2012 ISO New England

Electric Generator Air Emissions Report

ISO New England Inc.
System Planning
January 2014

TABLE OF CONTENTS

TABLE OF FIGURES

TABLE OF TABLES

{ This page left intentionally blank }

1 Executive Summary

The ISO New England Generator Air Emissions Report provides system and marginal emissions (kTons) and emission rates (lb/MWh & lb/MMBtu). It was previously known as the Marginal Emission Rate Analysis (MEA Report) and was initially developed in 1993.

Historically, the annual reports have provided the marginal emission rates of New England's electric generation system administered by ISO-NE. 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 emission rates was subsequently broadened to include the benefits of energy efficiency programs and renewable resource projects within the region. In 2008, the ISO New England Electric Generator Air Emissions Report (Emissions Report) replaced the MEA Report, to place a greater emphasis on air emissions produced by the entire ISO New England electric generation system, while still reporting marginal emission rates.

The 2012 system and marginal emissions and emission rates throughout the report are calculated primarily using measured air emissions reported by generator owners to the U.S. Environmental Protection Agency (EPA) and 2012 ISO New England hourly generation data as reported for ISO-NE settlement purposes.

There are two methodologies of calculating marginal emission that are included in the 2012 Emissions Report: the existing methodology that assumes the marginal units to be the oil- and natural gas-fired generating units (FTA) and the newly added methodology that utilize the marginal units used to set energy prices for the New England energy market (LMU).

The Fuel Type Assumed (FTA) Marginal Emission Analysis method has been used to calculate marginal emission rates since 2004. FTA marginal emission rates are calculated using the energy-weighted, average emission rates of generating units that are assumed to increase their output if regional energy demand was higher during the time periods of interest. The FTA marginal units are assumed to be those that are fueled with oil (including residual, distillate, diesel, kerosene, and jet fuel), and/or natural gas.[1]

The Locational Marginal Unit (LMU) Marginal Emission Analysis method is included in the Emissions Report for the first time. This method uses the emissions rates from the ISO-NE identified marginal unit(s) that set the Energy Market hourly Locational Marginal Price(s) (LMP). The LMP results from a process that minimizes total energy costs for the entire New England region, subject to a set of constraints reflecting physical limitations of the power system. Three sets of emission rate results are presented in this report utilizing this methodology. They are: 1) All LMUs; 2) Emitting LMUs; and 3) Oil- and Natural Gas-Fired (O&NG) LMUs. Calculations for the calendar years of 2009-2012 using the LMU analysis have been added to the results.

[1] All fuel types refer to the generating unit's primary fuel type, as reported within the 2013 CELT Report.

Table 1-1shows the 2011 and 2012 average system emissions (kTons) and average system emission rates (lb/MWh) of NO_X, SO_2 and CO_2. There are different factors that can contribute to the decreasing trend of emissions in New England. The 2012 total energy generation, 116,942 GWh, was lower than 2011 total energy generation by 3%, or 3,670 GWh. SO_2 had a significant decrease contributed by unit retirements, new emission control technologies installations and large decrease in generation by coal-fired units

Table 1-1: Differences between 2011 and 2012 System Emissions (kTons) and System Emission Rates (lb/MWh)

Annual System Emissions						
	2011 (kTons)	2012 (kTons)	Total Emissions % Change	2011 Emission Rate (lb/MWh)	2012 Emission Rate (lb/MWh)	Emission Rate % Change
NO_X	25.30	20.32	-19.7	0.42	0.35	-16.7
SO_2	57.01	16.61	-70.9	0.95	0.28	-70.5
CO_2	46,959	41,975	-10.6	780	719	-7.8

Table 1-2 and Table 1-3 show the 2011 and 2012 annual average marginal emission rates as calculated by the marginal emissions analysis methods of FTA and LMU (All LMUs and Emitting EMUs). There is an overall decreasing trend observed. Specifically, SO_2 has had a considerable decrease, similar to the system emissions.

Table 1-2: Differences between 2011 and 2012 FTA Marginal Emission Rates (lb/MWh)

Fuel Type Assumed Marginal Emissions			
	2011 Annual Rate (lb/MWh)	2012 Annual Rate (lb/MWh)	Percent Change 2011 to 2012 (%)
NO_X	0.14	0.14	0.0
SO_2	0.05	0.03	-40.0
CO_2	907	899	-0.9

Table 1-3: Differences between 2011 and 2012 LMU Marginal Emission Rates (lb/MWh)

LMU Marginal Emissions						
	All LMUs			Emitting LMUs		
	2011 Annual Rate (lb/MWh)	2012 Annual Rate (lb/MWh)	Percent Change 2011 to 2012 (%)	2011 Annual Rate (lb/MWh)	2012 Annual Rate (lb/MWh)	Percent Change 2011 to 2012 (%)
NO_X	0.27	0.22	-18.4	0.33	0.26	-22.1
SO_2	1.35	0.35	-73.9	1.63	0.42	-74.2
CO_2	922	854	-7.4	1,097	1,010	-7.9

Table 1-4 compares the two marginal emission analysis methods that have the same fuel type based assumption, which only accounts for oil- and natural gas-fired generators as marginal units. The difference for CO_2 marginal emission rates has been within 3.5% in the last four years. Although SO_2 and NO_X marginal emission rates have a larger percentage of difference, the magnitudes of the marginal emission rates are similar.

Table 1-4: Differences between LMU O&NG and FTA Marginal Emissions Rates (lb/MWh)

LMU O&NG vs. FTA Marginal Emissions									
	NO_X			SO_2			CO_2		
	LMU Annual Rate (lb/MWh)	FTA Annual Rate (lb/MWh)	Difference Between Methods (%)	LMU Annual Rate (lb/MWh)	FTA Annual Rate (lb/MWh)	Difference Between Methods (%)	LMU Annual Rate (lb/MWh)	FTA Annual Rate (lb/MWh)	Difference Between Methods (%)
2009	0.18	0.17	-7.1	0.15	0.22	46.7	928	930	0.2
2010	0.26	0.18	-30.8	0.13	0.09	-30.8	965	943	-2.3
2011	0.19	0.14	-27.8	0.09	0.05	-46.2	877	907	3.4
2012	0.16	0.14	-11.9	0.04	0.03	-28.6	915	899	-1.7

The 2012 calculated marginal heat rate was determined using mostly power plant heat input data obtained from the U.S. EPA combined with actual 2012 energy production obtained from an ISO-NE database used for energy market settlement purposes. This rate was used to convert the marginal emission rates from lb/MWh to lb/MMBtu. The 2012 calculated FTA marginal heat rate was determined to be 7.407 MMBtu/MWh, decreasing approximately 3.8% from the 2011 marginal heat rate of 7.926. The 2012 calculated LMU marginal heat rate was 7.407 MMBtu/MWh compared to 7.628 MMBtu/MWh or 2.8% less than in 2011.

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 (ERC) 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, VOC, and CO in Massachusetts to earn bankable and tradable emission credits by reducing actual power plant emissions below regulatory requirements.

Later in 1994, the *1993 Marginal Emission Rate Analysis* (MEA Report) was published, which provided expanded analysis of the impact of DSM programs on power plant NO_X, SO_2, and CO_2 air emissions for the calendar year 1993. MEA Reports have been published for the years 1994 through 2007, to provide similar annual environmental analyses for those years. For the 2008 emissions analysis, members of ISO New England's Environmental Advisory Group (EAG) requested that the MEA Report be restructured and renamed to reflect the importance of the amount of emissions from the entire ISO New England electric generation system.[2] The name of the MEA Report was changed to the ISO New England Electric Generator Air Emissions Report (Emissions Report), and the new report placed a greater emphasis on the calculated system emissions for the entire ISO New England electric generation system rather than focusing primarily on marginal emissions. The Emissions Report continues to include calculated marginal emission rates. These calculated marginal emissions can be used to estimate the impact DSM programs and renewable energy projects have had on reducing New England's NO_X, SO_2, and CO_2 power plant air emissions.

Beginning with the 2012 Emissions Report, a Locational Marginal Unit (LMU)-based Marginal Emissions Analysis methodology has been included. This was an effort prompted by ISO-NE stakeholders and began as a Pilot Program in 2011. This adds a second methodology that explores a different perspective of marginal emissions. Results are presented for calendar years 2009 to 2012 in this report.

The 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.

[2] The EAG is a stakeholder working group reporting to the Planning Advisory Committee (PAC). The EAG's web site is located at: http://www.iso-ne.com/committees/comm_wkgrps/prtcpnts_comm/eag/index.html

3 Methodologies

The total system emissions and the marginal emission rate calculations for NO_x, SO_2 and CO_2 were based primarily on the tons of air emissions reported in the U.S. EPA Clean Air Markets Division (CAMD) database.[3] When unit specific emissions data were not available from the CAMD database, the actual megawatt-hours (MWh) of generation, from ISO-NE database used for energy market settlement purposes, were used to calculate tons of emissions using emission rates from the New England Power Pool Generation Information System (NEPOOL GIS) or the U.S. eGRID database, or, alternatively, emission rates that were assumed based on a similar generator type.[4] The total system and marginal emission rates were calculated from the actual or calculated tons of power plant emissions.

All electric generators administered by ISO New England are included in these emissions calculations. Emissions from "behind the meter" generators or those generators not within the ISO New England balancing authority area are not part of this analysis

3.1 Calculating Total System Emission Rate

The total system emission rate (lb/MWh) is based on the emissions produced by all ISO New England generators during a calendar year. The formula for calculating the total annual system emission rate is:

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

3.2 Calculating Marginal Emission Rate

3.2.1 History of Marginal Emissions Analysis

In MEA studies performed prior to 2004, production simulation models were used to replicate, as closely as possible, the actual system operations for the study year (reference case). Then an incremental load scenario was modeled in which the system load was increased by 500 MW in each hour (marginal case). 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. The reference case simulation could not exactly match the actual unit-specific energy production levels of the study year due to a number of limitations in the production simulation model, including the inability to accurately represent historical overall dynamics of the energy dispatch, out-of-merit and reliability-based dispatches, unit specific outages and deratings, and effects of the daily volatility of regional (power plant) fuel prices.

Beginning in 2004, a new methodology was used to calculate the average emission rates of those units that are assumed to increase their loading when energy demand increases. Those units, which consist of all natural gas and oil-fired generators, are referred to as the Fuel-Type Assumed (FTA) marginal units. 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

[3] EPA Clean Air Markets Program Data can be found at http://ampd.epa.gov/ampd/.
[4] The U.S. EPA's eGRID2012Version 1.0 is located at: http://www.epa.gov/cleanenergy/energy-resources/egrid/index.html.

typically not be dispatched at higher levels in the event of higher loads on the system.[5] Other resources, such as hydro-electric, pumped storage, wind, solar, and nuclear units that do not vary in output to follow load, are also assumed not to be marginal units and excluded from the calculation of FTA marginal emission rates.

The methodology used the actual metered hourly generation used by ISO-NE for energy market settlement purposes, and the annual air emissions and emission rates obtained from the U.S. EPA databases, along with other default emission rates. For the time periods investigated, the average air emission rates of all of the FTA marginal units were calculated based on these information sources. The resultant emission rates were assumed to be the *FTA marginal emission rates.* In 2005, monthly emissions from both the U.S. EPA and the NEPOOL GIS were used, when available, to improve the accuracy of the FTA marginal emissions calculations. This methodology was further improved within the 2007 MEA Report with the use of hourly emissions data for those units that report hourly emissions to the U.S. EPA.[6]

In 2011, ISO-NE began developing a methodology of calculating the marginal emission rate based on the Locational Marginal Unit (LMU), which stemmed from recommendations of the stakeholders of the Environmental Advisory Group. The data sources are the same as the FTA methodology, but the way to account for marginal units is different. The LMP reflects a process that minimizes total cost of energy for New England while accounting for transmission and other constraints. By using this method, the marginal unit (LMU), or the last unit dispatched, can be identified.

3.2.2 Calculating Marginal Emissions with Fuel Type Assumed (FTA) Marginal Units

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

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

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

[5] In determining whether to consider coal units as marginal units, it was observed that higher or lower loads change the number of committed natural gas and/or oil units, while coal units would 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 to be marginal for establishing Locational Marginal Prices during those off-peak hours.

[6] Generators report emissions to the U.S. 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 (CAIR) took the place of the NO_X Budget Trading Program.) Generators subject to the Regional Greenhouse Gas Initiative also report CO_2 emissions to the U.S. EPA.

3.2.3 **Calculating Marginal Emissions with LMU Marginal Units**

The new methodology for calculating marginal emission rates uses the Locational Marginal Units (LMUs). LMUs are identified through the LMP process, which minimizes total energy costs for the entire New England region, subject to a set of constraints reflecting physical limitation of the power system.

For each 5 minute period, there will be at least one marginal unit (LMU) identified by the LMP. In some time periods, there may be physical limitations on the power system, such as a transmission constraint. For each binding constraint, this will add an additional marginal unit. This results in *n+1* marginal units (LMUs) for every *n* binding constraints.

The percent of time each generator is marginal in each month is calculated and linked to the generator's month-specific average emissions rate. The month and generator-specific average emissions rates are retrieved from the process of calculating system emission rates. The LMU Marginal Emission Rates are calculated as described below, where generator *k* is identified to be marginal during hour *h*, and has a specific monthly emission rate during month *m*. This calculation is used for on-peak and off-peak hours. Each generator was associated with its own on-peak or off-peak emissions rate.

$$LMU\ On-Peak\ Marginal\ Emission\ Rate = \frac{\sum_{k=1}^{LMP\ marginal\ units}\sum_{h=1}^{on-peak\ hours\ in\ year}(\%\ of\ LMP\ Unit\ Marginal_{k,h} \times On-Peak\ Emission\ Rate_{k,m})}{On-Peak\ Hours\ in\ Year}$$

$$LMU\ Off-Peak\ Marginal\ Emission\ Rate = \frac{\sum_{k=1}^{LMP\ marginal\ units}\sum_{h=1}^{off-peak\ hours\ in\ year}(\%\ of\ LMP\ Unit\ Marginal_{k,h} \times Off-Peak\ Emission\ Rate_{k,m})}{Off-Peak\ Hours\ in\ Year}$$

The annual LMU marginal emission rate is then calculated by combining the on-peak and off-peak calculations.

3.2.4 **Definition of Time Periods**

The 2012 marginal air emission rates for on and off-peak periods for New England 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 emissions reductions during those hours. The marginal emission rates for NO_X are calculated for five time periods:[7]

- 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

[7] There was a special report, developed by ISO-NE, titled *Analysis of New England Electric Generator's NO_X Emissions on 25 Peak-load Days in 2005-2009* released in 2011 that summarized ISO-NE's effort in conducting an analysis of NO_X emissions during peak days. This report is located at: http://www.iso-ne.com/genrtion_resrcs/reports/emission/peak_nox_analysis.pdf

- 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 2012 ISO New England Emissions Report are highlighted in this section. They include weather, emissions data sources, installed capacity and system generation.

4.1 2012 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 2012 total energy use and both cooling and heating degree days to previous years.

The summer peak electricity demand of 27,090 MW was 617 MW lower than the 2011 summer peak of 27,707 MW. There were 409 cooling degree days, which is 29.5% higher than the 20-year average.[8] The net energy for load was 3% lower in 2012 than 2011 over the year as a whole. With respect to the winter months, there was a decrease in heating degree days over 2011, and 2012 was below the 20-year average.

New England's historical cooling degree days and heating degree days for 1993 through 2012 are shown in Appendix Table 1. The difference between the cooling and heating degree days for a particular year and the average is also provided.

4.2 Emission Data

Individual generating unit emissions were calculated primarily from the 2012 actual emissions (tons) as reported under the U.S. EPA's Acid Rain Program, NO_X Clean Air Interstate Rule and the Regional Greenhouse Gas Initiative.[9] Hourly EPA emissions data were used for calculating the marginal emission rates. Prior to 2005, the MEA reports used annual data obtained primarily from the U.S. EPA Emissions Scorecard. In the 2005 and 2006 MEA Reports, monthly U.S. EPA data rather than hourly data were used for calculating marginal rates.

For those units that were not required to file emissions data under the Acid Rain Program, Clean Air Interstate Rule or the Regional Greenhouse Gas Initiative, monthly emission rates (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 (lb/MWh) from the U.S. EPA's eGRID2012 Version 1.0 (Year 2009) data[10] and, if that information was not available, emission rates based on eGRID data were obtained for similar type units. The emission rates were then multiplied by the 2012 energy generation reported to ISO-NE to obtain the emissions (tons) by each 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 83% of the SO_2 emissions and 84% of the CO_2 emissions were based on Clean Air Markets data. For NO_X, Clean Air Markets data were used for 84% of total emissions. For the total FTA marginal emissions, approximately 90% of the SO_2, 91% of the CO_2 and 91% 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.

[8] Over the 20-year span of 1993 to 2012, the average number of cooling degree days is 316 and the average number of heating degree days is 6,086.
[9] The U.S. EPA's Clean Air Markets emissions data can be accessed from http://www.epa.gov/airmarkets/.
[10] The U.S. EPA's eGRID2012Version 1.0 is located at: http://www.epa.gov/cleanenergy/energy-resources/egrid/index.html.

4.3 ISO New England System Installed Capacity

Table 4-1 and Table 4-2 show the total ISO New England generation capacity as obtained from ISO New England's 2013 Capacity, Energy, Loads and Transmission (CELT) Report[11] for the 2013 summer and winter periods, respectively.

The ISO-NE power grid operates as a unified system serving all loads in the region. The amount of generation by fuel type and its associated emissions are affected by a number of factors, including forced and scheduled maintenance outages of resources and transmission system elements, fuel and emission allowance costs, imports from and exports to neighboring regions, system peak load and energy consumption, water availability to hydro facilities and for thermal system cooling, and a variety of other factors.

Table 4-1: 2013 New England Summer Capacity[12, 13]

	Connecticut		Massachusetts		Maine		New Hampshire		Rhode Island		Vermont		New England	
Unit Type	MW	%	MW	%	MW	%	MW	%	MW	%	MW	%	MW	%
Combined Cycle	2,397.6	27.8	5,386.3	42.3	1,247.9	39.7	1,184.3	30.5	1,768.6	99.3	-	-	11,984.7	38.4
Gas Turbine	1,434.2	16.6	628.6	4.9	309.5	9.8	88.0	2.3	-	-	108.8	10.7	2,569.2	8.2
Hydro	88.8	1.0	179.5	1.4	474.2	15.1	437.0	11.3	0.4	0.0	193.7	19.1	1,373.6	4.4
Internal Combustion	23.1	0.3	126.7	1.0	18.6	0.6	1.2	0.0	10.7	0.6	21.4	2.1	201.6	0.6
Nuclear	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Pumped Storage	29.4	0.3	1,408.1	11.1	-	-	-	-	-	-	-	-	1,437.5	4.6
Fossil Steam	4,663.3	54.0	4,969.4	39.0	1,053.5	33.5	2,148.3	55.4	-	-	671.6	66.2	13,506.0	43.3
Wind & Photovoltaic	-	-	40.1	0.3	40.4	1.3	22.1	0.6	0.6	0.0	18.7	1.8	121.8	0.4
Total	8,636.4	100.0	12,738.6	100.0	3,144.0	100.0	3,881.0	100.0	1,780.2	100.0	1,014.1	100.0	31,194.3	100.0

Table 4-2: 2013 New England Winter Capacity[12, 13]

	Connecticut		Massachusetts		Maine		New Hampshire		Rhode Island		Vermont		New England	
Unit Type	MW	%	MW	%	MW	%	MW	%	MW	%	MW	%	MW	%
Combined Cycle	2,676.1	29.0	6,282.6	43.9	1,355.0	39.7	1,360.3	31.3	2,059.7	99.0	-	-	13,733.7	39.8
Gas Turbine	1,678.2	18.2	829.0	5.8	360.9	10.6	109.0	2.5	-	-	148.4	12.9	3,125.5	9.0
Hydro	112.0	1.2	245.9	1.7	512.9	15.0	487.6	11.2	2.8	0.1	279.7	24.3	1,640.8	4.8
Internal Combustion	23.2	0.3	136.3	1.0	19.7	0.6	1.6	0.0	16.0	0.8	21.5	1.9	218.2	0.6
Nuclear	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Pumped Storage	29.0	0.3	1,686.9	11.8	-	-	-	-	-	-	-	-	1,715.9	5.0
Fossil Steam	4,722.5	51.1	5,082.4	35.5	1,067.7	31.3	2,338.6	53.9	-	-	666.0	57.8	13,877.2	40.2
Wind & Photovoltaic	-	-	48.1	0.3	99.8	2.9	44.9	1.0	1.4	0.1	35.8	3.1	230.0	0.7
Total	9,240.9	100.0	14,311.2	100.0	3,415.9	100.0	4,341.9	100.0	2,079.9	100.0	1,151.5	100.0	34,541.3	100.0

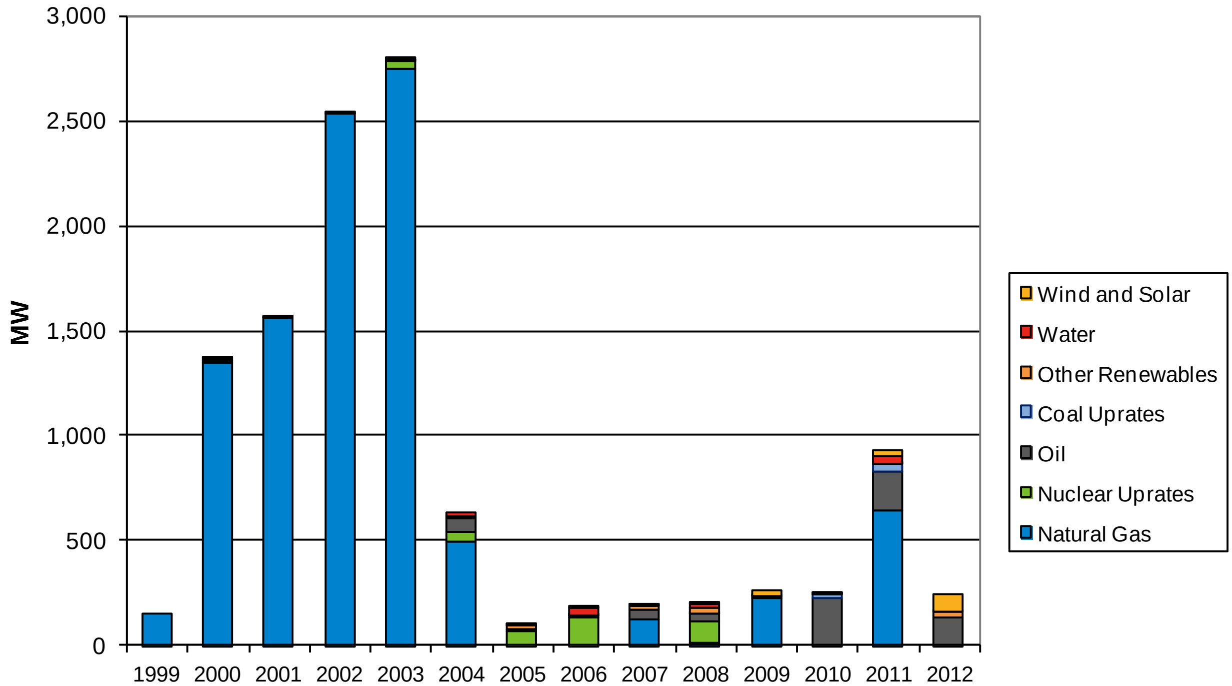
[11] The ISO-NE CELT Report is typically issued in April of each year. The 2013 CELT Report (using the January 1, 2013 ratings) was used in order to completely capture all the new capacity additions that occurred during the prior calendar year 2012. It can be accessed from http://www.iso-ne.com/trans/celt/report/index.html.

[12] Sum may not equal total due to rounding.

[13] Season Claimed Capability as of January 1, 2013.

Figure 4-1 illustrates the new generating capacity that was added to the ISO New England system during 1999 through 2012, 87% of which was gas-fired generation comprised mainly of combined cycle technologies. From 1999-2004, 9,053 MW of new capacity was added and nearly 100% of the new capacity additions were gas-fired, combined cycle technologies. From 2005-2012, 2,320 MW was added, with combustion turbines and combined cycle plants capable of burning natural gas or distillate oil making up 79% of this new capacity. The remaining additions consist of nuclear uprates and renewable generation.

Figure 4-1 : ISO New England Generator Unit Additions - 2001 through 2012[14]

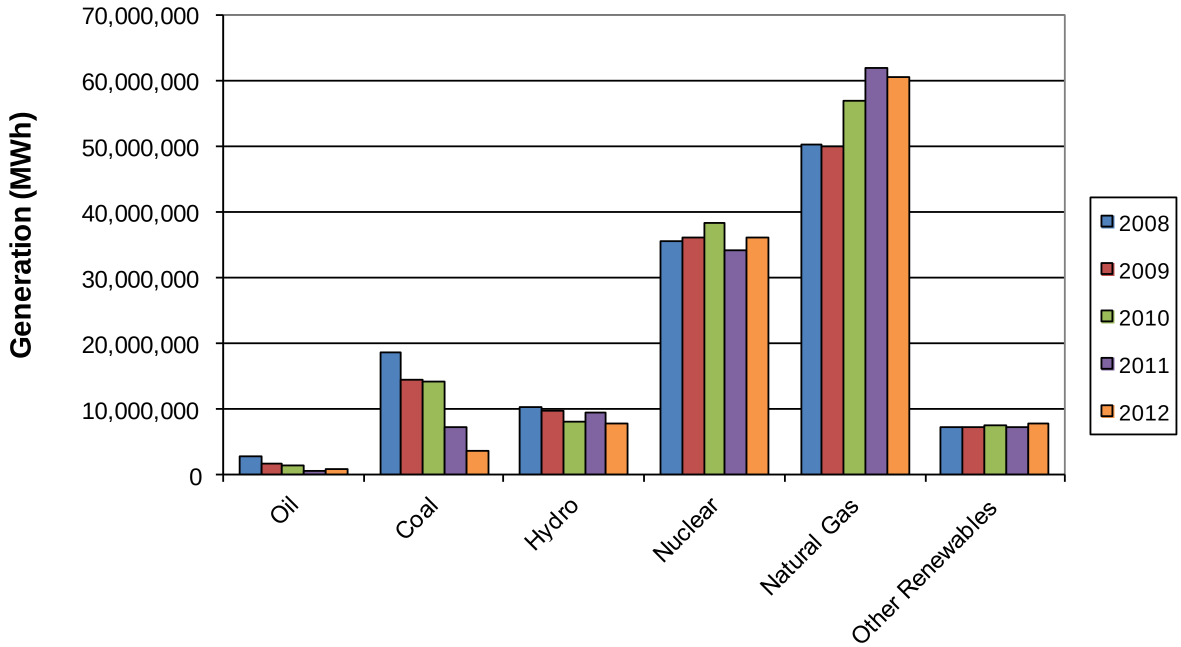


[14] The generator additions and uprate values are based on the Seasonal Claimed Capabilities as reported in the ISO-NE CELT Report of the year following the addition.

4.4 ISO New England System Energy Production

Figure 4.2 shows the generation (MWh) by fuel types from 2008-2012, based on the resource's primary fuel type listed in the 2013 CELT Report. In 2012, nuclear and oil-fired generation was about 1,833 GWh and 754 GWh higher, respectively, than in 2011. In contrast, coal-fired generation decreased by about 3,379 GWh, representing a nearly 48% decrease in generation. Natural gas and hydroelectric generation decreased by 1,314 GWh and 1,580 GWH respectively, or about 2% and 17%. Overall, system generation was about 3,670 GWh lower in 2012 than in 2011; 2012 total energy generation was 116,942 GWh.

Figure 4-2 : 2008 - 2012 Generation by Selected Fuel Types



4.5 Locational Marginal Units (LMUs)

The Locational Marginal Unit (LMU) is identified by the LMP, which is set by the cost of the capacity dispatched to meet the next increment of load at the pricing location. The resource that sets price is called the marginal unit (LMU). Because the price of electricity changes as the price of the marginal unit changes, and the price of the marginal unit largely is determined by its fuel type, examining marginal units by fuel type largely explains changes in electricity prices. The system has at least one marginal unit associated with meeting the energy requirements on the system during each pricing interval. If transmission is not constrained, the marginal unit is classified as the unconstrained marginal unit. In intervals with binding transmission constraints, there is one additional marginal unit for each constraint.

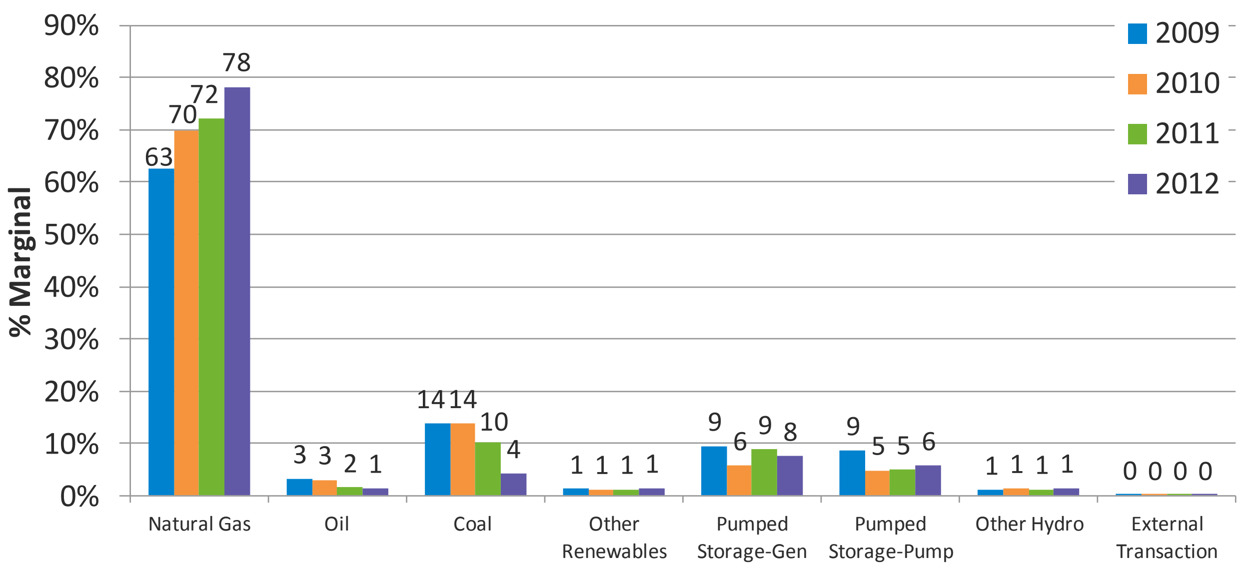
The analysis of LMU marginal emission rates is conducted in three different scenarios. Each scenario provides a different perspective by including or excluding certain generators depending on their characteristics. The three scenarios are described as followed:

- All LMUs – includes all Locational Marginal Units identified by the LMP
- Emitting LMUs - excludes all non-emitting units, such as pumped storage, hydro-electric generation, external transactions and other renewables with no associated air emissions
- Oil- and Natural Gas-fired (O&NG) LMUs – includes only oil- and natural gas-fired units identified by LMP

4.5.1 All LMUs

In this scenario, all identified marginal units (LMUs) are used to develop the marginal emission rates. Non-emitting generators such as hydro-electric generation and external transactions are associated with a zero emission rate. Figure 4-3 shows the historical percentages that each fuel type is marginal within a calendar year. It can be observed that natural gas has been the primary fuel type setting LMP in the last four years.

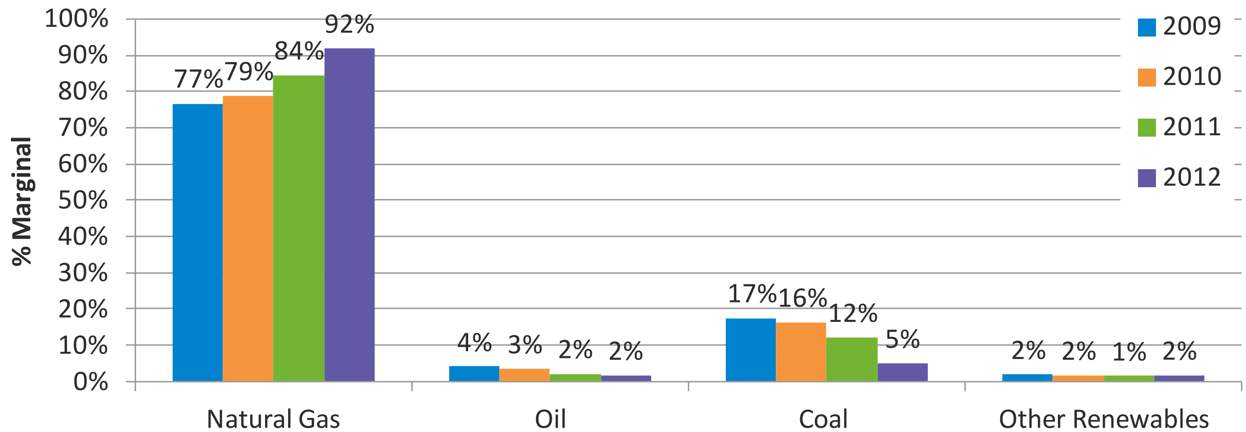
Figure 4-3: Percent of Time LMUs Marginal by Fuel Type – All LMUs



4.5.2 **Emitting LMUs**

Generating resources with no air emissions are excluded in this scenario. Therefore, hydro, pumped storage, external transaction and other renewables with no air emissions are not taken into account, while all other LMUs are.

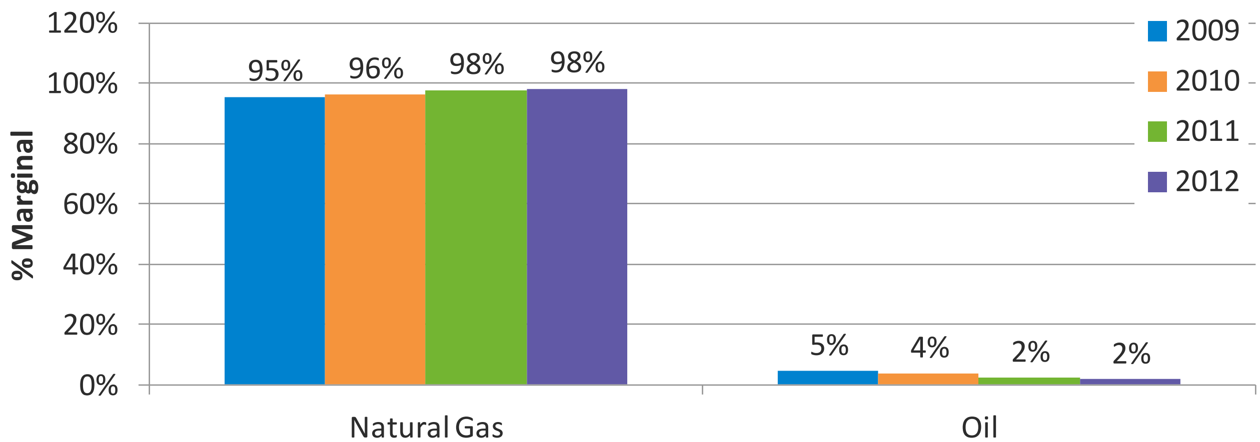
Figure 4-4: Percent of Time LMUs Marginal by Fuel Type – Emitting LMUs



4.5.3 **Oil- & Natural Gas-Fired LMUs**

This scenario only includes natural gas and oil-fired generators from all LMUs identified by the LMP and was created to provide a benchmark comparison with the previous method of Fuel Type Assumed (FTA) Marginal Emission Analysis.

Figure 4-5: Percent of Time LMUs Marginal by Fuel Type – O&NG LMUs



5 Results

5.1 ISO New England System Generator Air Emissions

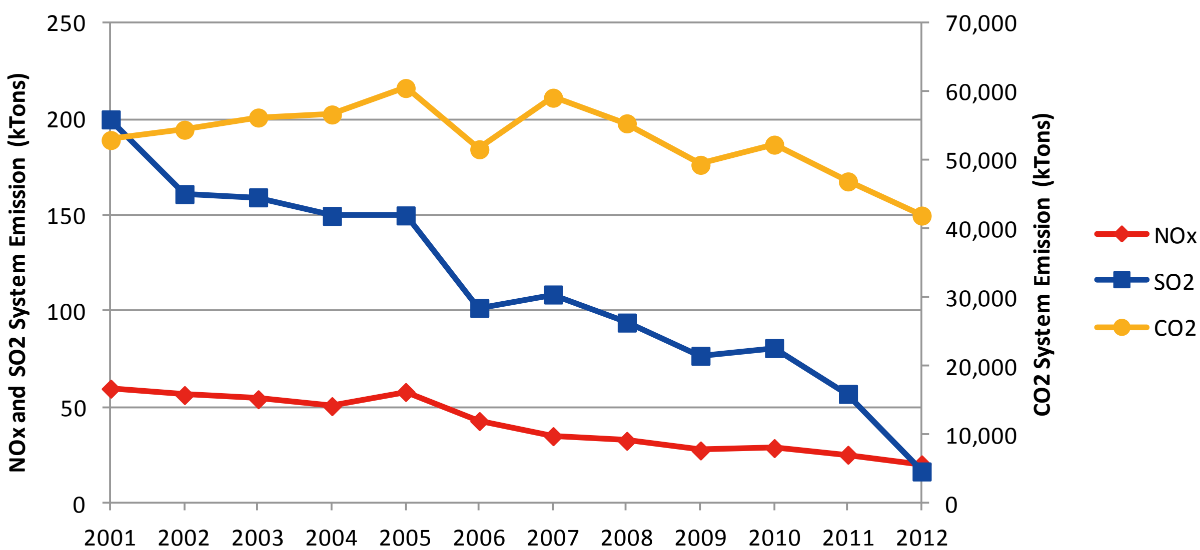
Table 5-1 shows the annual aggregate 2012 NO_X, SO_2, and CO_2 air emissions for each state and for all of New England. These emissions were calculated based on the actual generation of all generating units in ISO-NE's balancing authority area and the actual or assumed unit-specific air emissions or emission rates.[15]

Table 5-1: 2012 Calculated ISO New England Electric Generation System Annual Aggregate Emissions of NOX, SO2, and CO2 in kTons [16]

State	NO_x	SO_2	CO_2
Connecticut	4.90	0.82	9,366
Maine	2.24	0.94	4,851
Massachusetts	8.33	11.94	16,725
New Hampshire	3.56	2.09	6,695
Rhode Island	0.70	0.47	3,875
Vermont	0.60	0.34	463
New England	20.32	16.61	41,975

Figure 5-1 shows the annual aggregate NO_X, SO_2, and CO_2 air emissions for the years 2001 through 2012. Since 2001, NO_X emissions have dropped by 66% and SO_2 by 92%, while CO_2 has decreased by about 21%. Refer to Appendix Table 2 for historical system emissions by kTons.

Figure 5-1: 2001-2012 Annual System Aggregate Emissions of NO_X, SO_2, and CO_2 in kTons



[15] This does not include Northern Maine and the Citizens Block Load located in Northern Vermont, which is typically served by Quebec. These areas are not electrically connected to the ISO-NE Control Area.
[16] Sum may not equal total due to rounding.

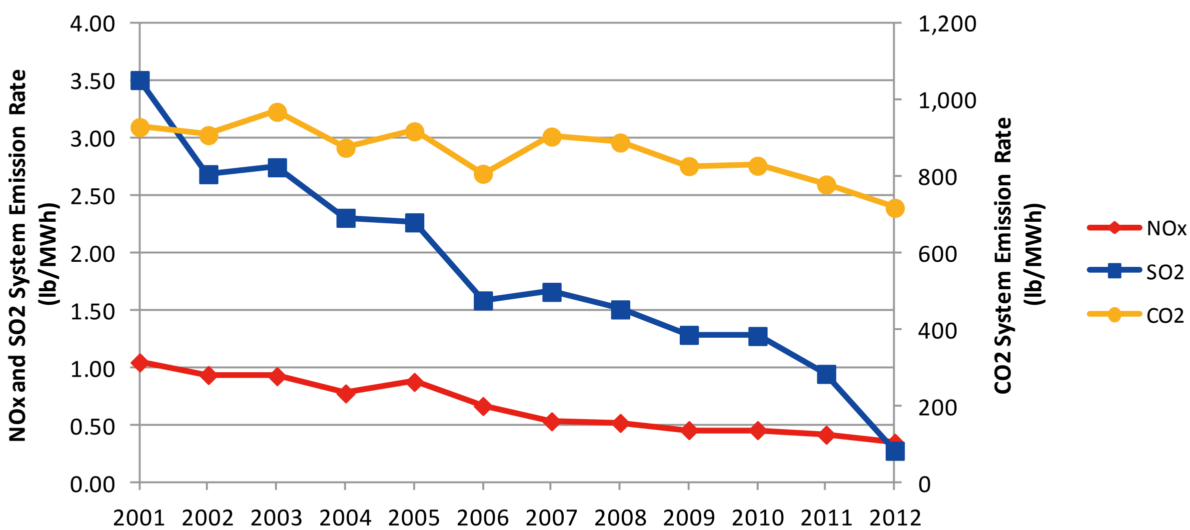
Table 5-2 shows the annual average 2012 NO_X, SO_2, and CO_2 air emission rates (lb/MWh), by state and for New England, calculated based on the actual hourly unit generation of ISO-NE generating units located within that specific state and the actual or assumed unit-specific air emissions or emission rates.

Table 5-2: 2012 Calculated ISO New England Electric Generation System Annual Average NO_X, SO_2, and CO_2 Emission Rates in lb/MWh

State	NO_x	SO_2	CO_2
Connecticut	0.28	0.05	536
Maine	0.41	0.17	889
Massachusetts	0.45	0.65	910
New Hampshire	0.37	0.22	694
Rhode Island	0.17	0.11	939
Vermont	0.18	0.10	139
New England	0.35	0.28	719

Figure 5-2 illustrates the annual average NO_X, SO_2, and CO_2 air emission rate values (lb/MWh), for the 2001 – 2012 time period. These annual emission rates were calculated by dividing the total air emissions by the total generation from all units. Since 2001, the annual average NO_X emission rate has decreased by 67%, SO_2 by 92%, and CO_2 by 23%. All historical emission rates can be seen in Appendix Table 3.

Figure 5-2: 2001-2012 ISO New England System Annual Average NO_X, SO_2, and CO_2 Emission Rates (lb/MWh)



5.1.1 Observations

2012 total energy generation was 3% lower than 2011 total energy generation. This was reflected in decreases in the NO_X, SO_2 and CO_2 total system emissions of 19.7%, 70.9% and 10.6%, respectively.. The calculated system emission rates for 2012 are also lower than the 2011 values. The NO_X, SO_2 and CO_2 rates have decreased by 16.7%, 70.5%, and 7.8%, respectively.

The decrease in average emission rates from 2001 to 2012 can be attributed to the increased use of new, more efficient natural-gas-fired power plants, a decline in the cost of natural gas, and the implementation of new emission controls on some of the region's oil- and coal-fired power plants.

5.2 2012 ISO New England Marginal Heat Rate

Prior to 1999, MEA studies assumed a fixed marginal heat rate of 10.0 MMBtu/MWh which was used to convert from lb/MWh to lb/MMBtu.[17] 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 a unit's heat rate is equal to its fuel consumption divided by its generation, the calculated marginal heat rate is defined as follows:[18]

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

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. The individual heat input values using the two methods, in MMBtu, were then 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 2012. The lower the marginal heat rate value, the more efficient the system or marginal generator(s) is with respect to converting raw fuel into electric energy.

5.2.1 Fuel Type Assumed (FTA) Marginal Heat Rate

Assuming natural gas and oil-fired generators as marginal units, the FTA Marginal Heat Rate is calculated with unit heat input (MMBtu) and their generation.

Table 5-3: Calculated New England Annual FTA Marginal Heat Rate (MMBtu/MWh)

Year	Marginal Heat Rate (MMBtu/MWh)
2001	9.279
2002	8.660
2003	8.249
2004	8.210
2005	8.140
2006	7.667
2007	8.095
2008	7.932
2009	7.774
2010	7.926
2011	7.628
2012	7.407

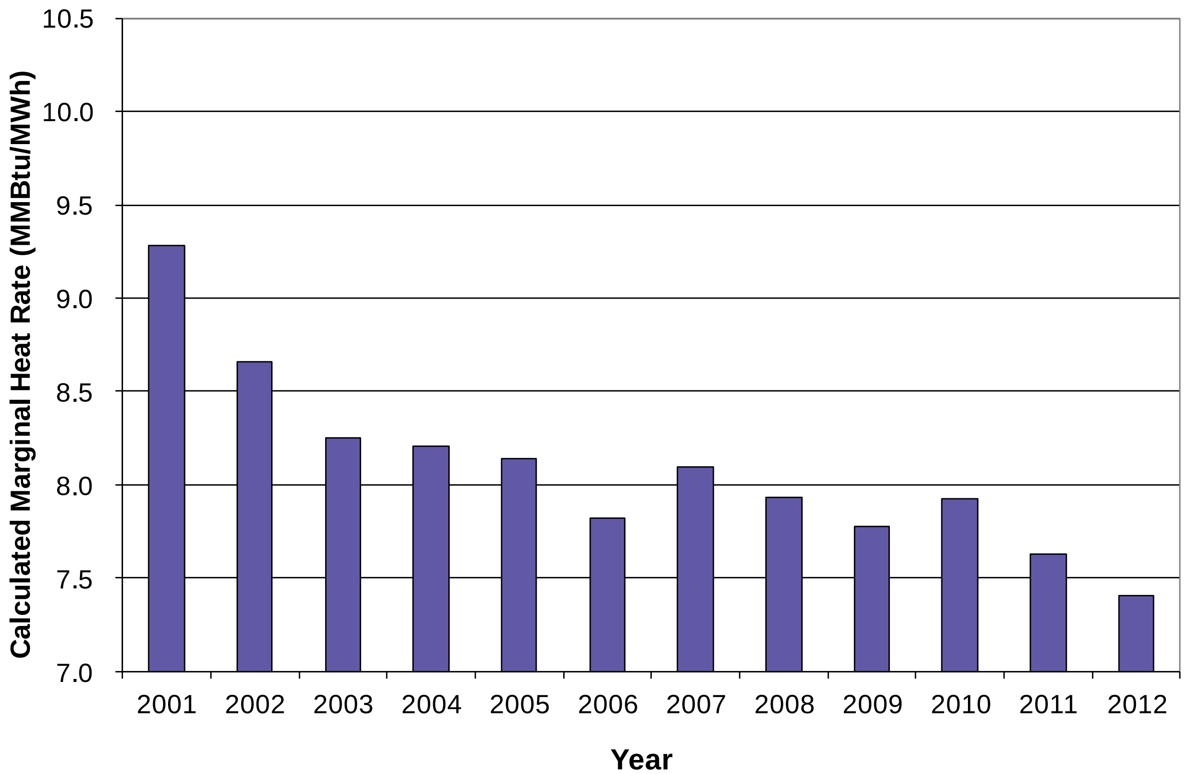
[17] 10 MMBtu/MWh is equivalent to 10,000,000 Btu/kWh.

[18] 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.

The annual calculated marginal heat rates from 2001 to 2012 are shown in Table 5-3 above. The rate has declined nearly 25% since 2001. The 2012 calculated marginal heat rate of 7.407 (MMBtu/MWh) was used as the conversion factor to convert from lb/MWh to lb/MMBtu for the marginal emission rates in this report.

Figure 5-3 illustrates the calculated annual marginal heat rate spanning the 2001-2012.

Figure 5-3: Historical New England Annual FTA Marginal Heat Rate (MMBtu/MWh)



5.2.2 LMU Marginal Heat Rate

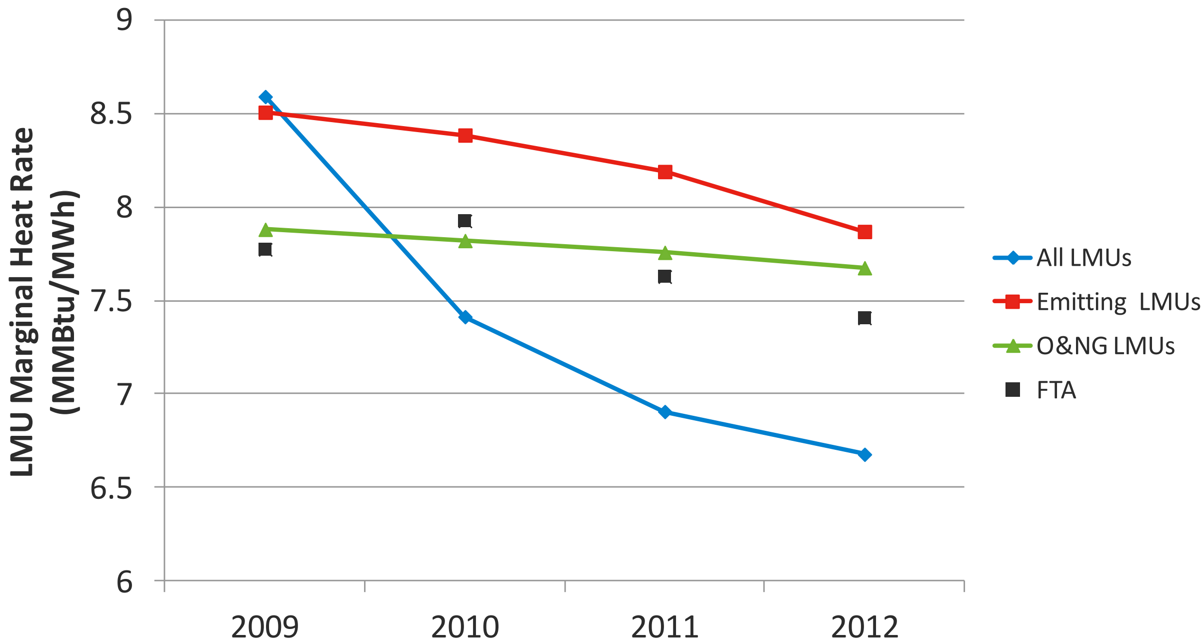
A heat rate is calculated for each individual generator. The percentage of time each generator is marginal per year leads to the same amount of contribution of that unit's heat rate to the LMU Marginal Heat Rate. Below are the historical LMU marginal heat rates for the years 2009-2012.

Table 5-4: LMU Marginal Heat Rate (MMBtu/MWh)

LMU Marginal Heat Rate (MMBtu/MWh)			
Year	All Marginal LMUs	Emitting LMUs	O&NG LMUs
2009	8.591	8.507	7.881
2010	7.414	8.385	7.821
2011	6.907	8.190	7.758
2012	6.678	7.870	7.676

Figure 5-4 displays Table 5-4 in graphical form while also adding the FTA Marginal Heat for comparing against the O&NG LMU Marginal Heat Rate.

Figure 5-4: Historical LMU Marginal Heat Rate (MMBtu/MWh)



5.2.3 Observations

Overall, the trend of decreasing marginal heat rates has been continuing, with rates declining from 10.013 MMBtu/MWh to 7.407 MMBtu/MWh over the past twelve years according to the FTA methodology. There has also been a downward trend with the LMU-based Marginal Heat Rate methodology. Both methodologies reflect the addition of over 9,000 MW of natural gas-fired generation, mainly comprised of combined cycle units with higher efficiency, i.e., lower heat rates, causing the decreasing trend.

5.3 2012 ISO New England Marginal Emission Rates

5.3.1 FTA Marginal Emission Rates

Table 5-5 shows the NO_X, SO_2, and CO_2 calculated marginal emission rates in lb/MWh for ISO 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, accounting only the on-peak, off-peak, and annual rates are provided for those emissions. Appendix Table 4 shows the same information expressed in lb/MMBtu. As noted earlier, the 2012 calculated marginal heat rate of 7.407 MMBtu/MWh was used as the conversion factor.

Table 5-5: 2012 Calculated New England FTA Marginal Emission Rates (lb/MWh) [19,20]

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	0.18	0.13	0.12	0.12	0.14
Annual Emissions (SO_2 and CO_2)					
Air Emission		Annual			Annual Average (All Hours)
		On-Peak	Off-Peak		
SO_2		0.04	0.02		0.03
CO_2		894	903		899

5.3.2 LMU Marginal Emission Rates

This section shows the 2012 calculated LMU-based Marginal Emission Rates in three different scenarios.

- All LMUs – includes all Locational Marginal Units identified by the LMP
- Emitting LMUs - excludes all non-emitting units, such as pumped storage, hydro-electric generation, external transactions and other renewables with no associated air emissions
- Oil- and Natural Gas-fired (O&NG) LMUs – includes only oil- and natural gas-fired units identified by LMP

[19] The Ozone Season is defined as occurring between May 1 and September 30, while the Non-Ozone Season is defined as occurring from January 1 to April 30 and from October 1 to December 31.
[20] On-Peak hours consist of all weekdays between 8 A.M. and 10 P.M. Off-Peak hours consist of all weekdays between 10 P.M. and 8 A.M. and all weekends.

5.3.2.1 All LMUs Marginal Emission Rates

These emission rates are calculated with all LMUs (units that are identified by the LMP to be marginal). Table 5-6 shows rates in lb/MWh, which is calculated from Appendix Table 5 (lb/MMBtu) and the associated marginal heat rate of 6.678 MMBtu/MWh.

Table 5-6: 2012 LMU Marginal Emission Rates – All LMUs (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	0.35	0.21	0.19	0.16	0.22
Annual Emissions (SO_2 and CO_2)					
Air Emission		Annual			Annual Average (All Hours)
		On-Peak	Off-Peak		
SO_2		0.39	0.32		0.35
CO_2		876	839		854

5.3.2.2 Emitting LMUs Marginal Emission Rates

Presented in Table 5-7 and Appendix Table 6 are the marginal emissions rates from emitting LMUs. The marginal heat rate for this scenario is 7.870 MMBtu/MWh.

Table 5-7: 2012 LMU Marginal Emission Rates – Emitting LMUs (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	0.40	0.26	0.23	0.19	0.26
Annual Emissions (SO_2 and CO_2)					
Air Emission		Annual			Annual Average (All Hours)
		On-Peak	Off-Peak		
SO_2		0.45	0.39		0.42
CO_2		1,019	1,003		1,010

5.3.2.3 O&NG Marginal Emission Rates

Table 5-8 and Appendix Table 7 include the O&NG marginal emission rates. These rates are calculated for benchmarking purposes to give a framework of how the FTA and O&NG LMU Marginal Emission Rates compare when just looking at natural gas and oil-fueled units. Since natural gas is low is sulfur content and O&NG LMU reflect natural gas on the margin 98% of the time (Figure 4-5), SO_2 rates are very low. The associated marginal heat rate is 7.676 MMBtu/MWh.

Table 5-8: 2012 LMU Marginal Emission Rates – O&NG LMUs (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	0.32	0.11	0.12	0.14	0.16
Annual Emissions (SO_2 and CO_2)					
Air Emission		Annual			Annual Average (All Hours)
		On-Peak	Off-Peak		
SO_2		0.07	0.02		0.04
CO_2		933	902		915

5.3.3 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. The amount of imports, the use of pumped storage and significant generator outages, such as a nuclear unit outage, could also affect emissions. The FTA and LMU Marginal Emission Rates will reflect these changing parts of the New England power system.

In observing both methodologies, there was a slight difference between the on-peak and off-peak marginal rates for NO_X, SO_2 and CO_2. There are higher emission rates in SO_2 and NO_X during on-peak hours and ozone season (for NO_X) compared to off-peak hours 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 economic to operate only during high energy price hours or may be older, fossil-steam resources with higher individual heat rates (lower thermal efficiency).

5.4 Historical Marginal Emission Rates

5.4.1 2001-2012 FTA Marginal Emission Rates

Figure 5-5, Figure 5-6 and Figure 5-7 show the historical calculated FTA marginal emission rates for NO_X, SO_2, and CO_2, respectively, in lb/MWh for the years 2001 through 2012. Figure 5-5 shows the ozone and non-ozone season rates, while the SO_2 and CO_2 figures include only the annual average emission rates. Appendix Table 8, Appendix Table 9 and Appendix Table 10 show the detailed historical emission rates in detail. All three tables show the annual average percentage change from the previous year.

Figure 5-5: Historically Calculated New England NO_X FTA Marginal Emission Rates

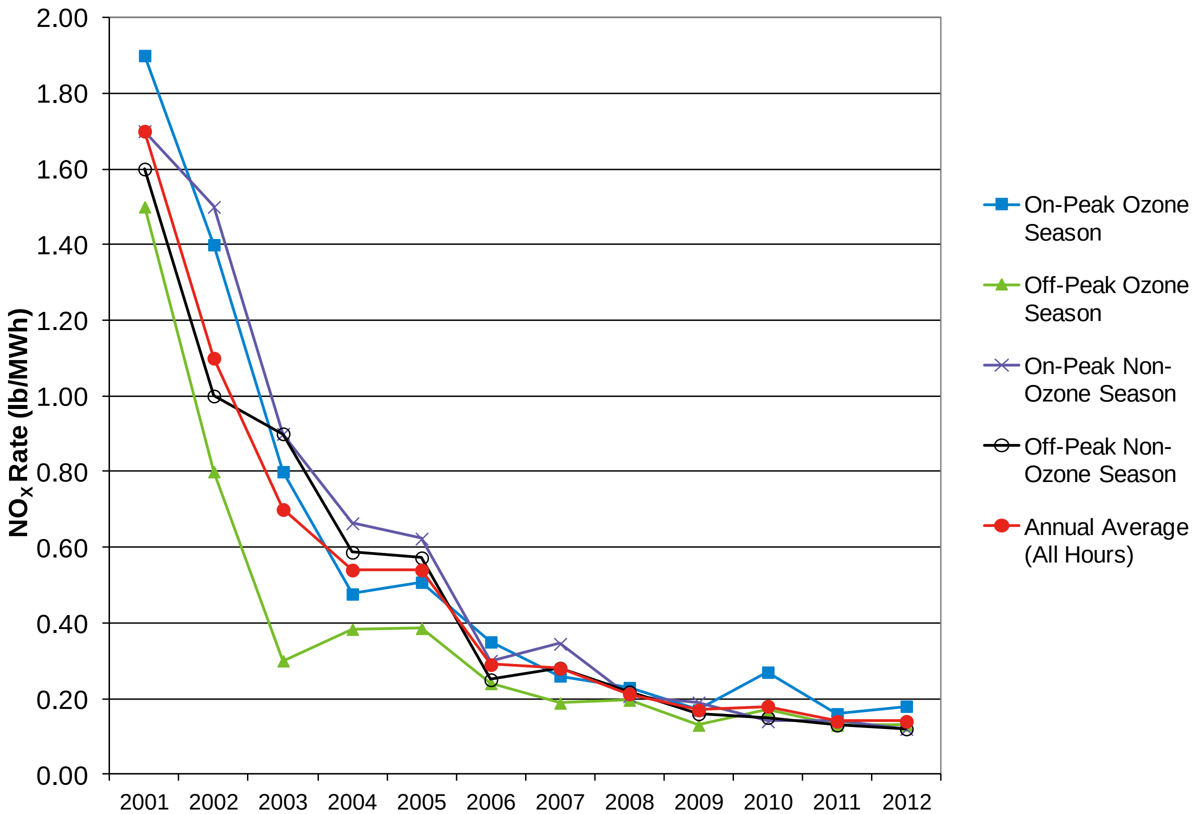


Figure 5-6: Historically Calculated New England SO_2 FTA Marginal Emission Rates

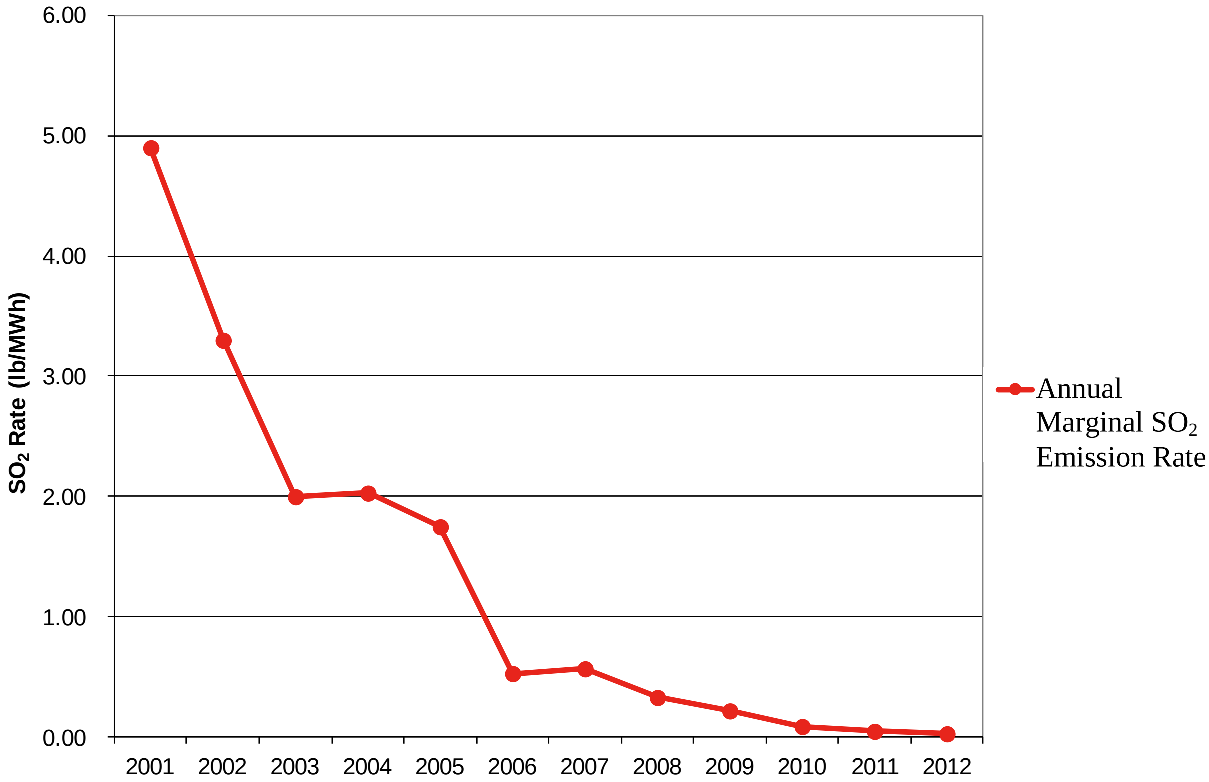
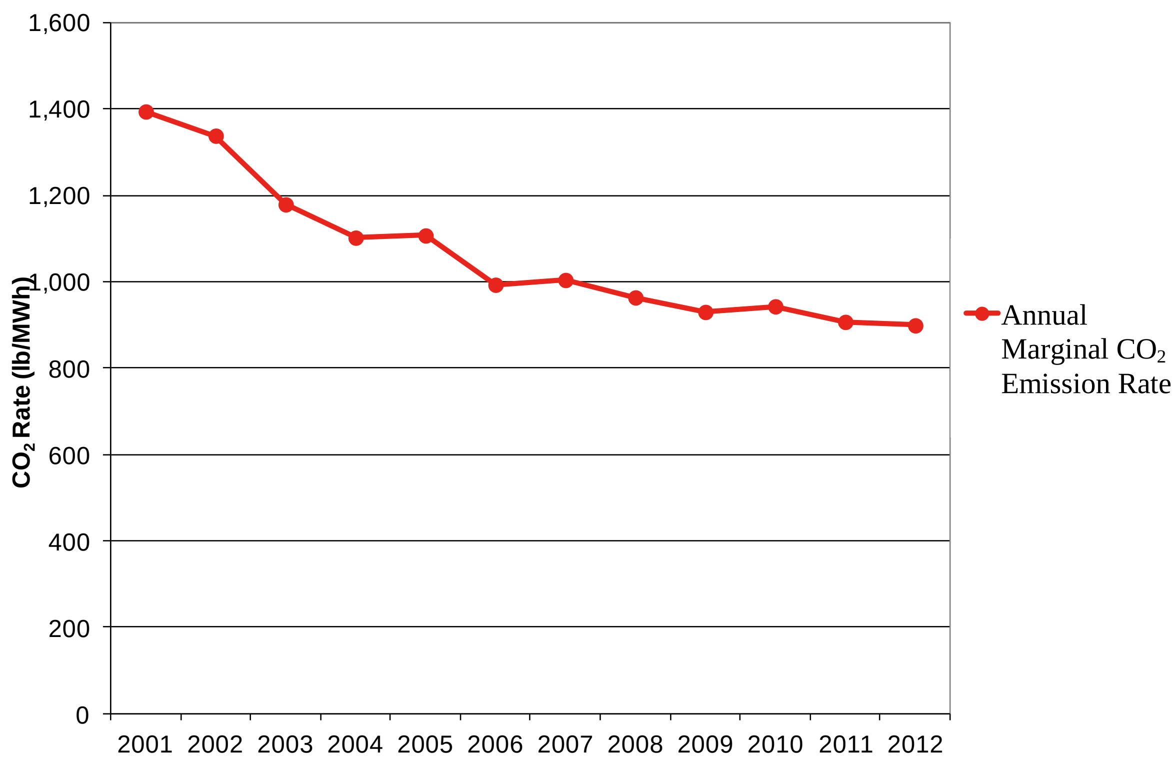


Figure 5-7: Historically Calculated New England CO_2 FTA Marginal Emission Rates



5.4.2 2009-2012 LMU Marginal Emission Rates

The LMUs (marginal units identified from the LMP) actively exhibit the changes in New England's energy production. When considering all LMUs versus emitting LMUs, the latter will result in high rates due to not accounting for zero air emission resources, which would lower the average rate. Figure 5-8, Figure 5-9 and Figure 5-10 summarize the three scenario of results calculated for the LMU Marginal Emission Rates, which are detailed in Appendix Table 11 through Appendix Table 19 in lb/MWh.

Figure 5-8: Historical LMU Marginal Emission Rates – All LMUs (lb/MWh)

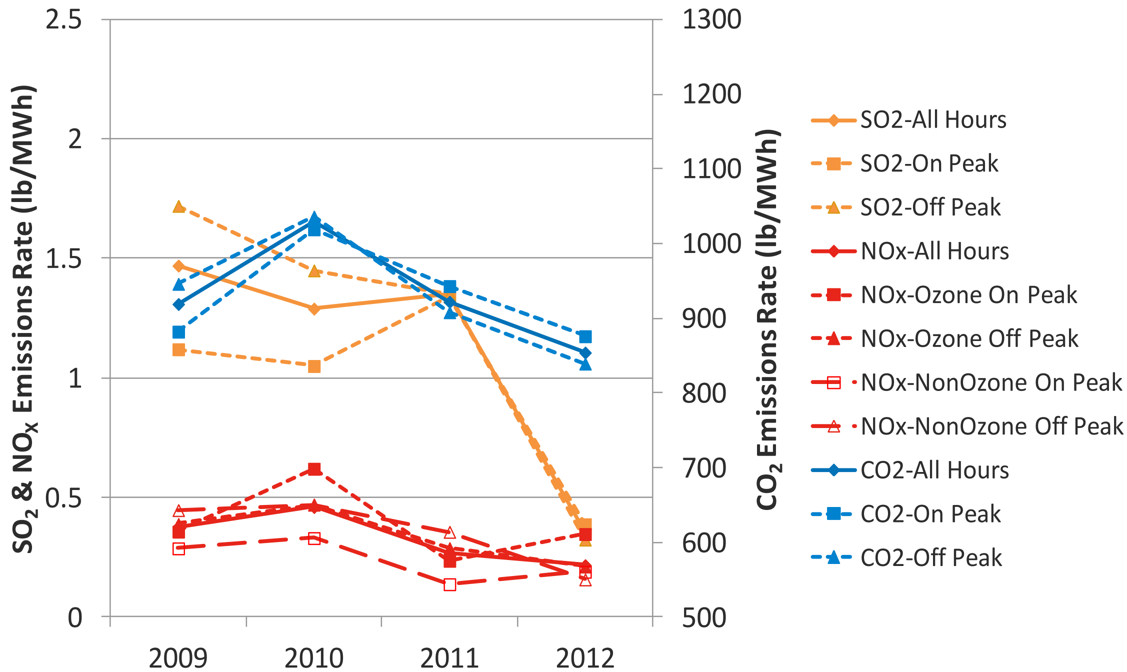


Figure 5-9: Historical LMU Marginal Emission Rates – Emitting LMUs (lb/MWh)

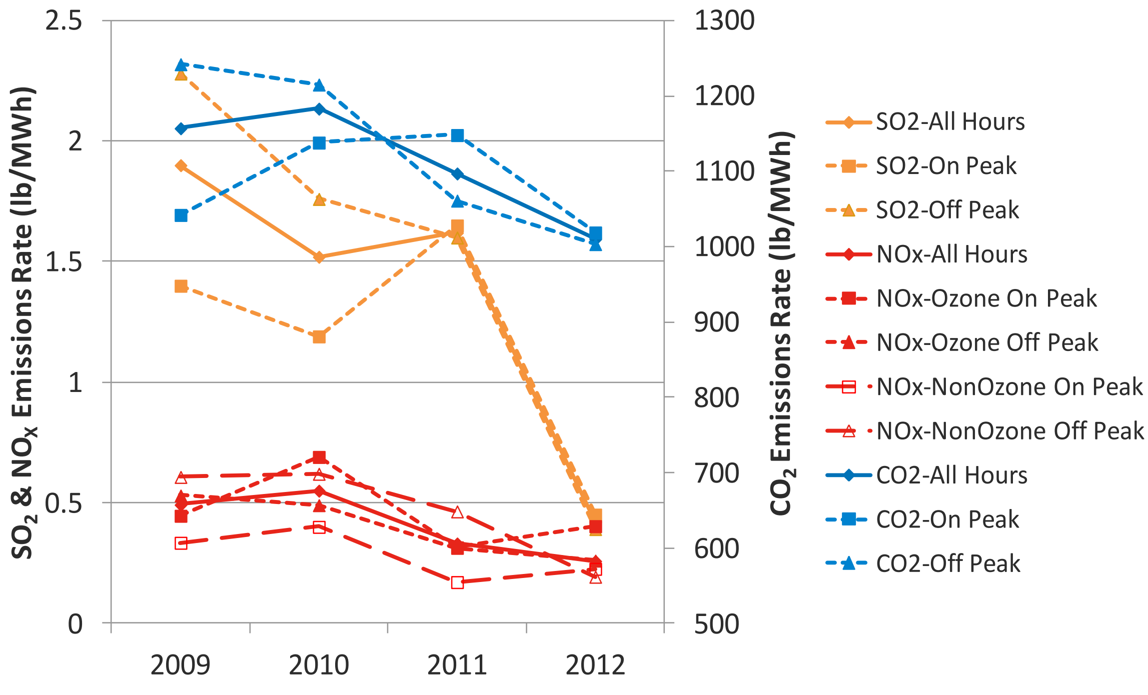
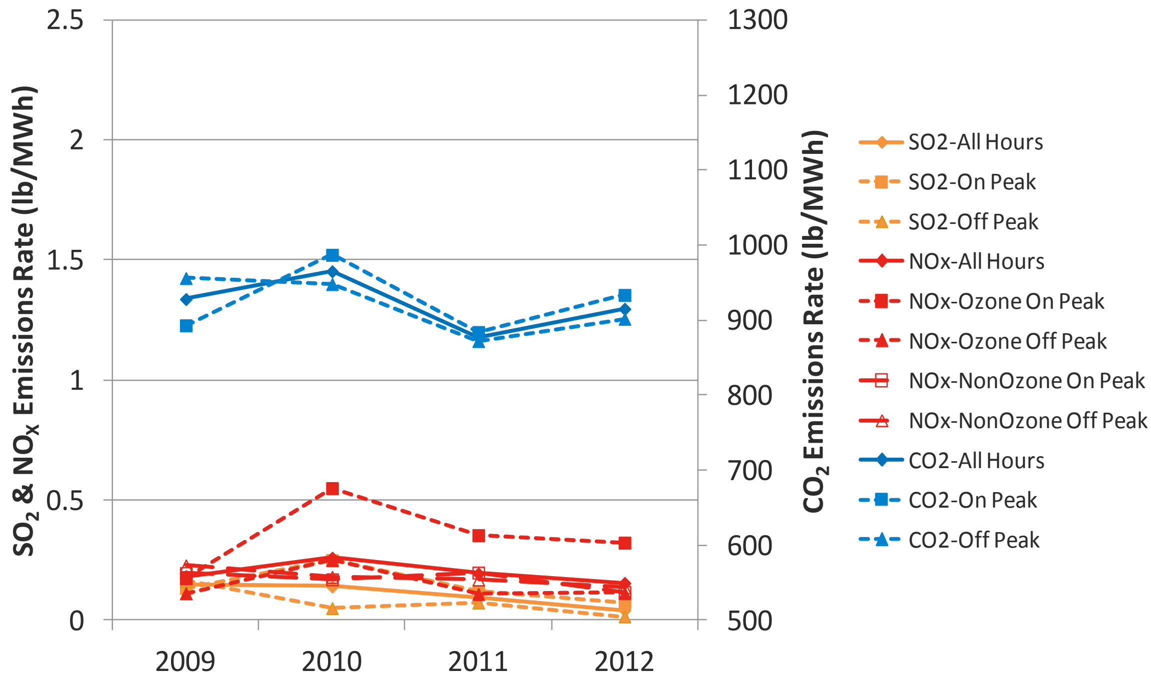


Figure 5-10: Historical LMU Marginal Emission Rates – O&NG LMUs (lb/MWh)



5.4.3 **Observations**

FTA CO_2 and SO_2 marginal emission rates both decreased by 45% and 40% between 2011 and 2012, while there was no change for the FTA NO_X marginal emission rates. This is compared to an average of 9%, 72% and 20% for when averaging the scenario of including all LMUs and the scenario of emitting LMUs marginal emission rates for CO_2, SO_2 and NO_X. The relatively large decrease observed in SO_2 emissions, also observed in system emissions, between 2011 and 2012 can primarily be attributed to the decrease in generation by coal-fired units, the installation of emission control technology on existing units and the recent retirement of generators.

As compared with 2001, the 2012 FTA SO_2 and NO_X annual marginal rates have declined by 92% and CO_2 by 36%. This decline is clearly illustrated in Appendix Table 8, Appendix Table 9 and Appendix Table 10. There was a noticeable decrease in the FTA 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 4-1), as well as a decrease in the price of natural gas. This was combined with the 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 New England's nuclear units as well as increases in some of their capacity ratings, and they have therefore been contributing more toward satisfying the base load electrical demand of the system.

Although FTA and LMU marginal emission rates uses two different assumptions, the years 2009-2012 have similar trends for the regions marginal emissions rates. NO_X and SO_2 have both continued their historical downward trend while CO_2 has had minimal changes and maintained at the same level. When comparing the FTA and the O&NG LMU marginal emission rates, they are within the same magnitude as emission rates.

5.5 FTA Marginal Emission Rates by State

Table 5-9, Table 5-10, and Table 5-11 show the 2012 calculated NO_X, SO_2 and CO_2 FTA 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 type of capacity located within each state is the major factor in the calculated state marginal emission rates. For example, Rhode Island, where 99% of the in-state capacity is gas-fired combined cycle, has much lower marginal emission rates than Vermont, which has the highest. The total amount of emissions (lb) in Vermont is the lowest in New England; it represented 0.02% of the total New England FTA marginal emissions. However, the marginal emission rates are high because the generating units in the marginal fossil category are mostly older, oil-fired, internal combustion engines and gas turbines.

Table 5-9: 2012 New England NO_X FTA Marginal Emission Rates by State (lb/MWh)[21,22]

	Ozone Season		Non-Ozone Season		
State	**On-Peak**	**Off-Peak**	**On-Peak**	**Off-Peak**	**Annual Average (All Hours)**
Connecticut	0.19	0.11	0.10	0.10	0.12
Maine	0.17	0.19	0.17	0.19	0.18
Massachusetts	0.20	0.14	0.12	0.11	0.14
New Hampshire	0.10	0.08	0.08	0.08	0.09
Rhode Island	0.14	0.18	0.14	0.18	0.16
Vermont	13.70	7.41	13.38	3.71	12.34
New England Average	0.18	0.13	0.12	0.12	0.14

[21] The Ozone Season is defined as occurring between May 1 and September 30, while the Non-Ozone Season is defined as occurring from January 1 to April 30 and from October 1 to December 31.
[22] On-Peak hours consist of all weekdays between 8 A.M. and 10 P.M. Off-Peak hours consist of all weekdays between 10 P.M. and 8 A.M. and all weekends.

Table 5-10: 2012 New England SO_2 FTA Marginal Emission Rates by State (lb/MWh)[23]

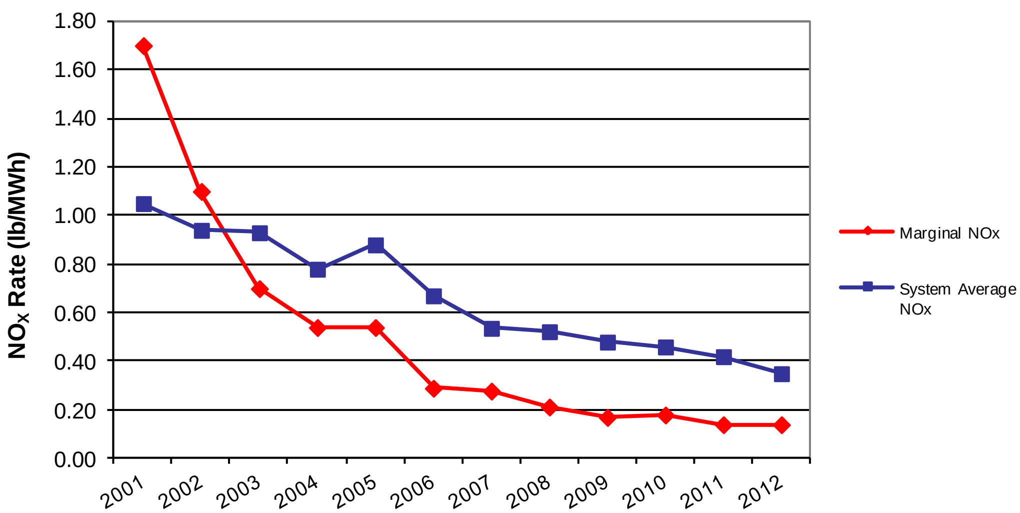
State	Annual On-Peak	Annual Off-Peak	Annual Average (All Hours)
Connecticut	0.04	0.02	0.03
Maine	0.15	0.08	0.12
Massachusetts	0.03	0.02	0.03
New Hampshire	0.05	0.01	0.03
Rhode Island	0.005	0.005	0.005
Vermont	10.24	9.11	10.06
New England Average	0.04	0.02	0.03

Table 5-11: 2012 New England CO_2 FTA Marginal Emission Rates by State (lb/MWh)

State	Annual On-Peak	Annual Off-Peak	Annual Average (All Hours)
Connecticut	844	839	842
Maine	990	1,055	1,020
Massachusetts	899	908	903
New Hampshire	881	896	888
Rhode Island	912	927	918
Vermont	3,589	2,342	3,388
New England Average	894	903	899

Figure 5-11, Figure 5-12 and Figure 5-13 show the relationship between the average system emission rates in Table 5-2 and the marginal emission rates for NO_X, SO_2, and CO_2 during 2001 to 2012.

Figure 5-11: 2001–2012 Calculated New England Annual Average System NO_X Emission Rate vs. NO_X FTA Marginal Emission Rate (lb/MWh)



[23] Actual values may differ from values due to rounding.

Figure 5-12: 2001 – 2012 Calculated New England Annual Average System SO_2 Emission Rate vs. SO_2 FTA Marginal Emission Rate (lb/MWh)

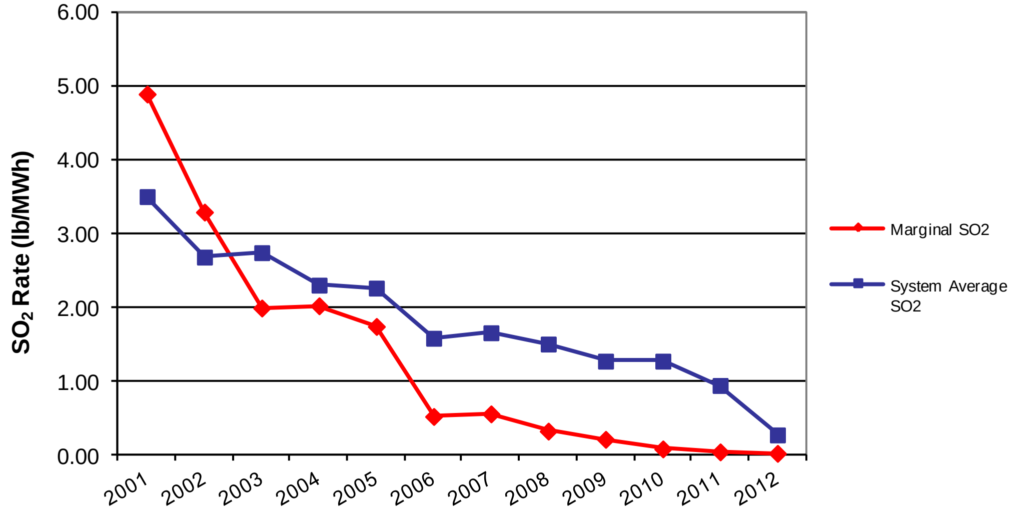
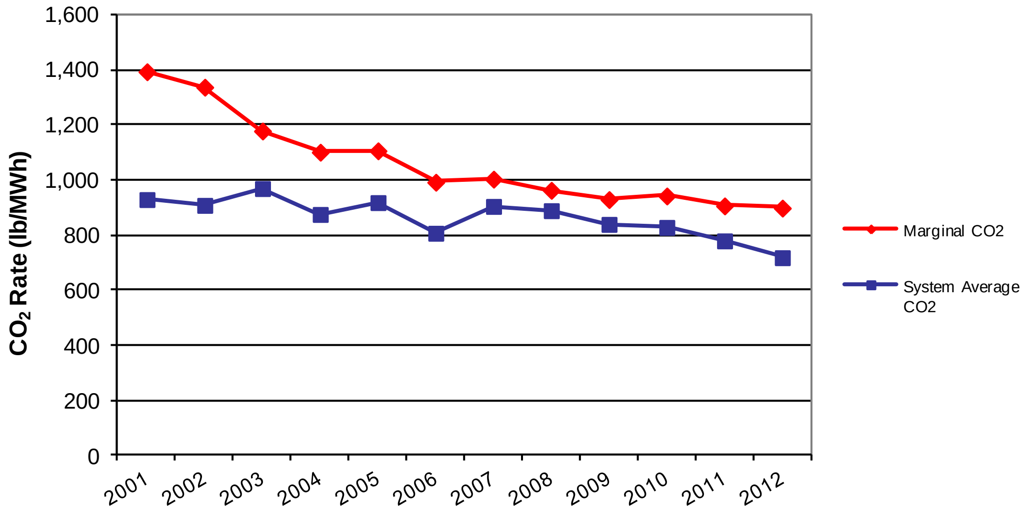


Figure 5-13: 2001 – 2012 Calculated New England Annual Average System CO_2 Emission Rate vs. CO_2 FTA Marginal Emission Rate (lb/MWh)



5.5.1 Observations

During the period from 2001 to 2012, the average system emission rates decreased for both NO_X and SO_2, but at a slower rate than the FTA marginal emission rates for those same pollutants. In fact, the FTA 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 23% between 2001 and 2012, while the FTA CO_2 marginal emission rate declined 36% during that same period. This was caused by increased load growth and demand for fossil-based energy that was counteracting the lower FTA marginal CO_2 rates as new units were added. Unlike the FTA SO_2 and NO_X marginal emission rates, the FTA CO_2 marginal emission rate has remained higher than the system emission rate during the entire period from 2001 through 2012. However, the FTA 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 2012.

6 Appendix

Appendix Table 1: 1993-2012 New England Total Cooling and Heating Degree Days

Year	Total Cooling Degree Days	Difference from Average (%)	Total Heating Degree Days	Difference from Average (%)
1993	283	-10.4	6,468	6.3
1994	374	18.4	6,403	5.2
1995	312	-1.2	6,318	3.8
1996	245	-22.4	6,454	6.1
1997	211	-33.2	6,432	5.7
1998	312	-1.2	5,483	-9.9
1999	360	14.0	5,774	-5.1
2000	217	-31.3	6,399	5.2
2001	323	2.3	5,895	-3.1
2002	354	12.1	5,959	-2.1
2003	355	12.4	6,651	9.3
2004	251	-20.5	6,354	4.4
2005	418	32.4	6,353	4.4
2006	335	6.1	5,552	-8.8
2007	288	-8.8	6,175	1.5
2008	281	-11.0	6,049	-0.6
2009	224	-29.1	6,278	3.2
2010	406	28.6	5,653	-7.1
2011	357	13.1	5,826	-4.3
2012	409	29.5	5,235	-14.0

Appendix Table 2: 2001-2012 ISO New England 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
2009	27.55	76.85	49,380
2010	28.79	80.88	52,321
2011	25.30	57.01	46,959
2012	20.32	16.61	41,975
Percent Reduction, 2001-2012	66	92	21

Appendix Table 3: 1999-2012 ISO New England System Annual Average NO_X, SO_2, and CO_2 Emission Rates (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
2009	119,282	0.46	1.29	828
2010	126,383	0.46	1.28	829
2011	120,612	0.42	0.95	780
2012	116,942	0.35	0.28	719
Percent Reduction, 1999 - 2012		74	94	29

Appendix Table 4: 2012 New England FTA Marginal Emission Rates (lb/MMBtu)

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	0.024	0.018	0.016	0.016	0.019
Annual Emissions (SO_2 and CO_2)					
Air Emission		**Annual**			**Annual Average (All Hours)**
		On-Peak	**Off-Peak**		
SO_2		0.005	0.003		0.004
CO_2		121	122		121

Appendix Table 5: 2012 LMU Marginal Emission Rates – All LMUs (lb/MMBtu)

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	0.047	0.028	0.026	0.021	0.029
Annual Emissions (SO_2 and CO_2)					
Air Emission		Annual			Annual Average (All Hours)
		On-Peak	Off-Peak		
SO_2		0.052	0.044		0.048
CO_2		118	113		115

Appendix Table 6: 2012 LMU Marginal Emission Rates – Emitting LMUs (lb/MMBtu)

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	0.054	0.035	0.031	0.026	0.035
Annual Emissions (SO_2 and CO_2)					
Air Emission		Annual			Annual Average (All Hours)
		On-Peak	Off-Peak		
SO_2		0.061	0.053		0.056
CO_2		138	135		136

Appendix Table 7: 2012 LMU Marginal Emission Rates – O&NG LMUs (lb/MMBtu)

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	0.044	0.015	0.016	0.018	0.021
Annual Emissions (SO_2 and CO_2)					
Air Emission		Annual			Annual Average (All Hours)
		On-Peak	Off-Peak		
SO_2		0.010	0.002		0.006
CO_2		126	122		124

Appendix Table 8: Historical New England Generation NO_X FTA 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
2009	0.17	0.13	0.19	0.16	0.17	-19.0
2010	0.27	0.17	0.14	0.15	0.18	5.9
2011	0.16	0.13	0.14	0.13	0.14	-22.2
2012	0.18	0.13	0.12	0.12	0.14	0.0
% Reduction 1993 - 2012	95.5	97.1	97.1	97.6	96.8	

Appendix Table 9: Historical New England Generation SO_2 FTA 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
2009	0.22	-33.3
2010	0.09	-59.1
2011	0.05	-44.4
2012	0.03	-40.0
% Reduction 1993 - 2012	99.8	

Appendix Table 10: Historical New England Generation CO_2 FTA 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
2009	930	-3.5
2010	943	1.4
2011	907	-3.8
2012	899	-0.9
% Reduction 1993 - 2012	**45.3**	

Appendix Table 11: Historical NO_X LMU Marginal Emission Rates – All LMUs (lb/MWh)

	Ozone Season		Non-Ozone Season			
Year	On-Peak	Off-Peak	On-Peak	Off-Peak	Annual Average (All Hours)	Annual Average Percentage Change
2009	0.36	0.39	0.29	0.45	0.38	-
2010	0.62	0.47	0.33	0.47	0.46	21.7
2011	0.24	0.29	0.14	0.36	0.27	-42.2
2012	0.35	0.21	0.19	0.16	0.22	-18.4
% Change 2009 - 2012	**-2.8**	**-45.8**	**-34.8**	**-64.9**	**-42.6**	

Appendix Table 12: Historical NO_X LMU Marginal Emission Rates – Emitting LMUs (lb/MWh)

	Ozone Season		Non-Ozone Season			
Year	On-Peak	Off-Peak	On-Peak	Off-Peak	Annual Average (All Hours)	Annual Average Percentage Change
2009	0.45	0.53	0.33	0.61	0.49	-
2010	0.69	0.49	0.40	0.62	0.55	11.8
2011	0.32	0.31	0.17	0.46	0.33	-39.8
2012	0.40	0.26	0.23	0.19	0.26	-22.0
% Change 2009 - 2012	**-9.7**	**-50.9**	**-32.3**	**-68.2**	**-47.5**	

Appendix Table 13: Historical NO_X LMU Marginal Emission Rates – O&NG LMUs (lb/MWh)

	Ozone Season		Non-Ozone Season			
Year	On-Peak	Off-Peak	On-Peak	Off-Peak	Annual Average (All Hours)	Annual Average Percentage Change
2009	0.18	0.11	0.20	0.23	0.18	-
2010	0.55	0.25	0.17	0.18	0.26	42.1
2011	0.35	0.11	0.20	0.17	0.19	-25.4
2012	0.32	0.11	0.12	0.14	0.16	-18.1
% Change 2009 - 2012	**84.4**	**0.9**	**-0.4**	**-39.9**	**-13.2**	

Appendix Table 14: Historical SO_2 LMU Marginal Emission Rates – All LMUs (lb/MWh)

Year	On-Peak	Off-Peak	Annual Average (All Hours)	Annual Average Percentage Change
2009	1.12	1.72	1.47	-
2010	1.05	1.45	1.29	-59.1
2011	1.34	1.35	1.35	27.6
2012	0.39	0.32	0.35	-71.1
% Change 2009 - 2012	**-65.4**	**-81.2**	**-76.0**	

Appendix Table 15: Historical SO_2 LMU Marginal Emission Rates – Emitting LMUs (lb/MWh)

Year	On-Peak	Off-Peak	Annual Average (All Hours)	Annual Average Percentage Change
2009	1.40	2.28	1.90	-
2010	1.19	1.76	1.52	-59.1
2011	1.65	1.60	1.62	38.7
2012	0.45	0.39	0.42	-72.7
% Change 2009 - 2012	**-67.8**	**-82.9**	**-78.1**	

Appendix Table 16 Historical SO_2 LMU Marginal Emission Rates – O&NG LMUs (lb/MWh)

Year	On-Peak	Off-Peak	Annual Average (All Hours)	Annual Average Percentage Change
2009	0.13	0.16	0.15	-
2010	0.25	0.05	0.13	-59.1
2011	0.12	0.07	0.09	-51.6
2012	0.07	0.02	0.04	-39.0
% Change 2009 - 2012	**-44.9**	**-90.7**	**-72.3**	

Appendix Table 17: Historical CO_2 LMU Marginal Emission Rates – All LMUs (lb/MWh)

Year	On-Peak	Off-Peak	Annual Average (All Hours)	Annual Average Percentage Change
2009	882	946	919	-
2010	1019	1036	1029	15.5
2011	943	908	922	-7.5
2012	876	839	854	-7.1
% Change 2009 - 2012	**-0.7**	**-11.3**	**-7.1**	

Appendix Table 18: Historical CO_2 LMU Marginal Emission Rates – Emitting LMUs (lb/MWh)

Year	On-Peak	Off-Peak	Annual Average (All Hours)	Annual Average Percentage Change
2009	1,042	1,242	1,157	-
2010	1138	1215	1183	9.2
2011	1148	1061	1097	0.9
2012	1019	1003	1010	-11.3
% Change 2009 - 2012	**-2.2**	**-19.2**	**-12.7**	

Appendix Table 19 Historical CO_2 LMU Marginal Emission Rates – O&NG LMUs (lb/MWh)

Year	On-Peak	Off-Peak	Annual Average (All Hours)	Annual Average Percentage Change
2009	893	956	928	-
2010	987	948	965	10.5
2011	884	872	877	-10.4
2012	933	902	915	5.6
% Change 2009 - 2012	**4.5**	**-5.7**	**-1.4**	

Prepared by:

ISO New England Inc. – System Planning

Customer Service: (413) 540-4220

http://www.iso-ne.com