The OTC Emission Reduction Workbook 2.1: Description and User's Manual

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1. Introduction

The Ozone Transport Commission's Emission Reduction Workbook version 2.1 ("Workbook") is designed to provide a simple, user-friendly means of assessing the emissions impacts of a range of different energy policies affecting the electric industry. The geographic focus of the Workbook is the northeastern U.S., specifically the three northeastern electricity control areas: Pennsylvania/New Jersey/Maryland (PJM), the New York ISO (NY ISO) and ISO New England (ISO NE).[1] The temporal focus is an eighteen-year period, beginning in 2002. While it is not a forecasting tool (designed to predict the future), the Workbook allows users to investigate different future scenarios easily and to discern the range of probable outcomes and the importance of different factors in determining these outcomes.

The Workbook is designed to be flexible and transparent. It is flexible in that the user can evaluate a range of energy program types. Specifically, three program types can be evaluated:

- Programs that would displace generation, such as energy efficiency programs and programs that incentivize new clean generation;
- Programs that would alter the average emission rate of the electricity used in a state or region, such as an Emissions Performance Standard (EPS); and
- Programs that would reduce the emission rates of specific generating units, such as multi-pollutant regulations applied to existing generating units.

The Workbook is also flexible in that users may use default assumptions contained in the Workbook or enter information based on their own assumptions.

The Workbook is transparent in that assumptions on which a scenario is based are clearly recorded for future reference. The Workbook contains default data from several different sources, and default information is clearly marked with its source.[2] Important data sources include:

- Default displaced emission rates developed for the three northeastern control areas using the PROSYM system dispatch model;
- Data on electricity use from the U.S. Energy Information Administration (EIA); and
- Data from the U.S. Environmental Protection Agency (EPA) on power plant emissions.

This transparency is extremely important in making the kind of predictions that the Workbook is designed to make, because these predictions are highly sensitive to certain assumptions. For example, predictions of emission reductions from programs that displaced emissions are highly sensitive to assumptions about plant additions and retirements over time. Predictions of reductions from multi-pollutant regulations are

[1] The term "ISO" refers to an Independent System Operator.

[2] In the current version of the Workbook, there is one exception to this rule. The data on the load shapes of energy efficiency programs are from a proprietary source.

highly dependent on assumptions about the affected units' utilization before and after the regulation. Because of these sensitivities, it is important that all assumptions on which a prediction is based are clearly stated along with the prediction. Also, because there may be considerable uncertainty around these input assumptions, it may be prudent to assess potential emission reductions using a range of different input assumptions.

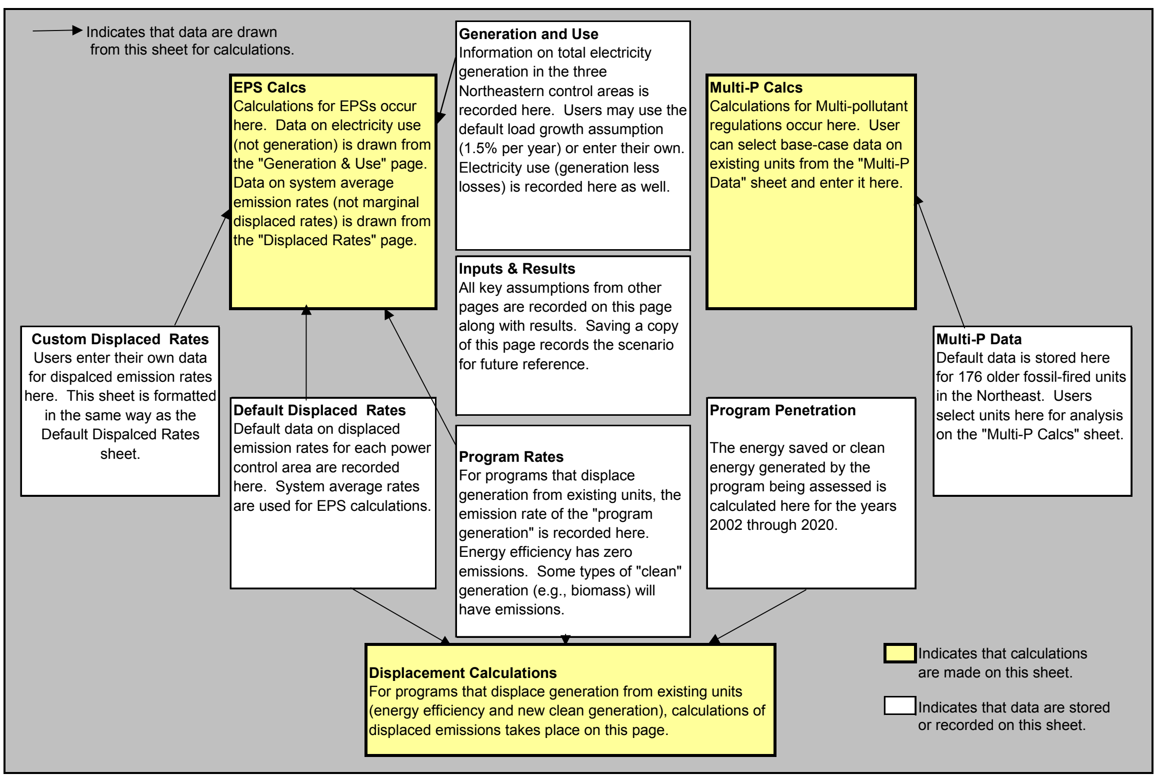
This document includes a user's manual for the Workbook (Section 2), a discussion of the default data stored in the Workbook (Section 3) and a summary of the strengths and limitations of the current version of the Workbook and suggested future work to improve it (Section 4).

2. User's Manual

Version 2.1 of the Workbook is a Microsoft Excel workbook consisting of ten spreadsheets for calculations and an "Overview" sheet.[3] Each type of calculation for which the Workbook is designed has a main spreadsheet on which most of the calculations are performed. These main sheets, shown in yellow in Figure 2.1, are called "Multi-P Calcs," "EPS Calcs," and "Displacement Calcs." The "Multi-P Calcs" sheet is for calculating emission reductions from multi-pollutant regulations applied to existing power plants. The "EPS Calcs" sheet is for assessing EPSs, and the "Displacement Calcs" sheet is for assessing policies that promote energy efficiency and new clean generation. Figure 2.1 below shows a schematic of the worksheets in the Workbook.

In addition to these three, main worksheets, there are seven sheets where (1) supporting calculations are made and (2) default input data are stored. In Figure 2.1 an arrow going from one sheet to another indicates that data is stored on the white sheet, which can be used for calculations on the yellow sheet. The worksheets in the Workbook can be reordered at any time by clicking on them and dragging them to the right or left. A small black arrow will appear when a sheet is being moved to help you place it where you want it.

Figure 2.1: Schematic of the Worksheets in the Workbook ("Overview" sheet)



[3] There are 13 spreadsheets in the Workbook in total, however two of these sheets ("Reference" and "No Displaced Rates") are used only by the Workbook itself for calculations.

There are four boxes on the “Inputs&Results” sheet. Each of these boxes records the key inputs and results of a calculation and contains a space for descriptions of key assumptions. Once you have completed a calculation, we suggest that you save or print a copy of the corresponding box as a record of your inputs and results.

The drop-down menus in the Workbook are driven by macros.

If these menus do not function properly, first check the security settings in Excel, then check the settings in your server and email program.

The drop-down menus in the Workbook are driven by macros. Because many viruses contain macros, email servers and software applications can be configured to disable them. If you find that the drop-down menus do not function properly, first check the security settings in Excel. To do this, go to the Tools menu and select “Macros” and “Security.” If the security level is set to “High,” set it to “Medium,” and then close Excel. Then reopen it and see if the Workbook functions properly. If not, try setting the macro security to “Low” and reopening again. If the Workbook still does not work, check the security settings in your server and/or email program to make sure these programs are not disabling the macros.

The use of Microsoft Excel for this Workbook is attractive in that the software is simple to use and many people are familiar with it. Excel does present limitations, however, when used for a calculation tool such as this one. The main limitation is that, where drop-down menus have been used, cells cannot be locked for editing. Thus, a user could inadvertently delete part of a table that is linked to a drop-down menu. **Users should only delete data they have entered using the “Clear” command in the Edit menu as discussed below.** If you think you have inadvertently deleted a portion of the Workbook, select “Undo Typing” from the Edit menu. In addition, always save a clean backup copy of the Workbook to start over on if need be.

To illustrate how the Workbook is used, the three subsections below discuss in detail three calculations using the Workbook.

2.1 Assessing Multi-Pollutant Regulations

Calculations of emission reductions from multi-pollutant regulations are made using two worksheets: "Multi-P Calcs" and "Multi-P Data." Key inputs and results are recorded in Box 3 on the "Inputs&Results" worksheet. The basic procedure for these calculations is as follows.

1. Predict “base-case” utilization of the affected units (i.e., without the new regulation) and calculate base-case emissions.
2. Predict utilization of the units under the new regulation and calculate regulated emissions.
3. Subtract regulated emissions from base-case emissions to get total emission reductions from the regulation.

Users will follow this procedure to assess regulations that apply a reduced emission rate to a group of generating units. Users assessing a regulation that caps emissions at a group of units will perform only step one and then simply subtract the tons allowed under the cap from base-case emissions to calculate total reductions. Below is a step-by-step description of how to assess emission reductions from a multi-pollutant regulation.

Step 1:

The results of each calculation, along with key inputs, are recorded in tables on the "Inputs&Results" sheet.

Print or save a copy of this table as a record of your calculation.

First you must "zero out" the tables you plan to use (i.e., remove any data left there from previous use). Zero out all tables with red text on the "Multi-P Calcs" sheet: Tables 1, 1.A, 4.A and 5.A through 5.D. To zero out tables, enter "0" in the upper left cell and copy it down and across the whole table. You must also delete any generating unit data that appear in Tables 2 through 2.F. To delete data, select the entire row and go to the File menu. Go to "Clear" and select "Contents." Do not delete data using the "Delete" key.

Next go to the "Inputs&Results" sheet of the Workbook and locate Box 3, at cell AC3. Here you will enter general information about the program you are assessing. Type in brief information for "Policy Assessed," "Region" and "Number of Affected Units" – see Figure 2.2 below. Note that the text next to these headings is red. Throughout the spreadsheet, red text in a cell indicates that data can be entered that cell. Text that appears in black is either default data or a number calculated by the Workbook. In Box 3 of the "Inputs&Results" sheet, cells with black text are linked to other cells in the Workbook, and this information will be recorded automatically as you enter information elsewhere.

Note also that there is a space at the bottom of Box 3 labeled "Notes on Key Assumptions." Here you may enter additional information on the assumptions that underlie your calculation, such as base case emission rates and unit utilization rates.

Figure 2.2: Inputs and Results for a Multi-Pollutant Regulation ("Inputs & Results" sheet)

3. Multi-Pollutant Regulations

Policy Assessed:	Enter Text

Assumptions

3.A: General Assumptions

Region:	Enter Text
Number of Affected Units:	0
Base Case Emission Rates:	Default

3.B: Regulated Emission Limits

Emission Limits for "Group 1" Units (lb/MWh)

Year:	0	0	0
NOx:	0.0	0.0	0.0
SO2:	0.0	0.0	0.0
CO2:	0	0	0
Hg:	0.0E+00	0.0E+00	0.0E+00

Emission Limits for "Group 2" Units (lb/MWh)

Year:	0	0	0
NOx:	0.0	0.0	0.0
SO2:	0.0	0.0	0.0
CO2:	0	0	0
Hg:	0.0E+00	0.0E+00	0.0E+00

Results ****Users should round NOx, SO2 and mercury results to two significant figures and CO2 results to three.****

3.C: Base Case Generation (MWh)

2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

3.D: Base Case Emissions (tons)

	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
NOx:	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
SO2:	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
CO2:	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Hg:	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000

3.E: Regulated Generation (MWh)

2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

3.D: Regulated Emissions (tons)

	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
NOx:	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
SO2:	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
CO2:	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Hg:	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000

3.E: Total Annual Emission Reductions (tons)

	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
NOx:	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
SO2:	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
CO2:	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Hg:	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000

Notes on Key Assumptions:

Note that, although it is not shown here, these tables extend to the right through 2020.

Step 2:

The calculations for a multi-pollutant regulation all take place on the "Multi-P Calcs" sheet. At the top of this sheet are Tables 1 and 1.A, where users enter the new emission limits to be applied to the affected plants. (See Figure 2.3 below.) Below these small tables are six rows of large tables stacked on top of each other. Below Tables 1 and 1.A are Tables 2 through 2.F, placed side-by-side and extending right on the spreadsheet all the way to Column "DT." Base-case data on the affected units are entered in these tables. Other tables in which data are entered or calculations made are in similar rows below these tables.

Note that in row 2 of the "Multi-P Calcs" sheet there are years listed in bold. These are the column headings for all tables on this sheet. Throughout the Workbook, columns are labeled once at the top of the Worksheet rather than many times at the top of each table. To align the column headings (years) at the top of the table on which you are working, simply scroll down the sheet until the row of years is in the right place.

> *To align the column headings (years) with the top of the table on which you are working, scroll down the sheet until the row of years is in the right place.*

Go to the "Multi-P Calcs" sheet and enter the emission rates that will be applied to the affected units in Table 1 or Tables 1 and 1.A. If all units will be subject to the same emission limits, use Table 1 only. To assess regulations that become tighter over time, enter the different limits in the columns of Table 1, with the trigger year in the top row. If different limits will apply to different groups of generating units, enter the limits for one group in Table 1 and limits for the other group in Table 1.A.

As an example, we will assess NO_x and SO_2 limits applied in 2005 to the four Danskammer units in New York. As seen in Figure 2.3, the NO_x limit we will assess is 1.5 lb/MWh, and the SO_2 limit is 3.0 lb/MWh. Note that throughout the Workbook, emission rates are stated in units of pounds per MWh of generation.

Figure 2.3: Entering the New Emission Limits ("Multi-P Calcs" sheet)

Calculations for Analysis of Multi-Pollutant Regulations

2002 2003 2004 2005 2006 2007 2008 2009 2010 2011

1. Emission Limits for "Group 1" Units (lb/MWh)

Year:	2005		
NOx	1.5	0.0	0.0
SO2	3.0	0.0	0.0
CO2	0	0	0
Hg	0.0E+00	0.E+00	0.E+00

1.A: Emission Limits for "Group 2" Units (lb/MWh)

Year:			
NOx	0.0	0.0	0.0
SO2	0.0	0.0	0.0
CO2	0	0	0
Hg	0.E+00	0.E+00	0.E+00

Notes: Enter the emission rates (in lb/MWh) to be app
Columns for several years are provided to asse
Several tables are provided to assess regulatio

Base Case Data: Default
Select Default or Custom data.

Step 3:

Indicate in the drop-down box below Table 1 whether you will be using the default information ("Default") on affected units or entering your own information ("Custom"). Your choice will be recorded on the "Inputs&Results" sheet. Descriptions of the default data sources and methodology are located in boxes at the bottom of each table on the "Multi-P Data" sheet.[4]

Step 4:

Next, enter base-case information on the affected generating units in Tables 2 through 2.F on the "Multi-P Calcs" sheet (at row 17). You may use either the default data stored in the Workbook or your own data on the affected units. The default information is stored on the "Multi-P Data" sheet. The default information is laid out on this sheet in exactly the same format as it will be entered on the "Multi-P Calcs" sheet. This format is shown in Figure 2.4. (On the "Multi-P Calcs" sheet, these are Tables 2 through 2.F. On the "Multi-P Data" sheet, these are Tables 1 through 1.F)

Figure 2.4: The Location of Information on Generating Units ("Multi-P Data" sheet)

Table 1	Table 1.A	Table 1.B	Table 1.C	Table 1.D	Table 1.E	Table 1.F
Unit Info	NO_x rate	SO_2 rate	CO_2 rate	Hg rate	Cap. Factor	Generation

The base case capacity factors listed in Table 1.E are taken from the base case PROSYM modeling runs performed to develop the default displaced emission rates. This modeling run simulates the operation of each northeastern control area under predicted future loads and base case assumptions about plant additions and retirements. (This modeling run and the underlying assumptions are discussed further in Section 3.1 below.) These capacity factors are an important input assumption to your calculation, and they should be presented with your results. Save or print a copy of Table 1.E for your records.[5]

Full sets of default data are included for most large steam generating units in PJM, NY ISO and ISO NE. Partial sets of data are included for a number of generating units in Pennsylvania but outside of the PJM region. For these units, emission rates are provided but

*To remove data that you have entered in the Workbook**, do <u>not</u> use the Delete button**.*

Select the Data and go to the Edit menu. Select "Clear" from this menu, and choose "Contents" from the drop-down menu that appears.

[4] Note that this list includes units located throughout Pennsylvania, not just units within the PJM control area. In contrast, the modeling runs performed to develop the default displaced emission rates only include generating units in PJM.

[5] To save this table electronically, select it, copy it and open a new Excel workbook. In the Edit menu of the new workbook, select "Paste Special." In the dialogue box that appears, select "Values," and allow the text pasted to remain selected. Then go to Edit and "Paste Special" again and select "Formats." In the new file, you may have to adjust the "Zoom" setting (in the View menu) and the column widths for best viewing. To print this table, select the table and click "Page Setup" under the File menu. In the dialogue box that appears, select "Portrait" and "Fit-to-One," and then click "Print." In the print dialogue box, click "Selection," and then "O.K.")

base case capacity factors and generation are not provided. The text “no data” appears in Tables 1.E and 1.F for these units. Users must develop a base case capacity factor assumption and calculate base case generation in order to assess regulations involving these units. If the term “#VALUE!” appears in row 224 of the “Multi-P Calcs” sheet, check to make sure there are capacity factors and generation figures (in Tables 2.E and 2.F) for all units you are assessing.

To use the default data, find the generating unit you want in Table 1 on the “Multi-P Data” sheet, and select and copy the entire row in which that unit appears. (To select the entire row, click on the row number at the far left of the worksheet.) Then go to the "Multi-P Calcs" sheet and paste the entire row of data into the first empty row in Table 2 (row 17). To paste in the entire row of data, you must either select the entire target row or select the first (leftmost) cell in that row. *By pasting the entire row, all the information from Table 1 through 1.F on the “Multi-P Data” sheet is placed in the correct spot in Tables 2 though 2.F on the "Multi-P Calcs" sheet, because this section of these two sheets is formatted exactly the same.* In Figure 2.4 below, as the highlighted rows are pasted into the spreadsheet, data on the four Danskammer units are inserted into Tables 2 through 2.F. (Note that Figure 2.4 only shows the leftmost portion of the spreadsheet; data will be also pasted into Tables 2.B through 2.F, to the right of this figure.)

Figure 2.5: Pasting Entire Rows of Data into the Tables on the “Multi-P Calcs” Sheet

1. Emission Limits for "Group 1" Units (lb/MWh)

Year:	2005		
NOx	1.5	0.0	0.0
SO2	3.0	0.0	0.0
CO2	0	0	0
Hg	0.0E+00	0.E+00	0.E+00

1.A: Emission Limits for "Group 2" Units (lb/MWh)

Year:			
NOx	0.0	0.0	0.0
SO2	0.0	0.0	0.0
CO2	0	0	0
Hg	0.E+00	0.E+00	0.E+00

Notes: Enter the emission rates (in lb/MWh) to be app
Columns for several years are provided to asse
Several tables are provided to assess regulatio

Base Case Data: Default
Select Default or Custom data.

2. Affected Units / **2.A: Base Case NOx Rates**

Station	No.	MW	NO$_x$ (lb/Mw								
Danskammer	1	64	2.0	1.9	1.9	1.9	1.9	1.9	1.9	1.9	1.9	1.9
Danskammer	2	125	2.0	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8
Danskammer	3	127	4.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0
Danskammer	4	232	4.2	3.1	3.1	3.1	3.1	3.1	3.1	3.1	3.1	3.1

After pasting in a row, check to make sure that Tables 2 through 2.F are filled with data in that row. Repeat this step for each affected unit, pasting the entire row of data into the next available row in Table 2.

If you are assessing a multi-pollutant regulation for a subset of the four pollutants in the Workbook (NO_x, SO_2, CO_2 and mercury), you must erase the data you entered for pollutants you are not assessing. Here, since we are only assessing NO_x and SO_2 regulations, you must clear the data pasted into Tables 2.C and 2.D. Do this by selecting all the data that were pasted into those tables and go to the “Edit” menu. Select “Clear” from this menu and then select “Contents” from the drop down menu that appears. **Do <u>not</u> clear data from the worksheet by using the “Delete” key**.

If you are entering your own data on affected units, type it directly into Tables 2 through 2.F on the “Multi-P Calcs” sheet. Make sure you enter data for each unit in all of these Tables, and make sure to enter emission rates in lb/MWh.

As information for each generating unit is added in Tables 2 through 2.F on the “Multi-P Calcs” sheet, total base-case emissions for the group will be summed in Tables 3 through 3.D (starting at row 119). For each unit, annual emissions are the product of base case generation from Table 2.F (MWh) and the base case emission rate (lb/MWh) divided by 2000 to get tons. The sums for the entire group of units are shown in row 226. Annual total emissions of all pollutants entered are summed for the years 2002 through 2020.

The emission rates for each unit in the default data are based on data in EPA’s 2000 Acid Rain Database. EPA cautions that some of these numbers may not reflect changes made recently at generating units. We recommend that users check all available documentation of air emissions at each generating unit they assess in order to estimate base-case emissions most accurately. More information on the default data appears in Section 3.2 below.

Step 5:

If you are assessing a multi-pollutant regulation that applies an emission cap to the affected units, you can now simply subtract the tons in the emission cap from the baseline tons to calculate total emission reductions. If you are assessing a regulation that applies reduced emission rates to the affected units, you must now estimate emissions under the new regulation.

Go to Table 4 on the “Multi-P Calcs” sheet (at row 226). Here you will enter your prediction of unit capacity factor (utilization rate) under the multi-pollutant rule. Note that the list of generating units you entered in Table 2 automatically appears in Table 4. Enter the predicted capacity factor for each unit in each year in Table 4.A (at cell F226). Your prediction of unit utilization should reflect the expected increase in each unit's operating costs due to the regulation. Ideally, users should use a system dispatch model to make this prediction, however, if you cannot do this, make assumptions about regulated capacity factors and present these assumptions with your results. If you use this approach, we recommend that you make calculations based on several different assumptions about regulated utilization and assess the range of results. Print a copy of Table 4.A with each scenario to record your assumptions for that scenario.[6]

As soon as you enter a capacity factor for a unit in a given year, the spreadsheet will automatically calculate total generation in that year in Table 4.B (at cell Z226).

[6] To save this table electronically, select it, copy it and open a new Excel workbook. In the Edit menu of the new workbook, select “Paste Special.” In the dialogue box that appears, select “Values,” and allow the text pasted to remain selected. Then go to Edit and “Paste Special” again and select “Formats.” In the new file, you may have to adjust the “Zoom” setting (in the View menu) and the column widths for best viewing. To print this table, select the table and click “Page Setup” under the File menu. In the dialogue box that appears, select “Portrait” and “Fit-to-One,” and then click “Print.” In the print dialogue box, click “Selection,” and then “O.K.”

Step 6:

Next you must calculate total emissions from the affected units under the multi-pollutant regulation. Go to Table 5.A on the "Multi-P Calcs" sheet (at cell F332). Here, in each cell of Tables 5.A through 5D, you will multiply the appropriate MWh value from Table 4.B by the appropriate emission limit you entered in Table 1 (or Tables 1 and 1.A) and divide by 2000 to convert from pounds to tons. The formula in the first cell of Table 5.A (cell F334) would be: "=Z228*$C$6/2000." The first term is the predicted generation in 2002 (based on your assumed capacity factor), and the second term is the emission limit (1.5 lb/MWh) you entered in Table 1. You must add the dollar signs in front of the terms "C" and "6" to lock the reference on this cell, allowing you to drag the formula into other cells.[7]

Now select the formula in cell F334 and copy it across the row all the way to rightmost column of Table 5.A. This will calculate NO_x emissions in every year for the first generating unit in your list. If you are evaluating multiple generating units, you can now select the entire row of formulas you have entered for the first unit on the list and drag that row down through all other rows. In our example, evaluating the four Danskammer units, we would drag the formulas down four rows.

You must set up the formulas in this way in as many tables (5.A through 5.D – corresponding to NO_x, SO_2, CO_2 and mercury emissions) as pollutants you are assessing. In this example, you only need to do it in Tables 5.A and 5.B. The formulas in each year for each generating unit will be the same across all tables (pollutants) except for the second term. The second term will change with each pollutant, targeting the appropriate emission limit in Table 1. Remember to use the dollar sign to lock the cell reference to the appropriate cell in Table 1, so you can copy the formula and paste it into other cells.

There are two significant figures in the default NO_x, SO_2 and mercury emission rates and three in the default CO_2 rates.

Be sure to round your results appropriately.

As you calculate emissions under the new emission limits in Tables 5.A through 5.D, the spreadsheet will automatically calculate total emission reductions from the regulation, in Tables 6.A through 6.D. The numbers in Tables 6 through 6.D will also appear in Box 3 on the "Inputs & Results" sheet, at cell AC3. Figure 2.2 above shows Box 3. You should round calculations of NO_x, SO_2 and mercury emissions to two significant figures and calculations of CO_2 reductions to three. These are the number of significant

[7] When you drag a formula in MS Excel, the cell references move as you drag the formula, preserving the relative locations of the cells in the formula. Placing a dollar sign in front of a term in the formula locks the reference to that cell. For example, if you typed in a cell "=D5*X2" and dragged the formula one cell to the right, the formula in the new cell would be "=E5*Y2." If you dragged the formula one cell down, the new formula would be "=D6*X3." However, if you typed "=$D$5*X2" and dragged it one cell to the right, the new formula would be "=$D$5*Y2." If you dragged it one cell down, the new formula would be "=$D$5*X3." Consult an Excel manual for more information on writing and dragging formulas.

figures in the default emission rates in the Workbook.[8] In most calculations, the Workbook will present results with far too many significant figures. In Box 3 there is also a space for notes. You should describe the assumptions you made regarding regulated utilization of the affected units and other key inputs. Save Box 3 to another Excel workbook or print it as a record of your calculation.[9]

2.2 Assessing Emission Performance Standards

Calculations of emission reductions from EPSs are made using four worksheets. The main calculations are made on the "EPS" sheet. Default data are stored and custom data are entered on the "Electricity Use," "Default Displaced Rates" and “Custom Displaced Rates” sheets. Inputs and results are recorded in Box 4 on the "Inputs & Results" worksheet.

The general approach to calculating emission reductions from EPSs is as follows.

1. Predict future annual electricity use.
2. Calculate total emissions in a “base-case” scenario (multiply electricity use in each region by regional average emission rates).
3. Calculate total emissions with the EPS (multiply electricity use in each region by the EPS emission limits).
4. Subtract total annual EPS emissions from total base case emissions in each region to get annual emission reductions from the EPS.

Below are detailed instructions for performing this calculation with the Workbook.

Step 1:

First, zero out Table 1 on the “Program Rates” sheet. To do this, enter “0” in the upper left cell and copy it down and across the whole table. Next, go to the “EPS” sheet and select “No Data” in the drop-down menus in Boxes 1, 2 and 3. This will ensure that you are starting with clean workspaces.

Now go to the “Inputs&Results” sheet and enter information about the program you will assess. Go to Box 4, at cell BD3. Box 4 is shown in Figure 2.10, below. Enter short, descriptive information in the spaced provided to describe the “Policy Assessed,” “Region” and “Annual Load Growth.” For “Annual Load Growth,” indicate your assumption for annual electricity load growth in the states you are assessing. If you use

[8] Of course, if you have used your own data for calculations, a different number of significant figures may be appropriate.

[9] To save this table electronically, select it, copy it and open a new Excel workbook. In the Edit menu of the new workbook, select “Paste Special.” In the dialogue box that appears, select “Values,” and allow the text pasted to remain selected. Then go to Edit and “Paste Special” again and select “Formats.” In the new file, you may have to adjust the “Zoom” setting (in the View menu) and the column widths for best viewing. To print this table, select the table and click “Page Setup” under the File menu. In the dialogue box that appears, select “Portrait” and “Fit-to-One,” and then click “Print.” In the print dialogue box, click “Selection,” and then “O.K.”

the default data in the Workbook on electricity use, load growth is 1.5 percent per year. Note that the text in the cells next to these words is red. Throughout the Workbook, red text indicates that you should enter information there. All of the cells with black text in Box 4 are linked to other cells in the Workbook.

Next, proceed to the "EPS," sheet. The "EPS" sheet consists of five boxes stacked vertically down the spreadsheet. There are no workspaces to the right of these boxes. In Boxes 1 through 3, users enter data and calculate emissions for the PJM, New York ISO and ISO New England areas, respectively. In Box 4, total emission reductions across all three regions are summed. In Box 5, users enter data on electricity use in each region.

Step 2:

Scroll down to Table 5 at the bottom of the "EPS" sheet (at cell B120). This is where you will enter your prediction of future electricity use in your region of interest. If you plan to use the default data on future electricity use, select "Default Data" in the drop-down menu in cell I120, and the default data will appear in the Table. Table 5 and the drop-down menu are shown in Figure 2.6 below. (The columns in Figure 2.6 are years, beginning with 2002. The years are labeled in the second row of the worksheet. To align the years at the top of the table, simply scroll down the worksheet until the years are in the right place.)

Figure 2.6: Selecting Data on Future Electricity Use ("EPS" sheet)

5: Annual Electricity Use (MWhs) Data Source: Default Data

New England									
CT	30,857,000	31,320,000	31,790,000	32,267,000	32,751,000	33,242,000	33,740,000	34,247,000	34,760,000
MA	50,339,000	51,094,000	51,861,000	52,639,000	53,428,000	54,229,000	55,043,000	55,869,000	56,707,000
ME	6,599,000	6,698,000	6,799,000	6,901,000	7,004,000	7,109,000	7,216,000	7,324,000	7,434,000
NH	10,278,000	10,432,000	10,589,000	10,748,000	10,909,000	11,072,000	11,239,000	11,407,000	11,578,000
RI	7,335,000	7,445,000	7,557,000	7,670,000	7,785,000	7,902,000	8,021,000	8,141,000	8,263,000
VT	5,809,000	5,896,000	5,985,000	6,074,000	6,166,000	6,258,000	6,352,000	6,447,000	6,544,000
New York	128,271,000	130,195,000	132,148,000	134,130,000	136,142,000	138,184,000	140,257,000	142,361,000	144,496,000
PJM									
MD	62,452,000	63,389,000	64,340,000	65,305,000	66,284,000	67,279,000	68,288,000	69,312,000	70,352,000
NJ	64,718,000	65,689,000	66,674,000	67,674,000	68,689,000	69,720,000	70,766,000	71,827,000	72,904,000
PA	101,108,000	102,625,000	104,164,000	105,727,000	107,312,000	108,922,000	110,556,000	112,214,000	113,898,000
Other									
DE	11,098,000	11,265,000	11,434,000	11,605,000	11,779,000	11,956,000	12,135,000	12,317,000	12,502,000
DC	10,937,000	11,101,000	11,268,000	11,437,000	11,608,000	11,782,000	11,959,000	12,138,000	12,321,000
Totals									
New England	111,217,000	112,885,000	114,579,000	116,297,000	118,042,000	119,812,000	121,610,000	123,434,000	125,285,000
New York	128,271,000	130,195,000	132,148,000	134,130,000	136,142,000	138,184,000	140,257,000	142,361,000	144,496,000
PJM	228,278,000	231,702,000	235,178,000	238,705,000	242,286,000	245,920,000	249,609,000	253,353,000	257,154,000
Other	22,035,000	22,366,000	22,701,000	23,042,000	23,387,000	23,738,000	24,094,000	24,456,000	24,822,000
OTC Total	489,801,000	497,148,000	504,605,000	512,174,000	519,857,000	527,655,000	535,570,000	543,603,000	551,757,000

The default electricity use data are based on 2000 data from the U.S. Energy Information Administration (EIA) on electricity use by state. We have increased EIA's 2000 numbers by 1.5 percent per year to derive the 2002 numbers, and future year estimates are calculated using the same annual growth factor.

If you would like to base your calculations on other assumptions about future electricity use, select "Custom Data" on the drop-down menu above Table 5. Then go to Table 2 on the "Electricity Use" sheet (cell B34) and calculate your data. This table is formatted so that you only need to (1) enter data for 2002 in the first column and (2) enter an annual load growth percentage in the box provided above the table (in cell H34). From these inputs, the table will calculate electricity use in all future years. Figure 2.7 shows the table on the "Electricity Use" sheet for calculating custom data on electricity use.

Figure 2.7: Calculating Future Electricity Use Numbers ("Electricity Use" sheet)

2: Custom Data (MWhs)				Annual Load Growth:	1.20%			
New England								
CT	30,857,000	31,227,284	31,602,011	31,981,236	32,365,010	32,753,390	33,146,431	33,544,188
MA	50,339,000	50,943,068	51,554,385	52,173,037	52,799,114	53,432,703	54,073,896	54,722,782
ME	6,599,000	6,678,188	6,758,326	6,839,426	6,921,499	7,004,557	7,088,612	7,173,675
NH	10,278,000	10,401,336	10,526,152	10,652,466	10,780,295	10,909,659	11,040,575	11,173,062
RI	7,335,000	7,423,020	7,512,096	7,602,241	7,693,468	7,785,790	7,879,219	7,973,770
VT	5,809,000	5,878,708	5,949,252	6,020,644	6,092,891	6,166,006	6,239,998	6,314,878
New York	128,271,000	129,810,252	131,367,975	132,944,391	134,539,723	136,154,200	137,788,050	139,441,507
PJM								
MD	62,452,000	63,201,424	63,959,841	64,727,359	65,504,087	66,290,137	67,085,618	67,890,646
NJ	64,718,000	65,494,616	66,280,551	67,075,918	67,880,829	68,695,399	69,519,744	70,353,981
PA	101,108,000	102,321,296	103,549,152	104,791,741	106,049,242	107,321,833	108,609,695	109,913,012
Other								
DE	11,098,000	11,231,176	11,365,950	11,502,342	11,640,370	11,780,054	11,921,415	12,064,472
DC	10,937,000	11,068,244	11,201,063	11,335,476	11,471,501	11,609,159	11,748,469	11,889,451
Totals								
New England	111,217,000	112,551,604	113,902,223	115,269,050	116,652,279	118,052,106	119,468,731	120,902,356
New York	128,271,000	129,810,252	131,367,975	132,944,391	134,539,723	136,154,200	137,788,050	139,441,507
PJM	228,278,000	231,017,336	233,789,544	236,595,019	239,434,159	242,307,369	245,215,057	248,157,638
Other	22,035,000	22,299,420	22,567,013	22,837,817	23,111,871	23,389,213	23,669,884	23,953,923
OTC Total	489,801,000	495,678,612	501,626,755	507,646,276	513,738,032	519,902,888	526,141,723	532,455,423

If you have calculated custom data on electricity use, return now to the "EPS" sheet.

Step 3:

Go to Box 1 (titled "PJM") at the top of the "EPS" page. From here, we will describe how to calculate emission reductions for and EPS implemented only in the PJM region. If you will be assessing EPSs in other regions, follow the directions below, using Box 2 on the "EPS" sheet for New York and Box 3 for New England. All three boxes look the same and work in the same way. The Workbook will sum emission reductions across all regions for which you enter data.

In Box 1 at the top of the "EPS" page, annual energy use appears in Table 1.A, from the data you just entered in Table 5. Now enter your assumption about PJM system average emission rates in Table 1.B by selecting default or custom data in the drop-down menu above the table. If you select "Default Data," the default data will automatically appear in Table 1.B, as shown in Figure 2.8.

Figure 2.8: Entering Data on Regional Average Emission Rates ("EPS" sheet)

Emission Performance Standards

1. PJM

1.A: PJM Electricity Use

	2002	2003	2004	2005	2006	2007	2008	2009	2010
MWhs:	228,278,000	231,702,000	235,178,000	238,705,000	242,286,000	245,920,000	249,609,000	253,353,000	257,154,000

1.B: Average PJM Emission Rates (lb/MWh) Data Source: Default Data

	2002	2003	2004	2005	2006	2007	2008	2009	2010
NOx:	2.8	2.5	2.3	1.7	1.7	1.7	1.7	1.7	1.7
SO2:	6.5	6.1	5.3	4.8	4.6	4.5	4.1	3.6	3.3
CO2:	1,521	1,451	1,366	1,318	1,294	1,286	1,269	1,242	1,244
Hg:	8.0E-05	7.9E-05	7.7E-05	7.4E-05	7.3E-05	7.3E-05	7.3E-05	7.3E-05	7.4E-05

If you would like to use other data on system average emission rates, select "Custom Data" in the drop-down menu above Table 1.B.

Step 4:

If are using default data on system average emission rates, skip to Step 5. If you are entering your own data on system average rates, select "Custom Data" in the drop-down menu above Table 1.B on the "EPS" sheet and then go to the "Custom Displaced Rates" sheet. Enter system average emission rates for PJM, for each year 2002-2020, in Table 1.E, as shown in Figure 2.9, below.

Figure 2.9: The Table for Custom Data on Average Regional Emission Rates ("Custom Displaced Rates" sheet)

1.D: PJM Non-Ozone Season Night/Weekend (lb/MWh)

NOx:	0	0	0	0	0	0	0	0	0	0	0
SO2:	0	0	0	0	0	0	0	0	0	0	0
CO2:	0	0	0	0	0	0	0	0	0	0	0
Hg:	0	0	0	0	0	0	0	0	0	0	0

1.E: PJM Annual Average (lb/MWh)

NOx:	0	0	0	0	0	0	0	0	0	0	0
SO2:	0	0	0	0	0	0	0	0	0	0	0
CO2:	0	0	0	0	0	0	0	0	0	0	0
Hg:	0	0	0	0	0	0	0	0	0	0	0

1.F: PJM Peak Day (lb/MWh)

NOx:	0	0	0	0	0	0	0	0	0	0	0

Make sure you enter emission rates in lb/MWh and enter rates for all pollutants and years. After you have entered data in Table 1.E of the "Custom Displaced Rates" sheet, your data will appear in Table 1.B on the "EPS" sheet. (If it does not appear, make sure you have selected "Custom Data" in the drop-down menu above Table 1.B on the "EPS" sheet.)

After you select default data or enter your own data in Table 1.B, the spreadsheet will automatically calculate total base-case emissions for PJM in Table 1.C of the "EPS" sheet. In this calculation, the spreadsheet will add seven percent to regional electricity use to account for line losses. This is necessary because the electricity use figures are for energy use at the end use site, not electricity generation.

If you are not assessing an EPS in a particular region, select "No Data" from the drop-down menu.

If data are left in tables for regions you are not assessing, the data will be included in your calculations.

On average, seven percent of all electricity generated in the Northeast is lost in transmission to end users. Thus, we increase energy use figures by seven percent to approximate total generation.

Finally, if you are not assessing an EPS in PJM, select "No Data" from the drop-down menu. This is important. The Workbook will ultimately sum results from all three control areas. If data are left in tables for regions you are not assessing, the data will be included in your calculation.

Step 5:

Next, enter the EPS emission limits you wish to apply in each region. Enter these rates for PJM in Table 1.D on the "EPS" sheet. (For New York and New England, use Tables 2.D and 3.D on this sheet.) The EPS rate is the rate that all retail electricity suppliers must meet, on a weighted average. Enter the EPS rate for each pollutant for each year 2002-2020. Make sure to enter rates in lb/MWh. To model a declining EPS, simply make the EPS rate decline over the period at any rate you wish.

Step 6:

If you are assessing an EPS across multiple regions, you will now need to go back and enter the same data for the other region(s). Follow steps 2 through 5 above, except use the Tables in Box 2 on the "EPS" sheet for New York and those in Box 3 for New England.

Caution! *Make sure that you have selected "No Data" for the regional average emission rate (in the drop down menus above Tables 1.B, 2.B and 3.B on the "EPS" sheet) for any region you are not assessing. You should see zeroes throughout the table. If you leave numbers in this table they will affect your results. Also make sure no data on EPS emission rates appear in Tables 1.D, 2.D and 3.D for regions you are not assessing.*

Once you have entered the EPS emission rates, the "EPS" spreadsheet automatically calculates four sets of numbers:

- Total emission reductions in each region (in Tables 1.F, 2.F and 3.F), and
- Total emission reductions across all three regions (in Box 4, cell B111).

Regional and total annual reductions will also appear in Box 4 on the "Inputs&Results" sheet, along with key input assumptions for this calculation. A portion of Box 4 is shown in Figure 2.10. Note that you must round your results to two significant figures at some point before you present them, because the default emission rates in the Workbook only contain two significant figures. In most calculations, the Workbook will present results with far too

There are two significant figures in the default NO_x, SO_2 and mercury emission rates and three in the default CO_2 rates.

Be sure to round your results appropriately.

many significant figures. There is also a space in Box 4 for notes on other important input assumptions. Save a copy of Box 4 as a record of your calculation.[10]

Figure 2.10: Inputs and Results Box for an EPS Calculation ("Inputs & Results" sheet)

4. Emission Portfolio Standards

Policy Assessed:	Enter Text

Assumptions

Notes on Key Assumptions:

4.A: General Assumptions

Region:	Enter Text
Annual Electricity Use Data:	Default Data
Annual Load Growth (PJM):	Enter Percent
Displaced Emission Rates (PJM):	No Data
Displaced Emission Rates (NY ISO):	No Data
Displaced Emission Rates (ISO NE):	No Data

4.B: Energy Use (MWhs)

	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
PJM	228,278,000	231,702,000	235,178,000	238,705,000	242,286,000	245,920,000	249,609,000	253,353,000	257,154,000	261,011,000	264,926,000	268,900,000	272,933,000	277,027,000	281,183,000
NY ISO	128,271,000	130,195,000	132,148,000	134,130,000	136,142,000	138,184,000	140,257,000	142,361,000	144,496,000	146,664,000	148,864,000	151,097,000	153,363,000	155,664,000	157,999,000
ISO NE	111,217,000	112,885,000	114,579,000	116,297,000	118,042,000	119,812,000	121,610,000	123,434,000	125,285,000	127,165,000	129,072,000	131,008,000	132,973,000	134,968,000	136,992,000
Total	467,766,000	474,782,000	481,905,000	489,132,000	496,470,000	503,916,000	511,476,000	519,148,000	526,935,000	534,840,000	542,862,000	551,005,000	559,269,000	567,659,000	576,174,000

4.C: PJM EPS Emission Rates (lb/MWh)

	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
NOx:	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SO2:	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CO2:	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
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	0.0E+00	0.0E+00	0.0E+00	0.0E+00	0.0E+00

4.D: NY ISO EPS Emission Rates (lb/MWh)

	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
NOx:	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SO2:	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CO2:	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
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	0.0E+00	0.0E+00	0.0E+00	0.0E+00	0.0E+00

4.E: ISO NE EPS Emission Rates (lb/MWh)

	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
NOx:	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SO2:	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CO2:	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
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	0.0E+00	0.0E+00	0.0E+00	0.0E+00	0.0E+00

Results ****Users should round NOx, SO2 and mercury results to two significant figures and CO2 results to three.****

4.F: PJM Emission Reductions (tons)

	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
NOx:	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SO2:	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CO2:	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
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	0.0E+00	0.0E+00	0.0E+00	0.0E+00	0.0E+00

4.G: NY ISO Emission Reductions (tons)

	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
NOx:	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SO2:	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CO2:	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
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	0.0E+00	0.0E+00	0.0E+00	0.0E+00	0.0E+00

4.H: ISO NE Emission Reductions (tons)

	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
NOx:	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SO2:	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CO2:	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
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	0.0E+00	0.0E+00	0.0E+00	0.0E+00	0.0E+00

4.I: Total Emission Reductions (tons)

Note that, although it is not shown here, these tables extend to the right through 2020.

[10] To save this table electronically, select it, copy it and open a new Excel workbook. In the Edit menu of the new workbook, select "Paste Special." In the dialogue box that appears, select "Values," and allow the text pasted to remain selected. Then go to Edit and "Paste Special" again and select "Formats." In the new file, you may have to adjust the "Zoom" setting (in the View menu) and the column widths for best viewing. To print this table, select the table and click "Page Setup" under the File menu. In the dialogue box that appears, select "Portrait" and "Fit-to-One," and then click "Print." In the print dialogue box, click "Selection," and then "O.K."

2.3 Assessing Energy Efficiency and Clean Generation Programs

Calculations of reductions from energy efficiency and clean generation use four spreadsheets. The main calculations are made on the "Displacement Calcs" sheet. Data are pulled from the "Program Pen." sheet, the "Program Rates" sheet and either the "Default Displaced Rates" sheet or the "Custom Displaced Rates" sheet.

The general approach to these calculations is as follows.

- Characterize energy saved or clean energy generated in future years on the "Program Pen." sheet.
- Enter the emission rates of the energy saved or clean energy generated (energy efficiency has an emission rate of zero).
- Enter data on the emission rate of the electricity displaced by the energy efficiency or clean generation (default data are provided and users may enter their own assumptions).

Below, we demonstrate how these calculations are made, using as an example a residential air conditioner subsidy in the PJM region.

Step 1.

First, you must zero out Table 1 on the "Program Pen" sheet and Table 1 on the "Program Rates" sheet, removing any numbers left there from previous work. To do this, enter "0" in the upper left cell and copy it down and across the whole table. Next, go to the "Displacement Calcs" sheet and select "No Data" in the drop-down menus in Boxes 1, 2, 4, 5, 7 and 8. This will ensure that you are starting with clean workspaces.

Next, go to the "Inputs&Results" sheet and locate Box 1 at cell B3. Key inputs and results of your calculation will be recorded here in Box 1 and Box 2 (directly under Box 1, at cell B41). Box 1 records key inputs, and Box 2 records key results. These boxes are shown in Figure 2.18 below. Enter general information about the program you are assessing in the four cells with red text in them. In this example, you might enter "Residential Air Conditioners" as the program assessed and "PJM" as the region. In the spaces for "Displaced Emission Rates" and "Load Profile Data," indicate whether you will be using the default data in the Workbook or your own data.

Step 2.

Now you will enter information on the energy saved or clean energy generated by the program you are assessing. Go to the "Program Pen" sheet. You will need to know the total annual MWhs reduced (or generated) by the program in each year of program operation. Enter the total MWhs saved in each year in the row called "PJM Total" (row 13 on the "Program Pen" sheet), as shown in Figure 2.11 below. For this example, we will simply enter 1,000 MWhs for each year, 2002 through 2012. (Note that the numbers in cell D13 are red, indicating that data should be entered there.) Default data provided in the Workbook will help you to estimate MWhs saved in each period of the year using the total annual savings numbers you just entered.

Figure 2.11: Entering Total Energy Savings ("Program Pen" sheet)

Program Penetration

1: Program Penetration

1.A: PJM MWhs Generated/Saved	**2002**	**2003**	**2004**	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**
Ozone Season Weekday	0	0	0	0	0	0	0	0	0	0
Ozone Season Night/Weekend	0	0	0	0	0	0	0	0	0	0
Non-Ozone Season Weekday	0	0	0	0	0	0	0	0	0	0
Non-Ozone Night/Weekend	0	0	0	0	0	0	0	0	0	0
Peak Day	0	0	0	0	0	0	0	0	0	0
Peak Hours	0	0	0	0	0	0	0	0	0	0
PJM Total	1,000	0	0	0	0	0	0	0	0	0

Step 3.

Next you will allocate total energy savings in each year to the five time periods of the year, listed in Table 1.A. You can do this using default data provided in the Workbook, or your own assumptions about the performance of the program. Note that Table 1.A includes six time periods into with which you can describe the operation of your program. The first four time periods should be used together to describe programs that operate across a number of seasons or different daily time periods. The final two should used separately, to describe programs that only operate during hours with very high loads. Thus, if you are assessing, for example, a load management program – which would only operate when loads reached extreme levels – you should place all energy savings in either the "Peak Day" or the "Peak Hours" category. If you are assessing a program that will operate at times other than (or in addition to) peak periods, you should allocate program savings across the first four periods. We will allocate savings from the residential air conditioner program across the first four time periods. We will do this using default data stored in the Workbook.

The first four time periods should be used together, to describe programs that operate across a number of seasons or daily time periods. Each of the final two should be used by itself, to characterize all the output of a program.

The default data on program load profile are stored in Box 2, directly under Box 1 on the "Program Pen" sheet. Scroll down to Table 2.F at cell C69. This table, shown in Figure 2.12, includes percentages designed to allocate the savings of a residential air conditioner program to different times of the year. There are load profiles in Box 2 for 18 different programs that users might want to assess.

Figure 2.12: Load Profile Data for Residential Air Conditioner Program ("Program Pen")

2.F: Residential Air Conditioner											
Ozone Season Weekday	65%	65%	65%	65%	65%	65%	65%	65%	65%	65%	65%
Ozone Season Night/Weekend	35%	35%	35%	35%	35%	35%	35%	35%	35%	35%	35%
Non-Ozone Season Weekday	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
Non-Ozone Night/Weekend	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%

You can use the data in Table 2.F to allocate program energy by multiplying the total annual energy savings figures you have entered in Table 1.A by the percentages in Table 2.F. Go to the first cell in Table 1.A (it is cell D6, for the Ozone Season Weekday in 2002). In this cell, multiply total annual MWhs saved in 2002 (cell D13 in the "PJM Total" row of Table 1.A) by the percentage of savings expected during this period in Table 2.F. The formula will be "=D$13*D70." Copy this formula down Table 1.A, filling in all six rows showing time periods in them. (Be careful not to drag this formula into the "PJM Total" row.) Then copy the formula across all the columns of Table 1.A, through year 2020. This will fill in Table 1.A, as shown in Figure 2.13. You should get 650 MWhs for each year in the ozone season weekday period, 350 MWhs in the ozone season night/weekend period and no savings in any other period.

Figure 2.13: Allocating Energy Savings to Time Periods ("Program Pen" sheet)

1: Program Penetration	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
1.A: PJM MWhs Generated/Saved												
Ozone Season Weekday	650	650	650	650	650	650	650	650	650	650	650	0
Ozone Season Night/Weekend	350	350	350	350	350	350	350	350	350	350	350	0
Non-Ozone Season Weekday	0	0	0	0	0	0	0	0	0	0	0	0
Non-Ozone Night/Weekend	0	0	0	0	0	0	0	0	0	0	0	0
Peak Day	0	0	0	0	0	0	0	0	0	0	0	0
Peak Hours	0	0	0	0	0	0	0	0	0	0	0	0
PJM Total	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	0

If we were assessing a program implemented in more than one region, we would now enter total energy savings in Tables 1.B and/or 1.C and allocate it to time periods.

Caution! *Make sure that numbers are not left in Box 1 of the "Program Pen" sheet for any control areas that you are not assessing. In this example, focused on PJM, Tables 1.B and 1.C (for New York and New England) should be filled with zeroes. Non-zero numbers in any of these tables will affect the final results.*

Step 4.

Now you must estimate air emissions from the program you are assessing. Because we are assessing an energy efficiency program in this example, emissions will be zero for all pollutants. However, if we were assessing a subsidy for clean generation, we would have to estimate emissions from this generation. To do this, you would go to the "Program Rates" sheet, and enter the estimated emission rates in Table 1. To help users estimate emissions, the Workbook includes default emission rates for clean generation and spaces for calculations.

Make sure that numbers are not left in Box 1 of the "Program Pen" sheet for any control areas that you are not assessing.

All numbers in this Box will affect the results.

For example, assume you are assessing a Renewable Portfolio Standard (RPS). The user will have to estimate the weighted average emissions of each pollutant from the energy generated by the RPS.

You could do this by either (1) using the default emission rates in Table 2 on the "Program Rates" sheet, or (2) by entering your own assumptions about emissions from different types of renewable generators in Table 3 – see Figure 2.14 below. Next in Table 4, you would enter your assumption about how much of the RPS energy would come from each technology. Finally, in each cell of Table 1, you would multiply the appropriate emission rate (from Table 2 or 3) by the appropriate weighting factor (from Table 4) for each technology expected to play a role in the RPS.[11]

Figure 2.14: The Tables for Entering Program Emission Rates ("Program Rates" sheet)

Program Emission Rates

1: Emission Rates of Clean Generation (lb/MWh)

	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
NOx:	0	0	0	0	0	0	0	0	0	0	0
SO2:	0	0	0	0	0	0	0	0	0	0	0
CO2:	0	0	0	0	0	0	0	0	0	0	0
Hg:	0	0	0	0	0	0	0	0	0	0	0

2: Default Clean Energy Emission Rates (lb/MWh)

Plant Type	NOx	SO2	CO2	Hg
Wind	0	0	0	0
Hydro	0	0	0	0
Photovoltaic	0	0	0	0
Biomass (existing)	1.5	0.3	0	0
Landfill Gas	0	0	0	0
Microturbine	0.5	0	1,425	0
Fuel Cell	0.03	0	1,050	0

Notes: See text box below.

3: Custom Clean Energy Emission Ra

Plant Type	NOx
Wind	0
Hydro	0
Photovoltaic	0
Biomass (existing)	0
Biomass (RPS)	0
Landfill Gas	0
Microturbine	0
Fuel Cell	0

4. Percentage of Energy Generated from Each Technology

Plant Type	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
Wind	0	0	0	0	0	0	0	0	0	0	0
Hydro	0	0	0	0	0	0	0	0	0	0	0
Photovoltaic	0	0	0	0	0	0	0	0	0	0	0
Biomass (existing)	0	0	0	0	0	0	0	0	0	0	0

Step 5.

Now you will direct the spreadsheet to calculate total emissions from the energy efficiency program. Go to the "Displacement Calcs" sheet. On this sheet there are nine boxes – three for each control area. Boxes 1 through 3 pertain to PJM; boxes 4 through 6 pertain to the NY ISO; and Boxes 7 through 9 pertain to ISO NE. In each Box there are six tables, corresponding with the same six time periods in Box 1 of the "Program Pen" sheet. Go to Box 1 on the "Displacement Calcs" sheet. This is where you will calculate the emissions from the program being assessed. The drop-down menu at the top of Table 1 allows you to select either "Energy Efficiency" or "Clean Generation." When you select "Energy Efficiency," the Tables within Box 1 are filled with zeroes, because there

[11] For example, if the user expected the RPS energy to be half wind energy and half landfill gas, the formula in the first cell of Table 1 would be "(E16*E30)+(E21*E35)," where E30 and E35 are both 50%. If the user were entering their own emission rates, the formula would be "(O16*E30)+(O21*E35)."

are no emissions from saved energy. See Figure 2.15. If you select "Clean Generation" in the drop-down menu, the MWh figures in Table 1.A of the "Program Pen." sheet will be multiplied by the emission rates for clean generation that you calculated on the "Program Rates" sheet.

Figure 2.15: Calculating Emissions from an Energy Efficiency Program ("Displacement Calcs" sheet)

Displacement Calculations

1: PJM Program Emissions

Program Assessed: Energy Efficiency

1.A: Ozone Season Weekday (tons)

	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
NOx:	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SO2:	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CO2:	0	0	0	0	0	0	0	0	0	0	0
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	0.0E+00

1.B: Ozone Season Night/Weekend (tons)

	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
NOx:	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SO2:	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CO2:	0	0	0	0	0	0	0	0	0	0	0
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	0.0E+00

1.C: Non-Ozone Season Weekday (tons)

	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
NOx:	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SO2:	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

Step 6.

Now you will enter information about the emissions "displaced" by the air conditioner program in PJM. These are the emission rates representative of the generating units projected to operate less because of the energy efficiency program. First, you must decide whether to use the default data for displaced emission rates or your own assumptions. The Workbook provides default displaced rates based on modeling of these three regions with the PROSYM dispatch modeling software. (For additional information about the development of the default displaced emission rates, see Section 3 below.) The default displaced rates are stored on the "Default Displaced Rates" sheet. The default rates for PJM are in Table 1, and the rates for New York and New England are in Tables 2 and 3, respectively.

To select the default rates or enter your own data, go to Box 2 on the "Displacement Calcs" sheet. It is directly to the right of Box 1, at cell Y4. Notice that there is a drop-down menu in Table 2 (at cell AH6) similar to the one in Table 1. If you would like to use the default displaced rates, select "Default Data" from this menu, and the Workbook will automatically multiply the appropriate energy savings figure on the "Program Pen" sheet by the appropriate default emission rate. The results of this multiplication will appear in Table 2 on the "Displacement Calcs" sheet, under the drop-down menu.

Figure 2.16: Selecting Default Data for the Displaced Emission Rates ("Displacement Calcs" sheet)

2: PJM Displaced Emissions

Displaced Rates: Default Data

2.A: Ozone Season Weekday (tons)

NOx:	0.7	0.7	0.7	0.6	0.6	0.5	0.4	0.3	0.3	0.2	0.2	0.2
SO2:	1.0	1.0	1.0	1.1	0.8	0.9	0.8	0.7	0.6	0.2	0.2	0.2

If you are using your own data rather than the default data, select "Custom Data" from this menu and go to the "Custom Displaced Rates" sheet. There are three Boxes on the "Custom Displaced Rates" sheet. Box 1 is for PJM, and Boxes 2 and 3 are for New York and New England, respectively. Enter your data on displaced system emission rates in the appropriate Box. In this example, you would enter custom data on displaced emissions in PJM in each of the first four time periods in Box 1 – the same time periods that ended up with energy savings in the in Table 1.A of the "Program Pen" sheet. Make sure to enter emission rates in lb/MWh, and make sure to enter emission rates for all years. If you have selected "Custom Data" in the menu on the "Displacement Calcs" sheet, the Workbook will automatically calculate displaced emissions (in tons) as you enter emission rates into the "Custom Displaced Rates" sheet.

Step 7.

As the "Displacement Calcs" sheet calculates program emissions (in Box 1) and displaced emissions (in Box 2), it also calculates total emission reductions in Box 3 (at cell AV4). In Tables 3.A through 3.D, total emission reductions are calculated for each of the four time periods. Figure 2.17 shows Box 3 on the "Displacement Calcs" sheet.

Figure 2.17: Total Emission Reductions are Calculated on Table 3 ("Displacement Calcs" sheet)

	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
3: PJM Emission Reductions																		
3.A: Ozone Season Weekday (tons)																		
NOx:	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SO2:	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CO2:	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
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	0.0E+00	0.0E+00	0.0E+00	0.0E+00	0.0E+00	0.0E+00	0.0E+00	0.0E+00
3.B: Ozone Season Night/Weekend (tons)																		
NOx:	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SO2:	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CO2:	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
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	0.0E+00	0.0E+00	0.0E+00	0.0E+00	0.0E+00	0.0E+00	0.0E+00	0.0E+00
3.C: Non-Ozone Season Weekday (tons)																		
NOx:	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SO2:	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CO2:	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
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	0.0E+00	0.0E+00	0.0E+00	0.0E+00	0.0E+00	0.0E+00	0.0E+00	0.0E+00
3.D: Non-Ozone Season Night/Weekend (tons)																		
NOx:	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SO2:	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CO2:	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
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	0.0E+00	0.0E+00	0.0E+00	0.0E+00	0.0E+00	0.0E+00	0.0E+00	0.0E+00
3.E: Peak Day (tons)																		
NOx:	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SO2:	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CO2:	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
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	0.0E+00	0.0E+00	0.0E+00	0.0E+00	0.0E+00	0.0E+00	0.0E+00	0.0E+00
3.F: Peak Hours (tons)																		
NOx:	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SO2:	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CO2:	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
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	0.0E+00	0.0E+00	0.0E+00	0.0E+00	0.0E+00	0.0E+00	0.0E+00	0.0E+00

Note that, although it is not shown here, these tables extend to the right through 2020.

If you are assessing a program implemented in more than one control area, you will need to go back and enter program emission rates and displaced emission rates (Steps 5 and 6) for the other control areas on the "Displacement Calcs" sheet. To do this, use Boxes 4 and 5 for New York and Boxes 7 and 8 for New England.

After you have done this, total emission reductions for each control area (summed across all time periods) will appear in Tables 10, 11 and 12, at cell BU5. These Tables will also appear in Box 2 of the "Inputs&Results" sheet at cell B41. (Box 1 shows key inputs, and Box 2 shows key results.) Figure 2.18 shows these Boxes. In addition, there is a space for notes at the bottom of Box 2. Record other important inputs and assumptions here. Note that you must round your results to two significant figures at some point before you present them, because the default emission rates in the Workbook only contain two significant figures. In most calculations, the Workbook will present results with far too many significant figures. Save or print Boxes 1 and 2 on this sheet as a record of your calculation.[12]

[12] To save these Boxes electronically, select them, copy them and open a new Excel workbook. In the Edit menu of the new workbook, select "Paste Special." In the dialogue box that appears, select "Values," and allow the text pasted to remain selected. Then go to Edit and "Paste Special" again and select "Formats." In the new file, you may have to adjust the "Zoom" setting (in the View menu) and the column widths for best viewing. To print this table, select the table and click "Page Setup" under the File menu. In the dialogue box that appears, select "Portrait" and "Fit-to-One," and then click "Print." In the print dialogue box, click "Selection," and then "O.K."

Figure 2.18: Inputs and Results Box for a Displaced Emissions Calculation ("Inputs & Results" sheet)

1. Displacement Policies -- Assumptions

Policy Assessed:	Enter Text

1.A: General Assumptions

Region:	Enter Text
Displaced Emission Rates:	Enter Text
Load Profile Data:	Enter Text

1.B: Program Emission Rates

Energy Efficiency (lb/MWh)

	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
NOx:	0	0	0	0	0	0	0	0	0	0	0	0	0	0
SO2:	0	0	0	0	0	0	0	0	0	0	0	0	0	0
CO2:	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Hg:	0	0	0	0	0	0	0	0	0	0	0	0	0	0

Clean Energy Generation (lb/MWh)

	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
NOx:	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SO2:	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CO2:	0	0	0	0	0	0	0	0	0	0	0	0	0	0
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	0.0E+00	0.0E+00	0.0E+00	0.0E+00

1.C: Energy Generated/Saved by Policy Assessed (MWhs)

	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
Ozone Season Weekday	0	0	0	0	0	0	0	0	0	0	0	0	0
Ozone Season Night/Weekend	0	0	0	0	0	0	0	0	0	0	0	0	0
Non-Ozone Season Weekday	0	0	0	0	0	0	0	0	0	0	0	0	0
Non-Ozone Night/Weekend	0	0	0	0	0	0	0	0	0	0	0	0	0
Peak Day	0	0	0	0	0	0	0	0	0	0	0	0	0
Peak Hours	0	0	0	0	0	0	0	0	0	0	0	0	0
Total	0	0	0	0	0	0	0	0	0	0	0	0	0

2: Displacement Policies -- Results

****Users should round NOx, SO2 and mercury results to two significant figures and CO2 results to three.****

2.A: PJM Emission Reductions (tons)

	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
NOx:	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
SO2:	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
CO2:	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
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	0.0E+00	0.0E+00	0.0E+00	0.0E+00	0.0E+00

2.B: NY ISO Emission Reductions (tons)

	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
NOx:	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
SO2:	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
CO2:	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
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	0.0E+00	0.0E+00	0.0E+00	0.0E+00	0.0E+00

2.C: ISO NE Emission Reductions (tons)

	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
NOx:	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
SO2:	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
CO2:	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
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	0.0E+00	0.0E+00	0.0E+00	0.0E+00	0.0E+00

2.D: Total Emission Reductions (tons)

	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
NOx:	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
SO2:	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
CO2:	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
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	0.0E+00	0.0E+00	0.0E+00	0.0E+00	0.0E+00

Note that, although it is not shown here, these tables extend to the right through 2020.

3. The Default Data

There are five types of default data stored in the Workbook: default system emission rates, data on existing generating units in the Northeast, emission factors for various clean generators, data on electricity use in the Northeast, and data on the load profiles of different energy efficiency programs and clean generators. The sources and development of these different types of default data are described in the subsections below.

3.1 The Default Emission Rates

The workbook includes default displaced rates for seven different time periods within the year. In other words, we provide, for example, an "ozone season daytime" displaced rate for assessment of programs that reduce demand or generate clean energy during those hours. The default emission rates, shown in Figures 3.1 through 3.3 below, extend from 2002 through 2020, reflecting predicted plant additions and retirements. The seven time periods for which displaced rates are provided are as follows:

1. Ozone season weekday – the average of all hourly marginal emission rates during weekdays, May through September, 7:00 am through 10:59 pm.
2. 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.
3. Non-ozone season weekday, the average of all hourly marginal emission rates during weekdays October through April, 7:00 am through 10:59 pm.
4. 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.
5. 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.)
6. 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.
7. Peak Hours – the average of the hourly marginal emission rates during the 150 highest-load hours of the year, regardless of day or time.

3.1.1 What is an Average Marginal Emission Rate?

The first thing to note about these default emission rates is that six of the seven default rates provided are *marginal* emission rates. As such, they do not reflect the operation of most of the units in the system. This is appropriate, because an energy efficiency program or new renewable generator would only affect the marginal unit (or units, depending on the number of MW displaced). Baseload units, such as nuclear and hydroelectric units, will not be affected by reductions in system demand. The "Annual Average" rate, however, is an average rate. This default rate is provided for use in assessing EPSs. Because an EPS would regulate retail suppliers' portfolio average emission rates, one must compare the EPS rate to the system average emission rate to calculate emission reductions. This is an important distinction regarding the default emission rates, and users should not use the "Annual Average" emission rates to assess energy efficiency or clean generation programs.

> *The displaced marginal Emission rates are "average marginal" emission rates.*
>
> *They are the average of all the hourly marginal emission rates during the period.*

The six marginal emission rates were calculated by comparing total system emissions from a base case modeling run and a "decrement run." First we performed a base case run, simulating plant dispatch over the entire Northeast to meet projected hourly loads during the period 2002 through 2010. (Note that all modeling runs included (Hydro Quebec, the Maritime Area and Ontario.) Next, we preformed three decrement runs, in which loads were reduced by two percent in each of the three control areas, PJM, NY ISO and ISO NE. To calculate displaced emission rates for PJM, we compared total emissions in the base case run and the decrement run in which loads were reduced in PJM. To assess the ozone season daytime period, we subtracted total emissions during these hours in the decrement run from total emissions in the base case run and divided the difference by the total MWhs "saved." (MWhs saved is simply the difference in MWh production in the two runs.)

Thus, the displaced marginal emission rates can be viewed as "average marginal" emission rates. They are the average of all the hourly marginal emission rates during the period. Importantly, when assessing base case and decrement case emissions, we factored in emissions *in all control areas simulated*, not just the control area in which we reduced loads. This is important, because load reductions (or additional generation) in one control area affects the operation of generating units in neighboring control areas, and changes in emissions in those areas are just as important as changes in the target control area. Thus, the default emission rates for New England, for example, reflect predicted changes in emissions in all control areas resulting from load reductions in New England.

3.1.2 Selecting the Right Default Emission Rate

Selecting the right default emission rate for the program you are assessing is crucial. An important point here is that the first four default rates (numbered 1 through 4 above) can be used together, while the final three should be used independently, to describe entire programs. In other words, users can spread the energy saved by an efficiency program across one, two or all four of the ozone/non ozone, day/night periods. Together, these four periods encompass all 8,760 hours in a year. For example, a user might take a baseload type energy efficiency program, and allocate the projected savings across the first four time periods. (Other default data has been included in the Workbook to help in this allocation – see Section 2.3 above.) In contrast, the "Peak Day" and "Peak Hours" emission rates should be used to describe an entire program that operates only during one of those periods. Users should not allocate program energy across, for example, the "Ozone Season Daytime" period and the "Peak Hours" period. The "Peak Hours" period

The first four default rates can be used together. Energy from a program can be allocated across these time periods.

The other three rates should be used independently, to describe entire programs.

is a subset of the "Ozone Season Daytime" period; designed to assess more accurately programs that operate only during the peak hours of the year.

As discussed above, the "Annual Average" rate should be used by itself to assess EPSs. Programs that displace generation from the grid should not be assessed using this default rate.

In Table 3.1 below, we indicate which default rates should be used for selected program types. As noted, on the "Program Pen" sheet of the Workbook, there is more detailed information to help users allocate energy across time periods.

Table 3.1: Choosing the Right Displaced Emission Rates

Energy Program	Best Displaced Emission Rate
Must-Run Renewables (e.g. wind, solar)	Allocate energy across first four default rates.
Dispatchable Generators (e.g. biomass)	Allocate energy across first four default rates.
Residential Refrigerators Subsidy	Allocate energy across first four default rates.
Residential Air Conditioner Subsidy	Allocate energy across first four default rates.
Load Management Programs	"Peak Hours" Rate
Emission Performance Standard	"Annual Average" Rate

3.1.3 How the Default Rates Were Developed

As discussed elsewhere in this manual, the default displaced emission rates within the OTC Workbook are divided into three time periods: 2002-2005; 2006-2010 and 2011-2020. (Throughout this paper these time periods are called the near term, medium term and long term, respectively.) The default rates for each of these periods were developed using different techniques.[13]

The near-term rates are based entirely on PROSYM modeling runs. We rely entirely on the model for the near term analysis, because we know the generating units that will constitute each regional power system in the near term with a relatively high level of certainty. PROSYM simulates system operation on an hourly basis, dispatching generating units each hour to meet load. The simulation is based on unit-specific information on the generating units in each of the three Northeast regions (information such as unit type and size, fuel type, heat rate curve, emission and outage rates and operating limitations). The simulation is done in chronological order, so actual constraints on system operation (such as unit ramp times and minimum up and down times) are taken into account.

In predicting emission reductions over the medium term and the long term, plant additions and retirements will play a significant role. This is because over the medium

[13] Note that users are not required to use the default displaced emission rates when evaluating programs; users may enter their own displaced emission rates.

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 the near term as well as new clean generators installed in this period. Similarly, demand forecasts made in 2011 will take into account programs implemented in the near term *and* the medium term. Some planned units will be deferred if energy efficiency has slowed load growth and new renewables have come on line, and some older plants may be retired earlier. Therefore, *at first, energy efficiency and new renewables displace energy from existing resources, but over time, they displace energy from a mix of existing resources and potential new resources – and they affect plant retirement decisions.* The different techniques we use to derive displaced emission rates in these three time periods reflect this fact. These techniques are described in the two subsections that follow.

3.1.4 The Near-Term Displaced Rates (2002-2005)

The near-term displaced rates 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.

Note that, when assessing load reductions in a given control area, we have analyzed changes in emissions across six interconnected control areas: PJM, New York ISO, ISO New England, Maritimes, Ontario and Quebec. Thus, the six sets of marginal rates take into account changes in generation in all these areas resulting from the load reductions in the target control area. In contrast, the system average rates only include emissions at generators in the target control area.

For the period 2002 through 2005, we add specific new generating units into PROSYM based on our analysis of power projects proposed and under construction in these three control areas. We retire old generating facilities based on a similar analysis of planned retirements. Unit additions and retirements for this period are shown in Appendix A of this document. These assumptions about unit additions and retirements have an important impact on the level of the displaced emission rates over this period. (This impact is discussed further in Section 3.1.3 below.) For the medium term and the long term, we do not attempt to predict the specific units that will be added and retired. We rely on a general assumption about unit additions and retirements.

Figure 3.1: The Default Displaced Emission Rates for PJM (lb/MWh)

1: PJM Default Data	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
1.A: PJM Ozone Season Weekday (lb/MWh)														
NOx:	2.2	1.9	1.8	1.8	1.7	1.6	1.4	1.2	1.0	0.8	0.8	0.8	0.8	0.8
SO2:	3.1	3.0	3.0	3.4	2.5	2.8	2.6	2.1	1.9	0.9	0.9	0.9	0.9	0.9
CO2:	1,300	1,260	1,210	1,230	1,140	1,160	1,160	1,130	1,130	1,030	1,030	1,030	1,030	1,030
Hg:	2.5E-05	2.3E-05	2.6E-05	3.0E-05	2.9E-05	3.0E-05	2.8E-05	2.5E-05	2.4E-05	2.4E-05	2.4E-05	2.4E-05	2.4E-05	1.0E+00
1.B: PJM Ozone Season Night/Weekend (lb/MWh)														
NOx:	3.5	1.8	1.8	1.7	1.4	1.2	1.1	1.0	0.9	0.8	0.8	0.8	0.8	0.8
SO2:	10.5	9.5	7.6	5.9	3.0	2.9	2.8	2.7	2.8	0.9	0.9	0.9	0.9	0.9
CO2:	1,690	1,610	1,480	1,380	1,180	1,160	1,150	1,140	1,150	1,030	1,030	1,030	1,030	1,030
Hg:	1.0E-04	9.6E-05	8.2E-05	6.5E-05	3.9E-05	3.5E-05	3.4E-05	2.8E-05	2.6E-05	2.4E-05	2.4E-05	2.4E-05	2.4E-05	2.4E-05
1.C: PJM Non-Ozone Season Weekday (lb/MWh)														
NOx:	2.1	1.8	1.5	1.3	1.2	1.0	1.0	1.0	0.9	0.8	0.8	0.8	0.8	0.8
SO2:	3.4	2.8	2.1	1.8	1.1	1.1	1.1	1.1	1.0	0.9	0.9	0.9	0.9	0.9
CO2:	1,420	1,310	1,220	1,160	1,060	1,070	1,080	1,090	1,090	1,030	1,030	1,030	1,030	1,030
Hg:	1.8E-05	1.5E-05	1.3E-05	1.1E-05	1.5E-05	1.6E-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
1.D: PJM Non-Ozone Season Night/Weekend (lb/MWh)														
NOx:	3.3	3.2	2.9	2.8	1.8	1.5	1.2	1.1	0.9	0.8	0.8	0.8	0.8	0.8
SO2:	8.9	9.0	8.5	8.0	4.3	3.9	3.3	2.9	2.6	0.9	0.9	0.9	0.9	0.9
CO2:	1,680	1,630	1,550	1,510	1,250	1,230	1,190	1,170	1,170	1,030	1,030	1,030	1,030	1,030
Hg:	8.5E-05	8.3E-05	7.8E-05	7.5E-05	4.8E-05	4.0E-05	2.9E-05	2.8E-05	2.6E-05	2.4E-05	2.4E-05	2.4E-05	2.4E-05	2.4E-05
1.E: PJM Annual Average (lb/MWh)														
NOx:	2.3	2.3	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1
SO2:	8.0	8.0	7.5	7.1	7.1	7.1	7.1	7.1	7.2	7.2	7.1	7.1	7.1	7.1
CO2:	1,180	1,180	1,150	1,130	1,140	1,140	1,150	1,150	1,170	1,170	1,170	1,170	1,170	1,170
Hg:	8.0E-05	7.9E-05	7.7E-05	7.4E-05	7.3E-05	7.3E-05	7.3E-05	7.3E-05	7.4E-05	7.4E-05	7.4E-05	7.4E-05	7.4E-05	7.4E-05
1.F: PJM Peak Day (lb/MWh)														
NOx:	4.0	4.4	4.7	4.6	3.5	3.3	3.0	2.7	2.6	2.5	2.5	2.5	2.5	2.5
SO2:	2.2	1.8	1.3	1.8	2.0	2.0	1.8	1.7	1.7	1.6	1.6	1.6	1.6	1.6
CO2:	1,500	1,370	1,230	1,240	1,370	1,450	1,450	1,490	1,480	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	0.0E+00	0.0E+00	0.0E+00	0.0E+00
1.G: PJM Peak Hours (lb/MWh)														
NOx:	3.2	3.5	3.8	4.0	3.3	3.0	2.9	2.8	2.6	2.5	2.5	2.5	2.5	2.5
SO2:	1.7	1.6	1.6	1.5	1.6	1.7	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6
CO2:	1,430	1,380	1,320	1,330	1,410	1,460	1,480	1,480	1,480	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	0.0E+00	0.0E+00	0.0E+00	0.0E+00

The default rates for the period 2016 through 2020 are the same as those in 2015.

Figure 3.2: The Default Displaced Emission Rates for New York ISO (lb/MWh)

2: NY ISO Default Data	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
2.A: NY ISO Ozone Season Weekday (lb/MWh)														
NOx:	2.1	2.0	1.8	1.7	1.1	0.9	0.9	0.8	0.7	0.6	0.6	0.6	0.6	0.6
SO2:	5.4	4.7	3.7	3.2	2.0	2.3	2.5	2.2	1.8	0.6	0.6	0.6	0.6	0.6
CO2:	1,370	1,370	1,330	1,280	1,110	1,120	1,130	1,130	1,120	970	970	970	970	970
Hg:	3.8E-05	3.2E-05	2.6E-05	2.4E-05	2.6E-05	2.9E-05	2.8E-05	2.5E-05	2.4E-05	2.4E-05	2.4E-05	2.4E-05	2.4E-05	2.4E-05
2.B: NY ISO Ozone Season Night/Weekend (lb/MWh)														
NOx:	2.8	2.5	2.0	1.7	1.1	0.9	0.7	0.7	0.6	0.6	0.6	0.6	0.6	0.6
SO2:	9.5	8.1	6.4	5.4	2.9	2.6	2.3	2.2	2.3	0.6	0.6	0.6	0.6	0.6
CO2:	1,670	1,560	1,450	1,390	1,160	1,110	1,060	1,050	1,060	970	970	970	970	970
Hg:	8.8E-05	8.0E-05	6.8E-05	6.0E-05	4.1E-05	3.4E-05	3.0E-05	2.5E-05	2.5E-05	2.4E-05	2.4E-05	2.4E-05	2.4E-05	2.4E-05
2.C: NY ISO Non-Ozone Season Weekday (lb/MWh)														
NOx:	2.1	1.7	1.5	1.4	1.6	0.8	0.8	0.7	0.6	0.6	0.6	0.6	0.6	0.6
SO2:	4.0	3.2	2.9	2.7	1.4	1.3	1.4	1.4	1.3	0.6	0.6	0.6	0.6	0.6
CO2:	1,460	1,380	1,310	1,280	1,100	1,090	1,090	1,110	1,120	970	970	970	970	970
Hg:	2.1E-05	1.6E-05	1.7E-05	2.0E-05	2.0E-05	1.9E-05	2.7E-05	2.1E-05	2.2E-05	2.4E-05	2.4E-05	2.4E-05	2.4E-05	2.4E-05
2.D: NY ISO Non-Ozone Season Night/Weekend (lb/MWh)														
NOx:	2.8	2.7	2.6	2.6	1.6	1.3	1.1	0.9	0.7	0.6	0.6	0.6	0.6	0.6
SO2:	8.5	7.9	7.8	8.1	4.2	3.8	3.5	3.3	2.9	0.6	0.6	0.6	0.6	0.6
CO2:	1,610	1,570	1,540	1,540	1,250	1,230	1,220	1,200	1,180	970	970	970	970	970
Hg:	7.4E-05	7.2E-05	7.1E-05	7.2E-05	4.7E-05	3.9E-05	2.9E-05	2.9E-05	2.6E-05	2.4E-05	2.4E-05	2.4E-05	2.4E-05	2.4E-05
2.E: NY ISO Annual Average (lb/MWh)														
NOx:	1.2	1.2	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1
SO2:	2.7	2.8	2.6	2.4	2.4	2.4	2.4	2.5	2.5	2.5	2.5	2.5	2.5	2.5
CO2:	810	830	820	800	800	810	820	830	840	840	840	840	840	840
Hg:	2.8E-05	2.9E-05	2.7E-05	2.5E-05	2.5E-05	2.5E-05	2.5E-05	2.5E-05	2.6E-05	2.6E-05	2.6E-05	2.6E-05	2.6E-05	2.6E-05
2.F: NY ISO Peak Day (lb/MWh)														
NOx:	3.1	2.8	2.6	3.3	3.2	3.1	3.0	3.0	2.7	2.5	2.5	2.5	2.5	2.5
SO2:	1.5	1.3	1.1	2.0	2.2	2.2	2.0	2.1	1.8	1.6	1.6	1.6	1.6	1.6
CO2:	1,770	1,740	1,710	1,760	1,640	1,620	1,580	1,560	1,530	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	0.0E+00	0.0E+00	0.0E+00	0.0E+00
2.G: NY ISO Peak Hours (lb/MWh)														
NOx:	2.4	2.2	1.9	2.2	2.4	2.4	2.5	2.6	2.5	2.5	2.5	2.5	2.5	2.5
SO2:	0.6	0.5	0.3	0.6	1.3	1.3	1.4	1.6	1.6	1.6	1.6	1.6	1.6	1.6
CO2:	1,590	1,610	1,640	1,660	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	0.0E+00	0.0E+00	0.0E+00	0.0E+00

The default rates for the period 2016 through 2020 are the same as those in 2015.

Figure 3.3: The Default Displaced Emission Rates for ISO New England (lb/MWh)

3: ISO NE Default Data	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
3.A: ISO NE Ozone Season Weekday (lb/MWh)														
NOx:	0.4	0.4	0.5	0.7	0.8	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7
SO2:	0.5	0.7	0.9	1.3	1.1	1.0	0.8	0.6	0.4	0.5	0.5	0.5	0.5	0.5
CO2:	900	900	920	980	1,030	1,010	980	980	980	1,040	1,040	1,040	1,040	1,040
Hg:	2.0E-06	3.0E-06	5.0E-06	9.0E-06	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
3.B: ISO NE Ozone Season Night/Weekend (lb/MWh)														
NOx:	1.2	1.1	0.8	0.6	0.6	0.5	0.5	0.6	0.7	0.7	0.7	0.7	0.7	0.7
SO2:	3.8	3.2	2.4	1.6	0.9	0.8	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5
CO2:	1,240	1,180	1,090	1,010	1,000	970	920	920	960	1,040	1,040	1,040	1,040	1,040
Hg:	4.7E-05	4.0E-05	3.0E-05	2.3E-05	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
3.C: ISO NE Non-Ozone Season Weekday (lb/MWh)														
NOx:	1.0	0.7	0.4	0.4	0.9	0.6	0.6	0.7	0.7	0.7	0.7	0.7	0.7	0.7
SO2:	1.4	1.0	0.8	0.7	0.5	0.4	0.4	0.5	0.4	0.5	0.5	0.5	0.5	0.5
CO2:	1,120	1,010	920	890	950	940	940	950	950	1,040	1,040	1,040	1,040	1,040
Hg:	4.0E-06	4.0E-06	4.0E-06	4.0E-06	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
3.D: ISO NE Non-Ozone Season Night/Weekend (lb/MWh)														
NOx:	1.7	1.4	1.1	1.1	0.9	0.8	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7
SO2:	4.0	3.8	3.3	3.0	1.6	1.3	1.1	0.9	0.7	0.5	0.5	0.5	0.5	0.5
CO2:	1,300	1,220	1,130	1,120	1,070	1,050	1,030	1,010	980	1,040	1,040	1,040	1,040	1,040
Hg:	2.7E-05	3.0E-05	2.7E-05	2.3E-05	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
3.E: ISO NE Annual Average (lb/MWh)														
NOx:	1.1	1.1	1.0	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9
SO2:	3.3	3.3	2.9	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7
CO2:	1,000	1,000	960	930	940	940	950	950	950	950	950	950	950	950
Hg:	2.8E-05	2.8E-05	3.1E-05	2.3E-05	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
3.F: ISO NE Peak Day (lb/MWh)														
NOx:	2.9	2.6	2.3	2.2	2.3	2.4	2.3	2.4	2.5	2.5	2.5	2.5	2.5	2.5
SO2:	3.2	3.4	3.6	4.1	3.1	2.9	2.3	2.1	1.9	1.6	1.6	1.6	1.6	1.6
CO2:	1,800	1,780	1,760	1,820	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	0.0E+00	0.0E+00	0.0E+00	0.0E+00
3.G: ISO NE Peak Hours (lb/MWh)														
NOx:	2.9	2.4	1.8	1.9	2.2	2.3	2.2	2.3	2.4	2.5	2.5	2.5	2.5	2.5
SO2:	2.6	3.5	4.5	4.5	3.1	2.9	2.2	1.9	1.8	1.6	1.6	1.6	1.6	1.6
CO2:	2,050	1,940	1,820	1,830	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	0.0E+00	0.0E+00	0.0E+00	0.0E+00

The default rates for the period 2016 through 2020 are the same as those in 2015.

3.1.5 The Medium-Term and Long-Term Displaced Rates (2006-2020)

Over the medium and long terms, decisions made by power plant owners and new plant developers will take into account many of the changes in the Northeast electric industry that took place during the near term. As noted, 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 displaced rates by blending the displaced rates from the existing system (derived using PROSYM) with emission rates representing new generating units and retired units. Our long-term displaced rates are based entirely on our assumption about unit additions and retirements.

Predicting plant additions and retirements over the long term is difficult, because it is not just a question of costs. Many factors – regulatory, political, economic and financial – influence the decision to build a new plant or retire an existing one, and plant developers and owners do not always behave like the rational market participants assumed in economics books. Boom and bust cycles in new plant development have become the rule in competitive power generation markets not the exception. Some of the factors, other than basic economics, that affect decisions about plant additions are the prevailing attitudes of capital markets, policies designed to support or discourage certain plant types and irrational behavior in the project development process. When it comes to retirements, key factors in the decision include: the actual operating cost of the unit, the capacity value of the unit (largely a function of ISO-specific rules) and the owner's assessment of the hedging value of keeping the plant available. These factors are discussed in greater detail in *Predicting Avoided Emissions from Policies that Encourage Energy Efficiency and Clean Power*, also an OTC report.

There are two approaches to predicting plant additions and retirements in a given regional electric system over time. One approach is to use an energy forecasting model that predicts additions and retirements based on an iterative analysis of supply, demand and price feedbacks. Another approach is to make predictions informed by close study of the existing wholesale market in the region, political and regulatory dynamics in the region and key economic and financial indicators. An advantage to using a forecasting model is that, once the input assumptions and algorithms have been set up, the model makes objective decisions, seeking the optimal future solution based on the inputs. This can lend a sense of credibility to the model's prediction that may be necessary in a policy-making setting. An important limitation of forecasting models is that their algorithms may not effectively represent the complex dynamics that affect the decisions to built new plants and retire old ones. Regulators and participants in a given regional energy market may be able to make an informed prediction that captures these complexities as well or better than a computer simulation of that market.[14]

We have not used a forecasting model to predict unit additions and retirements in the Northeast beyond 2010. Rather, long-term the displaced emission rates within the Workbook are based on the following assumptions about unit additions and retirements. The displaced emission rates for the Ozone Season Daytime, Ozone Season Night/Weekend, Non-Ozone Season Daytime and Non-Ozone Season Night/Weekend are based on the following assumption:

- 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 (2011 – 2020) displaced emission rates for the Peak Day and Peak Hours periods are based on the following assumption:

[14] These two approaches to forecasting are also discussed further in the report, *Predicting Avoided Emissions from Policies that Encourage Energy Efficiency and Clean Power*.

- 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.

As discussed above, the displaced emission rates in the Workbook 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 3.2: Weighting Factors for PROSYM Marginal Rates and New/Old Plant Rates

	2002 – 2005	2006	2007	2008	2009	2010	2011 – 2020
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

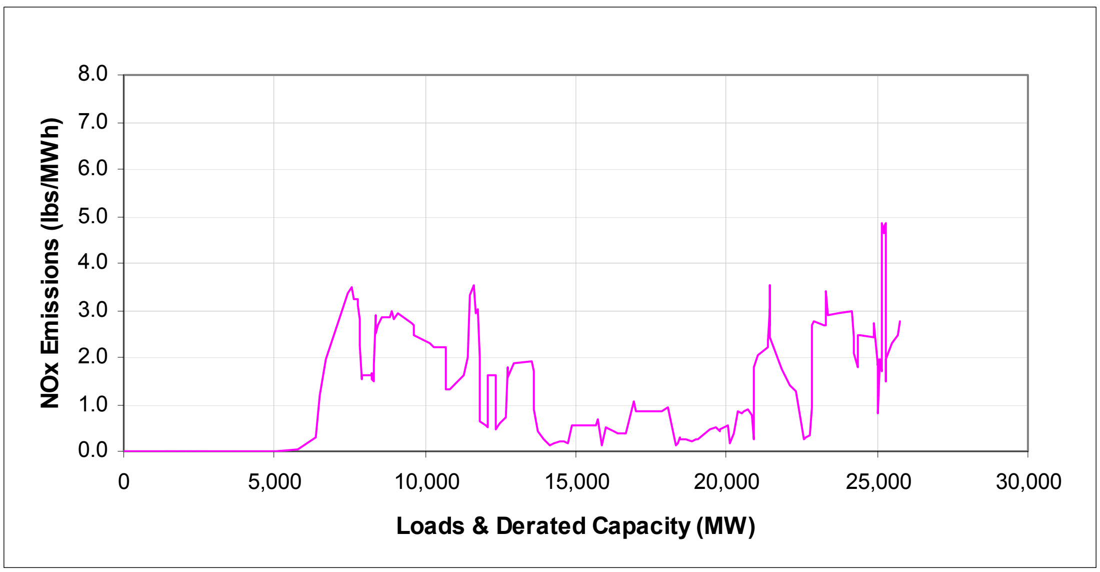
An important aspect of this methodology is that these assumptions are transparent. Users can clearly see the assumptions about unit additions and retirements on which these displaced rates are based and can alter these assumptions if they choose to. We believe this transparency is crucial, because the 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.

3.1.6 More Discussion of the Default Emission Rates

The most important thing to remember about the six marginal displaced emission rates is that they represent the average of all the marginal emission rates during the indicated time period. (In contrast, the rates labeled "average" are system average rates, including all generating units, not just the marginal unit.)

Keeping this fact in mind, note several important things regarding the displaced emission rates (shown in Figures 3.1 through 3.3). First, NO_x rates are generally higher during the night than during the day. In general, this is because during the day CCCTs and oil- or gas-fired steam units are on the margin much of the time, while at night, coal-fired units with higher NO_x rates are on the margin quite a bit. To illustrate this point, Figure 3.4 shows how the marginal NO_x rate changes along the supply curve in ISO New England. The line in Figure 3.4 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.[15] 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. By using this rolling average, we have smoothed the line somewhat but preserved its general trends.

Figure 3.4: NO_x Emission Rates Along the ISO New England Supply Curve in 2002



First, look at the shape of the NO_x supply curve. 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

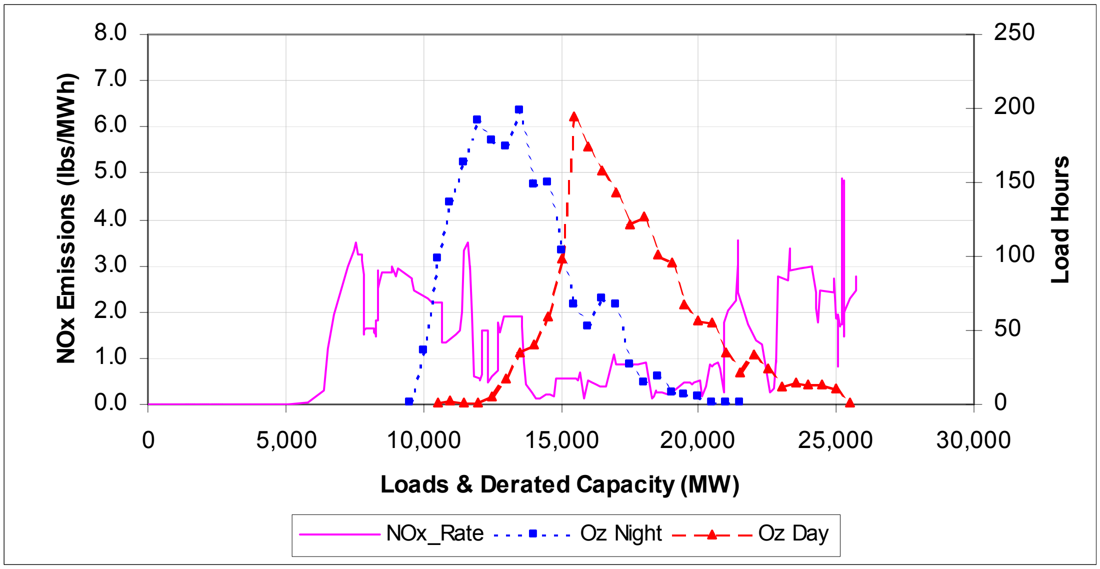
[15] All the generating units have been "derated" in Figure 3.4 to reflect the effect of outages. At any given point in time, some generators will be unavailable due to planned or unplanned maintenance. Thus, the regional system has less capacity in reality than it does on paper, where all units are assumed to be available. To shift the supply curve to a position closer to actual, we list units here at 90 percent of their reported capacity – a process called derating.

much higher NO_x rates. The area between about 17,000 and roughly 25,000 MW is dominated by relatively new 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. (The NO_x emission rates along the New York and PJM supply curves follow a very similar shape, except that the rates tend to be higher in New York and higher still in PJM. Figures 3.6 through 3.8 below compare the NO_x and SO_2 curves for each of these three control areas.) Looking at Figure 3.4, 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 3.5 shows the same graph of 2002 NO_x rates in ISO New England with curves added showing the distribution of loads. Here, the curves marked by triangles and squares are histograms showing the distribution of predicted hourly load levels in New England during the ozone season weekday period (triangles) and the ozone season night/weekend period (squares). The higher the curve is above the horizontal axis, the more hours during the period that the regional load was at that level. For example, the top of the weekday (triangle) histogram indicates that the peak hourly load is expected to be roughly 15,500 MW for about 195 ozone season weekday hours in 2002. (The number of hours associated with each histogram point is shown on the right-hand vertical axis.) The long "tail" on the right side of this histogram indicates that loads are expected to reach very high levels during ozone season weekdays in New England, but they are expected to do so for a very small number of hours.

Because generating unit capacities have been derated to develop Figure 3.5 and loads have been projected from 2001 loads, this should not be treated as a highly precise representation of these interactions. However, the level of precision is more than adequate to support the key points being illustrated: 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. The same patterns can be seen in the default displaced emission rates (shown in Figure 3.3), because they are based on the same data sets. The marginal NO_x rate for the ozone season is 0.4 lb/MWh, and the rate for the night/weekend period is 1.2 lb/MWh. The marginal NO_x rate for the "Peak Day" and "Peak Hours" periods are higher still, both at about 2.9 lb/MWh.

Figure 3.5: ISO New England NO_x Curves and Distribution of Loads



The policy implications of Figure 3.5 are significant. If the goal is to use energy efficiency programs, for example, to reduce NO_x emissions, then programs should be selected that reduce demand during the lowest load hours of the night/weekend period and the highest load hours of the daytime period.

Figures 3.6 through 3.8 compare the NO_x and SO_2 curves for PJM, NY ISO and ISO NE. Note that the emissions curves for the different control areas are different in some ways but all follow 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 a much larger region of baseload fossil units – with higher NO_x and SO_2 rates than do New York and New England. These graphs were constructed in the same way as Figure 3.4 using data on the generating units in the other two control areas.

Figure 3.6: Comparison of PJM NO_x and SO_2 Emission Rates

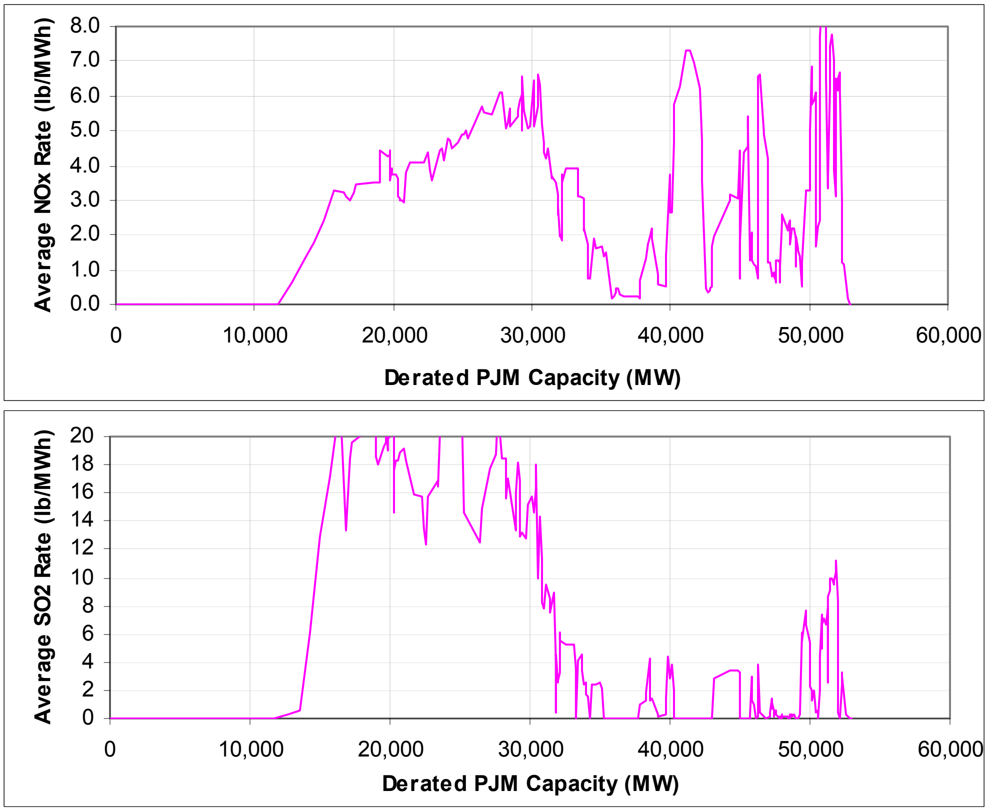


Figure 3.7: Comparison of New York NO_x and SO_2 Emission Rates

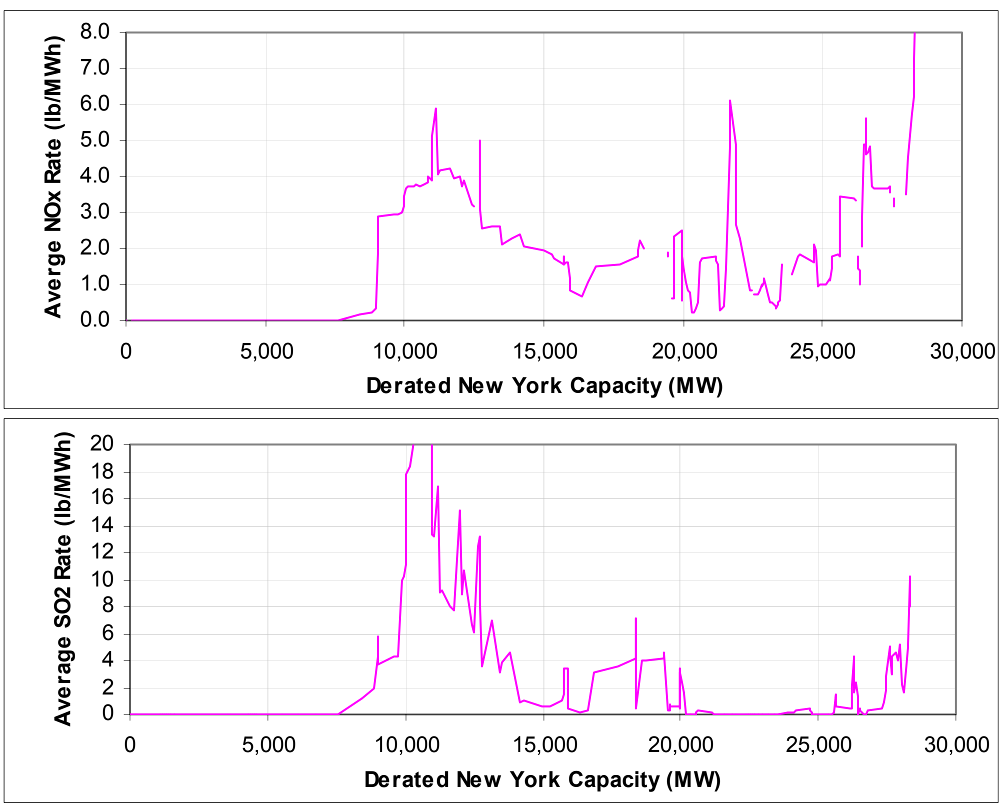
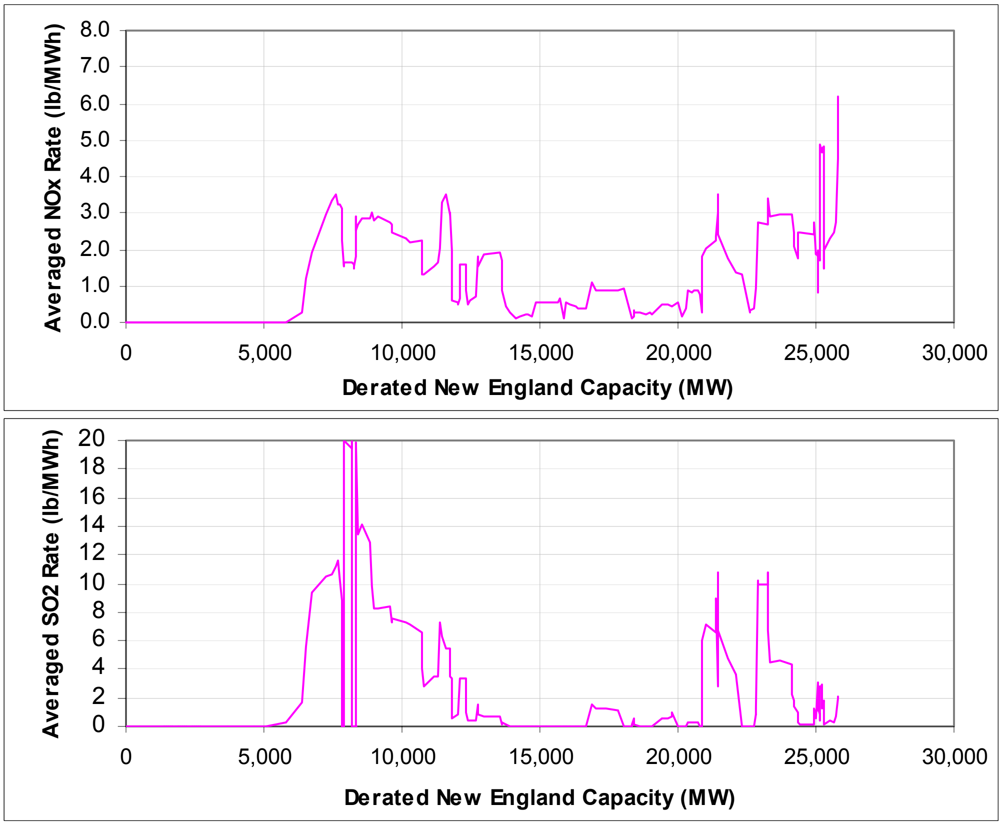


Figure 3.8: Comparison of New England NO_x and SO_2 Emission Rates



Returning to Figures 3.1 through 3.3, note also that in all control areas, NO_x rates fall rather quickly from their 2002 levels by the year 2005. 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. System average rates in New York and PJM stay near the SIP Call rates for most of the rest of the period. No other future environmental regulations are reflected in the displaced emission rates.

In addition, note that the displaced rates for both NO_x and SO_2 fall over the study period to levels that are quite similar across all three control areas in the period 2011 through 2020. This is a result of our transition from current actual rates (predicted by PROSYM) in the near term to long-term rates, which are based entirely on the assumption discussed above about plant additions and retirements. (The long-term assumption is the same for all three control areas).

In the near term and the medium term, the displaced rates change from year to year due to the interaction of two factors: load growth and plant additions and retirements. As electricity loads grow over time, if there were no new plants added, marginal NO_x and CO_2 rates would rise, as peaking turbines were operated more (and, of course, ultimately the system would fail to meet the load). So growing loads tend to exert an upward influence on marginal emissions over time. This influence is most pronounced on NO_x and CO_2 emissions, because peaking turbines have much higher NO_x and CO_2 rates than the fossil-fueled steam units just below them in the dispatch order. In contrast, plant additions and retirements exert a downward influence on marginal emission rates over time, as older, dirty units are replaced by new, cleaner ones. The interaction of these two dynamics causes marginal emission rates to move up and down year to year on a generally downward sloping trajectory.

To visualize the interaction between plant additions and load growth, return to Figure 3.5 above. As new plants are added – primarily CCCTs – envision the supply curve growing primarily by stretching in the low-NO_x "valley" in the middle of the curve. Load growth on this graph would appear as a slow, steady movement to the right of both load histograms. During a burst of capacity expansion, the low-NO_x "valley" in the middle of the curve would expand much faster than load growth, and much more of the daytime (triangle) load curve would fall in that valley. The daytime marginal NO_x rate would fall. Over time, as loads caught up to capacity expansion, more and more of the daytime hours would fall in the higher NO_x region of the curve, and the daytime marginal NO_x rate would rise again.

In fact, all three northeastern control areas are currently experiencing capacity expansion "booms," which will expand capacity margins. During the period 1999 through 2004 large amounts of new CCCT capacity are coming on line in each region. After about 2004, this building activity is expected to slow, and capacity margins to begin shrinking again.

3.2 Default Data on Existing Generating Units

In order to assess emission reductions from future multi-pollutant regulations users need information about the current emission rates and utilization of fossil-fueled plants in the region. We provide information on 178 fossil-fueled generating units in the OTR (see the "Multi-P Data" sheet). For each unit, we provide projected SO_2, NO_x, CO_2 and mercury emission rates for the years 2002 through 2020. The SO_2, NO_x and CO_2 rates are taken from EPA's Acid Rain database, 2000. The year 2000 NO_x rates from EPA's database are used for the 2002 rates on the "Multi-P Data" sheet. In 2003, the NO_x rates of all units go down to reflect compliance with the NO_x SIP Call rule. (None of the other emission rates reflect future regulations.) To represent seasonal compliance with the SIP Call, the following equation was used to calculate the post SIP Call NO_x rate for each unit:

$$(\text{Base Rate} * 7/12) + (0.15 \text{ lb/mmBtu} * 5/12)$$

Here, the "base rate" is the NO_x rate from the 2000 Acid Rain Database.

These default emission rates also reflect the implementation of Massachusetts and New Hampshire regulations affecting certain existing fossil-fueled boilers. The Massachusetts regulation is at 310 CMR 7.29, and the New Hampshire regulation is the "Clean Power Act," (House Bill 284) passed in 2002. As with the SIP Call, we have shown the "compliance emission rate" in the default data, regardless of whether compliance is expected via a rate reduction or via allowance or offset purchases.

The mercury emission rates for the coal-fired units in the default data have been replaced with rates developed using the 1999 stack tests performed for EPA's Information Collection Request (ICR). The new mercury rates are based on actual stack test data from the generating unit where stack test data are available. For units at which stack tests were not performed (most of the units on the list), we have used proxy emission rates developed from the ICR stack tests. To develop proxies, we first calculated the average results of the stack tests performed for each "coal-boiler-control" category established by EPA. Post-control emission rates in lb/mmBtu were taken from the actual stack test reports submitted by companies to EPA as part of the ICR. Next we placed the generating units on the multi-P default list (at which stack tests were not performed) into the same coal-boiler-control categories as those used in the ICR. Finally, we applied the appropriate category average mercury emission rate from the ICR to each unit.

For nineteen of the units on the new "Multi-P Data" sheet, stack test data have not been published and there is no corresponding coal-boiler-control category from the 1999 ICR stack tests. (In others words, EPA did not test any units exactly like the unit on the multi-P list.) Data from units or coal-boiler-control categories judged to be similar were used for these units.

For all pollutants, the lb/mmBtu emission rates from the Acid Rain Database or ICR stack tests were converted to output-based rates (lb/MWh) using unit-specific heat rates. These heat rates are shown in column DV of the new "Multi-P Data" worksheet.

We also provide capacity factors (utilization rates) for the units on the "Multi-P Data" sheet. These capacity factors are for the years 2002 through 2020. The factors for 2002 through 2010 are taken from the outputs of the base case PROSYM run used in calculating default emission factors. The capacity factors for the period 2011 through 2020 are reduced from the 2010 factor by two percent pear year.

3.3 Data on Clean Generators

Users assessing policies that incentivize new clean generation will need to make an assumption about what type of new clean units will result from the policy. For example, a user assessing an RPS will need to calculate a weighted average emission factor for the renewable generation meeting the RPS. To help users do this, we provide a table with default emission rates from clean generators (Table 2 on the "Program Rates" sheet).

The emission rates for landfill gas in this table are zero, based on the assumption that landfills large enough to contemplate electricity generation are currently required to capture and flare waste gases. So the baseline emission rates from these facilities are those of landfill gas burned in an open flare, and electricity generation is assumed to have no net emissions. More research is needed to test the validity of these assumptions and to compare the actual emissions from landfill gas generators with open flares.

Fuel cell emission rates are taken from literature from ONSI Corporation on emissions from the PC-25, a phosphoric acid fuel cell with an external fuel reformer. Microturbine emissions are based on information from Capstone Corporation about the Capstone C60 microturbine (operating on natural gas).

Emissions from existing biomass units assume combustion in a traditional steam boiler (not fluidized bed or gasified biomass) with NO_x controls. Unit heat rate is assumed to be 10,000 Btu/kWh. The biomass fuel is assumed to be grown in a carbon-neutral cycle, as is required by most RPSs. NO_x and SO_2 emissions from existing biomass are from *Powering the Midwest, Renewable Electricity for the Economy and the Environment*, a 1993 report of the Union of Concerned Scientists, and U.S. EPA's, *AP-42 Compilation of Air Pollutant Emission Factors*, Volume 1, 1996. We provide a row in Table 3 for the users of the Workbook to enter biomass emission limits specific to a particular RPS. The user can either assume that all biomass in the RPS meets the standard or only new biomass, using the rows for "existing" and "new" biomass in Table 3.

3.4 Data on Future Electricity Use

Data in future electricity use (2002 through 2020) is provided on the "Electricity Use" sheet for the evaluation of EPSs. The 2002 data is based on year 2000 electricity sales data from the U.S. Energy Information Administration (EIA). We have increased year 2000 electricity sales by 1.5 percent each year to derive energy use numbers for the 2002 – 2020 period. We also provide a Table (Table 2 on the "Electricity Use" sheet in which users can calculate future energy use using their own assumption about load growth.

3.5 Program and Technology Load Shapes

Default load profiles are provided for baseload generators and wind and solar generators. These profiles allocate the generation from these resource types into the first four time periods (shown in Figures 3.1, 3.2 and 3.3) for assessment with the default emission factors. The Workbook also includes load profiles for 16 energy efficiency program types.

The default load profile data for wind generation is based on actual generation data from a windfarm in Chandler, Minnesota. Ideally, this Workbook should have wind load profile based on a facility in the Northeast, however publicly available data from a Northeast site could not be found. There may not be a large difference in the distribution of wind energy across seasons between Minnesota and the Northeast, and this would make the Chandler data a fairly good approximation of the distribution of the Northeast wind resource. Future work on the Workbook could explore this question and continue to seek a set of hourly data from a Northeast wind site.

The default load profile data for solar generation was developed by Synapse Energy Economics using "typical meteorological year" insolation data from a location near the center of the Northeast. Typical meteorological year data are publicly available from the PV program at Sandia National Laboratory.

The default load profiles for energy efficiency programs are based on proprietary hourly data sets for each of the 18 technologies that have tables on the "Program Pen" sheet. Synapse Energy Economics reviewed these data sets and developed the tables on the "Program Pen" sheet. These are the only data in the Workbook that are not publicly available. The default load profiles for energy efficiency programs are shown in Table 3.3, below.

Table 3.3: Default Load Shapes for Energy Efficiency

Target End Use	Ozone Day	Ozone Night/ Weekend	Non-Ozone Day	Non-Ozone Night/ Weekend
Residential Appliances				
Energy Star Refrigerator	21%	22%	28%	29%
Energy Star Dishwasher	20%	22%	28%	31%
Energy Star Clotheswasher	24%	13%	42%	21%
Energy Star Residential Air Conditioner	65%	35%	0%	0%
Continuous Running Equip.	19%	21%	30%	29%
Residential Lighting				
Compact Fluorescents	22%	15%	37%	26%
RC Fluorescent Fixture	22%	15%	37%	26%
Torchiere	22%	15%	37%	26%
Fixtures Other	22%	15%	37%	26%
Commercial				
Commercial Lighting — New	26%	16%	36%	22%
Commercial Chillers — New and Retrofit	45%	39%	7%	9%
Commercial Large Motors — New and Retrofit	25%	16%	36%	23%
Commercial VSDs — New and Retrofit	22%	10%	47%	21%
Commercial Comprehensive New Construction Design	24%	19%	25%	32%
Industrial				
Industrial Lighting — New and Retrofit	26%	16%	36%	22%
Industrial Unitary HVAC	45%	39%	7%	9%
Industrial Chillers — New and Retrofit	45%	39%	7%	9%
Industrial Motors — New and Retrofit	35%	4%	56%	5%
Industrial VSDs — New and Retrofit	35%	4%	56%	5%
C&I Gas Absorption Chiller — New or Replacement	45%	39%	7%	9%

4. Strengths, Limitations and Recommended Work

The OTC Emission Reduction Workbook is intended to facilitate estimation of the emission impacts of (1) programs that support energy efficiency and clean generation, (2) EPSs, and (3) multi-pollutant standards applied to existing electric generating units. The workbook is designed to be transparent, meaning all input assumptions associated with a calculation are clearly stated.

The default data on displaced emission rates contained within the Workbook were developed using the PROSYM system dispatch software. These emission rates are based on clearly stated assumptions about the evolution of the three northeastern power pools. These assumptions are:

- Proposals for new generating units through 2005 have been reviewed, and selected units that appear likely to be completed are assumed to be built.
- After 2005, we add new combined-cycle combustion turbines (gas-fired) and retire older oil- and oil/gas-fired steam units.
- We assume that new capacity is added and older capacity retired at a ratio of 3:1. That is, for every 750 MW of new combined-cycle capacity added, 250 MW of old, steam capacity is retired.
- During the period 2002 – 2005, the displaced emission rates are from PROSYM calculations. During 2011 – 2020, the displaced emission rates are the weighted

average of unit additions and retirement. During 2006 – 2010, the displaced rates move linearly from the 2005 rates to the 2011 rates.

We believe that this is a reasonable forecast of the evolution of the northeastern power pools. However, we encourage work to test and refine this forecast, to explore other scenarios and the sensitivities of these systems to different input assumptions. Users are encouraged to develop their own assumptions about displaced emissions and explore them with the Workbook.

Specific strengths of this methodology are:

- The default rates were developed through system modeling with an hourly, chronological dispatch model including unit-specific information on generating units and detailed data on power flows and transmission constraints within and between ISOs.
- The default emission rates for programs in one region take into account emission changes in neighboring regions.
- All assumptions on which a calculation is based are clearly defined.
- Input assumptions are not "hard wired" into the Workbook; users can change assumptions to explore other scenarios.

Specific limitations of the Workbook that users should keep in mind include the following:

- Predictions of long-term avoided emissions using the Workbook are highly sensitive to the assumption stated above about unit additions and retirements.
- Only one level of load reduction (2 percent of system load) had been assessed to develop the displaced emission factors. Larger or smaller load reductions may lead to different emissions impacts.
- The annual operation of efficiency programs and clean generation must be fit into either four annual time periods or one (Peak Day or Peak Hours) period. More work needs to be done to assess how much this limitation affects projections of avoided emissions.
- Location-specific factors within a northeastern region (such as the solar or wind resource at a given site) are not accounted for.

Ways in which the Workbook could be made more versatile and useful are as follows:

- The Workbook could provide an area where users could alter the default assumptions about unit additions and retirements to aid them in assessing different future scenarios. In the current version of the Workbook, users must do this calculation themselves and input the resulting displaced emission rates as custom data.
- Research on the probable mix of unit additions and retirements in the Northeast would be very useful. This research could take the form of statistical analyses, discussions with key industry players and scenario exploration with a forecasting model.

- More specific load-profile data could be added. For example, the load profile of wind generation or PV output at specific locations in the Northeast could be added as default data.
- PROSYM runs using hourly data for an energy efficiency program or renewable generators could be performed and compared to the predictions using the four time periods in the Workbook (or the single peak period) to determine the impact of these four time periods on results.
- If the Workbook is widely used, it may be desirable to move it out of Microsoft Excel into a different software. Some common processes could be automated and the entire Workbook could be write protected. In its current form, certain sections of the Workbook cannot be locked for editing.

Appendix A. Additions and Retirements Assumed in PROSYM Runs

Unit Additions

Unit Name	No	Utility Code	UnitType	OnLine	OffLine	Trans Area
Athens	1a	3020	CC	08/01/03	08/01/58	NY-F G
Athens	1b	3020	CC	08/01/03	08/01/58	NY-F G
Athens	1c	3020	CC	08/01/03	08/01/58	NY-F G
Bayswater Peaker	1	1289712916	GT	05/01/02	05/01/57	NY-J K
Bayswater Peaker	2	1289712916	GT	05/01/02	05/01/57	NY-J K
Bellingham	1a	1744092483	CC	03/01/02	01/01/56	NE-SOUTH
Bellingham	1b	1744092483	CC	03/01/02	01/01/56	NE-SOUTH
Bellingham	1c	1744092483	CC	03/01/02	01/01/56	NE-SOUTH
Bergen CC	2	3001	CC	06/15/02	01/02/57	PJM-East
Fairless Works Energ	2a	610724894	CC	06/01/04	06/01/59	PJM-East
Fairless Works Energ	2b	610724894	CC	06/01/04	06/01/59	PJM-East
Fairless Works Energ	1a	610724894	CC	12/01/03	12/01/58	PJM-East
Fairless Works Energ	1b	610724894	CC	12/01/03	12/01/58	PJM-East
Fore River CC	1a	181598784	CC	04/01/02	01/01/57	NE-SOUTH
Fore River CC	1b	181598784	CC	04/01/02	01/01/57	NE-SOUTH
Fore River CC	1c	181598784	CC	04/01/02	01/01/57	NE-SOUTH
Fore River CC	1d	181598784	CC	04/01/02	01/01/57	NE-SOUTH
Granite Ridge	1a	103101	CC	05/19/02	01/02/57	NE-NC
Granite Ridge	1b	103101	CC	05/19/02	01/02/57	NE-NC
Granite Ridge	1c	103101	CC	05/19/02	01/02/57	NE-NC
Hay Road CC Exp	1a	3008	CC	06/01/02	01/02/57	PJM-East
Hay Road CC Exp	1b	3008	CC	06/01/02	01/02/57	PJM-East
Hay Road CC Exp	1c	3008	CC	06/01/02	01/02/57	PJM-East
Hazelton	2	486183406	GT	02/01/02	12/10/56	PJM-West
Hazelton	3	486183406	GT	02/01/02	12/10/56	PJM-West
Hazelton	4	486183406	GT	02/01/02	12/10/56	PJM-West
Hunterstown CC	1	1725001269	CC	06/01/03	06/01/58	PJM-West
Hunterstown CC	2	1725001269	CC	06/01/03	06/01/58	PJM-West
Hunterstown CC	3	1725001269	CC	06/01/03	06/01/58	PJM-West
Johnston (RI)	1a	1289712916	CC	11/01/02	01/02/57	NE-SOUTH
Johnston (RI)	1b	1289712916	CC	11/01/02	01/02/57	NE-SOUTH
Kendall Expansion	1	15811729	CC	06/01/02	01/02/57	NE-SOUTH
Lake Road	2a	3020	CC	04/15/02	04/15/57	NE-SOUTH
Lake Road	2b	3020	CC	04/15/02	04/15/57	NE-SOUTH
Lake Road	3a	3020	CC	04/15/02	04/15/57	NE-SOUTH
Lake Road	3b	3020	CC	04/15/02	04/15/57	NE-SOUTH
Lake Road	1a	3020	CC	01/12/02	01/12/57	NE-SOUTH
Lake Road	1b	3020	CC	01/12/02	01/12/57	NE-SOUTH

Appendix A (continued)

Unit Additions						
Unit Name	No	Utility Code	UnitType	OnLine	OffLine	Trans Area
Liberty Electric	1a	107114	CC	02/01/02	01/01/57	PJM-East
Liberty Electric	1b	107114	CC	02/01/02	01/01/57	PJM-East
Linden repower	2a	3001	CC	05/01/03	05/01/58	PJM-East
Linden repower	2b	3001	CC	05/01/03	05/01/58	PJM-East
Linden repower	1a	3001	CC	04/01/03	04/01/58	PJM-East
Linden repower	1b	3001	CC	04/01/03	04/01/58	PJM-East
Meridan	1a	3100	CC	06/01/03	06/01/58	NE-SOUTH
Meridan	1b	3100	CC	06/01/03	06/01/58	NE-SOUTH
Milford EPE	1a	108137	CC	08/15/02	01/01/56	NE-SOUTH
Milford EPE	1b	108137	CC	03/15/02	01/01/56	NE-SOUTH
Mount Bethel Project	1a	3003	CC	09/01/03	09/01/58	PJM-West
Mount Bethel Project	1b	3003	CC	09/01/03	09/01/58	PJM-West
Mystic CC	1	181598784	CC	04/15/02	01/01/57	NE-SOUTH
Mystic CC	2	181598784	CC	04/15/02	01/01/57	NE-SOUTH
Mystic CC	3	181598784	CC	04/15/02	01/01/57	NE-SOUTH
Mystic CC	4	181598784	CC	04/15/02	01/01/57	NE-SOUTH
n_Atlantic	1	181598784	CC	06/01/02	01/01/57	PJM-East
n_Bethlehem	1	3001	CC	08/01/04	01/01/47	NY-F G
n_Bowline_U3	1	7045	ST	06/01/04	01/01/44	NY-F G
n_Brookhaven	1	3001	CC	01/01/04	01/01/57	NY-CDE
n_Cabot	1	9012	CG	01/01/04	01/02/57	NE-SOUTH
n_Canal	1	7045	CC	01/01/03	01/02/57	NE-SOUTH
n_Chichester	1	3011	CT	06/01/02	01/01/44	PJM-West
n_Colora	2	3004	CT	05/01/03	01/01/44	PJM-West
n_Colora	1	3004	CT	05/01/02	01/01/44	PJM-West
n_Dickerson	1	3006	CT	05/01/04	01/01/44	PJM-West
n_Eagle	1	3009	CT	06/01/02	01/01/44	PJM-East
n_East River	1	9035	CC	09/01/04	01/01/57	NY-J K
n_Eddystone	1	3002	CT	06/01/02	01/01/44	PJM-East
n_Edgar	1	181598784	CC	05/01/02	01/02/57	NE-SOUTH
n_Erie West	1	181598784	CC	06/01/02	01/01/57	PJM-West
n_Heritage	1	181598784	CC	09/01/05	01/01/47	NY-CDE
n_Hosensack	2	3009	CT	01/01/03	01/01/44	PJM-East
n_Hosensack	1	3009	CT	01/01/02	01/01/44	PJM-East
n_Kearny	1	3001	CT	01/01/04	01/01/44	PJM-East
n_Lakewood	1	3009	CT	04/01/03	01/01/44	PJM-East
n_Londonberry	1	103101	CG	06/01/02	10/01/57	NE-NC
n_Medway	1	181598784	CT	01/01/04	01/02/57	NE-SOUTH
n_Mickleton	1	3007	CT	06/01/02	01/01/44	PJM-East

Appendix A (continued)

Unit Additions						
Unit Name	No	Utility Code	UnitType	OnLine	OffLine	Trans Area
n_Orion	1	512079618	CC	01/01/05	01/01/57	NY-J K
n_Passyunck	1	3002	GT	01/01/02	01/01/44	PJM-East
n_Peaker	1	9039	GT	01/01/04	06/21/56	NY-J K
n_Peaker	2	9039	GT	01/01/04	06/21/56	NY-J K
n_Peaker	3	9039	GT	01/01/04	06/21/56	NY-J K
n_Peaker	4	9039	GT	01/01/04	06/21/56	NY-J K
n_Peaker	5	9039	GT	01/01/04	06/21/56	NY-J K
n_Peaker	6	9039	GT	01/01/04	06/21/56	NY-J K
n_Peaker	7	9039	GT	01/01/04	06/21/56	NY-J K
n_Peaker	8	9039	GT	01/01/04	06/21/56	NY-J K
n_Peaker	9	9039	GT	01/01/04	06/21/56	NY-J K
n_Ramapo	1	1744092483	CC	06/01/04	01/01/47	NY-F G
n_Ravenswood	2	1285649679	CC	01/01/05	01/01/57	NY-J K
n_Ravenswood	1	1285649679	CC	08/01/03	01/01/57	NY-J K
n_Sewaren	1	3001	CT	01/01/05	01/01/44	PJM-East
n_Smithfield	1	2108060246	CC	01/01/04	01/02/57	NE-SOUTH
n_Susquehanna	1	3003	CT	01/01/02	01/01/44	PJM-West
n_Towanda	1	3010	CT	06/01/02	01/01/44	PJM-West
n_Towantic	1	229	CC	06/01/03	01/02/57	NE-SOUTH
n_Wawayanda	1	229	CC	01/01/04	01/01/57	NY-F G
Newington CC	1a	9035	CC	08/01/02	08/01/57	NE-NC
Newington CC	1b	9035	CC	08/01/02	08/01/57	NE-NC
Ontelaunee	1a	229	CC	05/01/02	01/02/57	PJM-West
Ontelaunee	1b	229	CC	05/01/02	01/02/57	PJM-West
PV_NY	1	1285649679	PV	01/01/04	12/31/11	NY-J K
Red Oak	1a	103101	CC	03/01/02	01/01/57	PJM-West
Red Oak	1b	103101	CC	03/01/02	01/01/57	PJM-West
Red Oak	1c	103101	CC	03/01/02	01/01/57	PJM-West
Red Oak	1d	103101	CC	03/01/02	01/01/57	PJM-West
SEFCO	1	2145374275	CG	07/01/02	07/01/57	NY-J K
SEFCO	2	2145374275	CG	07/01/02	07/01/57	NY-J K
Seward Coal RPW	1	8004	ST	05/01/04	05/01/59	PJM-West
Wallingford	5	3003	GT	02/01/02	08/15/56	NE-SOUTH
Wallingford	3	3003	GT	01/14/02	08/15/56	NE-SOUTH
Wallingford	4	3003	GT	01/14/02	08/15/56	NE-SOUTH
Wallingford	1	3003	GT	01/07/02	08/15/56	NE-SOUTH
Wallingford	2	3003	GT	01/07/02	08/15/56	NE-SOUTH

Appendix A (continued)

Unit Retirements

Unit Name	No	Utility Code	UnitType	OnLine	OffLine	Trans Area
Bar Harbor	1-4	9002	IC	01/01/60	01/01/02	NE-MAINE
Essex Dsl	1	9032	IC	01/01/47	01/01/02	NE-NC
CABOT	9	9012	ST	01/01/41	01/01/02	NE-SOUTH
So Norwalk Dsl 1-6	1	9008	IC	01/01/40	01/01/02	NE-SOUTH
Bethlehem Steel NUG	IPP	1980168286	ST	07/01/35	01/01/02	PJM-West
Hay Road Expansion	3	3008	GT	08/30/01	03/15/02	PJM-East
Hay Road Expansion	2	3008	GT	07/30/01	03/15/02	PJM-East
Hay Road Expansion	1	3008	GT	06/30/01	03/15/02	PJM-East
PERC-Orrington	1	9002	ST	01/01/88	12/31/02	NE-MAINE
Sewaren	1	3001	ST	12/01/48	01/01/03	PJM-East
Sewaren	2	3001	ST	11/01/48	01/01/03	PJM-East
Eastport Dsl IC	1-3	9002	IC	01/01/48	01/01/03	NE-MAINE
Linden	1	3001	ST	05/01/57	04/01/03	PJM-East
Linden	3	3001	GT	07/01/67	05/01/03	PJM-East
Linden	2	3001	ST	12/01/57	05/01/03	PJM-East
Warren	2	1725001269	ST	09/01/48	09/01/03	PJM-West
Seward	5	1725001269	ST	04/01/57	10/01/03	PJM-West
Seward	4	1725001269	ST	06/01/50	10/01/03	PJM-West
Caterpillar Tract	1	1482183565	OT	07/01/89	12/31/03	PJM-West
Riegel Paper	1	3009	OT	07/01/89	01/01/04	PJM-East
Hunlock	3	3013	ST	09/01/59	01/01/04	PJM-West
Sewaren	3	3001	ST	10/01/49	01/01/04	PJM-East
Waterside	9	9035	ST	10/01/49	01/01/04	NY-J K
Waterside	8	9035	ST	06/01/49	01/01/04	NY-J K
CABOT	6	9012	ST	01/01/49	01/01/04	NE-SOUTH
CABOT	8	9012	ST	01/01/49	01/01/04	NE-SOUTH
Astoria ST	4	512079618	ST	03/01/61	01/01/05	NY-J K
Astoria ST	3	512079618	ST	09/01/58	01/01/05	NY-J K
St. Albans 1-2	1	9032	IC	01/01/50	01/01/05	NE-NC
Danskammer	1	1127034565	ST	12/01/51	01/01/06	NY-F G
East River	6	9035	ST	11/01/51	01/01/06	NY-J K
Riverside BG&E	4	1312696120	ST	09/01/51	01/01/06	PJM-West
Sewaren	4	3001	ST	07/01/51	01/01/06	PJM-East
Albany	2	3001	ST	12/01/52	01/01/07	NY-F G
Glenwood	4	9038	ST	12/01/52	01/01/07	NY-J K
Howard Down	7	3007	ST	12/01/52	01/01/07	PJM-East
Albany	1	3001	ST	10/01/52	01/01/07	NY-F G
Mason Steam	5	1289712916	ST	01/01/55	12/31/07	NE-MAINE

Appendix A (continued)

Unit Retirements

Unit Name	No	Utility Code	UnitType	OnLine	OffLine	Trans Area
Mason Steam	3	1289712916	ST	01/01/52	12/31/07	NE-MAINE
Mason Steam	4	1289712916	ST	01/01/52	12/31/07	NE-MAINE
Far Rockaway	4	9038	ST	12/01/53	01/01/08	NY-J K
Albany	3	3001	ST	10/01/53	01/01/08	NY-F G
Delaware	7	313140452	ST	08/01/53	01/01/08	PJM-East
Delaware	8	313140452	ST	04/01/53	01/01/08	PJM-East
Edge Moor	3	3008	ST	12/01/54	01/01/09	PJM-East
Glenwood	5	9038	ST	11/01/54	01/01/09	NY-J K
Albany	4	3001	ST	10/01/54	01/01/09	NY-F G
Danskammer	2	1127034565	ST	09/01/54	01/01/09	NY-F G
Montville	5	3100	ST	01/01/54	01/01/09	NE-SOUTH
Rockville Centre	10	2022699621	IC	09/01/54	09/01/09	NY-J K
Rockville Centre	9	2022699621	IC	09/01/54	09/01/09	NY-J K
Oyster Creek	1	86743107	NB	12/01/69	12/15/09	PJM-East
Astoria ST	5	512079618	ST	05/01/62	01/01/10	NY-J K
Burlington MAAC	9	3001	GT	11/01/55	01/01/10	PJM-East
Howard Down	8	3007	ST	10/01/55	01/01/10	PJM-East
Cromby	2	313140452	ST	09/01/55	01/01/10	PJM-East
East River	7	9035	ST	06/01/55	01/01/10	NY-J K
Lovett	3	15811729	ST	02/01/55	01/01/10	NY-F G
Sayreville	4	1725001269	ST	04/01/55	04/01/10	PJM-East