2003 NEPOOL MARGINAL EMISSION RATE ANALYSIS

for

THE NEPOOL ENVIRONMENTAL PLANNING COMMITTEE

by

ISO New England Inc.

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1. EXECUTIVE SUMMARY

ISO New England analyzed the impact that demand side management (DSM) programs have had upon New England Power Pool's (NEPOOL) aggregate SO_2, NO_X, and CO_2 generating unit emissions. This 2003 NEPOOL Marginal Emission Rate Analysis (MEA Report) provides an estimate of marginal SO_2, NO_X, and CO_2 emissions for the calendar year 2003. The results of the 2003 marginal emission rate calculations are shown in Table 1.1 in Lbs/MWh and Table 1.2 in Lbs/MBtu. The NEPOOL Environmental Planning Committee (EPC) has published MEA reports for calendar years 1993 through 2002.

Table 1.1: 2003 Marginal Emission Rates (Lbs/MWh)

Emission	On-Peak Ozone Season	Off-Peak Ozone Season	On-Peak Non-Ozone Season	Off-Peak Non-Ozone Season	Annual Average
SO_2	2.46	0.59	2.26	2.39	1.98
NO_X	0.79	0.29	0.89	0.86	0.73
CO_2	1,204	974	1,259	1,236	1,179

Table 1.2: 2003 Marginal Emission Rates (Lbs/MBtu)[1]

Emission	On-Peak Ozone Season	Off-Peak Ozone Season	On-Peak Non-Ozone Season	Off-Peak Non-Ozone Season	Annual Average
SO_2	0.30	0.07	0.27	0.29	0.24
NO_X	0.10	0.04	0.11	0.10	0.09
CO_2	146	118	153	150	143

The 2003 values were developed using the Inter Regional Electric Market Model (IREMM) production simulation model under two scenarios. This is a different model than what has been used in previous MEA reports. The Reference Case scenario simulates, as closely as possible, the actual operation of the NEPOOL system during the year 2003. To calculate the amount of additional (marginal) SO_2, NO_X, and CO_2 emissions that would have been emitted if DSM programs were not in place, the second or Marginal Case was created by increasing all hourly loads by 500 MW (incremental load increase). The difference in total emissions between the two cases was calculated in Lbs/MWh and the resultant values are noted above in Table 1.1.

A 2003 Marginal Heat Rate was also calculated using simulation results and used to convert the Marginal Emission Rate in Lbs/MWh to Lbs/MBtu. The formula used to calculate the 2003 Marginal Heat Rate is:

2003 Calculated Marginal Heat Rate

$$= \frac{\text{(Marginal Case Fuel Consumption – Reference Case Fuel Consumption)}}{\text{(Marginal Case Generation – Reference Case Generation)}}$$

The 2003 Marginal Heat Rate was calculated to be: 8.25 MBtu/MWh.

[1] To convert from Lbs/MWh to Lbs/Mbtu, the 2003 calculated Marginal Heat Rate, as described in Section 5.1, is used.

Compared to the 2002 MEA results, 2003 Marginal Emission Rates are lower during all investigated time periods. In addition, the calculated marginal heat rate has dropped from 8.66 Mbtu/MWh in 2002 to 8.25 Mbtu/MWh in 2003. This drop in marginal emission rates and marginal heat rates can be attributed to the commercialization of almost 2,800 MW of natural gas-fired combined cycles during 2003.

2. BACKGROUND

In early 1994, the NEPOOL EPC conducted a study to analyze the impact that Demand Side Management (DSM) programs had on NEPOOL's NO_X emissions in the calendar year 1992. The results were presented in a report entitled*, 1992 Marginal NO_X Emission Rate Analysis*, which 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 analysis on the impact of DSM programs on SO_2, NO_X, and CO_2 emissions for the calendar year 1993. The MEA Report was also published for the years 1994 through 2002 to provide similar analysis.

The *2003 NEPOOL Marginal Emission Rate Analysis* provides an estimate of the impact of DSM programs on NEPOOL's SO_2, NO_X, and CO_2 emissions for the calendar year 2003. 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 gauge the value (avoided emissions) of Renewable Energy Certificates (REC) by providing both REC suppliers and stakeholders with a consistent methodology that results in the calculation and communication of the environmental benefits of RECs and works to enhance the overall REC marketplace.

3. METHODOLOGY

3.1. Models Used

Past MEA analyses were performed using Henwood Energy Services Inc.'s PROSYM model. For conducting the 2003 MEA, ISO-NE used the Inter-Regional Electric Market Model (IREMM) to simulate the system as ISO-NE's licensing agreement with Henwood Energy Services Inc. was not renewed. The use of the IREMM model is consistant with other ISO-NE published assessments as it has been used for economic assessments within the four Regional Transmission Expansion Plans[1] published by ISO New England.

Similar to the PROSYM model, IREMM is a chronological simulation tool that approximates the minimization of costs using the traditional short-run marginal cost based methodology. In modeling generating unit characteristics, IREMM uses a more simplistic method. For example, full load heat rates are used as opposed to heat rate curves when modeling the dispatch of generating units. Also, minimum up/down times and ramp rates are not modeled in IREMM. Although there are differences between the two models, results appear consistant based on last years results and trends.

IREMM was used to replicate, as closely as possible, actual 2003 NEPOOL system operations. However, because IREMM is a simulation model, there are modeling limitations and it is not possible to exactly replicate the discrete hourly events that occurred historically, such as daily changes in fuel prices, sudden forced outages, and unit deratings. IREMM simulates the NEPOOL power system as a one-bus model

[1] Copies of the Regional Transmission Expansion Plan can be obtained through ISO-NE's Customer Service Department.

and thus the impacts resulting from transmission constraints are not captured. A more detailed description of IREMM can be found in Appendix C.

3.2. Calculating Marginal Emissions

Marginal emissions are calculated by comparing two simulations. The first simulation is the Reference Case. This case was created to replicate, as closely as possible, the actual 2003 NEPOOL system operation. The Reference Case is created by running IREMM and comparing the calculated annual energies to the actual energies on a unit by unit basis. If a unit's calculated annual energies are not within 25% of the actual annual energy, the unit variable costs are adjusted and the program is re-run. This process is continued until all unit's calculated annual energies are within 25% of the actual annual energies. Because of modeling constraints, peaking unit capacity is not considered in the 25% analysis of actual vs. calculated annual energy production. The second simulation, the Marginal Case, calculates the amount of additional (marginal) emissions that would have been emitted if DSM programs were not in place. This Case is created by increasing all hourly loads by 500 MW (incremental load increase).

The 1994 Report entitled, *NEPOOL Forecast Report of Capacity, Energy, Loads and Transmission 1994-2009 (1994 CELT Report),* identified 1994 aggregate summer DSM programs in the amount of 1,034 MW. The incremental 500 MW was originally used to estimate the impacts from DSM programs because it represented an amount that was an average or median value. Marginal emission rates could have been calculated for the first (1) MW of incremental load and could also have been calculated for the 1,034 MW of incremental load. In 1994, the NEPOOL EPC decided to model the average effects of not having DSM programs at the average or median value of 500 MW incremental load. The 500 MW incremental load has been used in all MEA Reports since 1994, and thus provides a consistent base line for historical observations. The 2004 Report entitled, *NEPOOL Forecast Report of Capacity, Energy, Loads and Transmission 2004-2013 (2004 CELT Report),* identifies 2004 summer DSM programs totaling 1,534 MW and winter DSM programs totaling 1,452 MW.

ISO New England dispatches all the generating units in NEPOOL (New England) economically based on market offers to meet the hourly load and operating reserve requirements, subject to transmission constraints, contingency protection, self-scheduling of units, and Reliability Must-Run (RMR) contracts. This means that multiple units may increase output in response to an increase in load. Therefore, there is typically no single marginal unit that can be identified at any given time. Rather, typically there are multiple marginal units located throughout the six New England states.

This report calculates 2003 NEPOOL marginal SO_2, NO_X, and CO_2 emission rates that are expressed in both Lbs/MWh and Lbs/MBtu. Also included is incremental tons of emissions associatied with incremental generation by SMD Load Zone. This data is calculated by increasing the actual 2003 NEPOOL loads by 500 MW in all hours. Based on a comparison between the two simulations, Reference Case and Marginal Case, monthly differences in energy output and the corresponding SO_2, NO_X, and CO_2 emissions are then determined. These marginal emission rates are based on calculated energy production in 2003 and other discretely modeled system conditions. Caution should be exercised in using this information for years other than 2003 since the system changes every year as do fuel prices and electrical demand. It should also be noted that although Reference Case simulations approximately match actual operation, the simulations are run on a single-bus model and are subject to differences from actual hourly dispatch where transmission system constraints come into play. The final hourly NEPOOL marginal emissions are divided into the four time-periods described below.

1. 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.

2. 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.

3. 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.

4. 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.

4. ASSUMPTIONS

The key parameters and assumptions modeled within the 2003 Marginal Emissions Rate Analysis are highlighted below.

- Full Outages (forced and scheduled) that lasted three or more days during 2003 were modeled discretely within IREMM.
- NEPOOL DSM programs for 2003 have been modeled at the average aggregate of 500 MW in all hours.
- Actual historical hourly loads for 2003 were modeled for the NEPOOL system for the Reference Case based on aggregate hourly energy produced from New England generators. NEPOOL pumped-storage pumping load is included within the hourly NEPOOL loads.
- Interchange with external systems, New York, New Brunswick, and Hydro-Quebec is not modeled for purposes of this study. This results in the modeling of the actual native NEPOOL load and generation only.
- For all major hydro-electric stations and pumped storage facilities, actual 2003 monthly energies were input into all modeling runs. IREMM then used this input to dispatch the hydro-electric stations to meet the targeted monthly energies. All other generators were operated according to system economics.
- Monthly fuel prices for generating units were based on EIA data and then adjusted on a per unit basis through the unit variable costs as needed to mimic 2003 dispatch.
- Individual generating unit emission rates were calculated from the 2003 actual emissions as reported to the US EPA's Acid Rain Division and published in the preliminary US EPA Emissions Scorecard 2003[1]. For those units that were not required to file with the US EPA Acid Rain Division, the assumed emission rates were either the rate noted in EPA's E-Grid2002 version 2.0 data or defaulted to assumed emission rates based on similar unit types.

[1] Final data was not available from the US EPA as of September 1, 2004

5. RESULTS

5.1. 2003 Calculated Marginal Heat Rate

In MEA reports prior to 1999, a fixed Marginal Heat Rate of 10.0 MBtu/MWh was used to convert from Lbs/MWh to Lbs/MBtu. In the 1999 – 2003 *NEPOOL Marginal Emissions Rate Analysis*, the Marginal Heat Rate was calculated using the results of the modeling runs. This methodology has again been used to calculate the 2003 Marginal Heat Rate. Since heat rate is equal to fuel consumption divided by generation, the 2003 Calculated Marginal Heat Rate is defined as follows:

2003 Calculated Marginal Heat Rate

$$= \frac{\text{(Marginal Case Fuel Consumption – Reference Case Fuel Consumption)}}{\text{(Marginal Case Generation – Reference Case Generation)}}$$

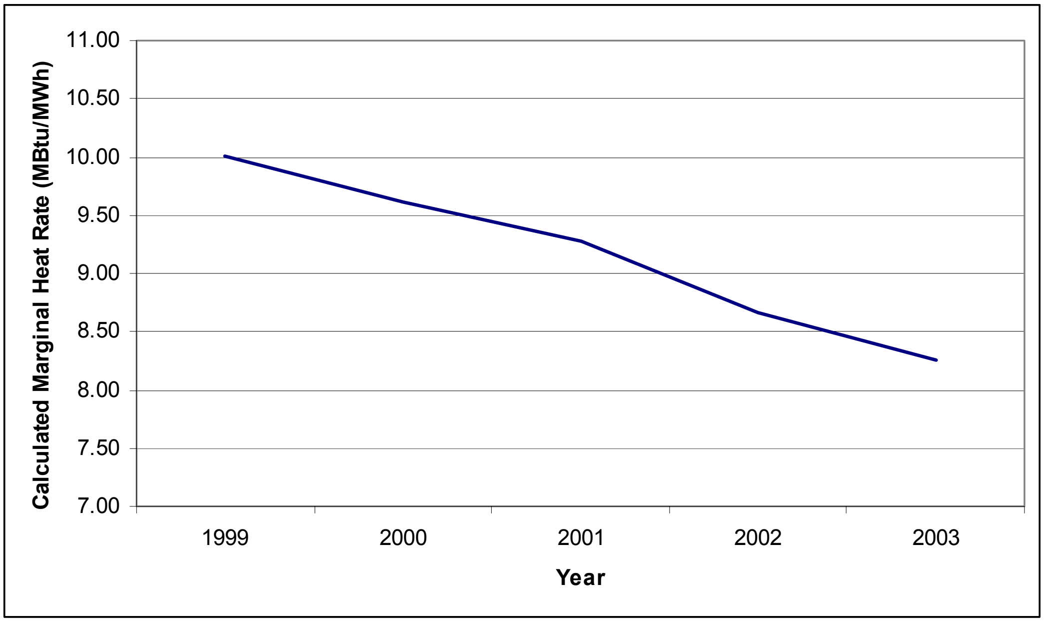
The calculated marginal heat rate reflects the average annual efficiency of the units dispatched to meet the additional load requirement in the marginal case. The lower the heat rate value, the more efficient the system or marginal generator is.

Table 5.1: 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

As shown in Table 5.1, the 2003 Calculated Marginal Heat Rate has decreased since 1999 from 10.013 MBtu/MWh to 8.249 MBtu/MWh. This is primarily due to the addition of approximately 13,100 MW of gas-fired combined cycle units with high efficiency rates. Figure 5.1 illustrates the calculated marginal heat rate spanning the 1999 – 2003 timeframe.

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



To convert from Lbs/MWh to Lbs/MBtu, the 2003 Calculated Marginal Heat Rate is used as the global conversion factor for all calculations within this report.

5.2. Incremental Generation By SMD Load Zones

Table 5.1 shows the incremental generation, by SMD load zones, for the Ozone Season and Non-Ozone Season time-periods. Also shown is the percent of total NEPOOL generation increase, by SMD load zones, resulting from a 500 MW increase in all NEPOOL hourly loads.

Table 5.2: 2003 Incremental Generation By SMD Load Zones

	Ozone Season		Non-Ozone Season		Annual	
State	**GWh**	**%**	**GWh**	**%**	**GWh**	**%**
Connecticut	193	10.5	424	16.7	617	14.1
Maine	305	16.7	455	18.0	760	17.4
New Hampshire	193	10.5	214	8.5	407	9.3
Rhode Island	261	14.2	273	10.8	534	12.2
Vermont	4	0.2	0	0.0	4	0.1
Massachusetts	876	47.8	1,166	46.1	2,042	46.8
Massachusetts (Divided into Load Zones)						
Northern MA & Boston	322	17.6	512	20.2	834	19.1
Southeastern MA	373	20.3	490	19.3	863	19.8
Western & Central MA	182	9.9	164	6.5	346	7.9
New England Total	1,832	100.0	2,533	100.0	4,364	100.0

5.3. 2003 Marginal Emission Rates

Table 5.2 shows SO_2, NO_X and CO_2 marginal emission rates in Lbs/MWh for the NEPOOL system for each of the four time-periods. Table 5.3 shows the same information expressed in Lbs/MBtu. As noted earlier, the 2003 Calculated Marginal Heat Rate of 8.25 MBtu/MWh was used as the global conversion factor.

The overall NEPOOL emissions for each state are very dependent on the specific units that are available to serve NEPOOL load. Therefore, there could be wide variations in the seasonal emissions, primarily due to changes in unit availability, fuel consumption, and load level.

The calculated marginal emission rates for SO_2, NO_X and CO_2 during the 2003 off-peak ozone season tend to decrease when compared to the annual average emission rates. This could possibly be attributed to the difference between oil and natural gas prices during the summer ozone and winter non-ozone periods. During the summer ozone period, when natural gas is usually less expensive than oil, gas-fired units tend to be dispatched or kept online during off-peak periods primarily due to system economics therefore lowering the marginal emission rate for this period. The opposite may be occurring during the winter non-ozone season, when natural gas tends to be (seasonably) more expensive than oil. This difference in fuel price may cause more oil units to be dispatched or kept online during the off-peak non-ozone period and therefore, would subsequently result in a higher marginal emissions rate versus the off-peak ozone season.

Table 5.3: 2003 Marginal Emission Rates (Lbs/MWh)

Emission	On-Peak Ozone Season	Off-Peak Ozone Season	On-Peak Non-Ozone Season	Off-Peak Non-Ozone Season	Annual Average
SO_2	2.46	0.59	2.26	2.39	1.98
NO_X	0.79	0.29	0.89	0.86	0.73
CO_2	1,204	974	1,259	1,236	1,179

Table 5.4: 2003 Marginal Emission Rates (Lbs/MBtu)

Emission	On-Peak Ozone Season	Off-Peak Ozone Season	On-Peak Non-Ozone Season	Off-Peak Non-Ozone Season	Annual Average
SO_2	0.30	0.07	0.27	0.29	0.24
NO_X	0.10	0.04	0.11	0.10	0.09
CO_2	146	118	153	150	143

5.4. Calculated Historical Marginal Emission Rates

Table 5.4 through Table 5.6 illustrates the calculated marginal emission rates for SO_2, NO_x, and CO_2 in Lbs/MWh for the years 1993 through 2003. Figure 5.2 through Figure 5.4 are graphical representations of Table 5.4 through Table 5.6, respectively. 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 2003 time frame. Most of the continued decrease can be attributed to the commercialization of many new gas-fired combined cycled plants in each year[1]. In 2003, there was almost 2,800 MW of new gas-fired capacity added to the NEPOOL system.

The increase in natural gas-fired capacity has also had an affect on the calculated CO_2 marginal emission rates during the ozone off-peak and on-peak periods. Specifically, a decrease can be seen in the 2003 calculated CO_2 marginal rate from the year 2000. This decrease is primarily due to the increase in natural gas-fired marginal generation coupled with the decrease in coal-fired marginal generation during the ozone off-peak period.

In 1997 to 1998, there is an increase in the marginal emission rates for CO_2 primarily attributed to the lower availability in nuclear generation and the subsequent increase in fossil-fired generation to compensate for that loss. A drop in marginal CO_2 emission rates into 2003 is most likely the result of the addition of the newly commercialized, highly efficient, low emitting natural gas-fired generating plants in New England. Overall, results for 2003 illustrate that marginal emission rates continue to decline with the commercialization of additional highly efficient natural gas-fired generating plants. This trend will not likely continue as no new such plants are currently under construction in the region.

Table 5.5: 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
1993	10.4	14.0	11.2	14.9	12.6
1994	9.4	8.6	10.9	10.4	9.8
1995	8.0	5.6	8.0	6.5	7.0
1996	9.5	9.0	10.6	9.1	9.6
1997	7.4	10.0	9.4	10.6	9.4
1998	6.6	4.9	6.8	6.6	6.2
1999	7.8	6.5	7.3	7.3	7.2
2000	6.6	6.0	6.3	5.9	6.2
2001	5.3	4.4	5.1	5.0	4.9
2002	3.7	2.0	4.9	3.0	3.3
2003	2.5	0.6	2.3	2.4	2.0

[1] See Appendix Table A.2

Table 5.6: 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
1993	4.0	4.5	4.1	5.0	4.4
1994	4.5	3.9	4.5	3.9	4.2
1995	3.4	2.8	3.5	3.1	3.2
1996	2.7	2.4	2.9	2.4	2.6
1997	2.6	2.6	2.7	2.6	2.6
1998	2.2	2.0	2.1	2.1	2.1
1999	2.2	2.0	1.9	1.8	2.0
2000	2.0	1.8	1.8	1.8	1.9
2001	1.9	1.5	1.7	1.6	1.7
2002	1.4	0.8	1.5	1.0	1.1
2003	0.8	0.3	0.9	0.9	0.7

Table 5.7: 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
1993	1,630.0	1,610.0	1,580.0	1,750.0	1,642.5
1994	1,767.0	1,334.0	1,796.0	1,396.0	1,573.3
1995	1,654.0	1,458.0	1,713.0	1,511.0	1,584.0
1996	1,696.0	1,575.0	1,752.0	1,590.0	1,653.3
1997	1,437.0	1,522.0	1,487.0	1,488.0	1,483.5
1998	1,621.7	1,431.9	1,537.6	1,490.6	1,520.4
1999	1,643.6	1,549.6	1,586.9	1,530.6	1,577.7
2000	1,544.7	1,504.7	1,462.8	1,440.1	1,488.1
2001	1,436.5	1,340.2	1,406.0	1,392.9	1,393.9
2002	1,412.2	1,170.6	1,535.6	1,299.5	1,337.8
2003	1,204.3	974.4	1,258.7	1,236.4	1,179.0

Figure 5.2: Calculated SO_2 Marginal Emission Rates

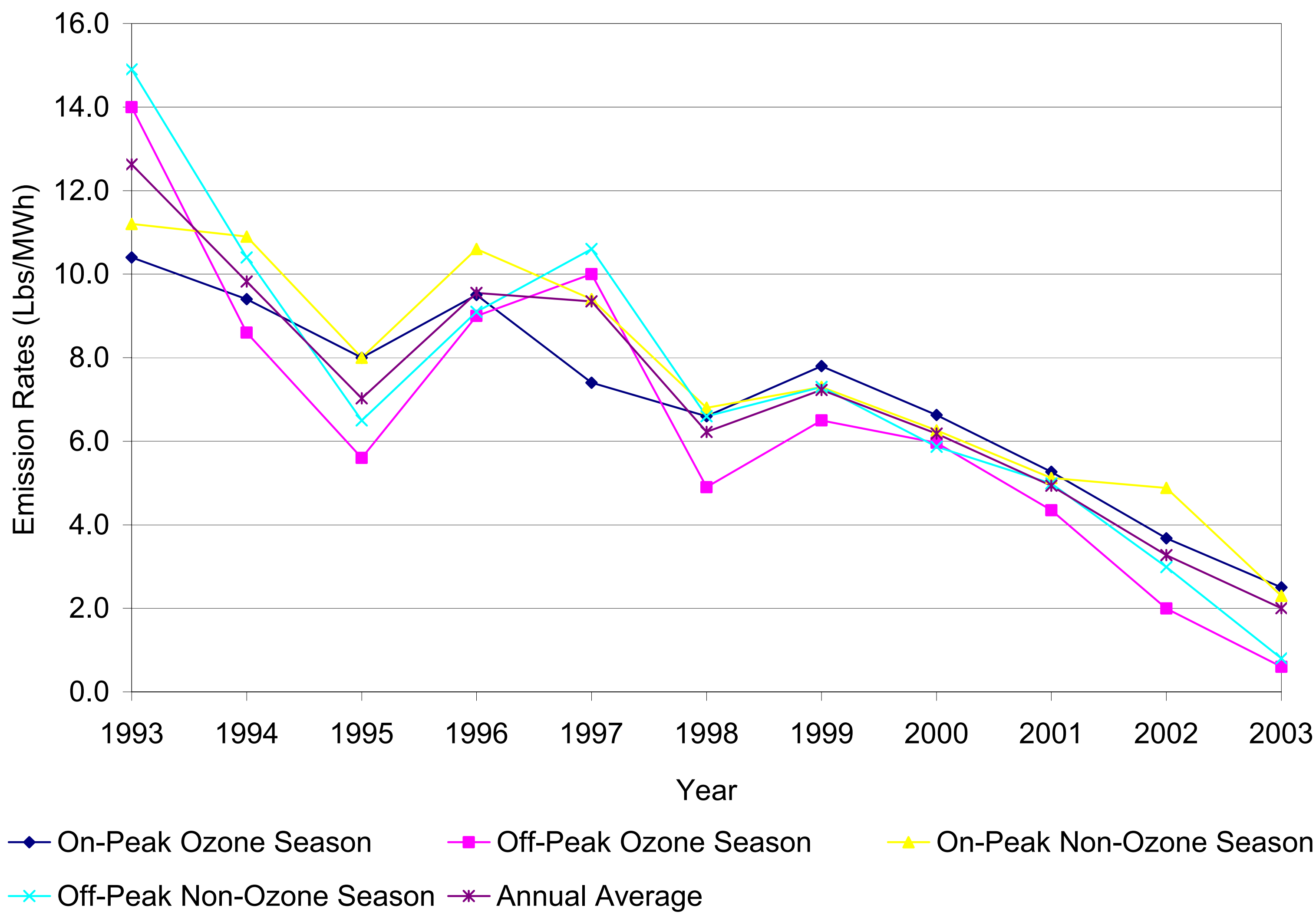


Figure 5.3: Calculated NO_X Marginal Emission Rates

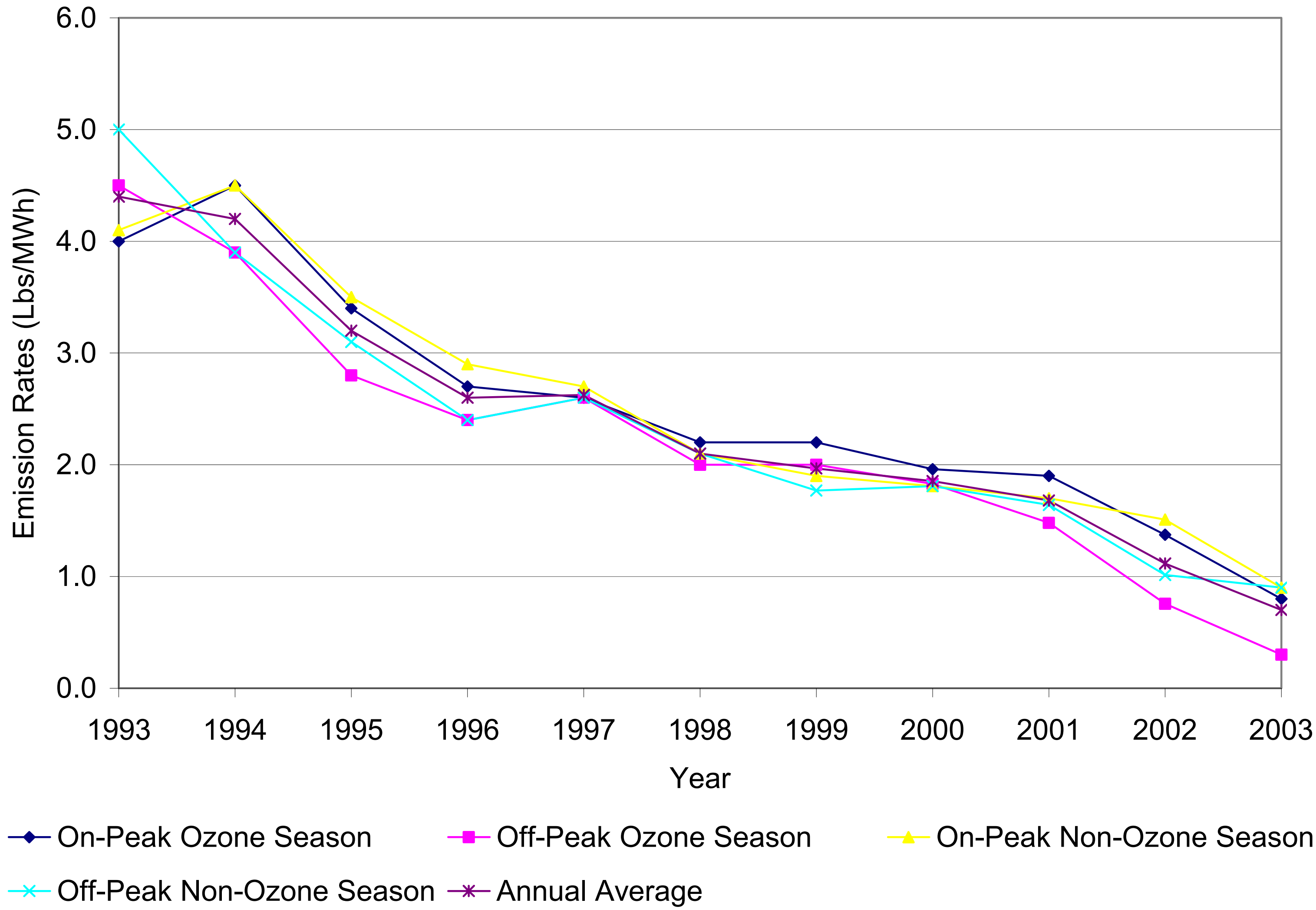
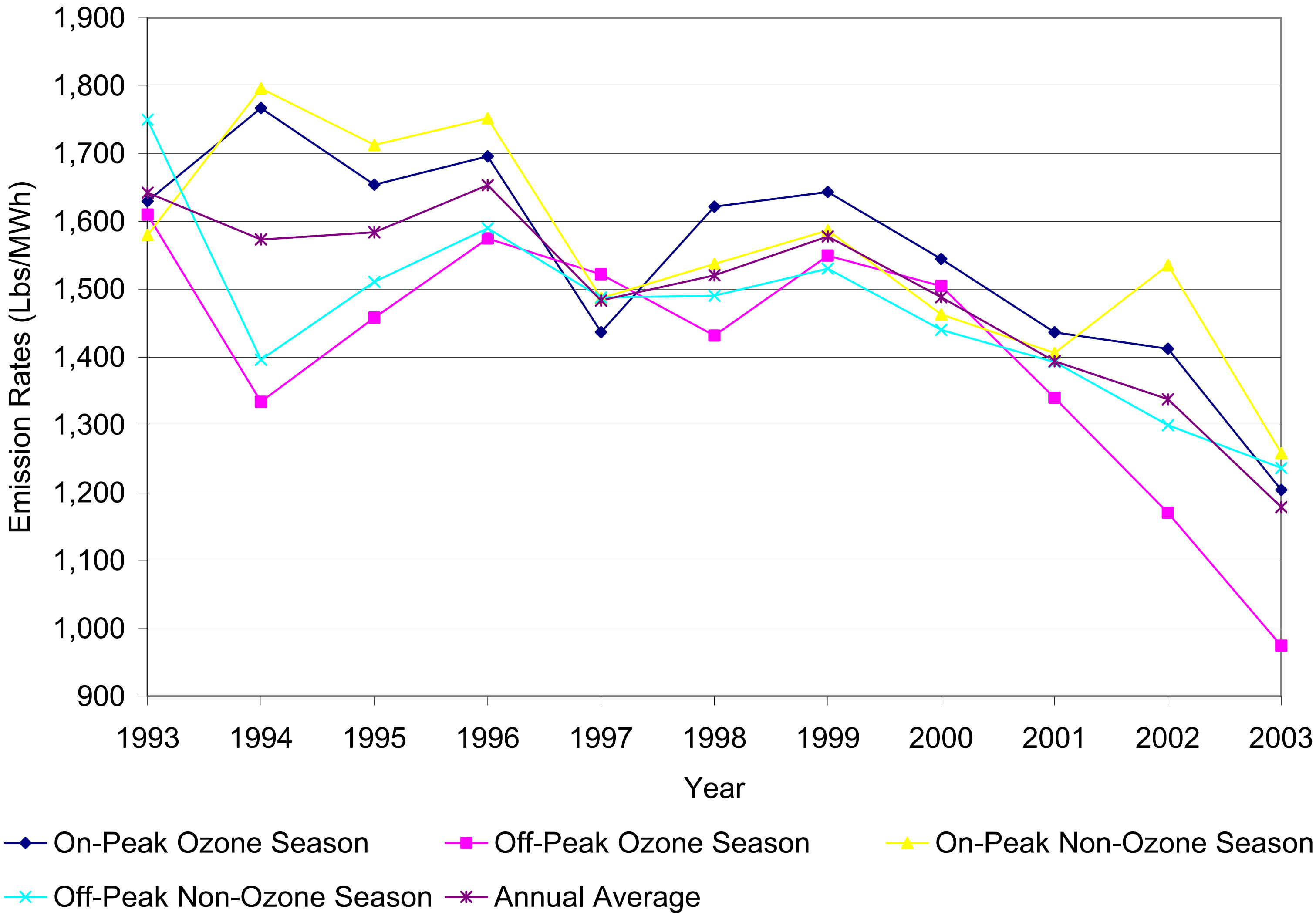


Figure 5.4: Calculated CO_2 Marginal Emission Rates



5.5. Incremental Emissions by SMD Load Zone and by Ozone & Non-Ozone Season

Table 5.7 through Table 5.9 illustrates the calculated incremental SO_2, NO_X, and CO_2 emissions, by SMD load zone, for the ozone and non-ozone season time-periods, that would have been produced if the total NEPOOL load in all hours was increased by 500 MW. Also shown is the percent of the total increase in emissions that would have correspondingly been produced within each state.

Table 5.8: 2003 Incremental SO_2 Emissions

	Ozone Season		**Non-Ozone Season**		**Annual**	
State	**kTons**	**%**	**KTons**	**%**	**kTons**	**%**
Connecticut	0.12	8.7	0.79	26.8	0.91	21.1
Maine	0.02	1.3	0.50	17.0	0.52	12.0
New Hampshire	0.55	39.8	0.02	0.7	0.57	13.1
Rhode Island	0.00	0.1	0.00	0.0	0.00	0.0
Vermont	0.00	0.0	0.00	0.0	0.00	0.0
Massachusetts	0.69	50.2	1.64	55.5	2.33	53.8
Massachusetts (Divided into Load Zones)						
Northern MA & Boston	0.13	9.2	0.77	26.2	0.90	20.8
Southeastern MA	0.43	31.6	0.74	25.1	1.18	27.2
Western & Central MA	0.13	9.4	0.12	4.1	0.25	5.8
New Enlgand Total	1.37	100.0	2.95	100.0	4.32	100.0

Notes:

1) The Incremental Emissions are calculated by increasing the actual 2003 NEPOOL loads by 500 MW in all hours.
2) Annual totals may not equal sum due to rounding.

Table 5.9: 2003 Incremental NO_X Emissions

	Ozone Season		Non-Ozone Season		Annual	
State	**KTons**	**%**	**KTons**	**%**	**kTons**	**%**
Connecticut	0.08	15.5	0.42	37.5	0.49	30.7
Maine	0.04	8.2	0.17	14.9	0.21	12.9
New Hampshire	0.09	17.7	0.01	1.0	0.10	6.1
Rhode Island	0.02	5.1	0.03	2.3	0.05	3.2
Vermont	0.00	0.9	0.00	0.0	0.00	0.3
Massachusetts	0.26	52.6	0.49	44.3	0.75	46.8
Massachusetts (Divided into Load Zones)						
Northern MA & Boston	0.07	14.4	0.24	21.7	0.31	19.5
Southeastern MA	0.13	26.7	0.21	18.6	0.34	21.1
Western & Central MA	0.06	11.5	0.04	3.9	0.10	6.2
New England Total	0.49	35.5	1.11	37.6	1.60	37.0

Table 5.10: 2003 Incremental CO_2 Emissions

	Ozone Season		Non-Ozone Season		Annual	
State	**KTons**	**%**	**KTons**	**%**	**kTons**	**%**
Connecticut	118	11.8	382	24.2	500	19.4
Maine	151	15.2	256	16.2	407	15.8
New Hampshire	116	11.6	94	6.0	210	8.2
Rhode Island	122	12.3	128	8.1	250	9.7
Vermont	6	0.6	0	0.0	6	0.2
Massachusetts	484	48.5	719	45.5	1,202	46.7
Massachusetts (Divided into Load Zones)						
Northern MA & Boston	179	18.0	350	22.2	529	20.5
Southeastern MA	209	21.0	278	17.6	487	18.9
Western & Central MA	96	9.6	91	5.7	186	7.2
New EnglandTotal	996	100.0	1,579	100.0	2,575	100.0

Notes:

1) The Incremental Emissions are calculated by increasing the actual 2003 NEPOOL loads by 500 MW in all hours.
2) Annual totals may not equal sum due to rounding.

APPENDIX A

Table A.1 shows the total NEPOOL capacity claimed for capability during the 2003 calendar year. NEPOOL capacity listed in Table A.1 was obtained from ISO New England's January 2004 Seasonal Claimed Capability (SCC) Report. Table A.2 and Table A.3 identifies new units that went into commercial operation during the 2003 and 2000 – 2002 calendar years, respectively.

Appendix Table A.1: 2003 NEPOOL Capacity by State and Unit Category (MW)

	Connecticut		Maine		Massachusetts		New Hampshire		Rhode Island		Vermont		New England Totals	
Unit Category	**Summer Net**	**Winter Net**	**Summer Net**	**Winter Net**	**Summer Net**	**Winter Net**	**Summer Net**	**Winter Net**	**Summer Net**	**Winter Net**	**Summer Net**	**Winter Net**	**Summer Net**	**Winter Net**
Combined Cycle	1,019	1,177	1,386	1,528	4,967	5,849	1,182	1,327	1,786	2,046	-	-	10,340	11,928
Diesel	5	5	18	20	83	84	-	-	-	-	14	14	121	123
Fossil	3,108	3,177	1,156	1,282	4,960	5,052	1,082	1,088	12	12	73	74	10,391	10,684
Gas Turbine	333	408	194	231	516	622	14	18	-	-	75	99	1,132	1,378
Hydro	149	155	556	587	314	323	552	574	1	1	143	167	1,716	1,807
Pumped Storage	-	-	-	-	1,643	1,665	-	-	-	-	-	-	1,643	1,665
Jet	321	416	-	-	354	506	67	82	-	-	11	18	753	1,021
Nuclear	1,997	2,036	-	-	685	685	1,159	1,161	-	-	506	529	4,347	4,411
Total	6,932	7,374	3,311	3,648	13,522	14,786	4,057	4,250	1,800	2,060	821	900	30,443	33,018

Appendix Table A.2: New Capacity Added to New England During 2003

Unit Name	Unit Category	State	Summer Net MW	Winter Net MW	In-Service Date
AES Granite Ridge	Combined Cycle	NH	678	767	Apr-2003
Mystic Block 8	Combined Cycle	MA	707	850	Apr-2003
Mystic Block 9	Combined Cycle	MA	707	850	Jun-2003
Edgar Fore River	Combined Cycle	MA	700	843	Aug-2003
		Total	**2,792**	**3,310**	

Appendix Table A.3: New Capacity Added to New England During 2000-2002

Unit Name	Unit Category	State	Summer Net MW	Winter Net MW	In-Service Date
Androscoggin Energy Center	Combined Cycle	ME	86	109	Jan-2000
Berkshire Power	Combined Cycle	MA	248	265	May-2000
Maine Independence Station	Combined Cycle	ME	494	547	Jun-2000
Tiverton Power	Combined Cycle	RI	251	286	Aug-2000
Bucksport	Combined Cycle	ME	165	193	Jan-2001
Millenium	Combined Cycle	MA	339	388	Apr-2001
Westbrook	Combined Cycle	ME	512	551	Apr-2001
ANP Blackstone Unit 1	Combined Cycle	MA	209	213	Jun-2001
ANP Blackstone Unit 2	Combined Cycle	MA	214	244	Jul-2001
Wallingford Units 1-5	Gas Turbine	CT	215	251	Jan-2002
Lake Road Units 1-2	Combined Cycle	CT	454	525	Mar-2002
Lake Road Unit 3	Combined Cycle	CT	237	272	May-2002
West Springfield 1 & 2	Gas Turbine	MA	86	100	Jun-2002
Newington Energy	Combined Cycle	NH	528	543	Sep-2002
RISE	Combined Cycle	RI	515	575	Oct-2002
ANP Bellingham Unit 1	Combined Cycle	MA	288	308	Oct-2002
Kendall Repowering	Combined Cycle	MA	172	234	Dec-2002
ANP Bellingham Unit 2	Combined Cycle	MA	288	308	Dec-2002
		Total	**5,301**	**5,912**	

APPENDIX B

Table B.1 illustrates the aggregate SO_2, NO_X, and CO_2 emissions as output from the Reference case production simulation runs and the aggregate emissions as reported to the US EPA on the Preliminary EPA Scorecard 2003. It must be noted that the calculated values are a result of computer simulation limited by certain assumptions and does not precisely match the historical unit commitment and dispatch of generating units. Also, the units that are listed in the Preliminary US EPA Scorecard 2003 account for approximately 65% of the total NEPOOL capacity. This is the primary reason for the difference between the calculated and reported aggregate emissions of SO_2, NO_X, and CO_2 for 2003.

Appendix Table B.1: 2003 Reference Case Calculated Aggregate Emissions of SO_2, NO_X, and CO_2

SMD Load Zone	SO_2 kTons	NO_X kTons	CO_2 kTons
Connecticut	11.16	9.56	10,690
Maine	4.81	3.61	6,441
New Hampshire	55.40	10.58	9,153
Rhode Island	0.19	0.49	2,333
Vermont	0.01	0.51	352
Total Massachusetts	87.85	29.48	27,309
Massachusetts Divided Into SMD Load Zones			
Northern MA & Boston	34.03	10.80	10,734
Southeastern MA	48.02	15.42	13,107
Western & Central MA	5.79	3.26	3,468
Calculated New England Total	159.41	54.23	56,278
Total as Noted in Preliminary 2003 US EPA Scorecard	152.45	40.13	46,942
Difference	6.97	14.10	9,336

Table B.2 and B.3 illustrates the annual average values, as output from the Reference Case production simulation runs, of SO_2, NO_X, and CO_2 rates in Lbs/MWh and Lbs/MBtu for the 1999 – 2003 time period. Table B.3 also gives the annual average heat rate for the NEPOOL system spanning the same time frame.

Appendix Table B.2: 1999 – 2003 Calculated Annual Averages of SO_2, NO_X, CO_2 in Lbs/MWh

Year	SO_2 (Lbs/MWh)	NO_X (Lbs/MWh)	CO_2 (Lbs/MWh)
1999	4.52	1.36	1009
2000	3.88	1.12	913
2001	3.51	1.05	930
2002	2.69	0.94	909
2003	2.75	0.93	970

Appendix Table B.3: 1999 – 2003 Calculated Annual Averages of SO_2, NO_X, CO_2 in Lbs/MBtu, and Heat Rates

Year	SO_2 (Lbs/MBtu)	NO_X (Lbs/MBtu)	CO_2 (Lbs/MBtu)	Heat Rate (MBtu/MWh)
1999	0.49	0.15	110	9.14
2000	0.43	0.12	100	9.03
2001	0.39	0.12	104	8.96
2002	0.31	0.11	105	8.66
2003	0.30	0.10	106	9.12

APPENDIX C

Inter Regional Electric Market Model (IREMM)

IREMM is a computer model that provides a chronological simulation of energy market behavior based on both game theory and the traditional, engineering-based production simulation model. The basic logic inside IREMM is a chronological and deterministic production cost model. In the beginning of the simulation procedure, IREMM calculates the hourly load data for each area, based on the input hourly load shape, or load forecast profile. Conventional hydro and pump storage units are modeled as load modifiers. For each hour, initially, IREMM dispatches generating units to meet the demand, starting with the least expensive unit. For any area short of energy, a very expensive proxy emergency unit is dispatched to provide the necessary energy. Once the demand is served from available resources, the amount of surplus energy available for sale and the amount of economically displaceable energy may be calculated for various price levels. If demand in an area cannot be satisfied, a price spike of $500/MWh is assigned. The program then proceeds to the next hour, and repeats the same process until the last hour of the study period.

While the IREMM simulation does not focus on the detailed unit-level model necessary when performing engineering design studies, it does provide a suitable representation of physical generator characteristics.

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