Estimating Emission Reductions from Energy Efficiency in the Northeast

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ABSTRACT

To shed light on emissions avoided by efficiency improvements, the authors modeled load reductions in three control areas of the northeastern U.S. "Avoided emission factors" were developed, based on marginal emission rates, for four pollutants for seven different periods of the day and year. The generation supply curves in the three control areas were found to have similar emission rate profiles, but significant differences in the magnitude of typical emission rates. In addition, marginal emission rates differed considerably across both time periods and pollutants. These marginal emission factors were embedded in a spreadsheet tool, designed to allow users to assess avoided emissions from various types of efficiency measures as well as different types of new generation. Users of the spreadsheet can use the avoided emission factors provide and can easily make calculations based on other input assumptions to explore different scenarios.

Introduction

Efforts to integrate energy and environmental regulation more effectively have highlighted the need to understand the air impacts of energy programs such as funding for energy efficiency. However, because the interconnected regional electricity systems in the U.S. operate in complex, integrated ways, the emissions impacts of efficiency programs are not easy to predict.

The most credible methods of estimating the emissions avoided by efficiency programs focus on the marginal generating unit(s) in the local power control area at the time the efficiency measures were reducing load. While some studies have used system average emission rates to calculate avoided emissions, this approach can be misleading, because baseload generating units (which affect system average emission rates significantly) are rarely affected by demand reductions.

However, in addition to focusing on the marginal generators, analyses of avoided emissions must also be as specific as possible in terms of location and time. Because U.S. regional electric systems differ considerably in their generating fuel mixes, estimates of avoided emission in one region are likely to be of little use in another. Similarly, within a given region, the type of generation on the margin can vary dramatically across different periods of the day and year. For example, emissions avoided by reduced demand during peak hours are likely to be quite different from emissions avoided during off-peak hours.

This paper presents a modeling analysis performed in 2002 to assess the emissions impacts of new energy efficiency measures and low-emission generation in the northeastern U.S. The results of the modeling work were embedded in a spreadsheet tool, designed for analysis of different energy technologies and policies over time. The work was funded by the Ozone Transport Commission (OTC), and the Emission Reduction Workbook is available from Synapse Energy Economics or the OTC free of change.

Developing the Avoided Emission Factors

The avoided emission factors developed in this project are essentially averages of system marginal emission rates during different time periods. To generate these marginal emission factors, we first modeled load reductions in each of the three power control areas of the Northeast (New York, New England and the Pennsylvania/New Jersey/Maryland Interconnection.) This modeling work was done with the PROSYM production costing model, an hourly dispatch model that includes unit-specific information on all major generating units and transmission facilities. To ensure that we captured all regional effects of the load reductions, the study area included six interconnected control areas, the three areas cited above and the three areas in eastern Canada. Thus, when loads were reduced in New York, for example, we assessed the emissions impacts across all six control areas.

Using this method, we developed marginal emission factors for each of the U.S. control areas during seven different time periods each year. We developed emission factors for the years 2002 through 2020, for NO_x, SO_2, CO_2 and mercury. Importantly, the emission factors for the near term, medium term and long term were developed from the modeling outputs using different approaches. These approaches reflect the fact that electric systems evolve over time, with generating assets being added and retired, and these changes affect avoided air emissions.

In the near term, new efficiency investments reduce the operation of plants in the existing generating system. Other than plants well into the planning or construction process, new generating plants will not be added to the system during this period. (For this project, the near term was defined as the period 2002 through 2005.) Over the longer term, efficiency investments avoid generation at a mix of existing plants and potential new plants – and they affect plant retirement decisions. This is because over the longer term, decisions made by power plant owners and new plant developers will take into account changes in the regional power system that took place during the near term. For example, demand forecasts made in 2006 will take into account conservation and load management programs implemented in prior years as well as new generators installed in this period. Some planned units will be deferred if energy efficiency has slowed load growth and new generators have come on line, and some older plants may be retired earlier.

Avoided Emissions in the Near Term (2002-2005)

As noted, the near-term avoided emission factors are derived from PROSYM analyses of system dispatch over the near term. To derive these emission rates, we first performed a "base case" model run, simulating plant dispatch across all three control areas for each year. We next performed three "decrement" model runs. In one decrement run, all hourly loads in PJM were reduced by one percent; loads in ISO New England and NY ISO were not reduced. In another decrement run, loads in ISO NE were reduced by one percent, and in the third, NY ISO loads were reduced. To calculate marginal emission rates for different periods, we calculated the total difference in kWhs generated between the base case and decrement case and the total difference in emissions. We then divided emissions by kWhs to derive the marginal emission rate for the time period.

For the period 2002 through 2005, we added specific new generating units into PROSYM based on our analysis of power projects proposed and under construction in these three control areas. The time periods for which we developed marginal emission rates are as follows:

- Ozone season weekday – the average of all hourly marginal emission rates during weekdays, May through September, 7:00 am through 10:59 pm.
- Ozone season night/weekend – the average of all hourly marginal emission rates during all nights, May through September, 11:00 pm through 6:59 am, and all weekend days during this period.
- Non-ozone season weekday, the average of all hourly marginal emission rates during weekdays October through April, 7:00 am through 10:59 pm.
- Non-ozone season night/weekend, the average of all hourly marginal emission rates during all nights, October through April, 11:00 pm through 6:59 am, and all weekend days during this period.
- Peak Day – the average of all hourly marginal emission rates during the period 7:00 am through 10:59 pm on the day with the highest predicted load of the year.
- Peak Hours – the average of the hourly marginal emission rates during the 150 highest-load hours of the year, regardless of day or time.
- Annual average – the average emission rate of all generating units operating throughout the year, weighted by the amount of production by unit. (NOTE: this is the only average emission rate of the group. The others are marginal emission rates.)

Table 1 below shows the near-term avoided emission rates developed for the New England region for the seven time periods. It is important to note that these are average marginal emission rates. That is, they are the average of all the hourly marginal emission rates during the time period.

Note several important characteristics of these avoided emission factors:

- As expected, marginal NO_x rates are highest during the highest-load hours, however NO_x rates are lower, on average, during weekday hours than during night/weekend hours.
- Like NO_x rates, marginal SO_2 rates are lower, on average, during weekday hours than night/weekend hours. But unlike NO_x rates, SO_2 rates are highest in the lowest load hours.

Marginal NO_x rates are highest in New England during the hours of highest demand, because the least efficient combustion turbines are called upon during these hours. This is consistent with the common conception in the Northeast of high peak-hour NOx rates.

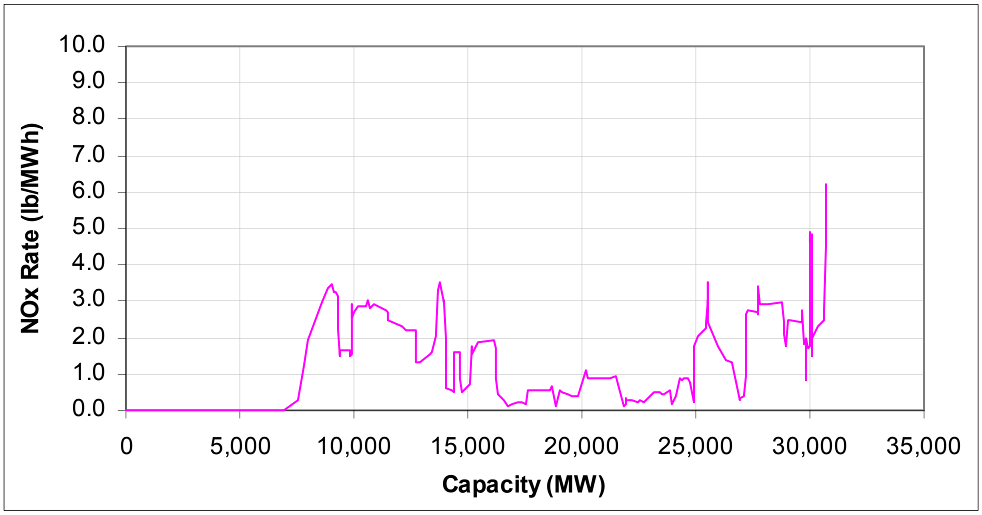
However, during many weekday hours, marginal NO_x rates are extremely low, because combined cycle gas turbines (CCCTs) are often on the margin during these hours. Marginal NO_x rates are high during the night/weekend hours, because older fossil-fueled steam units are often on the margin.

To illustrate these dynamics, Figure 1 shows how the marginal NO_x rate changes along the supply curve in New England.

Table 1. Near-Term Avoided Emission Factors for New England (lb/MWh)

	2002	2003	2004	2005
Ozone Season Weekday				
NOx:	0.4	0.4	0.5	0.7
SO2:	0.5	0.7	0.9	1.3
CO2:	900	900	920	980
Hg:	2.0E-06	3.0E-06	5.0E-06	9.0E-06
Ozone Season Night/Weekend				
NOx:	1.2	1.1	0.8	0.6
SO2:	3.8	3.2	2.4	1.6
CO2:	1,240	1,180	1,090	1,010
Hg:	4.7E-05	4.0E-05	3.0E-05	2.3E-05
Non- Ozone Season Weekday				
NOx:	1.0	0.7	0.4	0.4
SO2:	1.4	1.0	0.8	0.7
CO2:	1,120	1,010	920	890
Hg:	4.0E-06	4.0E-06	4.0E-06	4.0E-06
Non-Ozone Season Night/Weekend				
NOx:	1.7	1.4	1.1	1.1
SO2:	4.0	3.8	3.3	3.0
CO2:	1,300	1,220	1,130	1,120
Hg:	2.7E-05	3.0E-05	2.7E-05	2.3E-05
Peak Day				
NOx:	2.9	2.6	2.3	2.2
SO2:	3.2	3.4	3.6	4.1
CO2:	1,800	1,780	1,760	1,820
Hg:	0.0E+00	0.0E+00	0.0E+00	0.0E+00
Peak Hours				
NOx:	2.9	2.4	1.8	1.9
SO2:	2.6	3.5	4.5	4.5
CO2:	2,050	1,940	1,820	1,830
Hg:	0.0E+00	0.0E+00	0.0E+00	0.0E+00
Annual Average				
NOx:	1.1	1.1	1.0	0.9
SO2:	3.3	3.3	2.9	2.7
CO2:	1,000	1,000	960	930
Hg:	2.8E-05	2.8E-05	3.1E-05	2.3E-05

Figure 1. NO_x Emission Rates Along the ISO New England Supply Curve in 2002



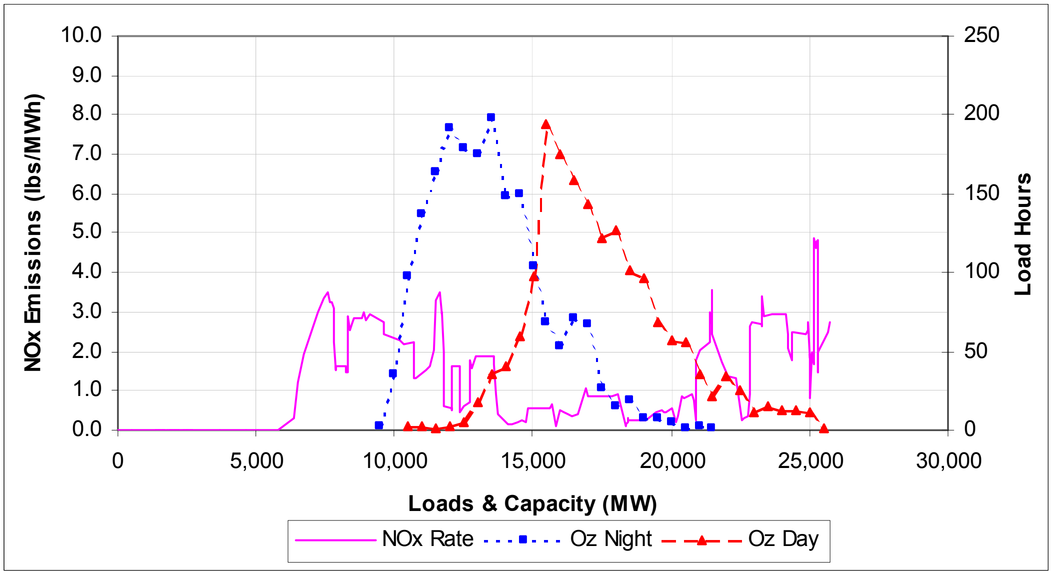
The line in Figure 1 is a rolling average of the NO_x rate of each generating unit along the ISO New England supply curve. The generating units have been lined up across the horizontal axis in order of increasing marginal costs, roughly the order in which they are dispatched to meet loads. The point graphed above each generating unit is the average of the NO_x rate of that unit and the four units around it (two on either side) in the supply curve. We have used this rolling average to smooth the line somewhat while preserving its general trends.

Roughly the first 7,000 MW in the New England system is hydro and nuclear baseload capacity. From 7,000 to about 17,000 MW, the region's fossil-fueled baseload and load-following plants dominate – units with much higher NO_x rates. The area between about 17,000 and roughly 25,000 MW is dominated by CCCTs (with very low NO_x rates) with oil- and gas-fired steam units interspersed. Above about 25,000 MW lie higher cost oil- and gas-fired steam units and the region's peaking turbines with extremely high NO_x rates. (As noted below, the NO_x emission rates along the New York and PJM supply curves follow a very similar shape, except that emission rates tend to be higher in New York and higher still in PJM.) Looking at Figure 1, we can see why marginal emission rates are different during different periods of the day and year – because loads fall in different areas of the supply curve during these periods.

To clarify this point, Figure 2 shows the same graph of 2002 NO_x rates in New England, with histograms added showing the distribution of expected loads in 2002. Here, the histogram marked by triangles shows the distribution of expected hourly loads during the ozone season weekday period, and the one marked with squares shows the distribution of loads during the ozone season night/weekend period. For these histograms, the higher the curve is above the horizontal axis, the more hours during the period that the regional load was at that level. Note that the bulk of the weekday hourly loads fall within the "low-NO_x valley" in the middle of the supply curve, while many of the night/weekend hours fall in the higher-NO_x region from 10,000 to 14,000 MW.

Because generating unit capacities have been derated to develop Figure 2 and loads have been "grown" from 2001 loads, this should not be treated as a highly precise representation of these interactions. However, the level of precision is adequate to support the idea that daytime loads tend to fall in a lower-NO_x region of the supply curve in New England and night/weekend loads, in a higher-NO_x region. Hence, the marginal NO_x emission factor for the ozone season daytime (in Table 1) is 0.4 lb/MWh, and the factor for the night/weekend period is 1.2 lb/MWh.

Figure 2: ISO New England NO_x Curves and Distribution of Loads



The policy implications of Figure 2 are significant. If the goal is to use energy efficiency programs to reduce NO_x emissions, then programs should be selected that reduce demand during the lowest load hours of the night/weekend period or the highest load hours of the daytime period. These are hours when the marginal generating unit is likely to be in one of the two high-NO_x ends of the supply curve. During many shoulder hours the marginal generating unit is likely to be in the low-NO_x valley in the middle of the curve, and demand reductions in this case would reduce NO_x at a lower rate.

Looking at SO_2 rates in New England in the same way explains why the avoided emission factors for SO_2 follow the same trends as the NO_x factors. Figure 3 compares the New England "NO_x supply curve" to the region's "SO_2 supply curve." The SO_2 curve follows the same shape, with two high emission zones at either end and a low emission zone in the middle. The extremely high SO_2 rates in the lower part of the supply curve belong to New England's coal-fired power plants. The moderately high SO_2 levels in the higher part of the curve belong to oil-fired units – steam units followed by combustion turbines.

As seen in Figures 4 and 5 below, the emissions curves for the other two northeastern control areas are different in some ways but still retain the same basic shape. The NO_x emission rates along the New York supply curve are higher than those in New England, and those in PJM are higher still. Also, PJM has more considerably more fossil steam capacity and less CCCT capacity than either New England or New York.

Bear in mind that, while the supply curves in the northeastern control areas are characterized by these emission profiles, not all control areas would be expected to share them. In particular, supply curves in regions with large amounts of hydroelectric capacity relative to other resources (e.g., Quebec and the northwestern U.S.) would have different profiles.

Figure 3: Comparison of New England NO_x and SO_2 Emission Rates

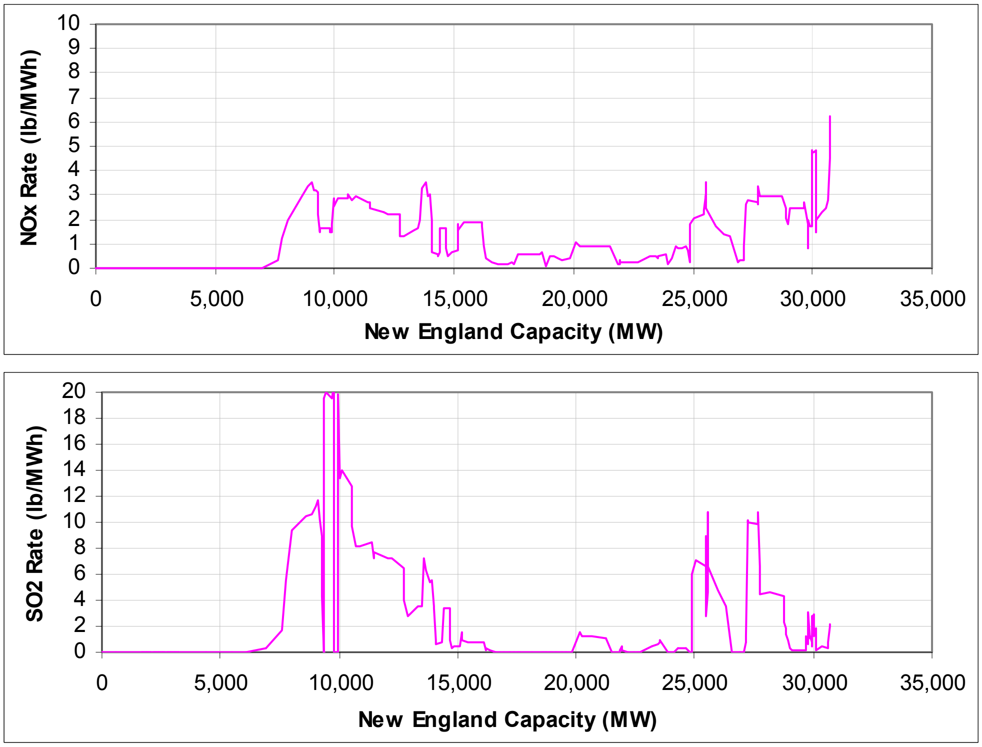


Figure 4: Comparison of PJM NO_x and SO_2 Emission Rates

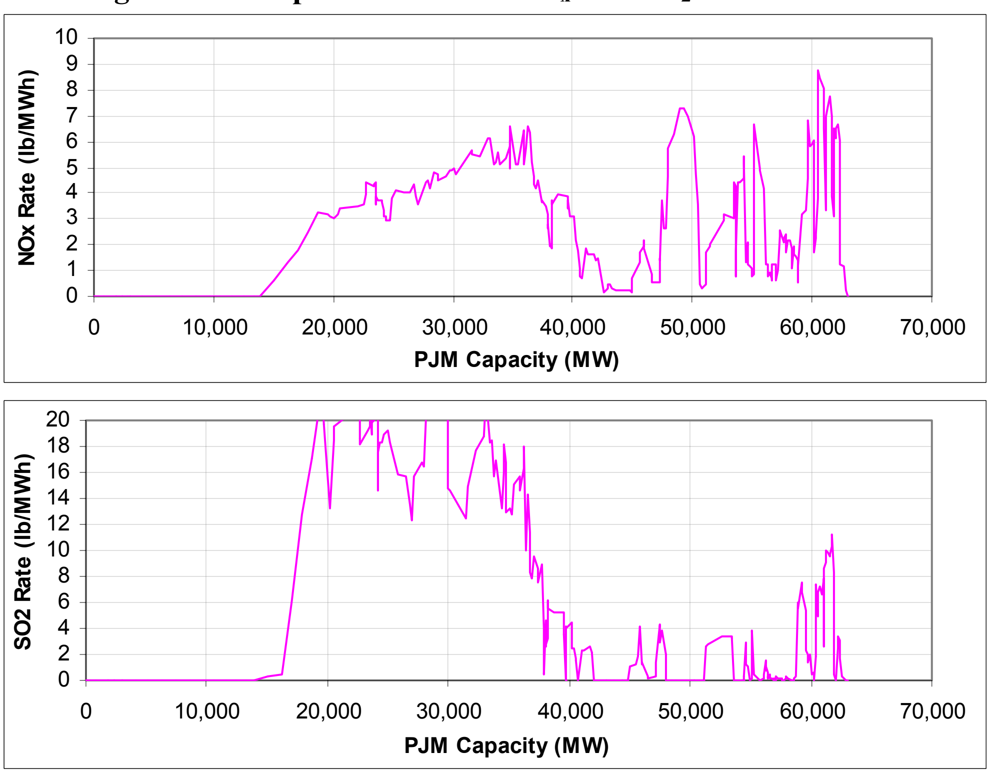
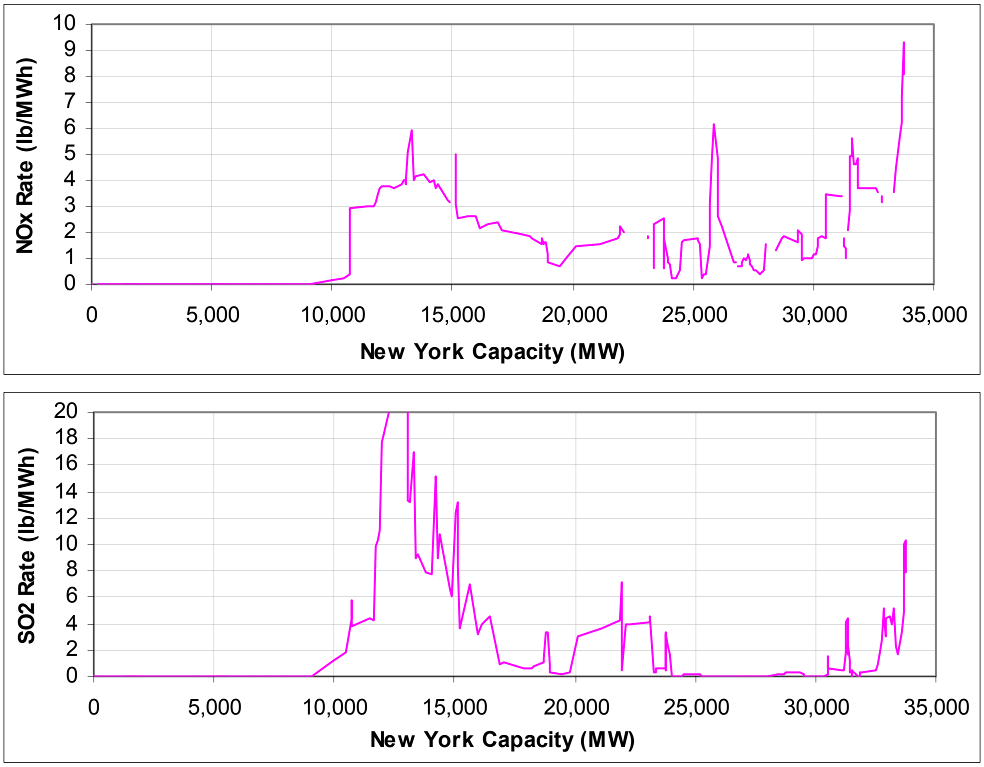


Figure 5: Comparison of New York NO_x and SO_2 Emission Rates



Avoided Emissions in the Longer Term (2006-2020)

Over the longer term, decisions made by power plant owners and new plant developers will take into account many of the changes in the region that took place in the near term. Demand forecasts made in 2007, for example, will take into account many of the conservation and load management programs implemented in the period 2002 through 2005 as well as new generators installed in this period. To account for this economic dynamic, we have developed medium-term avoided emission factors by blending the displaced rates from the existing system (derived using PROSYM) with emission rates representing new generating units and retired units.

To do this, we have broken the study period into three sections: the near term (2002 – 2005), the medium term (2006 – 2010) and the long term (2011 – 2020). As discussed in the previous section, we base our near-term avoided emission factors entirely on the modeling outputs. Our long term factors are based entirely on the emission rates of the new units likely to be built in the Northeast and the old units likely to be retired. This is consistent with the idea that, over the long term, energy efficiency essentially competes with other resources for market entry, and thus it displaces other potential market entrants and speeds the retirement of older plant. For the medium term period, we transition in a linear way from the near-term factors to the long term factors.

Our long-term avoided emission factors for the not peak time periods are based on the following assumptions about plant additions and retirements.

- New units added are assumed to be gas-fired combined-cycle combustion turbines (CCCTs) with NO_x controls (SCR). These units are assumed to have heat rates of 7,000 Btu per kWh and NO_x emission rates of 0.06 lb/MWh. SO_2 emissions are assumed to be zero.
- Old units retired are oil- or oil/gas-fired steam units built before 1960. Emission rates are assumed to be: 2.4 lb/MWh NO_x and 1.8 lb/MWh SO_2. These rates are the average of all the pre-1960 oil and oil/gas steam units in ISO New England, New York ISO and PJM.
- Capacity added is assumed to be greater than capacity retired by a ratio of 3:1.

The long-term emission factors for the Peak Day and Peak Hours periods are based on the following assumption:

- New units added are assumed to be a 50/50 mix of gas- and oil-fired simple-cycle peaking turbines with NO_x controls (SCR). These units are assumed to have heat rates of 9,700 Btu per kWh and NO_x emission rates of 0.1 pounds per MWh. SO_2 rates are assumed to be zero (gas-fired) and 2.9 lb/MWh (oil-fired).
- Old units retired are assumed to be a 50/50 mix of gas- and oil-fired simple-cycle peaking turbines without emission controls. These units are assumed to have heat rates of 14,400 Btu per kWh, representative of many older combustion turbines in the Northeast. NO_x emission rates are assumed to be 9.8 lb/MWh and SO_2 rates are zero lb/MWh (gas-fired) and 4.2 lb/MWh (oil-fired).
- Capacity added is assumed to be greater than capacity retired by a ratio of 3:1.

Of course, predicting capacity additions and retirements is an uncertain endeavor. Thus, we have designed the Emission Reduction Workbook for very easy scenario analysis. Users may calculate avoided emissions based on the default emission factors in the spreadsheet – the emission factors described here – and then easily input alternative assumptions about long-term avoided emissions to see how the results change. This type of scenario analysis, allowing the user to explore the sensitivity of results to different inputs, can often be more informative than a single "best guess" about the long-term evolution of the regional power system.

As discussed above, the avoided emission factors for the near term are derived entirely from PROSYM modeling runs. For the period 2006 through 2010, we blend the displaced emission rates developed with PROSYM (for the years 2006 through 2010) with the emission rates of new CCCTs and old steam units. For the long-term rates, PROSYM analysis was not used; the displaced emission rates consist entirely of a 3:1 blend of new CCCT emission rates and old oil-gas steam rates.

To make the transition from the near term rates to the long-term rates, we use a "straight-line weighting" method. For example, the PROSYM rates fall in a linear manner from being 50 percent of the displaced rates in 2006 to zero percent in 2011 and after. The new unit and retired unit emission rates together rise linearly from being 50 percent of the displaced rates in 2006 to 100 percent of them in 2011 and after. In each year, the weighting factor for the new unit emission rates is three times that of the factor for retired units. Table 3.2 shows the weighting factors for each of the three source rates used to derive the displaced rates for each year of the medium-term period.

Table 2. Weighting Factors for PROSYM Marginal Rates and New/Old Plant Rates

	2002 – 2005	2006	2007	2008	2009	2010	2011 – 2015
PROSYM Rates	1.00	0.50	0.40	0.30	0.20	0.10	0.00
New CCCT Rates	0.00	0.375	0.45	0.525	0.60	0.675	0.75
Old Oil/Gas Steam Rates	0.00	0.125	0.15	0.175	0.20	0.225	0.25

An important aspect of this methodology is that these assumptions are transparent. Users can clearly see the assumptions about unit additions and retirements on which these displaced rates are based and can alter these assumptions if they choose to. We believe this transparency is crucial, because the assumptions about unit additions and retirements are so important. Users are encouraged to use the Workbook to explore the effects of different assumptions about unit additions and retirements on long-term displaced emission rates.

Table 3 shows the long-term avoided emission factors for New England. (The emission factors through 2020 are the same as those in 2015.)

Table 3. Long-Term Emission Factors for New England (lb/MWh)

	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
Ozone Season Weekday										
NOx:	0.8	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7
SO2:	1.1	1.0	0.8	0.6	0.4	0.5	0.5	0.5	0.5	0.5
CO2:	1,030	1,010	980	980	980	1,040	1,040	1,040	1,040	1,040
Hg:	1.8E-05	1.9E-05	2.0E-05	2.1E-05	2.2E-05	2.4E-05	2.4E-05	2.4E-05	2.4E-05	2.4E-05
Ozone Season Night/Weekend										
NOx:	0.6	0.5	0.5	0.6	0.7	0.7	0.7	0.7	0.7	0.7
SO2:	0.9	0.8	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5
CO2:	1,000	970	920	920	960	1,040	1,040	1,040	1,040	1,040
Hg:	2.1E-05	1.8E-05	2.0E-05	2.1E-05	2.3E-05	2.4E-05	2.4E-05	2.4E-05	2.4E-05	2.4E-05
Non-Ozone Season Weekday										
NOx:	0.9	0.6	0.6	0.7	0.7	0.7	0.7	0.7	0.7	0.7
SO2:	0.5	0.4	0.4	0.5	0.4	0.5	0.5	0.5	0.5	0.5
CO2:	950	940	940	950	950	1,040	1,040	1,040	1,040	1,040
Hg:	1.3E-05	1.5E-05	2.5E-05	2.0E-05	2.2E-05	2.4E-05	2.4E-05	2.4E-05	2.4E-05	2.4E-05
Non-Ozone Season Night/Weekend										
NOx:	0.9	0.8	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7
SO2:	1.6	1.3	1.1	0.9	0.7	0.5	0.5	0.5	0.5	0.5
CO2:	1,070	1,050	1,030	1,010	980	1,040	1,040	1,040	1,040	1,040
Hg:	2.2E-05	2.1E-05	1.6E-05	2.1E-05	2.2E-05	2.4E-05	2.4E-05	2.4E-05	2.4E-05	2.4E-05
Annual Average										
NOx:	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9
SO2:	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7
CO2:	940	940	950	950	950	950	950	950	950	950
Hg:	2.3E-05	2.4E-05	2.4E-05	2.4E-05	2.3E-05	2.3E-05	2.3E-05	2.3E-05	2.3E-05	2.3E-05
Peak Day										
NOx:	2.3	2.4	2.3	2.4	2.5	2.5	2.5	2.5	2.5	2.5
SO2:	3.1	2.9	2.3	2.1	1.9	1.6	1.6	1.6	1.6	1.6
CO2:	1,680	1,630	1,520	1,540	1,540	1,490	1,490	1,490	1,490	1,490
Hg:	0.0E+00	0.0E+00	0.0E+00	0.0E+00	0.0E+00	0.0E+00	0.0E+00	0.0E+00	0.0E+00	0.0E+00
Peak Hours										
NOx:	2.2	2.3	2.2	2.3	2.4	2.5	2.5	2.5	2.5	2.5
SO2:	3.1	2.9	2.2	1.9	1.8	1.6	1.6	1.6	1.6	1.6
CO2:	1,660	1,650	1,540	1,510	1,500	1,490	1,490	1,490	1,490	1,490
Hg:	0.0E+00	0.0E+00	0.0E+00	0.0E+00	0.0E+00	0.0E+00	0.0E+00	0.0E+00	0.0E+00	0.0E+00

The avoided NO_x factors for the Ozone Season fall rather quickly even within the 2002 – 2005 period. This dynamic reflects the implementation of the federal NO_x SIP Call rule in 2003. We assume that plants affected by the SIP Call rule comply in the year 2003, achieving an emission rate equal to roughly 0.15 lb/mmBtu during the summer ozone season. No other future environmental regulations are reflected in the avoided emission factors.

Note how the New York marginal emission factors fall from the near-term rates, based on the existing fleet of generation in New York, to the long-term rates, based on plant additions and retirements. This dynamic is consistent with the idea that, in the short term, an energy efficiency investment reduces the operation of existing power plants, and over the long-term it defers the need for new capacity – effectively displacing new entrants.

Conclusions

This work indicates that marginal emission rates in the northeastern U.S. vary considerably across different control areas, time periods and pollutants. Specifically:

- On average, marginal NO_x and SO_2 emission rates tend to be higher during night and weekend hours than during weekday hours in all three control areas.
- Marginal NO_x emission rates tend to be highest during the hours of extremely high demand, but marginal SO_2 rates tend to be highest during hours of very low demand.
- Emission rates differ across the three control areas, with rates in PJM being the highest, rates in New England being the lowest and those in New York in the middle, however the supply curves in all three areas have similar NO_x and SO_2 profiles.
- These profiles are characterized by high emission rates in the high baseload and high peak areas and low emission rates in the low baseload and middle to low-peak areas.
- Not all regional supply curves are likely to share these emission rate profiles. Regions with abundant hydroelectric resources, for example, may differ considerably.
- Typical marginal emission rates at a given time of day differ slightly from one year to the next, based on the interplay between load growth and capacity expansion.

More generally, this work highlights the need to assess avoided emissions from energy efficiency in the most specific way possible, in terms of time, location and the pollutant of interest. Basing avoided emissions estimates on rules of thumb or on trends in other pollutants or other control areas – even within a small region like the Northeast – can be misleading.