2005 New England Marginal Emission Rate Analysis

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ISO New England Inc.

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1.0 EXECUTIVE SUMMARY

Since 1993, ISO New England Inc. (ISO-NE) has analyzed annually the impact that demand side management (DSM) programs have had upon New England's aggregate SO_2, NO_X, and CO_2 generating unit air emissions. This 2005 New England Marginal Emission Rate Analysis (MEA Report) provides calculated estimates of marginal SO_2, NO_X, and CO_2 air emissions for the calendar year 2005. Marginal emission rates were estimated using the energy weighted average emission rates of generating units that typically would increase loading during higher energy demands. In this document, these units are referred to as "intermediate fossil" units[1]. The results of the 2005 marginal emission rate calculations are shown in Table 1.1 in lbs/MWh and Table 1.2 in lbs/MBtu.

Table 1.1: 2005 Calculated New England Marginal Emission Rates (lbs/MWh)

	Ozone Season		Non-Ozone Season		Annual		Annual
Air Emission	On-Peak	Off-Peak	On-Peak	Off-Peak	On-Peak	Off-Peak	Average (All Hours)
SO_2					1.80	1.63	1.75
NO_X	0.51	0.39	0.62	0.57			0.54
CO_2					1,116	1,087	1,107

Table 1.2: 2005 Calculated New England Marginal Emission Rates (lbs/MBtu)[2]

	Ozone Season		Non-Ozone Season		Annual		Annual
Air Emission	On-Peak	Off-Peak	On-Peak	Off-Peak	On-Peak	Off-Peak	Average (All Hours)
SO_2					0.22	0.20	0.21
NO_X	0.06	0.05	0.08	0.07			0.07
CO_2					137	133	136

The 2005 marginal emission rate values were calculated based on the actual 2005 hourly generation. This method of calculating marginal emission rates was first used in the 2004 MEA analysis, and will continue to be used in future analyses. In MEA Reports prior to 2004, marginal emission rates were calculated using a production simulation model.

The 2005 Calculated Marginal Heat Rate was also determined using actual 2005 generation. This rate is used to convert the marginal emission rates from lbs/MWh to lbs/MBtu. The 2005 Calculated Marginal Heat Rate was determined to be 8.140 MBtu/MWh.

Calculated marginal emission rates for 2005 have changed only slightly from the 2004 calculated values. Although the 2005 NO_X and CO_2 rates remained nearly the same as the 2004 rates, the SO_2 rates decreased in all time periods studied. During 2005, 60 MW of new capacity went commercial. Since this additional capacity did not significantly change the capacity mix of the New England system, the marginal emission rates were not expected to change significantly.

[1] "Intermediate fossil" units, as defined in Section 3.1, are those fossil units that are fueled with oil (including distillate, residual, diesel and jet fuel), and/or natural gas.
[2] To convert from lbs/MWh to lbs/MBtu, the 2005 calculated Marginal Heat Rate of 8.14 MBtu/MWh is used.

As with the calculated marginal emission rates, the calculated marginal heat rate changed only slightly from that calculated for 2004. Specifically, the rate decreased from 8.210 MBtu/MWh to 8.140 MBtu/MWh.

The aggregate average annual emissions of the New England system were also calculated. The results showed that the 2005 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.

2.0 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 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 was used to support applications for obtaining NO_X emission reduction credits (ERCs) resulting from those DSM program impacts. 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 on the impact of DSM programs on SO_2, NO_X, and CO_2 air emissions for the calendar year 1993. Similar reports were also published for the years 1994 through 2004 to provide similar environmental analysis for each of these years. The 2005 New England Marginal Emission Rate Analysis provides calculated marginal emission rates that can be used to estimate the impact of DSM programs on New England's SO_2, NO_X, and CO_2 power plant air emissions during the calendar year 2005.

The MEA Report is used by a variety of stakeholders, including consulting firms, environmental advocacy groups, and state air regulators to estimate the avoided emissions of DSM programs and renewable energy projects. This can assist the Renewable Energy Certificates (REC) market by providing both REC suppliers and stakeholders with information to communicate the environmental benefits of RECs. This works to enhance the overall REC marketplace, as well as Renewable Portfolio Standards (RPS) that include energy efficiency, e.g. Connecticut's Class III RPS.

3.0 METHODOLOGY

3.1 CALCULATING MARGINAL EMISSIONS

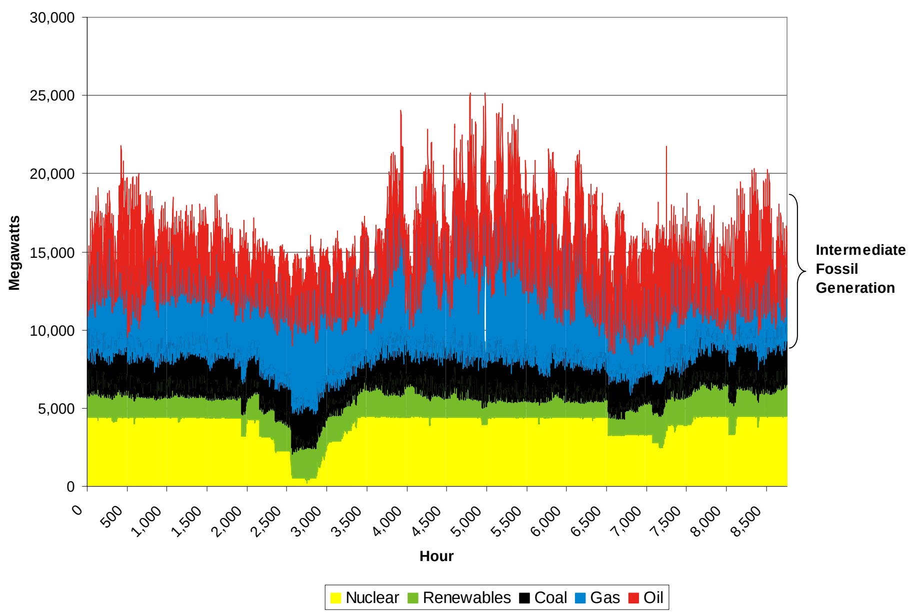
In MEA studies performed prior to 2004, production simulation models were used to replicate, as closely as possible, actual system operations for the study year. Then, an incremental load scenario was modeled in which the entire system load was increased by 500 MW in each hour. The marginal air emission rates were calculated based on the differences in emissions between these two scenarios. This methodology had some drawbacks. Since the reference case results were based on production simulation modeling, the reference case never exactly matched the previous year's energy production.

In 2004, a new methodology was developed to calculate the average emission rates of those units that are assumed to increase their loading during periods of high energy demand. This methodology used the actual hourly generation as reported to ISO-NE and annual average air emission rates from US Environmental Protection Agency (EPA) data and other default emissions data. For the time periods investigated, the average air emission rates of a defined subset of generating units were calculated based on this information. The resultant emission rates were assumed to be the marginal emission rates. This new methodology was again used to produce the 2005 MEA Report and will continue to be used for future MEA reports.

The subset of units, referred to as *intermediate fossil units* for purposes of the 2005 MEA Report, is comprised of those fossil units that are fueled with oil (including distillate, residual, diesel and jet fuel), and/or natural gas. Fossil units fueled with coal, wood, biomass, or refuse/landfill gas are excluded from the calculation as they typically operate as baseload units and would not be dispatched to higher levels in the event that more load was on the system. Hydro and nuclear units are also excluded from the calculation.

Figure 3.1 shows the 2005 New England hourly generation, and illustrates the way in which gas and oil units respond to system demand.

Figure 3.1: New England 2005 Hourly Generation



As stated above, the average SO_2, NO_X, and CO_2 emission rates of the intermediate fossil units in each time period studied are assumed to be equal to the marginal emission rates. These emission rates are calculated as:

$$\textit{Emission Rate (lbs/MWh)} = \frac{(\textit{Calculated Total Emissions in TimePeriod from Intermediate Fossil Units})}{(\textit{Total MWh in TimePeriod from Intermediate Fossil Units})}$$

This report calculates the NO_X 2005 marginal air emission rates for New England and each of the six states over the following 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 hour ending 9 A.M. and hour ending 10 P.M. from May 1 to September 30.
- Off-Peak Ozone Season consisting of all weekdays between hour ending 11 P.M. and hour ending 8 A.M. and all weekends from May 1 to September 30.
- On-Peak Non-Ozone Season consisting of all weekdays between hour ending 9 A.M. and hour ending 10 P.M. from January 1 to April 30 and October 1 to December 31.
- Off-Peak Non-Ozone Season consisting of all weekdays between hour ending 11 P.M. and hour ending 8 A.M. and all weekends from January 1 to April 30 and October 1 to December 31.
- Annual average consisting of all hours in 2005.

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

- On-Peak Annual consisting of all weekdays between hour ending 9 A.M. and hour ending 10 P.M.
- Off-Peak Annual consisting of all weekdays between hour ending 11 P.M. and hour ending 8 A.M. and all weekends.

4.0 DATA AND ASSUMPTIONS

The key parameters and assumptions modeled within the 2005 Marginal Emissions Rate Analysis are highlighted in the sections below.

4.1 EMISSION RATES

Individual generating unit emission rates were calculated from the 2005 actual monthly emissions as reported under the US EPA's Acid Rain Program and NO_X Budget Trading Program, and published on the EPA's web site under Clean Air Markets data[3]. The use of monthly data is a change from previous years' studies, which used annual data obtained primarily from the US EPA Emissions Scorecard.

For those units that were not required to file under the Acid Rain or NO_X Budget Trading Programs, the study used annual emission rates from the EPA's eGRID2006 Version 2.1 data[4] or, as a default, emission rates based on similar unit types.

4.2 2005 NEW ENGLAND WEATHER

Since the demand for energy and peak load is very much affected by the weather, it is useful to provide perspective for the changes in marginal emissions by comparing total energy use and cooling degree days to previous years.

In 2005, the summer months were hotter than normal, resulting in a summer peak electricity demand 11.5% above the 2004 summer peak. In addition, eight out of the region's all-time top-ten demand days and seven out of the top-ten weekend demand days occurred during the summer of 2005. There were 408 cooling degree days during the ozone season (May – September). This is 40% higher than the normal of 292 cooling degree days during those months, and 62% higher than the number of cooling degree days in 2004. The relatively high summer temperatures in 2005 are also reflected in the net energy during the ozone season months, which was 6.4% higher in 2005 than in 2004. This is in contrast to the net annual energy, which was only 2.9% higher in 2005. The winter months could be characterized as average during January and February, and colder than normal in December.

The historical ozone season cooling degree days since 1993 are shown in Table 4.1. The difference between the cooling degree days for a particular year and the normal of 292 cooling degree days is also provided.

[3] The Clean Air Markets emissions data can be accessed from http://www.epa.gov/airmarkets/.
[4] EPA's eGRID2006 Version 2.1 is located at http://www.epa.gov/cleanenergy/egrid/index.htm.

Table 4.1: New England Ozone Season Cooling Degree Days - 1993 through 2005

Year	Total Cooling Degree Days	Difference from Normal (%)
1993	283	-3.1
1994	374	28.1
1995	312	6.8
1996	245	-16.1
1997	211	-27.7
1998	311	6.5
1999	360	23.3
2000	218	-25.3
2001	324	11.0
2002	346	18.5
2003	355	21.6
2004	252	-13.7
2005	408	39.7

4.3 NEW ENGLAND SYSTEM INSTALLED CAPACITY

Table 4.2 and Table 4.3 show the total New England capacity claimed for capability as listed in ISO New England's 2006 Capacity, Energy, Loads and Transmission (CELT) Report for the summer and winter period, respectively. Table 4.4 illustrates the capacity that was added to the New England system during 1999 through 2005, 95% of which was gas-fired combined cycle.

Table 4.2: New England Summer (June through September) Capacity – 2006 CELT[5, 6]

	Connecticut		Massachusetts		Maine		New Hampshire		Rhode Island		Vermont		New England	
Unit Type	MW	%	MW	%	MW	%	MW	%	MW	%	MW	%	MW	%
Combined Cycle	1,728.8	23.1	5,150.0	39.5	1,406.0	44.7	1,159.2	28.9	1,790.4	99.0	-	-	11,234.4	36.9
Gas Turbine	661.8	8.9	542.7	4.2	29.0	0.9	88.4	2.2	-	-	61.8	6.4	1,383.7	4.5
Hydro	119.8	1.6	248.7	1.9	526.3	16.7	467.3	11.7	3.2	0.2	300.3	31.1	1,665.6	5.5
Internal Combustion	5.3	0.1	104.0	0.8	13.0	0.4	5.8	0.1	14.6	0.8	23.4	2.4	166.1	0.5
Nuclear	2,037.1	27.3	684.7	5.3	-	-	1,220.1	30.4	-	-	506.0	52.5	4,448.0	14.6
Pumped Storage	29.4	0.4	1,659.9	12.7	-	-	-	-	-	-	-	-	1,689.3	5.6
Fossil Steam	2,886.9	38.7	4,646.7	35.6	1,169.0	37.2	1,070.0	26.7	-	-	72.5	7.5	9,845.1	32.4
Wind	-	-	0.2	0.0	-	-	-	-	-	-	0.5	0.0	0.7	0.0
Total	7,469.1	100.0	13,037.0	100.0	3,143.2	100.0	4,010.8	100.0	1,808.2	100.0	964.5	100.0	30,432.9	100.0

Table 4.3: New England Winter (January through May, October through December) Capacity – 2006 CELT[5, 6]

	Connecticut		Massachusetts		Maine		New Hampshire		Rhode Island		Vermont		New England	
Unit Type	MW	%	MW	%	MW	%	MW	%	MW	%	MW	%	MW	%
Combined Cycle	1,987.4	25.0	6,068.4	41.6	1,535.4	45.6	1,304.4	31.0	2,047.2	99.1	-	-	12,942.9	39.0
Gas Turbine	831.0	10.4	750.5	5.1	37.5	1.1	107.8	2.6	-	-	88.1	8.6	1,814.9	5.5
Hydro	126.3	1.6	258.3	1.8	586.2	17.4	497.6	11.8	3.2	0.2	318.9	31.1	1,790.5	5.4
Internal Combustion	5.4	0.1	104.7	0.7	20.1	0.6	5.8	0.1	14.6	0.7	29.2	2.8	179.8	0.5
Nuclear	2,037.4	25.6	684.7	4.7	-	-	1,219.0	29.0	-	-	512.8	50.0	4,453.9	13.4
Pumped Storage	29.0	0.4	1,665.3	11.4	-	-	-	-	-	-	-	-	1,694.3	5.1
Fossil Steam	2,942.9	37.0	5,060.5	34.7	1,186.2	35.2	1,075.2	25.5	-	-	74.6	7.3	10,339.4	31.1
Wind	-	-	0.3	0.0	-	-	-	-	-	-	1.7	0.2	2.0	0.0
Total	7,959.4	100.0	14,592.8	100.0	3,365.4	100.0	4,209.8	100.0	2,065.1	100.0	1,025.2	100.0	33,217.6	100.0

[5] Sum may not equal total due to rounding.
[6] Capability as of January 1, 2006

Table 4.4: New England Generator Unit Additions - 1999 through 2005[7]

Generator Name	State	Unit Type	Summer Capability (MW)	Winter Capability (MW)	Commercial Date
Bridgeport Energy Phase II	CT	Combined Cycle	178	178	07/24/1999
Champion	ME	Steam Turbine	33	33	08/01/1999
Dighton	MA	Combined Cycle	144	144	08/01/1999
1999 Totals			**355**	**355**	
Maine Independence	ME	Combined Cycle	470	500	05/01/2000
Berkshire Power	MA	Combined Cycle	267	289	06/19/2000
Tiverton	RI	Combined Cycle	256	281	08/18/2000
Rumford	ME	Combined Cycle	266	279	10/16/2000
Androscoggin (Units 1 & 2)	ME	Combined Cycle	86	90	12/28/2000
Androscoggin (Unit #3)	ME	Combined Cycle	38	50	12/28/2000
2000 Totals			**1,383**	**1,489**	
Bucksport	ME	Combined Cycle	169	186	01/01/2001
Millennium	MA	Combined Cycle	331	388	04/06/2001
Westbrook	ME	Combined Cycle	520	578	04/13/2001
ANP Blackstone 1	MA	Combined Cycle	277	277	06/07/2001
ANP Blackstone 2	MA	Combined Cycle	277	277	07/13/2001
Wallingford Units 1 & 3	CT	Gas Turbine	84	98	12/31/2001
2001 Totals			**1,658**	**1,804**	
Wallingford Unit 4	CT	Gas Turbine	42	49	01/23/2002
Wallingford Unit 2	CT	Gas Turbine	42	49	02/07/2002
Wallingford Unit 5	CT	Gas Turbine	42	49	02/07/2002
Lake Road Unit #1	CT	Combined Cycle	270	270	03/15/2002
Lake Road Unit #2	CT	Combined Cycle	270	270	03/15/2002
Lake Road Unit #3	CT	Combined Cycle	270	270	05/22/2002
West Springfield 1 & 2	MA	Gas Turbine	80	98	06/07/2002
ConEd Newington Unit 1	NH	Combined Cycle	261	281	09/18/2002
ConEd Newington Unit 2	NH	Combined Cycle	261	281	09/18/2002
ANP Bellingham Unit #1	MA	Combined Cycle	288	308	10/24/2002
Hope Energy (RISE)	RI	Combined Cycle	500	531	11/05/2002
Kendall Repowering	MA	Combined Cycle	172	234	12/18/2002
ANP Bellingham Unit #2	MA	Combined Cycle	288	308	12/28/2002
2002 Totals			**2,787**	**2,997**	
AES Granite Ridge	NH	Combined Cycle	678	767	04/01/2003
Mystic Station Block 8	MA	Combined Cycle	707	850	04/13/2003
Great Lakes Hydro America	ME	Hydro	100	100	05/20/2003
Mystic Station Block 9	MA	Combined Cycle	707	850	06/11/2003
Pilgrim Uprate	MA	Nuclear	35	35	08/01/2003
Fore River	MA	Combined Cycle	700	843	08/04/2003
NECCO Cogeneration	MA	Internal Combustion	5	5	10/01/2003
2003 Totals			**2,932**	**3,450**	
Milford Power Unit 1	CT	Combined Cycle	268	287	02/12/2004
Ridgewood RI Generation	RI	Internal Combustion	2	2	02/18/2004
Millstone 2 Uprate	CT	Nuclear	16	3	03/10/2004
Cabot Turner’s Falls Uprate	MA	Hydro	9	9	05/01/2004
Milford Power Unit 2	CT	Combined Cycle	268	287	05/03/2004
Fraser Paper – Berlin, NH	NH	Steam Turbine	13	13	06/22/2004
Millstone 3 Uprate	CT	Nuclear	25	-	06/28/2004
2004 Totals			**601**	**601**	

[7] Sum may not equal total due to rounding

Generator Name	State	Unit Type	Summer Capability (MW)	Winter Capability (MW)	Commercial Date
Seabrook Power Uprate	NH	Nuclear	60	60	05/01/2005
2005 Totals			**60**	**60**	
1999-2005 Totals			**9,776**	**10,756**	

5.0 RESULTS

5.1 2005 CALCULATED MARGINAL HEAT RATE

In MEA studies prior to 1999, a fixed Marginal Heat Rate of 10.0 MBtu/MWh was assumed and then used to convert from lbs/MWh to lbs/MBtu. In the 1999 – 2003 New England Marginal Emissions Rate Analysis, the Marginal Heat Rate was calculated using the results of production simulation runs. For the 2004 and 2005 MEA analysis, it was based on the actual generation of *intermediate fossil units*. Since heat rate is equal to fuel consumption divided by generation[8], the 2005 Calculated Marginal Heat Rate is defined as follows:

$$\text{2005 Calculated Marginal Heat Rate} = \frac{\text{(Calculated Fuel Consumption of Intermediate Fossil Units)}}{\text{(Actual Generation of Intermediate Fossil Units)}}$$

The fuel consumption of the intermediate fossil units was calculated by multiplying each unit's generation by the heat rate information collected and maintained by ISO-NE Market Monitoring.

The calculated marginal heat rate reflects the average annual efficiency of the *intermediate fossil units* dispatched throughout 2005. The lower the marginal heat rate value, the more efficient the system or marginal generator(s).

Table 5.1: Historically Calculated New England 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

The 2005 Calculated Marginal Heat Rate is used as the global conversion factor to convert from lbs/MWh to lbs/MBtu for all calculations within this report.

5.1.1 Observations

As shown in Table 5.1, the annual Calculated Marginal Heat Rate has decreased since 1999 from 10.013 MBtu/MWh to 8.140 MBtu/MWh. This is primarily due to the addition of over 9,000 MW of gas-fired combined cycle units with high efficiency rates. Figure 5.1 illustrates the Calculated Marginal Heat Rate spanning the 1999 – 2005 timeframe.

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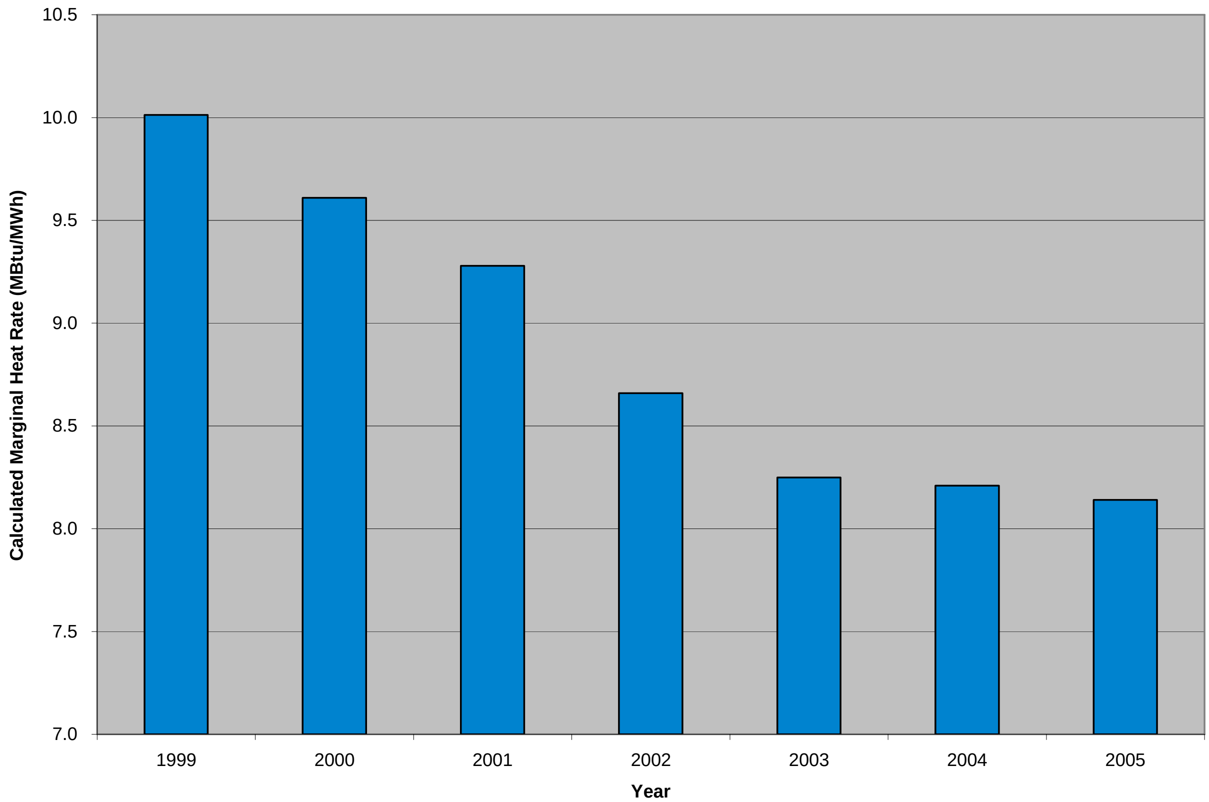
[8] Heat rate is the measure of efficiency in converting input fuel to electricity. Heart rate for power plants depends on the individual plant design, its operating conditions, and its level of electrical power output. The lower the heat rate, the more efficient the plant.

Figure 5.1: Historically Calculated New England Marginal Heat Rate (MBtu/MWh)



5.2 2005 Marginal Emission Rates

Table 5.2 shows the SO_2, NO_X, and CO_2 calculated marginal emission rates in lbs/MWh for the New England system. The NO_X data is 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 annual on-peak and off-peak rates are provided for those emissions. Table 5.3 shows the same information expressed in lbs/MBtu. As noted earlier, the 2005 Calculated Marginal Heat Rate of 8.140 MBtu/MWh was used as the conversion factor.

Table 5.2: 2005 Calculated New England Marginal Emission Rates (lbs/MWh)

	Ozone Season		Non-Ozone Season		Annual		Annual
Air Emission	On-Peak	Off-Peak	On-Peak	Off-Peak	On-Peak	Off-Peak	Average (All Hours)
SO_2					1.80	1.63	1.75
NO_X	0.51	0.39	0.62	0.57			0.54
CO_2					1,116	1,087	1,107

Table 5.3: 2005 Calculated New England Marginal Emission Rates (lbs/MBtu)

	Ozone Season		Non-Ozone Season		Annual		Annual
Air Emission	On-Peak	Off-Peak	On-Peak	Off-Peak	On-Peak	Off-Peak	Average (All Hours)
SO_2					0.22	0.20	0.21
NO_X	0.06	0.05	0.08	0.07			0.07
CO_2					137	133	136

5.2.1 Observations

The overall New England emissions are dependent on the specific units that are available and dispatched to serve load. Therefore, there could be wide variations in the seasonal emissions, primarily due to changes in unit availability, fuel consumption, fuel switching, and load levels.

In all ISO air emissions calculations, the on-peak marginal rates are consistently higher than the off-peak marginal rates. This is most likely because the additional generation that is brought on line to meet the higher demand during on-peak periods has higher emission rates. These typically are older peaking combustion turbines with little if any emission controls.

Table 5.3 also shows that NO_X emissions during the ozone season are lower than during the non-ozone season. NO_X is a precursor of ozone air pollution, which is only a problem during the hot summer months (i.e., the ozone season). The lower NO_X emissions during the ozone season are the result of higher natural gas use during the summer months. Natural gas is used more during the summer than the winter because it is readily available for power generation during the summer, as opposed to the winter when gas is needed for home heating. In addition, environmental permits limit the burning of oil during the summer months due to its higher NO_X emissions.

5.3 CALCULATED HISTORICAL MARGINAL EMISSION RATES

Table 5.4, Table 5.5, and Table 5.6 illustrate the calculated marginal emission rates for SO_2, NO_X, and CO_2 in lbs/MWh for the years 1993 through 2005. The SO_2 and CO_2 tables include only the annual average emission rates, while the NO_X table shows the ozone and non-ozone season details. All three tables show the annual average percentage change from the previous year. Figure 5.2, Figure 5.3, and Figure 5.4 are graphical representations of Table 5.4, Table 5.5, and Table 5.6, respectively.

Table 5.4: Calculated New England SO_2 Marginal Emission Rates (lbs/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

Table 5.5: Calculated New England NO_X Marginal Emission Rates (lbs/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

Table 5.6: Calculated New England CO_2 Marginal Emission Rates (lbs/MWh)

Year	Annual Average	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

5.3.1 Observations

There is a noticeable decrease in the marginal emission rates for NO_X in 1995 primarily due to the implementation of NO_X RACT regulations as required under Title I of the 1990 Clean Air Act Amendments. This decrease in the calculated NO_X marginal emission rate continued into the 2004 calendar year. However, there was no change in the annual average marginal NO_X emission rate between 2004 and 2005. Most of the decrease in emission rates that took place in previous years can be attributed to the commercialization of many highly efficient, low emitting natural gas-fired combined cycle plants over the last several years (see Table 4.4) and additional reductions required under the NO_X Budget Program. Since no new natural gas-fired capacity was added to the New England system in 2005, it is reasonable that the marginal NO_X emission rate did not change.

The CO_2 marginal emission rates also remained essentially the same between 2004 and 2005, which is a change in the trend of declining CO_2 rates that had been occurring since 1999. This may again be attributed to the fact that there were no additions of gas-fired power plants in 2005. However, the SO_2 emission rate did continue to decline in 2005, falling by approximately 14 percent between 2004 and 2005.

Throughout the years, many factors contribute to the calculated marginal emission rates shown. Since 1993, there has been an increase in the availability of the New England nuclear units[9], 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-fired generation to compensate for the unavailability of three nuclear units.

Overall, there has been a significant decrease in the marginal emission rates since 1993. In twelve years, SO_2 and NO_X annual marginal rates have declined by over 85% and CO_2 by 33%. This is evidence of a much cleaner generation fleet in New England today.

[9] This increase in nuclear availability is illustrated in *Understanding New England Generating Unit Availability* http://www.iso-ne.com/pubs/spcl_rpts/2001/understanding_ne_generating.pdf

Figure 5.2: Historically Calculated New England SO_2 Marginal Emission Rate

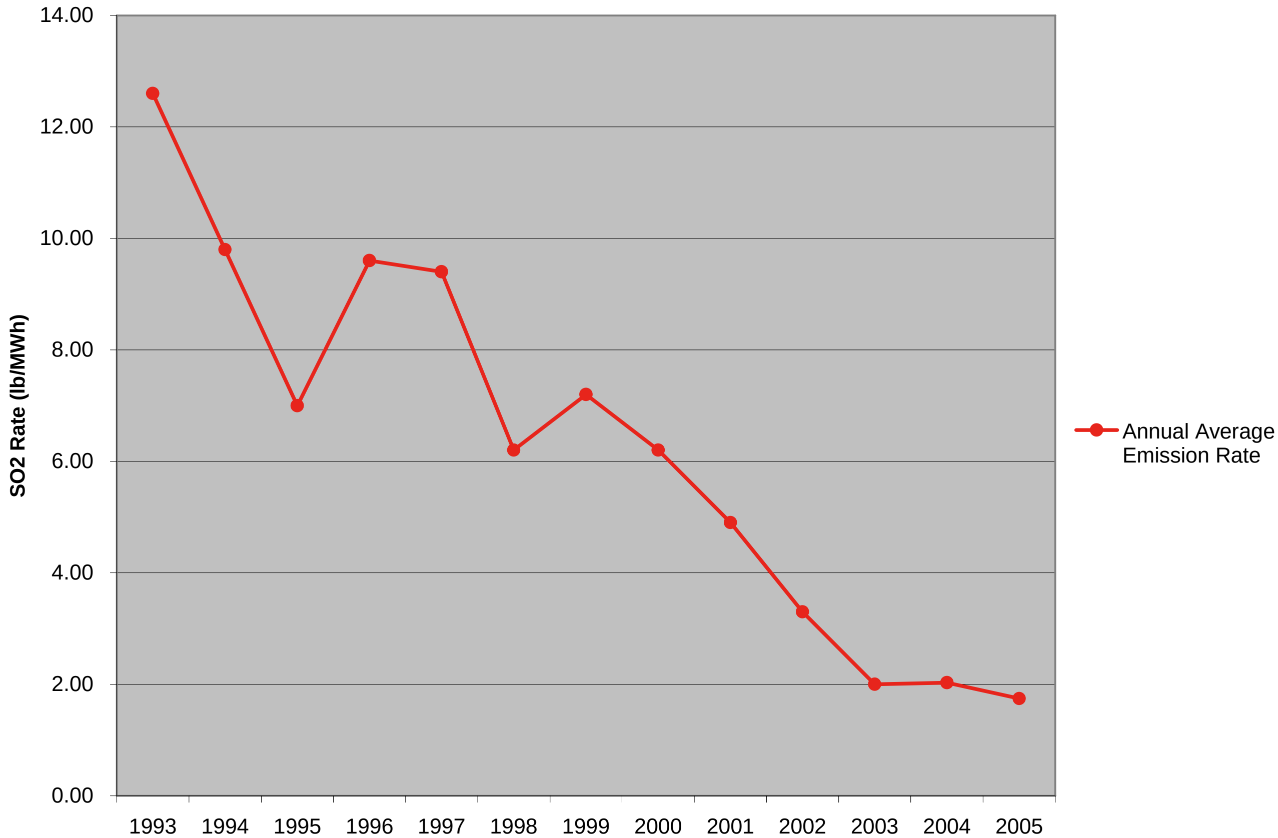


Figure 5.3: Historically Calculated New England NO_X Marginal Emission Rates

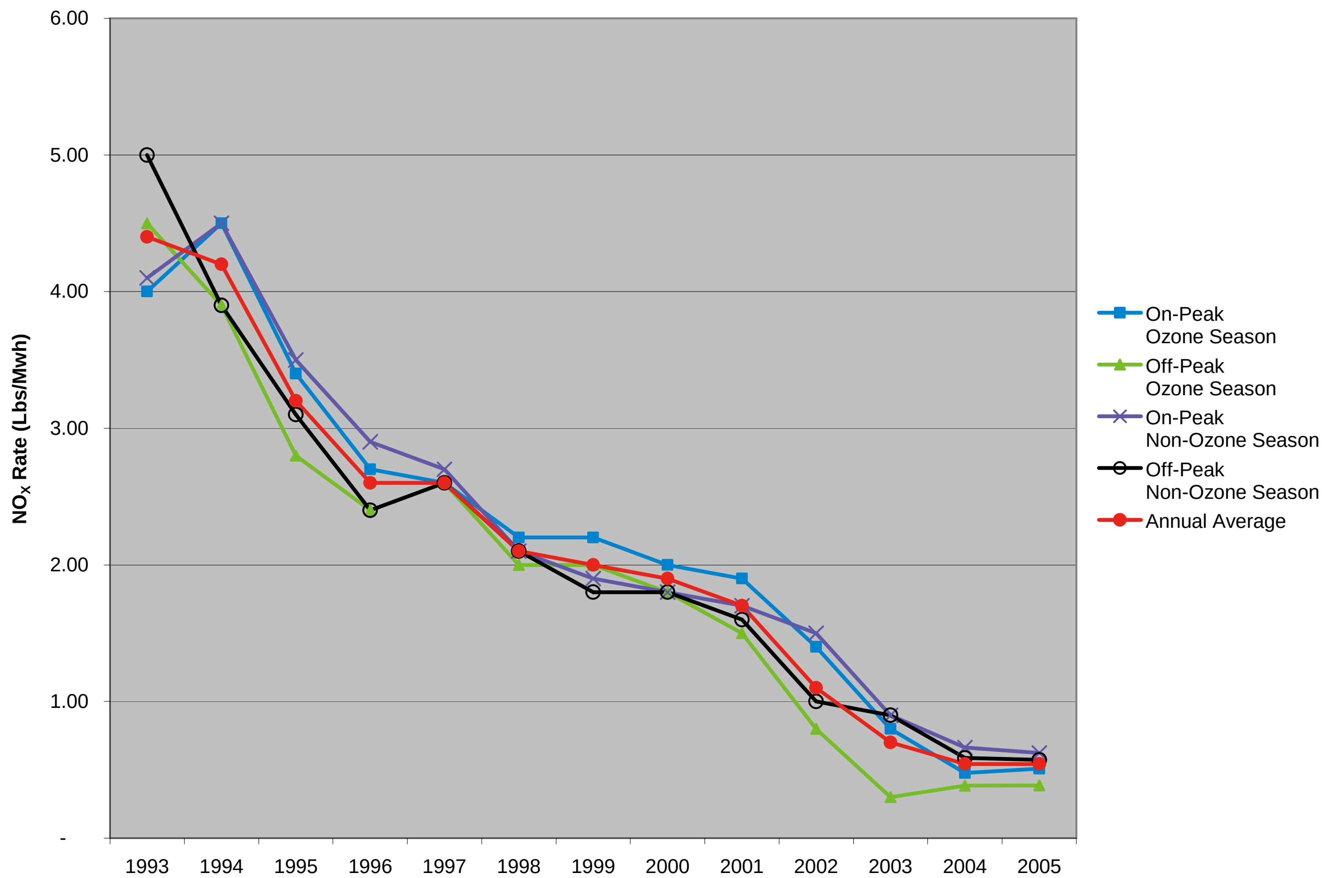
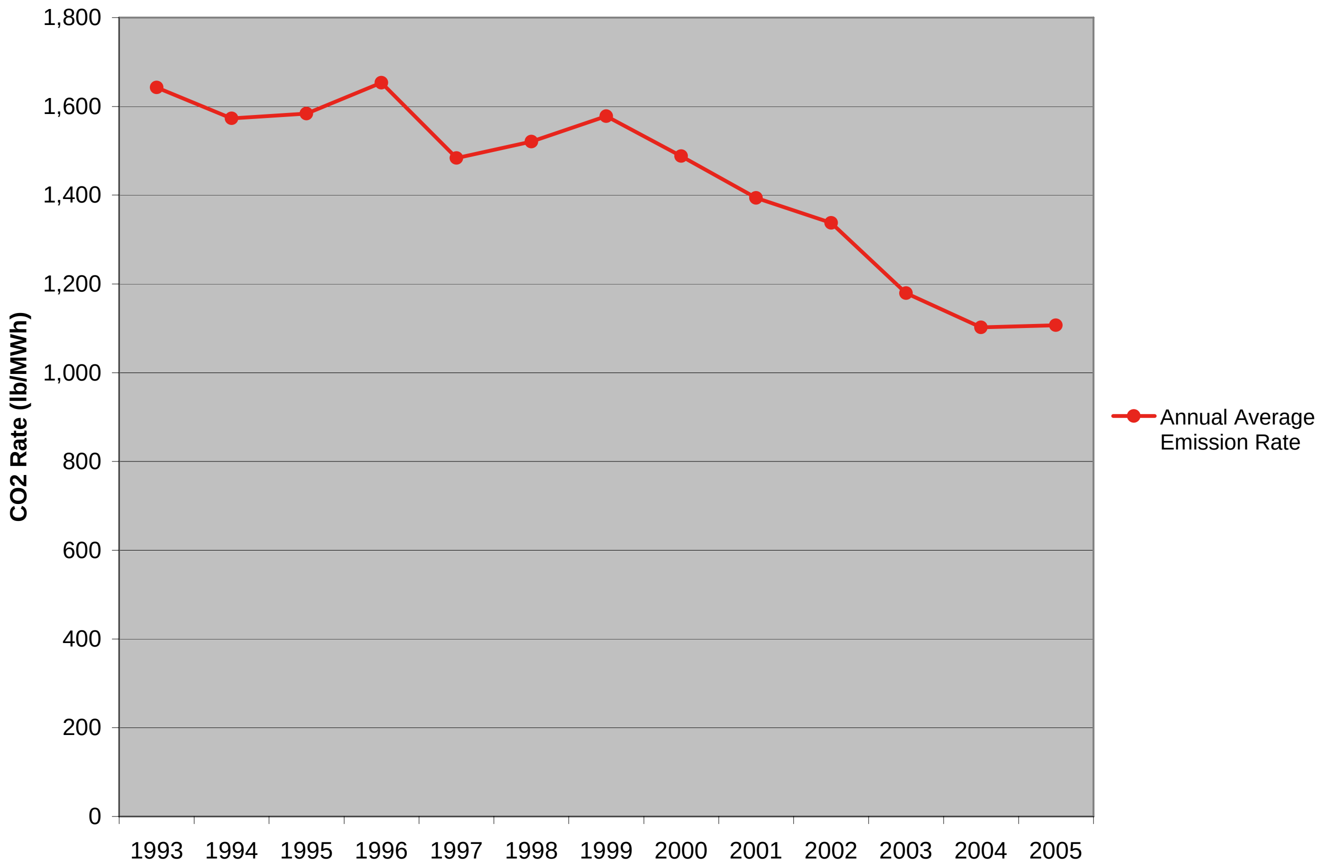


Figure 5.4: Historically Calculated New England CO_2 Marginal Emission Rate



5.4 CALCULATED MARGINAL EMISSION RATES BY STATE

Table 5.7, Table 5.8, and Table 5.9 illustrate the 2005 calculated SO_2, NO_X, and CO_2 marginal air emission rates, by 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 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, where the only generating units in the intermediate fossil category are internal combustion and gas turbine units.

Table 5.7: 2005 Calculated New England SO_2 Marginal Emission Rates by State (lbs/MWh)

State	Annual On-Peak	Annual Off-Peak	Annual Average (All Hours)
Connecticut	0.87	0.73	0.83
Maine	1.02	0.56	0.86
New Hampshire	2.85	1.86	2.51
Rhode Island	0.01	0.01	0.01
Vermont	4.22	4.24	4.22
Massachusetts	2.67	2.51	2.61
New England Average	1.80	1.63	1.75

Table 5.8: 2005 Calculated New England NO_X Marginal Emission Rates by State (lbs/MWh)

State	Ozone Season		Non-Ozone Season		
	On-Peak	Off-Peak	On-Peak	Off-Peak	Annual Average (All Hours)
Connecticut	0.74	0.55	0.76	0.76	0.72
Maine	0.51	0.45	0.62	0.58	0.55
New Hampshire	0.53	0.32	0.61	0.46	0.51
Rhode Island	0.16	0.10	0.17	0.10	0.15
Vermont	4.62	4.58	4.43	4.40	4.54
Massachusetts	0.49	0.36	0.68	0.59	0.56
New England Average	0.51	0.39	0.62	0.57	0.54

Table 5.9: 2005 Calculated New England CO_2 Marginal Emission Rates by State (lbs/MWh)

State	Annual On-Peak	Annual Off-Peak	Annual Average (All Hours)
Connecticut	1,182	1,133	1,167
Maine	1,033	994	1,020
New Hampshire	1,100	1,014	1,070
Rhode Island	919	877	910
Vermont	1,898	1,889	1,897
Massachusetts	1,172	1,152	1,165
New England Average	1,116	1,087	1,107

5.5 CALCULATED NEW ENGLAND SYSTEM AVERAGE EMISSIONS

In addition to calculating the marginal emission rates, the aggregate emissions of the system were also calculated. The 2005 system average emissions were calculated using the same types of data as the marginal emissions calculations: actual hourly generation reported to ISO-NE, along with available monthly or annual EPA emissions data, or, alternatively, assumed emission rates based on unit type. Table 5.10 shows the aggregate SO_2, NO_X, and CO_2 air emissions calculated based on the actual hourly unit generation of all units and the assumed unit air emission rates.

Table 5.10: 2005 Calculated New England Generation System Annual Aggregate Emissions of SO_2, NO_X, and CO_2 in kTons[10]

State	SO_2	NO_X	CO_2
Connecticut	9.29	8.97	11,900
Maine	5.71	10.85	7,780
Massachusetts	83.09	26.97	28,063
New Hampshire	51.65	10.10	9,527
Rhode Island	0.20	0.55	2,779
Vermont	0.06	0.57	516
New England	150.00	58.01	60,580

Table 5.11 shows the aggregate SO_2, NO_X, and CO_2 air emissions for the years 2001 through 2005, as calculated based on the modeled and actual generation[11] and the assumed air emissions.

Table 5.11: 2001 - 2005 Calculated New England Generation System Annual Aggregate Emissions of SO_2, NO_X, and CO_2 in kTons

Year	SO_2	NO_X	CO_2
2001	200.01	59.73	52,991
2002	161.1	56.4	54,497
2003	159.41	54.23	56,278
2004	149.75	50.64	56,723
2005	150.00	58.01	60,580

Table 5.12 illustrates the annual average SO_2, NO_X, and CO_2 air emission rate values in lbs/MWh for the 1999 – 2005 time period. These rates are calculated by dividing the total air emissions by the total generation from all units.

[10] Sum may not equal total due to rounding
[11] The 1999-2003 data is based on production simulation model results while the 2004 and 2005 data is based on actual generation and calculated air emissions.

Table 5.12: 1999 – 2005 Calculated New England Generation System Annual Average SO_2, NO_X, and CO_2 Emission Rates in lbs/MWh

Year	SO_2	NO_X	CO_2
1999	4.52	1.36	1,009
2000	3.88	1.12	913
2001	3.51	1.05	930
2002	2.69	0.94	909
2003	2.75	0.93	970
2004	2.31	0.78	876
2005	2.27	0.88	919

Figure 5.5, Figure 5.6, and Figure 5.7 show the relationship between the system emission rates in Table 5.12 and the marginal emission rates for SO_2, NO_X and CO_2 during that same period.

Figure 5.5: 1999 – 2005 Calculated New EnglandAnnual Average System Emission Rate vs. Marginal Emission Rate for SO_2, in lbs/MWh

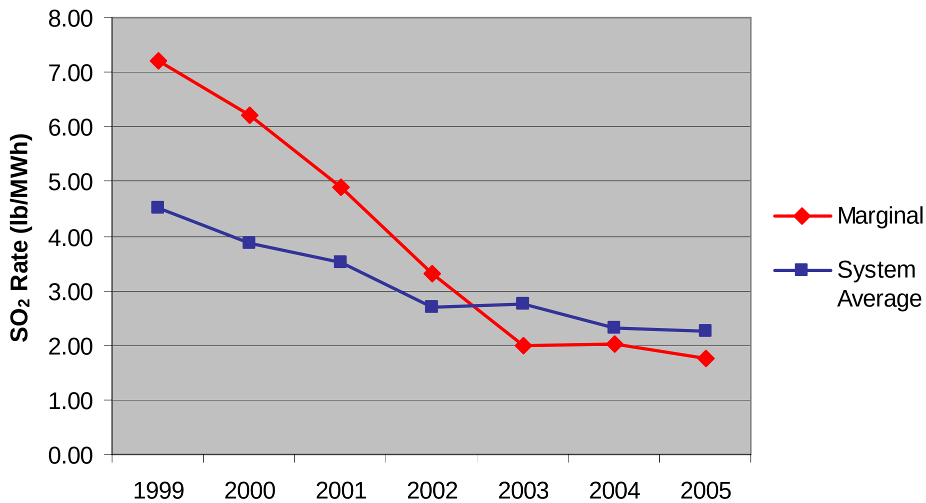


Figure 5.6: 1999 – 2005 Calculated New England Annual Average System Emission Rate vs. Marginal Emission Rate for NO_X, in lbs/MWh

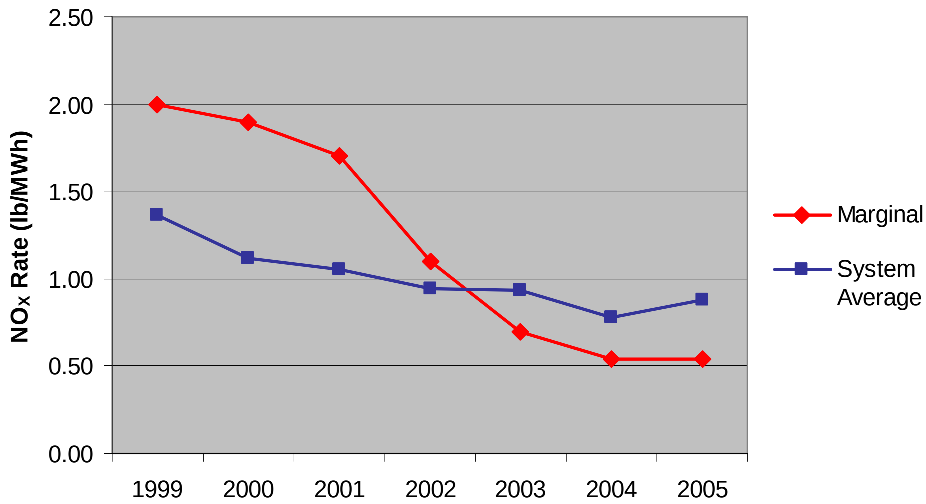
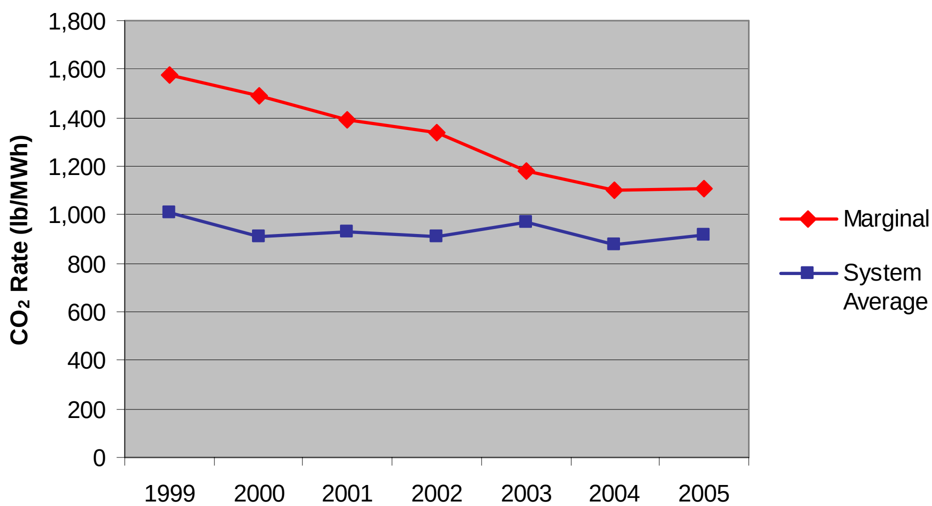


Figure 5.7: 1999 – 2005 Calculated New England Annual Average System Emission Rate vs. Marginal Emission Rate for CO_2, in lbs/MWh



5.5.1 Observations

During the period from 1999 to 2005, both the SO_2 and NO_X system emission rates decreased, but at a slower rate than the marginal emission rates for those pollutants. In fact, the marginal emission rates for SO_2 and NO_X 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 system emission rate has exhibited little change since 1999, while the CO_2 marginal emission rate has declined 30% during that period. Despite the decrease in the marginal emission rate, it has remained higher than the system emission rate during the entire period from 1999 through 2005.

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