2014 ISO New England Electric Generator Air Emissions Report

System Planning

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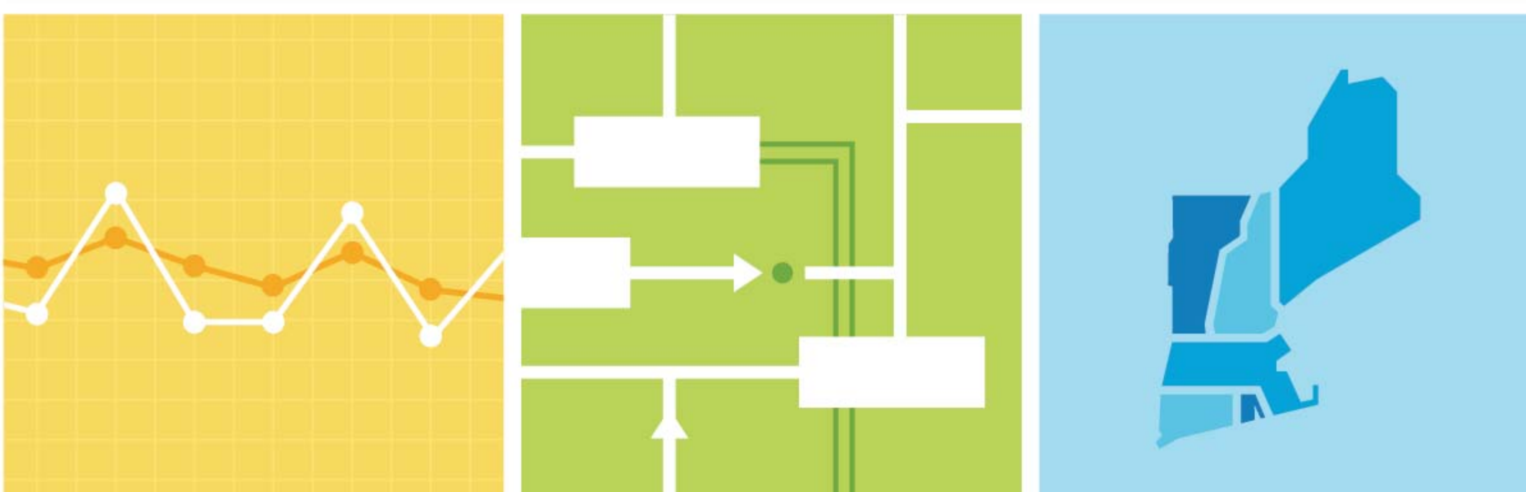

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Section 1
Executive Summary

This ISO New England (ISO) *Electric Generator Air Emissions Report* (*Emissions Report*) provides a comprehensive analysis of New England electric generator air emissions (nitrogen oxides [NO_X], sulfur dioxide [SO_2], and carbon dioxide [CO_2]) and a review of relevant system conditions. The main factors analyzed are as follows:

- System and marginal emissions (kilotons [ktons])[1]
- System and marginal emission rates (pounds per megawatt-hour [lb/MWh] and pounds per million British thermal unit [lb/MMBtu])
- System and marginal heat rate (MMBtu/MWh)

The report presents information for different time periods of interest:

- On-peak compared with off-peak hours
- Ozone season compared with non-ozone season
- Monthly variations
- High electric demand days (HEDDs)

The *Emissions Report*, first developed in 1993, has evolved in response to stakeholder needs. It was initially motivated by the need to determine the reductions of New England's aggregate NO_X, SO_2, and CO_2 generating unit air emissions resulting from demand-side management (DSM) programs. The use of these emission rates was subsequently broadened to reflect the emission-reduction benefits of energy-efficiency programs and renewable resource projects within the region.

From 2005 through 2014, total system emissions have decreased overall: NO_X by 65%, SO_2 by 92%, and CO_2 by 35%. The decline in emissions during this period reflects shifts in the regional fuel mix, with increasing natural gas generation offsetting decreases in coal- and oil-fired generation (see Figure 1-1).

[1]The mass value of "tons" is equivalent to a US short ton, or 2,000 lb, and "ktons" is equivalent to 2,000,000 lb.

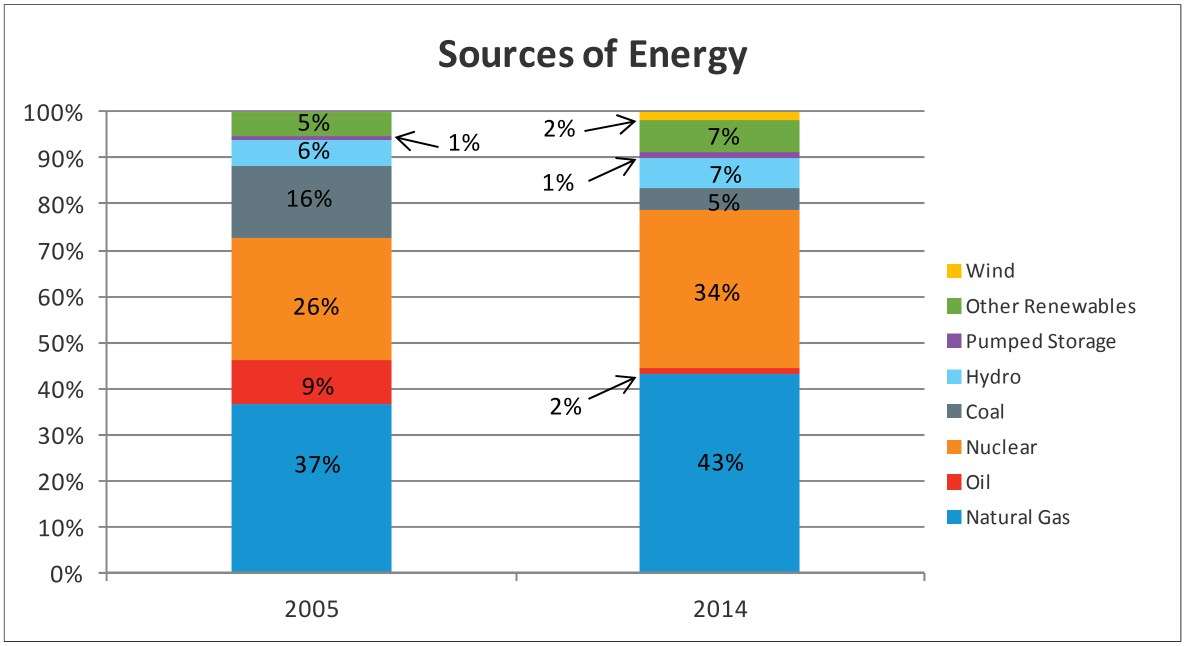

Figure 1-1: Percentage energy generation by fuel type, 2005 compared with 2014.

Compared with the 20-year average for heating and cooling days (i.e., an indicator of weather), 2014 had a 24% cooler summer and a 4% colder winter. From 2013 to 2014, the net energy for load was 2% lower, and system generation was lower by 3%. The amount of energy that New England received from neighboring areas in 2014 was approximately the same as imports in 2013. The energy generation by non-emitting generators (not including behind-the-meter generators) (e.g., pumped storage hydroelectric generation, nuclear, and wind and solar renewables) increased from 42% to 44%. Additionally, coal- fired generation decreased 19%. However, despite the long-term trend of increasing natural-gas-fired generation and decreasing oil-fired generation, from 2013 to 2014 the amount of natural gas-fired generation decreased, and the amount of oil-fired generation increased.

Table 1-1 shows the total 2013 and 2014 New England system emissions (ktons) and average system emission rates (lb/MWh) of NO_X, SO_2 and CO_2. Emission rates increased for NO_X and declined for SO_2 and CO_2 from 2013 to 2014.

Table 1-1
2013 and 2014 New England System Emissions (ktons)
and Emission Rates (lb/MWh)

Annual System Emissions						
	2013 Emissions (kTons)	2014 Emissions (kTons)	Total Emissions % Change	2013 Emission Rate (lb/MWh)	2014 Emission Rate (lb/MWh)	Emission Rate % Change
NO_X	20.32	20.49	0.8	0.36	0.38	5.6
SO_2	18.04	11.68	-35.3	0.32	0.22	-31.3
CO_2	40,901	39,317	-3.9	730	726	-0.5

Table 1-2 shows the 2013 and 2014 annual average marginal emission rates as calculated by the locational marginal unit (LMU) marginal emission analysis. This analysis uses the emission rates from the ISO's identified marginal unit(s) that set the energy market hourly locational marginal price(s) (LMP). The LMP results from economic dispatch, which minimizes total energy costs for the entire New England region, subject to a set of constraints reflecting physical limitations of the power system. This report presents the results for two scenarios of emission rates calculated using this methodology: 1) all LMUs; and 2) emitting LMUs.

Table 1-2
2013 and 2014 Average LMU Marginal Emission Rates (lb/MWh)

LMU Marginal Emissions						
	All LMUs			Emitting LMUs		
	2013 Annual Rate (lb/MWh)	2014 Annual Rate (lb/MWh)	Percent Change 2013 to 2014 (%)	2013 Annual Rate (lb/MWh)	2014 Annual Rate (lb/MWh)	Percent Change 2013 to 2014 (%)
NO_X	0.34	0.38	14.8	0.42	0.47	13.3
SO_2	0.55	0.45	-18.5	0.69	0.55	-19.7
CO_2	930	941	1.2	1,125	1,107	-1.6

Figure 1-2 summarizes the 2014 emission rates in New England. The all-LMU and emitting-LMU marginal emission rates for the top-five high electric demand days (HEDDs) characterize the emissions profiles of the marginal units responding to system demand during these days.

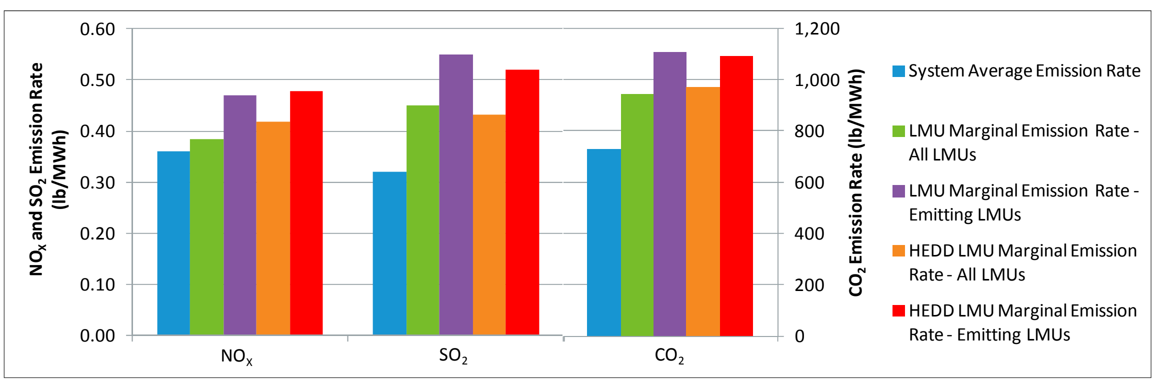

Figure 1-2: Comparison of 2014 New England emission rates (lb/MWh).

A generator's heat rate (MMBtu/MWh) is a measurement of its efficiency in converting fuel into electricity. The 2014 calculated all-LMU marginal heat rate of 7.692 MMBtu/MWh was 12% higher than the 2013 value of 6.841 MMBtu/MWh. When considering the emitting units only, the LMU marginal heat rate increased 9%, from 8.271 MMBtu/MWh in 2013 to 9.034 MMBtu/MWh in 2014.

Section 2
Background

In 1994, the New England Power Pool (NEPOOL) Environmental Planning Committee (EPC) analyzed the impact that demand-side management (DSM) programs had on 1992 nitrogen oxide (NO_X) air emissions of NEPOOL generating units. The results were presented in a report, *1992 Marginal NO_X Emission Rate Analysis*. This report was used to support applications to obtain NO_X Emission-Reduction Credits (ERC) in Massachusetts resulting from the impacts of DSM programs.[2] 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, volatile organic compounds (VOC), and carbon monoxide (CO) in Massachusetts to earn bankable and tradable emission credits by reducing actual power plant emissions below regulatory requirements.

Also in 1994, the *1993 Marginal Emission Rate Analysis* (*1993 MEA Report*) was published, which provided expanded analysis of the impact of DSM programs on power plant NO_X, sulfur dioxide (SO_2), and carbon dioxide (CO_2) air emissions for 1993. MEA reports were published annually from 1994 to 2007 to provide similar annual environmental analyses for these years.[3] For the 2008 emissions analysis, members of ISO New England's Environmental Advisory Group (EAG) requested that the *MEA Report* be restructured to include calculated system and marginal emissions for the entire ISO New England generation system, rather than focusing primarily on marginal emissions.[4] The revised report was renamed the *ISO New England Electric Generator Air Emissions Report* (*Emissions Report*), to reflect the importance of emissions from the entire New England electric generation system.

The *Emissions Report* includes a marginal emissions analysis that is based on the Locational Marginal Unit (LMU) methodology. This methodology, which was begun as a pilot program in 2011, uses marginal units identified by the Locational Marginal Price (LMP) to calculate the marginal emissions for LMUs.

Stakeholders can use the calculated marginal emissions to track air emissions from New England's electric generation system and to estimate the impact that DSM programs and non-emitting renewable energy projects (i.e., wind and solar units) have on reducing New England's NO_X, SO_2, and CO_2 power plant air emissions. The *2014 Emissions Report* focuses on analysis and observations over the past decade (2005 to 2014). The Appendix includes data for years before 2005 and values for the figures presented.

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[2] Massachusetts Executive Office of Energy and Environmental Affairs, "BWP AQ [Bureau of Waste Prevention—Air Quality] 18—Creation of Emission Reduction Credits," webpage (2015), http://www.mass.gov/eea/agencies/massdep/service/approvals/bwp-aq-18.html.

[3] ISO New England emissions analyses and reports from 1999 to the present are available at http://www.iso-ne.com/system-planning/system-plans-studies/emissions.

[4] The EAG is a stakeholder working group that assists the ISO's Planning Advisory Committee (PAC), the Reliability Committee (RC), and the associated Power Supply Planning Committee (PSPC); http://www.iso-ne.com/eag.

2.1 History of Marginal Emissions Methodologies

MEA studies performed before 2004 used production simulation models to replicate, as closely as possible, the actual system operations for the study year (reference case). An incremental load scenario was then modeled in which the system load was increased by 500 MW in each hour (marginal case). The calculation for the marginal air emission rates was based on the differences in generator air emissions between the reference and marginal scenarios. However, the reference case simulation could not exactly match the actual unit-specific energy production levels of the study year because the production simulation model had a number of limitations. For example, the model could not accurately represent the historical overall dynamics of the energy dispatch, out-of-merit and reliability-based dispatches, unit-specific outages and deratings, and the effects of the daily volatility of regional (power plant) fuel prices.

From 2004 to 2013, the Fuel Type Assumed (FTA) methodology was used to calculate the average marginal emission rates. This method was based on the assumption that all natural-gas-fired and oil-fired generators responded to changing system load by increasing or decreasing their loading. Units fueled with other sources, such as coal, wood, biomass, refuse, or landfill gas, were excluded from the calculation; historically (in the 2000s), these types of units operated as base load or were non-dispatchable and not typically dispatched to balance supply with demand on the system.[5] Other non-emitting resources, such as hydroelectric, pumped storage, wind, solar, and nuclear units that do not vary in output to follow load were also assumed not to be marginal units and were excluded from the FTA calculation of marginal emission rates.

In 2011, the ISO began developing a methodology for calculating the marginal emission rate based on the locational marginal unit, which stemmed from recommendations of the Environmental Advisory Group. This methodology identifies marginal units using the locational marginal price (LMP), a process that minimizes total cost of energy production for the entire New England region while accounting for transmission and other constraints reflecting physical limitations of the power system. This method identifies the last unit dispatched to balance the system, called the *locational marginal unit* (refer to Section 3.3). Results are presented starting in 2009, the earliest year of available data.

2.2 History of Heat Rate Methodologies

A thermal power plant's heat rate is a measure of its efficiency in converting fuel (British thermal units, Btus) to electricity (kWh); the lower the heat rate, the more efficient the facility. A plant's heat rate depends on the individual plant design, its operating conditions, and its level of electrical power output.

Before 1999, MEA studies assumed a fixed marginal heat rate of 10.0 million BTUs per megawatt-hour (MMBtu/MWh), which was used to convert from pound (lb)/MWh to lb/MMBtu.[6] In the 1999 to 2003 MEA studies, the marginal heat rate was calculated using the results of production

[5] One observation for determining whether to consider coal units as marginal units was that higher or lower loads change the number of committed natural gas and oil units, while coal units would be dispatched when available. During the low-load troughs of the daily cycle, coal units were 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 LMPs during these off-peak hours.

[6] 10 MMBtu/MWh is equivalent to 10,000,000 Btu/kWh.

simulation runs. Beginning with the 2004 MEA study, the marginal heat rate was based on the actual generation of marginal fossil units only.

Beginning with the *2007 MEA Report*, the marginal heat rate has been calculated using a combination of both US Environmental Protection Agency (EPA) heat input data and the ISO's heat-rate data. For the marginal fossil units with EPA data, the heat inputs reported to EPA were used. For units without EPA data, the heat inputs were calculated by multiplying each unit's monthly generation by the heat-rate information collected and maintained by the ISO. The individual heat input values (in MMBtu) using the two methods were then added and the sum divided by the total generation of the marginal fossil units.

In the current methodology (see Section 3.4), the calculation for the marginal heat rate is based on the heat rates for each individual LMU. The percentage of time each generator is marginal per year leads to the contribution of that unit's heat rate to the LMU marginal heat rate.

Section 3
Data Sources and Methodologies

This section discusses the data sources and methodologies used for the emissions analysis. The calculations for total system emission rate, marginal emission rate, and marginal heat rate are shown. The time periods studied are also described.

3.1 Data Sources

The New England power system emissions and marginal emission rate calculations for NO_x, SO_2, and CO_2 were primarily based on the 2014 actual air emissions (tons) reported by generators to the US EPA Clean Air Markets Division (CAMD) database[7] under EPA's Acid Rain Program and NO_X Clean Air Interstate Rule (CAIR) and the Regional Greenhouse Gas Initiative (RGGI).[8]

For those units not required to file emissions data under the Acid Rain Program, CAIR, or RGGI, monthly emission rates (lb/MWh) from the New England Power Pool Generation Information System (NEPOOL GIS) were used.[9] If this information was not available, annual emission rates (lb/MWh) from EPA's eGRID2012 were used. In the case of no other sources of data, emission rates based on eGRID data were obtained for similar type units. These unit-specific emission rates were used in conjunction with the actual megawatt-hours of generation, from the ISO's database used for energy market settlement purposes, to calculate tons of emissions.

All electric generators dispatched by ISO New England are included in the 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.

3.2 Total System Emission Rate Calculation

The total annual system emission rate is based on the emissions produced by all ISO New England generators during a calendar year. The rates are calculated by dividing the total air emissions by the total generation from all units. The formula for calculating the total annual system emission rate is:

$$\text{Annual System Emission Rate (lb/MWh)} = \frac{\text{Total Annual Emissions (lb)}_{\text{All Generators}}}{\text{Total Annual Energy (MWh)}_{\text{All Generators}}}$$

[7] EPA's Clean Air Markets Program data (2015) are available at http://ampd.epa.gov/ampd/, and the Clean Air Markets emissions data (2015) are available at http://www.epa.gov/airmarkets/. Generators report emissions to EPA under the Acid Rain Program, which covers generators 25 MW or larger, as well as CAIR, which includes generators 15 MW or larger in the affected states of Connecticut and Massachusetts (the predecessors of CAIR were the 1999-2002 Ozone Transport Commission NOx Budget Program, and EPA's 2003-2008 NO_X Budget Trading Program). Generators subject to RGGI also report CO_2 emissions to EPA.

[8] Before 2005, the MEA reports used annual data obtained primarily from the EPA Emissions Scorecard. In the 2005 and 2006 MEA Reports, monthly EPA data, rather than hourly data, were used for calculating marginal rates.

[9] The U.S. EPA's eGRID2012 database (2015) is available at http://www.epa.gov/cleanenergy/energy-resources/egrid/index.html.

3.3 Marginal Emission Rate Calculation

The cost of the generation dispatched to meet the next increment of load at a pricing location is called the marginal unit, which sets the locational marginal price. LMPs minimize total energy costs for the entire New England region, subject to a set of constraints reflecting physical limitations of the power system.

The process to determine the LMP identifies at least one locational marginal unit for each five-minute period, which is associated with meeting the energy requirements on the system during that pricing interval. When transmission is not constrained, the marginal unit is classified as the unconstrained marginal unit. Each binding transmission constraint adds an additional marginal unit, resulting in *n + 1 marginal units* (LMUs) for every *n* binding constraint, in each five-minute period. To calculate the marginal emission rates, the hourly emissions (lb) for those units in the EPA CAMD database were grouped into on-peak and off-peak periods (defined in Section 3.5) for each month. When only monthly NEPOOL GIS or annual eGRID data were available, these emission rates were multiplied by the associated monthly on-peak and off-peak generation. The amount of monthly emissions (lb) from each individual marginal fossil generator was then divided by that generator's monthly on-peak or off-peak generation to get the corresponding emission rate (lb/MWh) for that time period. For NO_X emission rates, the monthly totals (lb) for each generator were grouped into ozone and non-ozone season emissions and divided by the respective ozone and non-ozone season generation.

The percentage of time each generator was marginal in each month was calculated and then multiplied by the generator's month-specific on-peak or off-peak average emissions rate described above. That amount was summed for each marginal unit and then divided by the total on-peak or off-peak hours in the year. The LMU marginal emission rate calculations are as follows, where generator *k* is identified to be marginal during hour *h* and has a specific monthly emission rate during month *m*:

LMU On-Peak Marginal Emission Rate

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

LMU Off-Peak Marginal Emission Rate

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

The annual LMU marginal emission rate was then calculated by combining the on-peak and off-peak rates in a weighted calculation.

The analysis of LMU marginal emission rates was conducted for two different scenarios. Each scenario includes or excludes certain generators depending on their characteristics. The two scenarios are as follows:

- **All LMUs**—includes all locational marginal units identified by the LMP

- **Emitting LMUs**—excludes all non-emitting units with no associated air emissions, such as pumped storage, hydroelectric generation, nuclear, external transactions, and wind and solar renewables

3.4 Marginal Heat Rate Calculation

The marginal heat rate was calculated by first calculating a heat rate for each individual generator. The heat input values for the individual LMUs were then multiplied by the percentage of time each generator was marginal during the year. These values were then added together and divided by the total generation of the marginal units.

Since a unit's heat rate is equal to its heat input, or fuel consumption, divided by its generation, the calculated marginal heat rate is defined as follows:

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

3.5 Time Periods Analyzed

The 2014 marginal air emission rates for on- and off-peak periods for New England were calculated for this report. Data for the on-peak period is presented so that a typical industrial and commercial user that can provide load response during a traditional weekday can explicitly account for its emissions reductions during the on-peak hours. The marginal emission rates for NO_X were calculated for five time periods:[10]

- On-peak ozone season, consisting of all weekdays between 8:00 a.m. and 10:00 p.m. from May 1 to September 30
- Off-peak ozone season, consisting of all weekdays between 10:00 p.m. and 8:00 a.m. and all weekend hours from May 1 to September 30
- On-peak non-ozone season, consisting of all weekdays between 8:00 a.m. and 10:00 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 10:00 p.m. and 8:00 a.m. and all weekend hours from January 1 to April 30 and from October 1 to December 31
- Annual average

Because 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 8:00 a.m. and 10:00 p.m.
- Off-peak annual, consisting of all weekdays between 10:00 p.m. and 8:00 a.m. and all weekend hours
- Annual average

[10] The ISO developed a special report, *Analysis of New England Electric Generators' NO_X Emissions on 25 Peak-Load Days in 2005–2009*, released September 23, 2011, which summarized its analysis of NO_X emissions during peak days (http://www.iso-ne.com/genrtion_resrcs/reports/emission/peak_nox_analysis.pdf).

Section 4
Data and Assumptions

This section highlights the key parameters and assumptions modeled in the 2014 ISO New England Emissions Report, including weather, emissions data, installed capacity, and system generation.

4.1 2014 New England Weather

Because the weather significantly affects the demand for energy and peak loads, comparing 2014 total energy use and both cooling and heating degree days to previous years can provide some perspective.

The 2014 summer peak electricity demand of 24,443 MW was 2,936 MW lower than the 2013 summer peak of 27,379 MW. There were 240 cooling degree days in 2014, which is 24% lower than the 20-year average.[11] The net energy for load was 2% lower in 2014 than 2013. With respect to the winter months, there were 6,318 heating degree days, which is 4% higher than the 20-year average.

New England's historical cooling degree days and heating degree days for 1994 through 2014 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 Emissions Data

For calculating total system emissions, approximately 83% of the SO_2 emissions and 74% of the CO_2 emissions were based on EPA's Clean Air Markets data. For NO_X, Clean Air Markets data were used for 47% of total emissions.

The emission rates were multiplied by the 2014 energy generation reported to the ISO to obtain the emissions (tons) by each generator.

4.3 ISO New England System Installed Capacity

The ISO New England 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 the following:

- 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
- A variety of other factors

[11] Over the 20-year span from 1994 to 2014, the average number of cooling degree days was 318, and the average number of heating degree days was 6,082.

Figure 4-1 shows the total 2014 summer capacity for ISO New England generation as obtained from *ISO New England's 2015–2024 Forecast Report of Capacity, Energy, Loads and Transmission* (CELT).[12] Appendix Table 2 and Appendix Table 3 summarize the total summer and winter capacity for ISO New England generation by state and fuel type.

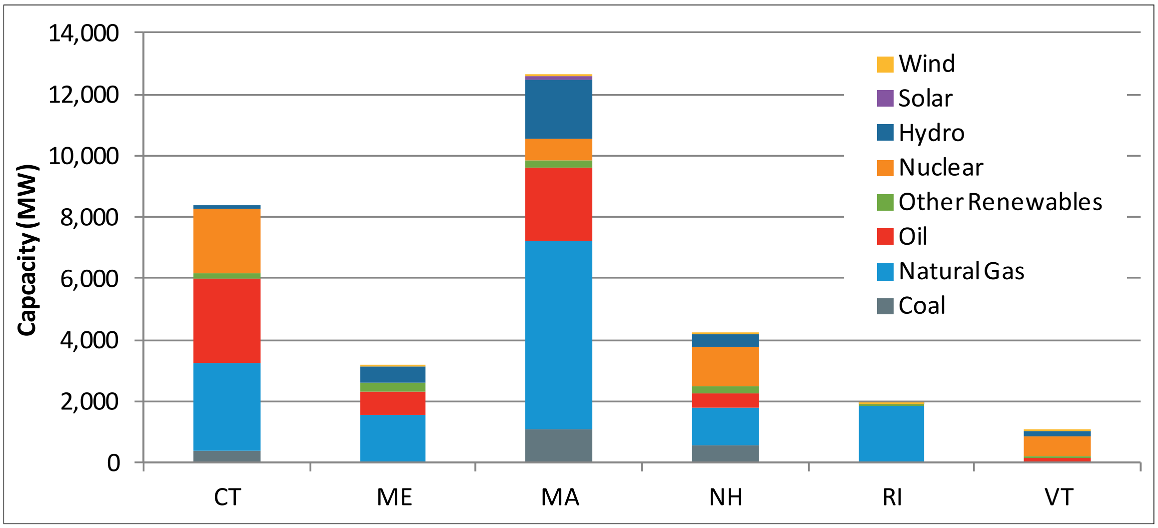

Figure 4-1: 2014 New England summer capacity by state (MW).

Figure 4-2 illustrates the new generating capacity added to the ISO New England system from 2005 through 2014. A total of 2,695 MW was added, with combustion turbines and combined-cycle plants capable of burning natural gas or distillate oil making up about 65% of this new capacity. The remaining additions consist primarily of nuclear uprates and renewable generation.

[12] The ISO New England *CELT Report* is typically issued in April of each year. The *2015 CELT Report* (using the January 1, 2015, ratings) was used to completely capture all the new capacity additions that occurred during the prior calendar year, 2014. The capacity also includes generators that retired in 2014. The CELT reports are available at http://www.iso-ne.com/system-planning/system-plans-studies/celt.

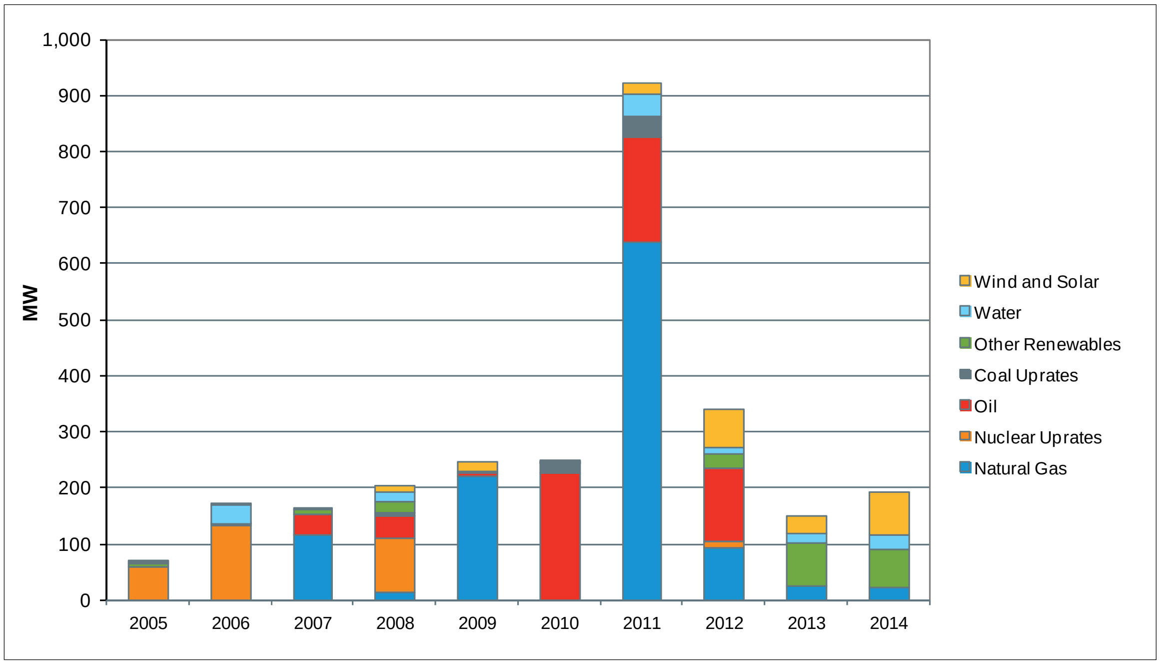

Figure 4-2 : ISO New England generator additions, 2005 to 2014 (MW).
Note: The generator additions and uprate values are based on the Seasonal Claimed Capabilities, as reported in the 2015 CELT Report.

Several recent large coal and oil-fired generators in New England have retired. The retirements, as shown in Figure 4-3, total 1,050 MW of coal and 567 MW of residual oil-fired generation since late 2011.

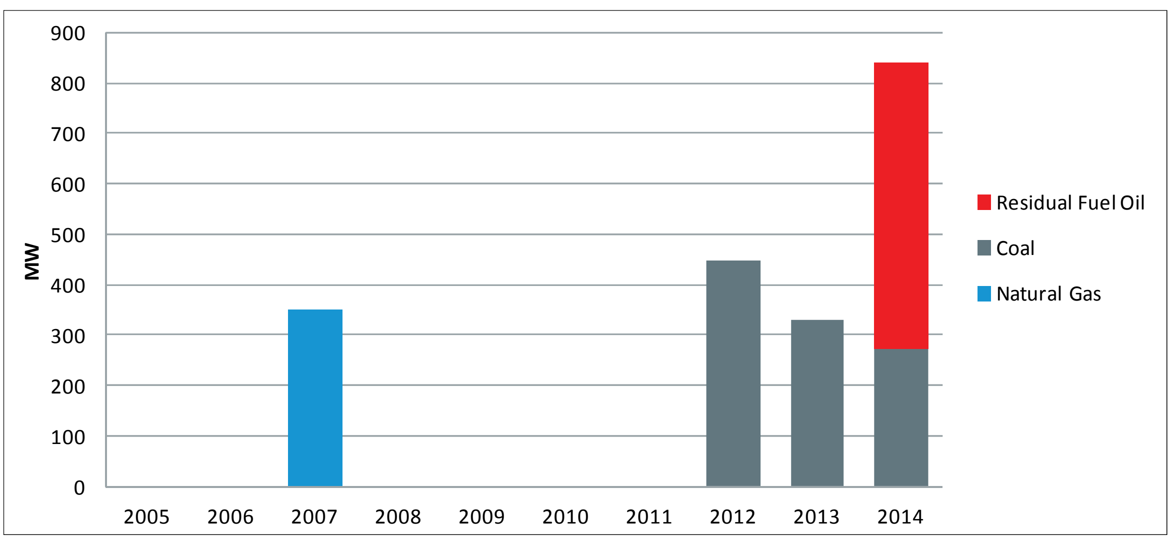

Figure 4-3: Major retirements in ISO New England, 2005 to 2014 (MW).
Note: The retirement date shown is not necessarily the year in which the retirement occurred. In the case of units that retired late in the year, the retirement is included in the following year because this is when the impact would primarily have been observed.

4.4 ISO New England System Energy Production

The ISO relies on generating units of all operating characteristics and fuel types, and a generator's fuel type directly correlates with the magnitude and characteristics of the unit's emissions. Section 4.4 shows the system's generation fuel types across months and years to explore one of the main factors affecting system emission rates and heat rates.

Figure 4-4 shows the 2014 monthly generation by fuel type. The overlaid black line represents the total generation in each month and corresponds with the right axis. Natural-gas-fired generation accounts for 29% to 52% of the total generation. The lowest monthly percentages of natural-gas-fired generation in 2014 were in January, February, and March, when natural gas prices were higher than normal. Correspondingly, these are also the months during which coal- and oil-fired generation had a larger contribution. In the past few years in general, the overall lower prices of natural gas, combined with the use of highly efficient generating units, have led to the growing contribution of natural gas to generate electric energy in New England. However, during months with higher energy demand and coupled with limitations in natural gas availability, other fuel types have increased their contribution to support the New England system. During the winter months, the use of natural gas supplies and transportation by the regional gas sector's firm local distribution company (LDC) customers take priority over the use of gas to generate electricity.[13] Many natural-gas-fired generating units lack both firm supply and transportation contracts. Additionally, hydroelectric and wind generation show seasonal differences, which reflect their fuel availability; there is less rain (water) and onshore wind during the summer months.

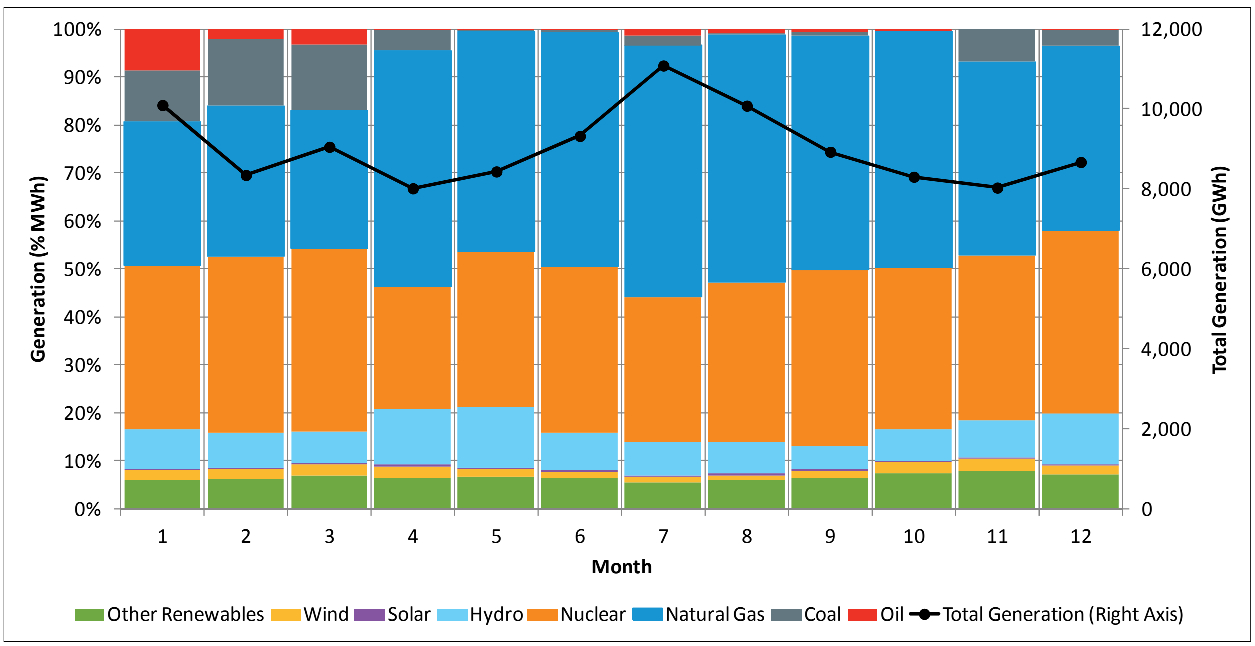

Figure 4-4: 2014 ISO New England monthly generation by fuel type (% MWh, GWh).

Figure 4-5 shows the generation (MWh) by fuel type from 2009 to 2014 based on the resource's primary fuel type listed in the *2015 CELT Report*. In 2014, coal-fired generation was about

[13] Firm customers of regional gas LDCs include residential, commercial, and industrial (RCI) customers.

1,203 GWh lower than in 2013, while oil-fired generation was 830 GWh higher. The decrease in coal-fired generation from 2013 to 2014 is consistent with the over 1,000 MW of coal capacity that retired between 2012 and 2014 (Figure 4-3). Natural-gas-fired generation decreased by about 3,926 GWh, or about 8% from 2013 to 2014. Overall system generation was about 3,683 GWh lower in 2014 than 2013; 2014 total energy generation was 108,357 GWh.

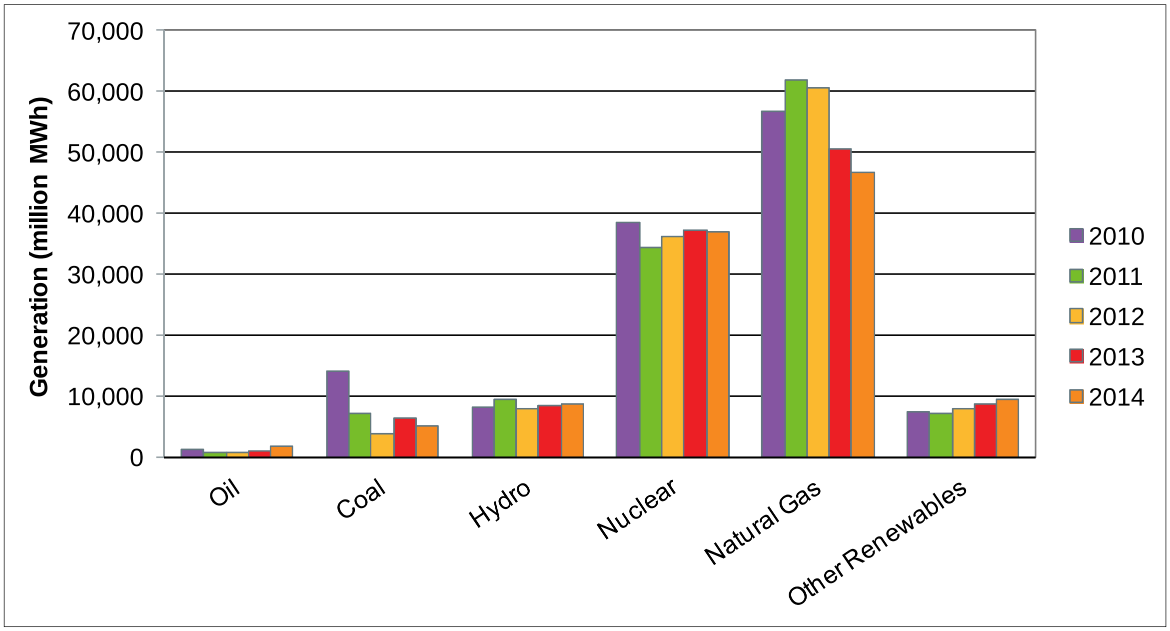

Figure 4-5: ISO New England annual generation by fuel type, 2010 to 2014 (million MWh).

4.5 Locational Marginal Unit Scenarios

The data and assumptions applied for the all-LMU and emitting-LMU scenarios are presented in this section, including the percentage of time various fuel types were marginal. Because the price of the marginal unit (and thus the price of electricity) is largely determined by the unit's fuel type and heat rate, examining the marginal units by fuel type can explain changes in electricity prices.

4.5.1 All LMUs

In this scenario, all identified locational marginal units were used to develop the marginal emission rates. Non-emitting generators were associated with a zero emission rate. Figure 4-6 shows each fuel type's time on the margin and month-to-month variations. Natural gas is marginal 45% to 86% of the time. More natural gas units were on in the margin from April through October, in the 79% to 86% range, while fewer were on in the margin from January through March, at the lower range of 45% to 51%. During January, February, and March, coal- and oil-fired generation was on the margin more than other months, at 12% to 26% (coal) and 8% to 21% (oil).

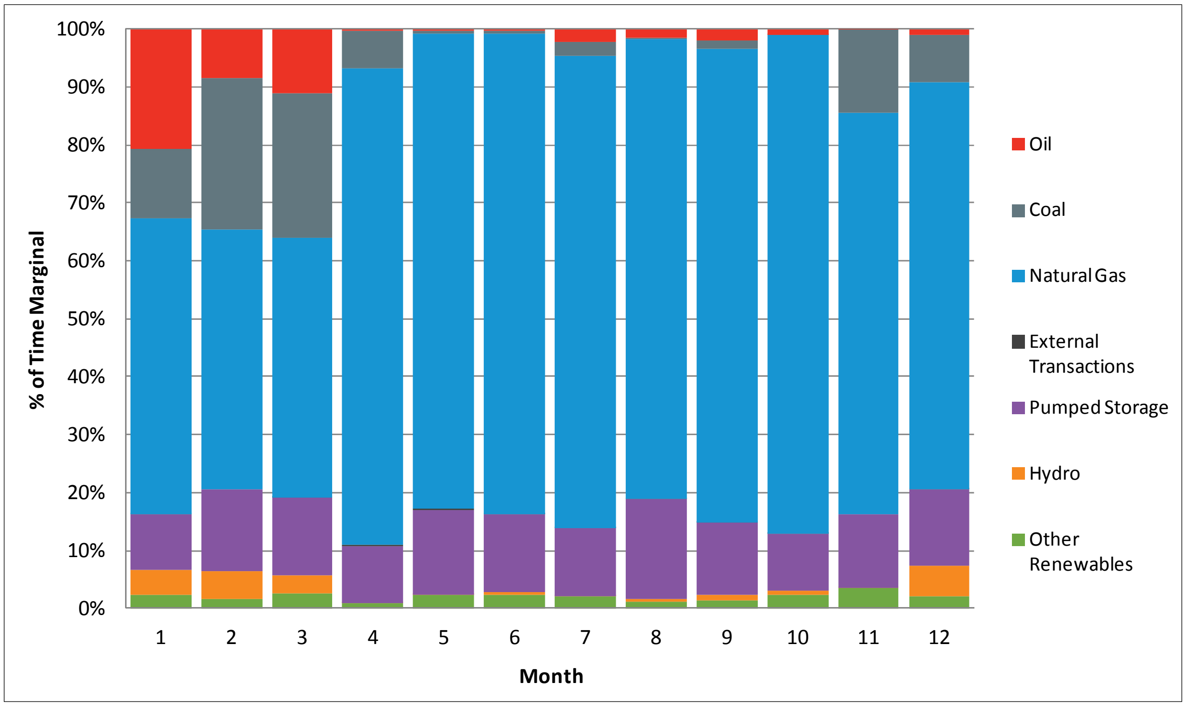

Figure 4-6: 2014 percentage of time various fuel types were marginal—all LMUs.

Figure 4-7 shows the historical percentages that each fuel type was marginal within a calendar year. Natural gas has been the primary marginal fuel type in the past five years. From 2013 to 2014, the percentages of time that natural gas and oil were marginal increased, while the time coal was the marginal fuel remained approximately the same.

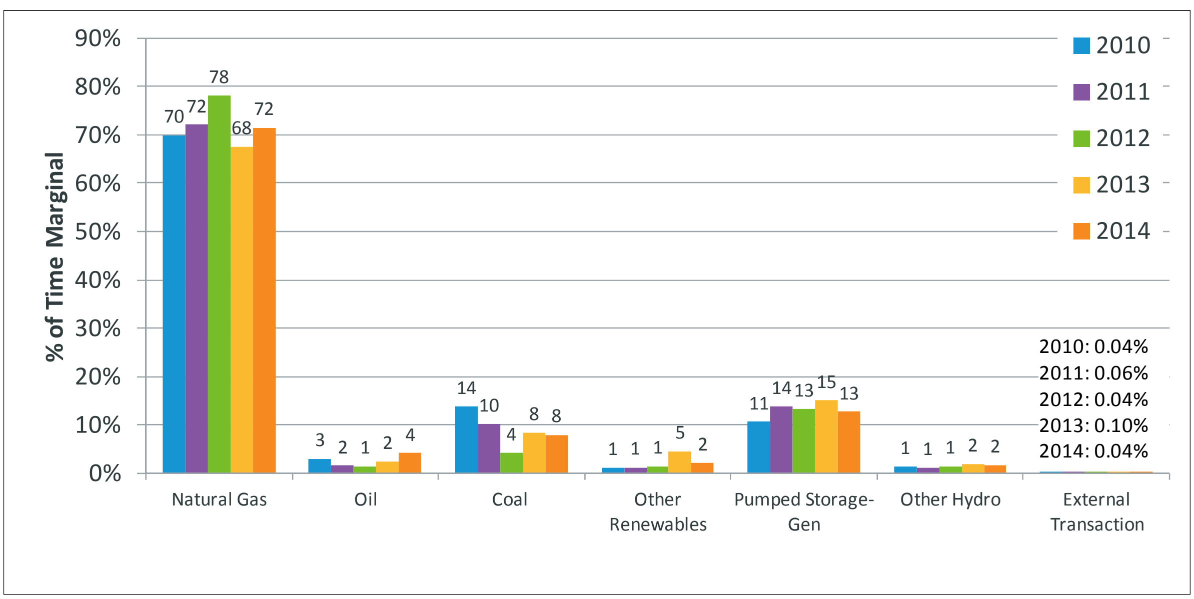

Figure 4-7: Annual percentage of time various fuel types were marginal—all LMUs, 2010 to 2014.

4.5.2 Emitting LMUs

Marginal generating resources with no air emissions were excluded in this scenario. Therefore, hydro, pumped storage, external transactions, and other renewables with no air emissions were not taken into account, while all other LMUs were.

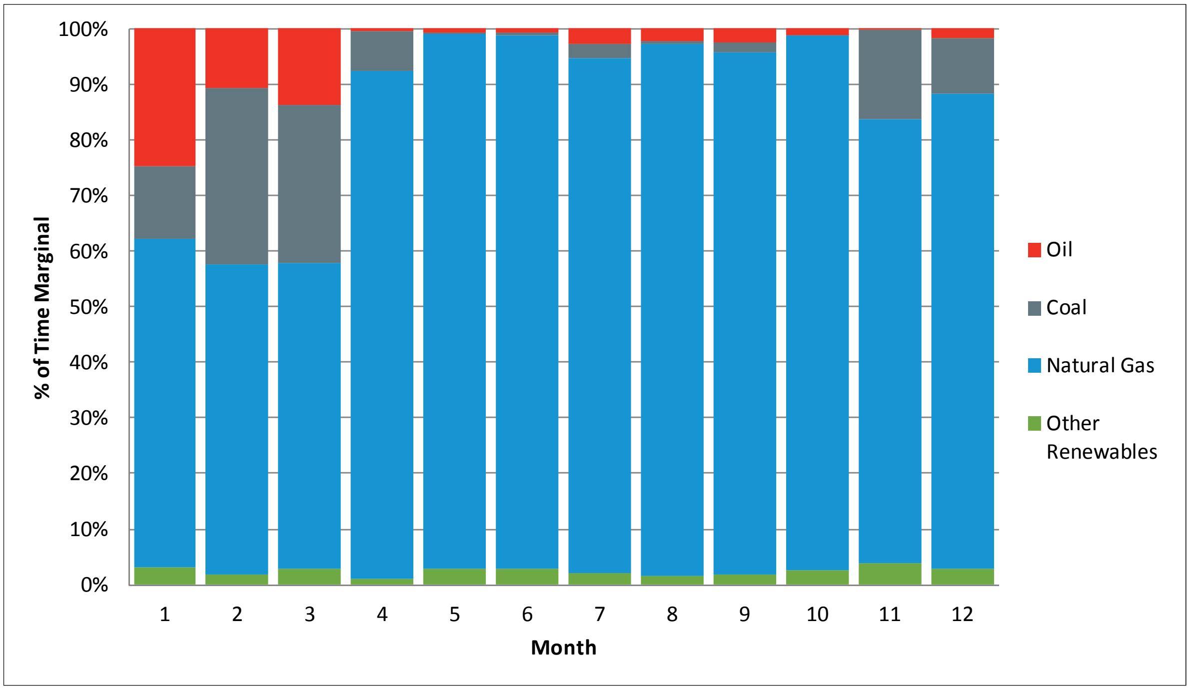

Figure 4-8: 2014 percentage of time various fuel types were marginal—emitting LMUs.

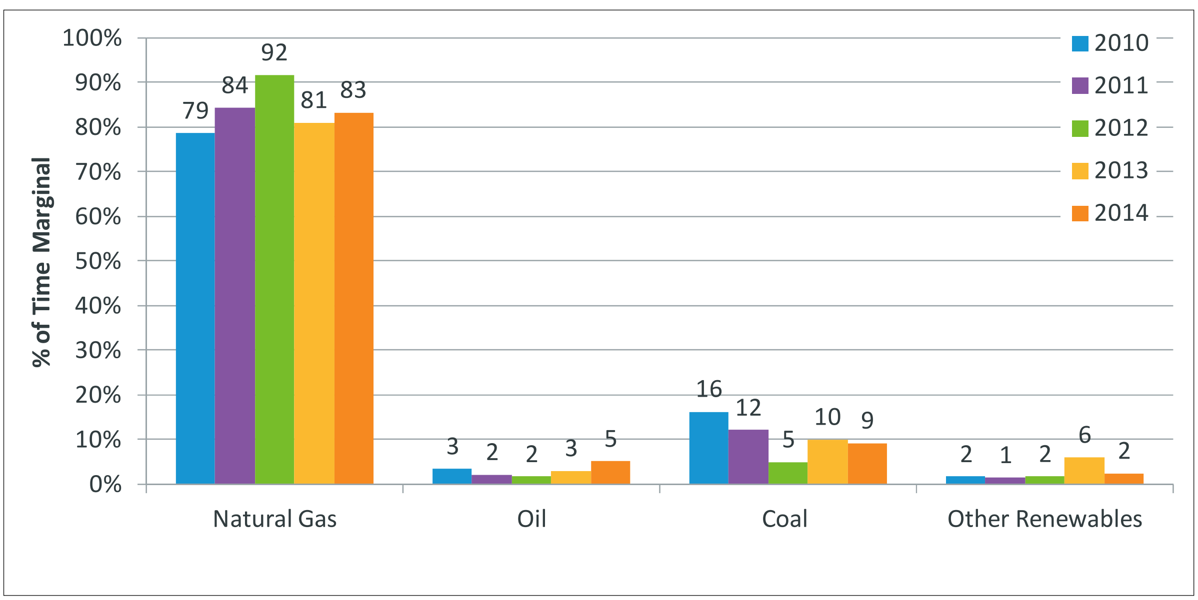

Figure 4-9: Annual percentage of time various fuel types were marginal—emitting LMUs, 2010 to 2014.

4.6 High Electric Demand Days

In New England, high electric demand days (HEDDs) are typically characterized with high temperatures leading to elevated cooling (energy) demand. During peak energy demand periods, such as HEDDs, the ISO relies on peaking units, which are less utilized during the rest of the year but respond quickly to meet system demand. These peaking units are often jet (aero-derivative) or combustion turbines with higher emission rates. Therefore, examining the marginal emission rates on HEDDs shows the units responding to system demand and the associated emission rate.

Section 5
Results and Observations

This section presents the results for ISO New England's 2014 system emissions representing all generators. It also provides the results for the annual marginal heat rates and the locational marginal unit emission rates for the all-LMU and emitting-LMU scenarios.

5.1 2014 New England System Emissions

Results are presented for the following metrics:

- Aggregate NO_X, SO_2, and CO_2 emissions for each state for 2014
- A comparison of aggregate NO_X, SO_2, and CO_2 emissions for 2005 to 2014
- 2014 annual average NO_X, SO_2, and CO_2 emission rates, by state and for New England
- Monthly variations in the emission rates for 2014
- A comparison of annual average NO_X, SO_2, and CO_2 emission rates for 2005 to 2014

5.1.1 Results

Figure 5-1 shows the annual aggregate 2014 NO_X, SO_2, and CO_2 air emissions for each state. The New England system total emissions for NO_X, SO_2, and CO_2 were 20.49 ktons, 11.68 ktons, and 39,317 ktons, respectively. The calculations for these emission levels were based on the actual generation of all generating units in ISO New England's balancing authority area and the actual or assumed unit-specific emission rates.[14] The reason for the divergent total emissions for each state is that the emissions are based on the physical locations of the generating units in each state (refer to Figure 4-1 showing summer capacity by state). Because ISO New England operates the New England power system as one unified grid, it dispatches a unit physically located in one state to serve the entire system, not only the unit's own state.

[14] This does not include northern Maine and the Citizens Block Load (in Northern Vermont), which is typically served by New Brunswick and Quebec. These areas are not electrically connected to the ISO New England Control Area.

Figure 5-1: 2014 New England system annual emissions of NO_X, SO_2, and CO_2 (ktons).
Note: Sum may not equal New England system total due to rounding.

Figure 5-2 shows the annual aggregate NO_X, SO_2, and CO_2 air emissions for 2005 through 2014. Since 2005, NO_X emissions have dropped by 65% and SO_2 by 92%, while CO_2 has decreased by about 35%. Refer to Appendix Table 4 for historical system emissions by ktons.

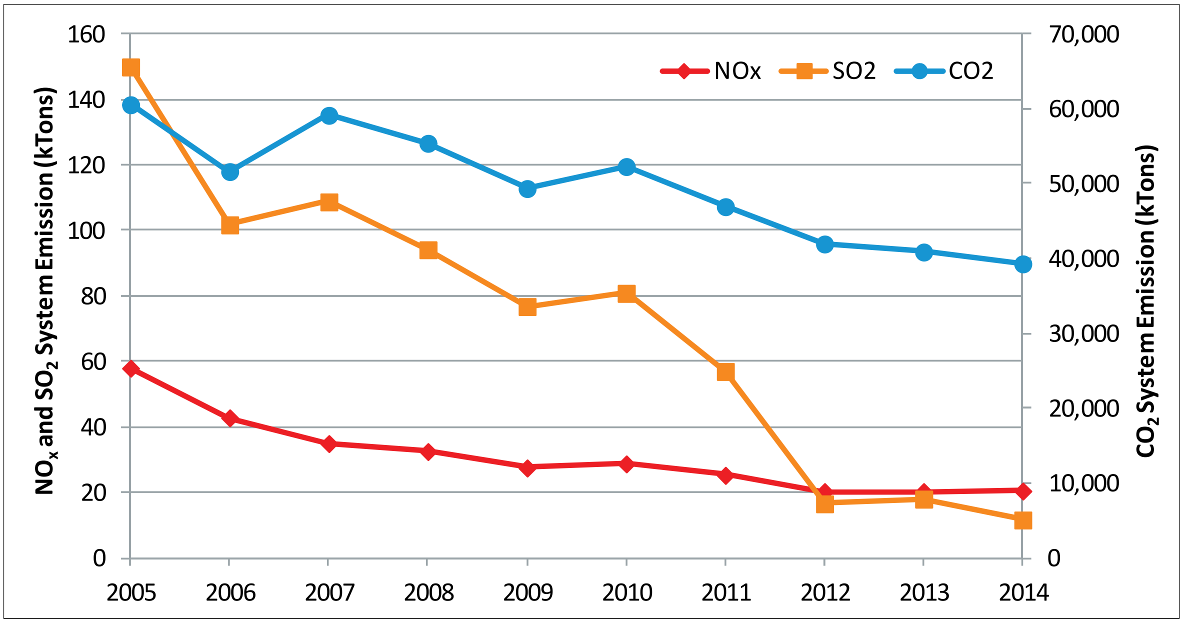

Figure 5-2: New England system annual emissions of NO_X, SO_2, and CO_2, 2005 to 2014 (ktons).

Table 5-1 shows the 2014 annual average NO_X, SO_2, and CO_2 air emission rates (lb/MWh), by state and for New England. The rate calculations were based on the actual hourly unit generation of ISO New England generating units located within each state and the actual or assumed unit-specific emission rates.

Table 5-1
2014 New England System
Annual Average NO_X, SO_2, and CO_2 Emission Rates (lb/MWh)

State	NO_x	SO_2	CO_2
Connecticut	0.29	0.11	592
Maine	0.43	0.28	838
Massachusetts	0.54	0.35	932
New Hampshire	0.40	0.29	665
Rhode Island	0.19	0.01	945
Vermont	0.10	0.01	210
New England	0.38	0.22	726

Monthly variations in the emission rates shown in Figure 5-3 reflect the different system fuel mixes shown in Figure 4-4. In 2014, emission rates were at a higher magnitude during January, February, and March, which had lower natural gas generation and higher coal- and oil-fired generation. Appendix Table 5 shows the values for this figure.

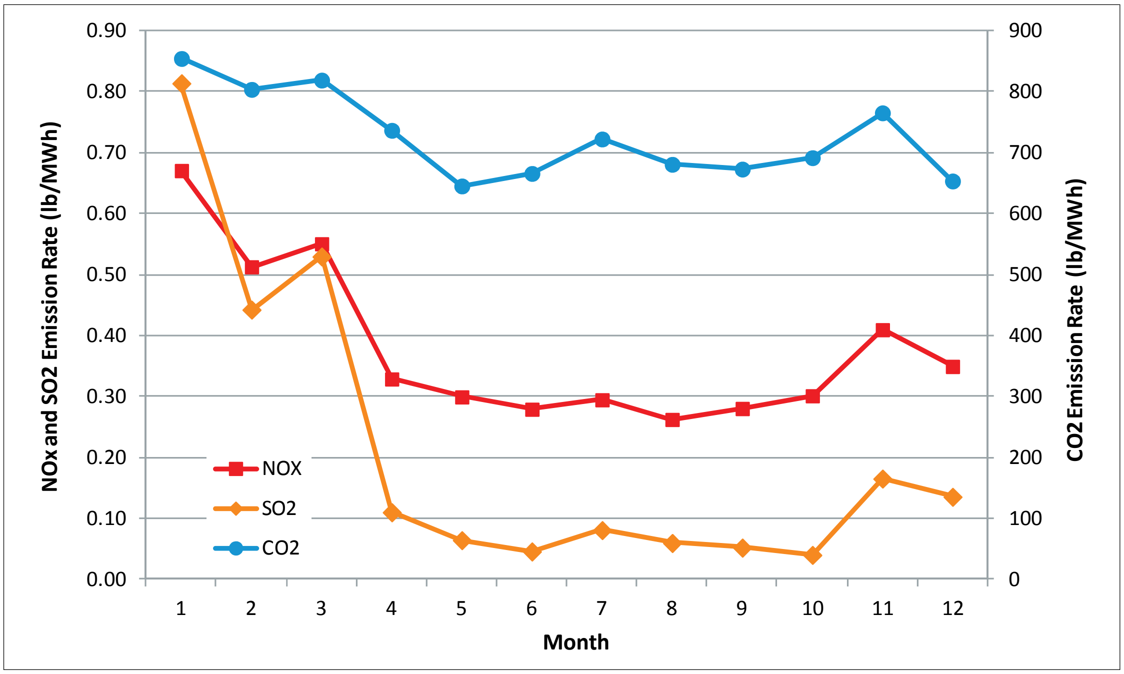

Figure 5-3: 2014 New England system monthly average NO_X, SO_2, and CO_2 emission rates (lb/MWh).

Figure 5-4 illustrates the annual average NO_X, SO_2, and CO_2 air emission rates (lb/MWh) for 2005 to 2014 using the calculation presented in Section 3.2. Since 2005, the annual average NO_X emission rate has decreased by 57%, SO_2 by 90%, and CO_2 by 21%. Appendix Table 6 shows all historical emission rates.

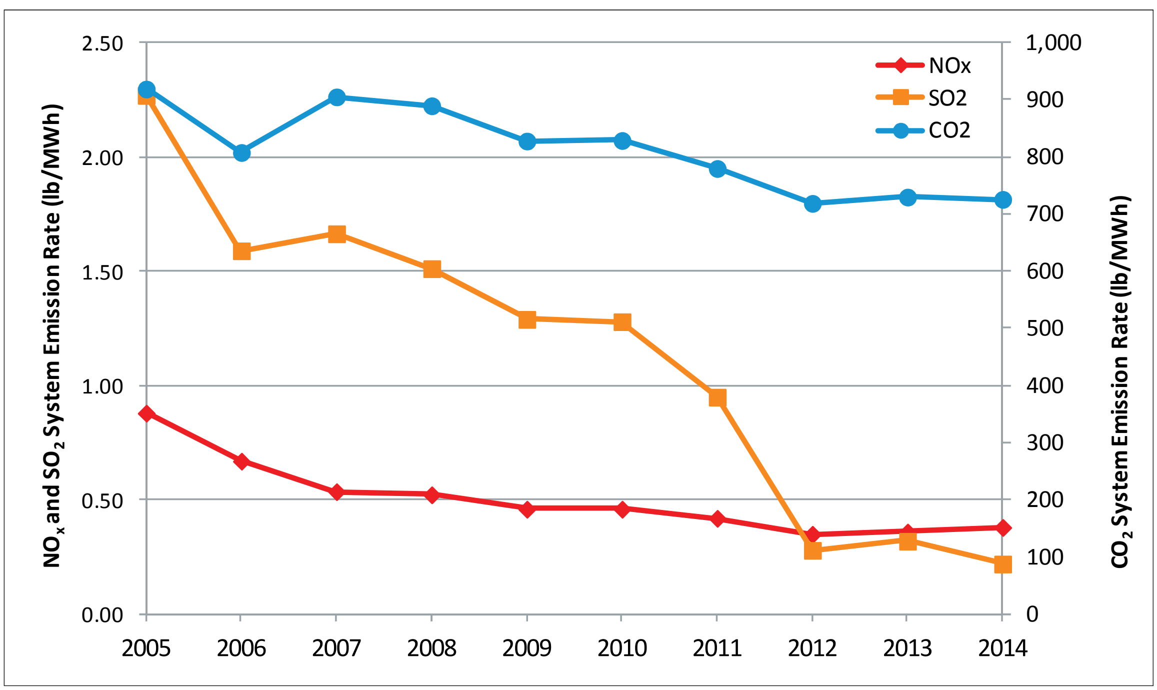

Figure 5-4: New England system annual average NO_X, SO_2, and CO_2 emission rates, 2005 to 2014 (lb/MWh).

5.1.2 Additional Observations

Total energy generation declined 3% in 2014 from 2013. There was less natural gas generation and more oil-fired generation in 2014 than in 2013. However, the most significant change occurred in coal-fired generation, which decreased by 19% and contributed to a 35% decrease in SO_2 system emissions from 2013 to 2014. Total CO_2 system emissions decreased by 3.9%, while NO_X system emissions increased very slightly from 2013 to 2014. The 2014 SO_2 and CO_2 emission rates decreased by 31.3% and 0.5%, respectively, from 2013 values, while the NO_X system emission rates for 2014 were higher than in 2013, increasing by 5.6%. Refer to Table 5-2, which summarizes the above system emission changes.

Table 5-2
2013 and 2014 New England System Emissions (ktons)
and Emission Rates (lb/MWh)

Annual System Emissions						
	2013 Emissions (kTons)	2014 Emissions (kTons)	Total Emissions % Change	2013 Emission Rate (lb/MWh)	2014 Emission Rate (lb/MWh)	Emission Rate % Change
NO_X	20.32	20.49	0.8	0.36	0.38	5.6
SO_2	18.04	11.68	-35.3	0.32	0.22	-31.3
CO_2	40,901	39,317	-3.9	730	726	-0.5

Overall, total system emissions have declined over the last 10 years, which can be attributed to several factors:

- Increased use of highly efficient natural-gas-fired generators
- Decline in the cost of natural gas
- Use of lower-sulfur fuels
- Retrofits of NO_X and SO_2 emission controls on some oil- and coal-fired generators

5.2 2014 New England Marginal Heat Rate

The calculated annual marginal heat rate reflects the average annual efficiency of all the marginal fossil units dispatched throughout 2014. The historical marginal heat rates for 2009 to 2014 are presented in Appendix Table 7. Figure 5-6 displays Appendix Table 7 in graphical form.

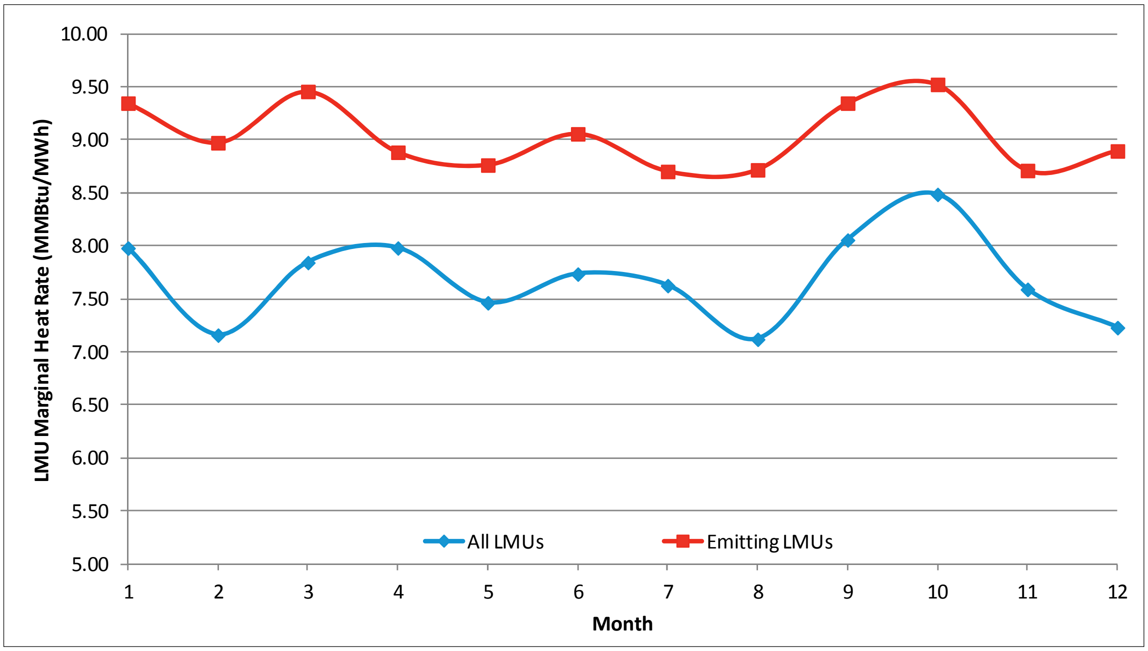

Figure 5-5: 2014 LMU monthly marginal heat rate (MMBtu/MWh).

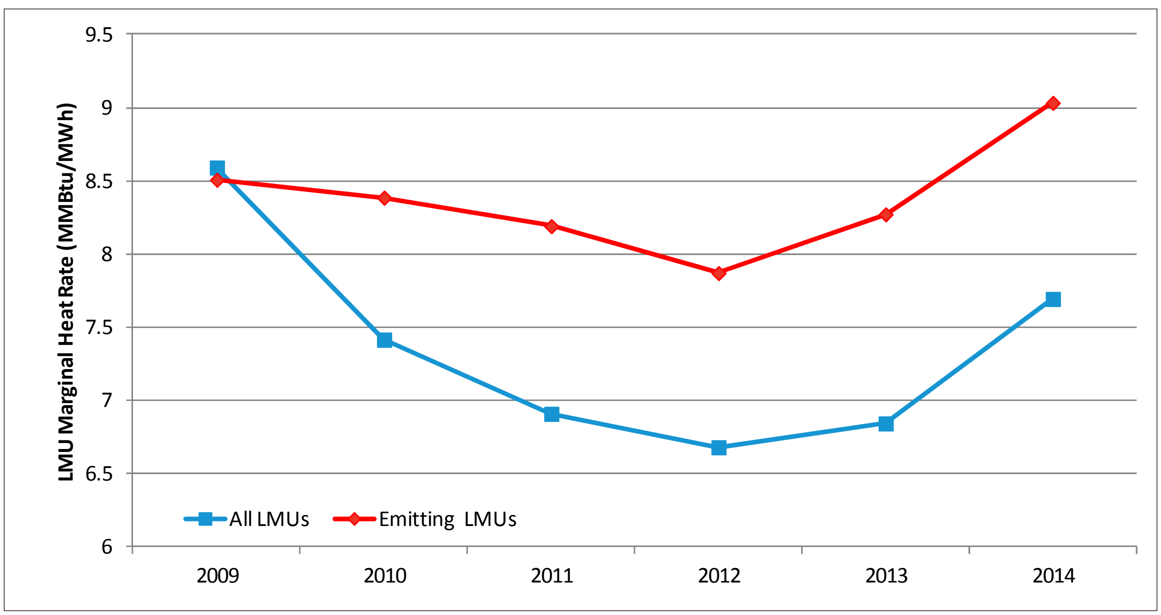

Figure 5-6: LMU annual marginal heat rate, 2009-2014 (MMBtu/MWh).

Marginal heat rates declined through 2012 but increased in 2013 and then again in 2014. In 2014, the marginal heat rate for the emitting LMUs was the highest it had been for the past six years. This is likely due to the increased amount of time that oil units were on the margin.

5.3 2014 New England Marginal Emission Rates

This section presents the 2014 calculated LMU-based marginal emission rates for the all-LMU and emitting-LMU scenarios, as defined in Section 4.5.

The NO_X data for both these scenarios are provided for each of the five time periods studied. Since the ozone and non-ozone seasons are not relevant to SO_2 and CO_2, only the on-peak, off-peak, and annual rates are provided for these emissions.

5.3.1 Marginal Emission Rates for the All-LMU Scenario

The all-LMU marginal emission rates were calculated with all LMUs (units the LMP identified as marginal). Table 5-3 shows the rates in lb/MWh. Appendix Table 8 shows these rates in lb/MMBtu, with the associated marginal heat rate of 7.692 MMBtu/MWh used as the conversion factor. It is helpful to compare Figure 5-7, which shows the monthly LMU marginal emission rates, with Figure 4-6 (showing the 2014 percentage of time various fuel types were marginal for all LMUs) and Figure 5-3 (showing the 2014 New England system monthly average NO_X, SO_2, and CO_2 emission rates). Appendix Table 9 lists the values behind Figure 5-7.

Table 5-3
2014 LMU Marginal Emission Rates—All LMUs (lb/MWh)[a, b]

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	0.21	0.14	0.51	0.56	0.38
Annual Emissions (SO_2 and CO_2)					
Air Emission		Annual			Annual Average (All Hours)
		On-Peak	Off-Peak		
SO_2		0.46	0.45		0.45
CO_2		931	949		941

(a) The ozone season occurs between May 1 and September 30, while the non-ozone season occurs from January 1 to April 30 and from October 1 to December 31.

(b) On-peak hours consist of all weekdays between 8:00 a.m. and 10:00 p.m. Off-peak hours consist of all weekdays between 10:00 p.m. and 8:00 a.m. and all weekend hours.

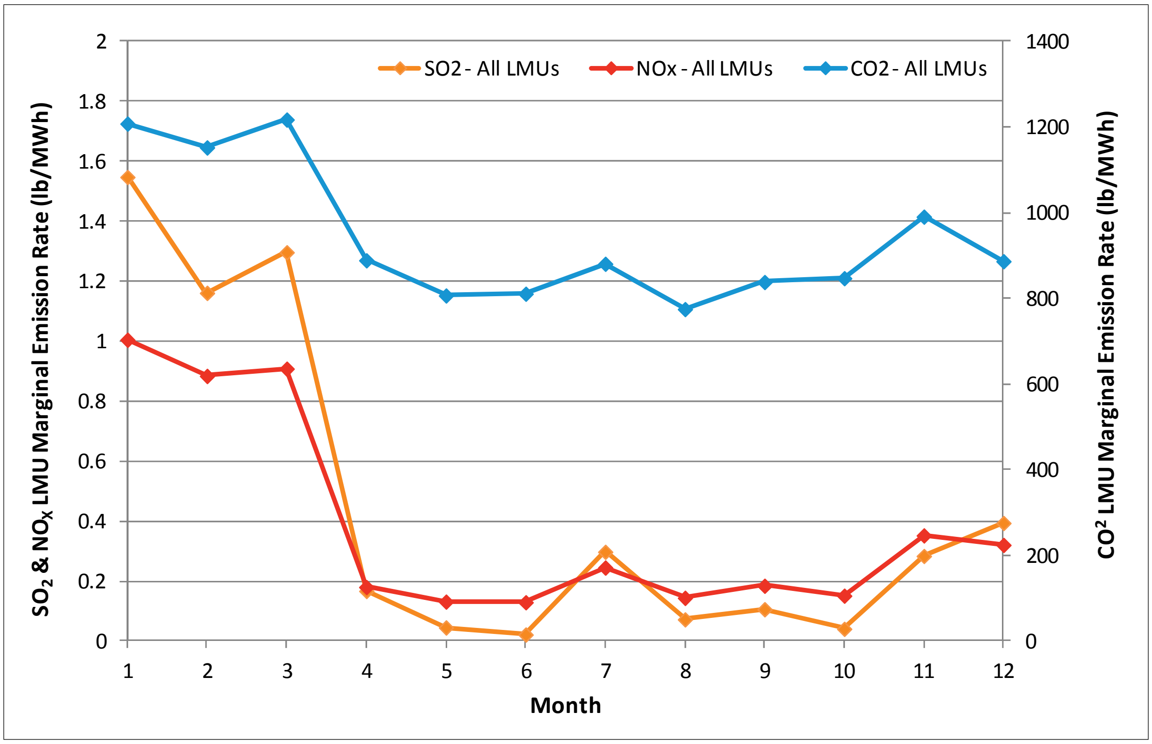

Figure 5-7: 2014 monthly LMU marginal emission rates—all LMUs (lb/MWh).

5.3.2 Marginal Emission Rates for the Emitting-LMU Scenario

Table 5-4 and Appendix Table 10 present the marginal emission rates for emitting LMUs. The marginal heat rate for this scenario is 9.034 MMBtu/MWh. The values for the monthly rates shown in Figure 5-8 are shown in Appendix Table 11.

Table 5-4
2014 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	0.26	0.17	0.59	0.72	0.47
Annual Emissions (SO_2 and CO_2)					
Air Emission		Annual			Annual Average (All Hours)
		On-Peak	Off-Peak		
SO_2		0.53	0.56		0.55
CO_2		1,064	1,138		1,107

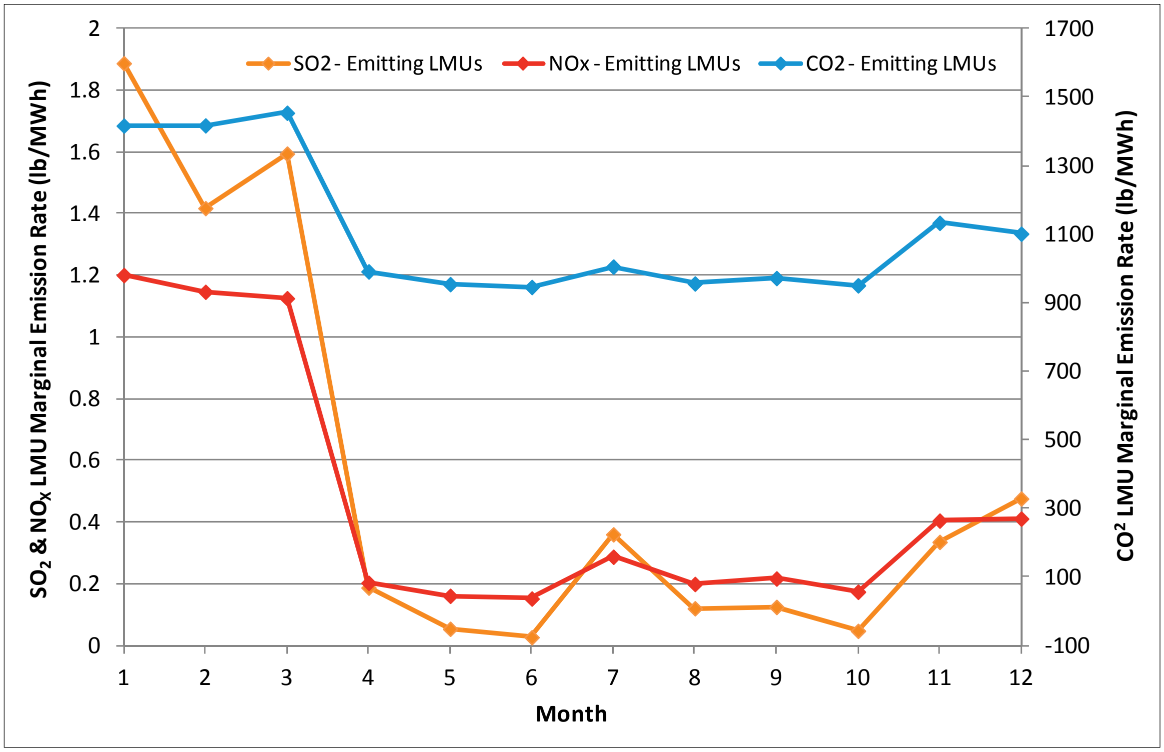

Figure 5-8: 2014 monthly LMU marginal emission rates—emitting LMUs (lb/MWh).

5.3.3 2009 to 2014 LMU Marginal Emission Rates

The LMUs actively exhibit the changes in New England's energy production. Compared with the emitting-LMU scenario, the all-LMU scenario has lower marginal emission rates because it includes zero-air-emission resources that lower the average emission rate. Figure 5-9 and Figure 5-10 summarize the results for the two LMU scenarios for marginal emission rates, which are detailed in Appendix Table 12 through Appendix Table 17 in lb/MWh.

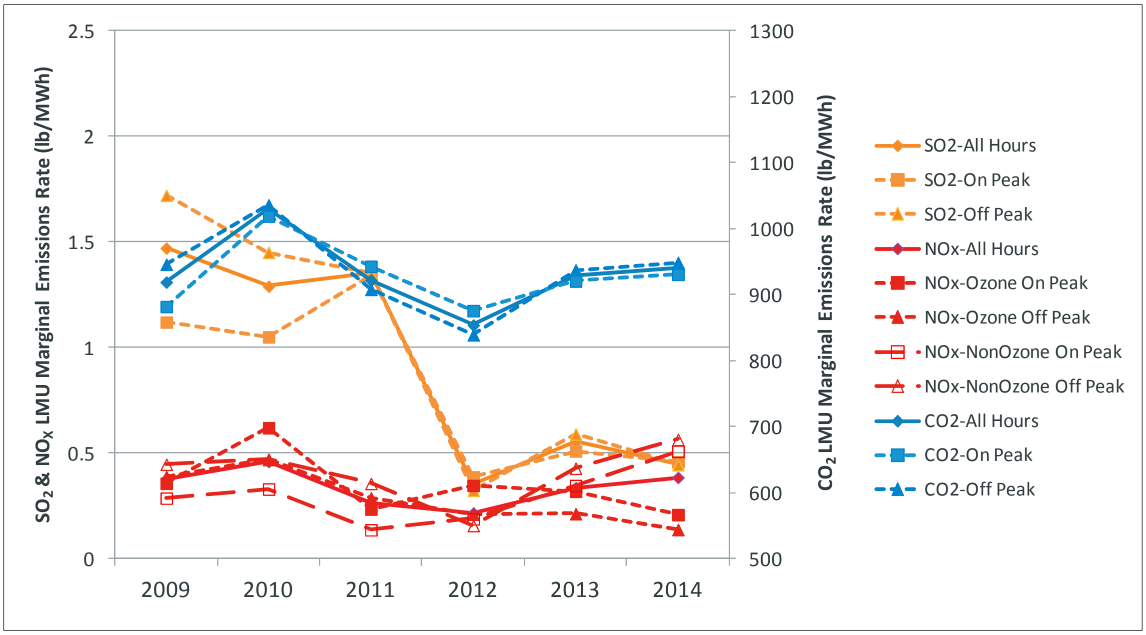

Figure 5-9: LMU marginal emission rates, 2009 to 2014—all LMUs (lb/MWh).

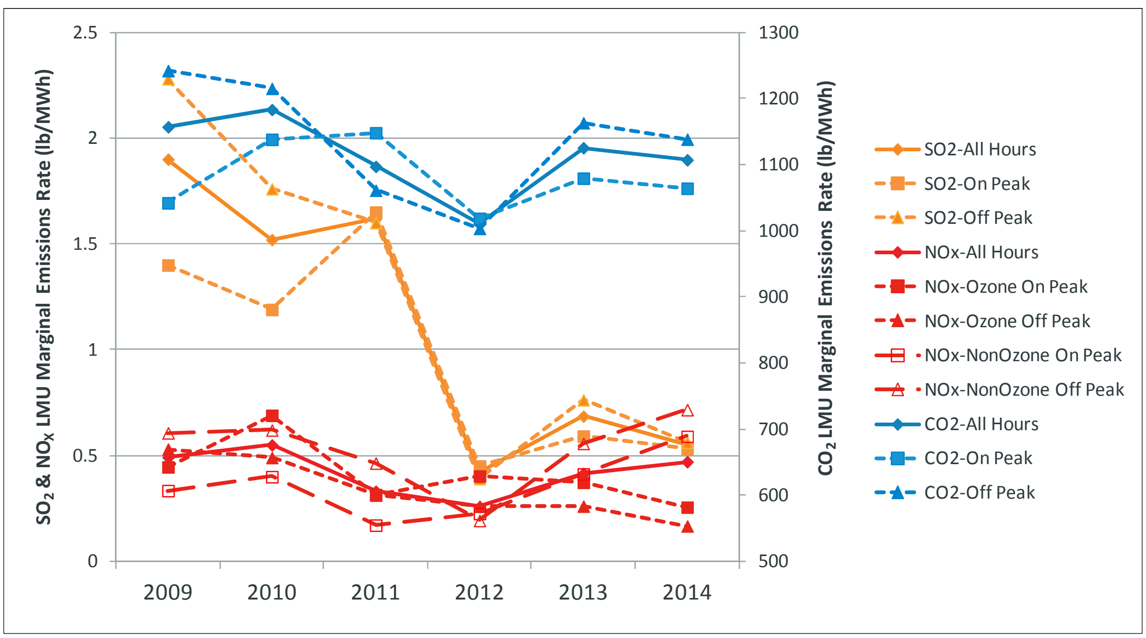

Figure 5-10: LMU marginal emission rates, 2009 to 2014—emitting LMUs (lb/MWh).

5.3.4 Marginal Emission Rates for High Electric Demand Days

Using the LMU methodology, the top-five energy demand days in 2014 were examined. In 2014, the top-five HEDDs were July 2, 3, 8, and 23, and September 2. The temperatures in New England during these days ranged from 85° to 88°F. Peak daily loads ranged from 23,542 MW on Thursday, July 3, to a high of 24,443 MW on Tuesday, July 2. Table 5-5 shows the average LMU marginal emission rate during these five days.

Table 5-5
High Electric Demand Day LMU Marginal Emission Rates (lb/MWh)

HEDD LMU Marginal Emission Rate (lb/MWh)		
	All LMUs	**Emitting LMUs**
NO_X	0.42	0.48
SO_2	0.43	0.52
CO_2	969	1,090

5.3.5 Observations

New England's power plant air emissions are directly dependent on the specific units available and dispatched to serve load for each hour of the year. Therefore, seasonal emissions can vary widely, primarily due to changes in economic and reliability dispatch, unit availability, fuel price and 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 LMU marginal emission rates reflect the dynamics of the New England power system.

Compared with 2009, the 2014 LMU SO_2 annual marginal rates have declined by approximately 70% for both the all-LMU and emitting-LMU scenarios. As illustrated in Figure 5-9 and Figure 5-10, most of this decline took place in 2012, when the percentage of time that oil and coal units were on the margin was lowest (see Figure 4-6 and Figure 4-8). CO_2 and NO_X LMUs have remained fairly steady during the past six years, with the lowest annual marginal rates also occurring in 2012.

In prior emissions reports, where long-term trends of fuel-type-assumed (FTA) marginal emission rates were calculated, the FTA marginal emission rates for NO_X decreased noticeably in 1995. This was primarily due to the implementation of reasonable available control technology (RACT) regulations for NO_X required under Title I of the 1990 *Clean Air Act Amendments*. 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 before that time in New England, as well as a decrease in the price of natural gas. Meeting the requirements of the 1999-2002 Ozone Transport Commission NO_X Budget Program, followed by EPA's NO_X Budget Trading Program, reduced emissions further. Because few new natural-gas-fired power plants have been added since 2004, the decline in marginal NO_X emission rates has tapered off.

In 2014, the off-peak marginal rates for SO_2 and CO_2, as well as for NO_X during the non-ozone season, are generally higher than the on-peak rates. In contrast, the NO_X on-peak rates during the ozone season are higher than the off-peak rates. This is likely due to the operation of older, less-efficient jets or combustion turbines dispatched to meet peak load.

Between 2013 and 2014, the SO_2 marginal emission rates decreased approximately 20%, and the NO_X marginal rates increased 12%, while the CO_2 rates remained about the same. Similar trends were observed in system emissions between 2013 and 2014, although the decrease in the SO_2 system emission rate was more pronounced and the increase the NO_X rate was less so. The changes in both marginal and system emission rates can primarily be attributed to the increase in generation by oil-fired units and the decrease in coal-fired generation.

Section 6
Appendix

Appendix Table 1
New England Total Cooling and Heating Degree Days, 1994 to 2014

Year	Total Cooling Degree Days	Difference from Average (%)	Total Heating Degree Days	Difference from Average (%)
1994	374	17.7%	6,403	5.3%
1995	312	-1.8%	6,318	3.9%
1996	245	-22.9%	6,454	6.1%
1997	211	-33.6%	6,432	5.8%
1998	312	-1.8%	5,483	-9.8%
1999	360	13.3%	5,774	-5.1%
2000	217	-31.7%	6,399	5.2%
2001	323	1.6%	5,895	-3.1%
2002	354	11.4%	5,959	-2.0%
2003	355	11.7%	6,651	9.4%
2004	251	-21.0%	6,354	4.5%
2005	418	31.5%	6,353	4.5%
2006	335	5.4%	5,552	-8.7%
2007	288	-9.4%	6,175	1.5%
2008	281	-11.6%	6,049	-0.5%
2009	224	-29.5%	6,278	3.2%
2010	406	27.8%	5,653	-7.0%
2011	357	12.3%	5,826	-4.2%
2012	409	28.7%	5,235	-13.9%
2013	401	26.2%	6,156	1.2%
2014	240	-24.5%	6,318	3.9%

Appendix Table 2
2014 New England Summer Capacity (MW, %)[a, b]

	Connecticut		Massachusetts		Maine		New Hampshire		Rhode Island		Vermont	
Unit Type	MW	%	MW	%	MW	%	MW	%	MW	%	MW	%
Coal	383.4	4.6	1,198.8	10.2	0.5	0.0	533.3	13.0	-	-	-	-
Natural Gas	2,843.1	33.9	6,078.2	51.7	1,523.9	49.1	1,183.1	28.9	1,833.8	99.8	-	-
Nuclear	2,097.3	25.0	677.3	5.8	-	-	1,247.1	30.5	-	-	619.4	56.6
Oil	2,758.6	32.9	1,591.9	13.5	810.5	26.1	482.9	11.8	-	-	127.4	11.6
Hydro	97.0	1.2	207.1	1.8	496.7	16.0	462.6	11.3	0.7	0.0	252.9	23.1
Pumped	28.9	0.3	1,690.2	14.4	-	-	-	-	-	-	-	-
Solar	-	-	52.5	0.4	-	-	0.0	0.0	3.7	0.2	-	-
Wind	-	-	13.9	0.1	50.4	1.6	23.6	0.6	0.2	0.0	13.2	1.2
Other	171.9	2.1	249.6	2.1	223.6	7.2	162.7	4.0	-	-	81.8	7.5
Total	8,380.1	100.0	11,759.6	100.0	3,105.6	100.0	4,095.3	100.0	1,838.3	100.0	1,094.8	100.0

(a) Sum may not equal total due to rounding.
(b) Seasonal Claimed Capability as of January 1, 2014.

Appendix Table 3
2014 New England Winter Capacity (MW, %)[a, b]

	Connecticut		Massachusetts		Maine		New Hampshire		Rhode Island		Vermont	
Unit Type	**MW**	**%**	**MW**	**%**	**MW**	**%**	**MW**	**%**	**MW**	**%**	**MW**	**%**
Coal	385.0	4.2	1,379.9	9.6	-	-	535.1	12.5	-	-	-	-
Natural Gas	3,144.6	34.0	6,963.6	48.6	1,669.6	49.2	1,322.3	30.8	2,092.6	99.6	-	-
Nuclear	2,110.9	22.8	683.4	4.8	-	-	1,246.7	29.0	-	-	615.0	53.7
Oil	3,310.1	35.7	3,080.6	21.5	880.9	26.0	502.1	11.7	-	-	166.0	14.5
Hydro	106.4	1.1	225.6	1.6	530.3	15.6	479.1	11.2	2.1	0.1	261.5	22.8
Pumped	28.1	0.3	1,701.9	11.9	-	-	-	-	-	-	-	-
Solar	-	-	23.3	0.2	-	-	-	-	3.6	0.2	-	-
Wind	-	-	20.6	0.1	81.5	2.4	42.3	1.0	2.0	0.1	18.6	1.6
Other	174.2	1.9	259.3	1.8	231.0	6.8	164.5	3.8	-	-	84.4	7.4
Total	9,259.3	100.0	14,338.4	100.0	3,393.2	100.0	4,292.1	100.0	2,100.3	100.0	1,145.5	100.0

(a) Sum may not equal total due to rounding.
(b) Seasonal Claimed Capability as of January 1, 2014.

Appendix Table 4
ISO New England System
Annual Emissions of NO_X, SO_2, and CO_2, 2001 to 2014 (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
2013	20.32	18.04	40,901
2014	20.49	11.68	39,317
Percent Reduction, 2001-2014	66	94	26

Appendix Table 5
2014 Monthly System Emission Rates of NO_X, SO_2, and CO_2 (lb/MWh)

System Marginal Emission Rates (lb/MWh)			
Month	NO_X	SO_2	CO_2
1	0.67	0.81	855
2	0.51	0.44	804
3	0.55	0.53	819
4	0.33	0.11	737
5	0.30	0.06	646
6	0.28	0.05	666
7	0.29	0.08	723
8	0.26	0.06	681
9	0.28	0.05	673
10	0.30	0.04	692
11	0.41	0.17	766
12	0.35	0.14	654

Appendix Table 6
New England System
Annual Average NO_X, SO_2, and CO_2 Emission Rates, 1999 to 2014 (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
2013	112,040	0.36	0.32	730
2014	108,356	0.38	0.22	726
Percent Reduction, 1999 - 2014		72	95	28

Appendix Table 7
LMU Marginal Heat Rate, 2009 to 2014 (MMBtu/MWh)

LMU Marginal Heat Rate (MMBtu/MWh)		
Year	All Marginal LMUs	Emitting LMUs
2009	8.591	8.507
2010	7.414	8.385
2011	6.907	8.190
2012	6.678	7.870
2013	6.841	8.271
2014	7.692	9.034

Appendix Table 8
2014 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	0.027	0.018	0.066	0.073	0.050
Annual Emissions (SO_2 and CO_2)					
Air Emission		Annual			Annual Average
		On-Peak	Off-Peak		
SO_2		0.060	0.058		0.059
CO_2		121	123		122

Appendix Table 9
2014 Monthly LMU Marginal Emission Rates—All LMUs (lb/MWh)

LMU Marginal Emission Rates (lb/MWh)			
Month	NO_X	SO_2	CO_2
1	1.01	1.55	1208
2	0.88	1.16	1153
3	0.91	1.30	1218
4	0.18	0.17	889
5	0.13	0.05	807
6	0.13	0.02	811
7	0.25	0.30	881
8	0.14	0.07	775
9	0.19	0.11	839
10	0.15	0.04	848
11	0.35	0.28	991
12	0.32	0.39	887

Appendix Table 10
2014 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	
NOX	0.028	0.018	0.065	0.079	0.052
Annual Emissions (SO2 and CO2)					
Air Emission		Annual			Annual Average
		On-Peak	Off-Peak		
SO2		0.059	0.062		0.061
CO2		118	126		123

Appendix Table 11
2014 Monthly LMU Marginal Emission Rates—Emitting LMUs (lb/MWh)

LMU Marginal Emission Rates (lb/MWh)			
Month	NO_X	SO_2	CO_2
1	1.20	1.89	1417
2	1.15	1.42	1418
3	1.13	1.59	1455
4	0.20	0.19	992
5	0.16	0.05	954
6	0.15	0.03	946
7	0.29	0.36	1006
8	0.20	0.12	957
9	0.22	0.13	972
10	0.17	0.05	951
11	0.40	0.34	1133
12	0.41	0.48	1102

Appendix Table 12
NO_X LMU Marginal Emission Rates, 2009 to 2014 —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
2013	0.32	0.21	0.35	0.43	0.34	56.7
2014	0.21	0.14	0.51	0.56	0.38	13.1
% Change 2009 - 2014	**-41.5**	**-64.4**	**75.4**	**26.4**	**1.8**	

Appendix Table 13
NO_X LMU Marginal Emission Rates, 2009 to 2014—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
2013	0.37	0.26	0.42	0.56	0.42	62.7
2014	0.26	0.17	0.59	0.72	0.47	12.1
% Change 2009 - 2014	**-42.6**	**-68.6**	**76.8**	**18.0**	**-4.3**	

Appendix Table 14
SO_2 LMU Marginal Emission Rates, 2009 to 2014—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	-12.2
2011	1.34	1.35	1.35	4.7
2012	0.39	0.32	0.35	-73.9
2013	0.51	0.59	0.55	56.0
2014	0.46	0.45	0.45	-18.0
% Change 2009 - 2014	**-59.0**	**-74.1**	**-69.3**	

Appendix Table 15
SO_2 LMU Marginal Emission Rates, 2009 to 2014—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	-20.0
2011	1.65	1.60	1.62	6.6
2012	0.45	0.39	0.42	-74.3
2013	0.59	0.76	0.69	65.9
2014	0.53	0.56	0.55	-20.2
% Change 2009 - 2014	**-61.9**	**-75.3**	**-71.0**	

Appendix Table 16
CO_2 LMU Marginal Emission Rates, 2009 to 2014—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	12.0
2011	943	908	922	-10.4
2012	876	839	854	-7.4
2013	921	937	930	8.9
2014	931	949	941	1.2
% Change 2009 - 2014	**5.5**	**0.3**	**2.4**	

Appendix Table 17
CO_2 LMU Marginal Emission Rates, 2009 to 2014—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	2.2
2011	1148	1061	1097	-7.3
2012	1019	1003	1010	-7.9
2013	1079	1163	1125	11.4
2014	1064	1138	1107	-1.6
% Change 2009 - 2014	**2.1**	**-8.4**	**-4.3**	