee	VISTAS	30,008	112,353	886	7,126	15,861	13,321	241
Virginia	VISTAS	60,615	109,391	921	14,017	13,505	11,757	553
West Virginia	VISTAS	51,177	115,322	1,382	11,896	6,344	3,643	177
	VISTAS Total	**507,583**	**1,242,334**	**12,877**	**186,205**	**144,586**	**112,094**	**8,513**
Illinois	MRPO	71,233	241,136	2,229	17,868	32,649	30,132	1,152
Indiana	MRPO	95,376	351,858	2,105	19,416	35,081	27,835	1,274
Michigan	MRPO	78,605	288,006	1,623	17,521	38,902	34,276	1,091
Ohio	MRPO	83,129	215,501	2,254	23,832	42,753	33,322	1,772
Wisconsin	MRPO	45,701	155,369	1,101	11,901	15,629	14,246	626
	MRPO Total	**374,044**	**1,251,871**	**9,311**	**90,539**	**165,015**	**139,812**	**5,915**
Arkansas	CENRAP	33,097	82,605	696	11,429	3,897	3,326	814
Iowa	CENRAP	51,119	147,305	770	8,758	10,033	8,615	569
Kansas	CENRAP	83,333	81,486	798	7,203	8,520	6,807	461
Louisiana	CENRAP	30,432	74,263	660	11,043	3,966	3,590	919
Minnesota	CENRAP	41,029	85,847	674	5,563	8,162	7,035	343
Missouri	CENRAP	77,660	280,887	1,579	13,165	18,456	16,769	799
Nebraska	CENRAP	50,781	73,629	450	3,590	2,296	1,914	217
Oklahoma	CENRAP	76,048	113,680	1,008	28,182	5,561	4,840	1,355
Texas	CENRAP	153,837	339,433	4,988	102,581	38,952	31,630	6,424
	CENRAP Total	**597,336**	**1,279,135**	**11,622**	**191,515**	**99,842**	**84,527**	**11,901**
Arizona	WRAP	59,774	55,941	724	17,806	2,811	634	630
California	WRAP	17,537	1,528	2,558	31,173	1,219	1,059	0
Colorado	WRAP	77,113	60,914	1,465	18,939	3,138	307	537
Idaho	WRAP	2,236	1,683	50	3,283	335	87	0
Montana	WRAP	44,733	31,303	565	11,818	1,796	247	13
Nevada	WRAP	54,300	22,118	1,570	10,598	4,230	768	903
New Mexico	WRAP	32,925	17,796	695	10,976	794	627	43
North Dakota	WRAP	82,741	152,828	909	13,647	3,958	2,645	383
Oregon	WRAP	15,742	15,096	474	5,753	1,288	323	219
South Dakota	WRAP	17,681	13,522	118	689	247	217	52
Utah	WRAP	76,136	41,394	597	17,150	4,637	2,000	1,350
Washington	WRAP	16,884	7,011	249	4,008	1,474	1,027	12
Wyoming	WRAP	104,142	96,745	1,147	18,871	10,445	7,411	404
	WRAP Total	**601,942**	**517,879**	**11,122**	**164,711**	**36,371**	**17,353**	**4,547**
National Total		**2,256,124**	**4,611,869**	**49,460**	**748,629**	**511,371**	**406,146**	**37,024**

4.6 Revised Results – VISTAS Base G2 Adjustment

VISTAS further refined their future predictions based on further state input. The resulting modeling file was called the Base G2 inventory. Table 7 presents State level emission results from the Base G2 2018 Inter-RPO CAIR Case IPM v. 2.1.9 parsed file modified by VISTAS.

Some states specified changes to the controls assigned by IPM to reflect their best estimates of emission control levels. These changes typically involved either 1) adding selective catalytic reduction (SCR) or scrubber controls to units where IPM did not predict SCR or scrubber controls, or 2) removing IPM-assigned SCR or scrubber controls at units where the commenting entity indicated their were no firm plans for controls at those units. These changes were based on those states' best available information about where and when emissions controls were expected to be installed, as well as information concerning IPM-predicted plant closures that were deemed unlikely to occur. In comparing Table 7 with Table 6, it can be seen that the changes included in the Base G2 inventory were requested by the states of Florida, Georgia, and North Carolina.

Note that no changes were made at this time by the MANE-VU states. The net effect of these changes was to reduce emissions of SO_2 relative to either Table 5 or Table 6.

Table 7. State Level Emission Summary; 2018 VISTAS Base G2 Modeling file egu_18_vistas_g2_20feb2007.txt. Based on 2018 VISTASII_PC_1f (fossil-only) with adjustments from VISTAS, MRPO, and WRAP.

		Annual Emissions (Tons)						
State	**RPO**	**NOx**	**SO2**	**VOC**	**CO**	**PM-10**	**PM-2.5**	**NH3**
Connecticut	MANE-VU	3,418	6,697	145	9,836	959	927	341
Delaware	MANE-VU	12,341	35,442	117	1,183	2,950	2,438	76
District Of Columbia	MANE-VU	103	83	5	154	104	99	12
Maine	MANE-VU	1,827	5,436	53	4,057	296	279	139
Maryland	MANE-VU	14,709	28,065	575	11,831	8,253	6,433	435
Massachusetts	MANE-VU	18,157	17,486	484	13,860	3,917	3,233	1,059
New Hampshire	MANE-VU	3,089	7,469	73	1,697	2,268	2,156	124
New Jersey	MANE-VU	13,636	32,495	352	7,611	4,017	3,515	564
New York	MANE-VU	24,376	51,445	758	22,242	11,031	9,343	1,471
Pennsylvania	MANE-VU	82,881	135,946	1,919	41,446	31,580	23,756	1,790
Rhode Island	MANE-VU	576	55	42	1,627	157	156	127
Vermont	MANE-VU	105	35	3	117	26	25	9
	MANE-VU Total	**175,219**	**320,651**	**4,528**	**115,660**	**65,558**	**52,360**	**6,148**
Alabama	VISTAS	62,860	135,782	1,620	21,611	7,385	4,380	1,033
Florida	VISTAS	58,341	139,200	1,904	42,947	9,355	6,331	2,665
Georgia	VISTAS	69,308	75,051	1,805	35,584	18,217	11,319	1,676
Kentucky	VISTAS	59,740	211,225	1,344	12,125	6,194	4,067	436
Mississippi	VISTAS	10,455	15,143	1,055	11,822	7,007	6,853	545
North Carolina	VISTAS	56,526	102,680	1,147	16,376	32,676	26,014	608
South Carolina	VISTAS	50,068	87,202	860	13,078	28,110	24,454	578
Tennessee	VISTAS	30,008	112,353	886	7,126	15,861	13,321	241
Virginia	VISTAS	60,615	109,391	921	14,017	13,505	11,757	553
West Virginia	VISTAS	51,177	105,932	1,382	11,896	6,344	3,643	177
	VISTAS Total	**509,098**	**1,093,959**	**12,923**	**186,579**	**144,654**	**112,137**	**8,513**
Illinois	MRPO	71,233	241,136	2,229	17,868	32,649	30,132	1,152
Indiana	MRPO	95,376	351,858	2,105	19,416	35,081	27,835	1,274
Michigan	MRPO	78,605	288,006	1,623	17,521	38,902	34,276	1,091
Ohio	MRPO	83,129	215,501	2,254	23,832	42,753	33,322	1,772
Wisconsin	MRPO	45,701	155,369	1,101	11,901	15,629	14,246	626
	MRPO Total	**374,044**	**1,251,871**	**9,311**	**90,539**	**165,015**	**139,812**	**5,915**
Arkansas	CENRAP	33,097	82,605	696	11,429	3,897	3,326	814
Iowa	CENRAP	51,119	147,305	770	8,758	10,033	8,615	569
Kansas	CENRAP	83,333	81,486	798	7,203	8,520	6,807	461
Louisiana	CENRAP	30,432	74,263	660	11,043	3,966	3,590	919
Minnesota	CENRAP	41,029	85,847	674	5,563	8,162	7,035	343
Missouri	CENRAP	77,660	280,887	1,579	13,165	18,456	16,769	799
Nebraska	CENRAP	50,781	73,629	450	3,590	2,296	1,914	217
Oklahoma	CENRAP	76,048	113,680	1,008	28,182	5,561	4,840	1,355
Texas	CENRAP	153,837	339,433	4,988	102,581	38,952	31,630	6,424
	CENRAP Total	**597,336**	**1,279,135**	**11,622**	**191,515**	**99,842**	**84,527**	**11,901**
Arizona	WRAP	59,774	55,941	724	17,806	2,811	634	630
California	WRAP	17,537	1,528	2,558	31,173	1,219	1,059	0
Colorado	WRAP	77,113	60,914	1,465	18,939	3,138	307	537
Idaho	WRAP	2,236	1,683	50	3,283	335	87	0
Montana	WRAP	44,733	31,303	565	11,818	1,796	247	13
Nevada	WRAP	54,300	22,118	1,570	10,598	4,230	768	903
New Mexico	WRAP	32,925	17,796	695	10,976	794	627	43
North Dakota	WRAP	82,741	152,828	909	13,647	3,958	2,645	383
Oregon	WRAP	15,742	15,096	474	5,753	1,288	323	219
South Dakota	WRAP	17,681	13,522	118	689	247	217	52
Utah	WRAP	76,136	41,394	597	17,150	4,637	2,000	1,350
Washington	WRAP	16,884	7,011	249	4,008	1,474	1,027	12
Wyoming	WRAP	104,142	96,745	1,147	18,871	10,445	7,411	404
	WRAP Total	**601,942**	**517,879**	**11,122**	**164,711**	**36,371**	**17,353**	**4,547**
National Total		**2,257,639**	**4,463,494**	**49,506**	**749,003**	**511,439**	**406,189**	**37,024**

5 ADDITIONAL ADJUSTMENTS BY NORTHEASTERN STATES AND MODELERS FOR REGIONAL HAZE SIP MODELING

5.1 Introduction

MANE VU used the G2 inventory as the basis for further adjustments to incorporate MANE-VU state changes and also to represent the MANE VU control strategy for key EGUs. These modifications resulted in a) SO_2 emissions reductions at one MANE-VU EGU source subject to Best Available Retrofit Technology (BART) requirements, 2) emissions increases in MANE-VU to reflect states' best estimates that some sources predicted by IPM to be closed would continue to operate and information about where and when emission controls would or would not be installed, 3) SO_2 emissions reductions at key EGUs (or alternative facilities) to reflect the MANE-VU EGU strategy, and 4) increases in SO_2 emissions to estimate the predicted effect of emissions trading under the CAIR program. Each of these is explained below.

5.2 Best Available Retrofit Technology (BART)

To assess the impacts of the implementation of the BART provisions of the Regional Haze Rule, NESCAUM included estimated reductions anticipated for BART-eligible facilities not covered by CAIR in the MANE-VU region in the 2018 CMAQ modeling analysis. A survey of state staff indicated that eight units would likely be controlled under BART alone. State-provided potential control technologies and levels of control for these sources were incorporated into the 2018 emission inventory projections used in MANE-VU's March 2008 modeling run (NESCAUM, 2008b). The eight BART-eligible units included one EGU point source, which is located in Maine (Wyman Station).

5.3 MANE-VU State Modifications of IPM Results

Previously, during development of the Base G and Base G2 inventories, MANE-VU states had relied on the RPO IPM model results (Base F) without revisions. In 2007, the MANE-VU states decided that they should revise the estimates, as other RPOs had done, to reflect their best estimates of future source operations and controls. State and regional staff reviewed and revised the IPM results with respect to when and where new SO_2 controls were planned to come online. Modifications were based on state rules, enforcement agreements, compliance plans, permits, and commitments from individual companies. States reviewed the IPM results to verify that known and existing controls and emission rates were properly reflected in the IPM results. In addition, states noted that some units predicted by IPM to close were very unlikely to cease operation.

The net effect of these adjustments was an increase in SO_2 emissions in the MANE-VU region as a whole. In Delaware SO_2 emissions decreased due to controls on a major source. Emissions in Connecticut, the District of Columbia, Rhode Island, and Vermont remained the same as predicted by RPO IPM 2.1.9 (Base F). Emissions of SO_2 in other MANE-VU states increased. No changes were made in emissions of other pollutants.

5.4 MANE-VU EGU Strategy

MANE-VU states have recognized that SO_2 emissions from power plants are the single largest contributing sector to visibility impairment in the Northeast's Class I areas. Sulfate formed through atmospheric processes from SO_2 emissions are responsible for over half the mass and approximately 70-80 percent of the extinction on the worst visibility days (NESCAUM, 2006a, and b). The emissions from power plants dominate the SO_2 inventory.

A modeling analysis was conducted to identify those EGUs with the greatest impact on visibility in MANE-VU. As part of the MANE VU Contribution Assessment, two MANE-VU modeling centers undertook CALPUFF modeling to identify the top 100 stacks that impacted three of the MANE VU Class I areas in the base year, 2002. These three areas are Acadia, Brigantine and Lye Brook. Details of the modeling are provided in Appendix D of the Contribution Assessment. (NESCAUM, 2006a) Appendix D of the Contribution Assessment includes a model performance evaluation, including comparisons of CALPUFF results from two different modeling groups using different meteorological drivers, as well as comparisons to other models and to ambient data. The overall CALPUFF results were similar and performance was acceptable.

The CALPUFF modeling results were sorted to identify the individual stacks causing the highest 24-hr concentrations at each of the three Class I areas. Impacts were not summed for all stacks at a facility. The 100 top stacks for each Class I area are listed in Tables 10 and 20 from Appendix D "Dispersion Model Techniques" of the Contribution Assessment.

The two modeling centers used 2002 U.S. EPA Continuous Emission Monitoring System (CEMS) data reported by the power companies, which is stack based rather than emission unit based. A power plant may have several stacks. Each stack may vent emissions from one or more units at the plant. The two modeling centers also used different meteorological data—one used data from the MM5 model and the other used National Weather Service observation-based meteorology.

There are differences between results from the two centers because of the differences in meteorological input data and also because of rounding when summing annual emissions. As a result the MM5-based modeling identified some stacks as being in the top 100 impacting a MANE-VU Class I area that were not identified by the observation-based modeling, and vice versa. For purposes of identifying key stacks, all stacks on either list were included.

MARAMA combined the lists of the top 100 EGU stacks in Tables 10 and 20 from Appendix D of the Contribution Assessment and eliminated both duplications and stacks that were outside the MANE-VU consultation area. (The consultation area includes states contributing at least 2% of the sulfate monitored at MANE-VU Class I areas in 2002.) This process resulted in 167 unique stacks impacting one or more of the three MANE-VU Class I areas. The use of stacks rather than units or facilities was chosen as more consistent with the results of the modeling presented in the Contribution Assessment. The Contribution Assessment Appendix D tables did not identify the units or facilities that were modeled, only providing a CEMS Identification number.

MARAMA used information contained in IPM input files to match the plant name and type where the stack was located. The resulting list of 167 stacks is found in Appendix A of this report.

MANE-VU asked states in the consultation area to pursue 90 percent control on all units emitting from those stacks by 2018. MANE-VU recognized that this level of control may not be feasible in all cases. NESCAUM modelers incorporated State comments gathered during the inter-RPO consultation process in estimating the impact of this strategy on visibility at Class I areas. This process is described below in Section 5.5.

5.5 Implementation of MANE-VU Control Strategy for Key EGUs

As part of the MANE-VU strategy to improve visibility, MANE-VU asked states to pursue a 90 percent reduction in SO_2 emissions from the 167 EGU stacks identified as described in Section 5.4 and listed in Appendix A. MARAMA gathered information from MANE-VU, MRPO, and VISTAS states and regional staff to obtain information about anticipated emissions changes.

State and local agencies and individual stakeholders from MANE-VU, MRPO and VISTAS reviewed and revised the IPM results with respect to controls planned to come online. They also reviewed the IPM results to verify that known and existing controls and emission rates were properly reflected in the IPM runs. In addition, commenters noted that some units predicted by IPM to be shutdown would not shutdown.

Adjustments to the IPM results were made to specific units using information states had obtained as part of the permitting process or other contact with the industry that indicated which units would install controls as a result of CAIR and when these new controls would come on-line (Koerber, 2007; VISTAS 2007). In general, the changes at specific EGUs provided by VISTAS reflected their Base G2 inventory, and, as discussed with MRPO, the changes NESCAUM made to emissions from sources in the MRPO were consistent with sources where controls were predicted in EPA's IPM 3.0 run for 2018, since MRPO modeling relied on IPM 3.0. In addition to the 167 stacks, MANE-VU incorporated further corrections to source emissions as requested by VISTAS states at the following locations: North Carolina (Cliffside), South Carolina (Jefferies), Kentucky (Spurlock), and Virginia (Chesapeake and Clinch River). .

NESCAUM determined the desired emissions levels for the 167 key stacks based on a 90 percent reduction in continuous emissions monitoring data from 2002. This established a target emissions level for the region from those stacks. NESCAUM compared these levels with the information provided by the states for those sources. In each region, predicted 2018 emissions exceeded the target level. Therefore, emissions reductions from other EGU sources were considered in order to meet the target emissions reductions for the region (both within MANE-VU and in other RPOs). This resulted in a net decrease in emissions in all three affected RPOs. Emissions of SO_2 would have decreased by over 14,000 tons per year in MANE-VU, over 304,000 tons per year in the Midwest, and over 197,000 tons per year in the VISTAS region.

However, MANE-VU planners recognized that CAIR allows emissions trading, and that reductions at one unit could be offset increases at another unit within the CAIR region. Because most states do not restrict trading, MANE-VU decided that emissions should be increased to represent the implementation of the strategy for the 167 stacks within the limits of the CAIR program. Therefore, NESCAUM increased the emissions from states subject to the CAIR cap and trade program. For MANE-VU, 75,809 tons were added back, leaving total regional emissions from the MANE-VU region greater than the original Inter-RPO IPM-based estimate but consistent with state projections. The remaining 440,541 tons added back were allocated to VISTAS and MRPO based on the fraction of their contribution to the total SO_2 emissions. The additional emissions correspond to an increase of 20.5 percent, with a total of 223,856 tons added to MRPO and 216,685 added to VISTAS.

Table 8 shows the emissions difference between the results of two IPM runs and the modeling inventories used by three Regional Planning Organizations (RPOs). VISTAS used Base G2, MANE-VU used the March 2008 Modeling Inventory, and MRPO used IPM 3.0..

Table 8. Comparison of Regional SO_2 Emissions Estimates for 2018
(1000 tons per year)

	MANE-VU	MRPO	VISTAS	TOTAL
RPO 2.1.9 (VISTASII_PC_1f) (fossil only)	**321**	**1,387**	**1,303**	**3,011**
Reductions made by VISTAS and MRPO (Base G2)	0	-136	-209	-344
Net additional changes made by MANE-VU	66	24	222	311
MANE-VU March 2008 Modeling Inventory (fossil only)	**387**	**1,276**	**1,316**	**2,978**
MANE-VU minus RPO 2.1.9 (negative numbers mean MANE-VU's modeling inventory was less than RPO 2.1.9)	66	-112	13	-33
EPA 3.0 (fossil only)	**421**	**1,328**	**1,458**	**3,207**
RPO 2.1.9 minus EPA 3.0 (negative number means RPO 2.1.9 was less than EPA 3.0)	-100	59	-155	-196
MANE-VU 3/08 minus EPA 3.0 (negative numbers mean MANE-VU's modeling inventory was less than EPA 3.0)	-34	-53	-142	-229

The intent of the MANE-VU modelers' final EGU emissions adjustments was to retain the same level of emissions as predicted by the RPO CAIR IPM run for the three regions together, but to modify the locations of the emissions to better reflect the states' estimates and to achieve reductions at the 167 stacks identified as important contributors to regional haze at MANE-VU Class I areas. As shown in Table 8, above, the MANE-VU adjustments resulted in total emissions from the three regions being less than the SO_2 emissions predicted by the RPO 2.1.9 IPM run but greater than emissions in the G2 inventory used by VISTAS modelers. In both the MANE-VU and VISTAS regions, the MANE-VU Modeling Inventory is greater than the VISTAS/Inter-RPO IPM run and in MRPO it is smaller. Results from IPM 3.0 also are provided for comparison, and are uniformly greater than the MANE-VU Modeling Inventory for EGUs.

All future EGU emissions estimates involve uncertainty. MANE-VU believes its process of adding back emissions resulted in a reasonable, conservative estimate of the implementation of the MANE-VU request for a 90% reduction at key EGU facilities.

5.6 State Results – Northeastern State Adjustments

Table 9 presents State level emission results as modified by the Northeastern States per the methods noted in the above sections. This table summarizes the input data used in the MANE-VU 2018 March 2008 Modeling run as documented in NESCAUM's *2018 Visibility Projections* report dated March 2008. Appendix A provides details for the top 167 EGU stacks.

Table 9. State Level 2018 Emission Summary; March 2008 MANE-VU EGU Modeling Inventory. (See next page for file names.)

		Annual Emissions (Tons)						
State	**RPO**	**NOx**	**SO2**	**VOC**	**CO**	**PM-10**	**PM-2.5**	**NH3**
Connecticut	MANE-VU	3,418	6,697	145	9,836	959	927	341
Delaware	MANE-VU	12,341	10,941	117	1,183	2,950	2,438	76
District Of Columbia	MANE-VU	103	83	5	154	104	99	12
Maine	MANE-VU	1,827	6,806	53	4,057	296	279	139
Maryland	MANE-VU	14,709	43,764	575	11,831	8,253	6,433	435
Massachusetts	MANE-VU	18,157	45,941	484	13,860	3,917	3,233	1,059
New Hampshire	MANE-VU	3,089	10,766	73	1,697	2,268	2,156	124
New Jersey	MANE-VU	13,636	15,918	352	7,611	4,017	3,515	564
New York	MANE-VU	24,376	74,587	758	22,242	11,031	9,343	1,471
Pennsylvania	MANE-VU	82,881	170,992	1,919	41,446	31,580	23,756	1,790
Rhode Island	MANE-VU	576	55	42	1,627	157	156	127
Vermont	MANE-VU	105	35	3	117	26	25	9
	MANE-VU Total	**175,219**	**386,584**	**4,528**	**115,660**	**65,558**	**52,360**	**6,148**
Alabama	VISTAS	62,860	163,567	1,620	21,611	7,385	4,380	1,033
Florida	VISTAS	58,341	167,685	1,903	42,946	9,355	6,330	2,665
Georgia	VISTAS	69,308	90,408	1,805	35,584	18,217	11,319	1,676
Kentucky	VISTAS	59,740	255,559	1,344	12,125	6,194	4,067	436
Mississippi	VISTAS	10,455	18,241	1,055	11,822	7,007	6,853	545
North Carolina	VISTAS	56,526	126,042	1,147	16,376	32,676	26,014	608
South Carolina	VISTAS	50,068	105,436	860	13,078	28,110	24,454	578
Tennessee	VISTAS	30,008	135,344	886	7,126	15,861	13,320	241
Virginia	VISTAS	60,615	125,849	921	14,017	13,505	11,757	553
West Virginia	VISTAS	51,177	127,609	1,382	11,896	6,344	3,643	177
	VISTAS Total	**509,098**	**1,315,740**	**12,922**	**186,579**	**144,653**	**112,137**	**8,512**
Illinois	MRPO	71,233	208,832	2,229	17,868	32,649	30,132	1,152
Indiana	MRPO	95,376	403,473	2,105	19,416	35,081	27,835	1,274
Michigan	MRPO	78,605	213,066	1,623	17,521	38,902	34,276	1,091
Ohio	MRPO	83,129	353,293	2,254	23,832	42,753	33,322	1,772
Wisconsin	MRPO	45,701	96,934	1,101	11,901	15,629	14,246	626
	MRPO Total	**374,044**	**1,275,598**	**9,311**	**90,539**	**165,015**	**139,812**	**5,915**
Arkansas	CENRAP	33,097	82,605	696	11,429	3,897	3,326	814
Iowa	CENRAP	51,119	147,305	770	8,758	10,033	8,615	569
Kansas	CENRAP	83,333	81,486	798	7,203	8,520	6,807	461
Louisiana	CENRAP	30,432	74,263	660	11,043	3,966	3,590	919
Minnesota	CENRAP	41,029	85,847	674	5,563	8,162	7,035	343
Missouri	CENRAP	77,660	280,887	1,579	13,165	18,456	16,769	799
Nebraska	CENRAP	50,781	73,629	450	3,590	2,296	1,914	217
Oklahoma	CENRAP	76,048	113,680	1,008	28,182	5,561	4,840	1,355
Texas	CENRAP	153,837	339,433	4,988	102,581	38,952	31,630	6,424
	CENRAP Total	**597,336**	**1,279,135**	**11,622**	**191,515**	**99,842**	**84,527**	**11,901**
Arizona	WRAP	59,774	55,941	724	17,806	2,811	634	630
California	WRAP	17,537	1,528	2,558	31,173	1,219	1,059	0
Colorado	WRAP	77,113	60,914	1,465	18,939	3,138	307	537
Idaho	WRAP	2,236	1,683	50	3,283	335	87	0
Montana	WRAP	44,733	31,303	565	11,818	1,796	247	13
Nevada	WRAP	54,300	22,118	1,570	10,598	4,230	768	903
New Mexico	WRAP	32,925	17,796	695	10,976	794	627	43
North Dakota	WRAP	82,741	152,828	909	13,647	3,958	2,645	383
Oregon	WRAP	15,742	15,096	474	5,753	1,288	323	219
South Dakota	WRAP	17,681	13,522	118	689	247	217	52
Utah	WRAP	76,136	41,394	597	17,150	4,637	2,000	1,350
Washington	WRAP	16,884	7,011	249	4,008	1,474	1,027	12
Wyoming	WRAP	104,142	96,745	1,147	18,871	10,445	7,411	404
	WRAP Total	**601,942**	**517,879**	**11,122**	**164,711**	**36,371**	**17,353**	**4,547**
National Total		**2,257,639**	**4,774,936**	**49,505**	**749,003**	**511,439**	**406,188**	**37,023**

Files used in preparing Table 9 include for CENRAP and WRAP, the VISTAS Base G2 Modeling file (egu_18_vistas_g2_20feb2007.txt.), and the following additional files:

MANE-VU:
- EGU2018_MANEVUv3_nonSO2.ida
- EGU2018_MANEVU_SO2_non167plus.ida
- EGU2018_MANEVU_SO2_167plus.ida

VISTAS:
- EGU2018_VISTASG2_SO2_non167plus_CAIRaddback.ida
- EGU2018_VISTASG2_SO2_167plus_CAIRaddback.ida
- EGU2018_VISTASG2_nonSO2.ida

MRPO:
- EGU2018_MWRPO_SO2_167plus_CAIRaddback.ida
- EGU2018_MWRPO_SO2_non167p_non65_CAIRaddback.ida
- EGU2018_MWRPO_SO2_65_CAIRaddback.ida
- EGU2018_MWRPO_nonSO2.ida

6 EGU PREPARATION TIMELINE

The following section provides a chronological review of the events and milestones that occurred during the preparation of EGU emission forecasts in support of regional haze SIP preparation.

2004

- VISTAS/MRPO sponsor first IPM 2.1.6 runs for 2018 (Phase I)
- Phase I (VISTAS_CAIR_2) results released

2005

- RPOs move to IPM 2.1.9 (Phase II)
- Revisions to NEEDS input file and global parameters submitted by RPOs for revised runs
- Phase II (VISTAS_II_PC_1f) results released
- IPM parsed to NIF and NIF to SMOKE IDA format conversion occurs
- Initial RPO adjustments and modifications of IPM results
- RPOs share IPM 2.1.9 inputs and configuration from Phase II with EPA
- EPA releases IPM 2.1.9 results of CAIR/CAMR modeling

2006

- Additional RPO control and modeling file adjustments to Phase II runs
- RPOs simulate 2018 forecast year to support regional haze SIP submittals
- RPOs work with EPA to configure NEEDS 3.0 for next round of EPA modeling
- EPA releases IPM 2006 revised projections
- RPOs identify potential control measures and estimate benefits for meeting reasonable progress goals
- Additional RPO control and modeling file adjustments to Phase II runs

2007

- RPOs analyze cost and other factors associated with potential control measures
- RPOs coordinate with EPA on inputs and runs of IPM 3.0
- EPA releases IPM 3.0 results of revised CAIR/CAMR/CAVR modeling
- Interstate and inter-regional consultation regarding potential control measures
- MANE-VU states agree to pursue several control measures
- RPOs begin regional modeling to assess visibility impacts of controls

2008

- RPOs model to determine progress goals for regional haze SIP

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Appendix A

TOP ELECTRIC GENERATING EMISSION POINTS CONTRIBUTING TO VISIBILITY IMPAIRMENT IN MANE-VU IN 2002

For each of three MANE-VU Class I Areas the 100 Electric Generating Unit (EGU) stacks with the most significant 2002 impact on visibility impairment were identified by CALPUFF modeling conducted by two modeling centers.[2] Many of these stacks have a regional impact and therefore significantly impact more than one Class I Area. When the "Top Impacting" stacks for each of the three areas are aggregated into a single group there are 167 individual "Top Impacting" stacks identified. Figure A-1 indicates the location of the 167 stacks, and the tables following the map provides identifying information, emissions used in the CALPUFF modeling, and predicted impacts.

The following information may be found in the listed columns of Table A-1:

1. Row Number (1 through 167)
2. CEMS Unit ID: an arbitrary number identifying the CEMS unit
3. ORIS ID: a standard identification number associated with each unit
4. Acadia MM5: The rank of this source based on its predicted sulfate ion annual impact on Acadia in 2002 using meteorological data from the MM5 model. (A blank in columns 4, 5, 6, 7, 8, or 9 indicates this source was not among the top 100 for this Class I area as predicted by the indicated model.)
5. Acadia VTDEC: The rank of this source in terms of its predicted sulfate ion annual impact on Acadia in 2002 using National Weather Service data.
6. Brig MM5: The rank of this source in terms of its predicted sulfate ion annual impact on Brigantine in 2002 using meteorological data from the MM5 model.
7. Brig VTDEC: The rank of this source in terms of its predicted sulfate ion annual impact on Brigantine in 2002 using National Weather Service data.
8. Lye MM5: The rank of this source in terms of its predicted sulfate ion annual impact on Lye Brook in 2002 using meteorological data from the MM5 model.
9. Lye VTDEC: The rank of this source in terms of its predicted sulfate ion annual impact on Lye Brook in 2002 using National Weather Service data.
10. MM5 2002 SO_2 Tons per Year: Emissions calculated from CEMS data and used by modelers who used the MM5 generated meteorological data
11. VTDEC 2002 SO_2 Tons per Year: Emissions calculated from CEMS data and used by modelers who used the national weather service generated meteorological data
12. Plant Number (1 through 105): The 167 stacks are located at 105 plants.
13. Plant Name—table is in alphabetical order by plant within each state
14. Plant Type: coal fired or oil/gas fired electric generating units
15. State Name—table is in alphabetical order by state
16. State Code

[2] For more information and detailed modeling results, see Appendix D: Source Dispersion Model Methods, in NESCAUM 2006a.

Note that this list was created using 2002 emissions. By 2018 some of the units using these stacks will have emission controls installed or be repowered or shut down. This list represents the EGU stacks that had the largest individual impacts on baseline visibility in 2002 at three MANE-VU Class 1 areas.

Table A-2 presents predicted 2018 emissions estimates for the same list of key stacks. Column 6 of Table A-2 gives the 2018 emissions predicted by the IPM run VISTAS_PC_1f. Column 7 lists the revised 2018 emissions used in MANE-VU's March 2008 modeling. Column 8 provides the basis for revising the emissions. See Section 5.5 of this report for more information.

Figure A-1. Top 167 US Electric Generating Facility Stacks Affecting MANE-VU Class I Areas in 2002.

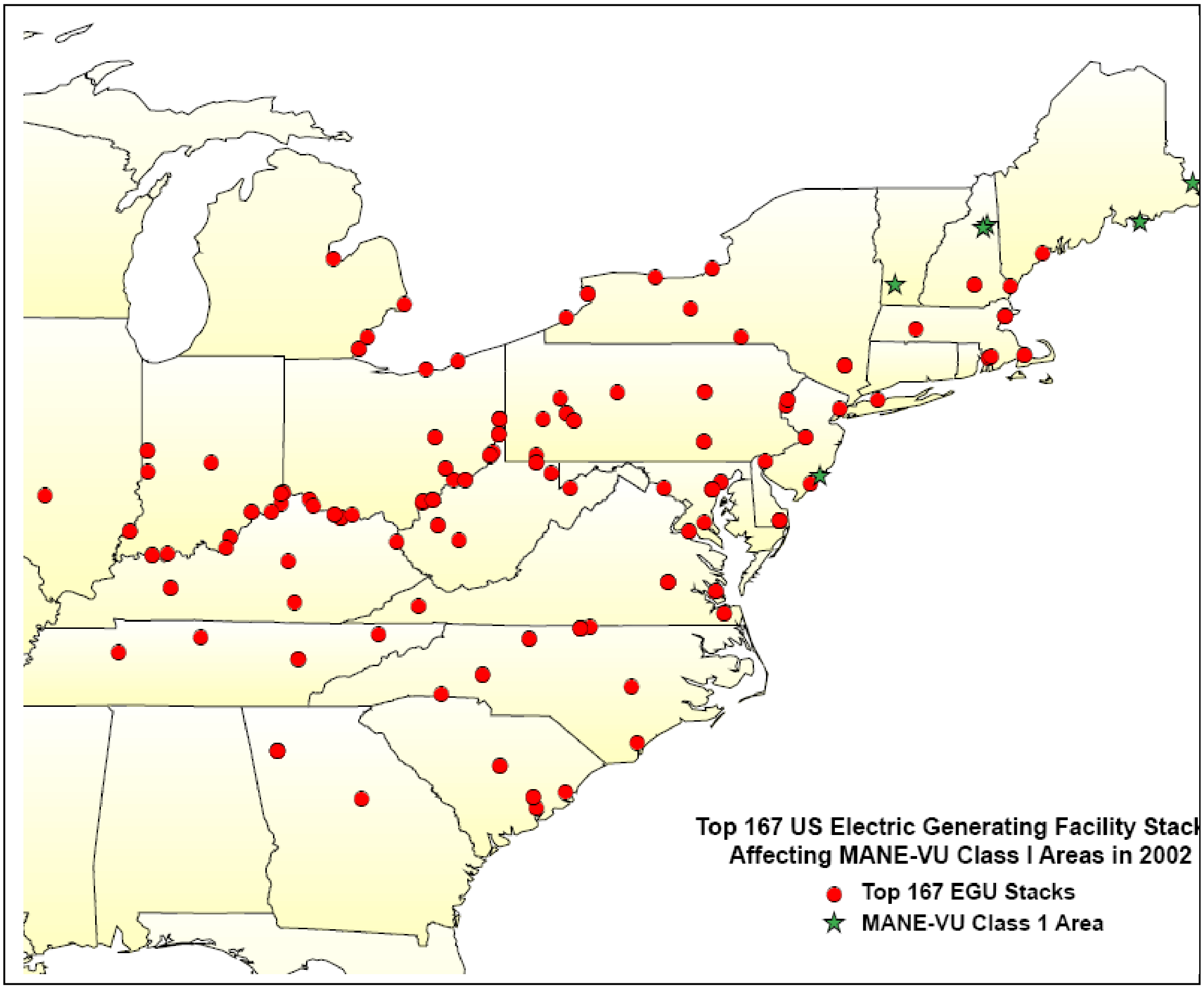

Table A-1. 2002 Data for Key EGU Stacks

Row number	CEMS Unit	ORIS ID	Acadia MM5	Acadia VTDEC	Brig MM5	Brig VTDEC	Lye MM5	Lye VTDEC	MM5 2002 S02 TPY	VTDEC 2002 SO2 TPY		Plant Name	Plant Type	State Name	State Code
1	D005935	593			90	54			2,138	2,136	1	EDGE MOOR	O/G Steam	Delaware	10
2	D005941	594				95				3,742	2	INDIAN RIVER	Coal Steam	Delaware	10
3	D005942	594				74				3,760	2	INDIAN RIVER	Coal Steam	Delaware	10
4	D005943	594			84	44			4,686	4,682	2	INDIAN RIVER	Coal Steam	Delaware	10
5	D005944	594			69	21			7,390	7,384	2	INDIAN RIVER	Coal Steam	Delaware	10
6	D007031LR	703	79			86		75	38,520	38,486	3	BOWEN	Coal Steam	Georgia	13
7	D007032LR	703	72		89		61	68	37,289	37,256	3	BOWEN	Coal Steam	Georgia	13
8	D007033LR	703	71	99	74	64	63	94	43,067	43,029	3	BOWEN	Coal Steam	Georgia	13
9	D007034LR	703	69	95	86	58	60	89	41,010	40,974	3	BOWEN	Coal Steam	Georgia	13
10	D00709C02	709		84		75	89	71	47,591	47,549	4	HARLLEE BRANCH	Coal Steam	Georgia	13
11	D00861C01	861	28	96		65	46	62	42,355	42,318	5	COFFEEN	Coal Steam	Illinois	17
12	D010011	1001			53				28,876	28,851	6	CAYUGA	Coal Steam	Indiana	18
13	D010012	1001	95		46	68			26,016	25,992	6	CAYUGA	Coal Steam	Indiana	18
14	D00983C01	983					52		19,922		7	CLIFTY CREEK	Coal Steam	Indiana	18
15	D00983C02	983					54		18,131		7	CLIFTY CREEK	Coal Steam	Indiana	18
16	D0099070	990		55	100	70		37	29,801	29,774	8	ELMER W STOUT	O/G Steam	Indiana	18
17	D06113C03	6113	30	48	14	43	22	41	71,182	71,119	9	GIBSON	Coal Steam	Indiana	18
18	D06113C04	6113	44	70	97	83	73	83	27,848	27,823	9	GIBSON	Coal Steam	Indiana	18
19	D01008C01	1008			73		100	47	24,109	24,087	10	R GALLAGHER	Coal Steam	Indiana	18
20	D01008C02	1008			98			55	23,849	23,828	10	R GALLAGHER	Coal Steam	Indiana	18
21	D06166C02	6166	62	44	30	81	33	57	51,708	51,663	11	ROCKPORT	Coal Steam	Indiana	18
22	D00988C03	988						77		15,946	12	TANNERS CREEK	Coal Steam	Indiana	18
23	D00988U4	988	14	29	52	34	7	19	45,062	45,022	12	TANNERS CREEK	Coal Steam	Indiana	18
24	D01010C05	1010	43	32	12	28	31	17	60,747	60,693	13	WABASH RIVER	Coal Steam	Indiana	18
25	D067054	6705	34	60	34		44	73	40,118	40,082	14	WARRICK	Coal Steam	Indiana	18
26	D06705C02	6705	92		75		96		27,895		14	WARRICK	Coal Steam	Indiana	18
27	D01353C02	1353	38	30	15	26	85	29	41,545	41,508	15	BIG SANDY	Coal Steam	Kentucky	21

Row number	CEMS Unit	ORIS ID	Acadia MM5	Acadia VTDEC	Brig MM5	Brig VTDEC	Lye MM5	Lye VTDEC	MM5 2002 S02 TPY	VTDEC 2002 SO2 TPY		Plant Name	Plant Type	State Name	State Code
28	D01384CS1	1384	22				58		21,837	21,817	16	COOPER	Coal Steam	Kentucky	21
29	D01355C03	1355	21		51	99	68	52	38,104	38,070	17	E W BROWN	Coal Steam	Kentucky	21
30	D060182	6018	83				39		12,083		18	EAST BEND	Coal Steam	Kentucky	21
31	D01356C02	1356	93	71		88	50	59	25,646	25,623	19	GHENT	Coal Steam	Kentucky	21
32	D060411	6041	61						18,375		20	H L SPURLOCK	Coal Steam	Kentucky	21
33	D060412	6041	53		91			98	20,491	20,473	20	H L SPURLOCK	Coal Steam	Kentucky	21
34	D013644	1364			81				7,185		21	MILL CREEK	Coal Steam	Kentucky	21
35	D013782	1378					87		20,245		22	PARADISE	Coal Steam	Kentucky	21
36	D013783	1378	76	100	11	84	55	42	46,701	46,660	22	PARADISE	Coal Steam	Kentucky	21
37	D015074	1507	78						1,170		23	WILLIAM F WYMAN	O/G Steam	Maine	23
38	D006021	602	90		38			100	20,014	19,996	24	BRANDON SHORES	Coal Steam	Maryland	24
39	D006022	602	99		29			99	19,280	19,263	24	BRANDON SHORES	Coal Steam	Maryland	24
40	D015521	1552			63				17,782	17,767	25	C P CRANE	Coal Steam	Maryland	24
41	D015522	1552			68				14,274	14,262	25	C P CRANE	Coal Steam	Maryland	24
42	D01571CE2	1571	42	47	1	4	20	28	48,566	48,522	26	CHALK POINT	Coal Steam	Maryland	24
43	D01572C23	1572	73	79	47	45	69	32	32,188	32,159	27	DICKERSON	Coal Steam	Maryland	24
44	D015543	1554			77				10,084	10,075	28	HERBERT A WAGNER	O/G Steam	Maryland	24
45	D015731	1573	67	50	16	12	56	38	36,823	36,790	29	MORGANTOWN	Coal Steam	Maryland	24
46	D015732	1573	59	53	10	13	51	39	30,788	30,761	29	MORGANTOWN	Coal Steam	Maryland	24
47	D016191	1619	37	80					9,252	9,244	30	BRAYTON POINT	Coal Steam	Massachusetts	25
48	D016192	1619	35	66					8,889	8,881	30	BRAYTON POINT	Coal Steam	Massachusetts	25
49	D016193	1619	4	14	65	56	79		19,325	19,308	30	BRAYTON POINT	Coal Steam	Massachusetts	25
50	D015991	1599	5	36			65		13,014	13,002	31	CANAL	O/G Steam	Massachusetts	25
51	D015992	1599	7	27			74		8,980	8,971	31	CANAL	O/G Steam	Massachusetts	25
52	D016061	1606						48		5,249	32	MOUNT TOM	Coal Steam	Massachusetts	25
53	D016261	1626	85						3,430		33	SALEM HARBOR	Coal Steam	Massachusetts	25
54	D016263	1626	91	78					4,971	4,966	33	SALEM HARBOR	Coal Steam	Massachusetts	25

Row number	CEMS Unit	ORIS ID	Acadia MM5	Acadia VTDEC	Brig MM5	Brig VTDEC	Lye MM5	Lye VTDEC	MM5 2002 S02 TPY	VTDEC 2002 SO2 TPY		Plant Name	Plant Type	State Name	State Code
55	D016264	1626	32	25					2,880	2,878	33	SALEM HARBOR	O/G Steam	Massachusetts	25
56	D016138	1613	94						4,376		34	SOMERSET	Coal Steam	Massachusetts	25
57	D01702C09	1702						96		4,565	35	DAN E KARN	Coal Steam	Michigan	26
58	D01733C12	1733	49	24	80	80	45	22	46,081	46,040	36	MONROE	Coal Steam	Michigan	26
59	D01733C34	1733	27	26		76	26	27	39,362	39,327	36	MONROE	Coal Steam	Michigan	26
60	D017437	1743		91						15,805	37	ST CLAIR	Coal Steam	Michigan	26
61	D017459A	1745					76	61	18,341	18,324	38	TRENTON CHANNEL	Coal Steam	Michigan	26
62	D023641	2364	2	57					9,356	9,348	39	MERRIMACK	Coal Steam	New Hampshire	33
63	D023642	2364	1	17	99		28	87	19,453	19,435	39	MERRIMACK	Coal Steam	New Hampshire	33
64	D080021	8002	45	74					5,033	5,028	40	NEWINGTON	O/G Steam	New Hampshire	33
65	D023781	2378		81	2	15			9,747	9,738	41	B L ENGLAND	Coal Steam	New Jersey	34
66	D024032	2403	63	97	25	50	40	44	18,785	18,768	42	HUDSON	O/G Steam	New Jersey	34
67	D024081	2408			95				8,076		43	MERCER	Coal Steam	New Jersey	34
68	D024082	2408			60				5,675		43	MERCER	Coal Steam	New Jersey	34
69	D02549C01	2549		64	41		42	72	25,343	25,320	44	C R HUNTLEY	Coal Steam	New York	36
70	D02549C02	2549					99		12,317		44	C R HUNTLEY	Coal Steam	New York	36
71	D024804	2480					71		7,720		45	DANSKAMMER	O/G Steam	New York	36
72	D02554C03	2554	33	51	62		27	51	30,151	30,125	46	DUNKIRK	Coal Steam	New York	36
73	D02526C03	2526					78		14,929		47	WESTOVER	Coal Steam	New York	36
74	D025276	2527					80		12,650		48	GREENIDGE	Coal Steam	New York	36
75	D025163	2516			96				7,359		49	NORTHPORT	O/G Steam	New York	36
76	D025945	2594		76						1,747	50	OSWEGO	O/G Steam	New York	36
77	D02642CS2	2642					91		14,086		51	ROCHESTER 7	Coal Steam	New York	36
78	D080061	8006						93		3,817	52	ROSETON	O/G Steam	New York	36
79	D080062	8006						88		2,840	52	ROSETON	O/G Steam	New York	36
80	D080421	8042	13	12	18	5	10	34	57,820	57,769	53	BELEWS CREEK	Coal Steam	North Carolina	37
81	D080422	8042	23	15	32	10	15	49	45,296	45,256	53	BELEWS CREEK	Coal Steam	North Carolina	37
82	D027215	2721	98	45	87	39	97	85	19,145	19,128	54	CLIFFSIDE	Coal Steam	North Carolina	37
83	D027133	2713		61						14,460	55	L V SUTTON	Coal Steam	North Carolina	37

Row number	CEMS Unit	ORIS ID	Acadia MM5	Acadia VTDEC	Brig MM5	Brig VTDEC	Lye MM5	Lye VTDEC	MM5 2002 S02 TPY	VTDEC 2002 SO2 TPY		Plant Name	Plant Type	State Name	State Code
84	D027093	2709				97				9,390	56	LEE	Coal Steam	North Carolina	37
85	D027273	2727	100	40		48	75	84	26,329	26,305	57	MARSHALL	Coal Steam	North Carolina	37
86	D027274	2727	89	39	83	51	66	82	27,308	27,284	57	MARSHALL	Coal Steam	North Carolina	37
87	D06250C05	6250	60	59		35	37		27,395	27,371	58	MAYO	Coal Steam	North Carolina	37
88	D027121	2712				59			12,031	12,020	59	ROXBORO	Coal Steam	North Carolina	37
89	D027122	2712	82	41	54	23	94		29,337	29,310	59	ROXBORO	Coal Steam	North Carolina	37
90	D02712C03	2712	56	37	57	24	21	78	30,776	30,749	59	ROXBORO	Coal Steam	North Carolina	37
91	D02712C04	2712	88	72		47	47		22,962	22,941	59	ROXBORO	Coal Steam	North Carolina	37
92	D0283612	2836	55	20	48	89	29	35	41,432	41,395	60	AVON LAKE	Coal Steam	Ohio	39
93	D028281	2828	29	9	31	30	24	8	37,307	37,274	61	CARDINAL	Coal Steam	Ohio	39
94	D028282	2828						56	20,598	20,580	61	CARDINAL	Coal Steam	Ohio	39
95	D028283	2828						80		15,372	61	CARDINAL	Coal Steam	Ohio	39
96	D028404	2840	3	1	6	2	2	3	87,801	87,724	62	CONESVILLE	Coal Steam	Ohio	39
97	D02840C02	2840	84	73			81	63	22,791	22,771	62	CONESVILLE	Coal Steam	Ohio	39
98	D028375	2837		86	56		35	70	35,970	35,938	63	EASTLAKE	Coal Steam	Ohio	39
99	D081021	8102			23	71	59	95	18,207	18,191	64	GEN J M GAVIN	Coal Steam	Ohio	39
100	D081022	8102				78			12,333	12,322	64	GEN J M GAVIN	Coal Steam	Ohio	39
101	D028501	2850	36	67	39	53		45	30,798	30,771	65	J M STUART	Coal Steam	Ohio	39
102	D028502	2850	24	65	40	49	98	46	28,698	28,673	65	J M STUART	Coal Steam	Ohio	39
103	D028503	2850	26		72	62			27,968	27,944	65	J M STUART	Coal Steam	Ohio	39
104	D028504	2850	20	77	45	52	88	54	27,343	27,319	65	J M STUART	Coal Steam	Ohio	39
105	D060312	6031			67	77		90	19,517	19,500	66	KILLEN STATION	Coal Steam	Ohio	39
106	D02876C01	2876	40	7	3	9	30	10	72,593	72,529	67	KYGER CREEK	Coal Steam	Ohio	39
107	D028327	2832	65	28	59	22	48	20	46,991	46,950	68	MIAMI FORT	Coal Steam	Ohio	39
108	D02832C06	2832				60	43	64	23,694	23,673	68	MIAMI FORT	Coal Steam	Ohio	39
109	D028725	2872	74	92	78		90	36	30,079	30,052	69	MUSKINGUM RIVER	Coal Steam	Ohio	39
110	D02872C04	2872	6	19	13	6	19	15	83,134	83,060	69	MUSKINGUM RIVER	Coal Steam	Ohio	39
111	D02864C01	2864	70	56	61	63	49	24	35,193	35,162	70	R E BURGER	Coal Steam	Ohio	39

Row number	CEMS Unit	ORIS ID	Acadia MM5	Acadia VTDEC	Brig MM5	Brig VTDEC	Lye MM5	Lye VTDEC	MM5 2002 S02 TPY	VTDEC 2002 SO2 TPY		Plant Name	Plant Type	State Name	State Code
112	D07253C01	7253		89	58	57		33	30,977	30,949	71	RICHARD GORSUCH		Ohio	39
113	D028665	2866		82				53	19,796	19,779	72	W H SAMMIS	Coal Steam	Ohio	39
114	D028667	2866	57	16	42	41	41	16	33,601	33,572	72	W H SAMMIS	Coal Steam	Ohio	39
115	D02866C01	2866	97	54	93	96	92	30	24,649	24,627	72	W H SAMMIS	Coal Steam	Ohio	39
116	D02866C02	2866		69	92			50	26,022	25,999	72	W H SAMMIS	Coal Steam	Ohio	39
117	D02866M6A	2866		85				58	19,564	19,546	72	W H SAMMIS	Coal Steam	Ohio	39
118	D060191	6019		93		72		60		21,496	73	W H ZIMMER	Coal Steam	Ohio	39
119	D028306	2830	46	38	70	40	12	69	30,466	30,439	74	WALTER C BECKJORD	Coal Steam	Ohio	39
120	D031782	3178	77	63				81	16,484	16,469	75	ARMSTRONG	Coal Steam	Pennsylvania	42
121	D031403	3140	31	34	9	46	18	18	38,801	38,767	76	BRUNNER ISLAND	Coal Steam	Pennsylvania	42
122	D03140C12	3140	52	46	49	69	25	23	29,736	29,709	76	BRUNNER ISLAND	Coal Steam	Pennsylvania	42
123	D082261	8226	25	21	33	42	36	9	40,268	40,232	77	CHESWICK	Coal Steam	Pennsylvania	42
124	D03179C01	3179	16	10	5	8	5	4	79,635	79,565	78	HATFIELD'S FERRY	Coal Steam	Pennsylvania	42
125	D031221	3122	11	6	26	38	17	14	45,754	45,714	79	HOMER CITY	Coal Steam	Pennsylvania	42
126	D031222	3122	9	4	37	92	13	11	55,216	55,167	79	HOMER CITY	Coal Steam	Pennsylvania	42
127	D031361	3136	8	2	4	14	6	1	87,434	87,357	80	KEYSTONE	Coal Steam	Pennsylvania	42
128	D031362	3136	18	3	8	19	8	2	62,847	62,791	80	KEYSTONE	Coal Steam	Pennsylvania	42
129	D03148C12	3148			71		84		17,214		81	MARTINS CREEK	Coal Steam	Pennsylvania	42
130	D031491	3149	19	8	35	7	1	6	60,242	60,188	82	MONTOUR	Coal Steam	Pennsylvania	42
131	D031492	3149	15	5	21	20	3	5	50,276	50,232	82	MONTOUR	Coal Steam	Pennsylvania	42
132	D031131	3113			82				9,674		83	PORTLAND	Coal Steam	Pennsylvania	42
133	D031132	3113			36		93		14,294		83	PORTLAND	Coal Steam	Pennsylvania	42
134	D03131CS1	3131	54	31	79		32	65	22,344	22,324	84	SHAWVILLE	Coal Steam	Pennsylvania	42
135	D033193	3319				100				11,045	85	JEFFERIES	O/G Steam	South Carolina	45
136	D033194	3319		90		87				11,838	85	JEFFERIES	O/G Steam	South Carolina	45
137	D03297WT1	3297		68		61				17,671	86	WATEREE	Coal Steam	South Carolina	45
138	D03297WT2	3297		83		73				17,199	86	WATEREE	Coal Steam	South Carolina	45
139	D03298WL1	3298		35	94	37			25,170	25,148	87	WILLIAMS	Coal Steam	South Carolina	45

Row number	CEMS Unit	ORIS ID	Acadia MM5	Acadia VTDEC	Brig MM5	Brig VTDEC	Lye MM5	Lye VTDEC	MM5 2002 S02 TPY	VTDEC 2002 SO2 TPY		Plant Name	Plant Type	State Name	State Code
140	D062491	6249		58		82				17,920	88	WINYAH	Coal Steam	South Carolina	45
141	D03403C34	3403			85				20,314		89	GALLATIN	Coal Steam	Tennessee	47
142	D03405C34	3405	39						19,368		90	JOHN SEVIER	Coal Steam	Tennessee	47
143	D03406C10	3406	10	11	27	33	4	43	104,523	104,431	91	JOHNSONVILLE	Coal Steam	Tennessee	47
144	D03407C15	3407	64	87		66	67	76	37,308	37,274	92	KINGSTON	Coal Steam	Tennessee	47
145	D03407C69	3407	48	98		91	82	91	38,645	38,611	92	KINGSTON	Coal Steam	Tennessee	47
146	D038033	3803				55				9,493	93	CHESAPEAKE	Coal Steam	Virginia	51
147	D038034	3803		94		16				10,806	93	CHESAPEAKE	Coal Steam	Virginia	51
148	D037974	3797				90				9,293	94	CHESTERFIELD	Coal Steam	Virginia	51
149	D037975	3797		88	44	27	86		19,620	19,602	94	CHESTERFIELD	Coal Steam	Virginia	51
150	D037976	3797	66	18	7	3	34	66	40,570	40,534	94	CHESTERFIELD	Coal Steam	Virginia	51
151	D03775C02	3775	47						16,674		95	CLINCH RIVER	Coal Steam	Virginia	51
152	D038093	3809		52	64	29			10,477	10,468	96	YORKTOWN	Coal Steam	Virginia	51
153	D03809CS0	3809	96	43	19	17	62		21,219	21,201	96	YORKTOWN	Coal Steam	Virginia	51
154	D039423	3942						79		10,126	97	ALBRIGHT	Coal Steam	West Virginia	54
155	D039431	3943	51	23	20	32	16	13	42,385	42,348	97	FORT MARTIN	Coal Steam	West Virginia	54
156	D039432	3943	50	22	22	31	14	12	45,850	45,809	97	FORT MARTIN	Coal Steam	West Virginia	54
157	D039353	3935	41	33	28	11	64	26	42,212	42,174	98	JOHN E AMOS	Coal Steam	West Virginia	54
158	D03935C02	3935	17	42	43	1	11	21	63,066	63,010	98	JOHN E AMOS	Coal Steam	West Virginia	54
159	D03947C03	3947	86	62	55		57	25	38,575	38,541	99	KAMMER	Coal Steam	West Virginia	54
160	D03936C02	3936				98			15,480	15,467	100	KANAWHA RIVER	Coal Steam	West Virginia	54
161	D03948C02	3948	58	13	17	36	9	7	55,405	55,356	101	MITCHELL	Coal Steam	West Virginia	54
162	D062641	6264	75	49	50	18	77	40	42,757	42,719	102	MOUNTAINEER	Coal Steam	West Virginia	54
163	D03954CS0	3954	68		24	25	23	67	20,130	20,112	103	MT STORM	Coal Steam	West Virginia	54
164	D0393851	3938				79		97	12,948	12,936	104	PHILIP SPORN	Coal Steam	West Virginia	54
165	D03938C04	3938				94			26,451	26,427	104	PHILIP SPORN	Coal Steam	West Virginia	54
166	D060041	6004			66		83	31	21,581	21,562	105	PLEASANTS	Coal Steam	West Virginia	54
167	D060042	6004			88			92	20,550	20,532	105	PLEASANTS	Coal Steam	West Virginia	54

Table A-2. Predicted 2018 SO_2 Emissions from Key EGU Stacks

State	Facility Name	ORIS ID	Unit ID	Unit Type	ORIGINAL 2018 (1) SO_2 TPY	REVISED 2018 (2) SO_2 TPY	BASIS FOR CHANGE (3)
Delaware	Edge Moor	593	5	O/G Steam	0.0	1,406.0	State Comments
Delaware	Indian River	594	1	Coal Steam	4,289.2	0.0	State Comments
Delaware	Indian River	594	2	Coal Steam	4,538.9	0.0	State Comments
Delaware	Indian River	594	3	Coal Steam	764.1	1,759.0	State Comments
Delware	Indian River	594	4	Coal Steam	19,665.8	3,657.0	State Comments
Georgia	Bowen	703	1 BLR	Coal Steam	4,830.8	2,909.7	VISTAS_2018G2
Georgia	Bowen	703	2 BLR	Coal Steam	4,864.7	2,930.1	VISTAS_2018G2
Georgia	Bowen	703	3 BLR	Coal Steam	6,111.3	3,681.0	VISTAS_2018G2
Georgia	Bowen	703	4 BLR	Coal Steam	6,294.3	3,791.1	VISTAS_2018G2
Georgia	Harllee Branch	709	3	Coal Steam	1,158.1	1,395.1	VISTAS_2018G2
Georgia	Harllee Branch	709	4	Coal Steam	1,132.6	1,364.4	VISTAS_2018G2
Illinois	Coffeen	861	01	Coal Steam	3,314.6	4,761.8	IPM 3.0
Illinois	Coffeen	861	02	Coal Steam	5,444.3	7,365.8	IPM 3.0
Illinois	Alcoa Allowance Management Inc (WARRICK)	6705	1	Coal Steam	0.0	10,013.5	IPM 3.0

State	Facility Name	ORIS ID	Unit ID	Unit Type	ORIGINAL 2018 (1) SO_2 TPY	REVISED 2018 (2) SO_2 TPY	BASIS FOR CHANGE (3)
Illinois	Alcoa Allowance Management Inc (WARRICK)	6705	2	Coal Steam	**0.0**	**9,604.4**	**IPM 3.0**
Illinois	Alcoa Allowance Management Inc (WARRICK)	6705	4	Coal Steam	**628.1**	**4,091.5**	**IPM 3.0**
Indiana	Cayuga	1001	1	Coal Steam	**4,660.7**	**6,298.8**	**IPM 3.0**
Indiana	Cayuga	1001	2	Coal Steam	**4,501.3**	**6,405.7**	**IPM 3.0**
Indiana	Clifty Creek	983	1	Coal Steam	**944.3**	**2,594.3**	**IPM 3.0**
Indiana	Clifty Creek	983	2	Coal Steam	**7,682.7**	**2,528.4**	**IPM 3.0**
Indiana	Clifty Creek	983	3	Coal Steam	**7,636.7**	**2,513.2**	**IPM 3.0**
Indiana	Clifty Creek	983	4	Coal Steam	**7,604.8**	**2,502.7**	**IPM 3.0**
Indiana	Clifty Creek	983	5	Coal Steam	**7,440.8**	**2,448.8**	**IPM 3.0**
Indiana	Clifty Creek	983	6	Coal Steam	**903.4**	**2,889.3**	**IPM 3.0**
Indiana	Gibson	6113	1	Coal Steam	**5,640.1**	**7,994.7**	**IPM 3.0**
Indiana	Gibson	6113	2	Coal Steam	**5,735.6**	**8,039.2**	**IPM 3.0**
Indiana	Gibson	6113	3	Coal Steam	**5,784.9**	**7,875.5**	**IPM 3.0**
Indiana	Gibson	6113	4	Coal Steam	**8,032.4**	**13,116.6**	**IPM 3.0**

State	Facility Name	ORIS ID	Unit ID	Unit Type	ORIGINAL 2018 (1) SO_2 TPY	REVISED 2018 (2) SO_2 TPY	BASIS FOR CHANGE (3)
Indiana	Harding Street Station (EW Stout)	990	70	Coal Steam	**1,845.9**	**5,476.9**	**IPM 3.0**
Indiana	R Gallagher	1008	1	Coal Steam	**5,383.2**	**3,571.1**	**IPM 3.0**
Indiana	R Gallagher	1008	2	Coal Steam	**5,284.7**	**3,505.7**	**IPM 3.0**
Indiana	R Gallagher	1008	3	Coal Steam	**5,309.2**	**3,522.0**	**IPM 3.0**
Indiana	R Gallagher	1008	4	Coal Steam	**5,383.2**	**3,571.1**	**IPM 3.0**
Indiana	**Rockport**	6166	MB1	Coal Steam	**32,349.8**	**15,531.2**	**IPM 3.0**
Indiana	**Rockport**	6166	MB2	Coal Steam	**32,660.4**	**15,680.3**	**IPM 3.0**
Indiana	**Tanners Creek**	988	U1	Coal Steam	**5,222.0**	**6,756.8**	**IPM 3.0**
Indiana	**Tanners Creek**	988	U2	Coal Steam	**3,770.1**	**6,562.1**	**IPM 3.0**
Indiana	**Tanners Creek**	988	U3	Coal Steam	**5,289.8**	**9,211.3**	**IPM 3.0**
Indiana	**Tanners Creek**	988	U4	Coal Steam	**4,507.6**	**12,433.5**	**Mark Janssen IPM 3.0**
Indiana	Wabash River	1010	2	Coal Steam	**3,037.1**	**5,827.8**	**Mark Janssen IPM 3.0**
Indiana	Wabash River	1010	3	Coal Steam	**3,071.1**	**5,397.1**	**Mark Janssen IPM 3.0**
Indiana	Wabash River	1010	4	Coal Steam	**3,071.1**	**5,640.3**	**Mark Janssen IPM 3.0**
Indiana	Wabash River	1010	5	Coal Steam	**3,528.1**	**5,954.8**	**Mark Janssen IPM 3.0**

State	Facility Name	ORIS ID	Unit ID	Unit Type	ORIGINAL 2018 (1) SO_2 TPY	REVISED 2018 (2) SO_2 TPY	BASIS FOR CHANGE (3)
Indiana	Wabash River	1010	6	Coal Steam	3,039.6	4,192.7	**Mark Janssen IPM 3.0**
Kentucky	**Big Sandy**	1353	BSU 1	Coal Steam	675.7	814.0	VISTAS_2018G2
Kentucky	**Big Sandy**	1353	BSU 2	Coal Steam	4,203.4	5,063.5	VISTAS_2018G2
Kentucky	Cooper	1384	1	Coal Steam	4,400.5	5,301.0	VISTAS_2018G2
Kentucky	Cooper	1384	2	Coal Steam	596.5	718.6	VISTAS_2018G2
Kentucky	E W Brown	1355	2	Coal Steam	748.0	901.1	VISTAS_2018G2
Kentucky	E W Brown	1355	3	Coal Steam	1,767.0	2,128.6	VISTAS_2018G2
Kentucky	East Bend	6018	2	Coal Steam	2,221.6	2,676.2	VISTAS_2018G2
Kentucky	Ghent	1356	3	Coal Steam	5,104.1	6,148.5	VISTAS_2018G2
Kentucky	Ghent	1356	4	Coal Steam	4,976.7	5,995.1	VISTAS_2018G2
Kentucky	H L Spurlock	6041	1	Coal Steam	767.6	924.7	VISTAS_2018G2
Kentucky	H L Spurlock	6041	2	Coal Steam	4,871.5	5,868.4	VISTAS_2018G2
Kentucky	Mill Creek	1364	4	Coal Steam	12,822.6	15,446.5	VISTAS_2018G2
Kentucky	Paradise	1378	2	Coal Steam	7,940.5	9,565.4	VISTAS_2018G2
Kentucky	Paradise	1378	3	Coal Steam	22,538.5	27,150.6	VISTAS_2018G2

State	Facility Name	ORIS ID	Unit ID	Unit Type	ORIGINAL 2018 (1) SO_2 TPY	REVISED 2018 (2) SO_2 TPY	BASIS FOR CHANGE (3)
Maine	William F Wyman	1507	4	O/G Steam	**0.0**	**1162.5**	**manevu_2002v3**
Maryland	Brandon Shores	602	1	Coal Steam	**3,799.8**	**5,392.0**	**State Comments**
Maryland	Brandon Shores	602	2	Coal Steam	**3,673.3**	**5,627.0**	**State Comments**
Maryland	C P Crane	1552	1	Coal Steam	**900.0**	**1,532.0**	**State Comments**
Maryland	C P Crane	1552	2	Coal Steam	**875.2**	**1,646.0**	**State Comments**
Maryland	Chalk Point	1571	1	Coal Steam	**1,506.2**	**2,606.0**	**State Comments**
Maryland	Chalk Point	1571	2	Coal Steam	**1,510.5**	**2,733.0**	**State Comments**
Maryland	Dickerson	1572	1	Coal Steam	**797.4**	**1,238.0**	**State Comments**
Maryland	Dickerson	1572	2	Coal Steam	**867.2**	**1,355.0**	**State Comments**
Maryland	Dickerson	1572	3	Coal Steam	**768.7**	**1,285.0**	**State Comments**
Maryland	Herbert A Wagner	1554	3	**Coal Steam**	**1,551.1**	**1,239.0**	**State Comments**
Maryland	Morgantown	1573	1	Coal Steam	**3,037.1**	**4,646.0**	**State Comments**
Maryland	Morgantown	1573	2	Coal Steam	**2,987.2**	**4,679.0**	**State Comments**
Massachusetts	Brayton Point	1619	1	Coal Steam	**1,924.7**	**925.2**	**State Comments**
Massachusetts	Brayton Point	1619	2	Coal Steam	**1,875.6**	**888.9**	**State Comments**

State	Facility Name	ORIS ID	Unit ID	Unit Type	ORIGINAL 2018 (1) SO_2 TPY	REVISED 2018 (2) SO_2 TPY	BASIS FOR CHANGE (3)
Massachusetts	Brayton Point	1619	3	Coal Steam	4,775.0	4,775.0	State Comments
Massachusetts	Canal	1599	1	O/G Steam	0.0	13066.0	manevu_2002v3
Massachusetts	Canal	1599	2	O/G Steam	0.0	8948.3	manevu_2002v3
Massachusetts	Mount Tom	1606	1	Coal Steam	242.6	242.6	State Comments
Massachusetts	Salem Harbor	1626	1	Coal Steam	3,421.5	3,421.5	IPM 2.1.9
Massachusetts	Salem Harbor	1626	3	Coal Steam	405.2	405.2	IPM 2.1.9
Massachusetts	Salem Harbor	1626	4	O/G Steam	0.0	2,897.0	manevu_2002v3
Massachusetts	Somerset	1613	8	Coal Steam	2,372.8	2,372.8	IPM 2.1.9
Michigan	Dan E Karn	1702	3	O/G Steam ?	0.0	3,358.5	2002 CEMS data
Michigan	Dan E Karn	1702	4	O/G Steam ?	0.0	2,169.2	2002 CEMS data
Michigan	Monroe	1733	1	Coal Steam	27,485.9	19,089.8	Mark Janssen IPM 3.0
Michigan	Monroe	1733	2	Coal Steam	27,806.6	19,530.4	Mark Janssen IPM 3.0
Michigan	Monroe	1733	3	Coal Steam	28,043.9	2,035.8	Mark Janssen IPM 3.0
Michigan	Monroe	1733	4	Coal Steam	30,584.3	1,987.6	Mark Janssen IPM 3.0

State	Facility Name	ORIS ID	Unit ID	Unit Type	ORIGINAL 2018 (1) SO_2 TPY	REVISED 2018 (2) SO_2 TPY	BASIS FOR CHANGE (3)
Michigan	St. Clair	1743	7	Coal Steam	17,052.2	11,925.8	Mark Janssen IPM 3.0
Michigan	Trenton Channel	1745	9A	Coal Steam	17,832.6	13,868.9	Mark Janssen IPM 3.0
New Hampshire	Merrimack	2364	1	Coal Steam	1,894.6	1,894.6	State Comments
New Hampshire	Merrimack	2364	2	Coal Steam	1,091.1	1,091.1	State Comments
New Hampshire	Newington	8002	1	O/G Steam	0.0	3,297.0	State Comments
New Jersey	B L England	2378	1	Coal Steam	5,201.3	520.1	State Comments
New Jersey	Hudson	2403	2	Coal Steam	10,958.4	1,095.8	State Comments
New Jersey	Mercer	2408	1	Coal Steam	1,921.0	1,921.0	State Comments
New Jersey	Mercer	2408	2	Coal Steam	1,921.0	1,921.0	State Comments
New York	C R Huntley	2549	63	Coal Steam	0.0	0.0	NOT-IN_ manevu_2002v3
New York	C R Huntley	2549	64	Coal Steam	3,602.1	0.0	IPM 2.1.9
New York	C R Huntley	2549	65	Coal Steam	0.0	0.0	NOT-IN_ manevu_2002v3
New York	C R Huntley	2549	66	Coal Steam	0.0	7,085.0	manevu_2002v3
New York	C R Huntley	2549	67	Coal Steam	633.0	0.0	State Comments
New York	C R Huntley	2549	68	Coal Steam	633.5	0.0	State Comments

State	Facility Name	ORIS ID	Unit ID	Unit Type	ORIGINAL 2018 (1) SO_2 TPY	REVISED 2018 (2) SO_2 TPY	BASIS FOR CHANGE (3)
New York	Danskammer	2480	4	Coal Steam	763.5	763.5	State Comments
New York	Dunkirk	2554	3	Coal Steam	667.4	0.0	State Comments
New York	Dunkirk	2554	4	Coal Steam	647.4	7,085.0	State Comments
New York	Goudey	2526	11	Coal Steam	1,921.1	1,921.1	State Comments
New York	Goudey	2526	12	Coal Steam	1,921.1	1,921.1	State Comments
New York	Goudey	2526	13	Coal Steam	3,856.1	3,856.1	IPM 2.1.9
New York	Greenidge	2527	6	Coal Steam	390.1	605.0	State Comments
New York	Northport	2516	3	O/G Steam	0.0	7,359.0	2002 CEMS data
New York	Oswego	2594	5	O/G Steam	0.0	1,747.0	**2002 VTDEC data**
New York	Rochester 7	2642	3	Coal Steam	2,800.4	0.0	State Comments
New York	Rochester 7	2642	4	Coal Steam	3,231.3	200.0	State Comments
New York	Roseton	8006	1	O/G Steam	0.0	3,817.0	**2002 VTDEC data**
New York	Roseton	8006	2	O/G Steam	0.0	2,840.0	**2002 VTDEC data**
North Carolina	Belews Creek	8042	1	Coal Steam	2,535.5	3,054.3	VISTAS_2018G2
North Carolina	Belews Creek	8042	2	Coal Steam	3,217.5	3,875.9	VISTAS_2018G2

State	Facility Name	ORIS ID	Unit ID	Unit Type	ORIGINAL 2018 (1) SO_2 TPY	REVISED 2018 (2) SO_2 TPY	BASIS FOR CHANGE (3)
North Carolina	Cliffside	2721	5	Coal Steam	**1,951.7**	**2,351.1**	**VISTAS_2018G2**
North Carolina	L V Sutton	2713	3	Coal Steam	**1,036.5**	**1,248.6**	**VISTAS_2018G2**
North Carolina	Lee	2709	3	Coal Steam	**697.6**	**8,403.5**	**VISTAS_2018G2**
North Carolina	Marshall	2727	3	Coal Steam	**2,242.9**	**2,701.9**	**VISTAS_2018G2**
North Carolina	Marshall	2727	4	Coal Steam	**2,207.8**	**2,659.6**	**VISTAS_2018G2**
North Carolina	Mayo	6250	1A	Coal Steam	**953.9**	**1,149.1**	**VISTAS_2018G2**
North Carolina	Mayo	6250	1B	Coal Steam	**953.4**	**1,148.5**	**VISTAS_2018G2**
North Carolina	Roxboro	2712	1	Coal Steam	**998.7**	**1,203.1**	**VISTAS_2018G2**
North Carolina	Roxboro	2712	2	Coal Steam	**2,438.0**	**2,936.9**	**VISTAS_2018G2**
North Carolina	Roxboro	2712	3A	Coal Steam	**1,071.1**	**1,290.3**	**VISTAS_2018G2**
North Carolina	Roxboro	2712	3B	Coal Steam	**1,071.1**	**1,290.3**	**VISTAS_2018G2**
North Carolina	Roxboro	2712	4A	Coal Steam	**1,253.0**	**1,509.4**	**VISTAS_2018G2**
North Carolina	Roxboro	2712	4B	Coal Steam	**1,253.0**	**1,509.4**	**VISTAS_2018G2**
Ohio	Avon Lake	2836	12	Coal Steam	**5,809.5**	**3,201.9**	**Mark Janssen IPM 3.0**
Ohio	**Cardinal**	2828	1	Coal Steam	**2,417.1**	**6,964.7**	**Mark Janssen IPM 3.0**

State	Facility Name	ORIS ID	Unit ID	Unit Type	ORIGINAL 2018 (1) SO_2 TPY	REVISED 2018 (2) SO_2 TPY	BASIS FOR CHANGE (3)
Ohio	**Cardinal**	2828	2	Coal Steam	**5,320.9**	**7,356.2**	**Mark Janssen IPM 3.0**
Ohio	**Cardinal**	2828	3	Coal Steam	**5,366.8**	**8,505.4**	**Mark Janssen IPM 3.0**
Ohio	**Conesville**	2840	1	Coal Steam	**582.1**	**701.2**	**IPM 2.1.9**
Ohio	**Conesville**	2840	2	Coal Steam	**592.8**	**714.1**	**IPM 2.1.9**
Ohio	**Conesville**	2840	4	Coal Steam	**7,333.9**	**6,616.6**	**Mark Janssen IPM 3.0**
Ohio	Eastlake	2837	5	Coal Steam	**5,113.7**	**13,883.0**	**Mark Janssen IPM 3.0**
Ohio	**Gen J M Gavin**	8102	1	Coal Steam	**6,479.2**	**8,584.7**	**Mark Janssen IPM 3.0**
Ohio	**Gen J M Gavin**	8102	2	Coal Steam	**6,464.9**	**8,565.7**	**Mark Janssen IPM 3.0**
Ohio	J M Stuart	2850	1	Coal Steam	**4,810.1**	**5,629.2**	**Mark Janssen IPM 3.0**
Ohio	J M Stuart	2850	2	Coal Steam	**4,718.1**	**5,497.4**	**Mark Janssen IPM 3.0**
Ohio	J M Stuart	2850	3	Coal Steam	**4,815.9**	**5,615.2**	**Mark Janssen IPM 3.0**
Ohio	J M Stuart	2850	4	Coal Steam	**4,828.2**	**5,637.7**	**Mark Janssen IPM 3.0**
Ohio	Killen Station	6031	2	Coal Steam	**4,879.0**	**5,823.1**	**Mark Janssen IPM 3.0**
Ohio	Kyger Creek	2876	1	Coal Steam	**942.9**	**1,521.3**	**Mark Janssen IPM 3.0**
Ohio	Kyger Creek	2876	2	Coal Steam	**953.8**	**1,539.0**	**Mark Janssen IPM 3.0**

State	Facility Name	ORIS ID	Unit ID	Unit Type	ORIGINAL 2018 (1) SO_2 TPY	REVISED 2018 (2) SO_2 TPY	BASIS FOR CHANGE (3)
Ohio	Kyger Creek	2876	3	Coal Steam	954.8	1,540.6	**Mark Janssen IPM 3.0**
Ohio	Kyger Creek	2876	4	Coal Steam	964.0	1,555.4	**Mark Janssen IPM 3.0**
Ohio	Kyger Creek	2876	5	Coal Steam	951.0	1,534.5	**Mark Janssen IPM 3.0**
Ohio	Miami Fort	2832	5-1	Coal Steam	1,502.5	1,035.5	**Mark Janssen IPM 3.0**
Ohio	Miami Fort	2832	5-2	Coal Steam	1,502.5	1,035.5	**Mark Janssen IPM 3.0**
Ohio	Miami Fort	2832	6	Coal Steam	6,285.1	3,790.2	**Mark Janssen IPM 3.0**
Ohio	Miami Fort	2832	7	Coal Steam	2,209.2	4,771.7	**Mark Janssen IPM 3.0**
Ohio	**Muskingum River**	2872	1	Coal Steam	883.8	7,366.3	**Mark Janssen IPM 3.0**
Ohio	**Muskingum River**	2872	2	Coal Steam	865.4	7,213.6	**Mark Janssen IPM 3.0**
Ohio	**Muskingum River**	2872	3	Coal Steam	913.4	9,149.2	**Mark Janssen IPM 3.0**
Ohio	**Muskingum River**	2872	4	Coal Steam	848.0	8,494.4	**Mark Janssen IPM 3.0**
Ohio	**Muskingum River**	2872	5	Coal Steam	5,033.7	5,430.2	**Mark Janssen IPM 3.0**
Ohio	R E Burger	2864	1	Coal Steam	0.0	0.0	**2002 CEMS data**
Ohio	R E Burger	2864	2	Coal Steam	0.0	0.0	**2002 CEMS data**
Ohio	R E Burger	2864	3	Coal Steam	0.0	0.0	**2002 CEMS data**

State	Facility Name	ORIS ID	Unit ID	Unit Type	ORIGINAL 2018 (1) SO_2 TPY	REVISED 2018 (2) SO_2 TPY	BASIS FOR CHANGE (3)
Ohio	R E Burger	2864	4	Coal Steam	**0.0**	**0.0**	**2002 CEMS data**
Ohio	R E Burger	2864	5	Coal Steam	**462.2**	**2,096.3**	**Mark Janssen IPM 3.0**
Ohio	R E Burger	2864	6	Coal Steam	**1,491.5**	**2,096.3**	**Mark Janssen IPM 3.0**
Ohio	R E Burger	2864	7	Coal Steam	**1,317.7**	**1,528.3**	**Mark Janssen IPM 3.0**
Ohio	R E Burger	2864	8	Coal Steam	**790.3**	**1,615.6**	**Mark Janssen IPM 3.0**
Ohio	Richard Gorsuch	7253	1	Coal Steam	**1,806.3**	**6,938.7**	**IPM 3.0**
Ohio	Richard Gorsuch	7253	2	Coal Steam	**1,436.9**	**8,117.3**	**IPM 3.0**
Ohio	Richard Gorsuch	7253	3	Coal Steam	**1,440.9**	**6,867.5**	**IPM 3.0**
Ohio	Richard Gorsuch	7253	4	Coal Steam	**1,801.4**	**6,520.9**	**IPM 3.0**
Ohio	W H Sammis	2866	1	Coal Steam	**836.0**	**4,510.1**	**Mark Janssen IPM 3.0**
Ohio	W H Sammis	2866	2	Coal Steam	**841.5**	**4,557.2**	**Mark Janssen IPM 3.0**
Ohio	W H Sammis	2866	3	Coal Steam	**862.5**	**4,713.0**	**Mark Janssen IPM 3.0**
Ohio	W H Sammis	2866	4	Coal Steam	**828.6**	**4,417.3**	**Mark Janssen IPM 3.0**
Ohio	W H Sammis	2866	5	Coal Steam	**1,357.2**	**7,004.0**	**Mark Janssen IPM 3.0**
Ohio	W H Sammis	2866	6A	Coal Steam	**3,544.3**	**3,217.1**	**Mark Janssen IPM 3.0**

State	Facility Name	ORIS ID	Unit ID	Unit Type	ORIGINAL 2018 (1) SO_2 TPY	REVISED 2018 (2) SO_2 TPY	BASIS FOR CHANGE (3)
Ohio	W H Sammis	2866	7	Coal Steam	**3,446.4**	**3,245.3**	**Mark Janssen IPM 3.0**
Ohio	Walter C Beckjord	2830	6	Coal Steam	**1,790.1**	**9,715.7**	**Mark Janssen IPM 3.0**
Ohio	W H Zimmer	6019	1	Coal Steam	**4,658.1**	**7,552.8**	**Mark Janssen IPM 3.0**
Pennsylvania	Armstrong	3178	2	Coal Steam	**779.1**	**1,674.1**	**State Comments**
Pennsylvania	Brunner Island	3140	1	Coal Steam	**1,072.8**	**599.0**	**IPM 2.1.9**
Pennsylvania	Brunner Island	3140	2	Coal Steam	**1,206.8**	**884.3**	**IPM 2.1.9**
Pennsylvania	Brunner Island	3140	3	Coal Steam	**2,289.6**	**1,963.3**	**IPM 2.1.9**
Pennsylvania	Cheswick	8226	1	Coal Steam	**4,636.9**	**2,011.6**	**IPM 2.1.9**
Pennsylvania	Hatfields Ferry	3179	1	Coal Steam	**2,215.0**	**2,784.8**	**IPM 2.1.9**
Pennsylvania	Hatfields Ferry	3179	2	Coal Steam	**2,220.1**	**2,650.8**	**IPM 2.1.9**
Pennsylvania	Homer City	3122	1	Coal Steam	**3,502.4**	**2,288.0**	**State Comments**
Pennsylvania	Homer City	3122	2	Coal Steam	**3,246.1**	**2,767.8**	**State Comments**
Pennsylvania	Keystone	3136	1	Coal Steam	**4,763.7**	**4,385.7**	**State Comments**
Pennsylvania	Keystone	3136	2	Coal Steam	**4,679.7**	**3,145.3**	**State Comments**
Pennsylvania	Martins Creek	3148	1	Coal Steam	**1,331.7**	**0.0**	**IPM 2.1.9**

State	Facility Name	ORIS ID	Unit ID	Unit Type	ORIGINAL 2018 (1) SO_2 TPY	REVISED 2018 (2) SO_2 TPY	BASIS FOR CHANGE (3)
Pennsylvania	Martins Creek	3148	2	Coal Steam	1,198.1	0.0	IPM 2.1.9
Pennsylvania	Montour	3149	1	Coal Steam	3,958.5	3,050.5	State Comments
Pennsylvania	Montour	3149	2	Coal Steam	3,993.4	2,522.4	State Comments
Pennsylvania	Portland	3113	1	Coal Steam	589.9	9,740.2	State Comments
Pennsylvania	Portland	3113	2	Coal Steam	830.2	14,568.8	State Comments
Pennsylvania	Shawville	3131	1	Coal Steam	444.0	7,144.7	State Comments
South Carolina	Jefferies	3319	3	Coal Steam	1,261.9	8,144.7	VISTAS_2018G2
South Carolina	Jefferies	3319	4	Coal Steam	1,233.6	7,962.0	VISTAS_2018G2
South Carolina	Wateree	3297	WAT 1	Coal Steam	15,017.8	1,809.1	VISTAS_2018G2
South Carolina	Wateree	3297	WAT 2	Coal Steam	875.2	1,054.3	VISTAS_2018G2
South Carolina	Williams	3298	WIL1	Coal Steam	1,279.9	1,541.8	VISTAS_2018G2
South Carolina	Winyah	6249	1	Coal Steam	680.9	820.2	VISTAS_2018G2
Tennessee	Gallatin	3403	3	Coal Steam	579.8	698.4	VISTAS_2018G2
Tennessee	Gallatin	3403	4	Coal Steam	573.1	690.4	VISTAS_2018G2
Tennessee	John Sevier	3405	3	Coal Steam	451.4	543.8	VISTAS_2018G2

State	Facility Name	ORIS ID	Unit ID	Unit Type	ORIGINAL 2018 (1) SO_2 TPY	REVISED 2018 (2) SO_2 TPY	BASIS FOR CHANGE (3)
Tennessee	John Sevier	3405	4	Coal Steam	463.8	558.7	VISTAS_2018G2
Tennessee	Johnsonville	3406	1	Coal Steam	5,030.4	6,059.8	VISTAS_2018G2
Tennessee	Johnsonville	3406	2	Coal Steam	4,729.2	5,696.9	VISTAS_2018G2
Tennessee	Johnsonville	3406	3	Coal Steam	4,559.1	5,492.0	VISTAS_2018G2
Tennessee	Johnsonville	3406	4	Coal Steam	4,722.8	5,689.3	VISTAS_2018G2
Tennessee	Johnsonville	3406	5	Coal Steam	4,576.6	5,513.1	VISTAS_2018G2
Tennessee	Johnsonville	3406	6	Coal Steam	4,540.0	5,469.0	VISTAS_2018G2
Tennessee	Johnsonville	3406	7	Coal Steam	6,287.6	7,574.2	VISTAS_2018G2
Tennessee	Johnsonville	3406	8	Coal Steam	5,584.7	6,727.4	VISTAS_2018G2
Tennessee	Johnsonville	3406	9	Coal Steam	5,474.9	6,595.2	VISTAS_2018G2
Tennessee	Johnsonville	3406	10	Coal Steam	4,869.1	5,865.5	VISTAS_2018G2
Tennessee	Kingston	3407	1	Coal Steam	371.9	448.0	VISTAS_2018G2
Tennessee	Kingston	3407	2	Coal Steam	371.9	448.0	VISTAS_2018G2
Tennessee	Kingston	3407	3	Coal Steam	371.9	448.0	VISTAS_2018G2
Tennessee	Kingston	3407	4	Coal Steam	371.9	448.0	VISTAS_2018G2

State	Facility Name	ORIS ID	Unit ID	Unit Type	ORIGINAL 2018 (1) SO_2 TPY	REVISED 2018 (2) SO_2 TPY	BASIS FOR CHANGE (3)
Tennessee	Kingston	3407	5	Coal Steam	486.8	586.4	VISTAS_2018G2
Tennessee	Kingston	3407	6	Coal Steam	486.8	586.4	VISTAS_2018G2
Tennessee	Kingston	3407	7	Coal Steam	486.8	586.4	VISTAS_2018G2
Tennessee	Kingston	3407	8	Coal Steam	486.8	586.4	VISTAS_2018G2
Tennessee	Kingston	3407	9	Coal Steam	602.3	725.5	VISTAS_2018G2
Virginia	Chesapeake	3803	3	Coal Steam	691.5	3,332.0	VISTAS_2018G2
Virginia	Chesapeake	3803	4	Coal Steam	1,038.8	5,005.2	VISTAS_2018G2
Virginia	Chesterfield	3797	4	Coal Steam	743.8	896.0	VISTAS_2018G2
Virginia	Chesterfield	3797	5	Coal Steam	1,560.6	1,879.9	VISTAS_2018G2
Virginia	Chesterfield	3797	6	Coal Steam	3,633.3	4,376.8	VISTAS_2018G2
Virginia	**Clinch River**	3775	1	Coal Steam	539.0	6,542.3	VISTAS_2018G2
Virginia	**Clinch River**	3775	2	Coal Steam	545.3	6,618.2	VISTAS_2018G2
Virginia	Yorktown	3809	1	Coal Steam	6,169.6	743.3	VISTAS_2018G2
Virginia	Yorktown	3809	2	Coal Steam	6,521.3	785.4	VISTAS_2018G2
Virginia	Yorktown	3809	3	Coal Steam	0.0	3,342.8	VISTAS_2018G2

State	Facility Name	ORIS ID	Unit ID	Unit Type	ORIGINAL 2018 (1) SO_2 TPY	REVISED 2018 (2) SO_2 TPY	BASIS FOR CHANGE (3)
West Virginia	Albright	3942	3	Coal Steam	660.1	795.2	VISTAS_2018G2
West Virginia	Fort Martin	3943	1	Coal Steam	4,922.1	5,929.3	VISTAS_2018G2
West Virginia	Fort Martin	3943	2	Coal Steam	4,890.0	5,890.6	VISTAS_2018G2
West Virginia	**John E Amos**	3935	1	Coal Steam	6,612.7	7,965.8	VISTAS_2018G2
West Virginia	**John E Amos**	3935	2	Coal Steam	6,693.9	8,063.7	VISTAS_2018G2
West Virginia	**John E Amos**	3935	3	Coal Steam	10,821.0	13,035.3	VISTAS_2018G2
West Virginia	**Kammer**	3947	1	Coal Steam	951.1	1,145.8	VISTAS_2018G2
West Virginia	**Kammer**	3947	2	Coal Steam	949.2	1,143.4	VISTAS_2018G2
West Virginia	**Kammer**	3947	3	Coal Steam	948.7	1,142.8	VISTAS_2018G2
West Virginia	**Kanawha River**	3936	1	Coal Steam	902.7	1,087.5	VISTAS_2018G2
West Virginia	**Kanawha River**	3936	2	Coal Steam	900.3	1,084.5	VISTAS_2018G2
West Virginia	**Mitchell**	3948	1	Coal Steam	7,646.2	9,210.8	VISTAS_2018G2
West Virginia	**Mitchell**	3948	2	Coal Steam	7,581.9	9,133.4	VISTAS_2018G2
West Virginia	**Mountaineer**	6264	1	Coal Steam	11,433.5	13,773.1	VISTAS_2018G2
West Virginia	Mount Storm	3954	1	Coal Steam	5,318.3	3,843.9	VISTAS_2018G2

State	Facility Name	ORIS ID	Unit ID	Unit Type	ORIGINAL 2018 (1) SO_2 TPY	REVISED 2018 (2) SO_2 TPY	BASIS FOR CHANGE (3)
West Virginia	Mount Storm	3954	2	Coal Steam	**5,318.3**	**3,843.9**	**VISTAS_2018G2**
West Virginia	Philip Sporn	3938	11	Coal Steam	**668.1**	**804.8**	**VISTAS_2018G2**
West Virginia	Philip Sporn	3938	21	Coal Steam	**647.6**	**780.1**	**VISTAS_2018G2**
West Virginia	Philip Sporn	3938	31	Coal Steam	**643.0**	**774.6**	**VISTAS_2018G2**
West Virginia	Philip Sporn	3938	41	Coal Steam	**633.2**	**762.8**	**VISTAS_2018G2**
West Virginia	**Philip Sporn**	3938	51	Coal Steam	**1,942.6**	**2,340.1**	**VISTAS_2018G2**
West Virginia	Pleasants	6004	1	Coal Steam	**6,334.0**	**1,898.0**	**VISTAS_2018G2**
West Virginia	Pleasants	6004	2	Coal Steam	**6,164.7**	**1,847.3**	**VISTAS_2018G2**
Wisconsin	Pleasant Prairie	6170	1	Coal Steam	**1,735.2**	**1,769.6**	**IPM 3.0**
Wisconsin	Pleasant Prairie	6170	2	Coal Steam	**1,748.1**	**1,782.9**	**IPM 3.0**