Final Draft
Ozone Transport Commission Electric Generating Unit Emission Inventory Analysis
September 18, 2014

Executive Summary

Introduction

The Ozone Transport Commission (OTC) Stationary and Area Source Committee (SAS) was directed to identify the largest individual and groupings of emitters of nitrogen oxides (NO_X) and volatile organic compounds (VOCs) located in an OTC state or an area that contributes to ozone levels in an OTC state. SAS was specifically directed to:

(1) examine individual sources and categories of sources with high short-term emissions of NO_X or VOCs;
(2) review electric generating unit (EGU) NO_X emission rates to adjust long-term and short-term expectations for emissions reductions; and
(3) develop state-by-state EGU NO_X emission rates achievable considering reasonably available controls.

SAS was additionally directed to "Evaluate OTR, super regional and national goals and means to reduce the emissions in a technical and cost effective manner from the identified units and groupings. The Committee should develop additional strategies, if necessary to reduce peak emissions from these units."

SAS fomerd the Largest Contributor Workgroup to fullfill the SAS Charge. An EGU Subgroup (Subgroup) was formed to specifally evaluate EGU emissions and evaluate the tasks listed above. This Whitepaper details the analysis conducted to date. The Subgroup, with the assistance of SAS and the OTC Modeling Committee, will perform additional cost-effectiveness and air quality impact analyses as necessary.

Project Scope

The Subgroup was directed to identify the largest individual and groupings of emitters of NO_X within and outside the Ozone Transport Region (OTR) by reviewing recent state, regional, and national emissions data. The Subgroup was additionally directed to evaluate the feasibility of reducing peak emissions and to establish reasonably available control technology-based emissions rate limits. Review of the data was completed to:

(1) determine the highest short-term emission sources regardless of total emissions;
(2) evaluate NO_X emission rates for EGUs considering multiple factors; and
(3) develop strategies for adjusting short-term and long-term expectations for emission rates for EGUs considering age, controls in use, and fuel type on a unit by unit basis.

The results of these analyses are a potential state-by-state EGU ozone season NO_X budget and short-term ozone season NO_X emission rates considering RACT and allowing for adjustments based on state specific knowledge on a case by case basis. The results of these data analyses will be used as inputs to the Eastern Regional Technical Advisory Committee (ERTAC) modeling tool.

The Subgroup, with the assistance of SAS and the OTC Modeling Committee will perform additional cost-effectiveness and air quality impact analyses as necessary. The results of these analyses may be used to make recommendations to the United States Environmental Protection Agency (EPA) for future EGU regulations.

Project Results

Operation of Emissions Controls

The analysis of the Top 25 Ozone Season NO_X and SO_2 Emitters in the OTC Modeling Domain for 2011, 2012, and 2013 demonstrates that some EGUs equipped with NO_X emissions controls are emitting NO_X at rates and in amounts equal to the pre-installation of post-combustion NO_X controls.[6] In 2012, approximately 35% of the coal-fired units equipped with post combustion NO_X controls had average ozone season NO_X emission rates at least 50% higher than its lowest ozone season NO_X emission rate between 2003 and 2012. This data suggests that some EGUs are either not operating or limiting the operation of their existing air pollution control devices.

Analysis 1: Ozone Season NO_X Controls and EGU Retirements

The results of NO_X control installation and the separate analysis on the potential impact of EGU retirements on ozone season NO_X emissions will vary from state to state. Some states anticipate no coal-fueled EGU retirements while other states anticipate a significant amount of coal-fueled EGU retirements. Analysis 1 results demonstrate that significant NO_X reductions can be achieved through the application of reasonably available controls, beyond what is achieved through retirements and fuel switching from coal to natural gas.

Analysis 2: Short-term- Hourly EGU NO_X emissions during a high ozone period

The results of the State of Delaware June 21-22, 2012 hourly EGU NO_X emissions and hourly NO_X emission rates demonstrate EGU NO_X emissions varied on an hourly basis with maximum emissions occurring during hour 16 on June 20, 2012. NO_X emission rates from all types of coal-fired EGU peaked during this period. The review of the related data also indicated:

- Many EGUs cycled on and off line during the period to meet the grid's electric demand, including a number of coal-fired EGUs;
- While the period experienced an air quality episode, many EGUs remained off line throughout the period, raising concerns if the electric demand was higher thereby causing additional EGUs to be brought on line;
- During hour 16, states subject to the CAIR ozone season NO_X program, coal- and natural gas-fired EGUs were responsible for the greatest heat input, with coal-fired EGU contributing approximately 79% and natural gas-fired EGUs contributing approximately 15% of the total NO_X mass emissions.

Analysis 2 results demonstrate that hourly NO_X emission rates from a number of EGUs were greater during the period studied than expected from units with pollution controls installed.

Analysis 3: Short-term Daily EGU NO_X Emissions

The results of the 2011 daily EGU NO_X emissions analyses demonstrate that daily EGU NO_X emissions increased with the ambient temperature, with the highest daily EGU NO_X emissions occurring on days with the highest daily temperatures. A large amount of EGU NO_X emitted on high energy demand days (HEDD) in the OTR and Lake Michigan Air Directors Consortium (LADCO) region during the 2011 ozone season were from coal-fired units. NO_X emissions from EGUs firing other fuels (e.g., diesel, residual oil, natural gas) were very small in the LADCO region, while their contribution was significant in the OTR, especially on HEDD.

Analysis 4: "Coal SCR Scorecard"

The results of the "Coal SCR Scorecard" analysis illustrates the relative performance of SCR coal units in listed states. The variations illustrate differing state regulations with respect to NO_X emissions. Analysis results indicate some EGUs are either not operating or limiting the operation of their pollution control devices.

Analysis 5: Recommendation for Modeling of Short-term NO_X Emission Limits

The NO_X emission rates for some EGUs in recent ozone seasons were significantly higher than the NO_X emission rate demonstrated by those EGUs in previous years and those expected from units with installed NO_X controls.

A potential solution to the air quality issues caused by sources not operating or limiting the operation of their emission controls is the establishment of short-term NO_X emission rate limits for EGUs based on state reported short-term NO_X emission rates and reflective of control practices using reasonably available applicable NO_X emissions controls.

The proposed short-term NO_X emission rates shown below are reflective of the reasonable application of NO_X controls and representative of the capabilities of layered combustion controls or post-combustion controls in retrofit installations. The proposed short-term NO_X emission rate limits account for varied EGU configurations and fuel differences. The proposed short-term NO_X emission rate limits include averaging periods that are necessary to support attainment and maintenance of short-term air quality standards, and are expected to be sustainable over a long period provided operators follow good operating and maintenance practices.

If the proposed short-term NO_X emission rate limits are adopted by regulatory bodies (state rules, regional MOUs, potential federal rule), in addition to an expectation of general air quality improvement, the reductions would be especially effective during HEDDs which often correspond to air quality episodes. The short-term NO_X emission rate limits would therefore be expected to help reduce the frequency and magnitude of air quality episodes in the OTR.

The proposed short-term NO_X emission rate limits are included in the following table:

Unit Type	Heat Input Capacity (MMBtu/hr)	Configuration	NO_X Limit (lb/MMBtu)	Averaging Period
Boiler - Solid Fuel	HI ≥ 1000	Arch	0.125	24-hours
		Cell	0.125	24-hours
		CFB	0.125	24-hours
		Cyclone	0.150*	24-hours
		Stoker	0.150	24-hours
		Tangential	0.125	24-hours
		Wall	0.125	24-hours
Boiler - Solid Fuel	HI < 1000	Arch	0.150	24-hours
		Cell	0.150	24-hours
		CFB	0.125	24-hours
		Cyclone	0.150*	24-hours
		Stoker	0.150	24-hours
		Tangential	0.150	24-hours
		Wall	0.150	24-hours
Boiler - Gas Fuel	All	All	0.125	24-hours
Boiler - Distillate Oil Fuel	All	All	0.125	24-hours
Boiler - Residual Oil Fuel	All	All	0.150	24-hours
Combustion Turbine - Gas Fuel	All	Simple Cycle	25 ppmvd@15%O2*	1-hour
			0.10 lb/MMBtu	1-hour
			1.0 lb./MWh**	1-hour
		Combined Cycle	25 ppmvd@15%O2*	1-hour
			0.10 lb/MMBtu	1-hour
			0.75 lb/MWh**	1-hour
Combustion Turbine - Oil Fuel	All	Simple Cycle	42 ppmvd@15%O2*	1-hour
			0.16 lb/MMBtu	1-hour
			1.6 lb/MWh**	1-hour
		Combined Cycle	42 ppmvd@15%O2*	1-hour
			0.16 lb/MMBtu	1-hour
			1.2 lb/MWh**	1-hour

* Some state rules also include provisions for: alternative emission limits NO_X RACT orders with alternative NO_X RACT emission limits, or the implementation of specific types of NO_X control technologies. Similar alternative compliance means may be necessary for some existing units that may not be able to achieve these NO_X rate limits with NO_X emission controls representative of RACT.
**lb/MWh emission rates calculated using an efficiency of 35% for simple cycle CTs and 46% for combined cycle CTs [lb/MWh = lb/MMBtu * 3.413 / efficiency]

Ozone Transport Commission Electric Generating Unit Emission Inventory Analysis

I. Introduction

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(1) examine individual sources and categories of sources with high short-term emissions of NO_X or VOCs;
(2) review electric generating unit (EGU) NO_X emission rates to adjust long-term and short-term expectations for emissions reductions; and
(3) develop state-by-state EGU NO_X emission rates achievable considering reasonably available controls[1].

SAS was additionally directed to "Evaluate OTR, super regional, and national goals and means to reduce the emissions in a technical and cost effective manner from the identified units and groupings. The Committee should develop additional strategies, if necessary to reduce peak emissions from these units.[2]"

SAS formed the Largest Contributor Workgroup to fullfill the SAS Charge. An EGU Subgroup (Subgroup) was formed to specifically evaluate EGU emissions and evaluate the tasks listed above. This Whitepaper details the analyses conducted to date. The Subgroup, with the assistance of SAS and the OTC Modeling Committee, will perform additional cost-effectiveness and air quality impact analyses as necessary.

II. Project Scope

The Subgroup was directed to identify the largest individual and groupings of emitters of NO_X within and outside the Ozone Transport Region (OTR) by reviewing recent state, regional, and national emissions data. The Subgroup was additionally directed to evaluate the feasibility of reducing peak emissions and to establish reasonably available control technology-based emissions rate limits. Review of the data was completed to:

(1) determine the highest short-term emission sources regardless of total emissions;

[1] Ozone Transport Commission charge to the Stationary and Area Source Committee at November 2012 Fall meeting, Attached and available at: http://www.otcair.org/upload/Documents/Formal%20Actions/Charge%20to%20SAS%20Committee.pdf
[2] Ozone Transport Commission charge to the Stationary and Area Source Committee at November 2013 Fall meeting available at: http://www.otcair.org/upload/Documents/Formal%20Actions/Chrg%20to%20SAS%20for%20Reg%20Attainment%20of%20Ozone.pdf

(2) evaluate NO_X emission rates for EGUs considering multiple factors[3]; and
(3) develop strategies for adjusting short-term and long-term expectations for emission rates for EGUs considering age, controls in use and fuel type on a unit by unit basis.

The Subgroup performed five inventory data analyses. The results of two analyses, a potential state-by-state EGU ozone season NO_X budget (Analysis 1); and short-term ozone season NO_X emission rates considering RACT and allowing for adjustments based on state specific knowledge on a case by case basis (Analysis 5) will be used as inputs to the Eastern Regional Technical Advisory Committee (ERTAC) modeling tool to demonstrate the effect that these recommendations may have on air quality if adopted.

The Subgroup, with the assistance of SAS and the OTC Modeling Committee will perform additional cost-effectiveness and air quality impact analyses as necessary. The results of these analyses may be used to make recommendations to the United States Environmental Protection Agency (EPA) for future EGU regulations.

III. Project Criteria

The scope of this inventory analysis is as follows:

- **Years:** The years 2011 and 2012 were selected. Data from the EPA's Clean Air Markets Division (CAMD) was available for both of these years**.** CAMD data from additional years was reviewed in order to fully evaluate the 2011 and 2012 CAMD data. CAMD data was supplemented with data from other sources (e.g., United States Energy Information Administration (EIA), etc.) and state inventory data where appropriate and as needed. The year 2011 was selected as the baseline year and also used as the primary year of data collection for the state level ozone season NO_X mass emissions evaluation and state level ozone season NO_X emission rate evaluation.

- **Geographic Area:** This analysis was performed for all states in the OTR: Connecticut, Delaware, District of Columbia, Maine, Maryland, Massachusetts,

[3] Ozone Transport Commission Draft Model Rule Control of Oil and Gas Fired Electric Generating Unit Boiler NOX Emissions, June 2010 available at http://www.otcair.org/upload/Documents/Meeting%20Materials/OTC%20Oil%20and%20Gas%20EGU%20Boiler%20NOX%20Model%20Rule%20Draft%20B_MOU_100603.pdf

Ozone Transport Commission Draft Model Rule Control of NOX Emissions from Natural Gas and Distillate Oil Fired HEDD Turbines, June 2010 available at http://www.otcair.org/upload/Documents/Model%20Rules/OTC%20Model%20Rule%20-%20HEDD%20Turbines%20Final.pdf

Ozone Transport Commission Memorandum of Understanding Among the States of the Ozone Transport Commission Concerning the Incorporation of High Electric Demand Day Emission Reduction Strategies into Ozone Attainment State Implementation Planning, March 2007, available at http://www.otcair.org/upload/Documents/Formal%20Actions/OTC_2007_SpecialMtg_%20HEDDMOU_Final_070302[1].pdf

New Hampshire, New Jersey, New York, Pennsylvania, Rhode Island, Vermont, and Virginia. This analysis was also performed to the extent of available data for all Clean Air Interstate Rule (CAIR) states, all states identified in the Cross-State Air Pollution Rule (CSAPR), and all states included in the current OTC Modeling domain.

- **Inventory Sector:** This analysis was performed for all EGUs included in EPA's CAMD database for the following EPA programs: Acid Rain (ARP), CAIR, CSAPR, and NO_X State Implementation Plan (SIP) Call program, where applicable. Other data sources were reviewed where necessary to supplement EPA's CAMD data.

  For the purposes of the state-by-state EGU ozone season NO_X budget analyses only EGUs with capacities of 25 Megawatts (MW) or greater found in EPA's CAMD database were included. EGU nameplate rating data was obtained from the EIA database as needed.

  For the purposes of the daily ozone season NO_X emission rate analyses all units reporting to EPA's CAMD database were included.

- **Pollutant considered:** Nitrogen Oxides (NO_X) was the air pollutant considered.

IV. Technical Approach

<u>Unit-level Criteria for NO_X emissions</u>

The 2011 and 2012 unit level NO_X emissions (mass and rate) were obtained from CAMD for ARP, CAIR, and CSAPR reported units. The following Excel spreadsheets were created and summarized by state in each spreadsheet:

- 2011 Ozone Season NO_X
- 2011 High Ozone Episode NO_X (hourly and daily, as available)
- 2012 Ozone Season NO_X
- 2012 High Ozone Episode NO_X (hourly and daily, as available)

Unit-level data elements include:

- State name
- Facility name
- Facility ID
- Unit ID
- NO_X emissions (tons)
- NO_X Rate (lb/mmBtu) reported
- NO_X Rate (lb/mmBtu) calculated
- NO_X Rate (lb/MWhr) calculated
- Heat Input (mmBtu)

- Operating Time (hours)
- Number of months reported
- Source Category
- Unit Type
- Fuel Type
- Age of Unit
- Capacity factor
- NO_X Controls

V. Top 25 Ozone Season NO_X Emitters in the OTC Modeling Domain

The Subgroup identified the Top 25 Ozone Season NO_X Emitters in the OTC Modeling Domain for 2011, 2012 and 2013. Criteria for inclusion in the list was the mass of NO_X emitted during the ozone season, the NO_X emission rate was included as additional information.

Top 25 NO_X Emitters 2011 Ozone Season

STATE	Facility Name	Facility ID	UNIT ID	Avg. NO_X Rate (lb/MMBtu)	NO_X (Tons)
IN	Rockport	6166	MB2	0.243	5,339
PA	Keystone	3136	2	0.363	5,044
PA	Keystone	3136	1	0.371	4,855
PA	Hatfield's Ferry Power Station	3179	1	0.492	4,288
PA	Conemaugh	3118	2	0.317	4,086
PA	Hatfield's Ferry Power Station	3179	2	0.474	3,984
AR	White Bluff	6009	1	0.275	3,956
PA	Conemaugh	3188	1	0.341	3,890
PA	Brunner Island	3140	3	0.376	3,834
AR	White Bluff	6009	2	0.279	3,794
IN	Rockport	6166	MB1	0.237	3,616
OH	W H Zimmer Generation Station	6019	1	0.218	3,559
AR	Independence	6641	1	0.259	3,302
PA	Montour	3149	1	0.332	3,298
PA	Montour	3149	2	0.315	3,132
PA	Hatfield's Ferry Power Station	3179	3	0.432	2,848
MI	Monroe	1733	2	0.285	2,811
GA	Harlee Branch	709	4	0.407	2,806
WV	Fort Martin Power Station	3943	1	0.351	2,660
NY	Lafarge Building Material, Inc.	880044	41000		2,647
AR	Independence	6641	2	0.227	2,463
KY	Paradise	1378	3	0.386	2,431
NY	Somerset Operating Company (kintigh)	6082	1	0.296	2,347
OH	Avon Lake Power Plant	2836	12	0.400	2,328
OH	EastLake	2837	5	0.262	2,323
* Red Text Indicates Units Scheduled to Retire					
* Blue Text indicates Units with Future Controls Planned					
* Pink Text indicates Units with Installed Pollution Controls					
* LaFarge Building Material, Inc., is not an EGU					
*Conemaugh has installed controls on Unit 1 and 2					
* Hatfield's Ferry closed as of October 2013					

Top 25 NO_X Emitters 2012 Ozone Season

STATE	Facility Name	Facility ID	UNIT ID	Avg. NO_X Rate (lb/MMBtu)	NO_X (Tons)
MO	New Madrid Power Plant	2167	1	0.627	5,786
IN	Rockport	6166	MB1	0.221	5,001
PA	Keystone	3136	1	0.365	4,661
IN	Rockport	6166	MB2	0.224	4,215
MO	New Madrid Power Plant	2167	2	0.505	4,134
PA	Conemaugh	3118	1	0.320	3,909
PA	Montour	3149	2	0.414	3,794
PA	Conemaugh	3118	2	0.300	3,789
PA	Keystone	3136	2	0.343	3,774
PA	Hatfield's Ferry Power Station	3179	3	0.509	3,677
PA	Hatfield's Ferry Power Station	3179	1	0.486	3,601
PA	Hatfield's Ferry Power Station	3179	2	0.520	3,589
PA	Montour	3149	1	0.402	3,543
AR	White Bluff	6009	1	0.278	3,504
AR	White Bluff	6009	2	0.246	3,383
MO	Thomas Hill Energy Center	2168	MB2	0.684	3,236
AR	Independence	6641	2	0.205	2,816
WV	Fort Martin Power Station	3943	1	0.319	2,730
AL	E C Gaston	26	5	0.203	2,656
WV	Harrison Power Station	3944	3	0.308	2,628
PA	Brunner Island	3140	3	0.346	2,601
WV	Harrison Power Station	3944	1	0.313	2,569
MI	Monroe	1733	2	0.259	2,536
MI	Monroe	1733	1	0.247	2,517
OH	Killen Station	6031	2	0.351	2,426
* Red Text Indicates Units Scheduled to Retire					
* Blue Text indicates Units with Future Controls Planned					
* Pink Text indicates Units with Installed Pollution Controls					
* Conemaugh has installed controls on Unit 1 and 2					
* Hatfield's Ferry closed as of October 2013					

Top 25 NO_X Emitters 2013 Ozone Season

STATE	Facility Name	Facility ID	UNIT ID	Avg. NO_X Rate (lb/MMBtu)	NO_X (Tons)
MO	New Madrid Power Plant	2167	2	0.499	4,328
OH	W H Zimmer Generating Station	6019	1	0.219	4,261
AR	White Bluff	6009	2	0.283	4,193
MO	New Madrid Power Plant	2167	1	0.609	4,126
AR	White Bluff	6009	1	0.291	4,096
PA	Conemaugh	3118	1	0.318	4,095
IN	Rockport	6166	MB1	0.213	3,997
PA	Hatfield's Ferry Power Station	3179	2	0.491	3,876
PA	Hatfield's Ferry Power Station	3179	1	0.471	3,712
PA	Conemaugh	3118	2	0.321	3,605
PA	Hatfield's Ferry Power Station	3179	3	0.444	3,365
MI	Monroe	1773	2	0.329	3,308
PA	Homer City	3122	3	0.332	3,235
IN	Rockport	6166	MB2	0.213	3,217
MI	Monroe	1733	1	0.315	3,062
PA	Montour	3149	2	0.424	3,050
OH	Killen Station	6031	2	0.304	2,951
WV	Fort Martin Power Station	3943	1	0.358	2,905
WV	Harrison Power Station	3944	3	0.301	2,874
PA	Montour	3149	1	0.398	2,864
WV	Harrison Power Station	3944	1	0.280	2,817
AR	Independence	6641	2	0.209	2,807
NC	Marshall	2727	4	0.341	2,639
PA	Homer City	3122	2	0.328	2,552
OH	Conesville	2840	5	0.479	2,530
* Red Text Indicates Units Scheduled to Retire					
* Blue Text indicates Units with Future Controls Planned					
* Pink Text indicates Units with Installed Pollution Controls					
*Conemaugh has installed controls on Unit 1 and 2					
* Hatfield's Ferry closed as of October 2013					

The Top 25 NO_X emitters for the 2011, 2012, and 2013 ozone seasons indicate that while there are units that appear during all three years, there is also a high degree of variation during the three years. The variation may be attributed to changes in fuel prices affecting economic dispatch, maintenance outages, electric demand, operation, and/or effectiveness of installed NO_X, controls, etc. The Subgroup expects that, due to the factors listed above and anticipated pollution controls, the list of Top 25 NO_X emitters will continue to change year to year.

The EGUs identified on the lists include EGUs equipped with combustion NO_X controls, post-combustion NO_X controls, and combinations of both types of NO_X controls. The EGUs identified on the list have commonalities, specifically, they are all relatively large coal-fired steam units with average ozone season NO_X emission rates that do not reflect the NO_X reduction capabilities of modern, layered combustion controls or post-combustion NO_X controls. While the EGUs identified in this section are located in the OTC modeling domain, it is indicative of the largest ozone season NO_X emitting EGUs on a national fleet basis.

The lists demonstrate that some EGUs equipped with NO_X emissions controls are emitting NO_X at rates and amounts equal to the pre-installation of post-combustion NO_X controls. In 2012 approximately 35% of the coal-fired units equipped with post combustion NO_X controls had average ozone season NO_X emission rates at least 50% higher than its lowest ozone season NO_X emission rate between 2003 and 2012. This data suggests that some EGU's are not operating, or limiting the operation of their controls.

VI. Analyses and Results

A. Analysis 1: Ozone Season NO_X Emission Controls and Unit Retirements

Analysis

Data from the EPA's CAMD Air Markets Program Data (AMPD) database (i.e., ARP, CAIR, and CSAPR program data) and information from EIA were used to examine reasonably cost-effective post combustion EGU control technologies and to determine fleet-wide average NO_X emission rates for fossil fuel-fired EGUs.

EGU data was used to identify existing controls and to determine average 2011 actual ozone season NO_X emission rates. By applying an enhanced EGU control strategy, a revised 2011 ozone season NO_X mass emissions were calculated. The calculation process included the following:

- The year 2011 was selected as the base year for determining the baseline ozone season EGU fleet, EGU ozone season NO_X mass emissions, and EGU ozone season heat input.
- The fleet of EGUs was identified in the CAMD AMPD database as electric utility or small power producers with nameplate capacity ≥ 25 MW, excluding units identified as co-generation or any industrial, commercial, or process unit.
- For existing EGUs with post-combustion NO_X controls, each EGU's NO_X emissions rate (lb/MMBTU) was obtained from CAMD AMPD data and the lowest ozone season average NO_X emissions rate between 2003 and 2012, inclusive, was selected. Each EGU's capacity factor was calculated from the CAMD AMPD data.
- The 2012 ozone season values were included in this analysis as it was the most recent ozone season average NO_X emission rate available and to potentially provide credit to an individual EGU for NO_X controls and/or NO_X emission rate reductions that have already been incorporated on that EGU.
- For each EGU, estimated ozone season NO_X emissions were calculated as the product of the actual 2011 NO_X mass emissions and the ratio of the estimated ozone season NO_X emissions rate after application of controls and the actual 2011 ozone season average NO_X emissions rate as follows:

Estimated Ozone Season =

(Actual 2011 OS NO_X Mass Emission) *(Estimated NO_X Emission Rate after Control/Actual 2011 OS NO_X Emission Rate)

1. *Coal-Fueled EGUs*:

A coal-fueled EGU was any EGU identified in the CAMD AMPD database that included coal or coal-refuse as a primary fuel or secondary fuel.

Coal-fueled EGUs of any size that were identified in the CAMD AMPD as having incorporated Selective Catalytic Reduction (SCR) technology, the estimated ozone season NO_X emissions rate was the lowest demonstrated ozone season NO_X emissions rate between the years 2003 and 2012.

If the lowest demonstrated ozone season average NO_X emissions rate between the years 2003 and 2012 was 0.06 lb/MMBTU or less, 0.06 lb/MMBTU was used as the estimated ozone season NO_X emissions rate regardless of the NO_X controls installation indicated in the AMPD.

Coal-fueled EGUs with a heat input rating of 2000 MMBTU/hr, or greater:

1) Coal-fueled EGUs identified in the AMPD as incorporating Selective Non-Catalytic Reduction (SNCR) technology with a lowest demonstrated ozone season NO_X emissions rate between the years 2003 and2012 greater than 0.06 lb/MMBTU, installation of SCR was assumed and the NO_X emissions rate was estimated as 50% of the lowest demonstrated ozone season NO_X emissions rate between the years 2003 and 2012. The floor NO_X emissions rate for this estimation was 0.06 lb/MMBTU.

2) Coal-fueled EGUs identified in the AMPD as incorporating neither SNCR nor SCR with a lowest demonstrated ozone season average NO_X emissions rate between the years 2003 and 2012 greater than 0.06 lb/MMBTU, installation of SCR was assumed and the NO_X emissions rate was estimated as 10% of the lowest demonstrated ozone season average NO_X emissions rate between the years 2003 and 2012. The floor NO_X emissions rate for this estimation was 0.06 lb/MMBTU.

Coal-fueled EGUs with a heat input rating of 1000 MMBTU/hr, or greater, but less than 2000 MMBTU/hr:

1) Coal-fueled EGUs identified in the AMPD as incorporating SNCR and with a 2011 ozone season heat input capacity factor less than 40% of the total capacity, the estimated ozone season NO_X emissions rate was the lowest demonstrated ozone season NO_X emissions between the years 2003 and 2012.

2) Coal-fueled EGUs identified in the AMPD as incorporating SNCR with a lowest demonstrated ozone season NO_X emissions rate between the years 2003 and 2012

greater than 0.06 lb/MMBTU and a 2011 ozone season heat input capacity factor 40% or greater of the total capacity, installation of SCR was assumed. The NO_X emissions rate was estimated as 50% of the lowest demonstrated ozone season NO_X emissions rate between the years 2003 and 2012. The floor NO_X emissions rate for this estimation was 0.06 lb/MMBTU.

3) Coal-fueled EGUs identified in the AMPD as incorporating neither SCR nor SNCR, with a lowest demonstrated ozone season NO_X emissions rate between the years 2003 and 2012 greater than 0.06 lb/MMBTU and the 2011 ozone season heat input capacity factor 40% or greater of the total capacity , installation of SCR was assumed. The NO_X emissions rate was estimated as 10% of the lowest demonstrated ozone season average NO_X emissions rate between the years 2003 and 2012. The floor NO_X emissions rate for this estimation was 0.06 lb/MMBTU.

4) Coal-fueled EGUs identified in the AMPD as incorporating neither SCR nor SNCR, with a lowest demonstrated ozone season NO_X emissions rate between the years 2003 and 2012 greater than 0.06 lb/MMBTU and the 2011 ozone season heat input capacity factor less than 40% of the total capacity, installation of SNCR was assumed. The NO_X emissions rate was estimated as 60% of the lowest demonstrated ozone season average NO_X emissions rate between the years 2003 and 2012. The floor NO_X emissions rate for this estimation was 0.06 lb/MMBTU.

Coal-fueled EGUs with a heat input rating of less than 1000 MMBTU/hr:

1) Coal-fueled EGUs identified in the AMPD as incorporating SCR or SNCR, the estimated ozone season NO_X emissions rate used was the lowest demonstrated ozone season NO_X emissions rate between the years 2003 and 2012.

2) Coal-fueled EGUs identified in the AMPD as incorporating neither SNCR nor SCR, installation of SNCR was assumed. The NO_X emissions rate was estimated as 60% of the lowest demonstrated ozone season average NO_X emissions rate between the years 2003 and 2012. The floor NO_X emissions rate for this estimation was 0.06 lb/MMBTU.

2. *Non-Coal Fueled Boilers Serving EGUs*

Non-coal fueled boilers serving EGUs were those EGU boilers identified in the AMPD as not including coal or coal-refuse as a primary or secondary fuel.

If the non-coal fueled EGU boiler's lowest demonstrated ozone season NO_X emissions rate between the years 2003 and2012 was less than 0.1 lb/MMBTU, 0.1 lb/MMBTU was the estimated ozone season NO_X emissions rate regardless of the NO_X controls installation indicated in the AMPD.

Non-coal-fueled EGU with a heat input rating of 2000 MMBtu/hr. or greater:

1) Non-coal fueled EGU boilers identified in the AMPD as incorporating SCR or SNCR, the NO_X emission rate was the lowest demonstrated ozone season NO_X emissions rate between the years 2003 and 2012.

2) Non-coal fueled EGU boilers identified in the AMPD as incorporating neither SCR nor SNCR, with a lowest demonstrated ozone season NO_X emissions rate between the years 2003 and 2012 greater than 0.1 lb/MMBTU, installation of SCR was assumed. The NO_X emissions rate was estimated as 20% of the lowest demonstrated ozone season average NO_X emissions rate between the years 2003 and 2012. The floor NO_X emissions rate for this estimation was 0.06 lb/MMBTU.

Non-coal fueled EGU boilers with a heat input rating of 1000 MMBTU/hr, or greater, but less than 2000 MMBTU/hr:

1) Non-coal fueled EGU boilers identified in the AMPD as incorporating SCR; the estimated ozone season NO_X emissions rate was the lowest demonstrated ozone season NO_X emissions rate between the years 2003 and 2012.

2) Non-coal fueled EGU boilers identified in the AMPD as incorporating SNCR with a 2011 ozone season heat input capacity factor less than 40% of the total capacity, the estimated ozone season NO_X emissions rate was the lowest demonstrated ozone season NO_X emissions rate between the years 2003 and 2012.

3) Non-coal fueled EGU boilers identified in the AMPD as incorporating SNCR, with a 2011 ozone heat input capacity factor 40% or greater of the total capacity, installation of SCR was assumed. The NO_X emission rate was estimated at 70% of the lowest demonstrated ozone season NO_X emissions rate between the years 2003 and 2012. The floor NO_X emission rate for this estimation was 0.06 lb/MMBTU.

4) Non-coal fueled EGU boilers identified in the AMPD as incorporating neither SCR nor SNCR, with a lowest demonstrated emissions rate between the years 2003 and 2012 greater than 0.1 lb/MMBTU and the 2011 ozone season heat input capacity factor 40% or greater of the total capacity, installation of SCR was assumed. The NO_X emissions rate was estimated as 20% of the lowest demonstrated ozone season average NO_X emissions rate between the years 2003 and 2012. The floor NO_X emissions rate for this estimation was 0.06 lb/MMBTU.

5) Non-coal-fueled EGU boilers identified in the AMPD as incorporating neither SCR nor SNCR, with a lowest demonstrated ozone season NO_X emissions rate between the years 2003 and 2012 greater than 0.06 lb/MMBTU and the 2011 ozone season heat input capacity factor was less than 40% of the total capacity, installation of SNCR was assumed. The NO_X emissions rate was estimated as 50% of the lowest demonstrated ozone season average NO_X emissions rate between the years 2003 and 2012. The floor NO_X emissions rate for this estimation was 0.06 lb/MMBTU.

Non-coal-fueled EGUs with a heat input rating of less than 1000 MMBTU/hr:

1) Non-coal fueled EGU boilers identified in the AMPD as incorporating SCR or SNCR, the estimated NO_X emission rate was the lowest demonstrated ozone season NO_X emissions rate between the years 2003 and 2012.

2) Non-coal fueled EGU boilers identified in the AMPD as incorporating neither SCR nor SNCR with a lowest demonstrated ozone season NO_X emissions rate between the years 2003 and 2012 greater than 0.1 lb/MMBTU installation of SNCR was assumed. The NO_X emissions rate was estimated as 60% of the lowest demonstrated ozone season average NO_X emissions rate between the years 2003 and 2012. The floor NO_X emissions rate for this estimation was 0.06 lb/MMBTU.

3. Combined Cycle (CC) and Combustion Turbine (CT) EGUs:

1) If the CC or CT EGU's lowest demonstrated ozone season NO_X emissions rate between the years 2003 and 2012 was less than 0.1 lb/MMBTU, 0.1 lb/MMBTU was the estimated ozone season NO_X emissions rate regardless of the NO_X controls installation indicated in the AMPD.

2) If the CC or CT EGU's lowest demonstrated ozone season NO_X emissions rate between the years 2003 and 2012 was 0.1 lb/MMBTU or greater, and the EGU was identified in the AMPD as incorporating Dry Low NO_X Burner (DLNB) or water injection, then the lowest demonstrated ozone season average NO_X emissions rate between the years 2003 and 2012 was the estimated ozone season NO_X emissions rate.

3) If the CC or CT EGU's lowest demonstrated ozone season NO_X emissions rate between the years 2003 and 2012 was 0.1 lb/MMBTU or greater, and the EGU was not identified in the AMPD as incorporating DLNB or water injection, installation of water injection was assumed. The NO_X emissions rate was estimated as 60% of the lowest demonstrated ozone season average NO_X emissions rate between the years 2003 and 2012.

For CC or CT EGU's that appear to be utilizing default values and did not indicate incorporation of DLNB, water injection, or SCR, the NO_X emissions reductions from those units was estimated as follows:

1) For a CC or CT unit, a NO_X emissions rate estimate was calculated using the non-default average NO_X emission rates for CCs or CTs (as appropriate) using the same primary fuel type and same heat input classification.

2) Using the AMPD reported 2011 heat input for that CC or CT EGU, the "actual" NO_X mass emissions was calculated by multiplying the heat input with the above estimated NO_X emissions rate.

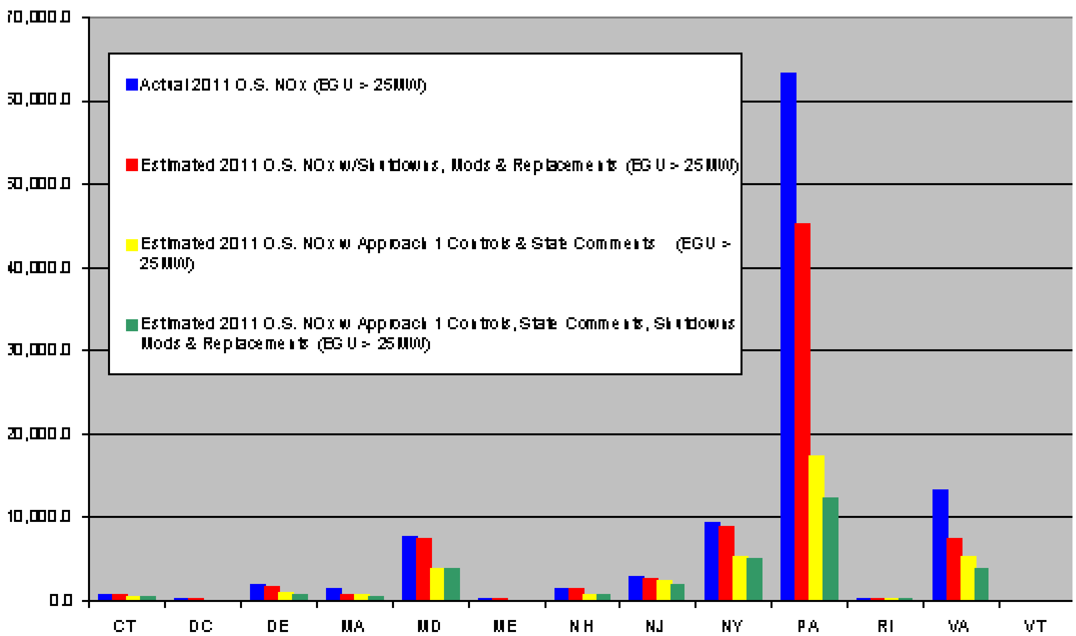
3) Assuming installation of water injection and a resulting 40% reduction in NO_X emissions rate, the reduction of NO_X mass emissions is estimated as 40% of the "actual" NO_X mass emissions.

As the above estimates are made on a unit-specific basis, NO_X mass caps could be calculated on a regional basis (state specific, CAIR region, etc.). The process outlined above allows for a NO_X mass cap calculation representative of the existing EGU fleet and its ability to achieve NO_X emissions reductions. It also identified areas where some of the existing regulatory and economic processes have produced some NO_X reduction success (such as increased use of well-controlled gas-fueled combined cycle units) and areas where NO_X reductions have diminished (such as discontinuing or ineffectively using existing NO_X controls on some coal-fired units).

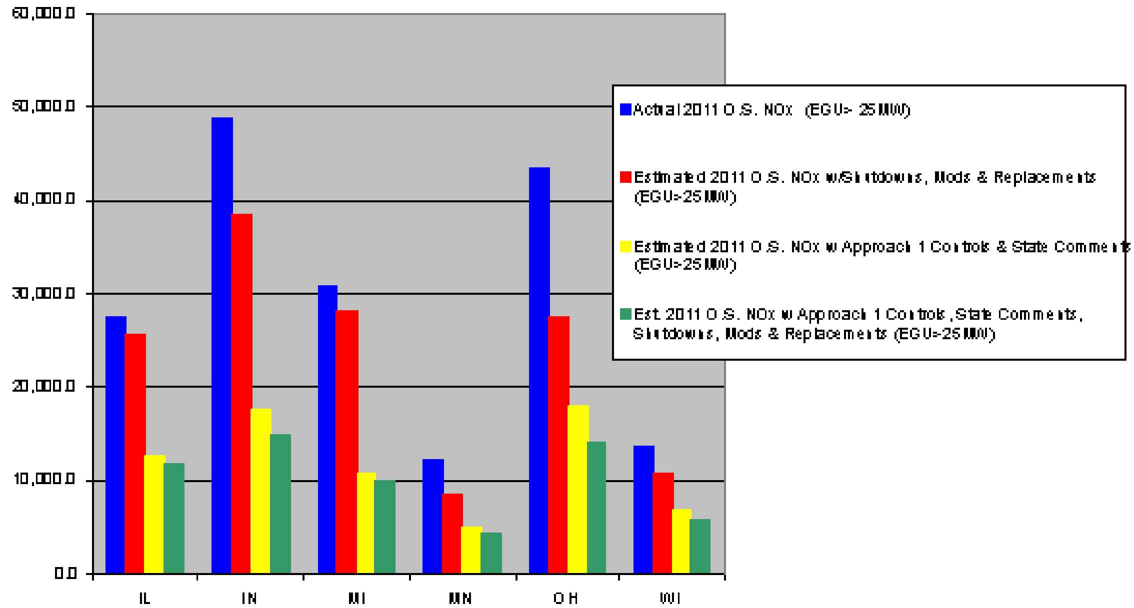
<u>Results</u>

The following graphs show the impact of Analysis 1 NO_X controls, and the potential impact of EGU retirements on state level ozone season NO_X mass emissions in tons. The spreadsheets used to create these graphs can be found in Appendix 3.

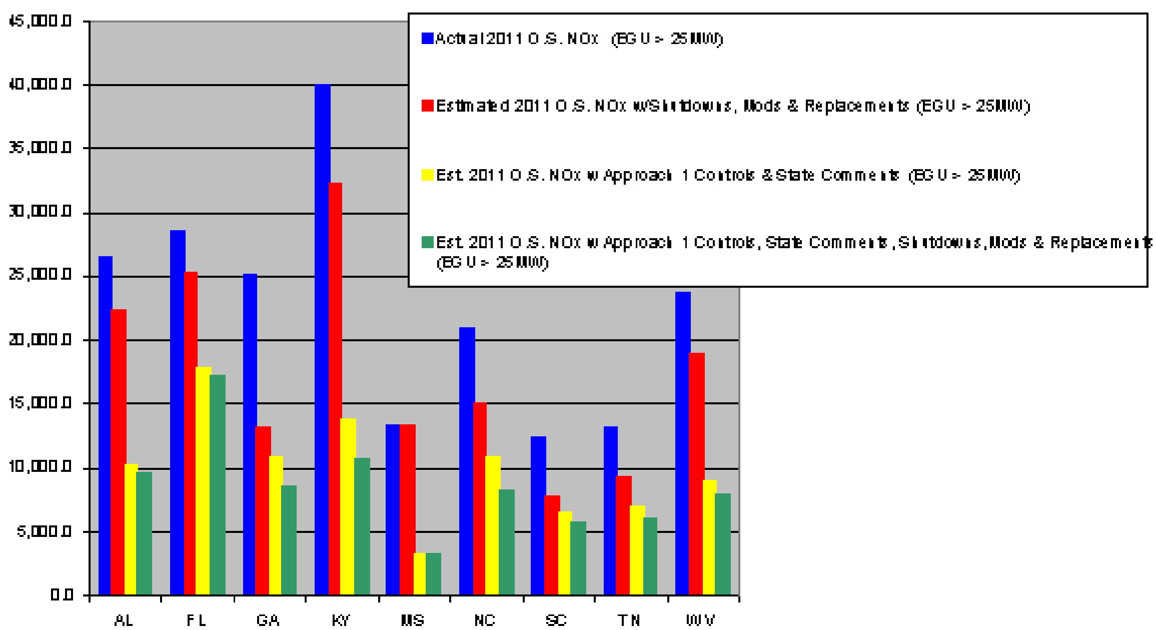
Estimated Impact of Coal-Fired EGU Retirements and Analysis 1 NO_X Controls on Ozone Season EGU NO_X Emissions for OTC States (Revised 11.25.2013) (Measured in Tons)



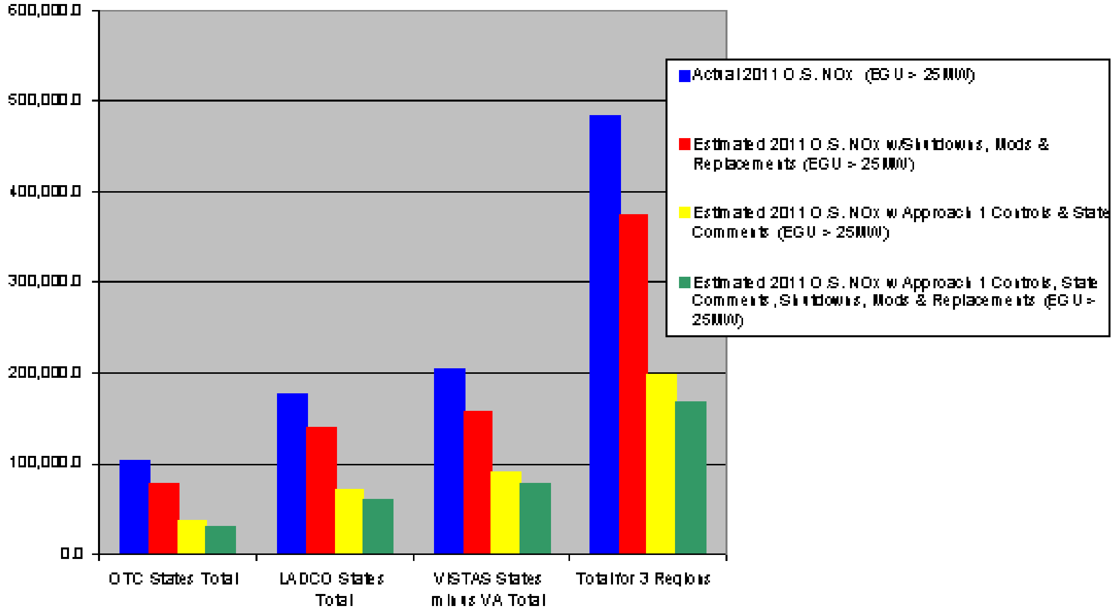
Estimated Impact of Coal-Fired EGU Retirements and Analysis 1 NO_X Controls on Ozone Season EGU NO_X Emissions for LADCO States (Revised 11.25.2013) (Measured in Tons)



Estimated Impact of Coal-Fired EGU Retirements and Analysis 1 NO_X Controls on Ozone Season EGU NO_X Emissions for VISTAS States minus Virginia (Revised 11.25.2013) (measured in Tons)

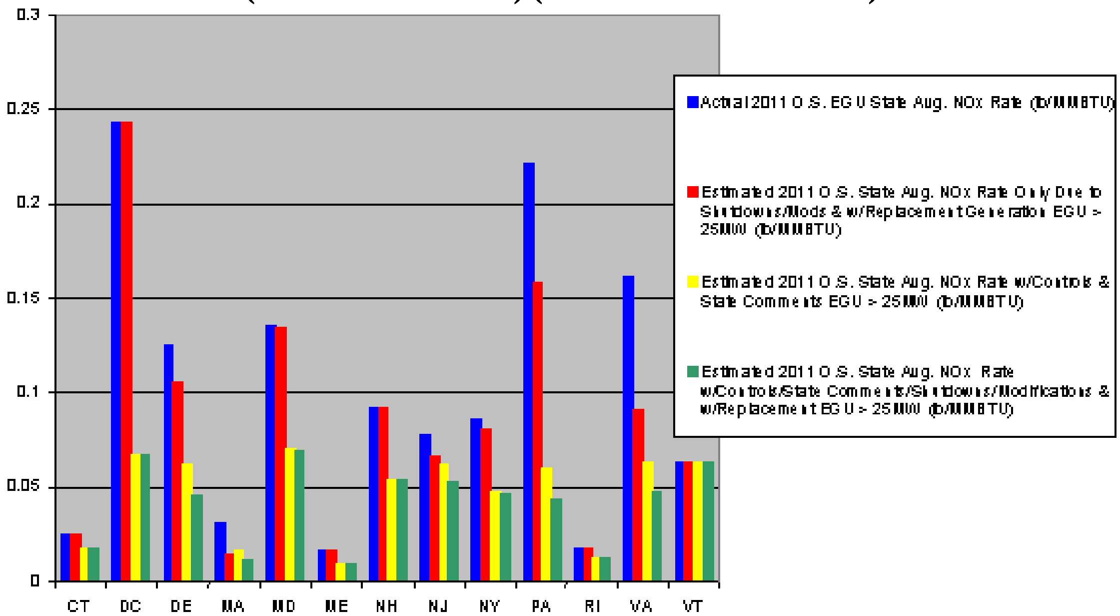


Estimated Impact of Coal Fired EGU Retirements and Analysis 1 NO_X Controls on Ozone Season EGU NO_X Emissions Regional Summary (Revised 11.25.2013) (Measured in Tons)

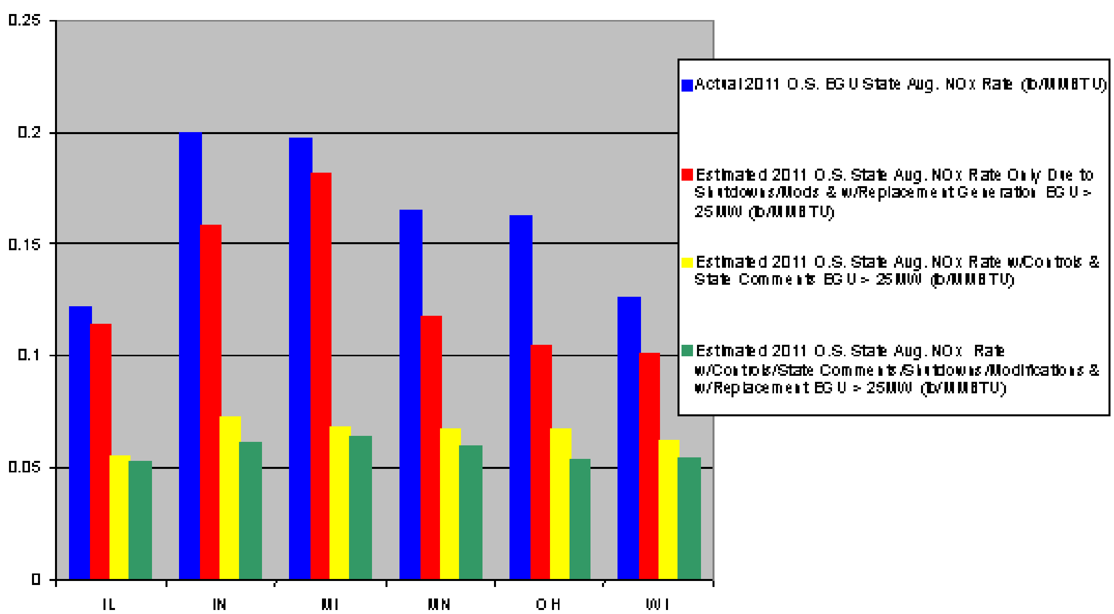


The following graphs demonstrate the potential impact of Analysis 1 NO_X controls and the potential impact of EGU retirements on state level ozone season NO_X emission rates in lbs NO_X/MMBtu. The spreadsheets used to create these graphs can be found in Appendix 4.

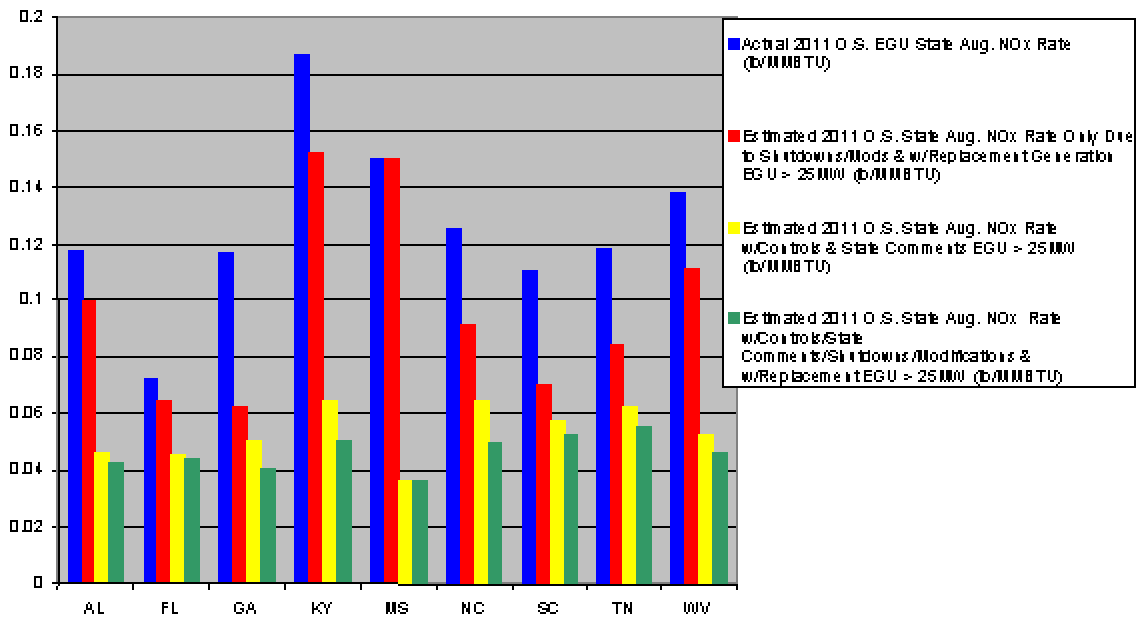
Estimated Impact of Coal Fired EGU Retirements and Analysis 1 NO_X Controls on Ozone Season Fleet Average NO_X Emission Rates for OTC States (Revised 11.25.2013) (Measured in lb/MMBtu)



Estimated Impact of Coal Fired EGU Retirements and Analysis 1 NO_X Controls on Ozone Season Fleet Average NO_X Emission Rates for LADCO States (Revised 11.25.2013) (Measured in lb/MMBtu)



Estimated Impact of Coal Fired EGU Retirements and Analysis 1 NO_X Controls on Ozone Season Fleet Average NO_X Emission Rates for VISTAS States minus Virginia (Revised 11.25.2013) (Measured in lb/MMBtu)



The results of the NO_X control installation analysis and the separate analysis on the potential impact of EGU retirements on ozone season NO_X emissions will vary from state to state. Some states anticipate no coal-fueled EGU retirements while other states anticipate a significant amount of coal-fueled EGU retirements. Analysis 1 results demonstrate that significant NO_X reductions can be achieved through the application of reasonably available controls, beyond what is achieved through retirements and fuel switching from coal to natural gas.

B. <u>Analysis 2: Short-term- Hourly EGU NO_X Emissions during a High Ozone Period</u>

<u>Analysis</u>

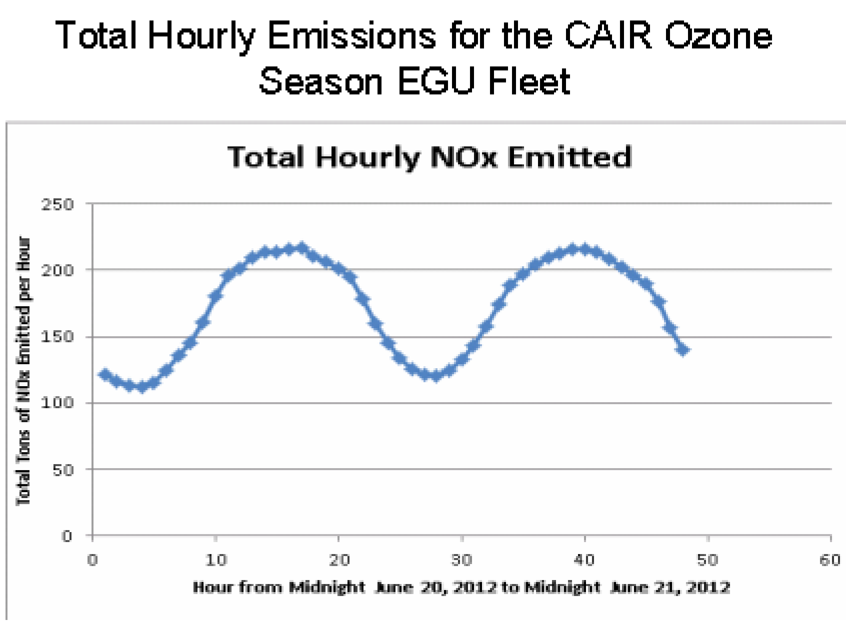
The State of Delaware prepared an analysis of hourly EGU NO_X emissions and hourly EGU NO_X emission rates during a high ozone period in Delaware. The Subgroup prepared a High Energy Demand Day (HEDD) analysis for the OTC Modeling Domain on: Low Emitting Combustion Turbines (LECTs with NO_X emissions <0.125 lb/mmBtu), High Emitting Combustion Turbines (HECTs with NO_X emissions >0.125 lb/mmBtu) and coal-fired EGUs with and without SCR controls installed during a high ozone period in Delaware & New Jersey.

Results

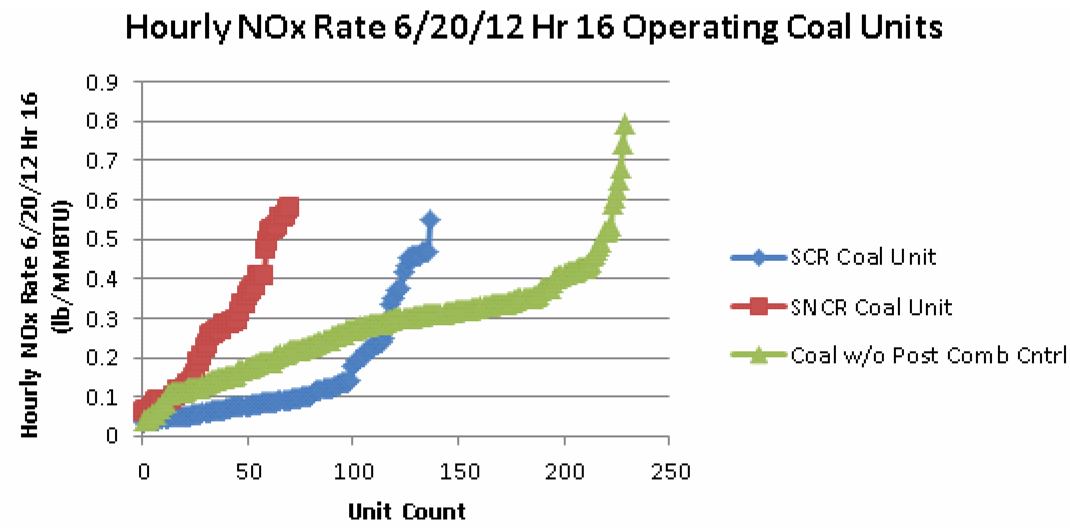
The results of the State of Delaware hourly EGU NO_X emissions and hourly NO_X emission rates (June 21-22, 2012) study demonstrate EGU NO_X emissions varied on an hourly basis with maximum emissions occurring during hour 16 on June 20, 2012. NO_X emission rates from all types of coal-fired EGU also peaked during this time. The review of the related data also indicated:

- Many EGUs were cycled on and off line during the period to meet the grid's electric demand, including a number of coal-fired EGUs;
- While the period experienced an air quality episode, many EGUs remained off line throughout the period, raising concerns if the electric demand was higher thereby causing additional EGUs to be brought on line;
- The NO_X emission rates from a number of EGUs were much greater than would be expected relative to the NO_X controls reported to be installed on those units;
- During hour 16, for states subject to the CAIR ozone season NO_X program, coal- and natural gas-fired EGUs were responsible for the greatest heat input, with coal-fired EGUs contributing approximately 79% and natural gas-fired EGUs contributing approximately 15% of the total NO_X mass emissions.

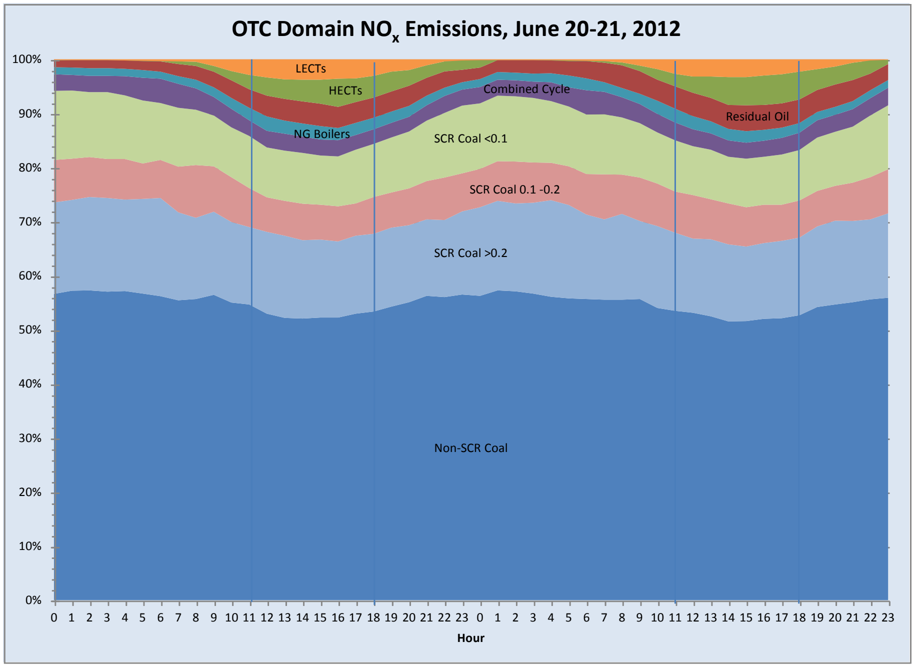
State of Delaware hourly EGU NO_X emissions and hourly NO_X emission rates (June 21-22, 2012)

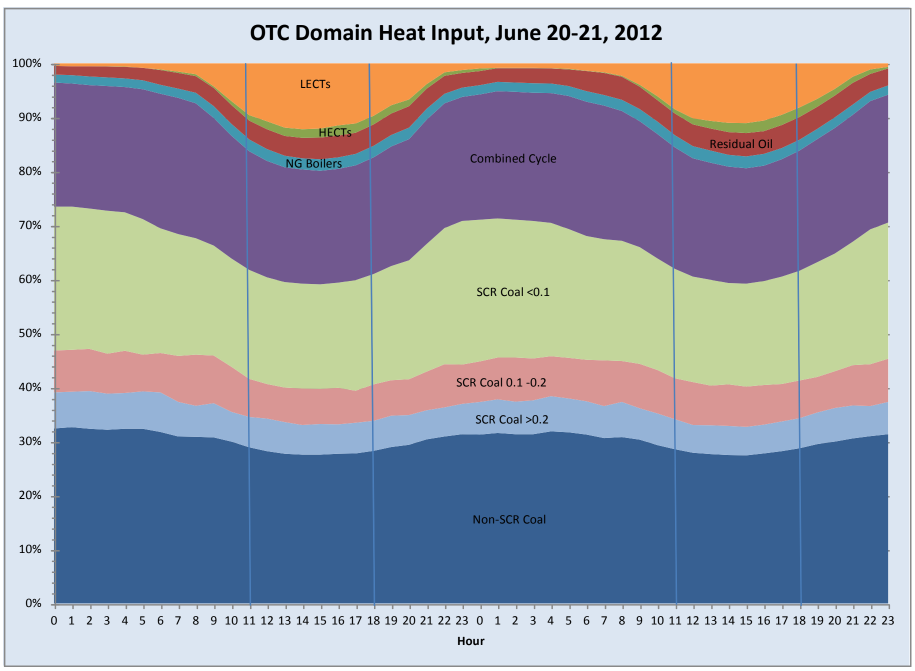


Hourly NO_X Rate on 06.20.12 for hour 16- Operating Coal Units for Connecticut, Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, New York, Ohio, Pennsylvania, Tennessee



Results of Subgroup HEDD analysis for the OTC Modeling Domain on: Low Emitting Combustion Turbines (LECTs with NO_X emissions <0.125 lb/mmBtu), High Emitting Combustion Turbines (HECTs with NO_X emissions >0.125 lb/mmBtu) and coal-fired EGUs with and without SCR controls are presented in the following graphs.





C. Analysis 3: Short-term Daily EGU NO_X Emissions

Analysis

An update of a previous analysis done in 2007 for daily NO_X emissions by fuel type and maximum daily temperature for EGUs located in the OTR and Lake Michigan Air Directors Consortium (LADCO) states was performed.

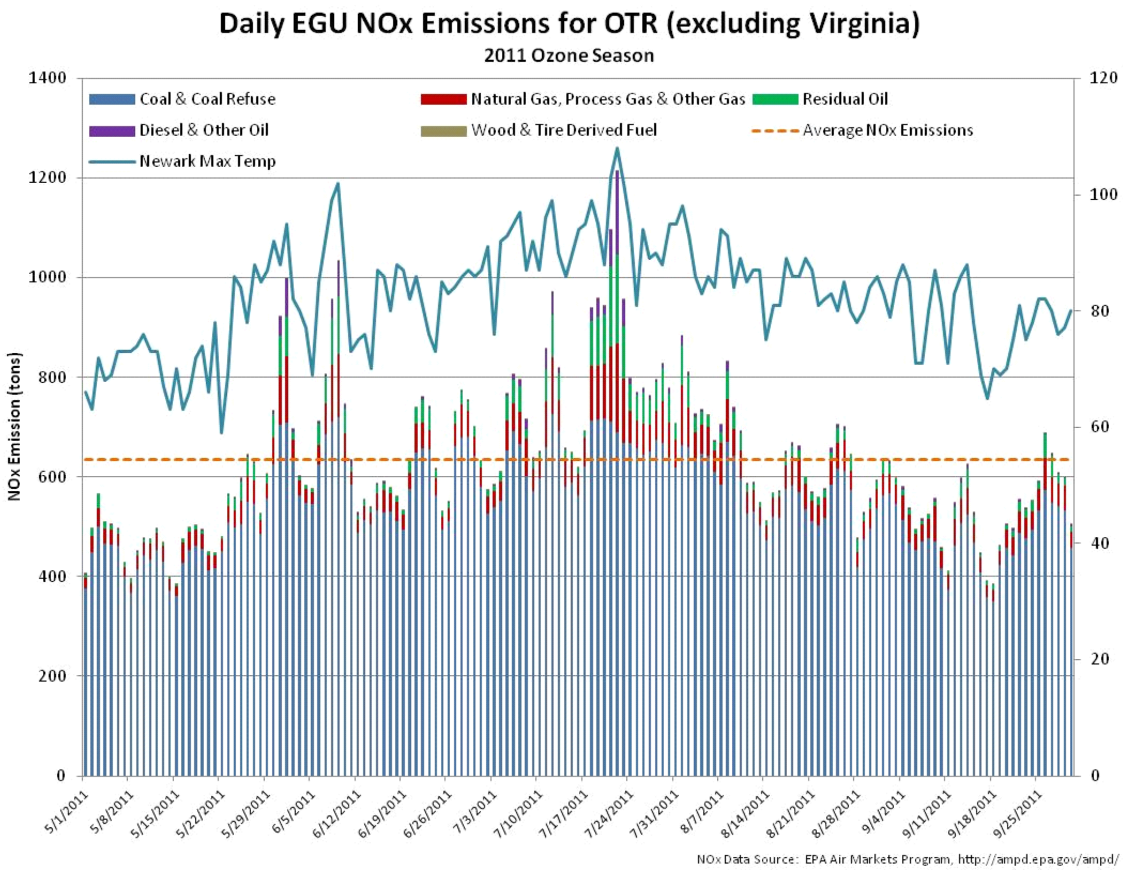
The total daily EGU NO_X emission for each fuel type was calculated to determine each fuel-type's contribution to daily regional NO_X emissions. The 2011 unit-level EGU NO_X emissions data was downloaded for each state from EPA's AMPD website[4]. The unit-level NO_X emissions data was summed by state and fuel type for each ozone-season day (May 1, 2011 through September 30, 2011). The state-level NO_X emissions for the OTC and LADCO states was then totaled by fuel type and the contribution to daily regional NO_X emissions of each fuel type was graphed for the OTC and LADCO states. The temperature data was obtained from the National Oceanic and Atmospheric Administration (NOAA)[5] website.

Results

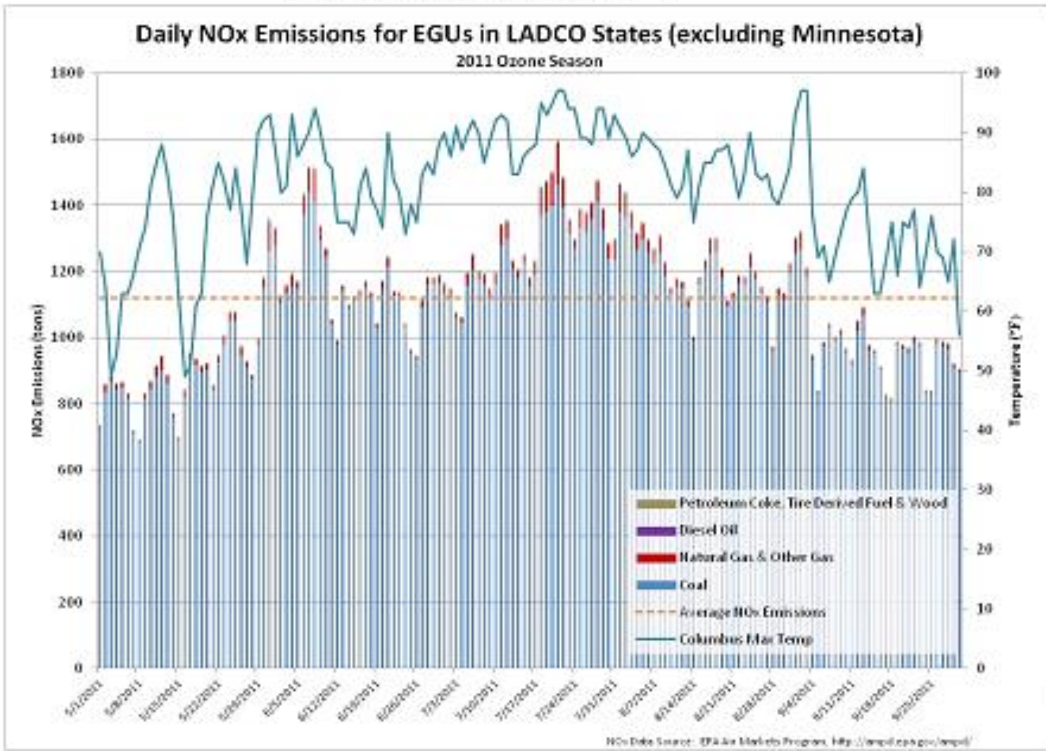
The results demonstrate that daily EGU NO_X emissions increased with the ambient temperature, with the highest daily NO_X EGU NO_X emissions occurring on days with the highest daily temperatures. In the OTC states, NO_X emissions from oil-fired EGU boilers and diesel fuel-fired EGUs also peaked on the days with highest daily temperatures.

The following graphs demonstrate the majority of EGU NO_X emitted on HEDD in the OTR and LADCO during the 2011 ozone season were from coal-fired units. NO_X emissions from EGUs firing other fuels (e.g., diesel, residual oil, natural gas) were very small in the LADCO region while their contribution was significant in the OTR, especially on HEDD.

[4] http://ampd.epa.gov/ampd/
[5] http://www.nws.noaa.gov/climate/


Daily EGU NOx Emissions for OTR (excluding Virginia)
2011 Ozone Season
Coal & Coal Refuse
Natural Gas, Process Gas & Other Gas
Residual Oil
Diesel & Other Oil
Wood & Tire Derived Fuel
Average NOx Emissions
Newark Max Temp
NOx Emission (tons)
Temperature (°F)
0
200
400
600
800
1000
1200
1400
0
20
40
60
80
100
120
5/1/2011
5/8/2011
5/15/2011
5/22/2011
5/29/2011
6/5/2011
6/12/2011
6/19/2011
6/26/2011
7/3/2011
7/10/2011
7/17/2011
7/24/2011
7/31/2011
8/7/2011
8/14/2011
8/21/2011
8/28/2011
9/4/2011
9/11/2011
9/18/2011
9/25/2011
NOx Data Source: EPA Air Markets Program, http://ampd.epa.gov/ampd/

LADCO 2011



D. Analysis 4: "Coal SCR Scorecard

Analysis

A "Coal SCR Scorecard" listing the number of power plants equipped with SCR controls with higher NO_X emission rates during the 2011, 2012, and 2013 ozone seasons than previously demonstrated was prepared by the Subgroup.

The scorecards illustrate the relative performance of SCR-equipped coal units in the listed states. For example, of the 5 SCR-equipped coal plants in Alabama, only 1 operated at an emission rate substantially greater than previously demonstrated or its "optimum" rate in 2011, for a "grade" of 80%. In 2012, another plant in Alabama operated at an emission rate substantially greater than previously demonstrated for a "grade" of 60%, while in 2013 only 4 plants operated, one sub-optimally for a "grade" of 75%. In Kentucky, 5 plants were sub-optimum in 2011, one of which appeared to not operate its SCR at all for a "grade" of 50%. While in 2012, 1 of the 5 Kentucky plants operations improved for a "grade" of 64%. Whereas, in Maryland and New Jersey, all plants operated their SCRs at optimum levels in 2011 and 2012. These variations imply differing state regulations with respect to NO_X emissions.

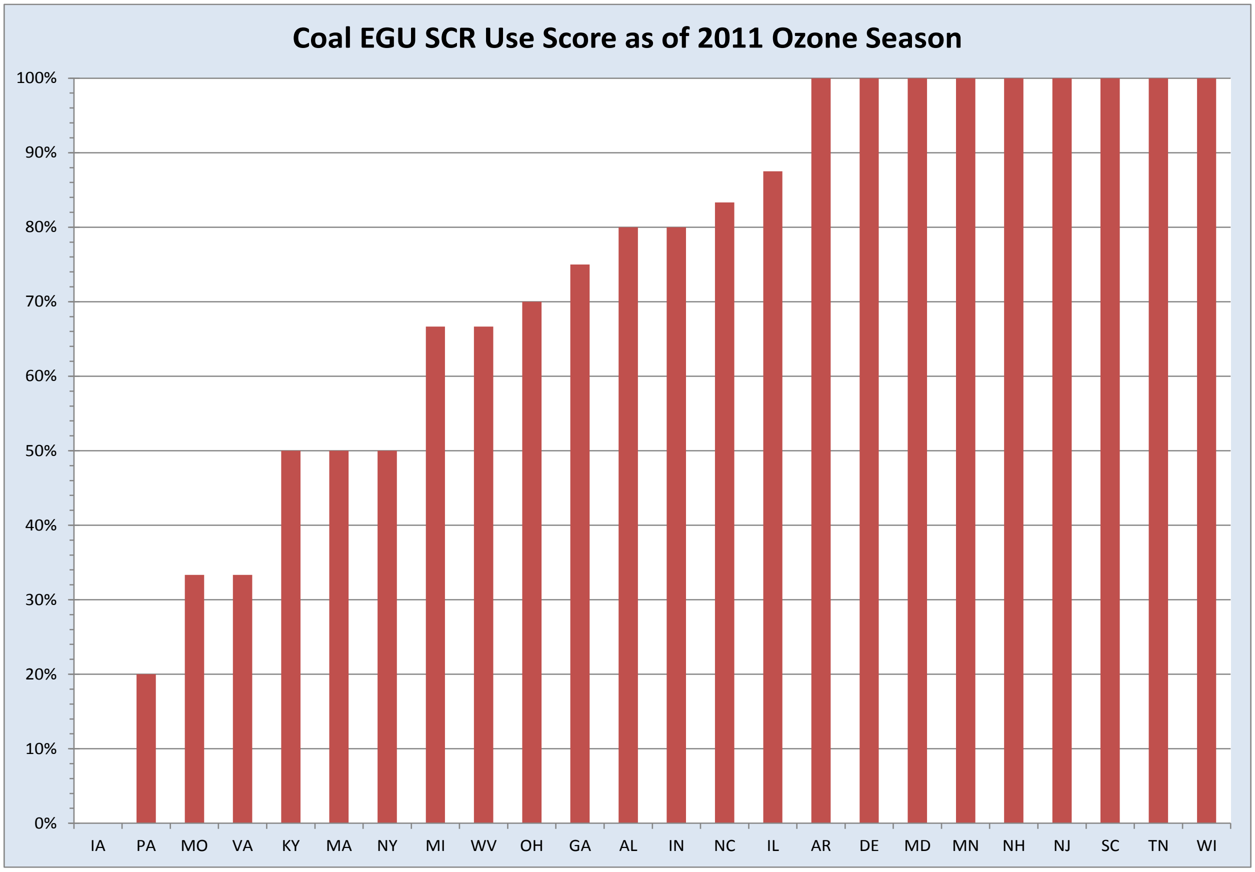
Results

The results of the "Coal SCR Scorecard" analysis demonstrate that in several cases power plants equipped with SCR controls had higher NO_X emission rates during the 2011, 2012, and 2013 ozone seasons than previously demonstrated. Analysis results indicate some EGUs are either not operating or limiting the operation of their existing air pollution control devices.

Coal Scorecard- 2011

State	Plants	Number of Plants in 2011 with NO_X Rate > Previously Demonstrated	SCR Off	SCR Less than Optimum	Grade	Comment
AL	5	1	0	1	80%	
AR	1	0			100%	
DE	0	0			100%	
GA	4	1	0	1	75%	
IA	1	1			0%	
IL	8	1	1		88%	
IN	10	2	0	2	80%	
KY	10	5	1	4	50%	
MA	2	1			50%	
MD	4	0			100%	
MI	3	1			67%	
MN	1	0			100%	
MO	3	2	0	2	33%	
NC	6	1		1	83%	
NH	1	0			0%	
NJ	4	0			100%	
NY	2	1		1	50%	1 of 4 in 2010
OH	10	3		3	70%	
PA	5	4	2	2	20%	
SC	5	0			100%	
TN	4	0			100%	
VA	3	2		2	33%	
WI	3	0			100%	
WV	6	2	0	2	67%	
Total	102	28	3	25		
Percentage of Total		27%	3%	25%		

Coal EGU SCR Use Score as of 2011 Ozone Season

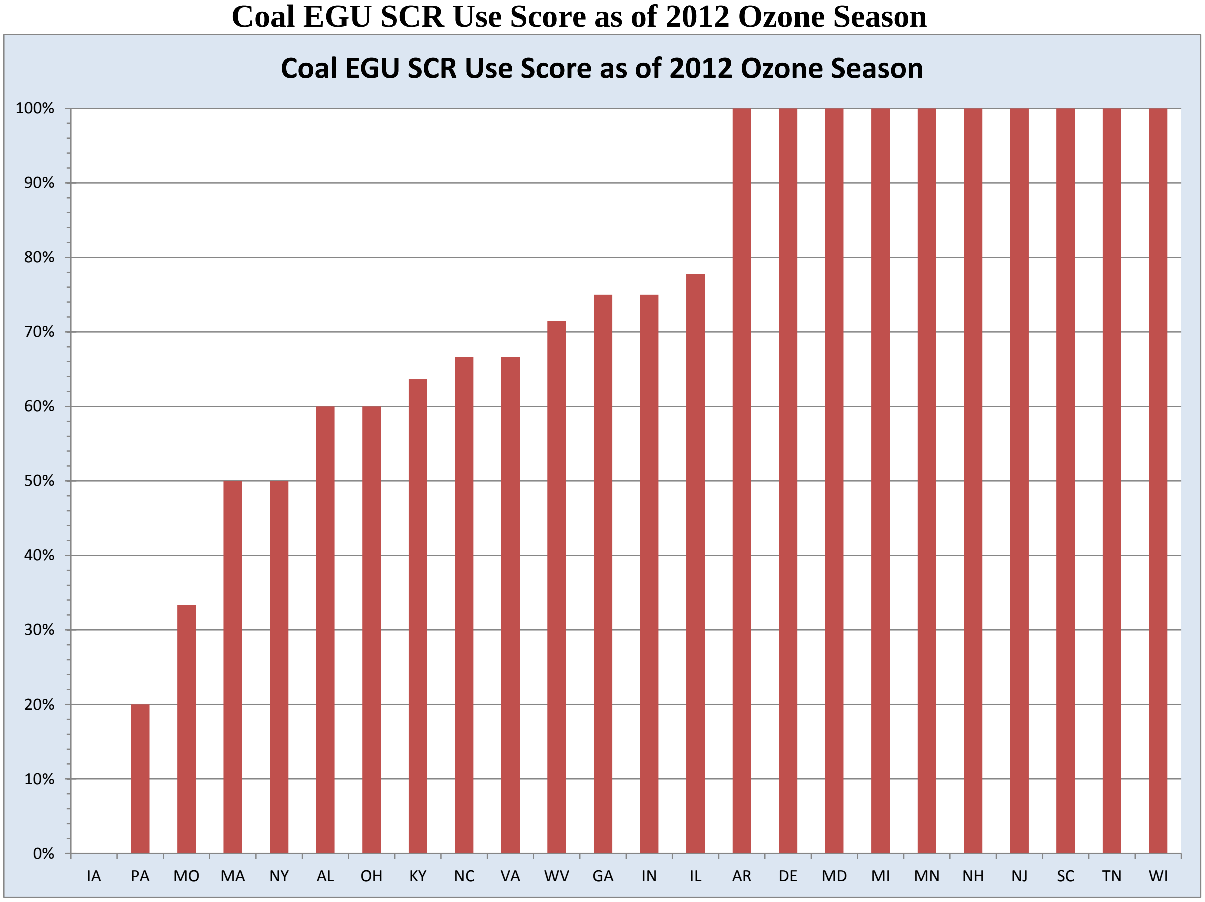


Coal Scorecard- 2012

State	Plants	Number of Plants in 2012 with NO_X Rate > Previously Demonstrated	SCR Off	SCR Less than Optimum	Grade	Comment
AL	5	2		2	60%	
AR	1	0			100%	
DE	1	0			100%	
GA	4	1	0	1	75%	
IA	1	1		1	0%	
IL	9	2		2	78%	
IN	12	3	1	2	75%	
KY	11	4	1	3	64%	
MA	2	1		1	50%	
MD	4	0			100%	
MI	3	0			100%	
MN	1	0			100%	

State	Plants	Number of Plants in 2012 with NOx Rate > Previously Demonstrated	SCR Off	SCR Less than Optimum	Grade	Comment
MO	3	2	2	0	33%	
NC	6	2	0	2	67%	
NH	1	0	0	0	100%	
NJ	4	0			100%	
NY	2	1		1	50%	1 of 4 in 2010
OH	10	4	2	2	60%	
PA	5	4	3	1	20%	
SC	5	0			100%	
TN	4	0			100%	
VA	3	1		1	67%	
WI	4	0			100%	
WV	7	2	1	1	71%	
Total	108	30	10	20		
Percentage of Total		28%	9%	19%		

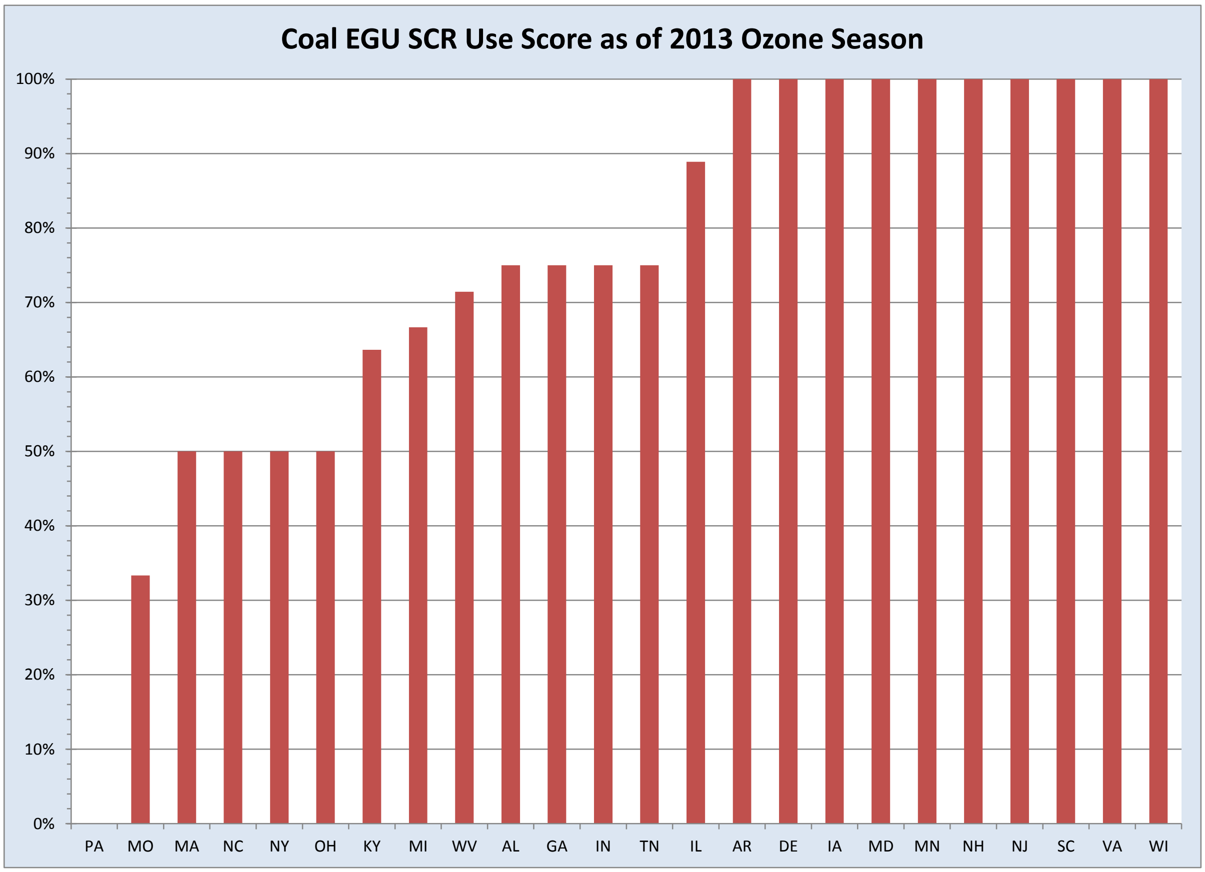
Coal EGU SCR Use Score as of 2012 Ozone Season



Coal Scorecard- 2013

State	Plants	Number of Plants in 2013 with NO_X Rate > Previously Demonstrated	SCR Off	SCR Less than Optimum	Grade	Comment
AL	4	1		1	75%	
AR	1	0			100%	
DE	1	0			100%	
GA	4	1	0	1	75%	
IA	1	1		1	0%	
IL	9	1		1	89%	
IN	12	3	2	1	75%	
KY	11	4	1	3	64%	
MA	2	1		1	50%	
MD	4	0			100%	
MI	3	1		1	67%	
MN	1	0			100%	
MO	3	2	2		33%	
NC	6	3		3	50%	
NH	1	0			100%	
NJ	4	0			100%	
NY	2	1		1	50%	
OH	10	5	2	3	50%	
PA	5	5	3	2	0%	
SC	5	0			100%	
TN	4	1		1	75%	
VA	3	0		0	100%	
WI	5	0			100%	
WV	7	2	1	1	71%	
Total	108	31	11	20		
Percentage of Total		29%	10%	19%		

Coal EGU SCR Use Score as of 2013 Ozone Season



E. Analysis 5: Recommendation for Modeling of Short-term NO_X Emission Limits[6]

Analysis

EGU NO_X emission rate data indicates that many of the EGU exhibited average NO_X emission rates in excess of what might be expected for EGUs incorporating post-combustion controls. In recent ozone seasons, some EGUs reported to incorporate post-combustion NO_X controls have exhibited average NO_X emission rates higher than previous ozone season averages. Application of short-term NO_X emission rate limits that

[6] Rates used in this section were provided by OTC States. The OTC EGU Subgroup requested from all OTC states short-term rates that were on the books. The EGU subgroup received responses from Connecticut, Delaware, New Hampshire, New Jersey, and New York. The emission rate for Wisconsin was provided by an OTC state. The rates in this section are meant to be reflective of base load units, peaking units and units used with lower capacity may have other limits with which to comply.

reflect the capabilities of NO_X emissions controls can reduce short-term emission rates to rates expected from units with installed post combustion NO_X controls.

The short-term NO_X limits listed in the following tables as “Current Thinking” are not intended to reflect technological edge of NO_X control capability, but rather to represent NO_X control retrofit capability for much of the EGU industry. The State rules included in analysis are from Connecticut, Delaware, New Hampshire, New Jersey, New York and Wisconsin. The averaging times for the EGU boiler NO_X limits found in state rules are stated in terms of 24 hr. rolling averages or 24 hr. calendar day averages. EGU combustion turbine NO_X limits found in state rules varied from state to state with some 1 hr avg. limits, some 24 hr avg. limits and some 30 day rolling avg. limits. The conversion factor used for EGU boilers assumed 0.1 lb/MM Btu ≈ 1.0 lb/MWh. For simple cycle turbines combusting natural gas fuel it was assumed that 50 ppmvd@15%O2 ≈ 0.1838 lb/MM Btu. For combined cycle turbines combusting natural gas fuel it was assumed that 42 ppmvd@15%O2 ≈ 0.1544 lb/MMBtu.

Short Term NOx Limits for EGU Boilers

Unit Type	Heat Input (MM Btu/hr)	Boiler Type	Current Thinking (lb/MMBtu) 24 hr. avg.	Range (lb/MMBtu) 24 hr. avg.	Range (lb/MWh)
Boiler – Solid Fuel	**HI= 1000**	Arch, Cell or CFB	0.125	0.125 - 0.150	1.25 - 1.5
		Cyclone Dry Bottom	0.150*	0.125 - 0.150	1.25 - 1.5
		Cyclone Wet Bottom		0.125 - 1.40	1.25 - 14.0
		Stoker	0.150	0.08 - 0.30	0.8 - 3.0
		Tangential	0.125	0.12 - 0.38	1.2 - 3.8
		Wall	0.125	0.12 - 0.50	1.2 – 5.0

Short Term NOx Limits for EGU Boilers

Unit Type	Heat Input (MM Btu/hr)	Boiler Type	Current Thinking (lb/MMBtu) 24 hr. avg.	Range (lb/MMBtu) 24 hr. avg.	Range (lb/MWh)
Boiler – Solid Fuel	**HI≤1000**	Arch or Cell CFB	0.150 0.125	0.125 - 0.150 0.125 - 0.150	1.25 - 1.5 1.25 - 1.5
		Cyclone Dry Bottom	0.150*	0.125 - 0.150	1.25 - 1.5
		Cyclone Wet Bottom		0.20 - 0.92	2.0 - 9.2
		Stoker	0.150	0.125 - 0.30	1.25 - 3.0
		Tangential	0.150	0.120 - 0.38	1.2 - 3.8
		Wall	0.150	0.120 - 0.50	1.2 - 5.0

Short Term NOx Limits for EGU Boilers

Unit Type	Heat Input (MM Btu/hr)	Boiler Type	Current Thinking (lb/MMBtu) 24 hr. avg.	Range (lb/MMBtu) 24 hr. avg.	Range (lb/MWh)
Boiler-Gas	All	All	0.125	0.08 - 0.125	0.8 - 1.25
Boiler-Distillate Oil	All	All	0.125	0.125 - 0.15	1.25 - 1.5
Boiler–Residual Oil	All	All	0.150	0.125 - 0.20	1.25 - 2.0

State Rules Summary (Cont'd) (CT, DE, NH, NJ, NY, & WI)

Short Term NOx Limits for EGU Turbines

Unit Type	Heat Input (MM Btu/hr)	Turbine Type	Current Thinking (ppmvd@15%O_2)	Range (ppmvd@15%O_2)	Range (lb/MWh)
Combustion Turbine Gas Fuel	All	Simple Cycle	25*	25 - 55	1.0 - 2.2
Combustion Turbine Gas Fuel	All	Combined Cycle	25*	25 - 43.3	0.75 - 1.3
Combustion Turbine Oil Fuel	All	Simple Cycle	42*	42 - 100	1.6 - 3.81
Combustion Turbine Oil Fuel	All	Combined Cycle	42*	42 - 88	1.2 - 2.51

Results

A potential solution to the air quality problems caused by sources not operating or limiting the operation of their emission controlling technology is the establishment of short-term NO_X emission rate limits for EGUs that are based on reported short-term NO_X emission rates and reflective of good emission control practices[7] using reasonably available NO_X emissions controls that are applicable for the particular types of EGUs.

The proposed short-term NO_X emission rates shown below are felt to be reflective of the capabilities of EGUs with reasonable application of NO_X controls when those units are operated in accordance with good emission control practices. The proposed short-term NO_X emission rate limits are felt to be representative of the capabilities of layered combustion controls or post-combustion controls in retrofit installations. In order to ensure that the emission rate reduction capabilities of various EGU configurations and fuel selections are addressed, the proposed short-term NO_X emission rate limits account for these EGU configurations and fuel differences.

The proposed short-term NO_X emission rate limits, based on reported short-term NO_X emission rates, include averaging periods that are felt to be necessary to support attainment and maintenance of short-term air quality standards, the proposed short-term NO_X emission rate limits are expected to be sustainable over a long period of time given good operating and maintenance practices.

[7] Good emission control practices means operating the NOX emission controls as efficiently as possible in order to reduce NOX emissions as much as possible. Good emissions control would also include maintaining the emission controls according to manufacturer's recommendations.

If the proposed short-term NO_X emission rate limits are adopted by regulatory bodies (state rules, regional MOUs, potential federal rule), there would not only be an expectation of general air quality improvement, but it would also be expected to be especially effective during periods of high electric demand which often correspond to air quality episodes. The short-term NO_X emission rate limits would therefore be expected to help reduce the frequency and magnitude of those air quality episodes.

The proposed short-term NO_X emission rate limits are included in the following table:

Unit Type	Heat Input Capacity (MMBtu/hr)	Configuration	NO_X Limit (lb/MMBtu)	Averaging Period
Boiler - Solid Fuel	HI ≥ 1000	Arch	0.125	24-hours
		Cell	0.125	24-hours
		CFB	0.125	24-hours
		Cyclone	0.150*	24-hours
		Stoker	0.150	24-hours
		Tangential	0.125	24-hours
		Wall	0.125	24-hours
Boiler - Solid Fuel	HI < 1000	Arch	0.150	24-hours
		Cell	0.150	24-hours
		CFB	0.125	24-hours
		Cyclone	0.150	24-hours
		Stoker	0.150	24-hours
		Tangential	0.150	24-hours
		Wall	0.150	24-hours
Boiler - Gas Fuel	All	All	0.125	24-hours
Boiler - Distillate Oil Fuel	All	All	0.125	24-hours
Boiler - Residual Oil Fuel	All	All	0.150	24-hours
Combustion Turbine - Gas Fuel	All	Simple Cycle	25 ppmvd@15%O2*	1-hour
			0.10 lb/MMBtu	1-hour
			1.0 lb./MWh**	1-hour
		Combined Cycle	25 ppmvd@15%O2*	1-hour
			0.10 lb/MMBtu	1-hour
			0.75 lb/MWh**	1-hour
Combustion Turbine - Oil Fuel	All	Simple Cycle	42 ppmvd@15%O2*	1-hour
			0.16 lb/MMBtu	1-hour
			1.6 lb/MWh**	1-hour
		Combined Cycle	42 ppmvd@15%O2*	1-hour
			0.16 lb/MMBtu	1-hour
			1.2 lb/MWh**	1-hour

* Some state rules also include provisions for: alternative emission limits, NO_X RACT orders with alternative NO_X RACT emission limits, or the implementation of specific types of NO_X control technologies. Similar alternative compliance means may be necessary for some existing units that may not be able to achieve these NO_X rate limits with NO_X emission controls representative of RACT.
**lb/MWh emission rates calculated using an efficiency of 35% for simple cycle CTs and 46% for combined cycle CTs [lb/MWh = lb/MMBtu * 3.413 / efficiency]

Appendices

1. Ozone Transport Commission charge to the Stationary and Area Source Committee at November 2012 Fall meeting, Attached and available at: http://www.otcair.org/upload/Documents/Formal%20Actions/Charge%20to%20SAS%20Committee.pdf

2. Ozone Transport Commission charge to the Stationary and Area Source Committee at November 2013 Fall meeting available at: http://www.otcair.org/upload/Documents/Formal%20Actions/Chrg%20to%20SAS%20for%20Reg%20Attainment%20of%20Ozone.pdf

3. Rev 11 25 13 EGU 25 MW MASS Shutdowns 121613 – Estimated NO_X Emissions Baseline & CHARTS.xls

4. Rev 11 25 13 EGU 25 MW RATES Shutdowns 121613 – Estimated NO_X Emissions Baseline & CHARTS.xls

List of References

1. Statement from the Ozone Transport Commission Requesting the Use and Operation of Existing Control Devises Installed at Electric Generating Units, June 2013 available at http://www.otcair.org/upload/Documents/Formal%20Actions/Statement_EGUs.pdf

2. Ozone Transport Commission Draft Model Rule Control of Oil and Gas Fired Electric Generating Unit Boiler NO_X Emissions, June 2010 available at http://www.otcair.org/upload/Documents/Meeting%20Materials/OTC%20Oil%20and%20Gas%20EGU%20Boiler%20NOX%20Model%20Rule%20Draft%20B_MOU_100603.pdf

3. Ozone Transport Commission Draft Model Rule Control of NO_X Emissions from Natural Gas and Distillate Oil Fired HEDD Combustion Turbines, June 2010 available at http://www.otcair.org/upload/Documents/Model%20Rules/OTC%20Model%20Rule%20-%20HEDD%20Turbines%20Final.pdf

4. Ozone Transport Commission Memorandum of Understanding Among the States of the Ozone Transport Commission Concerning the Incorporation of High Electric Demand Day Emission Reduction Strategies into Ozone Attainment State Implementation Planning, March 2007, available at http://www.otcair.org/upload/Documents/Formal%20Actions/OTC_2007_SpecialMtg_%20HEDDMOU_Final_070302[1].pdf

5. OTC Modeling Domain – Revised 041213.pptx

6. Ozone Transport Commission 2013 Annual Meeting, Stationary and Area Source Presentation, New Haven, Connecticut, slide 7-8, June 13, 2013

7. http://ampd.epa.gov/ampd/

8. http://www.nws.noaa.gov/climate/

9. "Final SAS Committee Update 040413 (2)".pptx

10. OTC Domain HEDD, June 21-22, 2012.pptx

11. Coal SCR Scorecard 3. pptx

12. Revised State Rules Summary Slides (CT, DE, NH, NJ, NY, & WI) 020414.pdf

13. NO_X Rate Limit Refs.xlsx

14. Short-term NO_X Limits Draft 9.xls

OZONE TRANSPORT COMMISSION

Connecticut

Delaware

District of Columbia

Maine

Maryland

Massachusetts

New Hampshire

New Jersey

New York

Pennsylvania

Rhode Island

Vermont

Virginia

J. Wick Havens
Interim Executive Director

444 N. Capitol St. NW
Suite 638
Washington, DC 20001
(202) 508-3840
FAX (202) 508-3841
Email: ozone@otcair.org

Charge to the Stationary and Area Source Committee to Pursue New Approaches in 2013

The Ozone Transport Commission (OTC) directs the Executive Staff and the OTC Stationary and Area Source Committee to perform technical, legal and economic analyses to help OTC develop the following strategies to achieve substantial emissions reductions of ozone-forming pollutants in the most cost effective manner:

(1)Largest Contributor Analysis.
Using the most recent available state and regional emissions inventory data, identify the largest individual and groupings of emitters of NOx and VOC within the OTC states and within any non-OTC state that contributes at least 1% of the 2008 ozone National Ambient Air Quality Standard (NAAQS) of 75 ppb to a monitor in the OTC region (see attached map). Appropriate goals and means to reduce the emissions from the identified units and groupings in a reasonable and equitable manner should be developed.

- High Short-Term Emissions Analysis.
Using the above mentioned inventories and other available data, identify individual emissions sources with the highest short-term emissions of NOx and VOC regardless of the total emissions from such sources and consider the coincidence between the high emission rates and high ozone days. The Committee should develop additional strategies, if necessary beyond current actions, to reduce the peak emissions from such units.

- Review and evaluate EGU operating emissions.
Review available data to evaluate the real world achievable NOx emission rates across load ranges, the effect of time/total operation on the effectiveness of controls, identify the periods of time that units operate without full utilization of their installed controls and variations due to fuels. Then utilize the data to adjust long and short term expectations for emissions reductions dependent upon controls/age/fuel. Develop a state -by -state EGU NOx emission rate achievable considering reasonably available controls.

(2)Distributed and Emergency Generator Inventory.
Through the actions of the OTC or the member states, obtain information from the regional system operators (PJM, ISO New England, NYISO) concerning the location, operations and emissions of all generation units that participate, and that are projected to participate, in the demand response and emergency demand response programs offered by each regional system operator. Analyze the collected data to understand the air quality impact of the operation of the distributed and emergency generators and make recommendations for potential control strategies to the Commission.

(3) Economic Impact Assessment.
As directed in a May 24, 2012 Charge to the Stationary and Area Source Committee, the Committee should provide an economic impact assessment of each new or significantly revised strategy that is presented to the Commission for action or consideration.

For any model rule adopted by the Stationary and Area Source committee that is based on a rule of the California Air Resources Board (CARB), the Committee should maintain such model rules by adding new product categories or revising standards so as to maintain consistency with any revised standards of CARB. The other committees of the OTC are directed to provide whatever assistance is needed to the Stationary and Area Source Committee in carrying out this Charge.

Adopted by the Commission on November 15, 2012

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J. Wick Havens
Interim Executive Director

444 N. Capitol St. NW
Suite 322
Washington, DC 20001
(202) 508-3840
FAX (202) 508-3841
Email: ozone@otcair.org

Charge to the Stationary and Area Source Committee to Pursue Potential Strategies in 2014 for Regional Attainment of Ozone National Ambient Air Quality Standards

The Ozone Transport Commission (OTC) directs the Executive Staff and the OTC Stationary and Area Source Committee to perform technical, legal and economic analyses to help OTC identify strategies to achieve substantial emissions reductions of ozone-forming pollutants in the most cost effective manner. The goal is to identify potential strategies (including appropriate geographical areas for application) for review at the 2014 Annual Meeting to address persistent nonattainment issues for consideration of strategies by the Fall 2014 Meeting.

(1) Largest Contributor Analysis.
Using the most recent available state and regional emissions inventory data with emphasis on states that contribute at least 1% of the 2008 ozone National Ambient Air Quality Standards (NAAQS) of 75 ppb to a monitor in the OTC region identify the largest individual and groupings of emitters of NOx within the OTC and non-OTC state. Evaluate OTR, super regional, and national goals and means to reduce the emissions in a technical and cost effective manner from the identified units and groupings. The Committee should develop additional strategies, if necessary to reduce the peak emissions from such units.

(2) Distributed and Emergency Generator Inventory.
Through the actions of the OTC or the member states, seek information from the regional system operators (PJM, ISO New England, NYISO) concerning the location, operations and emissions of all generation units that participate, and that are projected to participate, in the demand response and emergency demand response programs offered by each regional system operator. Work with states to use state authority to gather information on demand response engines within their jurisdictions. Determine the air quality impact of demand response engines replacing cleaner sources of energy on High Electric Demand Days. Analyze the collected data to understand the air quality impact of the operation of the distributed and emergency generators and make recommendations for potential control strategies to the Commission.

(3) Economic Impact Assessment.
As directed in a May 24, 2012 Charge to the Stationary and Area Source Committee, the Committee should provide an economic impact assessment of each new or significantly revised strategy that is presented to the Commission for action or consideration.

For any model rule currently approved by the Commission that is based on a rule of the California Air Resources Board (CARB), the Committee should maintain such model rules by adding new product categories or revising standards so as to maintain consistency with any revised standards of CARB. The other committees of the OTC are directed to provide whatever assistance is needed to the Stationary and Area Source Committee in carrying out this Charge.

Adopted by the Commission on November 14, 2013