2008 New England Electric Generator Air Emissions Report

System Planning Department
ISO New England Inc.

August 2010

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1. Executive Summary

Since 1993, ISO New England Inc. (ISO-NE) has analyzed annually the marginal emission rates of the New England generation system. This was motivated by the need to determine the emission reductions that demand-side management (DSM) programs have had upon New England's aggregate NO_X, SO_2, and CO_2 generating unit air emissions. The use of these rates was subsequently broadened to include the benefits of energy efficiency programs and renewable resource projects in the region. The marginal emission rates for NO_X, SO_2 and CO_2 were reported in the annual Marginal Emission Rate Analysis (MEA Report). This 2008 New England Electric Generator Air Emissions Report ("Emissions Report") is based on the previous MEA Reports, but has been restructured to place more of an emphasis on emissions produced by the entire New England electric generation system operated by ISO-NE while still reporting marginal emission rates. Accordingly, it provides estimates of the annual system NO_X, SO_2, and CO_2 generator air emissions during the calendar year 2008 as well as marginal emission rates. The results of the 2008 system emissions calculations are shown in Table 1.1 in pounds per megawatt-hour (lb/MWh) and in kTons.

Table 1.1: 2008 Calculated New England Annual System Emissions

	Annual System Emissions	
	Emission Rate (lb/MWh)	Total Emissions (kTons)
NO_X	0.52	32.57
SO_2	1.51	94.18
CO_2	890	55,427

Marginal emission rates are calculated using the energy-weighted average emission rates of generating units that would typically increase their output if regional energy demands were higher during the time periods of interest. The marginal units are considered to be those that are fueled with oil (including residual, distillate, diesel, kerosene, and jet fuel), and/or natural gas[1].

The results of the 2008 marginal emission rate calculation are shown in Table 1.2 in pounds per megawatt-hour (lb/MWh) and Table 1.3 in pounds per million British thermal units (lb/MBtu)[2].

[1] The marginal emission rates are based on the primary fuel type as reported in the 2009 CELT Report.
[2] To convert from lb/MWh to lb/MBtu, the 2008 calculated marginal heat rate of 7.932 MBtu/MWh is used.

Table 1.2: 2008 Calculated New England Marginal Emission Rates (lb/MWh)

Ozone / Non-Ozone Season Emissions (NOx)					
Air Emission	Ozone Season		Non-Ozone Season		Annual Average (All Hours)
	On-Peak	Off-Peak	On-Peak	Off-Peak	
NO_X	0.23	0.20	0.21	0.22	0.21
Annual Emissions (SO_2 and CO_2)					
Air Emission		Annual			Annual Average (All Hours)
		On-Peak	Off-Peak		
SO_2		0.33	0.33		0.33
CO_2		952	976		964

Table 1.3: 2008 Calculated New England Marginal Emission Rates (lb/MBtu)

Ozone / Non-Ozone Season Emissions (NOx)					
Air Emission	Ozone Season		Non-Ozone Season		Annual Average (All Hours)
	On-Peak	Off-Peak	On-Peak	Off-Peak	
NO_X	0.03	0.03	0.03	0.03	0.03
Annual Emissions (SO_2 and CO_2)					
Air Emission		Annual			Annual Average (All Hours)
		On-Peak	Off-Peak		
SO_2		0.04	0.04		0.04
CO_2		120	123		122

The 2008 system and marginal emissions and emission rates were calculated using primarily measured air emissions reported by generators to the U.S. Environmental Protection Agency (EPA) and actual 2008 hourly generation data received by ISO-NE. This same method was used to calculate system and marginal emission rates for the 2004 through 2007 MEA reports. In MEA Reports prior to 2004, marginal emission rates were calculated using the output of a production simulation model of the New England bulk power system.

The 2008 calculated marginal heat rate was determined using mostly heat input data obtained from the U.S. EPA and actual 2008 generation. This rate was used to convert the marginal emission rates from lb/MWh to lb/MBtu. The 2008 calculated marginal heat rate was determined to be 7.932 MBtu/MWh.

As shown in Table 1.4 below, system emission rates for 2008 have decreased slightly from the 2007 calculated values: the NO_X rate by 3.7%, the SO_2 rate by 9.0%, and the CO_2 rate by 1.7%. The decrease in emission rates can primarily be attributed to the decrease in residual oil and coal-fired generation between 2007 and 2008.

Table 1.4: Differences between 2007 and 2008 System Emission Rates (lb/MBtu)

	System Emissions		
	2007 Annual Rate (lb/MWh)	2008 Annual Rate (lb/MWh)	Percent Change 2007 to 2008
NO_X	0.54	0.52	-3.7
SO_2	1.66	1.51	-9.0
CO_2	905	890	-1.7

The calculated marginal heat rate also decreased slightly between 2007 and 2008, from 8.095 to 7.932 MBtu/MWh, a decrease of approximately 2.0%.

The marginal emission rates also decreased between 2007 and 2008. The changes in NO_X and SO_2 emission rates were the most significant, exhibiting reductions of 25% and 42%, respectively. The marginal CO_2 emission rate decreased by 4%[3].

The results showed that the 2008 SO_2 and NO_X system emission rates are higher than the marginal rates for those pollutants. The CO_2 system emission rates, on the other hand, are lower than the marginal rates.

[3] For 2007 vs. 2008 NO_X, SO_2, and CO_2 marginal emission rates, refer to Tables 5.8, 5.9, and 5.10.

2. Background

In early 1994, the NEPOOL Environmental Planning Committee (EPC) conducted a study to analyze the impact that Demand Side Management (DSM) programs had on NEPOOL's generating unit NO_X air emissions in the calendar year 1992. The results were presented in a report entitled *1992 Marginal* NO_X *Emission Rate Analysis*. This report was subsequently used to support applications for obtaining NO_X emission reduction credits (ERCs) resulting from the impacts of those DSM programs. Such applications were filed under the Massachusetts ERC banking and trading program, which became effective on January 1, 1994. The ERC program allows inventoried sources of NO_X, VOCs, and CO_2 in Massachusetts to earn bankable and tradable credits by reducing emissions below regulatory requirements.

In 1994, the *1993 Marginal Emission Rate Analysis* (MEA Report) was published, which provided expanded analysis of the impact of DSM programs on NO_X, SO_2, and CO_2 air emissions for the calendar year 1993. MEA Reports were also published for the years 1994 through 2007 to provide similar annual environmental analysis for those years. For the 2008 analysis, members of ISO New England's Environmental Advisory Group (EAG) requested that the report be restructured and renamed to reflect the importance of the amount of emissions produced by the entire New England generation system. The ISO agreed to change the name of the report to the New England Electric Generator Air Emissions Report ("Emissions Report"), and to place a greater emphasis on the calculated system emissions for the entire New England generation system rather than primarily on marginal emissions. The report continues to include calculated marginal emission rates that can be used to estimate the impact of DSM programs and renewable energy projects on reducing New England's NO_X, SO_2, and CO_2 power plant air emissions during the calendar year 2008.

The New England Emissions Report has been used by a variety of stakeholders to track air emissions from the electric generation system, and to estimate the avoided emissions resulting from DSM programs and renewable energy projects.

3. Methodologies

For this 2008 Emissions Analysis, both the total system emissions and the marginal emission rate calculations for SO_2, NO_x and CO_2 were based primarily on the tons of emissions reported in the U.S. EPA's Clean Air Markets Division (CAMD)[4] data. When the data were not available from CAMD, the analyses used emission rates from the New England Power Pool Generation Information System (NEPOOL GIS) or the EPA's eGRID database, or, alternatively, emission rates that were assumed based on a generator type. When the data were not available from CAMD, the actual megawatt-hours (MWh) of generation were used to calculate tons of emissions from the GIS or eGRID emission rates. The total system and marginal emission rates were calculated from the actual or calculated tons of power plant emissions.

Only generators that are administered by ISO New England are included in these calculations. Emissions from "behind the meter" generators or those generators not within the control area boundary are not part of this analysis.

3.1. Calculating Total System Emissions

The total system emissions are based on the emissions produced by all ISO New England Generators during a calendar year. The formula for calculating the total system emission rate is:

$$\textit{System Emission Rate (lb/MWh)} = \frac{\textit{(Actual and Calculated Total Annual Emissions (lb) from all Generators)}}{\textit{(Total Annual Energy (MWh) from all Generators)}}$$

3.2. Calculating Marginal Emissions

3.2.1. History of Marginal Emissions Calculations

In MEA studies performed prior to 2004, production simulation models were used to replicate, as closely as possible, actual system operations for the study year. Then, an incremental load scenario was modeled in which the system load was increased by 500 MW in each hour. The marginal air emission rates were calculated based on the differences in generator air emissions between these two scenarios. However, this methodology had some drawbacks. Since the reference case results were based on production simulation modeling, the reference case could never exactly match the unit-specific energy production levels of the previous year for a number of modeling reasons, including market dynamics, out-of-merit and reliability-based dispatches, and specific outages and deratings.

In 2004, a new methodology was used to calculate the average emission rates of those units that are assumed to increase their loading during periods of high energy demand. Those units, which consist of all natural gas and oil-fired generators, are referred to as the marginal fossil units. The methodology used the actual metered hourly generation transmitted to ISO-NE, and annual air emissions and emission rates from the U.S. Environmental Protection Agency's (EPA) databases, along with other default emissions data. For the time periods investigated, the average air emission rates of all of the marginal fossil units were calculated based on this information. The resultant emission rates were assumed to be the *marginal emission rates.* In 2005, monthly emissions from both the U.S. EPA and the NEPOOL Generation Information System (GIS) were used, when available, to improve the accuracy of the calculations. This methodology was further improved

[4] A ton is implied to be equivalent to a U.S. short ton, or 2,000 lb.

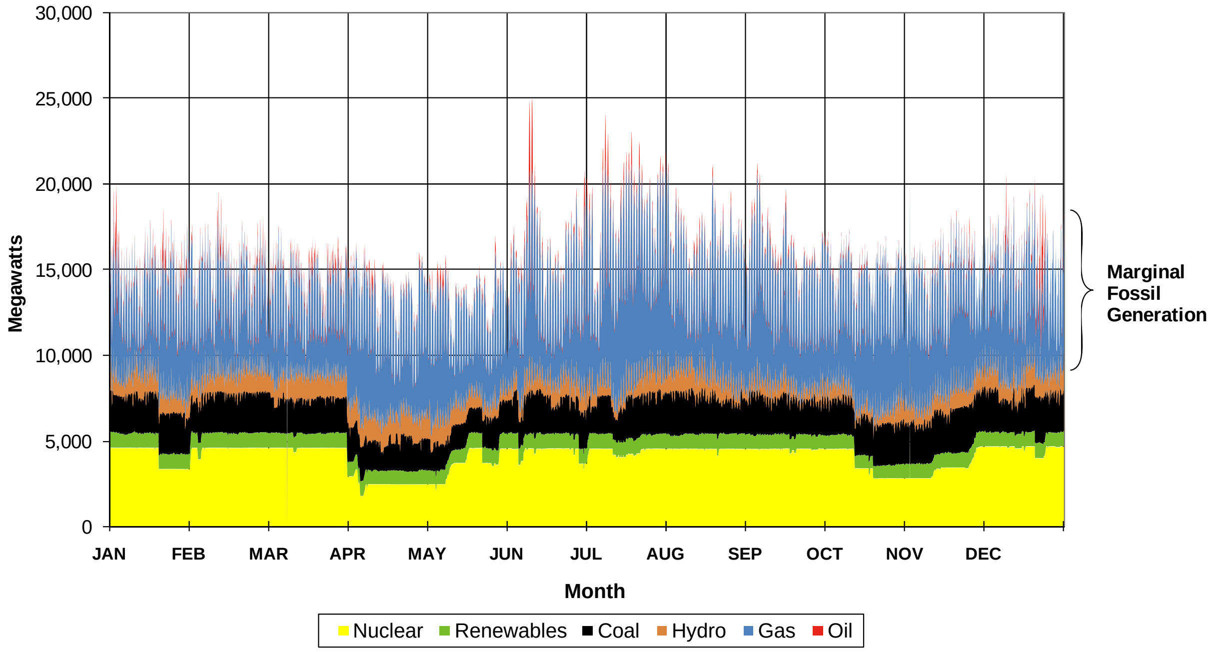
in the 2007 MEA Report with the use of hourly emissions data, for those units that report hourly emissions to the U.S. EPA[5].

3.2.2. Current Method of Calculating Marginal Emissions

The marginal fossil units, on which the marginal emissions are based, consist of fossil units fueled with oil (including residual, distillate, kerosene, diesel and jet fuel), and/or natural gas. Units fueled with coal, wood, biomass, refuse, or landfill gas are excluded from the calculation as they typically operate as base-load or non-dispatchable units and would typically not be dispatched to higher levels in the event of higher load on the system.[6] Non-emitting resources such as hydro, pumped storage, wind, and solar, as well as nuclear units, are also excluded from the calculation of marginal emissions rates.

Figure 3.1 shows the 2008 New England hourly generation and illustrates how natural gas and oil units typically respond to changes in system demand.

Figure 3.1: New England 2008 Hourly Generation



[5] Generators report emissions to the EPA under the Acid Rain Program, which covers generators 25 MW or larger, and the NO_X Budget Trading Program, which includes generators 15 MW or greater in the affected states of Connecticut and Massachusetts. Starting in 2009, the Clean Air Interstate Rule took the place of the NO_X Budget Trading Program.

[6] In an analysis of whether it would be appropriate to consider coal units as marginal units, ISO-NE found that although coal units were marginal 11% of the time in 2006, based on dispatch and load following for establishing Locational Marginal Prices, the analysis also confirmed that the dispatch of coal units was relatively independent of load levels. It was also observed that higher or lower loads would change the number of committed natural gas and/or oil units, while coal units would continue to be dispatched when available. During the low-load troughs of the daily cycle, coal units were seen to be load following. It is reasonable to expect that the coal units would continue to be available for load following during such low-load periods of the night and would likely continue being marginal for purposes of establishing Locational Marginal Prices during those off-peak hours. It was concluded that when comparing cases with higher vs. lower loads, the marginal units for energy and emissions purposes are still largely the oil and natural gas units, not the coal units.

The average NO_X, SO_2, and CO_2 emission rates of the marginal fossil units in each time period analyzed are assumed to be equal to the marginal emission rates. These emission rates are calculated as:

$$\textit{Emission Rate (lb/MWh)} = \frac{\textit{(Sum of Total Emissions (lb) in Time Period from Marginal Fossil Units)}}{\textit{(Total Energy (MWh) in Time Period from Marginal Fossil Units)}}$$

The 2008 marginal air emission rates for on- and off-peak periods for New England and for each of the six states have been calculated for this report. The on-peak period, which excludes weekends, is provided to enable typical industrial and commercial users that can provide load response during a traditional weekday to explicitly account for their reductions during those hours. The marginal emission rates for NO_X are calculated for five time periods:

- On-Peak Ozone Season (where the Ozone Season is defined as occurring from May 1 to September 30) consisting of all weekdays between 8 A.M. and 10 P.M. from May 1 to September 30
- Off-Peak Ozone Season consisting of all weekdays between 10 P.M. and 8 A.M. and all weekends from May 1 to September 30
- On-Peak Non-Ozone Season consisting of all weekdays between 8 A.M. and 10 P.M. from January 1 to April 30 and from October 1 to December 31
- Off-Peak Non-Ozone Season consisting of all weekdays between 10 P.M. and 8 A.M. and all weekends from January 1 to April 30 and from October 1 to December 31
- Annual average

Since the ozone and non-ozone seasons are only relevant to NO_X emissions, the SO_2 and CO_2 emission rates were only calculated for the following time periods:

- On-Peak Annual consisting of all weekdays between 8 A.M. and 10 P.M.
- Off-Peak Annual consisting of all weekdays between 10 P.M. and 8 A.M. and all weekends
- Annual average

4. Data and Assumptions

The key parameters and assumptions modeled in the 2008 New England Emissions Report are highlighted in this section. They include weather, emission data, and installed capacity.

4.1. 2008 New England Weather

Since the demand for energy and peak loads are significantly affected by the weather, it is useful to provide perspective for the changes in emission rates by comparing total energy use and both cooling and heating degree days to previous years.

In New England, the summer of 2008 can be characterized as below the average over the previous 20-year period with respect to overall temperature and humidity, with an unusually mild August. The summer peak electricity demand of 26,111 MW was 34 MW lower than the 2007 summer peak of 26,145 MW. There were 281 cooling degree days, which is 3.4% lower than the average of 294 cooling degree days. The net energy was 2.0% lower in 2008 than 2007 over the year as a whole, and 1.7% lower than in 2007 during the ozone season months. With respect to the winter months, both January and December 2008 can be characterized as milder than average.

New England's historical cooling degree days and heating degree days since 1993 are shown in Table 4.1. The difference between the cooling and heating degree days for a particular year and the average is also provided. The average number of cooling degree days is 294 and the average number of heating degree days is 6,252.

Table 4.1: New England Total Cooling and Heating Degree Days - 1993 through 2008

Year	Total Cooling Degree Days	Difference from Average (%)	Total Heating Degree Days	Difference from Average (%)
1993	283	-3.7	6,468	3.5
1994	374	27.2	6,403	2.4
1995	312	6.1	6,318	1.1
1996	245	-16.7	6,454	3.2
1997	211	-28.2	6,432	2.9
1998	312	6.1	5,483	-12.3
1999	360	22.4	5,774	-7.6
2000	217	-26.2	6,399	2.4
2001	323	9.9	5,895	-5.7
2002	354	20.4	5,959	-4.7
2003	355	20.7	6,651	6.4
2004	251	-14.6	6,354	1.6
2005	418	42.2	6,353	1.6
2006	335	13.9	5,552	-11.2
2007	288	-2.0	6,175	-1.2
2008	281	-3.4	6,049	-3.2

4.2. Emission Rates

Individual generating unit emissions were calculated primarily from the 2008 actual emissions (in tons) as reported under the U.S. EPA's Acid Rain Program and NO_X Budget Trading Program. This information is published on the U.S. EPA's web site under Clean Air Markets data[7]. Hourly EPA emissions data were used for calculating the marginal emission rates. In the 2005 and 2006 MEA Reports, monthly U.S. EPA data rather than hourly data were used for calculating marginal rates. Prior to 2005, the MEA reports used annual data obtained primarily from the U.S. EPA Emissions Scorecard[8].

For those units that were not required to file emissions data under the Acid Rain or NO_X Budget Trading Programs, monthly emission rates (in lb/MWh) from the NEPOOL Generation Information System (GIS) were used instead. If the data could not be obtained from either of those sources, the Emissions Report analysis used annual emission rates (in lb/MWh) from the U.S. EPA's eGRID2007 Version 1.1 data[9] or, if those were not available, emission rates based on eGRID data obtained for similar units. The emission rates were multiplied by the 2008 generation reported to the ISO to obtain the tons of emissions from a generator.

The U.S. EPA Clean Air Markets data were the primary source of emissions data used for this report. For calculating total system emissions, approximately 92% of the SO_2 emissions and 78% of the CO_2 emissions were based on Clean Air Markets data. For NO_X, Clean Air Markets data were used for 59% of total emissions. For the total marginal emissions, approximately 98% of the SO_2, 97% of the CO_2 and 84% of the NO_X emissions were based on Clean Air Markets data. Note that combined heat and power (CHP) units were included in this analysis. In calculating CHP units' emission rates, the units' emissions were assigned only to electric production and not to the heat generated, which resulted in slightly overestimating the system and marginal emission rates.

In calculating the marginal emission rates, the hourly emissions (in lbs) for those units in the U.S. EPA database were grouped into on-peak and off-peak periods. When only monthly NEPOOL GIS data or annual eGRID data were available, those lb/MWh emission rates were multiplied by the associated monthly on-peak and off-peak generation. The amount of emissions (in lbs) from each individual generator was added together to obtain an annual total emissions. This quantity was then divided by the total on-peak or off-peak generation to get the emission rates in lb/MWh for that time period. In the case of NO_X, the monthly totals were grouped into pounds of ozone and non-ozone season emissions and divided by the ozone and non-ozone season generation, respectively.

[7] The U.S. EPA's Clean Air Markets emissions data can be accessed from http://www.epa.gov/airmarkets/.
[8] The EPA Emissions Scorecard was the EPA's method of reporting emissions data prior to the establishment of the Clean Air Markets database.
[9] The U.S. EPA's eGRID2007 Version 1.1 is located at http://www.epa.gov/cleanenergy/energy-resources/egrid/index.html.

4.3. New England System Installed Capacity

Table 4.2 and Table 4.3 show the total New England generation capacity from ISO New England's 2009 Capacity, Energy, Loads and Transmission (CELT) Report[10] for the summer and winter period, respectively. Figure 4.1 illustrates the capacity that was added to the New England system during 1999 through 2008, 93% of which was gas-fired, combined cycle technologies. From 1999-2004, 9,600 MW of new capacity was added and nearly 100% of the new capacity additions were gas-fired combined cycle technologies. From 2005-2008, 750 MW was added, consisting of a mix of nuclear uprates, and new oil, natural gas, hydro, and other renewable generation.

Table 4.2: New England Summer Capacity – 2009 CELT[11, 12]

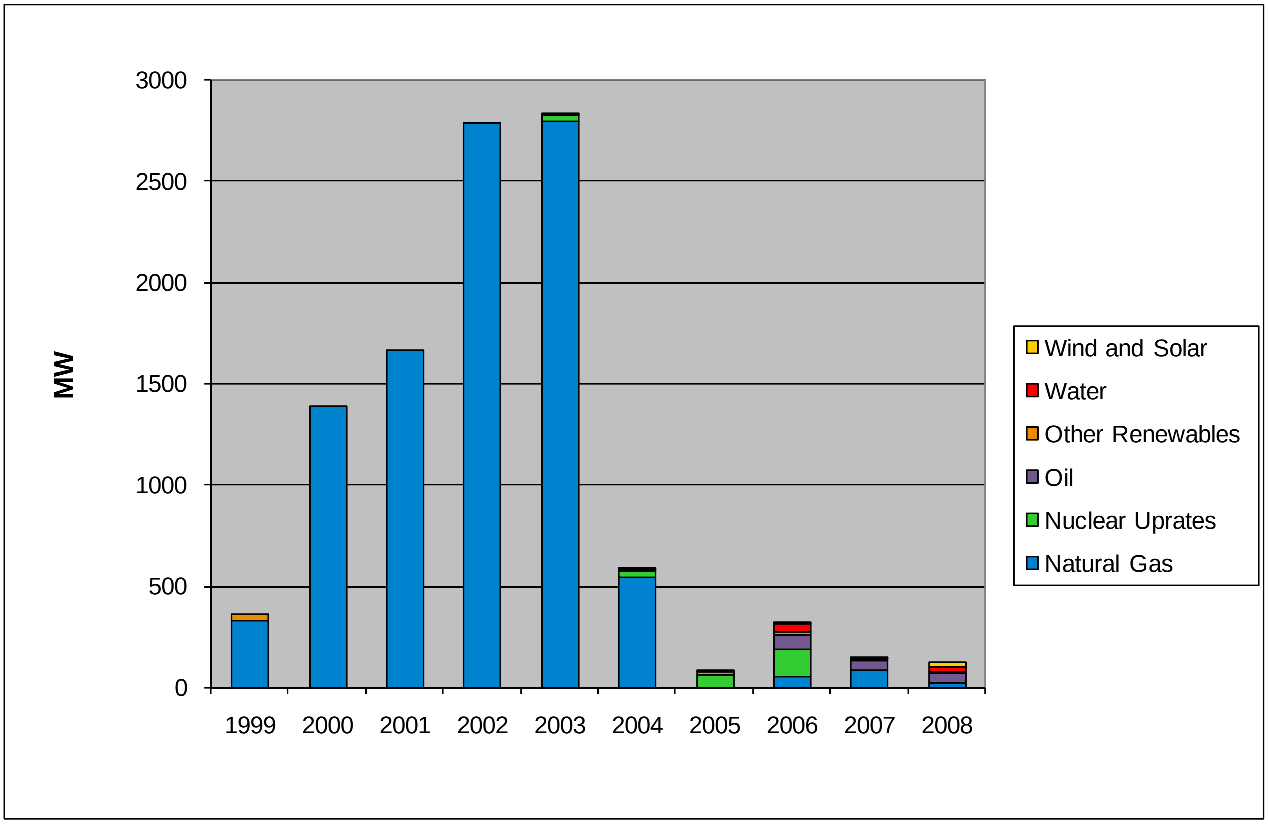
	Connecticut		Massachusetts		Maine		New Hampshire		Rhode Island		Vermont		New England	
Unit Type	MW	%	MW	%	MW	%	MW	%	MW	%	MW	%	MW	%
Combined Cycle	1,821.0	23.5	5,316.0	40.3	1,243.3	38.1	1,165.2	28.7	1,823.1	98.9	-	-	11,368.7	36.5
Gas Turbine	858.2	11.1	501.7	3.8	328.2	10.1	87.8	2.2	-	-	84.9	7.8	1,860.8	6.0
Hydro	106.7	1.4	247.0	1.9	585.3	18.0	456.8	11.3	0.5	0.0	298.2	27.5	1,694.5	5.4
Internal Combustion	21.1	0.3	139.4	1.1	16.0	0.5	5.2	0.1	19.7	1.1	25.6	2.4	227.1	0.7
Nuclear	2,014.4	26.0	677.3	5.1	-	-	1,245.5	30.7	-	-	604.3	55.6	4,541.4	14.6
Pumped Storage	29.4	0.4	1,659.7	12.6	-	-	-	-	-	-	-	-	1,689.1	5.4
Fossil Steam	2,898.1	37.4	4,649.7	35.2	1,086.5	33.3	1,070.3	26.4	-	-	72.5	6.7	9,777.2	31.3
Wind & Photovoltaic	-	-	4.4	0.0	1.0	0.0	23.5	0.6	0.5	0.0	0.7	0.1	30.1	0.1
Total	7,749.0	100.0	13,195.3	100.0	3,260.2	100.0	4,054.2	100.0	1,843.9	100.0	1,086.2	100.0	31,188.7	100.0

Table 4.3: New England Winter Capacity – 2009 CELT[12, 13]

	Connecticut		Massachusetts		Maine		New Hampshire		Rhode Island		Vermont		New England	
Unit Type	MW	%	MW	%	MW	%	MW	%	MW	%	MW	%	MW	%
Combined Cycle	2,077.5	24.8	6,243.5	43.3	1,350.4	38.4	1,317.4	30.8	2,077.7	98.9	-	-	13,066.6	38.6
Gas Turbine	1,063.0	12.7	694.7	4.8	396.5	11.3	108.4	2.5	-	-	110.9	9.4	2,373.4	7.0
Hydro	124.6	1.5	272.6	1.9	638.1	18.2	493.4	11.6	3.0	0.1	335.5	28.4	1,867.3	5.5
Internal Combustion	21.2	0.3	141.1	1.0	21.2	0.6	5.2	0.1	20.6	1.0	32.2	2.7	241.4	0.7
Nuclear	2,115.6	25.2	684.7	4.7	-	-	1,245.4	29.2	-	-	628.0	53.1	4,673.8	13.8
Pumped Storage	29.0	0.3	1,665.0	11.5	-	-	-	-	-	-	-	-	1,694.0	5.0
Fossil Steam	2,954.7	35.2	4,717.3	32.7	1,107.0	31.5	1,078.2	25.2	-	-	74.6	6.3	9,931.8	29.3
Wind & Photovoltaic	-	-	4.4	0.0	1.5	0.0	23.5	0.6	0.5	0.0	1.7	0.1	31.6	0.1
Total	8,385.5	100.0	14,423.4	100.0	3,514.6	100.0	4,271.6	100.0	2,101.8	100.0	1,183.0	100.0	33,879.9	100.0

[10] The CELT Report is typically issued in April of each year. The 2009 CELT Report (using the January 1, 2009 ratings) was used in order to completely capture all the capacity additions that occurred during calendar year 2008.
[11] Sum may not equal total due to rounding.
[12] Capability as of January 1, 2009.

Figure 4.1 : New England Generator Unit Additions - 1999 through 2008



5. Results

5.1. New England System Generator Air Emissions

Table 5.1 shows the aggregate 2008 NO_X, SO_2, and CO_2 air emissions for each state and for all of New England. These emissions were calculated based on the actual generation of all generating units in ISO's balancing authority area and the actual or assumed unit air emissions or emission rates.

Table 5.1: 2008 Calculated New England Generation System Annual Aggregate Emissions of NO_X, SO_2, and CO_2 in Short kTons[13]

State	NO_x	SO_2	CO_2
Connecticut	7.04	7.14	11,164
Maine	3.36	2.31	6,551
Massachusetts	15.28	47.72	24,767
New Hampshire	5.74	36.61	8,816
Rhode Island	0.56	0.27	3,514
Vermont	0.59	0.12	614
New England	32.57	94.18	55,427

Table 5.2 shows the aggregate annual NO_X, SO_2, and CO_2 air emissions for the years 2001 through 2008, as calculated based on the modeled and actual generation[14] and the actual or assumed air emissions or emission rates. Since 2001, NO_X emissions have dropped by 45% and SO_2 by 53%, while CO_2 has increased by about 5%.

Table 5.2: 2001 - 2008 Calculated New England Generation System Annual Aggregate Emissions of NO_X, SO_2, and CO_2 in kTons

Year	NO_x	SO_2	CO_2
2001	59.73	200.01	52,991
2002	56.40	161.10	54,497
2003	54.23	159.41	56,278
2004	50.64	149.75	56,723
2005	58.01	150.00	60,580
2006	42.86	101.78	51,649
2007	35.00	108.80	59,169
2008	32.57	94.18	55,427

[13] Sum may not equal total due to rounding.
[14] The 2001 through 2003 data are based on production simulation model results while the 2004 through 2008 data are based on actual generation and calculated air emissions.

Table 5.3 shows the average 2008 NO_X, SO_2, and CO_2 air emission rates in lb/MWh, by state and for New England as a whole, calculated based on the actual hourly unit generation of all ISO-NE generating units located within that specific state and the actual or assumed unit air emissions or emission rates.

Table 5.3: 2008 Calculated New England Generation System Annual Average NO_X, SO_2, and CO_2 Emission Rates in lb/MWh

State	NO_x	SO_2	CO_2
Connecticut	0.47	0.42	740
Maine	0.53	0.39	1,044
Massachusetts	0.68	2.14	1,100
New Hampshire	0.50	3.24	769
Rhode Island	0.15	0.07	959
Vermont	0.17	0.04	176
New England	0.52	1.51	890

Table 5.4 illustrates the annual average NO_X, SO_2, and CO_2 air emission rate values in lb/MWh for the 1999 – 2008 time period. These rates were calculated by dividing the total air emissions by the total generation from all units. Since 1999, the NO_X average emissions rate has decreased by 62%, SO_2 by 67% and CO_2 by 12%.

Table 5.4: 1999 – 2008 Calculated New England Generation System Annual Average NO_X, SO_2, and CO_2 Emission Rates in lb/MWh

Year	Total Generation (GWh)	NO_x	SO_2	CO_2
1999	104,409	1.36	4.52	1,009
2000	110,199	1.12	3.88	913
2001	114,626	1.05	3.51	930
2002	120,539	0.94	2.69	909
2003	127,195	0.93	2.75	970
2004	129,459	0.78	2.31	876
2005	131,874	0.88	2.27	919
2006	128,046	0.67	1.59	808
2007	130,723	0.54	1.66	905
2008	124,749	0.52	1.51	890
Percent Reduction, 1999 - 2008		62%	67%	12%

5.2. 2008 Calculated Marginal Heat Rate for the New England Electric Generation System

In MEA studies prior to 1999, a fixed marginal heat rate of 10.0 MBtu/MWh[15] was assumed and then used to convert from lb/MWh to lb/MBtu. In the 1999 – 2003 MEA studies, the marginal heat rate was calculated using the results of production simulation runs. Beginning with the 2004 MEA study, the marginal heat rate was based on the actual generation of marginal fossil units only. Since heat rate is equal to fuel consumption divided by generation[16], the calculated marginal heat rate is defined as follows:

$$\text{Calculated Marginal Heat Rate} = \frac{\text{(Calculated Fuel Consumption of } \textit{Marginal Fossil} \text{ Units (in MBtu))}}{\text{(Actual Generation of } \textit{Marginal Fossil} \text{ Units (in MWh))}}$$

Beginning with the 2007 MEA Report, the marginal heat rate has been calculated using a combination of both U.S. EPA heat input data and ISO-NE's heat rate data. For those marginal fossil units with U.S. EPA data, the heat inputs reported to U.S. EPA were used. For those units without U.S. EPA data, the heat inputs were calculated by multiplying each unit's monthly generation by the heat rate information collected and maintained by ISO-NE's Market Monitoring Department. The individual heat input values using the two methods, in MBtu, were added and the sum divided by total generation of the marginal fossil units.

The calculated annual marginal heat rate reflects the average annual efficiency of all of the marginal fossil units dispatched throughout 2008. The lower the marginal heat rate value, the more efficient the system or marginal generator(s) is with respect to converting raw fuel into electricity.

The annual calculated marginal heat rates from 1999 to 2008 are shown in Table 5.5 below. The rate has declined over 20% since 1999.

Table 5.5: Historically Calculated New England Annual Marginal Heat Rate (MBtu/MWh)

Year	Calculated Marginal Heat Rate (MBtu/MWh)
1999	10.013
2000	9.610
2001	9.279
2002	8.660
2003	8.249
2004	8.210
2005	8.140
2006	7.667
2007	8.095
2008	7.932

The 2008 calculated marginal heat rate was used as the conversion factor to convert from lb/MWh to lb/MBtu for the marginal emission rates in this report.

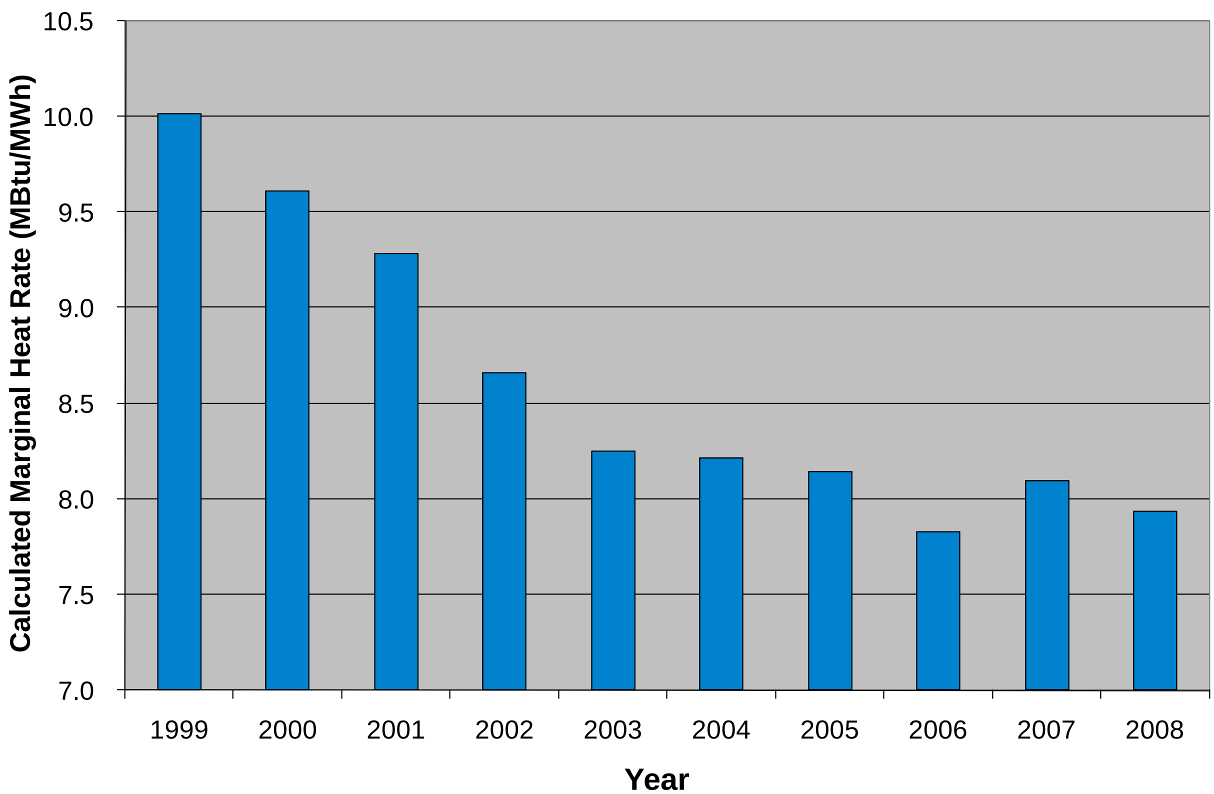
[15] 10 MBtu/MWh is equivalent to 10,000 Btu/kWh.

[16] Heat rate is the measure of efficiency in converting fuel input to electricity. The heat rate for a power plant depends on the individual plant design, its operating conditions, and its level of electrical power output. The lower the heat rate, the more efficient the power plant.

5.2.1. Observations

Overall, the trend of decreasing marginal heat rates has been continuing, with rates declining from 10.013 MBtu/MWh to 7.932 MBtu/MWh over the past nine years. This is primarily due to the addition of over 9,500 MW of natural gas-fired, combined cycle units with higher efficiency, i.e lower heat rates. Figure 5.1 illustrates the calculated marginal heat rate spanning the 1999 – 2008 timeframe. In general, the marginal heat rate has been declining since 1999. In 2006, there was a particularly large decrease in the marginal heat rate primarily due to a sharp decrease in residual oil-fired generation that year (see Figure 5.2). In 2007, residual oil-fired generation increased to about 4,700 GWh, an approximately 900 GWh increase over 2006 levels. This likely contributed to the increase in the marginal heat rate that occurred in 2007. The subsequent decrease in residual oil-fired generation in 2008 was accompanied by a decrease in the marginal heat rate that year.

Figure 5.1: Historically Calculated New England Electric System Generators' Marginal Heat Rate (MBtu/MWh)



5.3. 2008 New England Generation Marginal Emission Rates

Table 5.6 shows the NO_X, SO_2, and CO_2 calculated marginal emission rates in lb/MWh for New England's generation system. The NO_X data are provided for each of the five time periods studied. Since the ozone and non-ozone seasons are not relevant to SO_2 and CO_2, only the on-peak, off-peak, and annual rates are provided for those emissions**.** Table 5.7 shows the same information expressed in lb/MBtu. As noted earlier, the 2008 calculated marginal heat rate of 7.932 MBtu/MWh was used as the conversion factor.

Table 5.6: 2008 Calculated New England Marginal Emission Rates (lb/MWh)

Ozone / Non-Ozone Season Emissions (NOx)					
Air Emission	Ozone Season		Non-Ozone Season		Annual Average (All Hours)
	On-Peak	Off-Peak	On-Peak	Off-Peak	
NO_X	0.23	0.20	0.21	0.22	0.21
Annual Emissions (SO_2 and CO_2)					
Air Emission		Annual			Annual Average (All Hours)
		On-Peak	Off-Peak		
SO_2		0.33	0.33		0.33
CO_2		952	976		964

Table 5.7: 2008 Calculated New England Marginal Emission Rates (lb/MBtu)

Ozone / Non-Ozone Season Emissions (NOx)					
Air Emission	Ozone Season		Non-Ozone Season		Annual Average (All Hours)
	On-Peak	Off-Peak	On-Peak	Off-Peak	
NO_X	0.03	0.03	0.03	0.03	0.03
Annual Emissions (SO_2 and CO_2)					
Air Emission		Annual			Annual Average (All Hours)
		On-Peak	Off-Peak		
SO_2		0.04	0.04		0.04
CO_2		120	123		122

5.3.1. Observations

New England's power plant air emissions are directly dependent on the specific units that are available and dispatched to serve load for each hour of the year. Therefore, there could be wide variations in seasonal emissions, primarily due to changes in economic and reliability dispatch, unit availability, fuel consumption, fuel switching, transmission topology, and load levels.

In 2008, there was little or no difference between the on-peak and off-peak marginal rates for NO_X, SO_2 or CO_2. The greatest difference between on- and off-peak rates was for NO_X during the ozone season. The reason for this difference is most likely that the additional generation that is brought on line to meet the higher demand during on-peak periods generally has higher emission rates. These are typically peaking units that are more expensive or even uneconomic to operate except during high energy price hours, or are older, fossil-steam resources with higher individual heat rates, i.e., lower thermal efficiency. NO_X is a precursor of ozone air pollution, which is primarily a problem during the hot summer months (i.e., the ozone season), when peak load periods occur.

5.4. Calculated Historical Marginal Emission Rates

Table 5.8, Table 5.9, and Table 5.10 show the historical calculated marginal emission rates for NO_X, SO_2, and CO_2, respectively, in lb/MWh for the years 1993 through 2008. Table 5.8 shows the ozone and non-ozone season rates, while the SO_2 and CO_2 tables include only the annual average emission rates. All three tables show the annual average percentage change from the previous year. Figure 5.3, Figure 5.4, and Figure 5.5 are graphical representations of Table 5.8, Table 5.9 and Table 5.10 respectively.

Table 5.8: Calculated New England Generation NO_X Marginal Emission Rates (lb/MWh)

	Ozone Season		Non-Ozone Season			
Year	**On-Peak**	**Off-Peak**	**On-Peak**	**Off-Peak**	**Annual Average (All Hours)**	**Annual Average Percentage Change**
1993	4.00	4.50	4.10	5.00	4.40	-
1994	4.50	3.90	4.50	3.90	4.20	-4.5
1995	3.40	2.80	3.50	3.10	3.20	-23.8
1996	2.70	2.40	2.90	2.40	2.60	-18.8
1997	2.60	2.60	2.70	2.60	2.60	0.0
1998	2.20	2.00	2.10	2.10	2.10	-19.2
1999	2.20	2.00	1.90	1.80	2.00	-4.8
2000	2.00	1.80	1.80	1.80	1.90	-5.0
2001	1.90	1.50	1.70	1.60	1.70	-10.5
2002	1.40	0.80	1.50	1.00	1.10	-35.3
2003	0.80	0.30	0.90	0.90	0.70	-36.4
2004	0.48	0.38	0.66	0.59	0.54	-22.9
2005	0.51	0.39	0.62	0.57	0.54	0.0
2006	0.35	0.24	0.30	0.25	0.29	-46.3
2007	0.25	0.20	0.34	0.30	0.28	-3.4
2008	0.23	0.20	0.21	0.22	0.21	-25.0
% Reduction 1993 - 2008	**94.3**	**95.6**	**94.9**	**95.6**	**95.2**	

Table 5.9: Calculated New England Generation SO_2 Marginal Emission Rates (lb/MWh)

Year	Annual Average (All Hours)	Annual Average Percentage Change
1993	12.60	-
1994	9.80	-22.2
1995	7.00	-28.6
1996	9.60	37.1
1997	9.40	-2.1
1998	6.20	-34.0
1999	7.20	16.1
2000	6.20	-13.9
2001	4.90	-21.0
2002	3.30	-32.7
2003	2.00	-39.4
2004	2.03	1.5
2005	1.75	-13.8
2006	0.53	-69.7
2007	0.57	7.5
2008	0.33	-42.1
% Reduction 1993 - 2008	97.4	

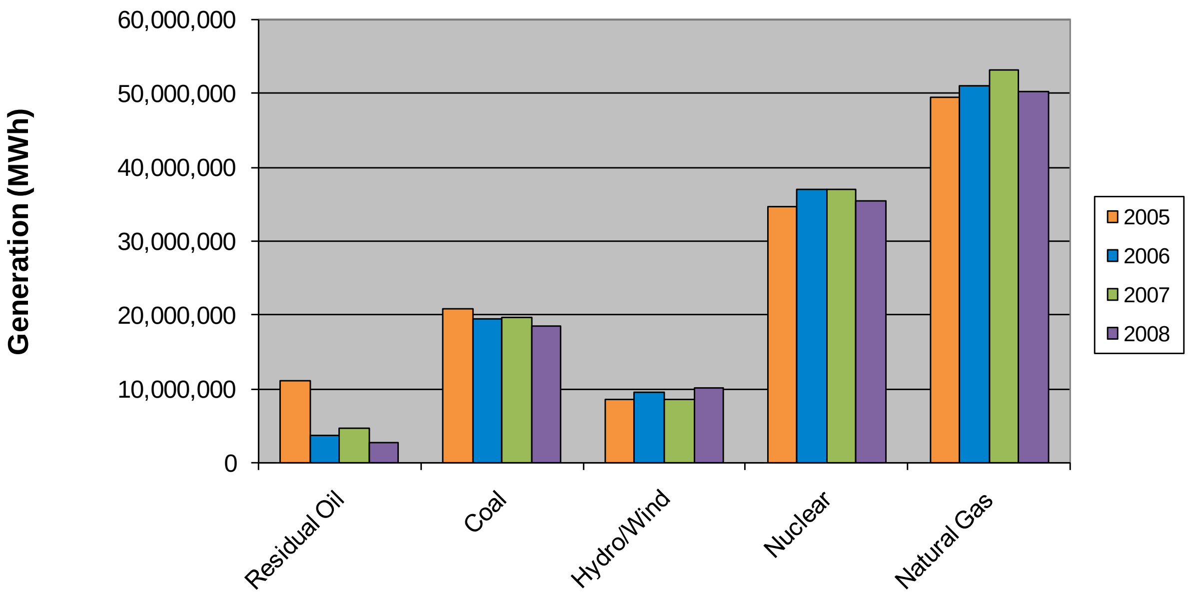
Table 5.10: Calculated New England Generation CO_2 Marginal Emission Rates (lb/MWh)

Year	Annual Average (All Hours)	Annual Average Percentage Change
1993	1,643	-
1994	1,573	-4.3
1995	1,584	0.7
1996	1,653	4.4
1997	1,484	-10.2
1998	1,520	2.4
1999	1,578	3.8
2000	1,488	-5.7
2001	1,394	-6.3
2002	1,338	-4.0
2003	1,179	-11.9
2004	1,102	-6.5
2005	1,107	0.5
2006	993	-10.3
2007	1,004	1.1
2008	964	-4.0
% Reduction 1993 - 2008	41.3	

5.4.1. Observations

Table 5.8 and Table 5.9 show that there was a significant change in the average annual marginal emission rates for NO_X and SO_2 between 2007 and 2008. NO_X emission rates decreased by 25.0%, while SO_2 emission rates decreased by 42.1%. As shown in Table 5.10, CO_2 emission rates decreased as well, but only by 4.0%. The relatively large decreases in NO_X and SO_2 emissions between 2007 and 2008 can primarily be attributed to the overall reduction in generation by residual oil-fired units in 2008, as seen in Figure 5.2. In 2008, residual oil-fired generation was about 2,000 GWh lower than in 2007. There was a slight decrease in natural gas generation, and minimal change in total generation by non-emitting units. Overall, system generation was about 6,132 GWh lower in 2008 than in 2007.

Figure 5.2: 2008 Generation by Selected Fuel Types Based on Primary Fuel Type in 2009 CELT Report



Since 1993, there has been a significant decrease in the marginal emission rates. In fifteen years, SO_2 and NO_X annual marginal rates have declined by over 95% and CO_2 by 41%. This decline is clearly illustrated in Figure 5.3, Figure 5.4, and Figure 5.5. There was a noticeable decrease in the marginal emission rates for NO_X in 1995 primarily due to the implementation of Reasonable Available Control Technology (RACT) regulations for NO_X as required under Title I of the 1990 Clean Air Act Amendments. This trend of decreasing NO_X marginal emission rates continued into the 2008 calendar year. Most of the decrease in emission rates that took place through 2004 can be attributed to the commercial installation of many highly efficient, low emitting, natural gas-fired combined cycle plants over the last several years in New England (see Figure 5.3) and additional emission reductions as required under the Ozone Transport Commission's 1999 and U.S. EPA's 2003 NO_X Budget Program. Because few new natural gas-fired power plants have been added since 2004, the decline in marginal NO_X emission rates has tapered off.

Other factors have also contributed throughout the years to the reduction in calculated marginal emission rates. Since 1993, there has been an increase in the availability of existing New England nuclear units as well as increases in some capacity ratings, and they have therefore been contributing more toward satisfying the base load electrical demand of the system. This base load generation offsets generation from those marginal units that tend to have higher emission rates. One period that is an exception to this is 1996 to 1998, when there was an increase in fossil-based generation to compensate for the unavailability of three nuclear units.

Figure 5.3: Historically Calculated New England NO_X Marginal Emission Rate

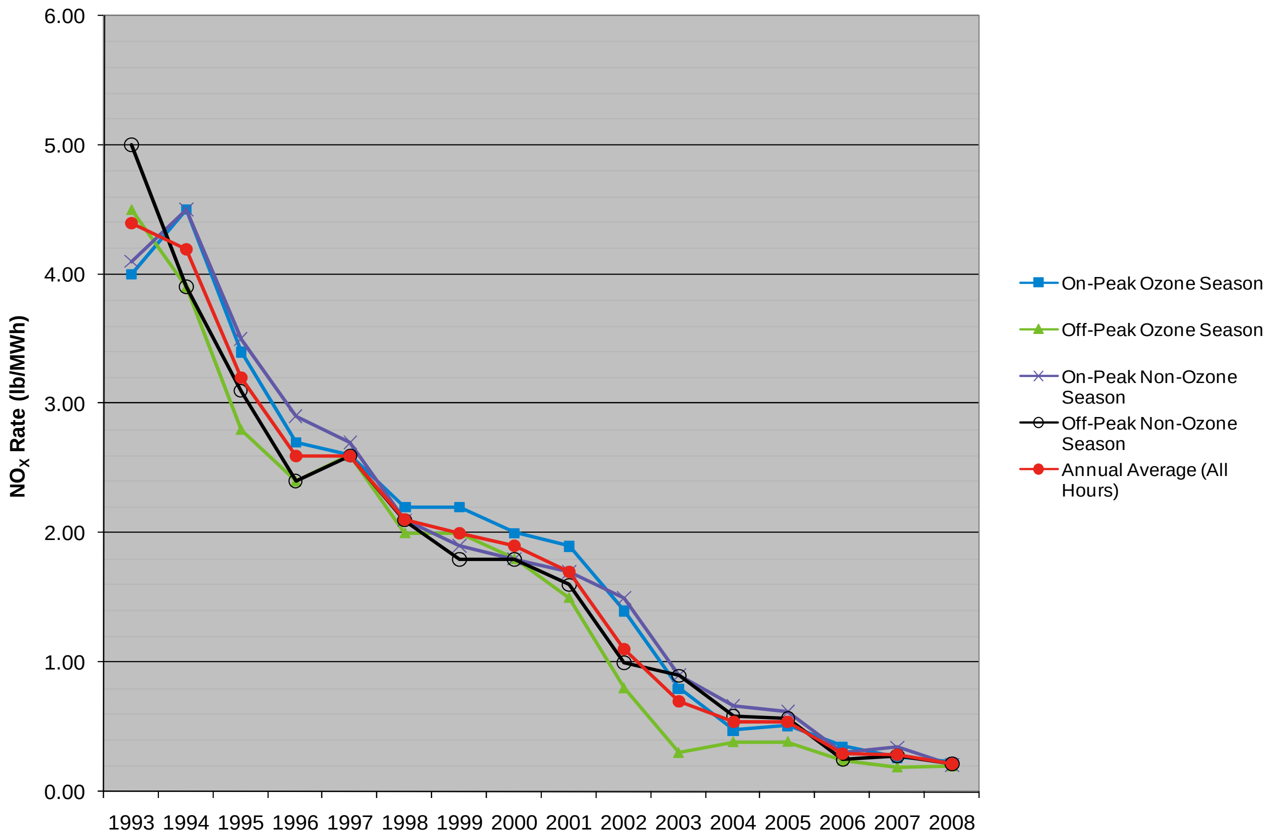


Figure 5.4: Historically Calculated New England SO_2 Marginal Emission Rates

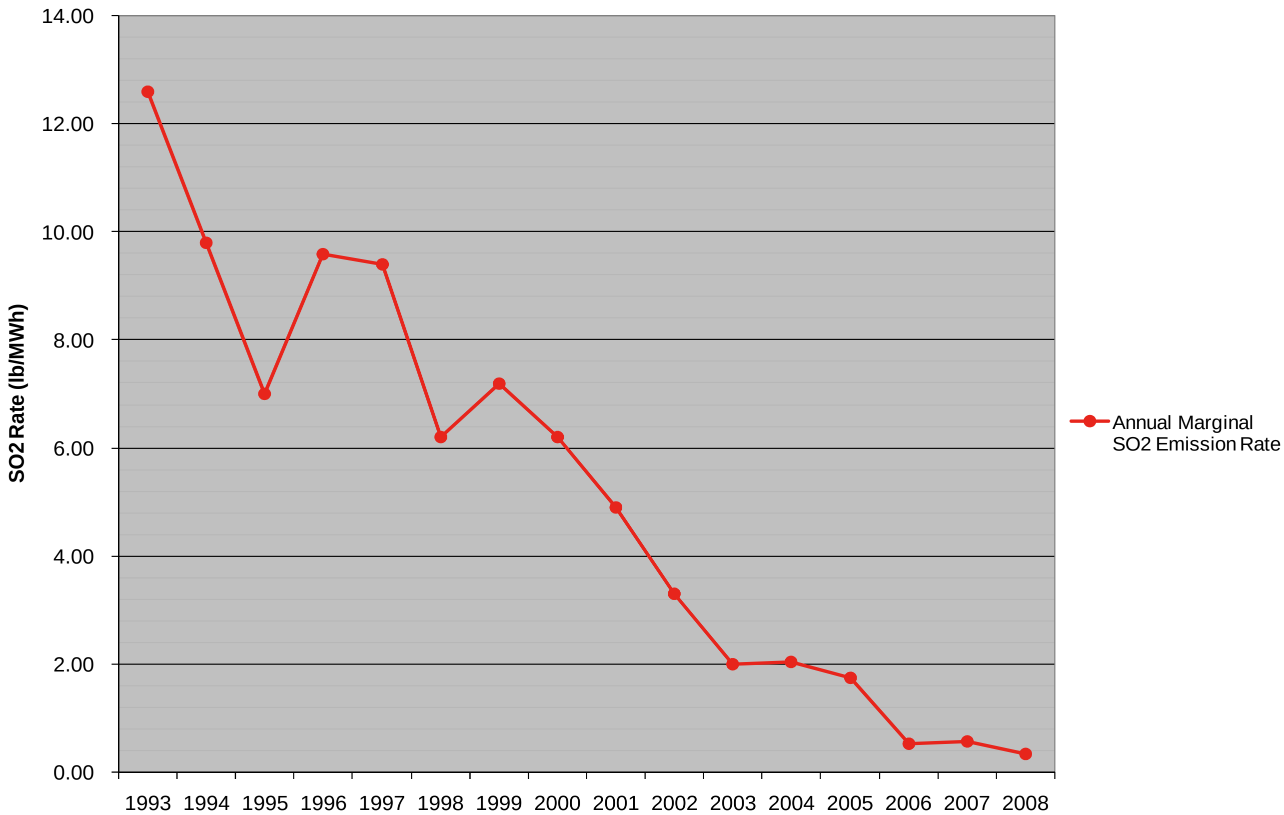
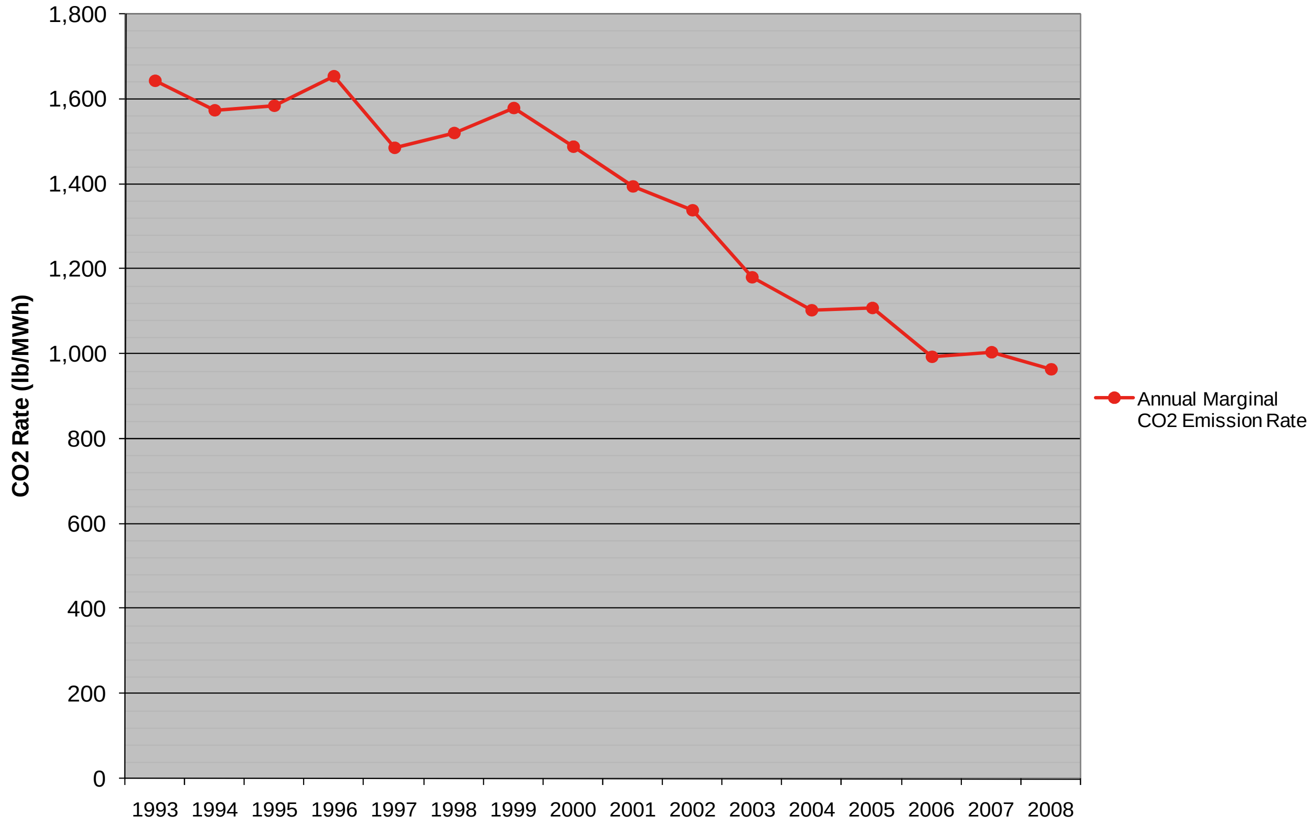


Figure 5.5: Historically Calculated New England CO_2 Marginal Emission Rate



5.5. Calculated Marginal Emission Rates by State

Table 5.11, Table 5.12, and Table 5.13 show the 2008 calculated NO_X, SO_2 and CO_2 marginal air emission rates for each state based on the generation that operated in that state. The NO_X emission rates are broken down into the ozone and non-ozone seasons, and the SO_2 and CO_2 rates are shown for the annual on-peak and off-peak hours.

The capacity located within each state is the major factor in the calculated state marginal emission rates. For example, Rhode Island, where 99% of its in-state capacity is gas-fired combined cycle, has much lower marginal emissions rates than Vermont, which has the highest. Although the total amount of emissions in Vermont is the lowest in New England, the marginal emission rates are high because the generating units in the marginal fossil category are mostly older, internal combustion engines and gas turbine units.

Table 5.11: 2008 Calculated New England NO_X Marginal Emission Rates by State (lb/MWh)

	Ozone Season		Non-Ozone Season		
State	On-Peak	Off-Peak	On-Peak	Off-Peak	Annual Average (All Hours)
Connecticut	0.34	0.30	0.30	0.35	0.32
Maine	0.17	0.18	0.19	0.24	0.20
New Hampshire	0.14	0.10	0.08	0.08	0.10
Rhode Island	0.10	0.12	0.14	0.16	0.13
Vermont	6.62	7.18	7.03	7.82	6.87
Massachusetts	0.27	0.21	0.24	0.24	0.24
New England Average	0.23	0.20	0.21	0.22	0.21

Table 5.12: 2008 Calculated New England SO_2 Marginal Emission Rates by State (lb/MWh)

State	Annual On-Peak	Annual Off-Peak	Annual Average (All Hours)
Connecticut	0.26	0.25	0.25
Maine	0.33	0.24	0.29
New Hampshire	0.25	0.09	0.17
Rhode Island	0.00	0.01	0.01
Vermont	3.05	3.93	3.23
Massachusetts	0.50	0.54	0.52
New England Average	0.33	0.33	0.33

Table 5.13: 2008 Calculated New England CO_2 Marginal Emission Rates by State (lb/MWh)

State	Annual On-Peak	Annual Off-Peak	Annual Average (All Hours)
Connecticut	973	1,008	988
Maine	1,000	1,071	1,033
New Hampshire	883	885	884
Rhode Island	923	917	920
Vermont	2,553	2,555	2,553
Massachusetts	960	983	971
New England Average	952	976	964

Figure 5.6, Figure 5.7, and Figure 5.8 show the relationship between the average system emission rates in Table 5.4 and the marginal emission rates for NO_X, SO_2, and CO_2 during that same period.

Figure 5.6: 1999 – 2008 Calculated New England Annual Average System NO_X Emission Rate vs. Marginal NO_X Emission Rate, in lb/MWh

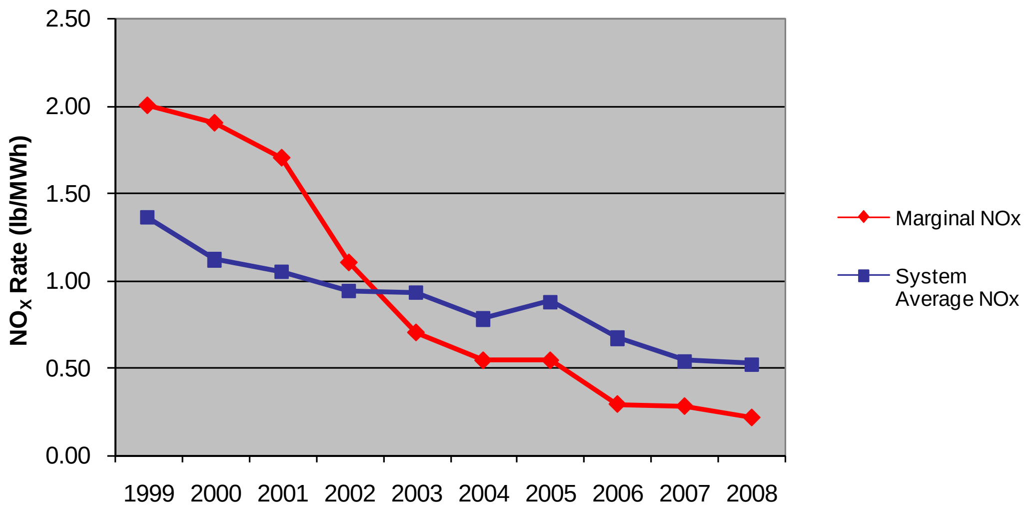


Figure 5.7: 1999 – 2008 Calculated New England Annual Average System SO_2 Emission Rate vs. Marginal SO_2 Emission Rate, in lb/MWh

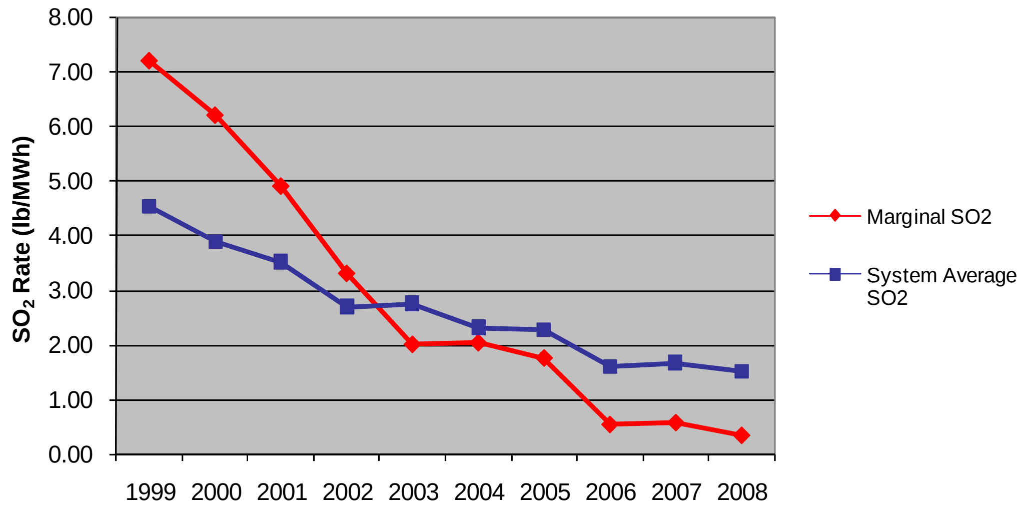
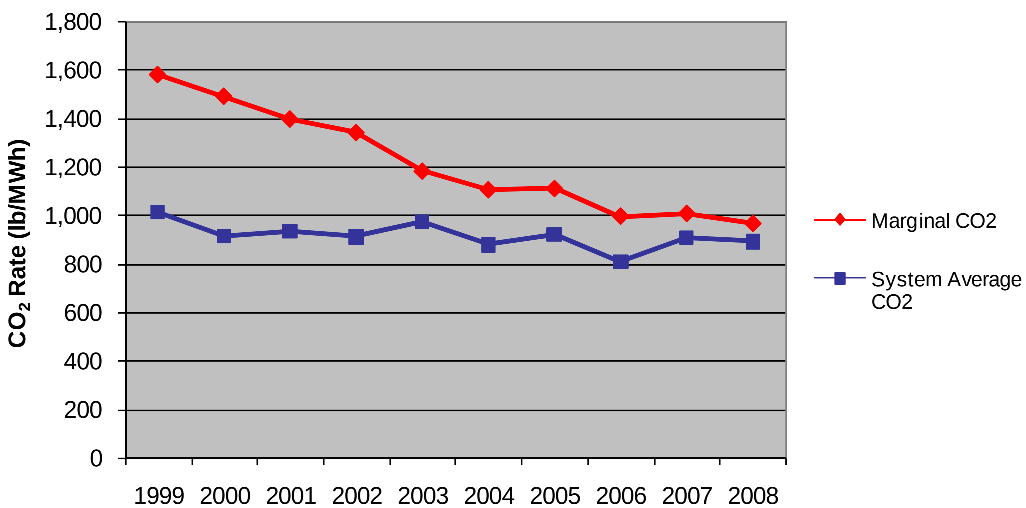


Figure 5.8: 1999 – 2008 Calculated New England Annual Average System CO_2 Emission Rate vs. Marginal CO_2 Emission Rate, in lb/MWh



5.5.1. Observations

During the period from 1999 to 2008, the average system emission rates decreased for both NO_X and SO_2, but at a slower rate than the marginal emission rates for those same pollutants. In fact, the marginal emission rates for NO_X and SO_2 were initially higher than the system emission rates for those pollutants, but due to their relatively fast decline, have been lower than the system rates since 2003.

The CO_2 average system emission rate decreased by about 12% between 1999 and 2008, while the CO_2 marginal emission rate declined 41% during that same period. This was caused by increased load growth and demand for fossil-based energy that was counteracting the lower marginal CO_2 rates as new units were added. Unlike the SO_2 and NO_X marginal emission rates, the CO_2 marginal emission rate has remained higher than the system emission rate during the entire period from 1999 through 2008. However, the CO_2 marginal emission rate has been decreasing more quickly than the system average emission rate over the past nine years, and the two rates were similar in 2008.

6. Peak-Day NO_X Analysis

The ISO has been conducting an analysis of NO_X emissions during the five highest peak days for the years 2005 through 2009, or a total of 25 peak days. This was in response to a request by state environmental regulators to ISO's Environmental Advisory Group and Planning Advisory Committee. This analysis is not yet complete and will be reported on in a separate document but is briefly described here.

The peak-day NO_X analysis consisted of two parts: 1) the calculation of the total generation system NO_X emissions for each of the 24 hours of each of the peak days and 2) an analysis of 500 MW of the highest bidding generators on these peak days after accounting for generation that would not vary with the load. The purpose of this part of the analysis was to determine the NO_X rates for this highest decrement of generation that might not be operating if the loads were 500 MW lower on these peak days due to energy efficiency.

The preliminary results show significantly higher NO_X rates on these peak days than the NO_X rate for the on-peak ozone season calculated in this report. The report on this peak NO_X analysis is anticipated to be finished in the third quarter of 2010.

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