OTC Stationary and Area Source Committee, HEDD Workgroup

White Paper: Examining the Air Quality Effects of Small EGUs, Behind the Meter Generators, and Peaking Units during High Electric Demand Days

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Executive Summary and Recommendations

A phenomenon that has received considerable attention from the air quality community is the concept of High Electric Demand Days (HEDDs). Hot summer days can lead to a higher demand for electricity relative to other days, and these same hot sunny days can also be the most conducive to ozone formation. Building on previous efforts to analyze HEDDs, a new OTC HEDD Workgroup was formed by the OTC SAS Committee and charged with estimating emissions from the use of demand response generation units. The Workgroup was further charged with developing a set of recommendations and providing a report on emissions during high electric demand days from demand response including small electric generating units (less than 25MW), behind the meter generators, and peaking units. To fulfill this charge, the HEDD Workgroup has compiled three separate analyses focusing on the air quality impacts of various electric generation activities on high electric demand days (HEDD). These three analyses include:

- Temporalization of small non-CAMD electric generating units (EGUs), conducted by Hannah Ashenafi & Emily Bull of Maryland Department of the Environment
- Review and estimate of emissions from diesel-fueled back-up generators (BUGs) that participate in demand response (DR) programs, conducted by a subgroup of the HEDD Workgroup
- Peaking EGUs, conducted by a subgroup of the HEDD Workgroup

A brief summary of the Workgroup's findings and a set of Workgroup recommendations are provided in the following two subsections.

ES1. Summary and Conclusions

Small non-CAMD EGUs

An analysis conducted by Maryland Department of the Environment (MDE) showed that using continuous hourly emissions data reported by EGUs via EPA's air markets programs is useful for improving the temporalization of smaller EGUs whose emissions are currently distributed evenly throughout the year using the default temporal profiles from emissions processing models. For a high electric demand day, MDE's analysis has shown that a more accurate temporalization of small EGUs can lead to a seven-fold increase in peak-day NOx emissions from these units relative to what their peak-day emissions would be using the default temporal profiles. Air quality modeling performed with the improved temporal profiles showed increases in predicted ozone concentrations of up to 5 ppb versus modeling performed with default profiles. With ever-tightening air quality standards, ozone concentration changes of this magnitude could make a difference in whether a jurisdiction attains the standard or not. In addition to health-based considerations, jurisdictions could be faced with the

additional regulatory and economic burdens associated with non-attainment of the standards. Understanding the true nature of these units' operating behavior and the magnitude of their emissions on high electric demand days can help air quality regulators develop more appropriate and effective control strategies.

<u>BUGs</u>

It is important to understand the air quality impact of back-up type diesel reciprocating generators (BUGs) participating in DR programs. The Workgroup's hypothetical high-bound modeling analysis showed that emissions from BUGs responding in an unlimited manner to a widespread DR event could increase predicted 8-hr ozone concentrations by 1 ppb. As mentioned above, even small changes in ozone concentrations could affect attainment of the standard and have significant health, regulatory, and economic implications. Although the focus of this effort was on ozone, the increased use of diesel-powered generators could have implications for meeting the 1-hour standard for nitrogen dioxide and the 24-hour standard for fine particulate matter.

The Workgroup performed a review of State regulations that pertain to the use of emergency generators in DR programs and found that most states prohibit the participation of emergency engines in voluntary or incentive-based DR programs. In most states, those engines that do participate in such programs must be permitted and/or are subject to notification and recordkeeping requirements. In many of these instances, the applicable engines must also meet strict emissions limits.

Peaking Units

To perform a meaningful analysis of peaking units, units of all operational types - base load, intermediate-use, and peaking - were included. For the episode days analyzed, the contribution to total OTR EGU NOx mass from peaking units ranged from 6% to approximately 34%. However, the Workgroup's analysis revealed that among all EGU operational types in the OTR, intermediate-use EGUs were consistently the highest contributors to total OTR EGU NOx emissions on an annual, ozone season, and episode day basis. The majority of this contribution came from coal-fired intermediate-use units with post combustion NOx controls.

The Workgroup analyzed the NOx emissions reduction potential that could be realized from those OTR combustion turbines for which the Air Markets Program Database (AMPD) did not indicate any installed NOx controls. The analysis revealed that, for the July 20, 2015 episode day, an approximately 21-ton NOx reduction could be realized if these uncontrolled CTs were to meet "moderate RACT" emission rate levels.

Further, the Workgroup recognized that any potential reduction in NOx emissions from peaking units would be obscured unless potential reductions were also sought from non-peaking units operating on HEDDs. The workgroup analyzed the NOx emissions reduction potential associated with EGUs operating existing controls consistently or operating those controls in a more efficient manner. For the July 20, 2015 episode day, over 184 tons of NOx emissions reductions could be realized if all coal-fueled EGUs operating in the OTR that day operated at NOx emission rates consistent with their lowest historical

ozone season NOx emission rates. The workgroup concluded that for July 20, 2015 many of the post combustion NOx control equipped coal-fired EGUs in the OTR were not operating installed post combustion controls, or were not operating the controls consistent with good pollution control practices.

ES2. Recommendations

Small non-CAMD EGUs

To more accurately model small EGUs that do not report to CAMD (and are therefore not modeled with actual hour-by-hour emissions), the default temporal profiles used in the SMOKE emissions model should be replaced with temporal profiles derived using reported hourly emissions data from CAMD-reporting EGUs with similar characteristics. This will better characterize the air quality impacts of small non-CAMD EGUs on high electric demand days and/or high ozone episode days. The small EGU temporal profiles developed through this effort are already included in MARAMA's Beta emissions inventories, which are being used in air quality modeling to support State Implementation Plans (SIPs) for ozone, regional haze, and other air quality management efforts.

<u>BUGs</u>

The Workgroup's hypothetical high-bound analysis of back-up generators has shown that these units could have a measureable impact on air quality if the units were to respond to a demand event in an unlimited manner. However, the workgroup's survey of state regulations has shown that, for the most part, states are doing an admirable job of regulating these units' participation in such programs. States should continue to maintain or improve such regulations, as applicable. For example, in some states, such regulations only apply to engines located at Major facilities. States should also continue, and improve where possible, their efforts to enforce regulations that pertain to emergency engines and engines participating in DR programs. Where resources permit, states should conduct outreach and education regarding the proper use of these types of engines.

Regarding stationary engines, the Workgroup offers the following topics for future analysis and discussion:

- Engines installed without permits, that are operated for non-emergency reasons, where the owner/operator does not know that those operations are not permitted;
- Engines installed with permits, but not enrolled with a Curtailment Service Provider (CSP), that are operated for non-emergency reasons, where the owner/operator does not know that those operations are not permitted;
- Engines installed with permits and enrolled with a CSP, that are operated for non-emergency reasons outside of those times that they are called upon by a CSP, where the owner/operator does not know that those operations are not permitted;
- Engines knowingly operated illegally; and
- The increasing use of micro-grids, their operation and permitting, and their effect on air quality.

Peaking Units

The Workgroup's analysis revealed that peaking units can contribute over 30% of total OTR EGU NOx mass on the episode days that were analyzed, and that a NOx emissions reduction potential of over 20 tons per day could be realized if gas and oil-fired combustion turbines without installed controls were to meet "moderate RACT" emissions levels. Where they have not already done so, states should adopt NOx RACT for gas and oil-fired combustion turbines (noting however that RACT must meet technological and economic feasibility requirements).

However, the recommendation of RACT for peaking units will not have as large an impact without also addressing coal-fired units that do not fully optimize their NOx controls. The view has long been held that the continued low price of NOx allowances remains a disincentive for running existing NOx controls in an optimal manner. As of August 12, 2016, the Cross State Air Pollution Rule (CSAPR) ozone season NOx allowance price was \$230/short ton. This is well below the estimated cost of \$439/short ton for running NOx controls (note: the high end of the range is \$1,755 to \$2,118/short ton). States should pursue appropriate rulemaking or other regulatory mechanisms that require EGUs of all types to operate their NOx controls effectively such that their best historic NOx rates are met at all times during the ozone season (such as the more stringent NOx RACT for EGU boilers in New York state). Alternatively, the issue could be addressed with significant reductions in CSAPR NOx allowance availability. EPA proposed an update to the CSAPR NOx budget on December 3, 2015 (80 FR 75706) to reduce the NOx allowances based on a cost of reduction of \$1300 per ton. (Note: EPA finalized the CSAPR Update on October 26, 2016 (81 FR 74504)).

Regarding peaking units, the workgroup offers the following topics for future analysis and discussion:

- 2009/2010 OTC Model Rule for High Electric Demand Day Combustion Turbines
- State HEDD Rules (e.g. New Jersey)
- Operating limits on forecasted high ozone days

1. Introduction

A phenomenon that has received considerable attention from the air quality community is the concept of High Electric Demand Days (HEDDs). Hot summer days can lead to a higher demand for electricity relative to other days, and these same hot sunny days can also be the most conducive to ozone formation. In March 2007, a Memorandum of Understanding (MOU) was signed by a set of Ozone Transport Commission (OTC) member states. In this MOU, states committed to pursue NOx reductions from HEDD units and resolved to further evaluate the HEDD issue (OTC's Memorandum of Understanding among the States of the Ozone Transport Commission Concerning the Incorporation of High Electrical Demand Day Emission Reduction Strategies into Ozone Attainment State Implementation *Planning*). Building on this MOU, and other previous efforts to examine EGU fleet activity on HEDDs, a new OTC HEDD Workgroup was formed by the OTC SAS Committee and charged with estimating the emissions from the use of demand response generation units. The Workgroup was further charged with developing a set of recommendations and providing a report on emissions during high electric demand days from demand response including small electric generating units (less than 25MW), behind the meter generators, and peaking units. To fulfill this charge, the Workgroup has compiled three separate analyses, which were carried out by the HEDD Workgroup and state air agency staff. These analyses focused on the following sets of emissions sources.

<u>Small non-CAMD EGUs</u>: The Maryland Department of the Environment (MDE) defined small non-CAMD EGUs as those EGUs with a capacity of 25 megawatts (MW) or less. These units a) directly feed the electrical grid and b), are included in the emissions inventory as discrete units. Unlike larger EGUs, however, these units do not report their hourly emissions to the Clean Air Markets Database (CAMD). The goal of the MDE analysis was to improve the temporalization of these units for air quality modeling, particularly as it relates to high electric demand days.

<u>Back-Up Generators (or BUGs</u>): Unlike the small non-CAMD EGUs, BUGs do not directly feed the electrical grid and are not included in the emissions inventory as discrete units (although BUGs are in theory included in the area source, or non-point, portion of the inventory by accounting for statewide fuel use). In general, BUGs were originally installed to provide power to a facility in the event that service from the electrical grid was interrupted (e.g. due to a grid failure or natural disaster). However, there has been increased use of these units as part of financial incentive programs to reduce grid electricity use during times of high demand (generally referred to as Demand Response (DR) programs). The workgroup performed a first-approximation analysis of the air quality effects of the use of BUGs in DR programs.

<u>Peaking Units</u>: Similar to non-CAMD EGUs, peaking units are included in the emissions inventory as discrete units. Previous analyses have shown that peaking units can contribute significant emissions of nitrogen oxides (NOx) on high electric demand days and/or peak ozone days. Therefore, the workgroup was interested in quantifying the contribution of peaking units to total NOx emissions.

Each of these emissions source categories and associated HEDD Workgroup analyses are discussed in more detail in the sections below.

2. Small non-CAMD EGUs

Emissions sources regulated under EPA's CAMD programs are required to report their emissions according to the requirements of 40 CFR Part 75. In general, affected sources comply with these requirements by installing continuous emission monitoring systems (CEMS) that monitor carbon dioxide (CO2), NOx, and sulfur dioxide (SO2) emissions, along with other parameters, on an hourly basis. One of the many uses for this hourly data is input into air quality models. Emissions modeling systems such as the Sparse Matrix Operator Kernel Emissions (SMOKE) model are used to spatially and temporally allocate emissions for input into the air quality model.

Hourly emissions data such as those measured with CEMS allow for an accurate characterization of not only the magnitude of the emissions, but of their temporal variation. However, generally only the largest EGUs (and other affected source types) install CEMS and report hourly emissions to CAMD. For smaller EGUs and other emissions types which report annual emissions, emissions and air quality modelers rely on default temporal profiles that are applied using the SMOKE emissions model. Some of these default temporal profiles simply allocate annual emissions evenly over all hours of the year. While this may be appropriate for some sources that have continuous consistent operations, this approach is not accurate to represent small EGUs, which do not operate continuously. On peak electric demand days, the default approach could lead to an underestimation of emissions from smaller EGUs that do not report hourly emissions to CAMD.

The goal of MDE's small EGU effort was to examine the CEMS-based operating profiles for EGUs that report to CAMD and use the data to develop temporal profiles for smaller non-CAMD EGUs that more realistically reflect these units' operating behavior, particularly on peak electric demand days. These small units typically operate for limited periods of time, such as high electricity demand periods or when larger units are offline for maintenance. The small EGUs may also operate at times when it is necessary to ensure grid reliability. Based on what is known about their typical operational patterns, profiles for these units should show limited annual operation and high peak day operation.

The first step in the analysis was to download 2011 heat input data from EPA's Air Markets Program Data (AMPD) web-based database (<u>http://ampd.epa.gov/ampd/</u>) and separate the data by fuel type (coal, oil, and gas) and geographic region. The daily distribution of heat input was graphed. This distribution is calculated by dividing the daily heat input by the annual heat input. To develop an appropriate peaking profile for the small EGUs, it was necessary to identify those EGUs that act as peaking units from within this master dataset. The peaking EGUs were identified using EPA's definition of a peaking unit, taken from its 2011v1 modeling platform. EPA identified peaking units greater than 25 MW as those units that had a capacity factor of less than 10% over a three-year average and less than 20% in each of three years (2010-2012) (note that in subsequent versions of its modeling efforts, EPA does not use this definition)¹.

Figure 2-1 shows the daily distribution for coal-fired peaking units greater than 25 MW in the Mid-Atlantic and Northeast States Visibility Union plus Virginia (MANE-VU+VA) region (note: the MANE-VU region covers the states of Connecticut, Delaware, the District of Columbia, Maine, Maryland, Massachusetts, New Hampshire, New Jersey, New York, Pennsylvania, Rhode Island, and Vermont). The peaking unit distribution (purple line) is overlaid on the daily distribution for all coal-fired units greater than 25 MW in the MANE-VU+VA region (blue line). The distribution for all coal units shows consistent operation throughout the year, with increased operations during the peak cold months of the winter and the peak hot months of the summer. The distribution for coal-fired peaking units shows the expected increases in operation during the summer months. It is suspected that the winter month peaks may be due to the shutdown of larger units for maintenance.

Figure 2-2 shows the distribution for all oil-fired EGUs greater than 25 MW (red line) and oil-fired peaking EGUs greater than 25 MW (blue line) in the MANE-VU+VA region. It can be seen in Figure 2-2 that oil-fired peaking units operate on more days than the coal-fired peaking units shown in Figure 2-1. However, the summer day peaks are still evident. Similarly, Figure 2-3 presents the operating distribution for all gas-fired EGUs greater than 25 MW (green line) and for gas-fired peaking EGUs greater than 25 MW (orange line) in the MANE-VU+VA region. Similar to the oil-fired units, the gas-fired peaking units operate on more days than coal-fired peaking units but the summer day peaks are still apparent. Figure 2-4 is a composite of all the operating profiles for all EGUs greater than 25 MW and peaking EGUs greater than 25 MW in the MANE-VU+VA region for all fuel types. It can be seen from the figure that the peak days align well for the different fuel types.

The data shown in Figures 2-1 through 2-4, specifically the data for the peaking EGUs (purple, blue and orange lines), were used to produce temporal profiles to be applied to small non-CAMD EGUs less than 25 MW in the MANE-VU+VA region. As a check for these profiles, 2011 daily heat input data were collected from a set of EGU facilities in Maryland. The data were separated for oil- and gas-fired units. Figure 2-5 shows the temporal profile developed for oil-fired small non-CAMD EGUs (blue line) overlaid against the operating profile for small oil-fired EGUs in Maryland (red line). Similarly, Figure 2-6 shows the temporal profile developed for gas-fired small non-CAMD EGUs (orange line) overlaid against the operating profile for small gas-fired EGUs in Maryland (green line). In both cases, the temporal profiles developed for this study matched well with the operational data, with the peaks occurring on similar days. It is suspected that the difference in the magnitude of the peaks may be a function of averaging a larger number of units in developing the temporal profiles for this study versus the actual data collected from a smaller number of Maryland-only units. (Note: Temporal profiles were developed in a similar manner for other geographic regions, using Regional Planning Organization (RPO) boundaries as a convenient way of grouping the data. In addition to the MANE-VU+VA region, temporal profiles were developed for the LADCO (Lake Michigan Air Directors Consortium), SESARM (Southeastern States Air Resources Managers), and CenSARA (Central States Air Resources Agencies) regions.)

The next step in the analysis was to identify and extract the units of interest for this study, namely small EGUs that do not report to CAMD and whose annual emissions are apportioned to an hourly basis using the assigned temporal profiles from the SMOKE emissions model. As mentioned earlier, the units of interest for the temporalization effort are units that are discretely included in the emissions inventory.

Figure 2-1: Temporal profiles for all coal-fired EGUs > 25 MW and peaking coal-fired EGUs > 25 MW in the MANE-VU+VA region.



Figure 2-2: Temporal profiles for all oil-fired EGUs > 25 MW and oil-fired peaking EGUs > 25 MW in the MANE-VU+VA region.



Figure 2-3: Temporal profiles for all gas-fired EGUs > 25 MW and gas-fired peaking EGUs > 25 MW in the MANE-VU+VA region.



Figure 2-4: Temporal profiles for all EGUs > 25 MW and peaking EGUs > 25 MW in the MANE-VU+VA region, composite of all fuel types.





Figure 2-5: Temporal profile for oil-fired small non-CAMD EGUs overlaid against operating profile for small oil-fired EGUs in MD.

Figure 2-6: Temporal profile for gas-fired small non-CAMD EGUs overlaid against operating profile for small gas-fired EGUs in MD.



The inventory that was used in this effort was the 2011/2018 Alpha modeling emissions inventory as compiled by the Mid-Atlantic Regional Air Management Association (MARAMA). Using MARAMA's installation of the Emissions Modeling Framework (EMF), the relevant facilities were identified and extracted using the North American Industry Classification System (NAICS) codes for EGUs. Using the appropriate Source Classification Codes (SCCs), coal-, oil-, and gas-fired EGUs were extracted for the selected facilities. Using Microsoft Access, the extracted data was quality assured and compared against other available databases to ensure that no units were double-counted and that no non-EGU units were included.

Using the SCCs for the selected units and the SMOKE temporal cross-reference file, the default temporal profiles for these types of small non-CAMD EGU units were extracted. This resulted in nine distinct profiles for coal units, 15 distinct profiles for oil units, and 20 distinct profiles for gas units. Figure 2-7 shows the default SMOKE temporal files assigned to oil-fired small non-CAMD EGUs (gray lines) overlaid against the distribution for all oil-fired EGUs greater than 25 MW (red line) and oil-fired peaking EGUs greater than 25 MW (blue line) in the MANE-VU+VA region (note that the red and blue lines in this figure are the same as those in Figure 2-2). Figure 2-8 shows the default SMOKE temporal files assigned to gas-fired small non-CAMD EGUs (gray lines) overlaid against the distribution for all gas-fired EGUs greater than 25 MW (orange line) in the MANE-VU+VA region (note that the red and blue lines in this figure are the same as those in Figure 2-2). Figure 2-8 shows the default SMOKE temporal files assigned to gas-fired small non-CAMD EGUs (gray lines) overlaid against the distribution for all gas-fired EGUs greater than 25 MW (orange line) and gas-fired peaking EGUs greater than 25 MW (orange line) in the MANE-VU+VA region (the green and orange lines in this figure are the same as those in Figure 2-3). Note: though a temporal profile was developed, the selection methodology yielded no coal-fired non-CAMD EGUs in the MANE-VU+VA region.

It can be seen in Figures 2-7 and 2-8 that the temporal profiles assigned to small non-CAMD EGUs by SMOKE tend to "smear" the emissions over 365 days of the year. As previously mentioned, this could underestimate the amount of emissions attributable to these types of units on peak electric demand days. Table 2-1 shows the total annual NOx mass emissions for the small non-CAMD EGU units that were the subject of this study. On an annual basis, 15,276 tons of NOx is not a particularly significant amount. For comparison, over 2 million tons of NOx were emitted from the electric generation sector and over 16 million tons of NOx were emitted from all anthropogenic sources in 2011 for the U.S.² However, for the purposes of air quality modeling and understanding the impact of these emissions on ozone formation during high electric demand days, when these emissions occur is important. For example, July 22, 2011 was a day when maximum observed 8-hour ozone values were 70 parts per billion (ppb) or higher in many parts of the eastern U.S., particularly in Long Island, New Jersey, and along the Chesapeake Bay (see Figure 2-9). Table 2-2 shows the NOx emissions from small non-CAMD EGUs on July 22, 2011 for all of the geographic regions analyzed. The figures in the fourth column represents that day's emissions as allocated by the default temporal profiles assigned to the units (as identified through the processes discussed above) in SMOKE. The fifth column shows the daily NOx emissions from these units as allocated with the temporal profiles developed in this effort. For the total of all the geographic regions analyzed, NOx emissions on July 22, 2011 would be 337 tons using the temporal profiles from this study, versus the 45 tons using the SMOKE default temporal profiles. This represents a seven fold increase in the amount of daily NOx emissions predicted for small non-CAMD EGUs on the July 22, 2011 peak demand day.



Figure 2-7: Default SMOKE temporal profiles for small oil-fired non-CAMD EGUs overlaid against profiles for all oil-fired EGUs > 25 MW and peaking oil-fired EGUs > 25 MW.

Figure 2-8: Default SMOKE temporal profiles for small gas-fired non-CAMD EGUs overlaid against profiles for all gas-fired EGUs > 25 MW and peaking gas-fired EGUs > 25 MW.



Table 2-1: Total annual NOx mass from small non-CAMD EGUs.

Region	Number of Units	Fuel	2011 Annual NOx Mass (Tons)
MANEVU+VA		Coal	N/A
	462	Oil	726
		Gas	308
MANEVU+VA Total	l		1,034
LADCO		Coal	5,217
	755	Oil	717
		Gas	1,189
LADCO Total			7,123
SESARM		Coal	225
	304	Oil	244
		Gas	1,535
SESARM Total			2,004
CENSARA		Coal	3,050
	511	Oil	671
		Gas	1,395
CENSARA Total			5,116
Total		Coal	8,491
	2,032	Oil	2,359
		Gas	4,426
Grand Total NOx N	/lass		15,276

Figure 2-9: Maximum observed 8-hour ozone values in the eastern U.S. on July 22, 2011 (ppb)



Table 2-2: Small non-CAMD EGU NOx emissions (tons) for July 22, 2011, SMOKE temporal profiles vs. profiles based on CEMS hourly data for peaking units.

Region	Number of Units	Fuel	7/22 nonCAMD Small EGU Contribution using SMOKE Profile (Tons)	7/22 nonCAMD Small EGU Contribution using MDE Profile (Tons)	Difference SMOKE vs. MDE (Tons)	Peak Day % Increase with nonCAMD Small EGU by MDE
MANEVU+VA	462	Coal	N/A	N/A	N/A	N/A
		Oil	2	39	37	1758%
		Gas	1	12	11	1228%
MANEVU+VA	Total		3	51	48	1600%
LADCO	LADCO 755	Coal	14	133	119	827%
			2	36	34	1550%
		Gas	3	36	33	971%
LADCO Total			20	206	186	931%
SESARM	304	Coal	1	3	2	313%
		Oil	1	5	4	603%
		Gas	5	18	14	295%
SESARM Total			6	25	19	330%
CENSARA	511	Coal	9	42	33	375%
		Oil	2	0	-2	-100%
		Gas	5	12	7	152%
CENSARA Tot	al		16	54	38	237%
Total	2,032	Coal	24	178	154	645%
		Oil	7	80	73	979%
		Gas	14	78	65	477%
Grand Total N	Ox Mass		45	337	292	650%

The next step in the analysis was to apply the temporal profiles described above to the universe of small non-CAMD EGUs using SMOKE and to assess the change in predicted ozone concentrations using the Community Multiscale Air Quality (CMAQ) model. CMAQ model runs were performed by air quality modeling staff at the University of Maryland (UMD) for the 2011 and 2018 Base Cases using the small EGU temporalization approach. Maximum 8-hr ozone difference plots for 2011 and 2018 for the July 21 and July 22, 2011 episode days are shown in Figures 2-10 and 2-11. These plots show the difference in maximum predicted 8-hr ozone concentrations between the base case runs with the small EGU temporalization and those without. This difference represents the portion of predicted 8-hr ozone concentrations that is attributable to the improved small EGU temporalization scheme. With the improved temporalization, over 330 tons of NOx mass were added to the modeling domain on July 21 (Figure 2-10) and over 290 tons were added on July 22 (Figure 2-11). Corresponding increases in predicted 8-hr ozone of up to 5 ppb are evident in the difference plots. Areas of NOx dis-benefit can be seen on July 22, primarily in Ohio and Michigan. NOx dis-benefit occurs when ozone is scavenged, and thereby reduced, by excess NOx emissions. Figures 2-10 and 2-11 show that improving the temporalization of small non-CAMD EGUs can have a significant effect on predicted peak day model results.

Figure 2-10: Maximum modeled 8-hour ozone concentrations attributable to improved small EGU temporalization for the July 21 episode day for the 2011 Base Case (left) and the 2018 Base Case (right) in parts per billion (ppb).



Additional NOx Added by Re-temporalization

MANE-VU: +41.09 Tons LADCO: +230.33 Tons Figure 2-11: Maximum modeled 8-hour ozone concentrations attributable to improved small EGU temporalization for the July 22 episode day for the 2011 Base Case (left) and the 2018 Base Case (right) in parts per billion (ppb).

2011

2018



Additional NOx Added by Re-temporalization MANE-VU: +48.07 Tons LADCO: +186.01 Tons

UMD CMAQ Modeling

3. BUGs

3.1 <u>First-Approximation Estimate of BUG Emissions during a DR Event and the BUG's Impact on Air</u> <u>Quality</u>

A related but separate analysis was performed by a sub-group of the OTC HEDD Workgroup to make a first-approximation estimate of emissions from back-up generators, or BUGs, responding to a demand response event and the resulting effect on air quality. Unlike the small non-CAMD units addressed in Section 2, these BUG units, which are also commonly referred to as behind-the-meter (BTM) units, a) do not directly feed the electrical grid, and b) are not included in the emissions inventory as discrete units. These types of units are typically diesel-fired reciprocating internal combustion engines (RICE) that were originally installed to provide power to a facility to maintain essential functions in the event of an interruption of power from the electrical grid. BUGs are also sometimes used for other emergency purposes, for example to power pumps for fire suppression purposes. However, there has been an increased use of BUGs as part of electricity market Demand Response (DR) programs. According to the Federal Energy Regulatory Commission (FERC), DR is the reduction of energy consumption by customers in response to the increased price of electricity or in response to financial incentives to reduce electric demand³. DR may consist of curtailment, namely the practice of shutting down certain operations at a facility to reduce electricity consumption during times of peak demand. DR may also involve generation, which reduces demand on the electrical grid by using BTM resources such as BUGs to generate electrical power at a facility.

Since BUGs are not included in the emissions inventory as discrete units, they are typically included in the area source category (also sometimes referred to as the non-point category) of the emissions inventory. Area sources are those sources of emissions that are too widespread or numerous to be inventoried individually. Therefore, their emissions are estimated in aggregate using broad-based data such as statewide fuel consumption, population, or employment. Similar to the challenges described earlier for small non-CAMD EGUs, the temporal profiles used in the emissions model for many area source categories tend to smear emissions evenly over the year. This could lead to an underestimate of emissions due to BUGs operating on a peak electric demand day.

The goal of this part of the study was to develop a first-approximation estimate of NOx emissions from BUGs responding to a DR event in the Mid-Atlantic and Northeast U.S., and to evaluate the effect of those emissions on air quality modeling results. This first-approximation estimate involved a range of assumptions, which are described further below. Emissions from this first-approximation estimate were added into a 2011 Base Case modeling run performed with the CMAQ modeling system. It should be noted that this modeling exercise was intended as a hypothetical high-bound analysis and is not being suggested as a SIP-quality modeling scenario.

The first step in the analysis was to come up with an independent estimate of the megawatts (MW) associated with BUGs responding to a "typical" DR event. This study focused on the regions covered by the Independent System Operators (ISOs) in the Northeast: ISO-NE, NYISO, and PJM. For ISO-NE, it was assumed that approximately 270 MW of these types of resources would respond during a typical event;

this figure is based on the enrolled MW of Real-Time Emergency Generation Resources (RTEG) in ISO-NE in 2014⁴. This is a conservative (i.e. with the intention of producing a high-bound estimate) assumption because there were likely somewhat fewer of these assets available in 2011 than in 2014 (as mentioned above, the air quality modeling was performed for a 2011 case). For NYISO it was assumed that 247 MW of BUG-type resources would respond during a typical event, based on the generating resources enrolled in NYISO DR programs as of May, 2011⁵. In addition, 29.5 MW of reduction was achieved on July 22, 2011 through Consolidated Edison's Commercial System Relief Program (CSRP)⁶. It was assumed that 20% of this reduction was achieved with the use of BTM BUG resources. Therefore, for the purposes of this first-approximation estimate, the total MW associated with BUG resources for the NYISO region was assumed to be 253 MW. For PJM, 10,600 MW of DR resources were committed for 2016 with 14%, or approximately 1,500 MW, being attributable to RICE⁷. Data from PJM showed a tenfold increase in registered DR resources between 2011 and 2015. Accounting for the fact that DR resources were approximately ten times lower in 2011 than in 2015, and assuming that the 14% of generation attributable to RICE is an underestimate, it was felt that 250 MW was a conservative firstapproximation for the MWs associated with BUGs responding to a DR event in PJM.

Using the MW assumptions described above, low- and high-bound NOx emission factors were applied to obtain a range of estimates for the amount of NOx emitted from BTM BUGs responding during a typical high electric demand event. A low bound NOx emission factor of 4 g/kW-hr was used, corresponding to the Tier 3 standard for non-road diesel engines⁸. A high-bound NOx emission factor of 16 g/kW-hr was taken from Zhang & Zhang and was based on an analysis of diesel backup emergency generators in New York City done by the New York State Department of Environmental Conservation⁹. For this analysis, it was assumed that a typical DR "event" would last for six hours and occur between the hours of noon and 6PM¹⁰. It was also assumed that an average RICE generator would be 90% efficient at turning mechanical energy into electricity. The resulting low-bound estimates ranged from 7 to 8 tons of NOx per "event". High-bound estimates ranged from 29 tons per event for the PJM region to 32 tons per event for the ISO-NE region. These results compare well with those of Zhang & Zhang⁹ and NESCAUM³ (see Table 3-1).

The next step in this analysis was to prepare the resulting emissions estimates for input into the air quality model. Only the high-bound estimate was used in the modeling. The SMOKE emissions model requires input emissions to be specified at the county level for area sources. As mentioned earlier, emissions from area sources are estimated in aggregate and the location of each individual unit is not known. Therefore, the total BUG emissions estimate for each ISO region was apportioned to the county level using the number of employment establishments from the 2011 U.S. Census County Business Patterns¹¹. Emissions for each county in each ISO region were calculated using the equation:

Emissions_{Countyi} = Total Emissions_{ISO} x (# establishments_{Countyi}/Total establishments_{ISO})

For this first-approximation estimate, only states that are wholly enclosed by the PJM region were considered in the county-level apportioning (the PJM region includes only portions of some states). For the purposes of this analysis, the wholly-enclosed PJM states included Delaware, the District of Columbia, Maryland, New Jersey, Ohio, Pennsylvania, Virginia, and West Virginia (although noting that a

	OTC Workgroup	Zhang & Zhang ^a	NESCAUM
Low-Bound Estimates			
ISO-NE	8	-	-
NYISO	7	1.6 - 8.1	-
PJM	7	-	-
High-Bound Estimates			
ISO-NE	32	-	-
NYISO	30	12.1 - 60.3	15
PJM	29	-	33 – 110 ^b

Table 3-1: Low- and high-bound NOx estimates for BTM BUGs responding during a typical DR "event" in tons per event.

a. Zhang & Zhang examined a range of emission factor and generation penetration scenarios.

b. NESCAUM examined a range of generator penetration scenarios for the PJM region.

very small part of far western Virginia is not in PJM). The SMOKE emissions model then apportioned the county-level estimates to the model grid cell level using appropriate spatial surrogates. The SMOKE emissions model also apportions the estimates to each modeled hour, and, as mentioned earlier, it was assumed that these emissions would occur between the hours of noon and 6 PM. Figure 3-1 shows the "per event" BUG NOx emissions estimates apportioned to the county level. This figure also shows the emissions as apportioned to the model grid cells for a single model hour. (Note: It can be seen in Figure 3-1 that the county-level emissions estimates are relatively high for counties in eastern Massachusetts and in the New York City/Long Island area, but less so for the Washington, D.C. metropolitan area, Philadelphia, and other large cities in the PJM region. The sub-group suggests that the sheer number of counties for states in the PJM region may have artificially diluted the county-level emissions estimates when using a county-level data set to apportion the emissions.)

After the emissions were processed by the SMOKE emissions model as described above, the CMAQ air quality model was run for the 2011 Base Case. For this analysis, the model was run for the July 21 and July 22, 2011 episode days (note that the July 20 episode day was also run for model spin-up purposes). These episode days were chosen because demand response events were known to have occurred on these days in NYISO¹⁰, PJM¹², and ISO-NE¹³. Further, July 22 in particular was known to be a day with elevated ozone levels in parts of the eastern U.S. (see Figure 2-9). This first-approximation analysis included some very conservative assumptions. First, it was assumed that a DR "event" was called in all three ISO regions simultaneously on both July 21 and July 22. According to historical data, events were called by NYISO on July 21 and 22 and by PJM only on July 22; DR resources were called by ISO-NE only on July 22, although RTEG backup generators were not directly dispatched³. Second, for this first-approximation estimate, no attempt was made to account for state rules that restrict the participation of emergency generators in DR programs.

Figure 3-2 shows the maximum modeled 8-hour ozone concentrations attributable to the BUG emissions estimates from this analysis. The results in the figure represent the difference in maximum modeled 8-hour ozone concentrations between the 2011 Base Case and the 2011 Base Case plus BUG emissions

Figure 3-1: BUG NOx emissions estimates apportioned to counties (left) and to model grid cells (right). The left panel is total tons per "event" (i.e. tons per day), and the panel on the right shows emissions for a single modeled hour in tons per hour.



scenario. The difference in modeled concentrations between the two cases is the portion attributable to the BUG emissions estimates from this exercise. NOx dis-benefit can be clearly seen in the figure, particularly in the Boston and New York City areas. NOx dis-benefit most often occurs in urban areas, which is evident in the figure. For the July 21 episode day (left side of figure), modeled 8-hour ozone increases in the 0.5 to 1 ppb range can be seen in parts of Connecticut and Massachusetts, as well as coastal areas of Maine and New Hampshire. For the July 22 episode day (right side of figure), modeled 8-hour ozone increases of 0.5 to 1 ppb can be seen in parts of southeastern Massachusetts. All of these areas have been known to have elevated levels of monitored ozone during the summer months. Further, for the July 22 episode day, modeled 8-hour ozone increases of 1 ppb or more were predicted for over-water model grid cells east of Massachusetts. Overwater ozone plumes can affect ozone concentrations over land if they are carried back to shore by sea breezes. It should be noted that these model results were derived using the conservative assumptions outlined above. Therefore these results are not intended to be a realistic representation of what actually occurred on July 21 and 22, 2011, but rather a conservative first-approximation estimate of what the impact from diesel back-up emergency generators *could be* if they responded in an unlimited matter to a widespread demand response event.

3.2 Review of State Regulations Pertaining to the Use of Emergency Generators in DR Programs

The OTC HEDD Workgroup performed a review of the State rules and regulations that pertain to the participation of emergency generators in demand response programs. The Workgroup's findings indicate that most states have regulations that limit the operation of emergency generators to true



Figure 3-2: Maximum modeled 8-hour ozone concentrations attributable to BUGs for the July 21 episode day (left) and the July 22 episode day (right) in parts per billion (ppb).

emergency situations (most rules also allow a certain number of operating hours for maintenance, readiness testing, etc.). Most state regulations define emergencies in a similar manner: e.g. a failure of the electrical grid; an on-site equipment failure; a flood, fire, or natural disaster; or significant deviations in voltage. Some states also include ISO-declared reliability emergencies in their definition of emergency. In some states, a permit is required for emergency generators and in many of these cases, emergency generators are covered under a "general", or generic, permit specifically applicable to these types of units.

In most states, an engine that participates in a voluntary demand response program or other supply arrangement with a utility or system operator is considered a non-emergency engine. The terminology can vary from state to state, but these non-emergency engines are often referred to as distributed generators. But whatever the terminology, in most states, engines used for this purpose must be permitted and/or are subject to notification and recordkeeping requirements. In many states, these types of engines must also meet stringent emissions limits.

For member states of NESCAUM (Northeast States for Coordinated Air Use Management), regulations pertaining to the use of emergency and non-emergency engines are summarized in Appendix A: State Emergency Engine Regulations of NESCAUM's 2012 (rev. 2014) report, *Air Quality, Electricity, and Back-up Stationary Diesel Engines in the Northeast*³. For other states in the BUG sub-group's analysis area (see Figure 3-1), regulations pertaining to emergency and non-emergency engines are summarized in Appendix A of this white paper.

3.3 Recent Changes in Demand Response Participation

It should be noted that there have been some recent changes in the amount of generation resources that are participating in demand response programs. On April 15, 2016, the EPA provided its "Guidance on Vacatur of RICE NESHAP and NSPS Provisions for Emergency Engines". This guidance clarified and modified the EPA's requirements concerning the participation of generation resources in nonemergency programs. The guidance specifies that the previous allowance for emergency engines to operate when an Energy Emergency Alert (EEA) Level 2 has been declared, or when there are specific voltage or frequency deviations, is vacated as of May 2, 2016. The EPA further clarifies that any such operation for these purposes would be considered non-emergency operation after this date. A further discussion of the recent RICE rule history can be found in Appendix B. On April 29, 2016, PJM issued a memo to its DR program participants notifying them of the EPA guidance and re-stating that they expected all DR program participants to follow all applicable federal, state and local requirements when participating in the PJM DR programs¹⁴.

While it is not known whether the EPA's and PJM's requirements or other market influences had the most significant impact, it appears that there was a large reaction from the PJM demand response participants. Table 3-2 below shows the change in resources offered into PJM DR programs between the 2015 report (report dated May 9, 2016)¹⁵ and 2016 report (report dated June 16, 2016)¹⁶.

PJM Demand Response Participation	2015 Report Dated May 9, 2016	2016 Report Dated June 16, 2016	Change
Unique Locations	19351	15974	3377 reduction
Unique MW	12866	9654	3212 reduction
% Generation	23%	12%	11% reduction

Table 3-2: PJM Demand Response Report Data

It can be seen in the above table that the amount of generating resources that cleared the PJM auction for DR participation has been greatly reduced in PJM between the 2015 report and the 2016 report. This would potentially have a significant impact on the NOx emissions expected from this segment. It may also be possible that the generation provided in the past from the reduced DR resources will be made up by the fast start/stop peaking combustion turbine EGUs.

4. Peaking Units

The OTC HEDD Workgroup was also charged with analyzing the contribution of peaking EGU units to total NOx emissions on high electric demand days. However, the workgroup decided that in order to perform a meaningful analysis of peaking units, it was necessary to examine EGUs of all operating characteristics that operate on high electric demand days. Therefore, for the purposes of the peaking unit analysis, the Workgroup looked at three distinct categories, namely peaking units, base load units, and what the Workgroup has termed "intermediate units". The Workgroup adopted its own definitions

for each of these categories, based on units' on-line factor (i.e. the number of hours of annual operation). These definitions are shown below:

- Base load = Annual on-line factor of 89% or more
- Intermediate = Annual on-line factor between 10% and 89%
- Peaking = Annual on-line factor of 10% or less

The peaking unit definition of a 10% on-line factor was chosen to represent units that have the ability to start and stop on a fairly rapid basis. These units are typically operated only during a few hours per year to meet the electric grid peak demand condition. This is in part because many of these units fire premium cost fuels and/or have high heat rates, and their operation is higher on the incremental cost curve than other units. These units can generally be started just as the daily electric demand peaks are encountered and can be shut down as soon as the peak demand drops off. They may be started and stopped multiple times a day to meet morning and afternoon/evening peaks.

Conversely, a base load unit was considered to be a unit that is on-line whenever it is capable of operation. Baseload EGUs typically plan for a 1-month maintenance outage every one to two years. Further, a typical EGU may encounter a forced outage at an average rate of 2.5% to 6% of the time. The figure of 2.5% was considered representative of those units that go through fewer starts/stops and load changes than the average unit. Accounting for these forced outages and planned maintenance outages, a breakpoint definition of an 89% on-line factor was chosen for base load units.

Intermediate EGUs were considered to be those units that did not fall into the peaking or base load categories. These EGUs may shut down for weekends, nights, or other periods of expected low cost, load, or reliability concerns. They also have a higher tendency to move load while on-line, as they tend to be at or close to the marginal cost point at various times of the day.

As with the small non-CAMD EGU and BUG analyses, the Workgroup chose a series of episode days for analysis. These episode days, and the rationale for choosing them, are shown in the bullets below.

- July 21 & 22, 2011: Demand response events were known to have occurred on these days in NYISO (July 21 and 22), PJM (July 22 only), and ISO-NE (July 22 only) (see Section 3.1). July 22 in particular was a day with elevated ozone levels in parts of the eastern U.S. (Figure 2-9). Lastly, these episode days are consistent with those that were used in the small non-CAMD EGU and BUG analyses.
- June 18, 2014: This was the highest 2014 ozone season electric demand day in PJM. This episode day was of particular interest for the analysis because it represents a "moderate weather" year (that is, a year with a cooler than average summer).
- June 20, 2015: This was the highest 2015 ozone season electric demand day in PJM. This episode day was of particular interest for the analysis because it represents a "recent fleet" year (that is, a year that reflects recent changes to the EGU fleet such as retirements, fuel switches, etc.).

In addition to the episode days listed, the Workgroup also examined annual and ozone season NOx emissions from base load units, intermediate units, and peaking units for 2011, 2014, and 2015.

For each of the time periods discussed above, EGU NOx emissions for all EGUs in the Ozone Transport Region (OTR) were downloaded from the AMPD database. For each of the relevant time periods, the data were grouped into the base load, intermediate, and peaking categories using the definitions described earlier. The data were grouped even further by the following fuel types and unit configurations: coal, oil, gas, wood, combined cycle, and combustion turbine. Figure 4-1 shows the annual count of OTR EGUs in the base load, intermediate, and peaking categories for 2011 and 2015. Figure 4-2 shows the annual count of OTR EGUs in the various configuration categories for 2011 and 2015. The resulting grouped EGU NOx emissions for each of the selected episode days (as well as the corresponding annual and ozone season emissions) are presented in the sections below.

4.1 July 21 & 22, 2011

Table 4-1 shows the contribution to total OTR EGU NOx mass, expressed as a percent, for base load, intermediate, and peaking units for 2011 annual, ozone season, and the July 21 and 22, 2011 episode days. These categories are further broken down by fuel type, with coal units being further subdivided into those with and without post combustion controls. The data in this and subsequent tables represent all EGUs in the OTR that report to AMPD. Peaking units contributed approximately 25% and 34% of the total NOx mass on the July 21 and 22, 2011 episode days, respectively. Among the peaking units, the oil subcategory had the highest contribution, with 15% and 22%, respectively, on the two episode days. However, it can be seen that the intermediate units consistently had the highest contribution to NOx mass. This contribution hovered around 50%, ranging from 46.4% on the July 22 episode day to 54.7% for annual. The bulk of the intermediate unit contribution came from the intermediate coal subcategory. For example, of the 54.7% intermediate annual contribution, 48.1% of that came from intermediate coal units. The majority of that contribution, or 36.4%, came from intermediate coal units with post combustion controls.

As would be expected, the contribution from peaking units was higher for the episode days than for annual or ozone season. For example, the NOx mass contribution from peaking units was 33.6% on the July 22 episode day versus 3.1% for annual and 4.7% for ozone season. As would also be expected, the contribution from base load units was lower on the individual episode days than for annual or ozone season (roughly 20% contribution for each of the episode days versus roughly 40% for annual and ozone season).

Table 4-2 shows the OTR EGU NOx mass and heat input, expressed as a percent of total, for 2011 annual, 2011 ozone season, and the two episode days. It can be seen in the table that in 2011, on an annual basis, coal steam EGUs contributed a little over half of total heat input, but they contributed over



Figure 4-1: Count of OTR fuel-fired EGUs by operating mode, operating anytime during annual period

Figure 4-2: Count of OTR fuel-fired EGUs by configuration, operating anytime during annual period



Table 4-1: NOx mass, expressed as % of total, for 2011 annual, 2011 ozone season, and the July 21-22,2011 episode days for all OTR EGUs that report to AMPD.

EGU Operating Mode	Category	Portion of 2011 Annual OTR EGU NOx Mass Emissions (%)	Portion of 2011 O.S. OTR EGU NOx Mass Emissions (%)	Portion of 7/21/11 OTR EGU NOx Mass Emissions (%)	Portion of 7/22/11 OTR EGU NOx Mass Emissions (%)
Base	Total	42.2	40.8	23.4	20
Base	Subcategory Wood	0	0	0	0
Base	Subcategory Gas	0.4	0.4	0.3	0.3
Base	Subcategory Coal	41.8	40.4	23.1	19.7
Base	Subcategory Coal w/o Post Comb Cntrls	22.3	21.7	12.2	10.4
Base	Subcategory Coal with Post Comb Cntrls	19.5	18.8	10.9	9.2
Intermediate	Total	54.7	54.5	51.5	46.4
Intermediate	Subcategory Wood	0.1	0.1	<0.1	<0.1
Intermediate	Subcategory Gas	4.3	4.8	5	5
Intermediate	Subcategory Oil	2.2	2.5	6.5	6.5
Intermediate	Subcategory Coal	48.1	46.9	39.8	34.9
Intermediate	Subcategory Coal w/o Post Comb Cntrls	11.7	12.2	11.6	10.7
Intermediate	Subcategory Coal with Post Comb Cntrls	36.4	34.8	28.1	24.1
Peaking	Total	3.1	4.7	25.1	33.6
Peaking	Subcategory Gas	1.3	2.1	8.7	10
Peaking	Subcategory Oil	1.5	2.3	15	22
Peaking	Subcategory Coal	0.4	0.2	1.4	1.6
All Modes	Total	100	100	100	100

Unit Configuration	2011 Annual NOx Mass (%)	2011 Annual Heat Input (%)	2011 O.S. NOx Mass (%)	2011 O.S. Heat Input (%)	7/21/11 NOx Mass (%)	7/22/11 NOx Mass (%)	7/21/11 Heat Input (%)	7/22/11 Heat Input (%)
Coal Steam	90.2	52.4	87.6	50.5	64.4	56.1	41.7	39.3
Oil Steam	3.2	3.6	3.9	4.5	15.7	15.6	13	14
Gas Steam	1.7	3.2	2.4	4.2	4.5	5	7	7.2
Wood Steam	0.1	0.3	0.1	0.3	0.1	0.1	0.2	0.2
Combined Cycle	3.2	38.8	3.2	38	3	2.9	28.8	28.7
Combustion Turbine (total)	1.7	1.6	2.8	2.4	12.3	20.4	8.3	10.6
Total	100	100	100	100	100	100	99	100
Subgroup CT – Oil	0.5	0.2	0.9	0.3	5.5	12.7	1.9	3.8
Subgroup CT - Gas	1.2	1.5	1.9	2.2	6.8	7.7	6.4	6.9
Subgroup CT - (AMPD <25 MW)	1	11	1.2	10.2	2.6	5.4	7.4	7.8
Subgroup Coal - All Post Comb Cntrls	56.2	37.9	53.7	36.5	40.4	34.8	30.5	28.5
Subgroup Coal – SCR	41.1	29.7	39.6	28.9	25.2	21.2	22.7	20.9
Subgroup Coal – SNCR	15.1	8.2	14.1	7.6	15.2	13.6	7.8	7.6
Subgroup Coal - No Post Comb Cntrls	34	14.5	33.9	14	24	21.3	11.3	10.9

Table 4-2: Heat input and NOx mass, expressed as % of total, for 2011 annual, 2011 ozone season, and the July 21-22, 2011 episode days for all OTR EGUs that report to AMPD.

90% of the total NOx mass. Conversely, combined cycle units contributed almost 40% of the annual heat input, but only about 3% of the total NOx mass. Corresponding percentages for the 2011 ozone season were similar.

For the individual episode days, the coal steam units contributed somewhat less, on a percentage basis, to total NOx mass and heat input than they did for annual and ozone season. For the episode days, the combined cycle units made a similar, but slightly smaller, contribution to NOx mass and heat input than they did for annual and ozone season. The combustion turbines, however, had a greater contribution to NOx mass and heat input on the individual episode days than they did for annual and ozone season. For example, for the July 22, 2011 episode day, combustion turbines contributed over 20% of the NOx mass (versus 1.7% for annual) and almost 11% of the heat input (versus 1.6% for annual). Note that Table 4-2 (and other subsequent corresponding tables) provides a further detailed breakdown for combustion turbines and coal units.

4.2 June 18, 2014

Table 4-3 shows the contribution to OTR EGU NOx mass, expressed as a percent, for base load, intermediate, and peaking units for 2014 annual, ozone season, and the June 18, 2014 episode day. Similar to Table 4-1, these categories are further broken down by fuel type, with coal units being further subdivided into those with and without post combustion controls. On the June 18th episode day, peaking units contributed 6% of the total NOx mass, which is a significantly smaller percentage than that observed for the 2011 episode days (e.g. 34% on July 22, 2011). Gas peaking units had the highest peaking unit contribution on the 2014 episode day at 3.6% (oil peaking units had the highest contribution amongst peaking units for the 2011 episode days). However, similar to 2011, intermediate units had the highest contribution to NOx mass; in fact, their contribution was higher in 2014 than in 2011 (e.g. 74.7% for 2014 annual versus 54.7% for 2011 annual). As with 2011, the bulk of the intermediate contribution came from intermediate coal units, with the bulk of that coming from those with post combustion controls.

Table 4-4 shows the OTR EGU NOx mass and heat input, expressed as a percent of total, for 2014 annual, 2014 ozone season, and the episode day. The pattern of contribution in this table is generally similar to that seen in Table 4-2, although in 2014 coal steam units had a somewhat smaller contribution to NOx mass and heat input than they did in 2011. For example, in 2014, the annual and ozone season coal steam contribution to NOx mass hovered just above 80%, while in 2011 it hovered around 90%. In 2014, combined cycle units and combustion turbines had a somewhat higher contribution to NOx mass and heat input than they did in 2011. Tables 4-3 and 4-4 show no distinct difference in the pattern of contribution between annual, ozone season, and the June 18 episode day.

Table 4-3: NOx mass, expressed as % of total, for 2014 annual, 2014 ozone season, and the June 18,2014 episode day for all OTR EGUs that report to AMPD.

EGU Operating Mode	Category	Portion of 2014 Annual OTR EGU NOX Mass Emissions (%)	Portion of 2014 O.S. OTR EGU NOx Mass Emissions (%)	Portion of 6/18/14 OTR EGU NOx Mass Emissions (%)
Base	Total	22.7	22.9	20
Base	Subcategory Wood	0.1	0.1	<0.1
Base	Subcategory Gas	1.7	0.6	0.4
Base	Subcategory Coal	20.9	22.2	19.6
Base	Subcategory Coal w/o Post Comb Cntrls	0.1	0.2	0.1
Base	Subcategory Coal with Post Comb Cntrls	20.8	22.1	19.5
Intermediate	Total	74.7	73.5	73.6
Intermediate	Subcategory Wood	0.7	0.9	0.6
Intermediate	Subcategory Gas	7.7	9.6	9
Intermediate	Subcategory Oil	2.7	2.8	2.8
Intermediate	Subcategory Coal	63.6	60.2	61.2
Intermediate	Subcategory Coal w/o Post Comb Cntrls	8.4	5.7	8
Intermediate	Subcategory Coal with Post Comb Cntrls	55.2	54.5	53.2
Peaking	Total	3.7	3.3	6
Peaking	Subcategory Gas	1.7	2	3.6
Peaking	Subcategory Oil	1.9	1.3	2.4
Peaking	Subcategory Coal	0.1	<0.1	0
All Modes	Total	101	100	100

Unit Configuration	2014 Annual NOx Mass (%)	2014 Annual Heat Input (%)	2014 O.S. NOx Mass (%)	2014 O.S. Heat Input (%)	6/18/14 NOx Mass (%)	6/18/14 Heat Input (%)
Coal Steam	84.7	46.1	82.6	40.6	81.3	43.4
Oil Steam	3.5	3.4	3.3	3.2	4.5	5.3
Gas Steam	3.2	4.3	4.1	5.3	5.1	6.3
Wood Steam	0.8	1	1	1.1	0.6	0.8
Combined Cycle	5.2	41.6	6	45.6	5	38.2
Combustion Turbine (total)	2.8	3.5	2.9	4	3.6	6
Total	100	100	100	100	100	100
Subgroup CT - Oil	0.9	0.3	0.6	0.2	0.5	0.2
Subgroup CT - Gas	1.9	3.2	2.3	3.9	3.1	5.8
Subgroup CT - (AMPD <25 MW)	0.1	<0.1	0.2	<0.1	0.3	0.1
Subgroup Coal - All Post Comb Cntrls	76	42.1	76.6	38.2	72.7	39.9
Subgroup Coal - SCR	58.9	32.3	59.8	29.6	54.5	29.9
Subgroup Coal - SNCR	17.1	9.8	16.8	8.6	18.2	10
Subgroup Coal - No Post Comb Cntrls	14.7	4	6	2.4	8.6	3.5

Table 4-4: Heat input and NOx mass, expressed as % of total, for 2014 annual, 2014 ozone season, and the June 18, 2014 episode day for all OTR EGUs that report to AMPD.

4.3 July 20, 2015

Table 4-5 shows the contribution to OTR EGU NOx mass, expressed as a percent, for base load, intermediate, and peaking units for 2015 annual, ozone season, and the July 20, 2015 episode day. On the July 20th episode day, peaking units contributed 12.6% of the total NOx mass, with gas peaking units having the highest contribution amongst the peaking units at 7.5%. However, as in the other years, intermediate units had the highest contribution to NOx mass, with the majority of that being attributable to intermediate coal units with post combustion controls. For 2015, the contribution percentages from these units in the 70s) was more in line with 2014 (which had contribution percentages from these units in the 70s). However the pattern for 2015 was more similar to 2011 in the sense that the individual episode day displayed a distinctly different pattern than annual and ozone season. For example, base load units had a somewhat lower contribution on the individual episode day (11.7%) than for annual (23.3%) and ozone season (20%). Conversely, peaking units had a higher contribution on the individual episode day (12.6%) than for annual (3.1%) and ozone season (3.6%).

Table 4-6 shows the OTR EGU NOx mass and heat input, expressed as a percent of total, for 2015 annual, 2015 ozone season, and the July 20th episode day. A similar pattern is evident here as in the other years: coal steam units contributed the majority of the NOx mass and a significant percentage of the heat input, while combined cycle units contributed a significant percentage of the heat input, but only a small percentage of the NOx mass. The pattern for 2015 is more similar to 2011 than 2014 in the sense that coal steam units had a smaller contribution on the individual episode day than for annual or ozone season. Combustion turbines seemed to pick up the difference, having a higher contribution on the episode day than they did for annual or ozone season (e.g. 11.8% NOx mass for the July 20 episode day versus 2.7% for annual).

4.4 Analysis of Combustion Turbine Emission Rates and Potential NOx Emissions Reductions

For the July 20, 2015 HEDD event, EGUs listed as combustion turbines in the AMPD represented the largest number of EGUs operating for some portion of the event. Of the 377 combustion turbine EGUs that operated on July, 20, 2012, a total of 338 of those combustion turbine EGUs fell into the Workgroup's "peaking unit" category. Of the 338 operating peaking unit combustion turbines, AMPD lists 176 as having oil as the primary fuel and 162 as having gas as the primary fuel.

The AMPD NOx emissions data for the OTR fleet of fossil fueled EGUs operating on July 20, 2015 also indicated that the category of combustion turbine (CT) EGUs was the second highest category of NOx mass emissions (although significantly smaller than the highest category, coal fired EGUs). Note that the fleet of CTs operating in the OTR represented by the AMPD may not include all CTs, as many small CTs (<25MW nameplate) are not required to submit emissions data to the AMPD. This category of the OTR fossil fueled EGUs operating on July 20, 2015 consisted of a range of unit sizes from 15MW to 198MW, and had a range of operating durations from two hours to the entire 24 hour day.

EGU Operating Mode	Category	Portion of 2015 Annual OTR EGU NOx Mass Emissions (%)	Portion of 2015 O.S. OTR EGU NOx Mass Emissions (%)	Portion of 2015 7/20/15 OTR EGU NOx Mass Emissions (%)
Base	Total	23.3	20	11.7
Base	Subcategory Wood	0.2	0.2	0.1
Base	Subcategory Gas	0.7	0.8	0.5
Base	Subcategory Coal	22.4	19	11
Base	Subcategory Coal w/o Post Comb Cntrls	0	0	0
Base	Subcategory Coal with Post Comb Cntrls	22.4	19	11
Intermediate	Total	73.6	76.3	75.7
Intermediate	Subcategory Wood	0.5	0.5	0.4
Intermediate	Subcategory Gas	9.5	12.5	13.6
Intermediate	Subcategory Oil	5.7	6.8	6.8
Intermediate	Subcategory Coal	57.9	56.5	55
Intermediate	Subcategory Coal w/o Post Comb Cntrls	8	8.5	8.9
Intermediate	Subcategory Coal with Post Comb Cntrls	49.9	48	46.1
Peaking	Total	3.1	3.6	12.6
Peaking	Subcategory Gas	1.5	2.4	7.5
Peaking	Subcategory Oil	1.5	1.3	5
Peaking	Subcategory Coal	0	0	0
All Modes	Total	100	100	100

Table 4-5: NOx mass, expressed as % of total, for 2015 annual, 2015 ozone season, and the July 20,2015 episode day for all OTR EGUs that report to AMPD.

Table 4-6: Heat input and NOx mass, expressed as % of total, for 2015 annual, 2015 ozone season, and the July 20, 2015 episode day for all OTR EGUs that report to AMPD.

Unit Configuration	2015 Annual NOx Mass (%)	2015 Annual Heat Input (%)	2015 O.S. NOx Mass (%)	2015 O.S. Heat Input (%)	7/20/15 NOx Mass (%)	7/20/15 Heat Input (%)
Coal Steam	80.3	37.4	75.5	34.4	66	34.9
Oil Steam	6.3	5.1	6.9	5.4	7.4	6.8
Gas Steam	4.6	5.3	6.4	6.5	9.2	9.7
Wood Steam	0.7	0.9	0.7	0.8	0.5	0.6
Combined Cycle	5.3	47.7	6.4	48	5	39
Combustion Turbine (total)	2.7	3.6	3.9	4.9	11.8	9.4
Total	100	100	100	100	100	100
Subgroup CT - Oil	0.7	0.2	7	0.2	3.9	1.1
Subgroup CT - Gas	2	3.4	3.2	4.7	7.9	8.3
Subgroup CT - (AMPD <25 MW)	0.4	0.1	0.8	0.2	3.6	0.1
Subgroup Coal - All Post Comb Cntrls	71.9	33.8	66.6	31.4	56.8	31.4
Subgroup Coal - SCR	64.7	30.2	59.9	27.9	48.8	27.1
Subgroup Coal - SNCR	7.4	4	6.8	3.6	8.5	4.9
Subgroup Coal - No Post Comb Cntrls	8.2	3.1	8.7	2.6	9.1	2.9

The AMPD data for CT EGUs showed that a number of the units utilized default NOx emission rate factors instead of measured or test-based NOx emission rate values. These default rate values tend to overestimate the unit's NOx emission rate, often by a factor of two or more. In order to minimize the impact of the use of default emission factors, a correction factor was estimated for each of the affected combustion turbine EGUs. Historic ozone season average NOx emission rate values in the AMPD were examined for the time frame of 2006 through 2015, and if any ozone season had an average NOx emission rate that did not utilize default values, that ozone season value was assumed to be the "corrected" NOx emission rate value for the July 20, 2015 event. If all historic ozone season data for a given individual combustion turbine appeared to use default NOx emission rates, a NOx emission rate factor of 0.5 lb/MMBTU was utilized for oil-fired combustion turbines and a NOx emission rate factor of 0.4 lb/MMBTU was utilized for gas-fired combustion turbines. After estimating this correction for the subject units, the July 20, 2015 NOx mass emissions from all operating CT EGUs in the OTR (and represented in the AMPD) was estimated to be approximately 62.8 tons. In order to assess potential NOx emissions reductions from the fleet of OTR CTs operating on July 20, 2015, where the AMPD data did not indicate any installed NOx controls (low-NOx combustors, water injection, or SCR), it was assumed that water injection or low-NOx combustors could be installed to meet moderate RACT type emission levels of 42 ppm NOx for gas fired CTs and 88 ppm NOx for oil fired CTs. For the OTR CTs that operated on July 20, 2015 with average NOx emission rate values below the selected moderate NOx RACT values, these CTs were assumed to operate at those actual July 20th emission rates. Under this scenario, the NOx mass emissions from the operating fleet of OTR CTs on July 20, 2015 would have been reduced from 62.8 tons to 41.5 tons. This represents an estimated reduction of approximately 21.3 tons, or an approximate 34% reduction from the July 20th NOx mass emissions. While not specifically intended to focus on "peaking unit" combustion turbine EGUs, it should be noted that this estimation methodology resulted in estimated NOx emissions reductions from combustion turbine EGUs that would be categorized as "peaking units".

4.5 Analysis of Coal Unit Emission Rates and Potential NOx Emissions Reductions

For the July 20, 2015 episode day, an analysis was performed to examine the NOx emission rates of coalfired EGUs operating in the OTR and the NOx emissions reductions that could be realized if OTR coalfired EGUs with existing post combustion NOx controls were being operated at or near their best historically demonstrated average NOx emission rates. For this review, the July 20, 2015 episode day was chosen as it represents the most recent OTR fossil-fuel EGU operating fleet for an HEDD event.

During the July 20, 2015 episode day, 55 of 74 coal-fired EGUs in the OTR were operating; 45 of these operating coal-fired EGUs were equipped with post combustion NOx controls. The fleet of units with post combustion NOx controls had a range of daily average NOx emission rates of 0.0356 lb/MMBTU to 0.4143 lb/MMBTU. Of this group, 12 had a daily average NOx emission rate exceeding 0.3000 lb/MMBTU, 20 had a daily average NOx emission rate exceeding 0.2000 lb/MMBTU, and 27 had a daily average NOx emission rate exceeding 0.1500 lb/MMBTU. Of the SCR equipped units operating on July 20, 2015, 9 had a daily average NOx emission rate exceeding 0.3000 lb/MMBTU, 12 had a daily average NOx emission rate exceeding 0.1500 lb/MMBTU. These emission rate ranges are illustrated in Figure 4-3.



Figure 4-3: NOx emission rates from coal-fired EGUs operating in the OTR on July 20, 2015.

EGU Group	Average NOx Rate (Ib/MMBTU)
Operating OTR Coal-Fired EGU Fleet - Total	0.1969
Operating OTR Coal-Fired EGU Fleet - with Post Combustion NOx Controls	0.1865
Operating OTR Coal-Fired EGU Fleet - w/o Post Combustion NOx Controls	0.3010

To examine the potential NOx reductions that could be realized if units with post combustion NOx controls were being operated at or near their best historic rates, the following methodology was used. For the OTR coal-fired EGUs operating on July 20, 2015, the best estimated average NOx emission rate was determined as follows:

- a) The lowest ozone season average NOx emission rate for the 2002 through 2015 ozone seasons was identified.
- b) The July 20, 2015 daily average NOx emission rate (in lb/MMBTU) was compared to the lowest historic ozone season NOx emission rate identified in (a) above.
 - If the July 20, 2015 daily average NOx emission rate was 110% or less than the lowest historic rate identified in (a), then the July 20th daily average NOx emission rate was used as the best estimated NOx rate value.
 - If the daily average NOx emission rate was greater than 110% of the lowest historic rate identified in (a), then the best estimated NOx rate value was calculated as 105% of the lowest historic rate identified in (a).

The 110% break point between the July 20th NOx emission rate and the lowest 2002 through 2015 ozone season rate was chosen because it would be expected that a long term average value (such as an ozone season average) would smooth out short term rate spikes that might have a higher impact on a shorter term average (such as daily). In this case, a 10% factor was selected to address this potential impact. In this way, if the July 20th value was 110% or less of the best demonstrated ozone season average, then it was judged that the July 20th daily average NOx emission rate demonstrates the best attainable.

For the scenarios where the best estimated average NOx emission rate was determined to be 105% of the lowest historic rate, it was assumed that the lowest historic rate was representative of the best possible value with "like new" SCR catalyst being operated for best emissions control. It is known that SCR catalyst efficiency degrades over time and must be periodically cleaned and/or replaced to restore full NOx reduction capabilities. The 105% factor was selected to be representative of operation in a "not new" catalyst configuration and therefore provide an estimated NOx emission rate that might be more representative of routine operation.

Using the above estimation process, along with the actual OTR fossil-fuel fired EGU fleet operating on July 20, 2015 and the associated AMPD emissions values, Table 4-7 was prepared to show the NOx reduction potential from the OTR coal-fired EGUs. Note that only potential NOx emissions reductions from coal-fired OTR EGUs that were operating on July 20, 2015 are represented in the table. It can be seen that on July 20th there is a NOx mass emissions reduction potential of over 167 tons for the SCR equipped coal-fired EGUs if those EGUs had operated their SCRs or had operated their SCRs at higher NOx control efficiency levels. The data in the table also indicates that there is some additional NOx emissions reduction potential for the coal-fired EGUs operating on July 20th equipped with either SNCR (approximately 7 tons of NOx reduction potential) or no post combustion controls (approximately 10 tons of NOx reduction potential). Altogether, the estimated additional NOx emissions reduction potential from the coal-fired EGUs in the OTR operating on July 20, 2015 was approximately 184 tons, or approximately 32% of the total fossil-fuel fired EGUs operating in the OTR on that day.

Note that of the 19 OTR coal-fired EGUs that were not operating on July 20, 2015, nine were equipped with SNCR, five were equipped with SCR, and 6 were equipped with no post-combustion controls. So the portion of the OTR coal-fired fleet not operating on July 20th had a reasonably large percentage of post combustion controlled EGUs.

4.6 Variability of OTR EGU Fleet

While the review of OTR fossil fuel fired EGU operating data and emissions for any given event provides a good basis for understanding EGU NOx emissions during a HEDD, it should be noted that any particular event may not provide a full representation of the entire OTR fossil fuel fired EGU fleet that could be operating. Many factors influence which OTR fossil fueled EGUs are called on during any particular day, including startup/shutdown costs, start/stop characteristics, allowable number of starts, ability to pick up load, incremental generation costs, minimum load capability, and transmission congestion. On any given ozone season day, there may be a difference in the operating fleet that could impact regional NOx mass emissions and more directly impact local and downwind areas. For example, Figure 4-4 compares the fleet of OTR fossil fuel fired EGUs operating on the July 20, 2015 event (the day of highest electric demand in PJM during the 2015 ozone season) with the fossil fuel fired EGUs that operated at any time during the 2015 ozone season.

 Table 4-7: NOx emissions reduction potential from coal-fired EGUs in the OTR for the July 20, 2015 episode day.

OTR Fossil Fuel-Fired EGU Category	AMPD 7/20/15 NOx Mass Emissions (tons)	Estimated Coal EGU NOx Mass Emissions Using Estimated Best NOx Emission Rate Capability (tons)	Estimated Reduction (tons)	Estimated Category Percent Reduction (%)	No. Configuration EGUs Operating 7/20/15
All Fossil Fuel-Fired EGU	574	194	184	32	490 of 731
All Coal EGU	379	194	184	49	55 of 74
Subcategory - Coal EGU w/SCR	280	113	167	60	29 of 33
Subcategory - Coal EGU w/SNCR	48	41	7	15	21 of 30
Subcategory - Coal EGU w/o Post Comb Controls	51	41	10	20	5 of 11



Figure 4-4: Number of EGUs that operated in the OTR on July 20, 2015 and during the 2015 ozone season compared with the total number of units in each category

The data in Figure 4-4 indicates that the fleet of OTR coal-fired EGUs and combined cycle EGUs that were called on to support the electric grid during the 2015 ozone season was fairly consistent, likely due to the fact that these units generally represent some of the lower cost fossil fueled generating sources. However, the data shows that over the ozone season, the OTR operating fleet of combustion turbines and oil and gas steam EGUs exhibited a higher amount of variability relative to the July 20, 2015 event day. A number of factors may contribute to this, such as short run times anticipated by the dispatch organization (favoring CTs with short startup and shutdown times and lower startup/shutdown costs), incremental fuel costs and availability, and transmission constraints. This is an indication that, even though any particular unit was not operating and contributing emissions for any given event, it is still possible that the particular EGU could be operating and contributing emissions during any future event. Therefore the potential emissions from any OTR fossil fueled EGU should not be ignored in future analysis or for consideration for adequate NOx emissions control.

5. Summary and Conclusions

5.1 Small non-CAMD EGUs

Using continuous hourly emissions data reported by EGUs via EPA's air markets programs has proven useful for improving the temporalization of smaller EGUs whose emissions are currently distributed evenly throughout the year using the default temporal profiles from the SMOKE model. For a high

electric demand day, MDE's analysis has shown that a more accurate temporalization of small EGUs can lead to a seven-fold increase in peak-day NOx emissions from these units relative to what their peak-day emissions would be using the default temporal profiles. Air quality modeling performed with the improved temporal profiles showed increases in predicted ozone concentrations of up to 5 ppb versus modeling performed with default profiles (Figure 2-10). With ever-tightening air quality standards, ozone concentration changes of this magnitude could make a difference in whether a jurisdiction attains the standard or not. In addition to health-based considerations, jurisdictions could be faced with the additional regulatory and economic burdens associated with non-attainment of the standards. Understanding the true nature of these units' operating behavior and the magnitude of their emissions on high electric demand days can help air quality regulators develop more appropriate and effective control strategies.

5.2 <u>BUGs</u>

It is important to understand the air quality impact of back-up type diesel reciprocating generators participating in DR programs. The BUG sub-group's hypothetical high-bound modeling analysis showed that emissions from BUGs responding in an unlimited manner to a widespread DR event could increase predicted 8-hr ozone concentrations by 1 ppb. As mentioned earlier, even small changes in ozone concentrations could affect attainment of the standard and have significant health, regulatory, and economic implications. Although the focus of this effort was on ozone, the increased use of diesel-powered RICE could have implications for meeting the 1-hour standard for nitrogen dioxide and the 24-hour standard for fine particulate matter.

The Workgroup's review of State regulations that pertain to the use of emergency generators in DR programs has demonstrated that most states prohibit the participation of emergency engines in voluntary or incentive-based DR programs. In most states, those engines that do participate in such programs must be permitted and/or are subject to notification and recordkeeping requirements. In many of these instances, the applicable engines must also meet strict emissions limits.

As mentioned in Section 3.3, EPA released its RICE rule vacatur guidance in April 2016, and PJM subsequently issued a memo to re-iterate that all their DR program participants must follow all applicable federal, state, and local requirements. While it is not known whether EPA's or PJM's requirements had the most significant effect, there was a noticeable decrease in the amount of generating resources that cleared the PJM auction for DR participation between 2015 and 2016. It is possible that the reduced generation from these DR resources could be made up by peaking combustion turbine EGUs.

5.3 Peaking Units

As discussed in Section 4, to perform a meaningful analysis of peaking units, units of all operational types - base load, intermediate, and peaking - were included. For the episode days analyzed, the contribution to total OTR EGU NOx mass from peaking units ranged from 6% on June 18, 2014 to approximately 34% on July 22, 2011. However, the Workgroup's analysis revealed that among all EGU operational types in the OTR, intermediate-use EGUs were consistently the highest contributors on an

annual, ozone season, and episode day basis. The majority of this contribution came from coal-fired intermediate-use units with post combustion NOx controls.

The Workgroup analyzed the NOx emissions reduction potential that could be realized from those OTR combustion turbines for which the AMPD did not indicate any installed NOx controls. The analysis revealed that, for the July 20, 2015 episode day, an approximately 21-ton NOx reduction could be realized if these uncontrolled CTs were to meet "moderate RACT" emission rate levels (see Section 4.4).

Further, the Workgroup also analyzed the NOx emissions reduction potential associated with EGUs operating existing controls consistently or operating those controls in a more efficient manner. For the July 20, 2015 episode day, over 184 tons of NOx emissions reductions could be realized if all coal-fueled EGUs operating in the OTR that day operated at NOx emission rates consistent with their lowest historical ozone season NOx emission rates. The Workgroup concluded that for July 20, 2015 many of the post combustion NOx control equipped coal-fired EGUs in the OTR were not operating installed post combustion controls, or were not operating the controls consistent with good pollution control practices.

6. Recommendations

6.1 Small non-CAMD EGUs

To more accurately model small EGUs that do not report to CAMD (and are therefore not modeled with actual hour-by-hour emissions), the default temporal profiles used in the SMOKE emissions model should be replaced with temporal profiles derived using reported hourly emissions data from CAMD-reporting EGUs with similar characteristics. This will better characterize the air quality impacts of small non-CAMD EGUs on high electric demand days and/or high ozone episode days. The small EGU temporal profiles developed through this effort are already included in MARAMA's Beta emissions inventories, which are being used in air quality modeling to support State SIPs for ozone, regional haze, and other air quality management efforts.

6.2 <u>BUGs</u>

The Workgroup's hypothetical high-bound analysis of back-up generators has shown that these units could have a measureable impact on air quality if the units were to respond to a demand event in an unlimited manner. However, the workgroup's survey of state regulations has shown that, for the most part, states are doing an admirable job of regulating these units' participation in such programs. States should continue to maintain or improve such regulations, as applicable. For example, in some states, such regulations only apply to engines located at Major facilities. States should also continue, and improve where possible, their efforts to enforce regulations that pertain to emergency engines and engines participating in DR programs. Where resources permit, states should conduct outreach and education regarding the proper use of these types of engines.

Regarding stationary engines, the Workgroup offers the following topics for future analysis and discussion:

- Engines installed without permits, that are operated for non-emergency reasons, where the owner/operator does not know that those operations are not permitted;
- Engines installed with permits, but not enrolled with a Curtailment Service Provider (CSP), that are operated for non-emergency reasons, where the owner/operator does not know that those operations are not permitted;
- Engines installed with permits and enrolled with a CSP, that are operated for non-emergency reasons outside of those times that they are called upon by a CSP, where the owner/operator does not know that those operations are not permitted;
- Engines knowingly operated illegally; and
- The increasing use of micro-grids, their operation and permitting, and their effect on air quality.

6.3 Peaking Units

The Workgroup's analysis revealed that peaking units can contribute over 30% of total OTR EGU NOx mass on the episode days that were analyzed, and that a NOx emissions reduction potential of over 20 tons per day could be realized if gas and oil-fired combustion turbines without installed controls were to meet "moderate RACT" emissions levels. Where they have not already done so, states should adopt NOx RACT for gas and oil-fired combustion turbines (noting however that RACT must meet technological and economic feasibility requirements).

However, the recommendation of RACT for peaking units will not have as large an impact without also addressing coal-fired units that do not fully optimize their NOx controls. While the coal-fired units cannot be categorized as peaking units, the emissions from the coal-fired units on HEDDs under the current market and regulatory conditions overwhelm the emissions of the peaking units on HEDDs, obscuring benefits from any potential reductions in peaking unit emissions. The continued low price of Cross State Air Pollution Rule (CSAPR) ozone season NOx allowances remains a disincentive for running existing NOx controls in an optimal manner. As of August 12, 2016, the CSAPR ozone season NOx allowance price was \$230/short ton¹⁷. This cost is well below the estimated cost of \$439/short ton for running NOx controls, which is the low end of the range of the cost of controls estimated with the Sargent & Lundy method (note: the high end of the range is \$1,755 to \$2,118/short ton)¹⁸. States should pursue appropriate rulemaking or other regulatory mechanisms that require EGUs of all types to operate their NOx controls effectively such that their best historic NOx rates are met at all times during the ozone season (such as the more stringent NOx RACT for EGU boilers in New York state). Alternatively, the issue could be addressed with significant reductions in CSAPR NOx allowance availability. EPA proposed an update to the CSAPR NOx budget on December 3, 2015 (80 FR 75706) to reduce the NOx allowances based on a cost of reduction of \$1300 per ton. (Note: EPA finalized the CSAPR Update on October 26, 2016 (81 FR 74504)).

Consideration should be given to updating NOx RACT requirements for peaking units or EGUs that otherwise have been previously exempt from application of RACT level controls due to small size, low capacity factor, etc. The review of HEDD events indicated that these high NOx emission rate EGUs continue to operate and emit relatively high levels of NOx during HEDD periods that also tend to coincide with atmospheric conditions that are conducive to ozone formation. Industry information indicates that there may be a greater availability of effective RACT level NOx controls across a broader range of types, sizes, and makes/models of peaking units (including combustion turbine EGUs) than might have been available during earlier NOx RACT evaluations.

Regarding peaking units, the workgroup offers the following topics for future analysis and discussion:

- 2009/2010 OTC Model Rule for High Electric Demand Day Combustion Turbines
- State HEDD Rules (e.g. New Jersey)
- Operating limits on forecasted high ozone days

7. References

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Appendix A: Summary of State Regulations Governing the Use of Diesel Engines in Demand Response Programs

Non-NESCAUM States (where information was available) -- for NESCAUM states, please see Appendix A: State Emergency Engine Regulations of *Air Quality, Electricity, and Back-up Stationary Diesel Engines in the Northeast*, NESCAUM, August 1, 2012, Revised January 2, 2014 (http://www.nescaum.org/activities/major-reports)

OTC SAS Committee, HEDD Workgroup, DRAFT 2/18/16

Delaware

Emergency generators and distributed generators are regulated under 1144 Control of Stationary Generator Emissions of DE Administrative Code Title 7. Notification and recordkeeping requirements apply to <u>both</u>.

<u>Emergency generators</u> may operate during an electrical outage cause by a failure of the electrical grid; on-site equipment failure; a flood, fire, or natural disaster; or severe weather. They may also operate during a deviation in voltage of frequency or 3% above, or 5% below, standard voltage or frequency. An emergency generator may <u>not</u> be operated in conjunction with a voluntary demand response program or any other interruptible power supply arrangement with a utility, other market participant, or system operator. New (i.e., installed after January 11, 2006) emergency generators must meet the emissions standards of EPA's Non-Road engine rule.

<u>Distributed generators</u> must meet the following emissions standards:

Generator Installation Date	NOx Emissions Limit (lb/MWh)
Existing	4.0
On or after January 1, 2008	1.0
On or after January 1, 2012	0.6

DE Reference:

http://regulations.delaware.gov/AdminCode/title7/1000/1100/1144.shtml

Maryland

Emergency generators and load shaving units are regulated under Code of Maryland Regulations (COMAR) 26.11.36.03.

<u>Emergency generators</u> can only operate for emergencies, testing, or maintenance. An emergency is defined in COMAR 26.11.36.01 as a disruption of the primary power source due to failure of the electrical grid; on-site disaster or equipment failure; flood, fire, natural disaster, or severe weather; or a PJM declared emergency (per PJM Manual 13,

https://www.epsa.org/forms/uploadFiles/204490000004E.filename.Attachments_to_Comments_on_Se_ttlement.pdf or http://www.pjm.com/~/media/documents/manuals/m13.ashx)

Load shaving units are subject to the following requirements outlined below.

Those installed on or before January 1, 2009:

- Must meet a NOx limit of 1.4 g/BHP;
- Be replaced with an engine that meets Federal NSPS and was installed after Jan. 1, 2009; or
- Be operated 10 hours or less from May 1 to Sep 30 (except for emergencies, testing, & maint.)

Those installed after January 1, 2009:

- Must meet a NOx limit of 1.4 g/BHP; or
- Be operated 10 hours or less from May 1 to Sep 30 (except for emergencies, testing, & maint.)
- Those under 1,000 HP that meet Federal NSPS are exempt from these requirements

Owner or operators of load shaving units (whether installed before or after Jan 1, 2009) can alternately comply with this rule by securing NOx allowances. Load shaving units are subject to recordkeeping requirements.

MD Reference:

http://www.dsd.state.md.us/comar/comarhtml/26/26.11.36.03.htm

http://www.dsd.state.md.us/comar/comarhtml/26/26.11.36.01.htm

Ohio

Emergency engines are regulated under Ohio Administrative Code (OAC) Chapter 3745-31.

Emergency engines are only used during the following circumstances:

1) They may operate during emergencies, which are defined as:

- Flooding, damaging winds or tornado, fire, or other natural disaster
- Electrical power outage due to failure of the electrical grid, local supply equipment failure, or facility equipment failure
- Any situation that the director determines to be an immediate threat to human health, property, or the environment

2) Any combination of the following activities for a maximum of 100 hours per calendar year:

- Maintenance and readiness testing
- Emergency demand response during periods of NERC EEA Level 2

- Deviations of voltage or frequency 5% above or below standard
- 50 hours per calendar year (which are counted as part of the 100) operation as part of a financial arrangement, if certain procedural requirements are met

OH Reference:

http://www.epa.state.oh.us/portals/27/regs/3745-31/3745-31-01f.pdf

Virginia

Compression ignition units participating in demand response programs and emergency generation units require a General Permit, depending upon installation date.

<u>Compression ignition units</u> participating in demand response programs are regulated under VA State Air Pollution Control Board Regulation 9VA5 Chapter 530, Electric Generator Voluntary Demand Response General Permit. This Chapter applies to units that were installed, modified, etc. on or after June 28, 2011. Such devices are exempt if they are located at facilities whose emissions are less than <u>all</u> of the thresholds in 9VA5-80-1105 C 1 or D1 (example threshold: facility uncontrolled NOx emissions less than 40 TPY or a project with a NOx increase of less than 10 TPY). Cl units subject to this Chapter must meet a NOx emissions limit of 0.67 g/kW-hr (0.5 g/bhp-hr).

<u>Emergency generation units</u> are regulated under Chapter 540 Emergency Generator General Permit. Emergency generation units only operate during emergencies, required maintenance, or operability and emissions testing. An emergency is defined as a failure of the electrical grid; on-site disaster or equipment failure; public service emergencies such as flood, fire, natural disaster, or severe weather; or an ISO-declared emergency. An ISO-declared emergency consists of the following:

An abnormal system condition requiring manual or automatic action to maintain system frequency, to prevent loss of firm load, equipment damage, or tripping of system elements that could adversely affect the reliability of an electric system or the safety of persons or property.
 Constitute definition on a second tripping.

(2) Capacity deficiency or capacity excess conditions.

(3) A fuel shortage requiring departure from normal operating procedures in order to minimize the use of such scarce fuel.

(4) Abnormal natural events or man-made threats that would require conservative operations to posture the system in a more reliable state.

(5) An abnormal event external to the ISO service territory that may require ISO action.

This Chapter applies to units that were installed, modified, etc. on or after June 28, 2011, that are not exempted under 9VA5-80-1105, and that have aggregate rated electrical power output less than or equal to the following (plus displacement and model year provisions):

Attainment Areas	Nonattainment Areas
6,906 kW (<10 liters/cylinder, MY 2010)	3,850 kW (<10 liters/cylinder, MY 2010)
8,472 kW (<10 liters/cylinder, MY 2011+)	4,722 kW (<10 liters/cylinder, MY 2011+)
8,146 kW (10-15 liters/cylinder, MY 2010+)	4,540 kW (10-15 liters/cylinder, MY 2010+)

Emergency generation units located in attainment areas must not operate more than 450 hours in a consecutive 12-month period, and those in nonattainment areas must not operate more than 500 hours in a consecutive 12-month period. They must meet the emissions limits in 9VAC5-540-180 (limits vary widely depending on attainment status, generator size in kW, displacement, model year, etc.).

VA References:

http://deq.state.va.us/Portals/0/DEQ/Air/Regulations/c530.pdf

http://deq.state.va.us/Portals/0/DEQ/Air/Regulations/c540.pdf

West Virginia

<u>Emergency generators</u> are those installed for the purpose of allowing key systems to continue to operate without interruption during times of utility power outages. Emergency generators that operate 500 hours per year or less (plus other applicability provisions) are eligible for registration under General Permit Number G60-C or G65-C.

WV Reference:

http://www.dep.wv.gov/daq/permitting/pages/airgeneralpermit.aspx

Appendix B: Recent RICE Rule History and Changes in Demand Response Participation

There have been recent changes to federal regulations which limit the amount of distributed generation resources that are participating in demand response programs. Beginning in 2010, the RICE NESHAP (National Emission Standards for Hazardous Air Pollutants) specified that BUGs were allowed to operate without emission controls for fifteen hours each year as part of "demand response programs" during "emergency conditions that could lead to a potential electrical blackout" (75 FR 9,648, 9,667, 9,677, March 3, 2010). Soon after, and in response to petitions for reconsideration, the EPA proposed new regulations which better defined emergency. These new regulations also limited the operation of uncontrolled, emergency engines to a maximum of 100 hours per year, and to periods in which the regional transmission authority or equivalent balancing authority and transmission operator had declared an EEA Level 2 condition (as defined in NERC Reliability Standard EUP-002-3), or during periods where there is a deviation of voltage or frequency of 5% or greater below standard voltage frequency (78 FR 6674, January 30, 2013). These, along with associated proposed regulations, prevented peak shaving by uncontrolled BUGs, generally occurring during periods of high electric demand which is often aligned with high electric cost and the potential for elevated ozone levels. Enrollment in DR programs focused on reduced demand for electricity, curtailment, and operation of permitted, controlled engines.

On April 1, 2013, Delaware and others filed a petition with the US Court of Appeals requesting judicial review of the exemption which allowed the operation of uncontrolled BUGs to operate during emergency conditions for up to 100 hours per year. The Court responded by vacating portions of the recently finalized NSPS (New Source Performance Standards) and NESHAP, specifically eliminating the operation of emergency, uncontrolled BUGs during an EEA Level 2 condition and when the deviation of voltage or frequency was greater than 5% (USCA #13-1093, Document 1550129, May 1, 2015). In response, the EPA requested and was granted a 1 year stay. On April 15, 2016, EPA issued a memo which summarized the history of the rulings, and outlined the impact of the court's decision to disallow operation of uncontrolled engines during emergency conditions for up to 100 hours per year. Thus, as of May 2, 2016, the operation of any uncontrolled engines during any situation, other than an electrical blackout, is not permissible, and the situation described above will no longer be possible.