March 2014

DRAFT
Electric Generating Unit Emissions Inventory Analyses 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 (NOx) 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 NOx or VOCs;
(2) review electric generating unit (EGU) NOx emission rates to adjust long- term and short-term expectations for emissions reductions; and
(3) develop state-by-state NOx emissions rates that would be considered reasonably available control technology (RACT)[1].

SAS was additionally instructed 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]."
An EGU subgroup (Subgroup)within the OTC Largest Contributors Workgroup of SAS was formed to examine EGU emissions and address the tasks listed above. This document presents the results of the inventory analyses performed to date by the Subgroup. The Subgroup, with the assistance of SAS and the OTC Modeling Committee will perfrom additional analyses as necessary and provide those results in a future report.

Project Scope

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

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

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[1] Ozone Transport Commission charge to the Stationary and Area Source Committee at November 2012 Fall meeting, Attached and available at:
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(2) evaluate NOx emission rates for EGUs considering multiple factors;[3,4,5] and
(3) develop strategies for adjusting short term and long term expectations for emission rate reductions from 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 NOx budget and short term ozone season NOx 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 ERTAC model and may eventually be used to make recommendations to the United States Environmental Protection Agency (EPA) for future regulations of EGU operations.

Project Results

Operation of Emissions Controls

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

Approach 1 NOx Controls and EGU Retirements

The results of the Approach 1 NOx control analyses and the separate analysis performed on the potential impact of EGU retirements on ozone season NOx emissions demonstrate that the potential impact of the Approach 1 NOx controls and the potential impact of the EGU retirements will vary from state to state. In some states no coal-fueled EGU

[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

[4] 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

[5] 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

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

retirements are anticipated while in other states a significant amount of coal-fueled EGU retirements are projected. The projected impact of Approach 1 NOx controls, if implemented, will result in larger reductions of NOx emissions than the projected impact of EGU retirements.

Analysis of Short Term (Hourly) EGU NOx Emissions – 2012

The results of the State of Delaware hourly EGU NOx emissions and hourly NOx emission rates (June 21-22, 2012) study demonstrate EGU NOx emissions varied on an hourly basis with maximum emissions occurring during hour 16 on June 20, 2012. NOx emission rates from all types of coal-fired EGU also peaked during this time. The review of the related data for the 48-hour period from June 20 through June 21, 2012 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 for the potential air quality impact if the electric demand was higher thereby causing additional EGUs to be brought on line;
- The NOx emission rates from a number of EGUs were much greater than would be expected relative to the NOx controls reported to be installed on those units;
- During hour 16, for states subject to the CAIR ozone season NOx 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 NOx mass emissions.

Analysis of Short Term (Daily) EGU NOx Emissions – 2011

The results of the 2011 daily EGU NOx emissions analyses demonstrate that daily EGU NOx emissions increased with the ambient temperature, with the highest daily NOx EGU NOx emissions occurring on days with the highest daily temperatures. In the OTC states, NOx emissions from oil-fired EGU boilers and diesel fuel-fired EGUs also peaked on the days with highest daily temperatures.

"Coal SCR Scorecard" Analysis – 2011 & 2012

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

Recommendation for Modeling of Short Term NOx Emission Limits

As discussed in the section on Approach 5 of this document, the EGU NOx emissions rate data indicates that some EGU's with NOx controls reported to be installed are emitting at rates in excess of what might be expected from EGUs with installed NOx controls. The NOx emission rates for some EGUs in recent ozone seasons were significantly higher than the NOx emission rate demonstrated by those EGUs in previous years.

A potential solution is the establishment of short term NOx emission rate limits for EGUs that are based on reported short term NOx emission rates and reflective of good emission control practices using reasonably available applicable NOx emissions controls.

The proposed short term NOx emission rates shown below are reflective of the reasonable application of NOx controls. The proposed short term NOx emission rate limits are 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 NOx emission rate limits account for these EGU configurations and fuel differences.

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

If the proposed short term NOx 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 NOx emission rate limits would therefore be expected to help reduce the frequency and magnitude of those air quality episodes.

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

Unit Type	**Heat Input Capacity (MMBtu/hr)**	**Configuration**	**NOx 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 NOx RACT orders with alternative NOx RACT emission limits, or the implementation of specific types of NOx control technologies. Similar alternative compliance means may be necessary for some existing units that may not be able to achieve these NOx rate limits with NOx 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]

OTC Largest Contributor EGU Subgroup
EGU Emissions Inventory Analyses - Draft Whitepaper
Date: March 2014

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Project Criteria

The scope of this inventory analysis is as follows:

- **Years:** The years 2011 and 2012 were selected as years of interest. Data from the EPA's Clean Air Markets Division (CAMD) was available for both of these years. In addition, data from other years was reviewed in order to fully evaluate the 2011 and 2012 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 NOx mass emissions evaluation and state level ozone season NOx emission rate evaluation.

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

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- **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 NOx 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 NOx budget analyses only the 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 NOx emission rate analyses all units reporting to EPA's CAMD database were included.

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

Technical Approach

Unit-level Criteria for NOx emissions

The 2011 and 2012 unit level NOx emissions (mass and rate) were copied 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 NOx
- 2011 High Ozone Episode NOx (hourly and daily, as available)
- 2012 Ozone Season NOx
- 2012 High Ozone Episode NOx (hourly and daily, as available)

Unit-level data elements include:
- State name
- Facility name
- Facility ID
- Unit ID
- NOx emissions (tons)
- NOx Rate (lb/mmBtu) reported
- NOx Rate (lb/mmBtu) calculated
- NOx Rate (lb/MWhr) calculated
- Heat Input (mmBtu)
- Operating Time (hours)
- # of months reported

- Source Category
- Unit Type
- Fuel Type
- Age of Unit
- Capacity factor
- NOx Controls

Analyses and Results

A detailed description of each analysis performed by the Subworkgroup and a summary of the results are set out below.

Top 25 Ozone Season NOx Emitters in the OTC Modeling Domain

Analysis

The Subworkgroup prepared an analysis of the Top 25 Ozone Season NOx Emitters in the OTC Modeling Domain for 2011 and 2012. Criteria for inclusion in the list was the mass of NOx emitted during the ozone season, the NOx emission rate was included as additional information.

	State	Facility Name	Facility ID	Unit ID	SO2 (tons)	Avg. NOx Rate (lb/MMBtu)	NOx (tons)
Top 25 NOx Emitters 2011 OS	IN	Rockport	6166	MB2	15215.217	0.2431	5,339
	PA	Keystone	3136	2	12003.958	0.3630	5,044
	PA	Keystone	3136	1	11465.644	0.3717	4,855
	PA	**Hatfield's Ferry Power Station**	**3179**	**1**	240.25	0.4923	4,288
	PA	Conemaugh	3118	2	1741.005	0.3170	4,086
	PA	**Hatfield's Ferry Power Station**	**3179**	**2**	211.755	0.4746	3,984
	AR	White Bluff	6009	1	8193.767	0.2755	3,956
	PA	Conemaugh	3118	1	1581.72	0.3411	3,890
	PA	Brunner Island	3140	3	3941.335	0.3760	3,834
	AR	White Bluff	6009	2	7577.479	0.2798	3,794
	IN	Rockport	6166	MB1	10408.895	0.2372	3,616
	OH	W H Zimmer Generating Station	6019	1	7574.883	0.2189	3,559
	AR	Independence	6641	1	6946.97	0.2591	3,302
	PA	Montour	3149	1	4217.97	0.3323	3,298
	PA	Montour	3149	2	4088.761	0.3159	3,132
	PA	**Hatfield's Ferry Power Station**	**3179**	**3**	272.927	0.4320	2,848
	MI	Monroe	1733	2	10698.832	0.2851	2,811
	GA	**Harllee Branch**	**709**	**4**	13145.319	0.4076	2,806
	WV	Fort Martin Power Station	3943	1	1001.621	0.3514	2,660
	NY	Lafarge Building Materials, Inc.	880044	41000			2,647
	AR	Independence	6641	2	5911.525	0.2270	2,463
	KY	Paradise	1378	3	1413.673	0.3865	2,431
	NY	Somerset Operating Company (Kintigh)	6082	1	4574.54	0.2965	2,347
	OH	Avon Lake Power Plant	2836	12	15158.146	0.4000	2,328
	OH	**Eastlake**	**2837**	**5**	14532.978	0.2621	2,323

Pink Highlight indicates Unit with SCR Controls
Units highlighted in bold red font have been announced for retirement

	State	Facility Name	Facility ID	Unit ID	SO2 (tons)	Avg. NOx Rate (lb/MMBtu)	NOx (tons)
Top 25 NOx Emitters 2012 OS	MO	New Madrid Power Plant	2167	1	3783.145	0.627	5,786
	IN	Rockport	6166	MB1	13080.843	0.221	5,001
	PA	Keystone	3136	1	8325.276	0.365	4,661
	IN	Rockport	6166	MB2	10779.121	0.224	4,215
	MO	New Madrid Power Plant	2167	2	2741.181	0.505	4,134
	PA	Conemaugh	3118	1	1476.726	0.320	3,909
	PA	Montour	3149	2	3832.866	0.414	3,794
	PA	Conemaugh	3118	2	1542.654	0.300	3,789
	PA	Keystone	3136	2	5821.209	0.343	3,774
	PA	**Hatfield's Ferry Power Station**	**3179**	**3**	646.229	0.509	3,677
	PA	**Hatfield's Ferry Power Station**	**3179**	**1**	511.008	0.486	3,601
	PA	**Hatfield's Ferry Power Station**	**3179**	**2**	537.327	0.520	3,589
	PA	Montour	3149	1	3524.199	0.402	3,543
	AR	White Bluff	6009	1	7759.429	0.278	3,504
	AR	White Bluff	6009	2	8209.766	0.246	3,383
	MO	Thomas Hill Energy Center	2168	MB2	1842.916	0.684	3,236
	AR	Independence	6641	2	8125.103	0.205	2,816
	WV	Fort Martin Power Station	3943	1	961.538	0.319	2,730
	AL	E C Gaston	26	5	4615.664	0.203	2,656
	WV	Harrison Power Station	3944	3	2624.735	0.308	2,628
	PA	Brunner Island	3140	3	2868.012	0.346	2,601
	WV	Harrison Power Station	3944	1	2174.755	0.313	2,569
	MI	Monroe	1733	2	11776.072	0.259	2,536
	MI	Monroe	1733	1	12493.547	0.247	2,517
	OH	Killen Station	6031	2	1654.736	0.351	2,426

Pink Highlight indicates Unit with SCR Controls
Units highlighted in bold red font have been announced for retirement

The lists of Top 25 NOx emitters for the 2011 and 2012 ozone seasons indicate that while many of the same EGUs show up on both lists, there are also changes in EGUs included on the lists. These changes may be attributed to variations in ozone season EGU NOx emissions due to many causes, including: changes in fuel prices affecting economic dispatch, maintenance outages, electric demand, operation and/or effectiveness of installed NOx, controls, etc. The EGUs identified on the list are equipped with combustion NOx controls, post-combustion NOx controls, and combinations of both types of NOx controls.

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

<u>Results</u>

The analysis of the Top 25 Ozone Season NOx & SO_2 Emitters in the OTC Modeling Domain for 2011 and 2012 show that some EGUs equipped with NOx emissions controls are emitting NOx at rates and amounts equal to the pre-installation of post-combustion NOx controls. In 2012 approximately 35% of the coal-fired units equipped with post combustion NOx controls had average ozone season NOx emission rates at least 50%

higher than its lowest ozone season NOx emission rate between 2003 and 2012. This data suggests that some EGU's are either not operating or limiting the operation of their controls.

Approach 1: Ozone Season NOx Emission Controls and Unit Retirements

Analysis

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

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

General:

- The year 2011 was selected as the base year for determining the baseline ozone season EGU fleet, EGU ozone season NOx 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- nameplate capacity ≥ 25 MW, excluding units identified as co-generation or any industrial, commercial, or process unit.

- For existing EGUs with post-combustion NOx controls, each EGU's NOx emissions rate (lb/MMBTU) was copied from CAMD AMPD data and the lowest ozone season average NOx 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 NOx emission rate available and to potentially provide credit to an individual EGU for NOx controls and/or NOx emission rate reductions that have already been incorporated on that EGU.

- For each EGU, an estimated ozone season NOx emissions were calculated as the product of the actual 2011 NOx mass emissions and the ratio of the estimated ozone season NOx emissions rate after application of controls and the actual 2011 ozone season average NOx emissions rate as follows:

Estimated Ozone Season = (Actual 2011 OS NOx Mass Emission) *(Estimated NOx Emission Rate After Control/Actual 2011 OS NOx Emission Rate)

Coal-Fueled EGUs:

For this evaluation, 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 Technology (SCR), the estimated ozone season NOx emissions rate was the lowest demonstrated ozone season NOx emissions rate between the years 2003 and 2012.

If the lowest demonstrated ozone season average NOx emissions rate in the AMPD between the years 2003 and 2012 was 0.06 lb/MMBTU or less, 0.06 lb/MMBTU was used as the estimated ozone season NOx emissions rate regardless of the NOx 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 Technology (SNCR) and the lowest demonstrated ozone season NOx emissions rate of the calendar years 2003 through 2012 was greater than 0.06 lb/MMBTU, installation of SCR was assumed and the NOx emissions rate was estimated as 50% of the lowest demonstrated ozone season NOx emissions rate between the years 2003 and 2012. The floor NOx emissions rate for this estimation was 0.06 lb/MMBTU.

2) Coal-fueled EGUs identified in the AMPD as not incorporating either SNCR or SCR and the lowest demonstrated ozone season average NOx emissions rate in the AMPD between the years 2003 and 2012 was greater than 0.06 lb/MMBTU, installation of SCR was assumed and the resulting NOx emissions rate was estimated as 10% of the lowest demonstrated ozone season average NOx emissions rate in the AMPD between the years 2003 and 2012. The floor NOx 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 NOx emissions rate was the lowest demonstrated ozone season NOx emissions between the years 2003 and 2012.

2) Coal-fueled EGUs identified in the AMPD as incorporating SNCR, and with the lowest demonstrated ozone season NOx 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 NOx emissions rate was estimated as 50% of the lowest demonstrated ozone season NOx emissions rate between the years 2003 and 2012. The floor NOx emissions rate for this estimation was 0.06 lb/MMBTU.

3) Coal-fueled EGUs identified in the AMPD as not incorporating SCR or SNCR, with the lowest demonstrated ozone season NOx emissions rate of the calendar years 2003 through 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 resulting NOx emissions rate was estimated as 10% of the lowest demonstrated ozone season average NOx emissions rate in the AMPD for the calendar years 2003 through 2012. The floor NOx emissions rate for this estimation was 0.06 lb/MMBTU.

4) Coal-fueled EGUs identified in the AMPD as not incorporating SCR or SNCR, with the lowest demonstrated ozone season NOx 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 resulting NOx emissions rate was estimated as 60% of the lowest demonstrated ozone season average NOx emissions rate in the AMPD between the years 2003 and 2012. The floor NOx 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 NOx emissions rate used was the lowest demonstrated ozone season NOx emissions rate in the AMPD between the years 2003 and 2012.

2) Coal-fueled EGUs identified in the AMPD as not incorporating either SNCR or SCR, installation of SNCR was assumed. The resulting estimated NOx emissions rate was calculated as 60% of the lowest demonstrated ozone season average NOx emissions rate in the AMPD between the years 2003 and 2012. The floor NOx emissions rate for this estimation was 0.06 lb/MMBTU.

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 NOx emissions rate between the years 2003 and2012 was less than 0.1 lb/MMBTU, 0.1 lb/MMBTU was used as the estimated ozone season NOx emissions rate regardless of the NOx 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 individual unit's selected NOx emission rate was the lowest demonstrated ozone season NOx emissions rate between the years 2003 and 2012.

2) Non-coal fueled EGU boilers identified in the AMPD as having a heat input rating of 2000 MMBTU/hr, or greater, and the lowest demonstrated ozone season NOx emissions rate between the years 2003 and 2012 was greater than 0.1 lb/MMBTU, and was not identified in the AMPD as incorporating SCR or SNCR, installation of SCR was assumed. The resulting NOx emissions rate was estimated as 20% of the lowest demonstrated ozone season average NOx emissions rate in the AMPD between the years 2003 and 2012. The floor NOx 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 NOx emissions rate used was the lowest demonstrated ozone season NOx emissions rate between the years 2003 and2012.

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 NOx emissions rate used was the lowest demonstrated ozone season NOx emissions rate between the years 2003 and 2012.

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

4) Non-coal fueled EGU boilers identified in the AMPD as not incorporating SCR or SNCR, and the 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 resulting NOx emissions rate was estimated as 20% of the lowest

demonstrated ozone season average NOx emissions rate in the AMPD between the years 2003 and 2012. The floor NOx emissions rate for this estimation was 0.06 lb/MMBTU.

5) Non-coal-fueled EGU boilers identified in the AMPD as not incorporating SCR or SNCR, and the lowest demonstrated ozone season NOx emissions rate between the years 2003 and 2012 was 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 resulting NOx emissions rate was estimated as 50% of the lowest demonstrated ozone season average NOx emissions rate in the AMPD between the years 2003 and 2012. The floor NOx 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 individual unit's selected NOx emission rate was the lowest demonstrated ozone season NOx emissions rate between the years 2003 and 2012.

2) Non-coal fueled EGU boilers identified in the AMPD as having a heat input rating less than 1000 MMBTU/hr, and the lowest demonstrated ozone season NOx emissions rate between the years 2003 and 2012 was greater than 0.1 lb/MMBTU, and was not identified in the AMPD as incorporating SCR or SNCR, installation of SNCR was assumed. The resulting NOx emissions rate was estimated as 60% of the lowest demonstrated ozone season average NOx emissions rate in the AMPD between the years 2003 and 2012. The floor NOx emissions rate for this estimation was 0.06 lb/MMBTU.

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

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

2) If the CC or CT EGU's lowest demonstrated ozone season NOx 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 NOx Burner (DLNB), water injection, or SNCR, then the lowest demonstrated ozone season average NOx emissions rate between the years 2003 and 2012 was used as the estimated ozone season NOx emissions rate.

3) If the CC or CT EGU's lowest demonstrated ozone season NOx emissions rate between the years 2003 and2012 was 0.1 lb/MMBTU, or greater, and the EGU

was not identified in the AMPD as incorporating DLNB, water injection, or SNCR, installation of water injection for NOx control was assumed. The estimated NOx emissions rate was calculated as 60% of the lowest demonstrated ozone season average NOx 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 NOx emissions reductions from those units was estimated as follows:

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

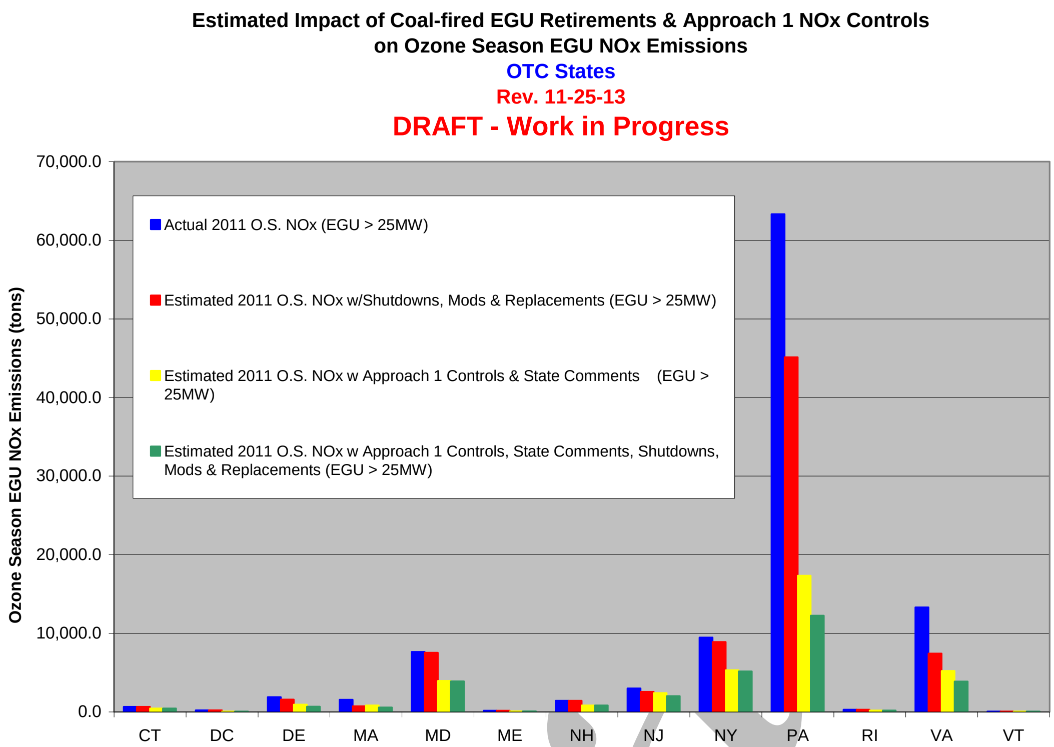
2) Using the AMPD reported 2011 heat input for that CC or CT EGU, the "actual" NOx mass emissions was calculated by multiplying the heat input with the above estimated NOx emissions rate.

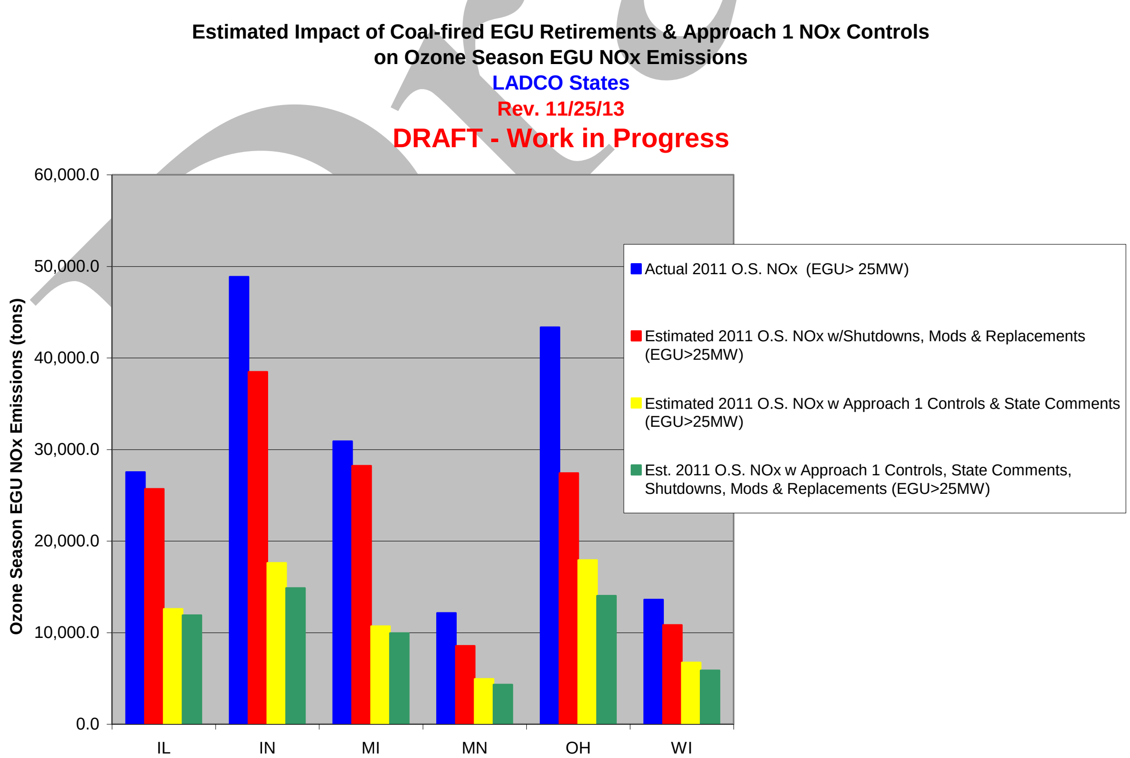
3) Assuming installation of water injection and a resulting 40% reduction in NOx emissions rate, the reduction of NOx mass emissions is estimated as 40% of the "actual" NOx mass emissions calculated in step 2 abovethe above step 2.

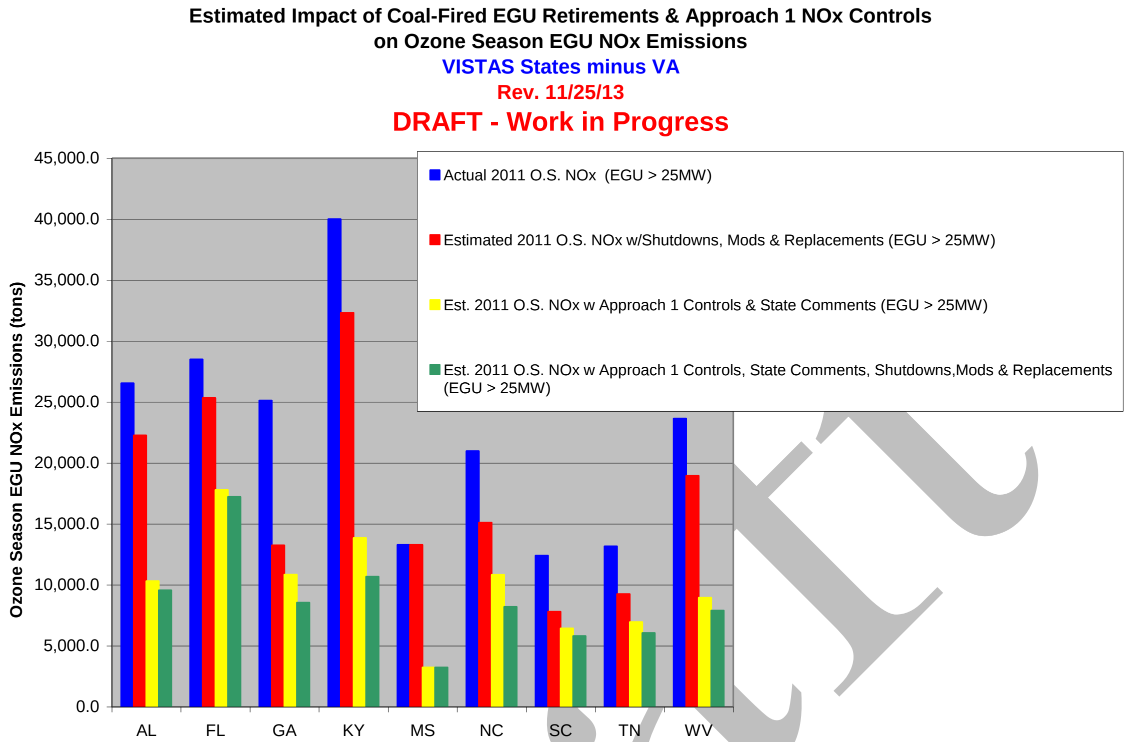
Since the above estimates are made on a unit-specific basis, NOx mass caps could be easily calculated in any type of regional basis (state specific, CAIR region, etc). The process described above allowed for a NOx mass cap calculation representative of the existing EGU fleet and its ability to achieve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

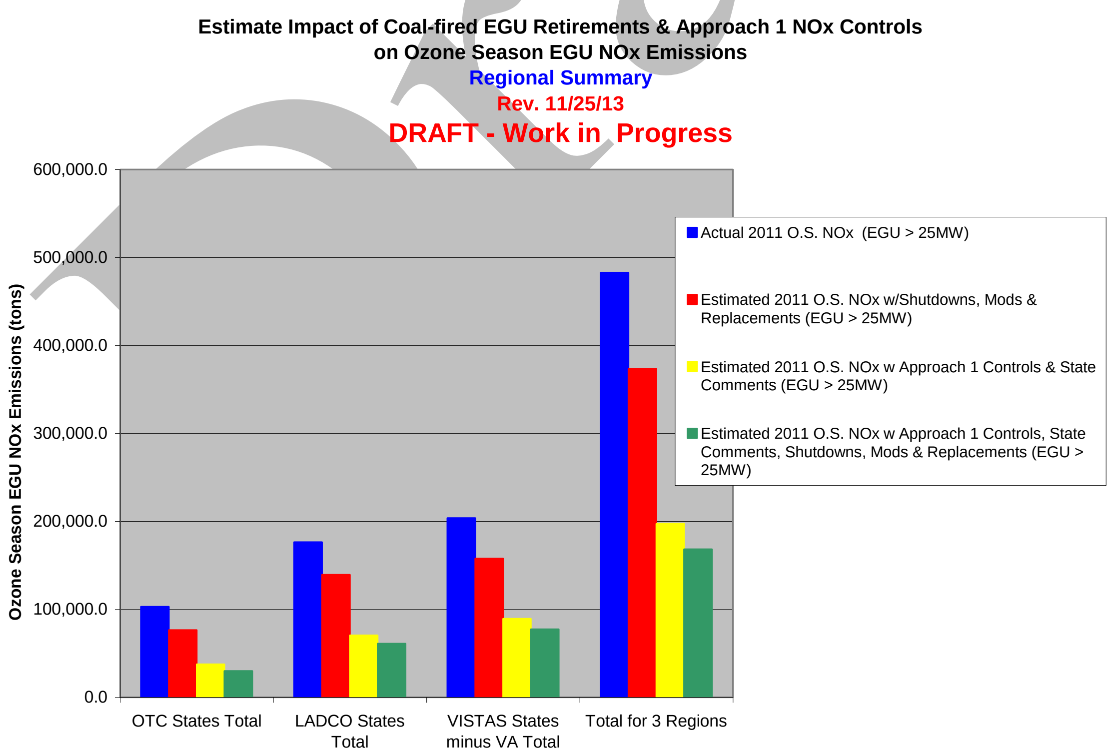
<u>Results</u>

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


Estimated Impact of Coal-fired EGU Retirements & Approach 1 NOx Controls
on Ozone Season EGU NOx Emissions
OTC States
Rev. 11-25-13
DRAFT - Work in Progress
Ozone Season EGU NOx Emissions (tons)
70,000.0
60,000.0
50,000.0
40,000.0
30,000.0
20,000.0
10,000.0
0.0
Actual 2011 O.S. NOx (EGU > 25MW)
Estimated 2011 O.S. NOx w/Shutdowns, Mods & Replacements (EGU > 25MW)
Estimated 2011 O.S. NOx w Approach 1 Controls & State Comments (EGU > 25MW)
Estimated 2011 O.S. NOx w Approach 1 Controls, State Comments, Shutdowns, Mods & Replacements (EGU > 25MW)
CT
DC
DE
MA
MD
ME
NH
NJ
NY
PA
RI
VA
VT

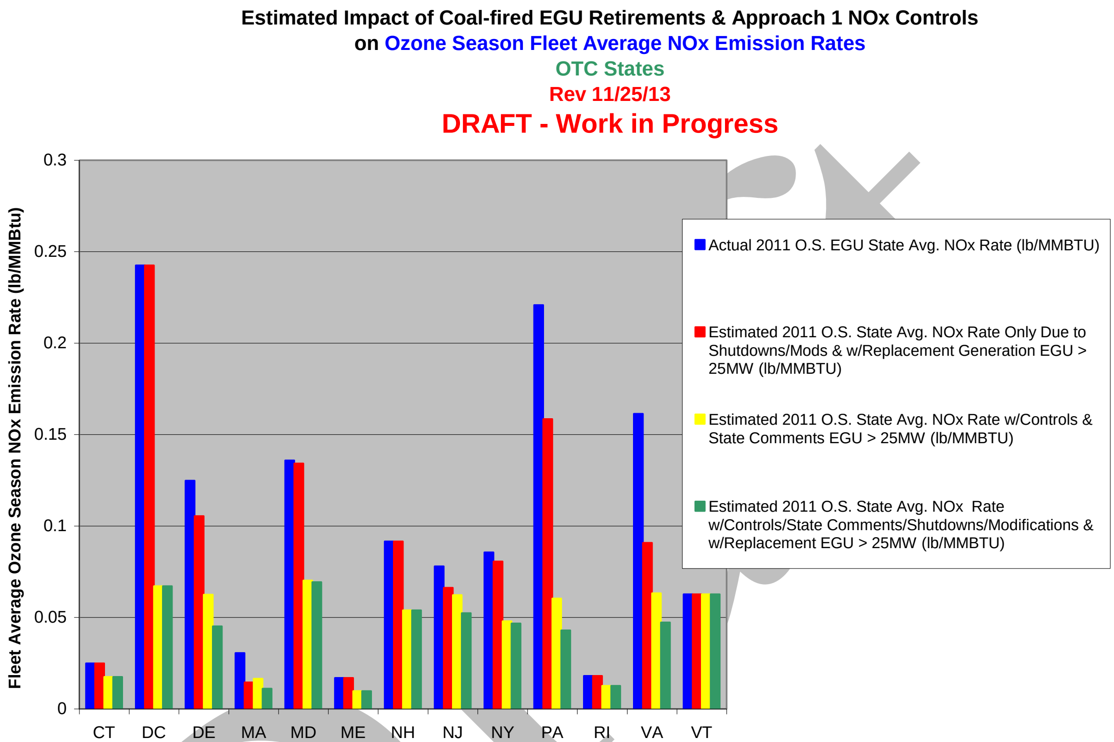

Estimated Impact of Coal-fired EGU Retirements & Approach 1 NOx Controls
on Ozone Season EGU NOx Emissions
LADCO States
Rev. 11/25/13
DRAFT - Work in Progress
Ozone Season EGU NOx Emissions (tons)
60,000.0
50,000.0
40,000.0
30,000.0
20,000.0
10,000.0
0.0
Actual 2011 O.S. NOx (EGU> 25MW)
Estimated 2011 O.S. NOx w/Shutdowns, Mods & Replacements (EGU>25MW)
Estimated 2011 O.S. NOx w Approach 1 Controls & State Comments (EGU>25MW)
Est. 2011 O.S. NOx w Approach 1 Controls, State Comments, Shutdowns, Mods & Replacements (EGU>25MW)
IL
IN
MI
MN
OH
WI

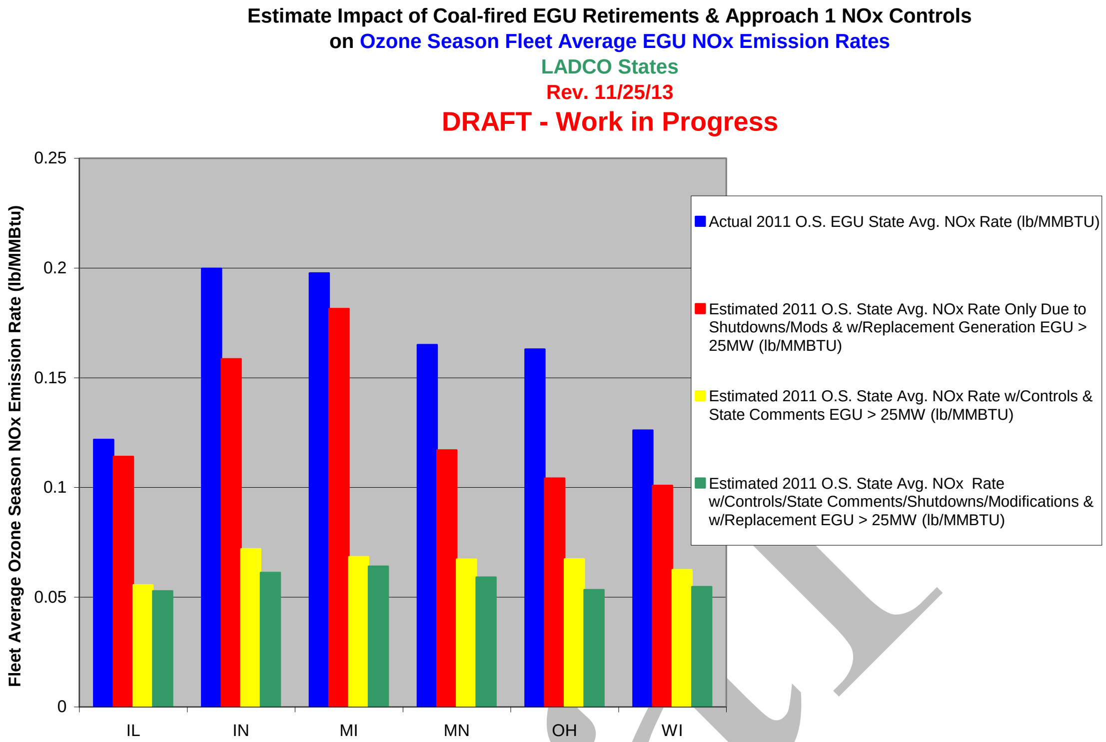

Estimated Impact of Coal-Fired EGU Retirements & Approach 1 NOx Controls
on Ozone Season EGU NOx Emissions
VISTAS States minus VA
Rev. 11/25/13
DRAFT - Work in Progress
Ozone Season EGU NOx Emissions (tons)
45,000.0
40,000.0
35,000.0
30,000.0
25,000.0
20,000.0
15,000.0
10,000.0
5,000.0
0.0
AL
FL
GA
KY
MS
NC
SC
TN
WV
Actual 2011 O.S. NOx (EGU > 25MW)
Estimated 2011 O.S. NOx w/Shutdowns, Mods & Replacements (EGU > 25MW)
Est. 2011 O.S. NOx w Approach 1 Controls & State Comments (EGU > 25MW)
Est. 2011 O.S. NOx w Approach 1 Controls, State Comments, Shutdowns,Mods & Replacements (EGU > 25MW)

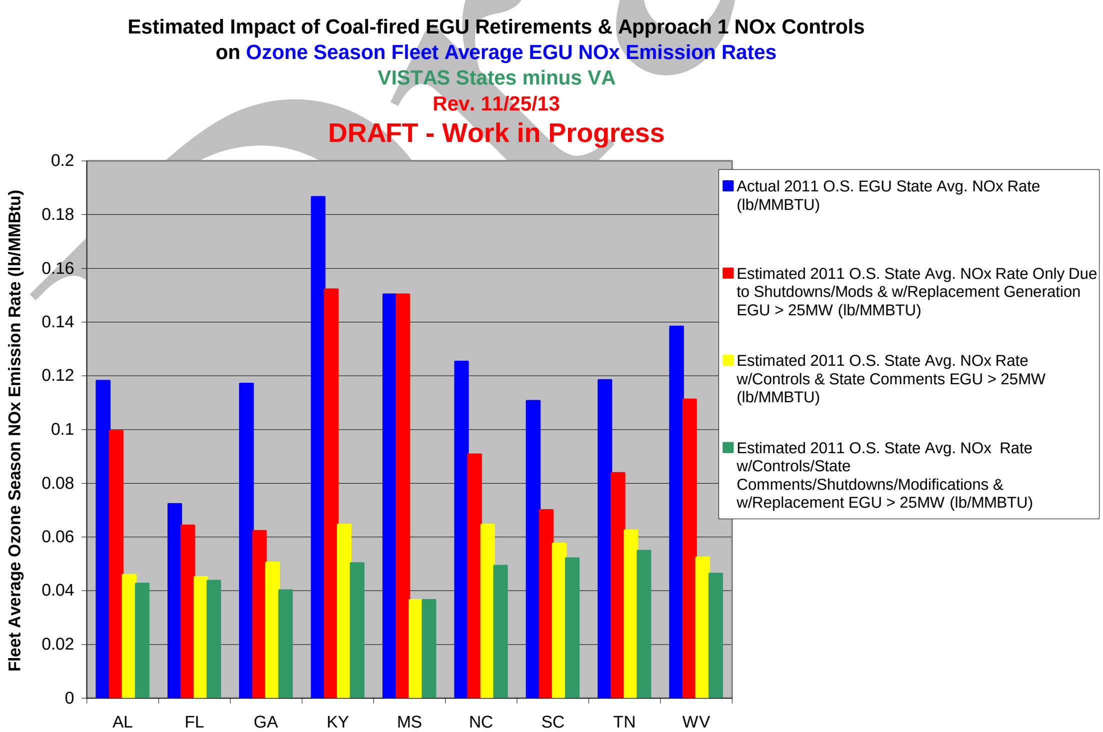

Estimate Impact of Coal-fired EGU Retirements & Approach 1 NOx Controls
on Ozone Season EGU NOx Emissions
Regional Summary
Rev. 11/25/13
DRAFT - Work in Progress
Ozone Season EGU NOx Emissions (tons)
600,000.0
500,000.0
400,000.0
300,000.0
200,000.0
100,000.0
0.0
OTC States Total
LADCO States Total
VISTAS States minus VA Total
Total for 3 Regions
Actual 2011 O.S. NOx (EGU > 25MW)
Estimated 2011 O.S. NOx w/Shutdowns, Mods & Replacements (EGU > 25MW)
Estimated 2011 O.S. NOx w Approach 1 Controls & State Comments (EGU > 25MW)
Estimated 2011 O.S. NOx w Approach 1 Controls, State Comments, Shutdowns, Mods & Replacements (EGU > 25MW)

-

The next three graphs show the show the potential impact of Approach 1 NOx controls and the potential impact of EGU retirements on state level ozone season NOx emission rates in lb.NOx/MMBtu. Copies of the detailed spreadsheets used to create these charts can be found in Appendix 4 of this whitepaper.







The results of the Approach 1 NOx control analyses and the separate analysis performed on the potential impact of EGU retirements on ozone season NOx emissions demonstrate that the potential impact of the Approach 1 NOx controls and the potential impact of the EGU retirements will vary from state to state. In some states no coal-fueled EGU retirements are anticipated while in other states a significant amount of coal-fueled EGU retirements are projected. The projected impact of Approach 1 NOx controls, if implemented, will result in larger reductions of NOx emissions than the projected impact of EGU retirements.

Approach 2: Hourly EGU NOx emissions during a high ozone period in Delaware and New Jersey

Analysis

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

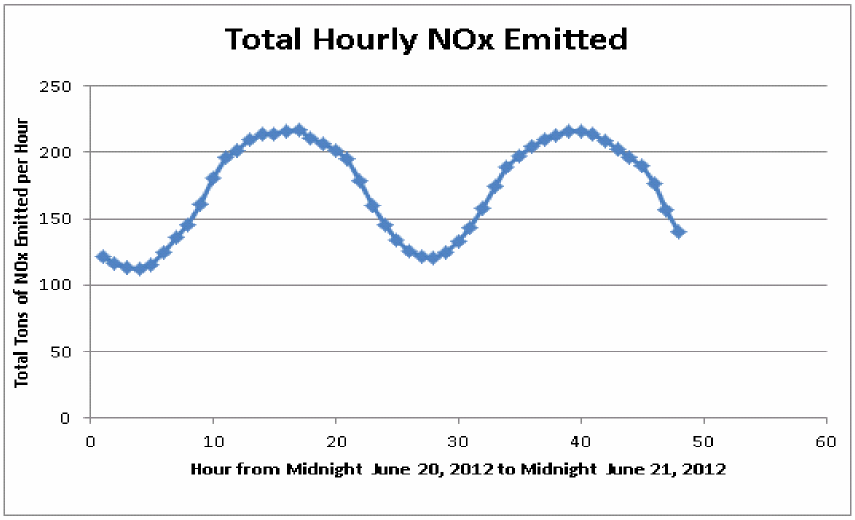
Results

The results of the State of Delaware hourly EGU NOx emissions and hourly NOx emission rates (June 21-22, 2012) study demonstrate EGU NOx emissions varied on an hourly basis with maximum emissions occurring during hour 16 on June 20, 2012. NOx emission rates from all types of coal-fired EGU also peaked during this time. The review of the related data for the 48-hour period from June 20 through June 21, 2012 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 for the potential air quality impact if the electric demand was higher thereby causing additional EGUs to be brought on line;
- The NOx emission rates from a number of EGUs were much greater than would be expected relative to the NOx controls reported to be installed on those units;
- During hour 16, for states subject to the CAIR ozone season NOx 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 NOx mass emissions.

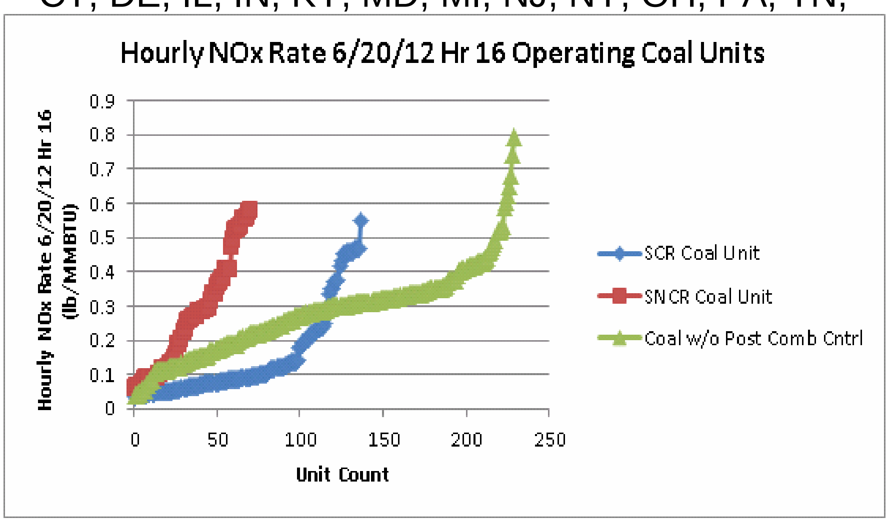
Results of State of Delaware hourly EGU NOx emissions and hourly NOx emission rates (June 21-22, 2012) are presented in the following graphs.

Total Hourly Emissions for the CAIR Ozone Season EGU Fleet



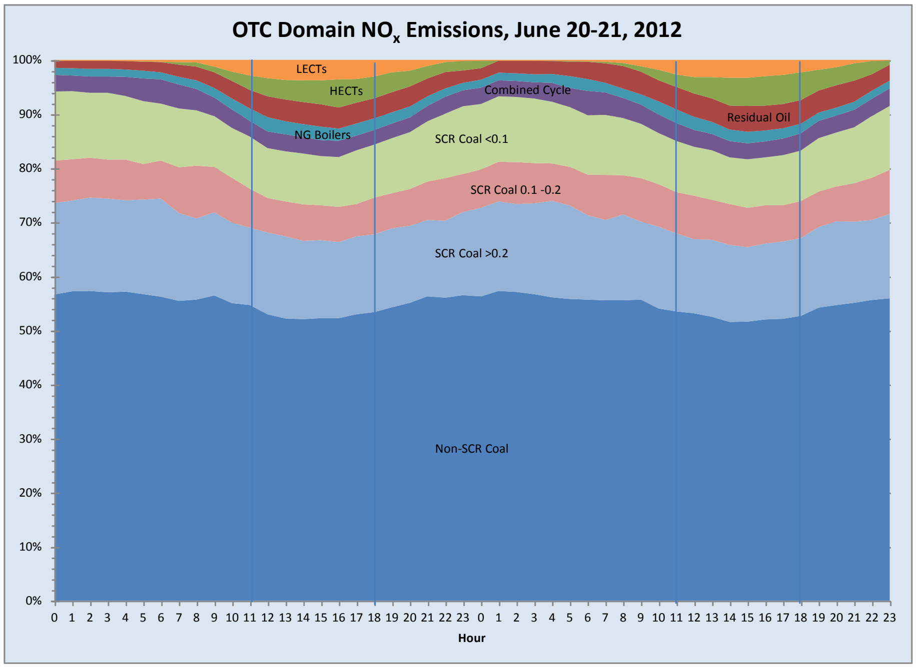
9

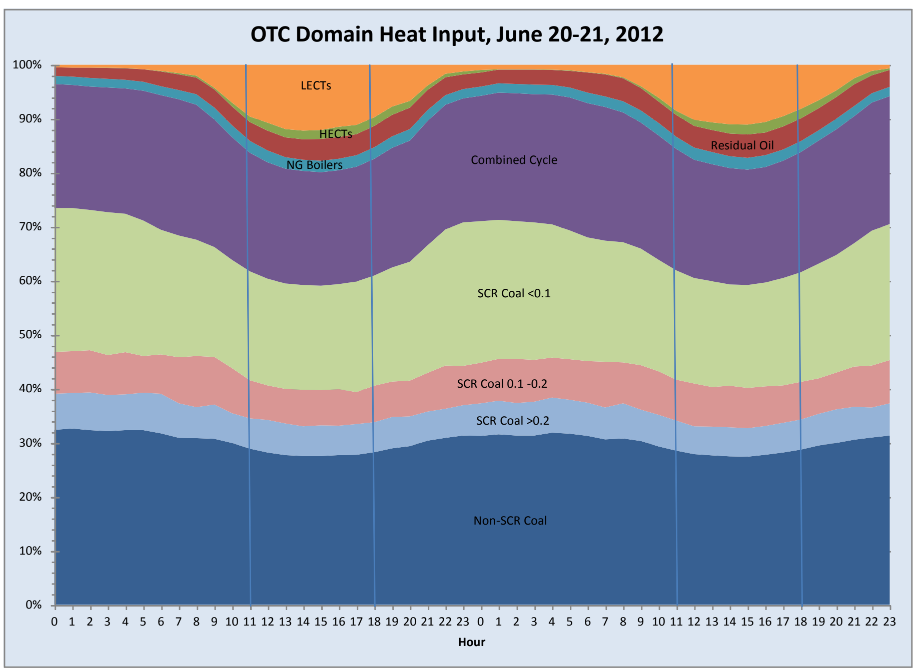
CT, DE, IL, IN, KY, MD, MI, NJ, NY, OH, PA, TN,



10

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


OTC Domain NO_x Emissions, June 20-21, 2012
100%
90%
80%
70%
60%
50%
40%
30%
20%
10%
0%
LECTs
HECTs
Combined Cycle
Residual Oil
NG Boilers
SCR Coal <0.1
SCR Coal 0.1 -0.2
SCR Coal >0.2
Non-SCR Coal
0 1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 0 1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23
Hour


OTC Domain Heat Input, June 20-21, 2012
100%
90%
80%
70%
60%
50%
40%
30%
20%
10%
0%
LECTs
HECTs
Residual Oil
NG Boilers
Combined Cycle
SCR Coal <0.1
SCR Coal 0.1 -0.2
SCR Coal >0.2
Non-SCR Coal
0 1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 0 1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23
Hour

Approach 3: Daily NOx emissions during the Ozone Season

Analysis

This analysis is an update of the previous analysis that included charts of 2007 daily NOx emissions by fuel type and maximum daily temperature for EGUs located in the OTR and Lake Michigan Air Directors Consortium (LADCO) states

The sum of the daily EGU NOx emissions for each fuel type was calculated to analyze each fuel-type's contribution to daily regional NOx emissions. 2011 unit-level EGU NOx emissions data was downloaded for each state from EPA's AMPD website[4] by selecting 'EGU' as the facility type under the "unit classification' tab. The unit-level NOx emissions data was summed by state and fuel type for each ozone-season day (May 1, 2011 through September 30, 2011). The state-level NOx emissions for the OTC states and the LADCO states were then summed by fuel type and the contribution to daily regional NOx emissions of each fuel type was graphed for the OTC and LADCO states. The temperature data is from the National Oceanic and Atmospheric Administration (NOAA)[5] website.

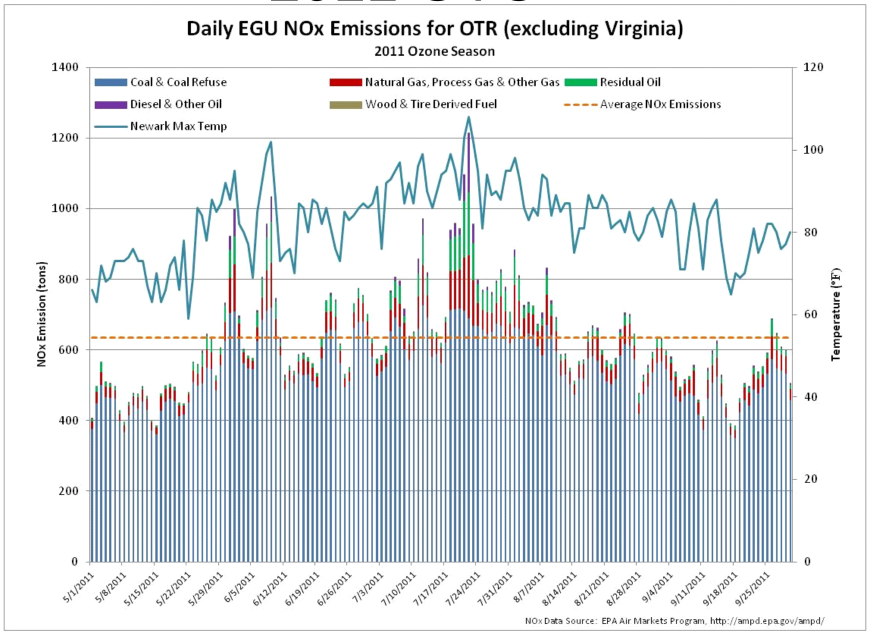
Results

The results of the 2011 daily EGU NOx emissions analyses demonstrate that daily EGU NOx emissions increased with the ambient temperature, with the highest daily NOx EGU NOx emissions occurring on days with the highest daily temperatures. In the OTC states, NOx emissions from oil-fired EGU boilers and diesel fuel-fired EGUs also peaked on the days with highest daily temperatures.

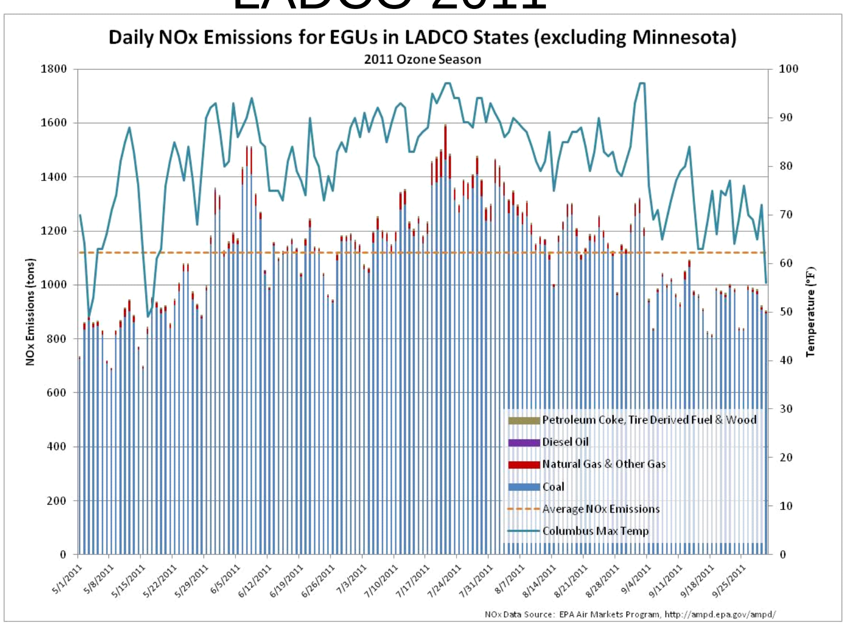
As the following graphs show, the majority of EGU NOx emitted in the OTC and LADCO regions during the 2011 ozone season were from coal-fired units. NOx emissions from EGUs firing other fuels (e.g., diesel, residual oil, natural gas) were very small in the LADCO region. While the contribution of coal-fired units to daily NOx emissions was dominant in the OTR in 2011, the contribution from diesel, residual oil, and natural gas-fired units was significant, especially on HEDD days.

[6] http://ampd.epa.gov/ampd/
[7] (http://www.nws.noaa.gov/climate/).

2011 OTC



LADCO 2011



Approach 4: "Coal SCR Scorecard Analysis – 2011 & 2012

Analysis

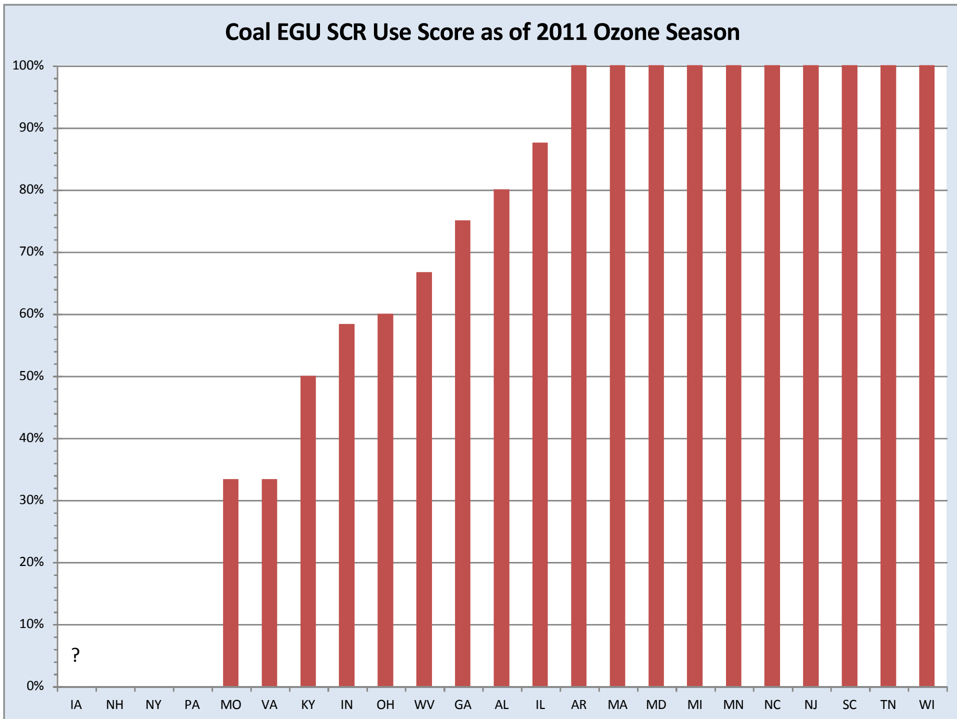
A "Coal SCR Scorecard" listing the number of power plants equipped with SCR controls with higher NOx emission rates during the 2011 and 2012 ozone seasons than previously demonstrated was prepared by the Subworkgroup.

Results

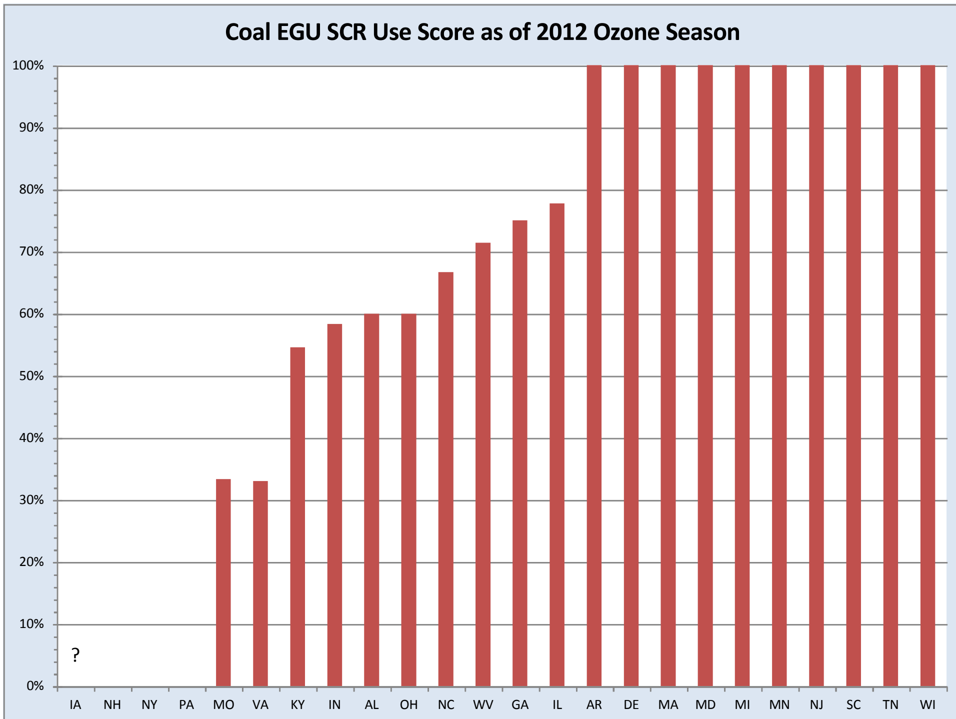
The results of the "Coal SCR Scorecard" analysis demonstrate that in several cases power plants equipped with SCR controls had higher NOx emission rates during the 2011 and 2012 ozone seasons than previously demonstrated. Analysis results indicate some EGUs are either not operating or limiting the operation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

The results of the "Coal SCR Scorecard" analysis are present in the following tables and charts.

	Plants	Number of Plants in 2011 with NO_x Rate > Previously Demonstrated	SCR Off	SCR Less Than Optimum	Grade	
AL	5	1	0	1	80%	
AR	1	0			100%	
DE	0	0				
GA	4	1		1	75%	
IA	1				?	~60% reduction
IL	8	1	1		88%	
IN	12	5	0	5	58%	
KY	10	5	1	4	50%	
MA	2	0			100%	
MD	4	0			100%	
MI	3	0			100%	
MN	1	0			100%	
MO	3	2		2	33%	
NC	6	0			100%	
NH	1	1		1	0%	
NJ	4	0			100%	
NY	2	2		2	0%	1 of 4 in 2010
OH	10	4		4	60%	
PA	5	5	2	3	0%	
SC	5	0			100%	
TN	4	0			100%	
VA	3	2		2	33%	
WI	4	0			100%	
WV	6	2	1	1	67%	
	104	31	5	26		
Percent of Total		30%	5%	25%	70%	



	Plants	Number of Plants in 2012 with NO_x Rate > Previously Demonstrated	SCR Off	SCR Less Than Optimum	Grade	
AL	5	2	1	1	60%	
AR	1	0			100%	
DE	1	0			100%	
GA	4	1		1	75%	
IA	1				?	~60% reduction
IL	9	2	2		78%	
IN	12	5	1	4	58%	
KY	11	5	2	3	55%	
MA	2	0			100%	
MD	4	0			100%	
MI	3	0			100%	
MN	1	0			100%	
MO	3	2	2		33%	
NC	6	2	0	2	67%	
NH	1	1		1	0%	
NJ	4	0			100%	
NY	2	2		2	0%	1 of 4 in 2010
OH	10	4	2	2	60%	
PA	5	5	3	2	0%	
SC	5	0			100%	
TN	4	0			100%	
VA	3	2		2	33%	
WI	5	0			100%	
WV	7	2	1	1	71%	
	109	35	14	21		
Percent of Total		32%	13%	19%	69%	



Approach 5: Short Term NOx Emission Rates

Analysis

Review of the EGU NOx emission rate data indicates that many of the EGU exhibited average NOx emission rates in excess of what might be expected for EGUs reported to have incorporated post-combustion controls. These higher NOx emission rates may impact the ability of downwind states to meet air quality standards. In recent ozone seasons, some EGUs reported to incorporate post-combustion NOx controls have exhibited average NOx emission rates higher than previous ozone season averages. Application of short term NOx emission rate limits that reflect the capabilities of NOx emissions controls provide a potential incentive to ensure that EGU short term NOx emission rates do not increase to a level to adversely impact attainment of short term air quality standards in downwind areas.

The Short Term NOx Limits listed in the following tables as “Current Thinking” are not intended to reflect technological edge of NOx control capability, but rather to represent NOx control retrofit capability for much of the EGU industry. The State rules included in analysis are from CT, DE, NH, NJ, NY & WI. The averaging times for the EGU boiler NOx limits found in state rules are stated in terms of 24 hr. rolling averages or 24 hr. calendar day averages. EGU combustion turbine NOx limits found in state rules varied from state to state with some 1hr 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

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

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

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

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

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

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

Project Results

Operation of Emissions Controls

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

Approach 1 NOx Controls and EGU Retirements

The results of the Approach 1 NOx control analyses previously discussed and the separate analysis performed on the potential impact of EGU retirements on ozone season NOx emissions demonstrate that the potential impact of the Approach 1 NOx controls and the potential impact of the EGU retirements will vary from state to state. In some states no coal-fired EGU retirements are anticipated while in other states a significant amount of coal-fueled EGU retirements are projected. The projected impact of Approach 1 NOx controls, if implemented, will result in larger reductions of NOx emissions than the projected impact of EGU retirements.

Analysis of Short Term (Hourly) EGU NOx Emissions – 2012

The results of the State of Delaware hourly EGU NOx emissions and hourly NOx emission rates (June 21-22, 2012) study demonstrate EGU NOx emissions varied on an hourly basis with maximum emissions occurring during hour 16 on June 20, 2012. NOx emission rates from all types of coal-fired EGU also peaked during this time. The review of the related data for the 48-hour period from June 20 through June 21, 2012 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 for the potential air quality impact if the electric demand was higher thereby causing additional EGUs to be brought on line;
- The NOx emission rates from a number of EGUs were much greater than would be expected relative to the NOx controls reported to be installed on those units;
- During hour 16, for states subject to the CAIR ozone season NOx 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 NOx mass emissions.

Analysis of Short Term (Daily) EGU NOx Emissions – 2011

The results of the 2011 Daily EGU NOx emissions analyses demonstrate that daily EGU NOx emissions increased with the ambient temperature with the highest daily NOx EGU NOx emissions occurring on days with the highest daily temperatures. In the OTC states, NOx emissions from oil-fired EGU boilers and diesel fuel-fired EGUs also peaked on the days with highest daily temperatures.

"Coal SCR Scorecard" Analysis – 2011 & 2012

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

Recommendation for Modeling of Short Term NOx Emission Limits

As discussed above in the section on Approach 5 of this white paper, the EGU NOx emissions rate data included in this study indicates that some EGU's with NOx controls reported to be installed are emitting at rates are in excess what might be expected from EGUs with installed NOx . The NOx emission rates for some EGUs in recent ozone seasons were significantly higher than the NOx emission rate demonstrated by those

EGUs in previous years. Additionally, some EGUs without post-combustion controls exhibited very high NOx emission rates that do not appear to be consistent with good pollution control practices.

A potential solution is the establishment of short term NOx emission rate limits for EGUs that are based on reported short term NOx emission rates and reflective of good emission control practices using reasonably available NOx emissions controls that are applicable for the particular types of EGUs. NOx emission rate limits based on reported short term NOx emission rates appear to offer the potential to reduce the frequency and/or magnitude of air quality episodes in downwind states and therefore benefit public health and welfare. Proposed short term NOx emission rate limits should be established to be representative of reasonably achievable modern controls for particular types of EGUs on a retrofit basis that still help to ensure significant levels of NOx emissions reductions in support of this concept.

The proposed short term NOx emission rates shown below are felt to be reflective of the capabilities of EGUs with reasonable application of NOx controls when those units are operated in accordance with good emission control practices. The proposed short term NOx 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 NOx emission rate limits account for these EGU configurations and fuel differences.

The proposed short term NOx emission rate limits, based on reported short term NOx 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 NOx emission rate limits are expected to be sustainable over a long period of time given good operating and maintenance practices.

If the proposed short term NOx 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 NOx emission rate limits would therefore be expected to help reduce the frequency and magnitude of those air quality episodes.

Adoption of these proposed short term NOx emission rate limits will be protective of short term NAAQS and therefore help provide significant benefit to public health and welfare.

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

Unit Type	Heat Input Capacity (MMBtu/hr)	Configuration	NOx 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 , NOx RACT orders with alternative NOx RACT emission limits, or the implementation of specific types of NOx control technologies. Similar alternative compliance means may be necessary for some existing units that may not be able to achieve these NOx rate limits with NOx 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 for OTC EGU LC Subgroup White Paper

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 NOx Emissions Baseline & CHARTS.xls

4. Rev 11 25 13 EGU 25 MW RATES Shutdowns 121613 – Estimated NOx 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 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

3. Ozone Transport Commission Draft Model Rule Control of NOx 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. NOx Rate Limit Refs.xlsx

14. Short Term NOx Limits Draft 9.xls

OZONE TRANSPORT COMMISSION

Connecticut

Delaware

District of Columbia

Maine

Maryland

Massachusetts

New Hampshire

New Jersey

New York

Pennsylvania

Rhode Island

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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

OZONE TRANSPORT COMMISSION

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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