2004 New England Marginal Emission Rate Analysis

ISO New England Inc.

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1 EXECUTIVE SUMMARY

Since 1993, ISO New England Inc. (ISO-NE) has analyzed 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 2004 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 2004. 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 2004 marginal emission rate calculations are shown in Table 1.1 in Lbs/MWh and Table 1.2 in Lbs/MBtu.

Table 1.1: 2004 Marginal Emission Rates (Lbs/MWh)

Air Emission	On-Peak Ozone Season	Off-Peak Ozone Season	On-Peak Non-Ozone Season	Off-Peak Non-Ozone Season	Annual Average (All Hours)
SO_2	1.77	1.43	2.45	2.24	2.03
NO_X	0.48	0.38	0.66	0.59	0.54
CO_2	1,072	1,040	1,147	1,124	1,102

Table 1.2: 2004 Marginal Emission Rates (Lbs/MBtu)[2]

Air Emission	On-Peak Ozone Season	Off-Peak Ozone Season	On-Peak Non-Ozone Season	Off-Peak Non-Ozone Season	Annual Average (All Hours)
SO_2	0.22	0.17	0.30	0.27	0.25
NO_X	0.06	0.05	0.08	0.07	0.07
CO_2	131	127	140	137	134

The 2004 marginal emission rate values were calculated based on the actual 2004 hourly generation. The 2004 MEA values were developed using a different calculation methodology than what has been used in previously published MEA reports. Prior MEA Reports reflect marginal emission rates calculated using a production simulation model.

The 2004 Calculated Marginal Heat Rate was also determined using actual 2004 generation. This rate is used to convert the marginal emission rates from Lbs/MWh to Lbs/MBtu. The 2004 Calculated Marginal Heat Rate was determined to be 8.21 MBtu/MWh.

Calculated marginal emission rates for 2004 have only slightly changed from the 2003 calculated values. The 2004 rates have decreased from the 2003 rates in most time periods studied. However, in a few instances the rate has increased. Although the method of calculation has changed, these results are consistent with what is expected. During 2004, just over 500 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.

As with the calculated marginal emission rates, the calculated marginal heat rate has changed only slightly from that calculated for 2003. Specifically, the rate has decreased from 8.25 MBtu/MWh to 8.21 MBtu/MWh.

[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 2004 calculated Marginal Heat Rate of 8.21 Mbtu/MWh is used.

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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 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. One of the activities is electric utility DSM programs installed since January 1, 1992. 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 2003 to provide similar environmental analysis for each of these years.

The MEA Report is used by a variety of stakeholders including consulting firms, environmental advocacy groups, and state air regulators. For example, the MEA Report can be used to estimate the value (avoided emissions) of Renewable Energy Certificates (REC) by providing both REC suppliers and stakeholders with information that can be used to communicate the environmental benefits of RECs and works to enhance the overall REC marketplace.

The 2004 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 air emissions during the calendar year 2004.

3 METHODOLOGY

3.1 CALCULATING MARGINAL EMISSIONS

In past studies, 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.

For 2004, a new methodology has been 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 uses 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 are calculated based on this information. The resultant emission rates are assumed to be the marginal emission rates.

The subset of units, referred to as *intermediate fossil units* for purposes of the 2004 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.

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:

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

This report calculates the 2004 New England, and each of the six states' marginal air emission rates for SO_2, $NO_{X,}$ and CO_2 covering 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 2004.

4 ASSUMPTIONS

The key parameters and assumptions modeled within the 2004 Marginal Emissions Rate Analysis are highlighted in the sections below.

4.1 EMISSION RATES

Individual generating unit emission rates were calculated from the 2004 actual emissions as reported to the US EPA's Acid Rain Division and published in the preliminary US EPA Emissions Scorecard 2004. For those units that were not required to file with the US EPA Acid Rain Division, the study used emission rates from the EPA's E-Grid2002 Version 2.0 data or, as a default, emission rates based on similar unit types.

4.2 NEW ENGLAND SYSTEM INSTALLED CAPACITY

Table 4.1 and Table 4.2 show the total New England capacity claimed for capability as listed in ISO New England's 2005 Capacity, Energy, Loads and Transmission (CELT) Report for the summer and winter period, respectively. Table 4.3 illustrates the capacity that was added to the New England system during 1999 through 2004.

Table 4.1: New England Summer (June through September) Capacity – 2005 CELT[3]

	Connecticut		Massachusetts		Maine		New Hampshire		Rhode Island		Vermont		Total	
Unit Type	MW	%	MW	%	MW	%	MW	%	MW	%	MW	%	MW	%
Combined Cycle	1,759.7	23.4	5,206.0	38.9	1,534.5	47.0	1,169.5	29.5	1,790.4	99.0	-	-	11,460.1	37.1
Gas Turbine	666.8	8.9	545.4	4.1	29.0	0.9	87.6	2.2	-	-	79.5	8.1	1,408.3	4.6
Hydro	119.8	1.6	247.3	1.8	534.5	16.4	469.4	11.8	3.2	0.2	295.5	30.3	1,669.6	5.4
Internal Combustion	5.3	0.1	101.9	0.8	18.5	0.6	5.7	0.1	14.7	0.8	22.0	2.3	168.0	0.5
Nuclear	2,037.1	27.1	684.8	5.1	-	-	1,159.3	29.3	-	-	506.0	51.8	4,387.1	14.2
Pumped Storage	29.2	0.4	1,642.9	12.3	-	-	-	-	-	-	-	-	1,672.0	5.4
Steam Turbine	2,886.9	38.5	4,957.0	37.0	1,151.0	35.2	1,070.0	27.0	-	-	72.5	7.4	10,137.4	32.8
Wind	-	-	0.2	0.0	-	-	-	-	-	-	0.5	0.0	0.7	0.0
New England	7,504.9	100.0	13,385.5	100.0	3,267.5	100.0	3,961.3	100.0	1,808.2	100.0	976.0	100.0	30,903.4	100.0

Table 4.2: New England Winter (January through May, October through December) Capacity – 2005 CELT[4]

	Connecticut		Massachusetts		Maine		New Hampshire		Rhode Island		Vermont		Total	
Unit Type	MW	%	MW	%	MW	%	MW	%	MW	%	MW	%	MW	%
Combined Cycle	2,015.7	25.2	6,122.5	41.9	1,691.5	48.3	1,314.7	31.6	2,050.9	99.1	-	-	13,195.3	39.5
Gas Turbine	836.5	10.5	752.5	5.2	37.5	1.1	107.0	2.6	-	-	105.8	10.0	1,839.3	5.5
Hydro	126.3	1.6	257.1	1.8	586.2	16.7	499.7	12.0	3.2	0.2	314.8	29.9	1,787.4	5.4
Internal Combustion	5.4	0.1	104.7	0.7	20.3	0.6	5.7	0.1	14.7	0.7	27.7	2.6	178.4	0.5
Nuclear	2,037.4	25.5	684.8	4.7	-	-	1,161.0	27.9	-	-	529.1	50.2	4,412.2	13.2
Pumped Storage	29.0	0.4	1,665.3	11.4	-	-	-	-	-	-	-	-	1,694.3	5.1
Steam Turbine	2,943.3	36.8	5,008.3	34.3	1,168.9	33.4	1,075.2	25.8	-	-	74.6	7.1	10,270.2	30.8
Wind	-	-	0.3	0.0	-	-	-	-	-	-	1.7	0.2	2.0	0.0
New England	7,993.7	100.0	14,595.4	100.0	3,504.4	100.0	4,163.2	100.0	2,068.8	100.0	1,053.7	100.0	33,379.1	100.0

[3] Sum may not equal total due to rounding
[4] Sum may not equal total due to rounding

Table 4.3: Generator Unit Additions - 1999 through 2004[5]

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
Millenium	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 Unit 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	67	70	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
2003 Totals			**2,894**	**3,415**	
Milford Power Unit 1	CT	Combined Cycle	245	262	02/12/2004
Millstone 2 Uprate	CT	Nuclear	30	30	03/10/2004
Milford Power Unit 2	CT	Combined Cycle	245	262	05/03/2004
Fraser Paper[6]	NH	Steam Turbine	13	13	06/22/2004
2004 Totals			**533**	**567**	
1999-2004 Totals			**9,690**	**10,627**	

[5] Sum may not equal total due to rounding
[6] Generation is currently located behind the meter at Fraser Paper. The 13 MW is from additional capacity being added to the system that will feed into the New England bulk power grid.

5 RESULTS

5.1 2004 NEW ENGLAND POWER SYSTEM OPERATIONS

During 2004, the most severe test of the New England power system occurred due to the cold snap experienced on January 14–16 (the January 2004 Cold Snap)[7], during which New England experienced extremely low temperatures and record winter peak demand. Overall during this time, the New England electricity markets and infrastructure produced reliable operations and competitive outcomes. While installed capacity was more than adequate to meet demand, plant operational difficulties, caused by cold weather and inadequate firm natural gas contracting, rendered unavailable a significant portion of New England's generation supply.

The summer months were cooler than normal, resulting in a peak electricity demand 2.3% below the 2003 peak. Mild weather coupled with a surplus of installed capacity provided for robust reserve margins throughout the summer.

5.2 2004 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 – 2004 New England Marginal Emissions Rate Analysis, the Marginal Heat Rate was calculated using the results of production simulation runs. For the 2004 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 2004 Calculated Marginal Heat Rate is defined as follows:

2004 Calculated Marginal Heat Rate

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

The calculated marginal heat rate reflects the average annual efficiency of the *intermediate fossil units* dispatched throughout 2004. The lower the marginal heat rate value, the more efficient the system or marginal generator(s) is.

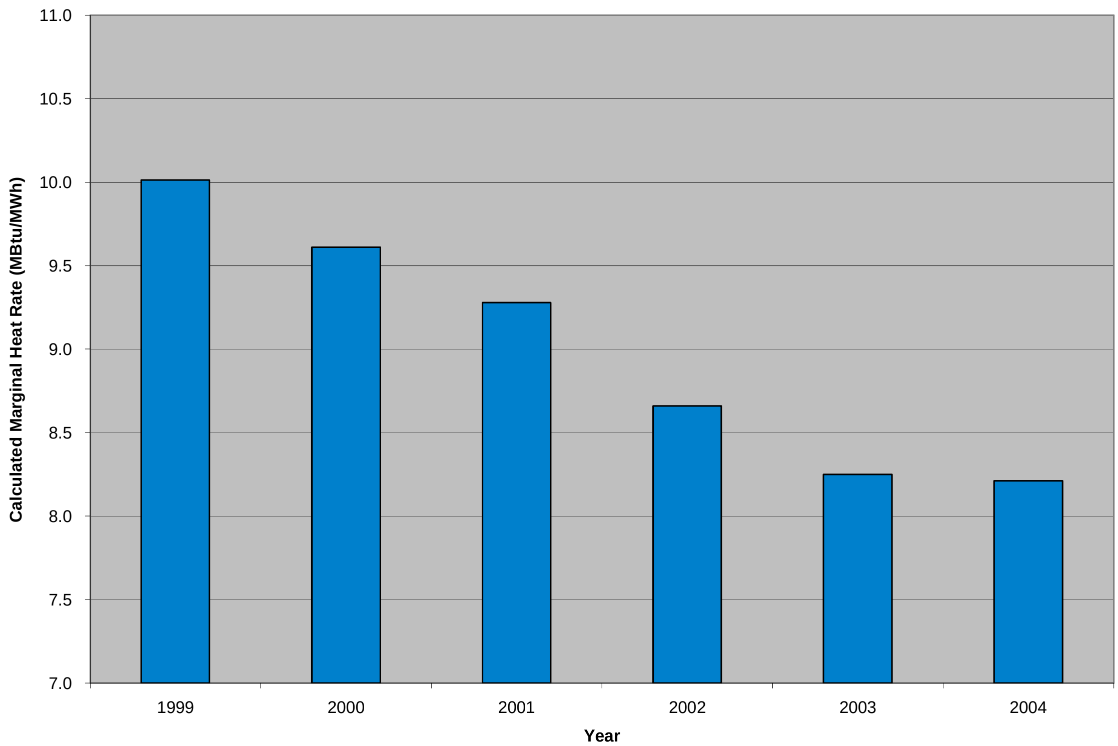
Table 5.1: Historically Calculated Marginal Heat Rate (MBtu/MWh)

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

[7] The ISO-NE Cold Snap Report can be found on the ISO-NE website at http://www.iso-ne.com/pubs/spcl_rpts/2005/cld_snp_rpt/index.html

[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 Marginal Heat Rate (MBtu/MWh)



To convert from Lbs/MWh to Lbs/MBtu, the 2004 Calculated Marginal Heat Rate is used as the global conversion factor for all calculations within this report.

5.2.1 <u>Observations</u>

As shown in Table 5.1, the annual Calculated Marginal Heat Rate has decreased since 1999 from 10.013 MBtu/MWh to 8.210 MBtu/MWh. This is primarily due to the addition of approximately 10,000 MW of gas-fired combined cycle units with high efficiency rates. Figure 5.1 illustrates the Calculated Marginal Heat Rate spanning the 1999 – 2004 timeframe.

5.3 2004 Marginal Emission Rates

Table 5.2 shows SO_2, NO_X, and CO_2 marginal emission rates in Lbs/MWh for the New England system for each of the five time-periods studied. Table 5.3 shows the same information expressed in Lbs/MBtu. As noted earlier, the 2004 Calculated Marginal Heat Rate of 8.21 MBtu/MWh was used as the global conversion factor.

Table 5.2: 2004 Marginal Emission Rates (Lbs/MWh)

Air Emission	On-Peak Ozone Season	Off-Peak Ozone Season	On-Peak Non-Ozone Season	Off-Peak Non-Ozone Season	Annual Average (All Hours)
SO_2	1.77	1.43	2.45	2.24	2.03
NO_X	0.48	0.38	0.66	0.59	0.54
CO_2	1,072	1,040	1,147	1,124	1,102

Table 5.3: 2004 Marginal Emission Rates (Lbs/MBtu)

Air Emission	On-Peak Ozone Season	Off-Peak Ozone Season	On-Peak Non-Ozone Season	Off-Peak Non-Ozone Season	Annual Average (All Hours)
SO_2	0.22	0.17	0.30	0.27	0.25
NO_X	0.06	0.05	0.08	0.07	0.07
CO_2	131	127	140	137	134

5.3.1 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, and load level.

In all studied air emissions results, the on-peak marginal rates are consistently higher than the off-peak marginal rates. This is most likely due to the higher level of generation needed to serve the higher electrical demands experienced over the on-peak periods as compared to off-peak periods.

5.4 Calculated Historical Marginal Emission Rates

Table 5.4, Table 5.5, and Table 5.6 respectfully illustrate the calculated marginal emission rates for SO_2, NO_X, and CO_2 in Lbs/MWh for the years 1993 through 2004. 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 SO_2 Marginal Emission Rates (Lbs/MWh)

Year	On-Peak Ozone Season	Off-Peak Ozone Season	On-Peak Non-Ozone Season	Off-Peak Non-Ozone Season	Annual Average (All Hours)
1993	10.40	14.00	11.20	14.90	12.60
1994	9.40	8.60	10.90	10.40	9.80
1995	8.00	5.60	8.00	6.50	7.00
1996	9.50	9.00	10.60	9.10	9.60
1997	7.40	10.00	9.40	10.60	9.40
1998	6.60	4.90	6.80	6.60	6.20
1999	7.80	6.50	7.30	7.30	7.20
2000	6.60	6.00	6.30	5.90	6.20
2001	5.30	4.40	5.10	5.00	4.90
2002	3.70	2.00	4.90	3.00	3.30
2003	2.50	0.60	2.30	2.40	2.00
2004	1.77	1.43	2.45	2.24	2.03

Table 5.5: Calculated NO_X Marginal Emission Rates (Lbs/MWh)

Year	On-Peak Ozone Season	Off-Peak Ozone Season	On-Peak Non-Ozone Season	Off-Peak Non-Ozone Season	Annual Average (All Hours)
1993	4.00	4.50	4.10	5.00	4.40
1994	4.50	3.90	4.50	3.90	4.20
1995	3.40	2.80	3.50	3.10	3.20
1996	2.70	2.40	2.90	2.40	2.60
1997	2.60	2.60	2.70	2.60	2.60
1998	2.20	2.00	2.10	2.10	2.10
1999	2.20	2.00	1.90	1.80	2.00
2000	2.00	1.80	1.80	1.80	1.90
2001	1.90	1.50	1.70	1.60	1.70
2002	1.40	0.80	1.50	1.00	1.10
2003	0.80	0.30	0.90	0.90	0.70
2004	0.48	0.38	0.66	0.59	0.54

Table 5.6: Calculated CO_2 Marginal Emission Rates (Lbs/MWh)

Year	On-Peak Ozone Season	Off-Peak Ozone Season	On-Peak Non-Ozone Season	Off-Peak Non-Ozone Season	Annual Average (All Hours)
1993	1,630	1,610	1,580	1,750	1,643
1994	1,767	1,334	1,796	1,396	1,573
1995	1,654	1,458	1,713	1,511	1,584
1996	1,696	1,575	1,752	1,590	1,653
1997	1,437	1,522	1,487	1,488	1,484
1998	1,622	1,432	1,538	1,491	1,520
1999	1,644	1,550	1,587	1,531	1,578
2000	1,545	1,505	1,463	1,440	1,488
2001	1,437	1,340	1,406	1,393	1,394
2002	1,412	1,171	1,536	1,300	1,338
2003	1,204	974	1,259	1,236	1,179
2004	1,072	1,040	1,147	1,124	1,102

5.4.1 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 continues into the 2004 calendar year. Most of the continued decrease can be attributed to the commercialization of many new natural gas-fired combined cycled plants over the last several years as shown in Table 4.3. In 2004, there was approximately 500 MW of new natural gas-fired capacity added to the New England system.

The increase in natural gas-fired capacity has also had an affect on the calculated SO_2 and CO_2 marginal emission rates. In all years since 1999, a general decline in these marginal emission rates is shown.

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 therefore, they have been contributing more towards satisfying 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 exception to this is the 1996 to 1998 timeframe when there was an increase in fossil-fired generation to compensate for the unavailability of three nuclear units.

In addition to the increased availability of nuclear generation, the additions of highly efficient, low emitting natural gas-fired generating plants in New England have contributed towards a decline in the calculated marginal emission rates. Overall, results for 2004 illustrate that marginal air emission rates continue to decline from prior years.

[9] This increase in nuclear availability is illustrated in *Understanding New England Generating Unit Availability* http://www.iso-ne.com/pubs/spcl_rpts/2002/Understanding_New_England_Generating_Unit_Availability.pdf

Figure 5.2: Historically Calculated SO_2 Marginal Emission Rates

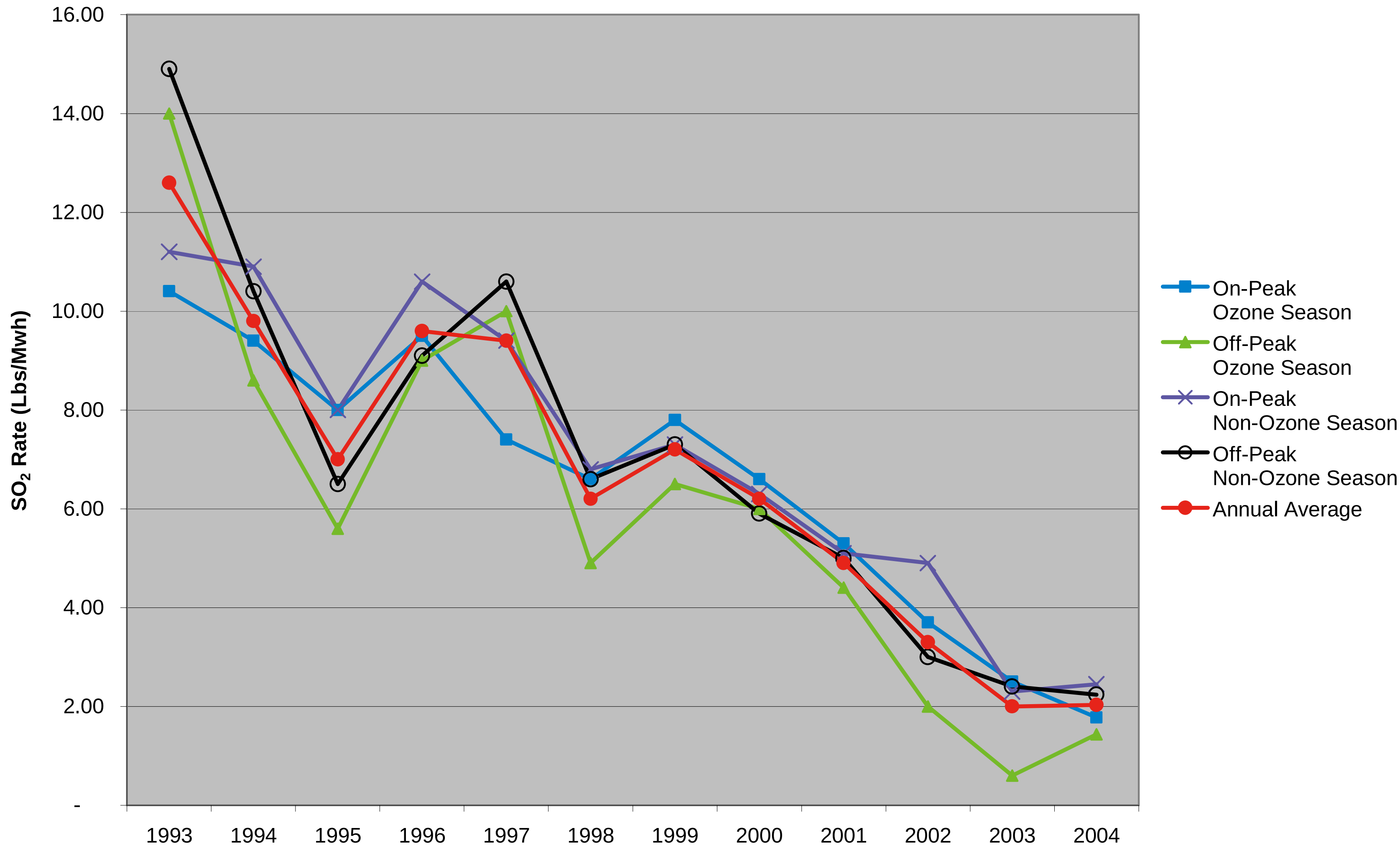


Figure 5.3: Historically Calculated NO_X Marginal Emission Rates

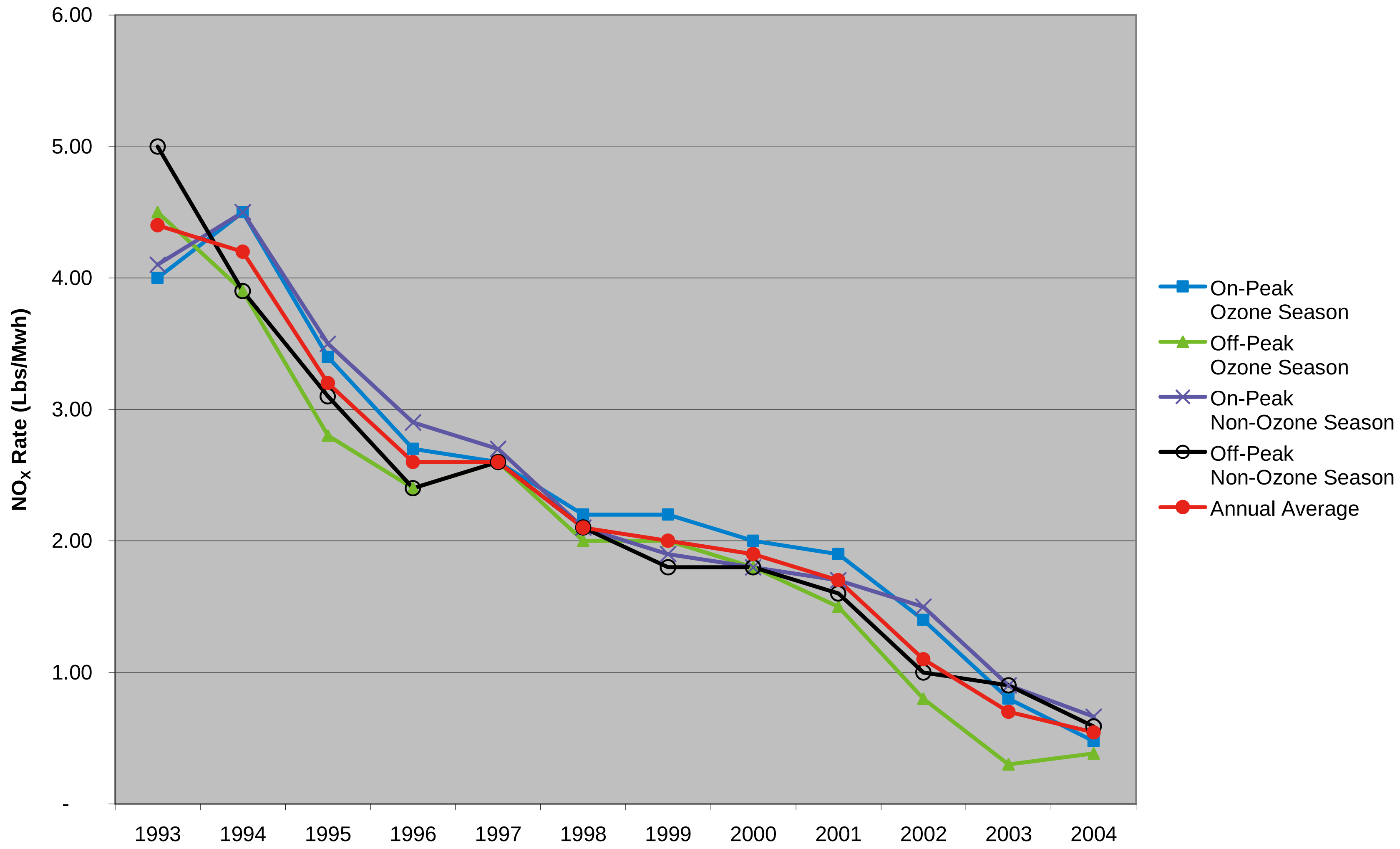
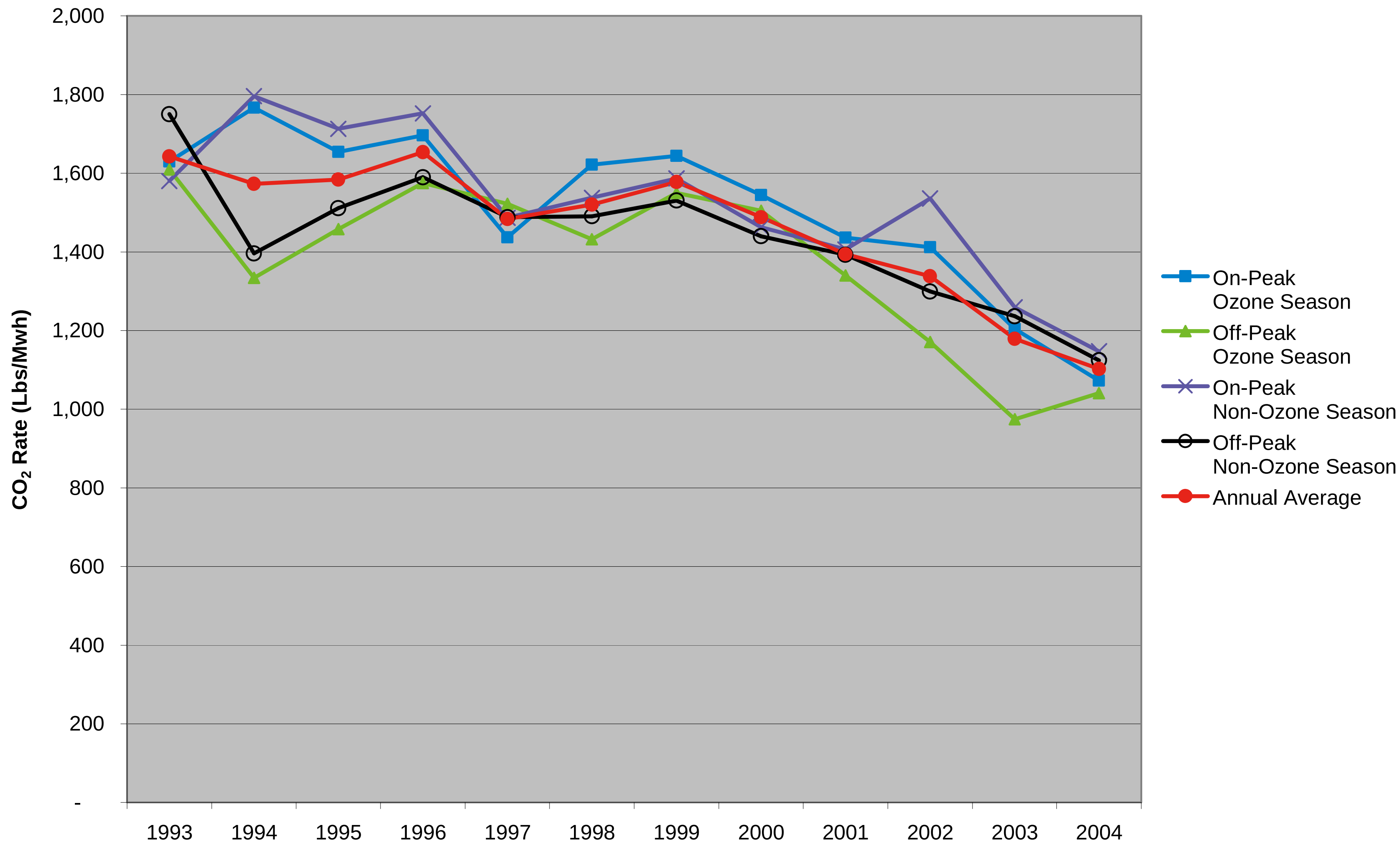


Figure 5.4: Historically Calculated CO_2 Marginal Emission Rates



5.5 CALCULATED MARGINAL EMISSION RATES BY STATE

Table 5.7, Table 5.8, and Table 5.9 illustrate the calculated SO_2, NO_X, and CO_2 marginal air emission rates, by state, for the five time-periods studied. The capacity located within each state is a 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 compared to Vermont, which has only internal combustion and gas turbines units classified as intermediate fossil units.

Table 5.7: 2004 SO_2 Marginal Emission Rates by State (Lbs/MWh)

State	On-Peak Ozone Season	Off-Peak Ozone Season	On-Peak Non-Ozone Season	Off-Peak Non-Ozone Season	Annual Average (All Hours)
Connecticut	0.57	0.32	1.02	0.87	0.70
Maine	0.36	0.19	1.08	0.69	0.64
Massachusetts	2.15	1.90	3.18	3.02	2.65
New Hampshire	5.98	4.22	5.02	4.04	4.79
Rhode Island	0.00	0.00	0.00	0.00	0.00
Vermont	6.27	6.20	6.53	6.33	6.40
New England	1.77	1.43	2.45	2.24	2.03

Table 5.8: 2004 NO_X Marginal Emission Rates by State (Lbs/MWh)

State	On-Peak Ozone Season	Off-Peak Ozone Season	On-Peak Non-Ozone Season	Off-Peak Non-Ozone Season	Annual Average (All Hours)
Connecticut	0.45	0.31	0.75	0.64	0.55
Maine	0.17	0.16	0.33	0.26	0.24
Massachusetts	0.52	0.45	0.78	0.72	0.64
New Hampshire	1.01	0.73	0.88	0.71	0.83
Rhode Island	0.19	0.13	0.18	0.12	0.16
Vermont	12.81	12.79	12.90	12.83	12.86
New England	0.48	0.38	0.66	0.59	0.54

Table 5.9: 2004 CO_2 Marginal Emission Rates by State (Lbs/MWh)

State	On-Peak Ozone Season	Off-Peak Ozone Season	On-Peak Non-Ozone Season	Off-Peak Non-Ozone Season	Annual Average (All Hours)
Connecticut	1,025	959	1,126	1,081	1,050
Maine	983	1,002	1,056	1,045	1,027
Massachusetts	1,105	1,080	1,211	1,187	1,155
New Hampshire	1,277	1,166	1,218	1,155	1,203
Rhode Island	936	882	927	874	911
Vermont	2,248	2,247	2,295	2,265	2,273
New England	1,072	1,040	1,147	1,124	1,102

5.6 CALCULATED SYSTEM AVERAGE EMISSION RATES

In addition to calculating the marginal emission rates, the aggregate emissions of the system can also be calculated. For 2004, this information is based on actual hourly generation reported to ISO-NE. Table 5.10 illustrates 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: 2004 Calculated System Aggregate Emissions of SO_2, NO_X, and CO_2 in kTons[10]

State	SO_2	NO_X	CO_2
Connecticut	8.56	8.59	10,728
Maine	4.89	4.31	6,523
Massachusetts	81.85	26.41	27,246
New Hampshire	54.21	10.19	9,458
Rhode Island	0.19	0.49	2,251
Vermont	0.06	0.65	518
New England	149.75	50.64	56,723

Table 5.11 illustrates the annual average SO_2, NO_X, and CO_2 air emission rate values in Lbs/MWh, as calculated based on the modeled and actual generation[11] and calculated air emissions for the 1999 – 2004 time period. These rates are calculated by dividing the total air emissions by the total generation from all units.

Table 5.11: 1999 – 2004 Calculated Annual Averages of SO_2, NO_X, CO_2 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

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

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