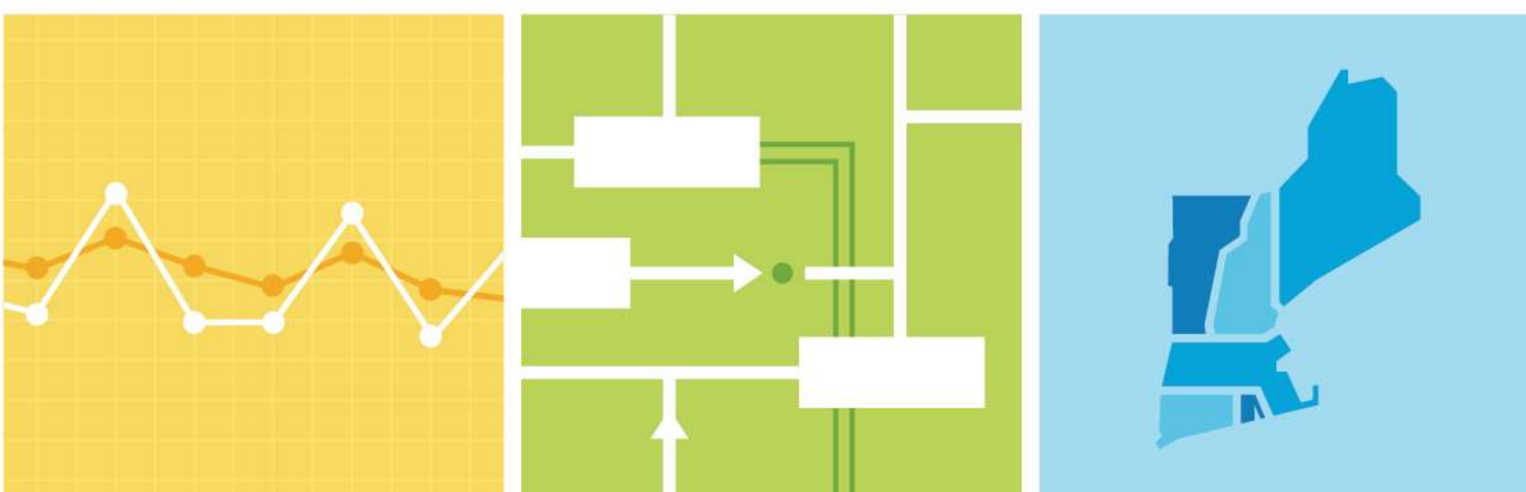
2018 ISO New England Electric Generator Air Emissions Report

System Planning

MAY 2020



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Summary of Changes to the 2018 Emissions Report

The primary change to the *2018 Emissions Report* is the addition of a load-weighted approach to calculating the marginal emission rates. This new approach is consistent with the way in which ISO New England's Internal Market Monitor has begun representing the marginal units by fuel type in its quarterly and annual markets reports[1]. The *Emissions Report* now includes the marginal emission rates based on both the current method, referred to as the time-weighted approach, and the new load-weighted approach.

The following is a summary of the additional information provided in the *2018 Emissions Report*:

- Figures 4-10 and 4-11 show the percentage of load for which various resource types were marginal
- Figures 4-12 and 4-13 compare the 2018 time-weighted and load-weighted percent marginal for various resource types
- Figures 5-5 and 5-6 include the monthly and annual load-weighted marginal heat rate values
- Section 5.3.2 includes the results of the load-weighted LMU marginal emission rate calculations
- Section 5.3.3 compares the marginal emission rates using the time- and load-weighted approaches
  - Table 5.7 compares the annual rates
  - Figures 5-13, 5-14, and 5-15 illustrate the differences between the time- and load-weighted monthly marginal emission rates for SO_2, NO_X, and CO_2
- Section 5.4 includes the load-weighted HEDD LMU marginal emission rates

In addition, the following changes were made to various figures in the report showing attributes by fuel type:

- The natural gas fuel category was split into combined cycle and simple cycle generator types in the following figures:
  - Figure 4-1, ISO-NE summer capacity by state
  - Figure 4-4, ISO-NE monthly generation by fuel type
  - Figures 4-6, 4-8, 4-10, and 4-11: percentage of time/load that various resource types were marginal
    - Figures 4-6 and 4-10 also reflect pumped storage demand, i.e., pumping load, as separate from the total pumped storage category

Questions regarding the *2018 Emissions Report* may be directed to ISO-NE Customer Support:

Email: custserv@iso-ne.com
Phone: (413) 540-4220

[1] https://www.iso-ne.com/markets-operations/market-monitoring-mitigation/internal-monitor/

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[2] and marginal emissions (in thousand short tons [ktons])[3]
- System and marginal emission rates (pounds per megawatt-hour [lbs/MWh] and pounds per million British thermal unit [lbs/MMBtu])
- 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 ISO 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.

During the ten-year period from 2009 through 2018, total system emissions have decreased overall: NO_X by 43%, SO_2 by 94%, and CO_2 by 31%. The decline in emissions during this period reflects shifts in the regional generation mix, with increasing natural gas-fired generation as well as wind generation offsetting decreases in coal- and oil-fired generation (see Figure 1-1).

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[2] For purposes of this report, "System" refers to native generation located within the ISO New England Balancing Authority Area. It does not include imports.

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

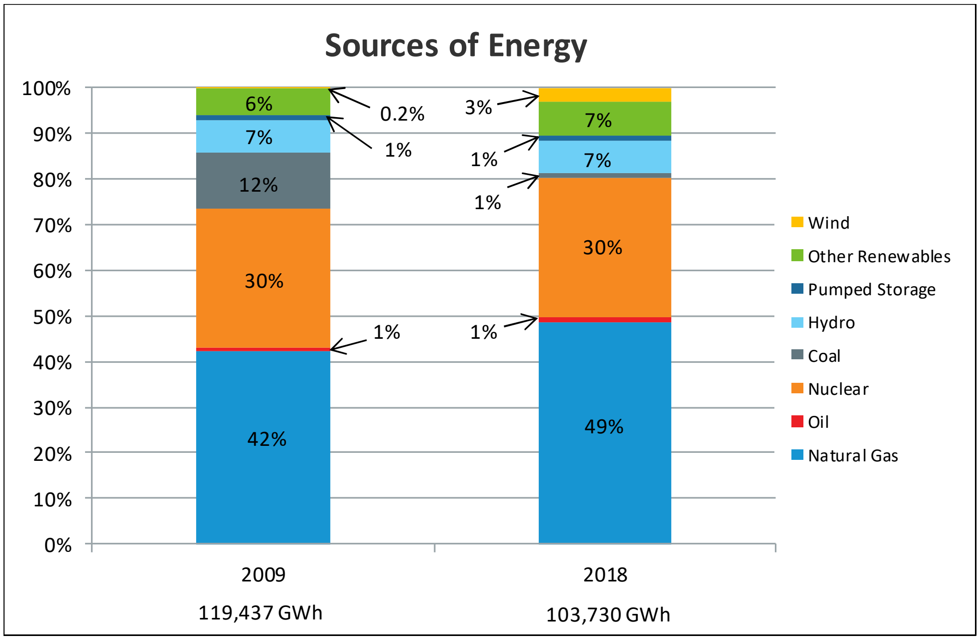

Figure 1-1: Percentage energy generation by fuel type, 2009 compared with 2018.
Note: This chart does not include net imports, which comprised 7% of total ISO New England energy in 2009, and 17% of total energy in 2018. Imports were excluded because they are assumed to have zero emissions in this report.[4]

Compared with the 20-year average for heating and cooling days (i.e., an indicator of weather), 2018 had a 51% warmer summer and an average winter. From 2017 to 2018, the net energy for load[5] and system generation increased by 1.9% and 1.1%, respectively. The net energy that ISO New England received from neighboring areas in 2018 was approximately 6% higher than the previous year. Generation by hydro, wind, and solar resources increased by 5%, while nuclear generation declined by 0.5%. From 2017 to 2018, coal-fired generation decreased by 34%, but oil-fired generation increased by 57%, and natural gas-fired generation by 3%.

Table 1-1 shows the total 2017 and 2018 ISO New England system emissions (ktons) and average system emission rates (lbs/MWh) of NO_X, SO_2 and CO_2. System emissions increased for NO_X and SO_2 from 2017 to 2018, but decreased for CO_2. The SO_2 emission rate increased in 2018, but there was no change in the NO_X rate, and the CO_2 emission rate decreased.

[4] Although the generation behind ISO-NE's imports does produce emissions, the Emissions Report has historically reported only the emissions from generators located within the ISO-NE footprint. In the marginal emissions analysis, imports have been marginal only a small percentage of the time (<0.1%), and the ISO has assumed zero emissions from those imports due to the lack of environmental attributes data available from some adjoining control areas sourcing those imports. However, as a result of recent requests to begin reporting the emissions produced by imported generation in both the system and marginal analyses, the ISO is developing a methodology for estimating those emissions.

[5] Net energy for load (NEL) is calculated by summing the metered output of native generation, price-responsive demand, and net interchange (imports minus exports). It excludes the electric energy required to operate pumped storage plants.

Table 1-1
2017 and 2018 ISO New England System Emissions (ktons) and Emission Rates (lbs/MWh)

Annual System[a] Emissions						
	2017 Emissions (kTons)	2018 Emissions (kTons)	Change in Emissions (%)	2017 Emission Rate (lbs/MWh)	2018 Emission Rate (lbs/MWh)	Change in Emission Rate (%)
NO_X	15.30	15.61	2.1	0.30	0.30	0.0
SO_2	4.00	4.96	24.0	0.08	0.10	25.0
CO_2	34,969	34,096	-2.5	682	658	-3.5

(a) The term "system" refers to native generation here and throughout the report.

Table 1-2 shows the 2017 and 2018 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 ISO New England system, subject to a set of constraints reflecting physical (transmission) limitations of the power system.

In response to stakeholder requests, the ISO calculated additional marginal emission metrics this year. The 2018 LMUs are calculated using two different approaches: a time-weighted approach, which is the method used in previous years, and a load-weighted approach. The time-weighted LMUs are based on the percentage of time that the LMUs are marginal in an hour, and assume that when the system is constrained and more than one unit is marginal, all marginal units contribute equally to meeting load across the system. In contrast, and new this year, the ISO calculated load-weighted LMUs, which reflect the share of load for which the generator is marginal when the system is constrained.

For both the time-weighted and load-weighted LMUs, this report presents the results of two scenarios of emission rates: 1) all LMUs, and 2) emitting LMUs.

Table 1-2
2017 and 2018 Annual Time-Weighted and Load-Weighted LMU Marginal Emission Rates (lbs/MWh)

LMU Marginal Emission Rates					
	Time-Weighted			Load-Weighted	
	2017 Annual Rate	2018 Annual Rate	Percent Change 2017 to 2018	2018 Annual Rate	2018 Load-Weighted vs. 2018 Time-Weighted
	(lbs/MWh)	(lbs/MWh)	(%)	(lbs/MWh)	(%)
All LMUs					
NO_X	0.15	0.17	13.3	0.20	17.6
SO_2	0.08	0.11	37.5	0.13	18.2
CO_2	654	655	0.2	745	13.7
Emitting LMUs					
NO_X	0.23	0.28	21.7	0.27	-3.6
SO_2	0.12	0.17	41.7	0.16	-5.9
CO_2	971	1,005	3.5	971	-3.4

Figure 1-2 summarizes the 2018 ISO New England emission rates. 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. On those HEDD days, the percentage of coal and oil units on the margin was higher than on average during the year.

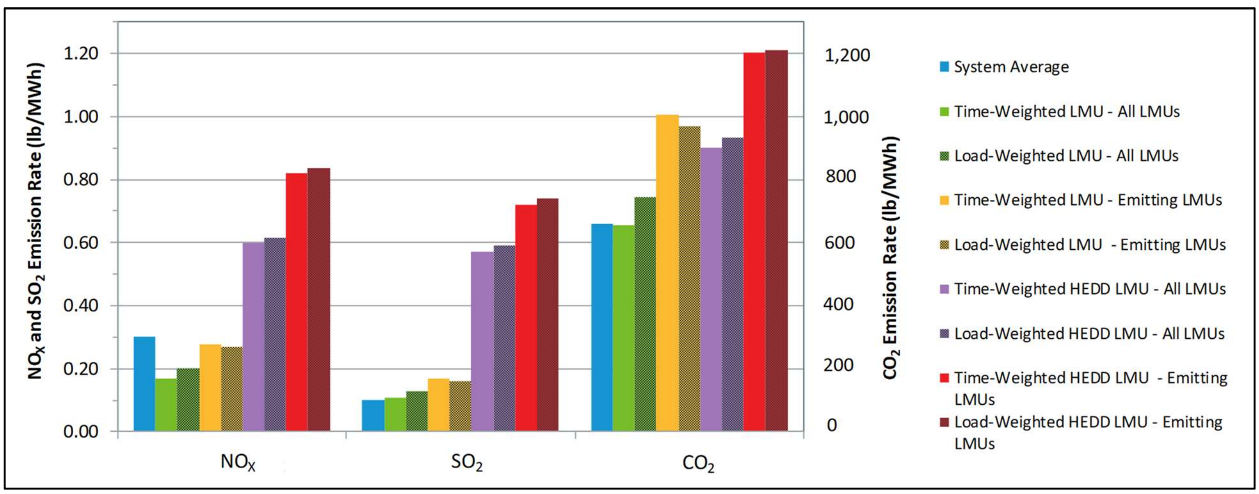

Figure 1-2: Comparison of 2018 ISO New England system and marginal emission rates (lbs/MWh).

A generator's heat rate (MMBtu/MWh) is a measurement of its efficiency in converting fuel into electricity. Using the time-weighted LMU approach, the 2018 calculated all-LMU marginal heat rate of 5.153 MMBtu/MWh was 5% lower than the 2017 value of 5.428 MMBtu/MWh. When considering the emitting units only, the LMU marginal heat rate decreased 2%, from 8.043 MMBtu/MWh in 2017 to 7.855 MMBtu/MWh in 2018.

The heat rates were also calculated using the load-weighted approach, which resulted in 2018 marginal heat rates of 5.962 MMBtu/MWh and 7.744 MMBtu/MWh for the all-LMU and emitting-LMU scenarios, respectively.

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.[6] 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.[7] 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.[8] In response, the report was revised and renamed the *ISO New England Electric Generator Air Emissions Report* (*Emissions Report*), to reflect the importance of emissions from the entire ISO 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. The emissions are based on a time-weighted approach, which reflects the percentage of time that a resource was marginal.

The *Emissions Report* continues to evolve. This year, in response to a request by the EAG, the report includes a new, load-weighted approach, which reflects the emissions associated with the amount of load served by the marginal unit when the system is constrained. The load-weighted approach is akin to the approach used by the ISO New England Internal Market Monitor in the reporting of marginal units in their quarterly and annual reports.

Stakeholders can use the calculated marginal emissions to track air emissions from ISO 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 ISO New England's NO_X, SO_2, and CO_2 power plant air emissions. The *2018 Emissions Report* focuses on analysis and

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[6] Massachusetts Executive Office of Energy and Environmental Affairs, "BWP AQ [Bureau of Waste Prevention—Air Quality] 18—Creation of Emission Reduction Credits," webpage (2019), http://www.mass.gov/eea/agencies/massdep/service/approvals/bwp-aq-18.html.

[7] 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.

[8] 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.

observations over the past decade (2009 to 2018). The Appendix includes data for years before 2009, as well as the values behind the figures presented.

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. 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 (EAG). This methodology identifies marginal units using the LMP, a process that minimizes total cost of energy production for the entire ISO New England system 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 (LMU)* (refer to Section 3.3). Results are presented starting in 2009, the earliest year of available data.

The current method for calculating the marginal emission rate, as described above, is based on the assumption that when there are multiple marginal resources within a time interval, they split the load equally. In this report, this is referred to as the time-weighted LMU approach. However, when more than one resource is marginal, the system is typically constrained and marginal resources likely do not contribute equally to meeting load across the system. At the request of regional stakeholders and the EAG, the ISO has added a new method for calculating marginal emission rates, which is based on the percentage of system load a marginal unit can serve. This method, referred to as the load-weighted LMU approach, is based on the assumptions used by the ISO New England Internal Market Monitor (IMM) beginning in 2018 to report the percentage of the total system load that can be served by marginal units of a particular fuel or unit type.[9] The marginal emission rates

[9] The IMM began weighting marginal resources by their contribution to load to more clearly show the impact of the marginal resources on the LMP. Renewable-type generation resources with lower marginal costs are located in export-constrained areas of northern New England and frequently set real-time prices in these areas. This is particularly true of

calculated with the load-weighed LMU approach are included in the *2018 Emissions Report* along with the time-weighted LMU marginal emission rates.

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, its level of electrical power output, etc.

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 pounds (lbs)/MWh to lbs/MMBtu.[10] In the 1999 to 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.

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 heat-rate information collected and maintained by the ISO. 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 ISO's heat-rate data. 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.

As described in Section 3.4, the calculation of the marginal heat rate is based on the heat rates for each individual LMU. In the current methodology, the percentage of time each generator is marginal per year leads to the contribution of that unit's heat rate to the time-weighted LMU marginal heat rate. With the addition of the load-weighted LMU methodology to the *Emissions Report*, a similar marginal heat rate calculation has been performed based on the percentage of load served by each marginal generator.

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wind resources, which became marginal much more frequently with the implementation of the Do Not Exceed (DNE) dispatch rules on May 25, 2016. DNE incorporates wind and hydro intermittent units into unit dispatch, making the units eligible to set price. Previously, these units had to self-schedule their output in the real-time market and, therefore, could not set price.

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

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 primary source of data for the ISO New England power system emissions and marginal emission rate calculations for NO_x, SO_2, and CO_2 was the US EPA Clean Air Markets Division (CAMD) database.[11] The database contains measured 2018 air emissions (tons) reported by generators under EPA's monitoring and recordkeeping requirements for the Acid Rain Program and NO_X mass emissions and the Regional Greenhouse Gas Initiative (RGGI).[12]

For those units not required to report emissions data to EPA under 40 CFR Part 75 for a federal or state regulation, monthly emission rates (lbs/MWh) from the New England Power Pool Generation Information System (NEPOOL GIS) were used. If this information was not available, annual emission rates (lbs/MWh) from EPA's eGRID2016 were used.[13] 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:

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

[11] EPA's Clean Air Markets Program data (2019) are available at http://ampd.epa.gov/ampd/, and the Clean Air Markets emissions data (2019) 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. Generators subject to RGGI also report CO_2 emissions to EPA. Additional details for the monitoring, recordkeeping, and reporting requirements of SO_2, NO_X, and CO_2 emissions, volumetric flow, and opacity data from affected units under 40 CFR Part 75 are available at https://www.epa.gov/airmarkets/clean-air-markets-emissions-monitoring.

[12] 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.

[13] The U.S. EPA's eGRID2016 database (2019) is available at http://www.epa.gov/cleanenergy/energy-resources/egrid/index.html. The eGRID2018 database, which was released on 1/28/20, was not available in time for this report.

3.3 Marginal Emission Rate Calculation

The Locational Marginal Unit (LMU) is identified by the LMP, which is set by the cost of the generation dispatched to meet the next increment of load at the pricing location. The resource that sets price is called the marginal unit. LMPs minimize total energy costs for the entire ISO New England system, 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 constraints, in each five-minute period.

The LMU percent marginal in an hour was calculated using two different approaches: the time-weighted and load-weighted approach. The time-weighted approach involves calculating the percentage of time that each unit was marginal in an hour based on the five-minute interval data. With the load-weighted approach, the amount of load served by each unit in a five-minute interval was used to calculate the percentage of total system load served by each unit in an hour.

To calculate the marginal emission rates, the hourly emissions (lbs) 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 (lbs) from each individual marginal fossil generator was then divided by that generator's monthly on-peak or off-peak generation to obtain the corresponding emission rate (lbs/MWh) for that time period. For NO_X emission rates, the monthly totals (lbs) 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 (in the case of the time-weighted approach) or the percentage of load served by the generator in each month (in the case of the load-weighted approach) during on- or off-peak hours was calculated and then multiplied by the generator's month-specific on-peak or off-peak average emission rate as 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

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

LMU Off-Peak Marginal Emission Rate

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

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 time-weighted and load-weighted 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, and nuclear generation, as well as and wind and solar renewables. Pumped storage demand, i.e., the energy used to pump water into a pumped-storage unit's storage pond, and external transactions were also assumed to have no emissions.

3.4 Marginal Heat Rate Calculation

The marginal heat rate was calculated by first calculating a heat rate for each individual generator[14]. The heat rates for the individual LMUs were then multiplied by the percentage of time each generator was marginal (time-weighted LMU), or by the percentage of load served (load-weighted LMU).

These values were then added together and divided by the total number of hours in the year, resulting in the time-weighted and load-weighted LMU marginal heat rates.

Similar to the marginal emission rate calculation, the analysis was performed for both the all-LMU and the emitting-LMU scenarios.

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:

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

[14] The heat rate for noncombustible renewables, i.e., pumped storage, hydroelectric, wind, and solar resources, was considered to be zero in these calculations since those resources do not burn fuel to produce energy. Pumped storage demand and imports were also assumed to have a zero heat rate.

3.5 Time Periods Analyzed

The 2018 marginal air emission rates for on- and off-peak periods for ISO New England were calculated for this report. Data for the on-peak period are 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:[15]

- 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

[15] 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 (https://www.iso-ne.com/static-assets/documents/genrtion_resrcs/reports/emission/peak_nox_analysis.pdf

Section 4
Data and Assumptions

This section highlights the key parameters and assumptions modeled in the *2018 Emissions Report*, including weather, emissions data, installed capacity, and system generation.

4.1 2018 New England Weather

Because the weather significantly affects the demand for energy and peak loads, comparing 2018 temperatures, total energy use and both cooling and heating degree days to previous years can provide some perspective.

New England experienced an extreme cold wave at the beginning of the year that stretched from the end of December 2017 through the first week of January 2018. The average temperature in January was 26°F, which was slightly below the 20-year average of 27°F. Summer 2018 was considerably warmer and more humid than 2017. The average temperature for the summer was 72°F, which was the third hottest summer over the past ten years, and the average Temperature Humidity Index (THI) of 69°F was the hottest of the last ten years.

The 2018 summer peak electricity demand of 25,980 MW was 8.4% higher than the 2017 summer peak of 23,968 MW. There were 499 cooling degree days in 2018, which is 50.8% higher than the 20-year average.[16] The net energy for load was 1.9% higher in 2018 than 2017. With respect to the winter months, there were 6,060 heating degree days, which is 0.9% higher than the 20-year average.

New England's historical cooling and heating degree days for 1999 through 2018 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 66% of the SO_2 emissions and 73% of the CO_2 emissions were based on EPA's Clean Air Markets data. For NO_X, Clean Air Markets data were used for 34% of total emissions.

The emission rates were multiplied by the 2018 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:

[16] Over the 20-year span from 1999 to 2018, the average number of cooling degree days was 331, and the average number of heating degree days was 6,004.

- Forced and scheduled maintenance outages of resources and transmission system elements
- Fuel prices and emission allowance costs
- Imports from and exports to neighboring regions
- System peak load and energy consumption
- Water availability to hydroelectric facilities and for thermal power plant cooling
- A variety of other factors

Figure 4-1 shows the total 2018 summer capacity for ISO New England generation as obtained from *ISO New England's 2019–2028 Forecast Report of Capacity, Energy, Loads and Transmission* (CELT).[17] Appendix Table 2 and Appendix Table 3 summarize the total summer and winter capacity for ISO New England generation by state and fuel type.[18]

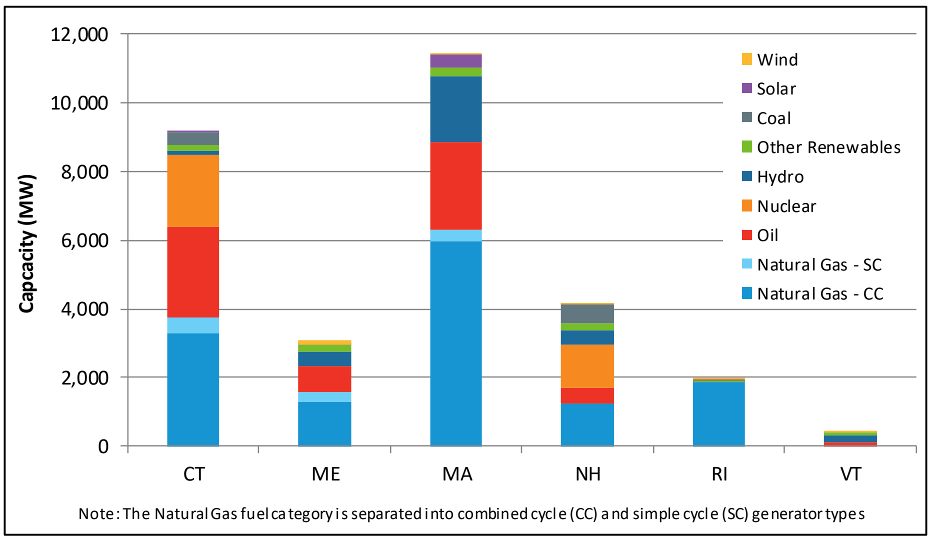

Figure 4-1: 2018 ISO New England summer capacity by state (MW).

Figure 4-2 illustrates the new generating capacity added to the ISO New England system from 2009 through 2018. A total of 4,092 MW was added, with combustion turbines and combined-cycle plants capable of burning natural gas or distillate oil making up about 78% of this new capacity. Notably, over half of the total natural gas capacity additions during this period occurred in 2018, with approximately 1,600 MW of new gas-fired capacity. The remaining additions over the prior ten years consist primarily of renewable generation, including 14% of total capacity from wind and solar resources.

[17] The ISO New England *CELT Report* is typically issued in May of each year. The *2019 CELT Report* (using the seasonal claimed capabilities (SCC) as of January 1, 2019) was used to completely capture all the new capacity additions that occurred during the prior calendar year, 2018. The capacity may also include generators that retired in 2018. The CELT reports are available at http://www.iso-ne.com/system-planning/system-plans-studies/celt.

[18] The natural gas capacity in this chart and elsewhere in the report has been broken out into combined cycle (CC) and simple cycle (SC) generators to show the portion of the natural gas capacity that is comprised of peaking plants.

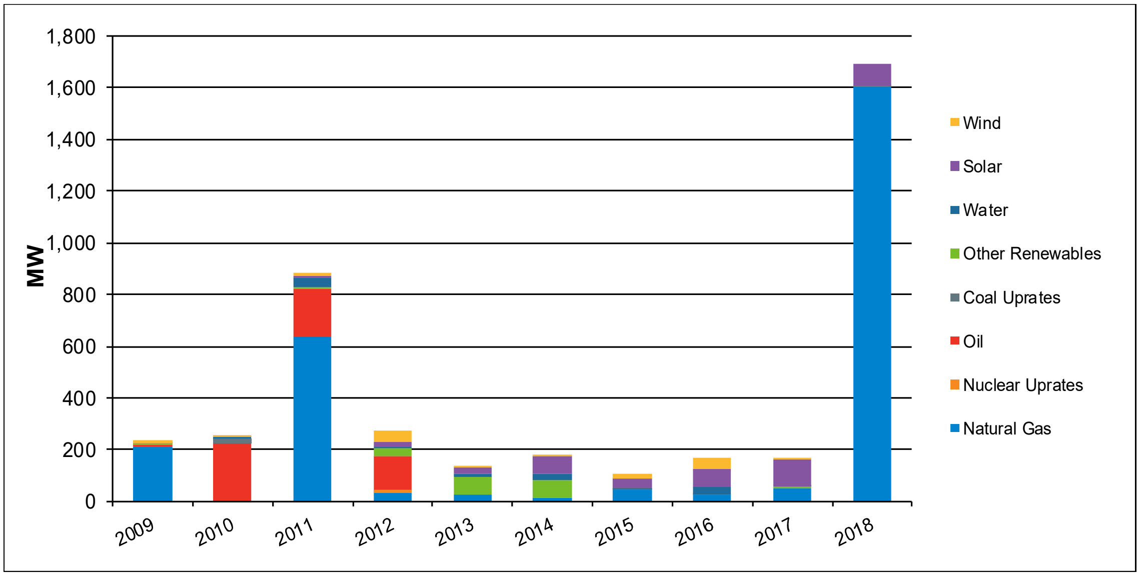

Figure 4-2 : ISO New England generator additions, 2009 to 2018 (MW).
Note: The generator additions and uprate values are based on the summer Seasonal Claimed Capabilities, as reported in the 2019 CELT Report.

Several large generators in New England have retired in the past ten years. The retirements, as shown in Figure 4-3, total 1,829 MW of coal, 1,332 MW of residual oil, and 604 MW of nuclear generation since late 2011.

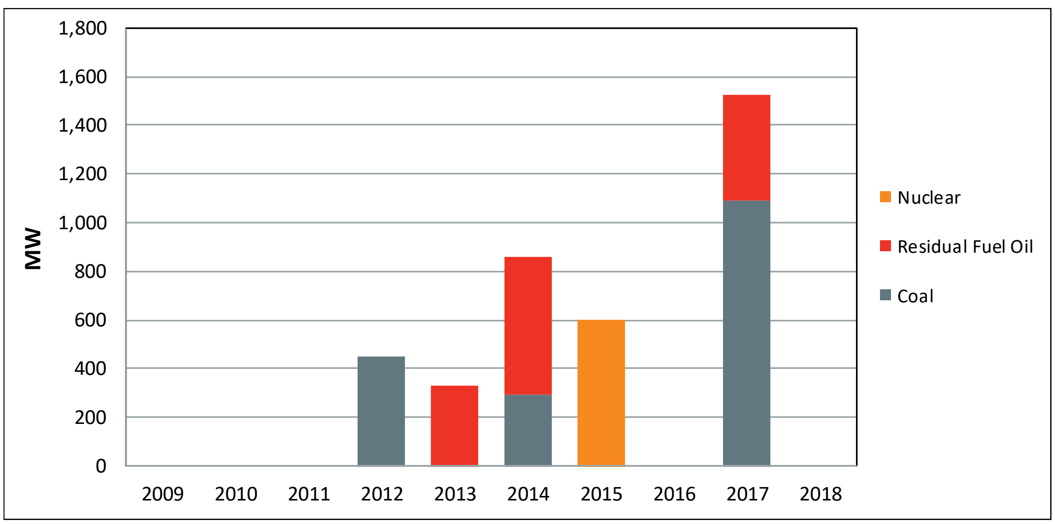

Figure 4-3: Major retirements in ISO New England, 2009 to 2018 (MW).
Note: The retirement date shown is not necessarily the year in which the retirement occurred. In the case of units that retired late in the year, the retirement is included in the following year because that is when the impact would 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.

Figure 4-4 shows the 2018 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 accounted for 35% to 62% of the total generation in each month.[19]. During winter months with higher energy demand and occasional limitations in natural gas availability, other fuel types have increased their energy contribution to support the ISO New England system.[20] During the winter months, the use of firmly contracted gas pipeline transportation by the regional gas sector's local distribution company (LDC) customers takes priority over the use of the interruptible and/or secondary pipeline capacity which is primarily used by gas-fired generators to generate electricity.[21] Almost all gas-fired generating units lack both firm supply and transportation contracts.

Although oil- and coal-fired generation were each only 1% of the annual total in 2018, their contribution to total generation in the month of January was significantly higher than normal (11% and 4%, respectively) due to an extreme cold wave during the first part of the month. The percentage of natural-gas-fired generation was lowest in the winter and spring months and increased to meet the higher demand in the summer months and during fall generator outages.

Hydroelectric, solar, and wind generation accounted for 8% to 18% of the total 2018 generation. These fuel types exhibit seasonal differences in their generation due to fuel availability; typically hydroelectric and wind generation decline over the summer months due to less rainfall replenishing reservoirs and rivers and less favorable onshore wind conditions, while solar generation peaks between March and September.

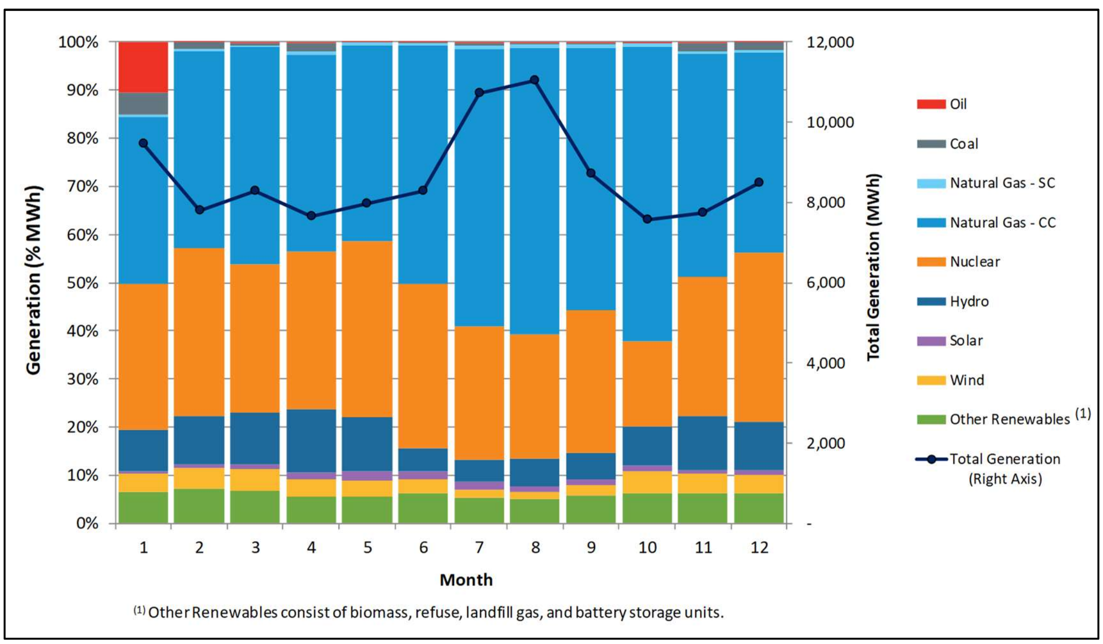

Figure 4-4: 2018 ISO New England monthly generation by fuel type (% MWh, MWh).

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[19] Annual energy production share for natural gas-fired generation was 49% in 2018, compared to 48% in 2017.

[20] Annual energy production share by fuel type remained generally consistent between 2017 and 2018.

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

Figure 4-5 shows the generation (MWh) by fuel type from 2014 to 2018 based on the resource's primary fuel type listed in the *2019 CELT Report*. In 2018, coal-fired generation continued its decline, and was about 570 GWh lower than in 2017. In contrast, oil-fired generation decreased by 460 GWh in 2018. Natural-gas-fired generation in 2018 was about 1,300 GWh higher than in 2017, increasing by about 3%. Nuclear generation was about the same as in 2017, decreasing by less than 1%. Generation by non-emitting renewable resources increased in 2018: hydroelectric generation grew 2%, and solar and wind together increased by 435 GWh, or 10% over 2017. The overall system generation of 103,740 GWh in 2018 was 1% higher than the 2017 level.

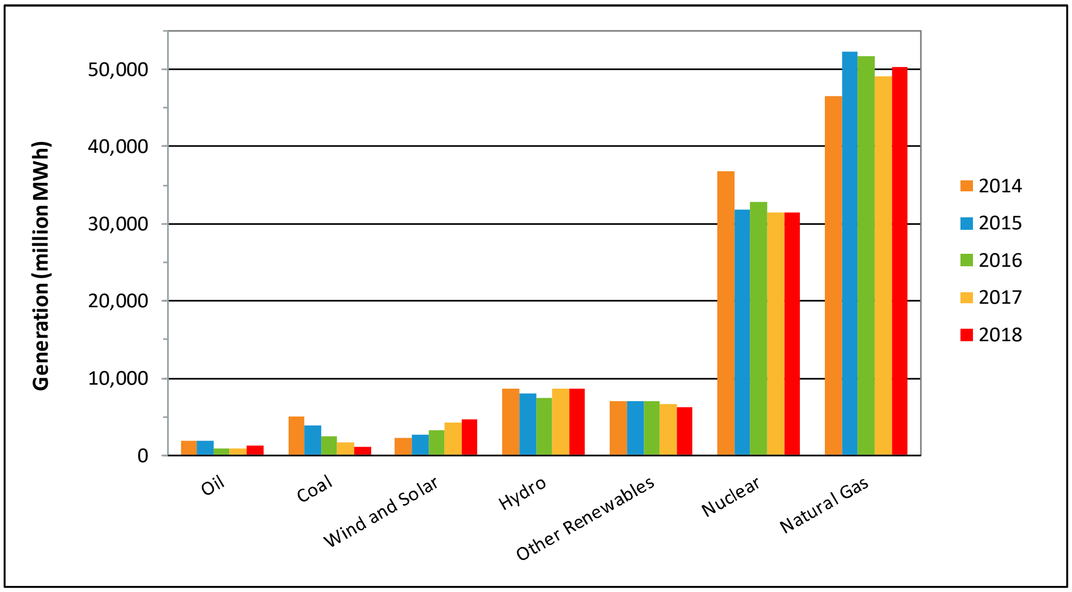

Figure 4-5: ISO New England annual generation by fuel type, 2014 to 2018 (million MWh).

4.5 Locational Marginal Unit Scenarios

The data and assumptions applied for the all-LMU and emitting-LMU scenarios for both the time-weighted and load-weighted approaches 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 and emissions.

4.5.1 Time-Weighted Approach

4.5.1.1 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 was marginal 43% to 80% of the time. The months when natural gas units were marginal the most, in the range of 78% to 80% of the time, were June through August. Although oil-fired generation was on the margin an average of only 1% during the year, it was marginal approximately 13% of the time in January when there was a period of extreme cold weather. During the months of April and November, coal-fired generation was on the margin more than other months, about 4% of the time. Other

Renewables, which consist of biomass, refuse, and landfill gas units, were marginal an average of 2% of the time, with a peak of 5% in September. Intermittent resources became eligible to be dispatched and set price beginning in May 2016, when the Do Not Exceed dispatch rules went into effect. In 2018, the time that wind was marginal ranged from 1% in August to a maximum of 30% in October. Note that Figure 4-6 includes a breakdown of the pumped storage category into pumped storage generation and pumped storage demand[22], which were marginal an average of 9% and 5% of the time, respectively.

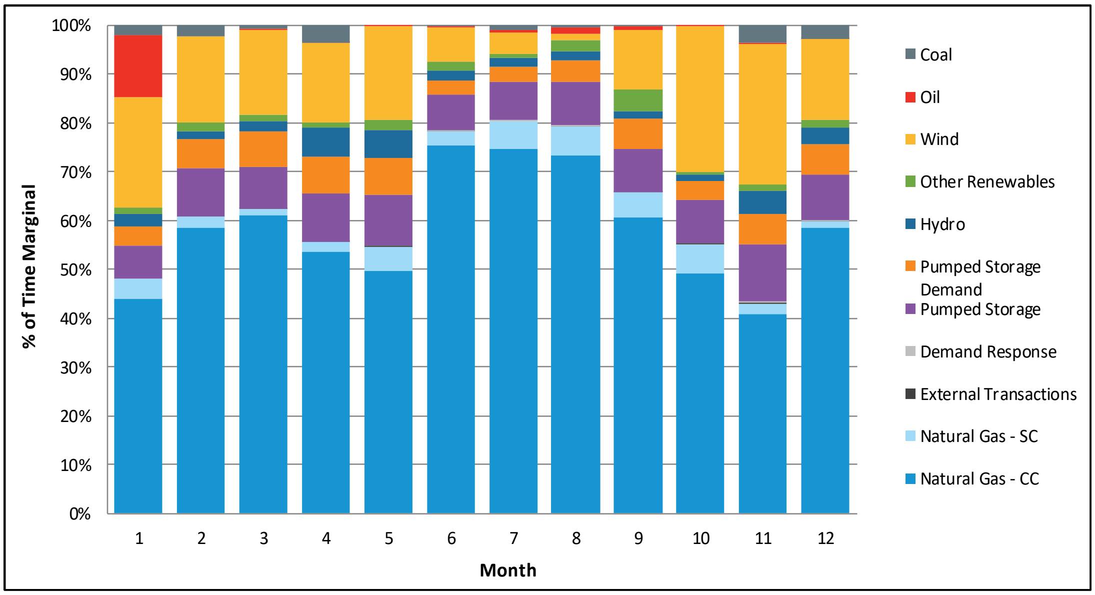

Figure 4-6: 2018 percentage of time various resource types were marginal —all LMUs.

Figure 4-7 shows the historical percentage of time that each fuel type was marginal within a calendar year. Natural gas has been the primary marginal fuel type during the past five years. From 2017 to 2018, the percentage of time that natural gas was marginal decreased by 3%. The amount of time that oil was the marginal fuel remained at 1% in 2018, and coal decreased from 2% in 2017 to 1%. The percentage of time that the Other Renewables category was marginal decreased by 1%. In 2018, as in 2017, wind often displaced gas as the price-setting fuel. However, wind predominantly set price in small, local export-constrained areas of the system, as opposed to setting price for large parts of the system. Though wind was marginal 16% of the time in 2018, it was generally marginal in a very local congested area and did not directly impact system price. At the system level, wind was the marginal fuel type approximately 1% of the time.[23]

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[22] Pumped storage demand refers to the electric energy used to pump water into a pumped-storage unit's storage pond.
[23] Beginning with the 2018 Spring Quarterly Markets Report (July 2018), the ISO-NE Internal Market Monitor (IMM) recalculated the percentage of time marginal units by fuel type by quarter, using a load-weighted analysis for 2016 through the first half of 2018. The IMM switched to the load-weighted marginal resources methodology to better reflect the impact of system constraints since resources within an export-constrained area are not able to fully contribute to meeting the load for the wider system. The IMM reports are available at https://www.iso-ne.com/markets-operations/market-monitoring-mitigation/internal-monitor/.

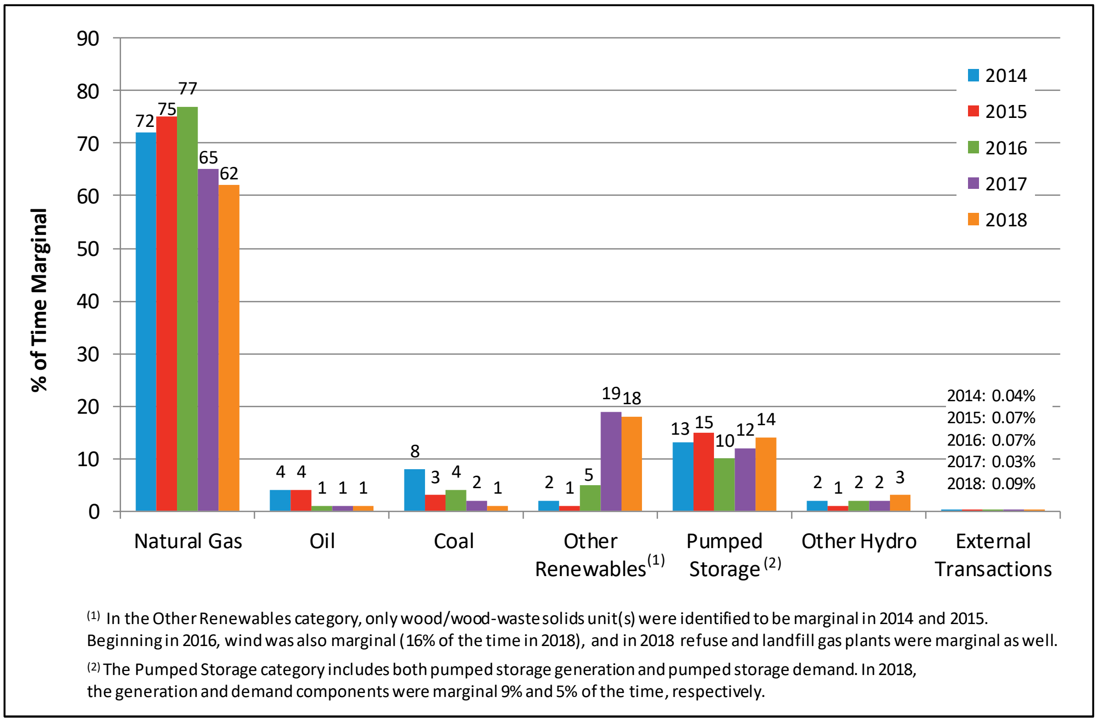

Figure 4-7: Annual percentage of time various resource types were marginal —all LMUs, 2014 to 2018.

4.5.1.2 Emitting LMUs

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

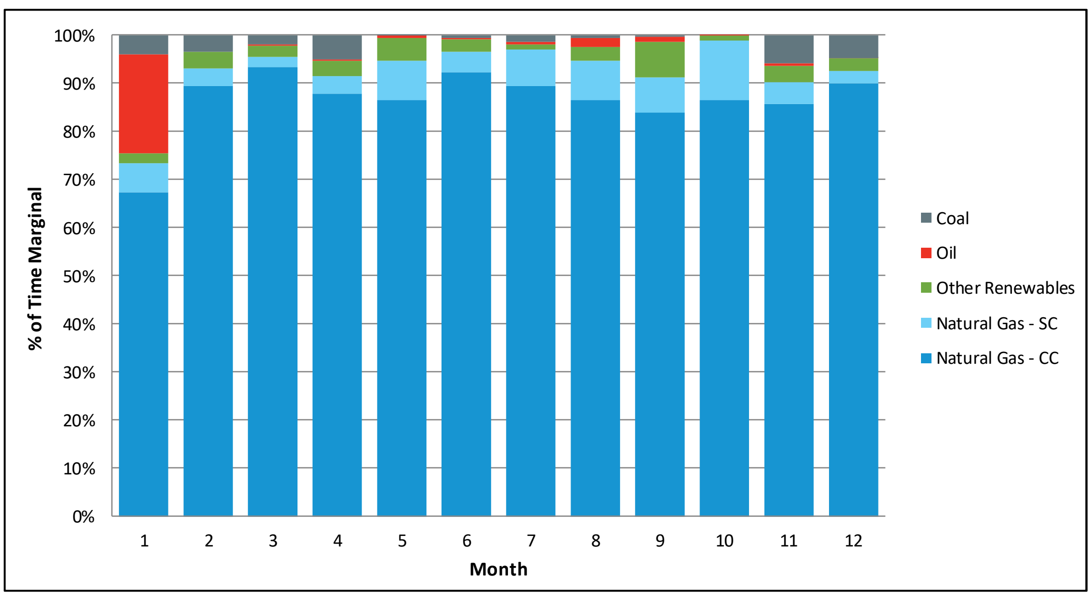

Figure 4-8: 2018 percentage of time various resource types were marginal —emitting LMUs.

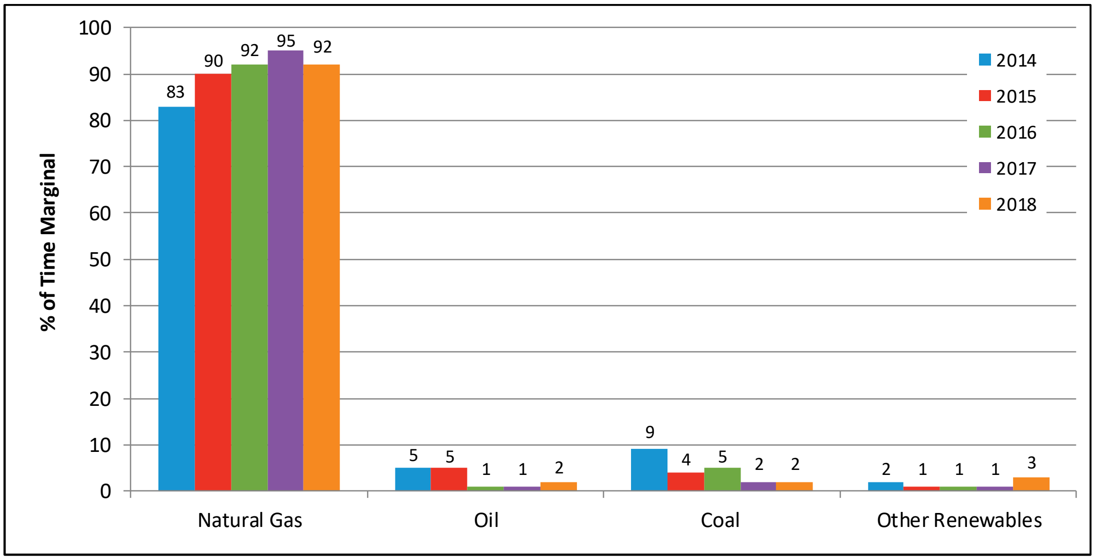

Figure 4-9: Annual percentage of time various resource types were marginal – emitting LMUs, 2014 to 2018.

4.5.2 Load-Weighted Approach

4.5.2.1 All LMUs

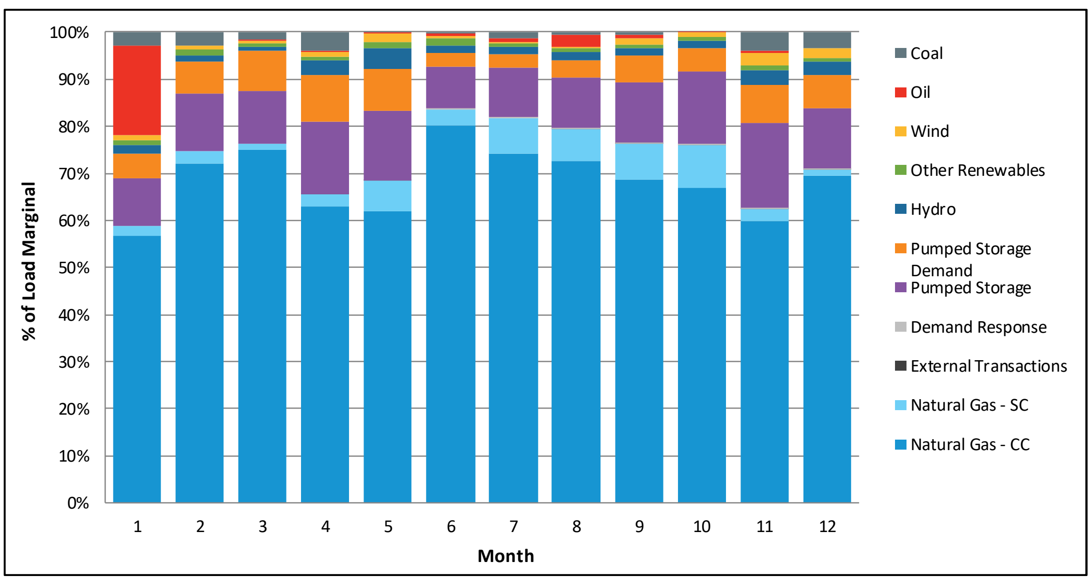

Figure 4-10: 2018 percentage of load for which various resource types were marginal —all LMUs.

4.5.2.2 Emitting LMUs

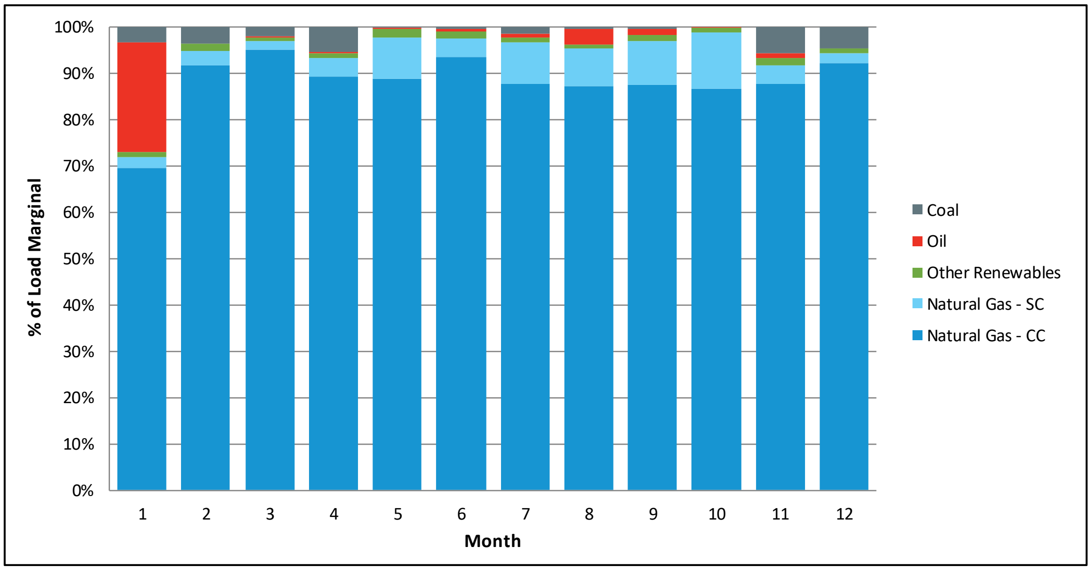

Figure 4-11: 2018 percentage of load for which various resource types were marginal —emitting LMUs.

4.5.3 Time-Weighted vs. Load-Weighted Approach

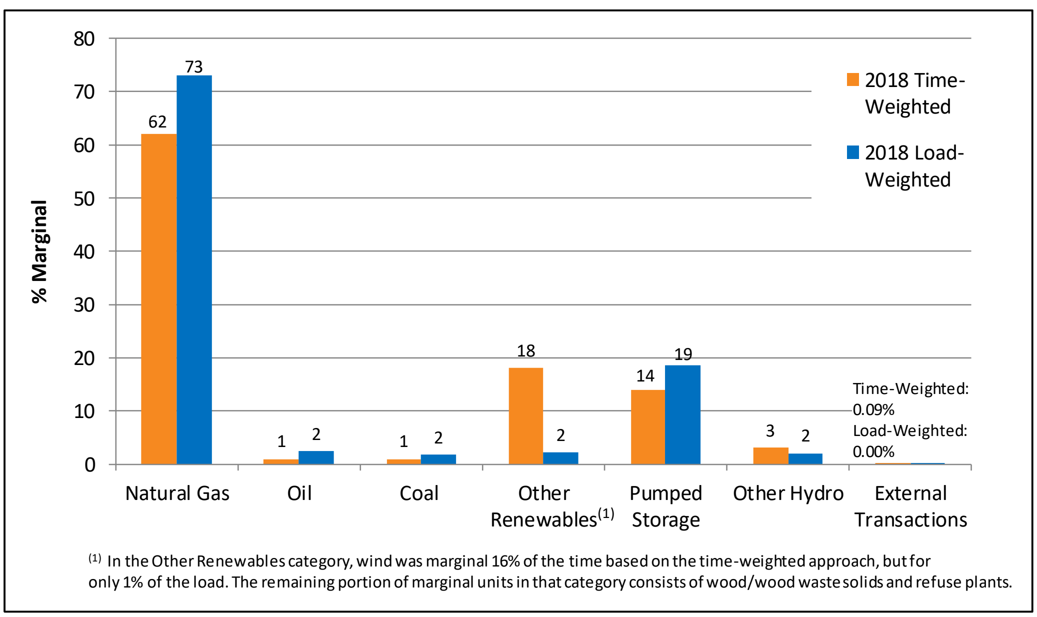

Figure 4-12: Comparison of 2018 annual marginality for various resource types using the time-weighted vs. load-weighted approach —all LMUs.

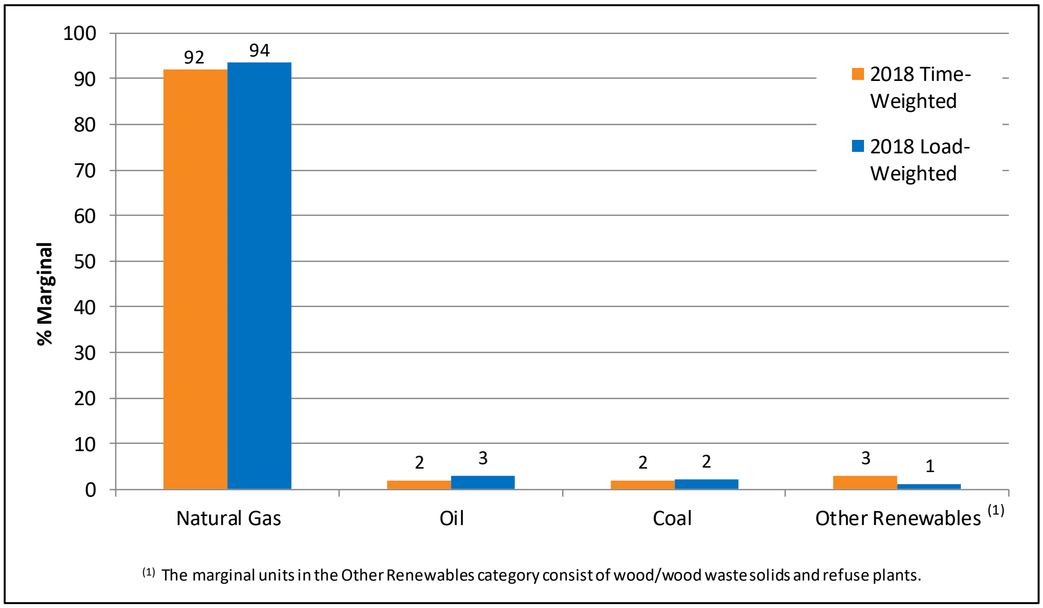

Figure 4-13: Comparison of 2018 annual marginality for various resource types using the time-weighted vs. load-weighted approach —emitting LMUs.

4.6 High Electric Demand Days

In New England, high electric demand days (HEDDs) are typically characterized by high temperatures leading to elevated cooling (energy) demand. During peak energy demand periods, such as HEDDs, the ISO relies on peaking units, which are utilized less 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 (see Section 5.4) reveals the emission rates associated with the units responding to higher system demand.

Section 5
Results and Observations

This section presents the results for ISO New England's 2018 system[24] 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, using both the time-weighted and load-weighted approaches.

5.1 2018 ISO New England System Emissions

Results are presented for the following metrics:

- Aggregate NO_X, SO_2, and CO_2 emissions for each state for 2018
- A comparison of aggregate NO_X, SO_2, and CO_2 emissions for 2009 to 2018
- 2018 annual average NO_X, SO_2, and CO_2 emission rates, by state and for the ISO New England system as a whole
- Monthly variations in the emission rates for 2018
- A comparison of annual average NO_X, SO_2, and CO_2 emission rates for 2009 to 2018

5.1.1 Results

Figure 5-1 shows the 2018 annual aggregate NO_X, SO_2, and CO_2 air emissions for each state. The ISO New England system total emissions for NO_X, SO_2, and CO_2 were 15.61 ktons, 4.96 ktons, and 34,096 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.[25] The reason for the divergent total emissions for each state is that the total emissions reflect the generation of units physically located in that state (refer to Figure 4-1 showing summer capacity by state) rather than emissions associated with the generation needed to meet that state's energy demand.

[24] In this report, "system" refers to native generation within the ISO New England Balancing Authority Area.

[25] 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.

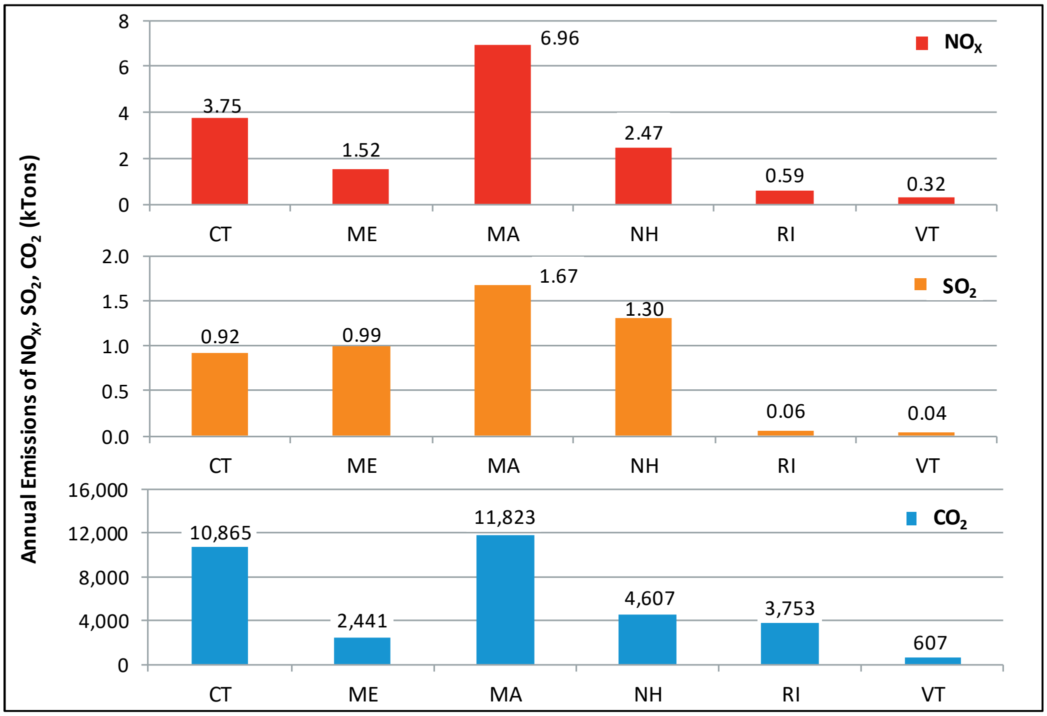

Figure 5-1: 2018 ISO New England system annual emissions of NO_X, SO_2, and CO_2 (ktons).
Note: System annual emissions based on physical location of the generating resources. Sum may not equal ISO New England system total due to rounding.

Figure 5-2 shows the annual aggregate NO_X, SO_2, and CO_2 air emissions for 2009 through 2018. Since 2009, NO_X emissions have dropped by 43% and SO_2 by 94%, while CO_2 has decreased by about 31%. Refer to Appendix Table 4 for the values behind this graph.

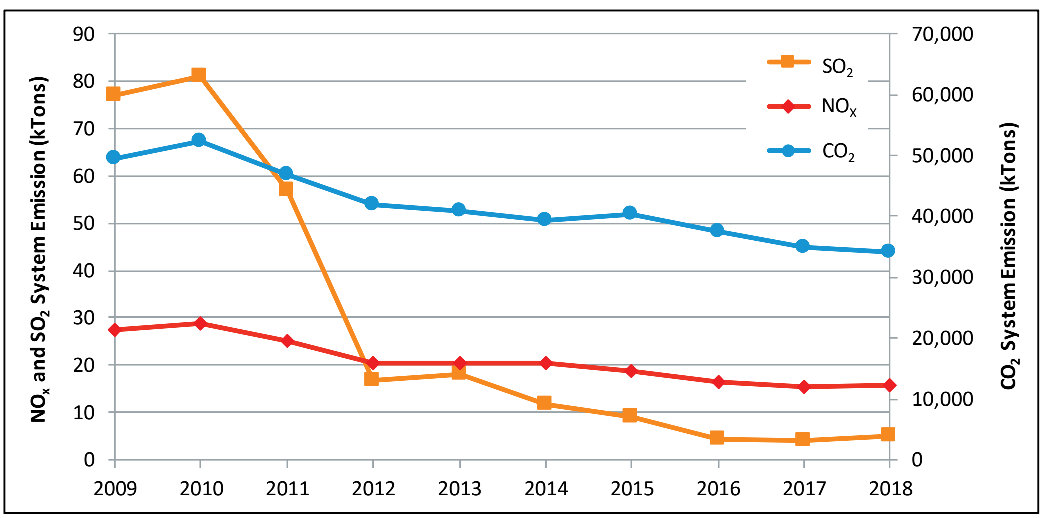

Figure 5-2: ISO New England system annual generator emissions, 2009 to 2018 (ktons).

Table 5-1 shows the 2018 annual average NO_X, SO_2, and CO_2 air emission rates (lbs/MWh), by state and for the New England system as a whole. 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
2018 ISO New England System
Annual Average Generator Emission Rates (lbs/MWh)

State	NO_x	SO_2	CO_2
Connecticut	0.19	0.05	560
Maine	0.35	0.23	568
Massachusetts	0.48	0.12	817
New Hampshire	0.29	0.15	538
Rhode Island	0.14	0.01	916
Vermont	0.31	0.03	591
New England	0.30	0.10	658

Monthly variations in the emission rates shown in Figure 5-3 reflect the generation by different fuel types shown in Figure 4-4. In 2018, the highest emission rates by far occurred in January. This was due to a cold snap that resulted in oil-fired plants generating a significant portion of the region's electricity. At other times during the year, emission rates rose in April, July, November, and December, when there were slight increases in coal- and oil-fired generation. In addition, higher loads in the summer, as well as a reduction in nuclear generation in the early fall, resulted in higher emissions due to increased gas-fired generation during those months.

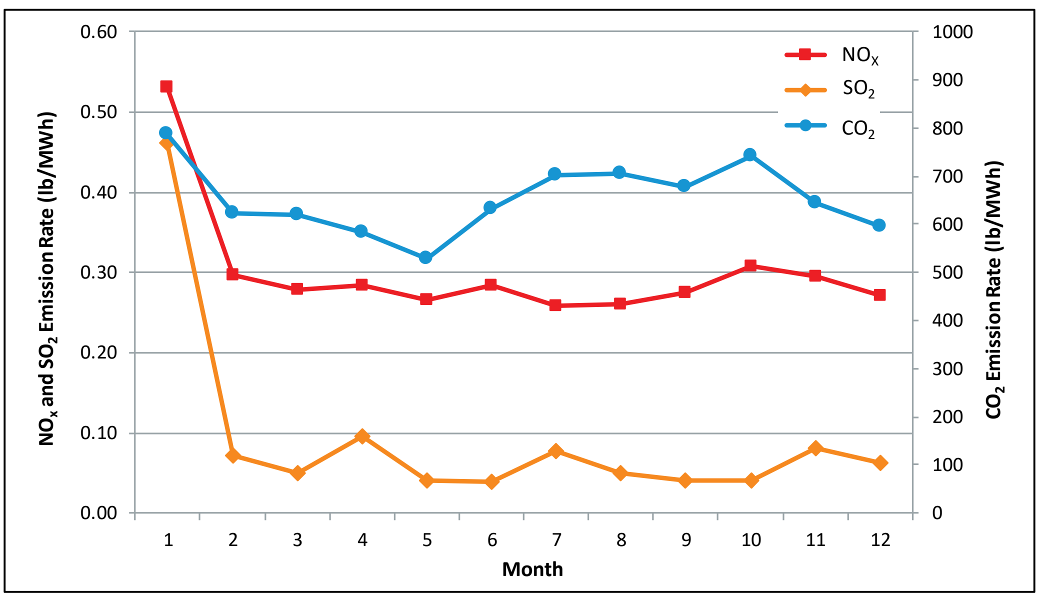

Figure 5-3: 2018 ISO New England system monthly average generator emission rates (lbs/MWh).

Figure 5-4 illustrates the annual average NO_X, SO_2, and CO_2 air emission rates (lbs/MWh) for 2009 to 2018 using the calculation method presented in Section 3.2. Since 2009, the annual average NO_X emission rate has decreased by 35%, SO_2 by 92%, and CO_2 by 21%. Appendix Table 6 shows historical emission rates since 1999.

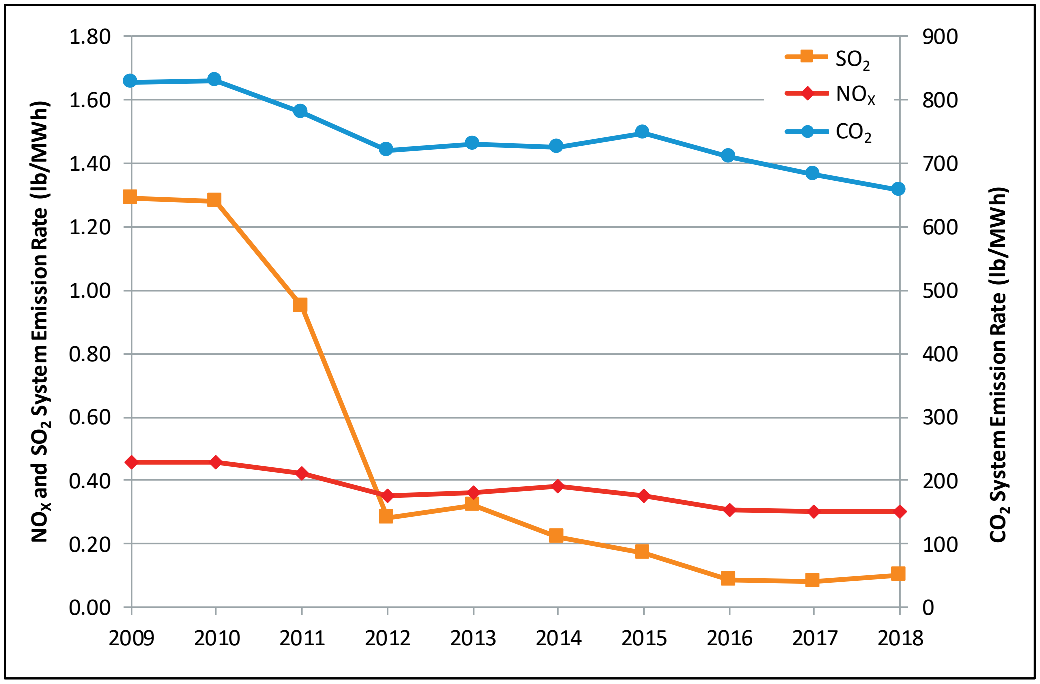

Figure 5-4: ISO New England system annual average generator emission rates, 2009 to 2018 (lbs/MWh).

5.1.2 Additional Observations

Total energy generation decreased by 1.1% in 2018 from 2017. The amount of energy from coal-fired generation continued its decline in 2018, decreasing by 34% to 1.1% of total generation. Energy from oil-fired generators increased by about 57% to 1.2% of total generation, primarily due to the large amount of oil generation in January. Natural gas-fired generation increased by 3% to 48.6% of total generation. In contrast, there was a 1% increase in total energy produced by non-emitting sources, which includes nuclear generation. Although nuclear generation itself decreased by 0.5%, photovoltaic and wind generation grew by 10%, and generation by hydroelectric facilities rose 2%. The impacts on system emissions resulting from these changes in the generation mix can be seen in Table 5-2. The increase in oil-fired generation from 2017 to 2018 contributed to increases of 2.1% and 24.0% in system emissions for NO_X and SO_2. CO_2 emissions decreased by 2.5%. Similar changes were also observed in the 2018 emission rates: the NO_X rate stayed the same, SO_2 increased by 25.0%, and CO_2 decreased by 3.5%.

Table 5-2
2017 and 2018 ISO New England System Emissions (ktons)
and Emission Rates (lbs/MWh)

Annual System Emissions						
	2017 Emissions (kTons)	2018 Emissions (kTons)	Change in Emissions (%)	2017 Emission Rate (lbs/MWh)	2018 Emission Rate (lbs/MWh)	Change in Emission Rate (%)
NO_X	15.30	15.61	2.1	0.30	0.30	0.0
SO_2	4.00	4.96	24.0	0.08	0.10	25.0
CO_2	34,969	34,096	-2.5	682	658	-3.5

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
- Mandated use of lower-sulfur fuels
- Retirement of oil- and coal-fired generation, and retrofits of NO_X and SO_2 emission controls on some of the remaining oil- and coal-fired generators

5.2 2018 ISO New England Marginal Heat Rate

The calculated annual marginal heat rate reflects the average annual efficiency of all the marginal fossil units dispatched throughout 2018. The 2018 monthly marginal heat rates for both the time-weighted and load-weighted all-LMU and emitting-LMU scenarios are shown in Figure 5-5, and the historical marginal heat rates for 2010 to 2018 are presented in Figure 5-6. The values behind Figure 5-6 are provided in Appendix Table 7.

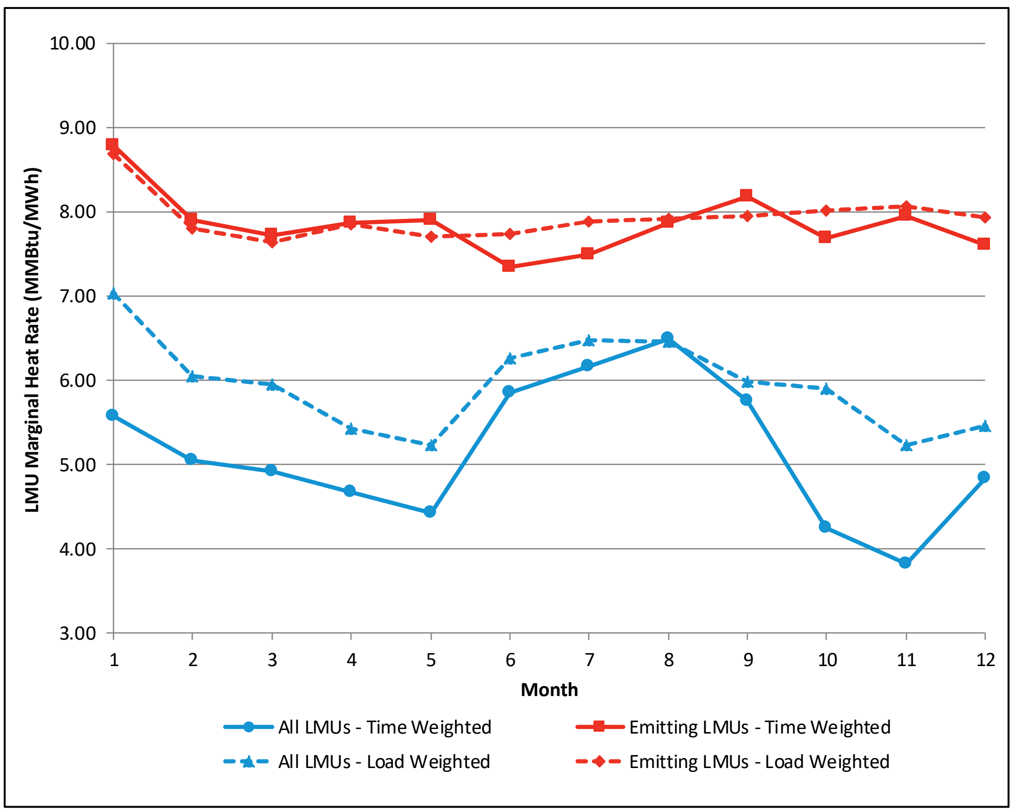

Figure 5-5: 2018 time- and load-weighted LMU monthly marginal heat rate (MMBtu/MWh).

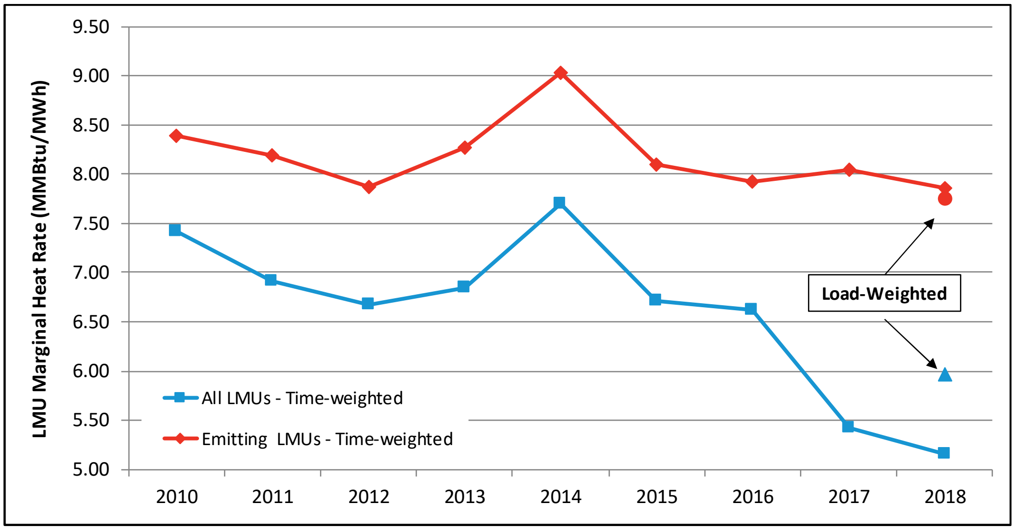

Figure 5-6: LMU annual marginal heat rate, 2010-2018 (MMBtu/MWh).

There has been an overall trend of declining heat rates from 2010 through 2016, with the exception of a spike in 2014. Beginning in 2017, there has been a steep drop in the heat rate in the all-LMU scenario due to the large amount of wind units on the margin, which was a result of the DNE dispatch rules implemented in May 2016. Figure 5-6 includes the 2018 LMU marginal heat rates that were calculated using the load-weighted approach. In that case, the value for the all-LMU scenario was 16% higher than the value based on the time-weighted approach because a significant portion of the wind plants are located in export-constrained northern New England. For the emitting-LMUs scenario, the marginal heat rate calculated using the load-weighted approach was somewhat lower than the time-weighted results because several biomass plants, which generally have higher heat rates, are also located in export-constrained areas.

5.3 2018 ISO New England Marginal Emission Rates

This section presents the 2018 calculated LMU-based marginal emission rates for the all-LMU and emitting-LMU scenarios, as defined in Section 4.5. The 2018 rates based on both the time-weighted and load-weighted LMU approaches are included; however, only time-weighted LMU results are available for years prior to 2018.

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 Using the Time-Weighted Approach

5.3.1.1 All-LMU Scenario

The time-weighted all-LMU marginal emission rates were calculated with all LMUs (units the LMP identified as marginal). Table 5-3 shows the rates in lbs/MWh. Appendix Table 8 shows these rates in lbs/MMBtu, with the associated marginal heat rate of 5.153 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 2018 percentage of time various fuel types were marginal for all LMUs) and Figure 5-3 (showing the 2018 ISO 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
2018 Time-Weighted LMU Marginal Emission Rates—All LMUs (lbs/MWh)[a, b]

Ozone / Non-Ozone Season Emissions (NO_X)					
Air Emission	Ozone Season		Non-Ozone Season		Annual Average (All Hours)
	On-Peak	Off-Peak	On-Peak	Off-Peak	
NO_X	0.20	0.14	0.19	0.17	0.17
Annual Emissions (SO_2 and CO_2)					
Air Emission		Annual			Annual Average (All Hours)
		On-Peak	Off-Peak		
SO_2		0.14	0.08		0.11
CO_2		690	630		655

(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.

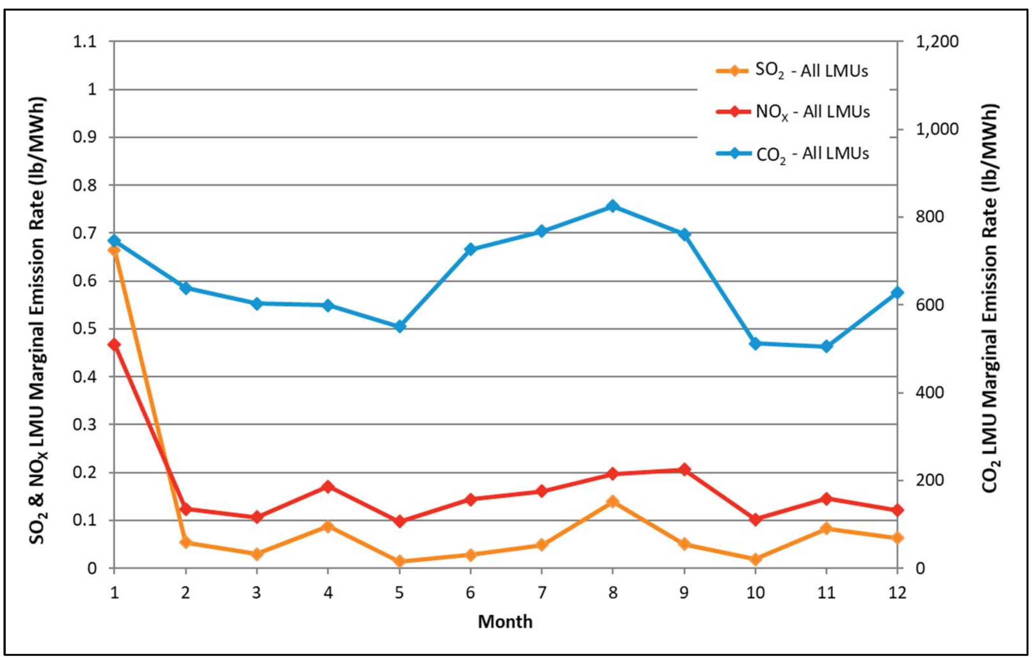

Figure 5-7: 2018 time-weighted monthly LMU marginal emission rates—all LMUs (lbs/MWh).

5.3.1.2 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 7.855 MMBtu/MWh. The values for the monthly rates shown in Figure 5-8 are shown in Appendix Table 11.

Table 5-4
2018 Time-Weighted LMU Marginal Emission Rates—Emitting LMUs (lbs/MWh)

Ozone / Non-Ozone Season Emissions (NO_X)					
Air Emission	Ozone Season		Non-Ozone Season		Annual Average (All Hours)
	On-Peak	Off-Peak	On-Peak	Off-Peak	
NO_X	0.27	0.20	0.31	0.31	0.28
Annual Emissions (SO_2 and CO_2)					
Air Emission		Annual			Annual Average (All Hours)
		On-Peak	Off-Peak		
SO_2		0.21	0.14		0.17
CO_2		1,028	989		1,005

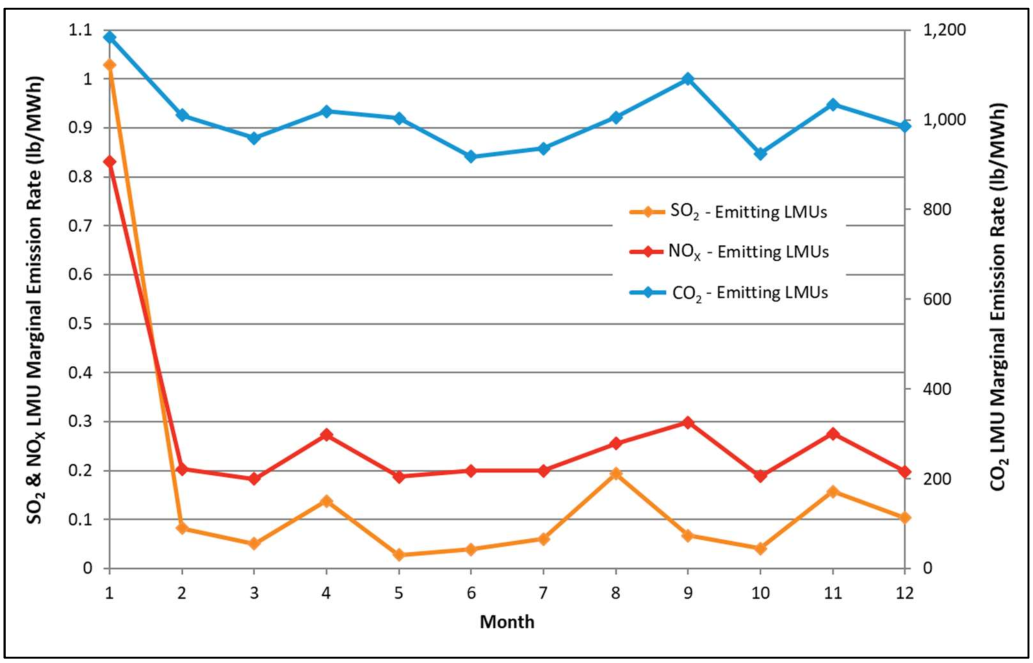

Figure 5-8: 2018 time-weighted monthly LMU marginal emission rates—emitting LMUs (lbs/MWh).

5.3.1.3 2009 to 2018 Time-Weighted LMU Marginal Emission Rates

The LMUs actively exhibit the changes in ISO 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 marginal emission rates for the two LMU scenarios based on the time-weighted approach. The values behind the graphs are provided in Appendix Table 12 through Appendix Table 17 in lbs/MWh.

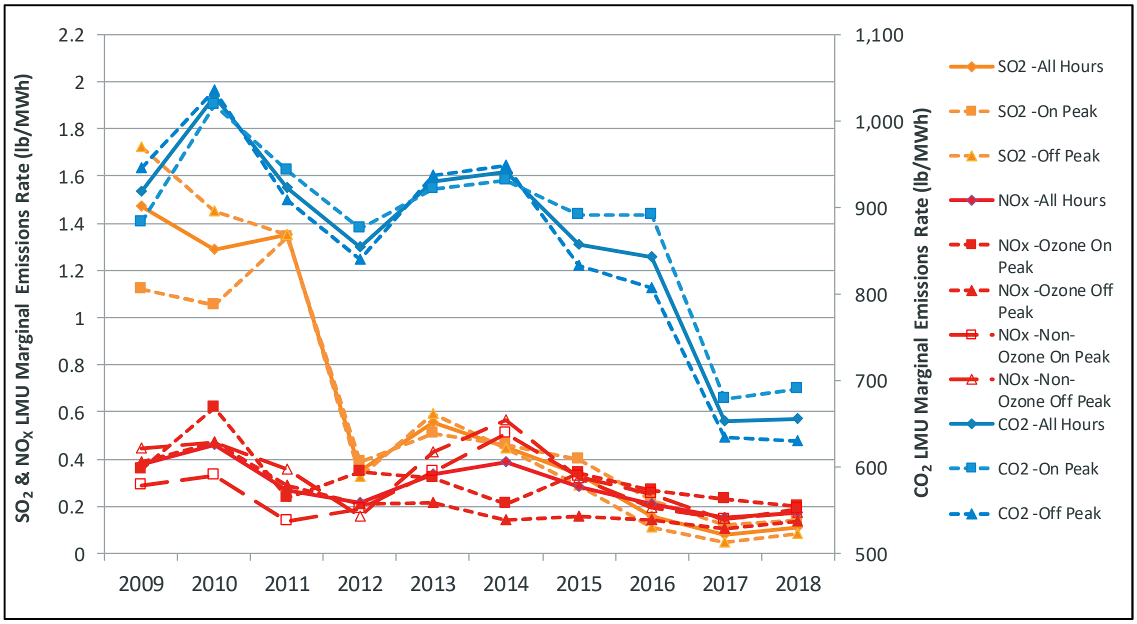

Figure 5-9: Time-weighted LMU marginal emission rates, 2009 to 2018—all LMUs (lbs/MWh).

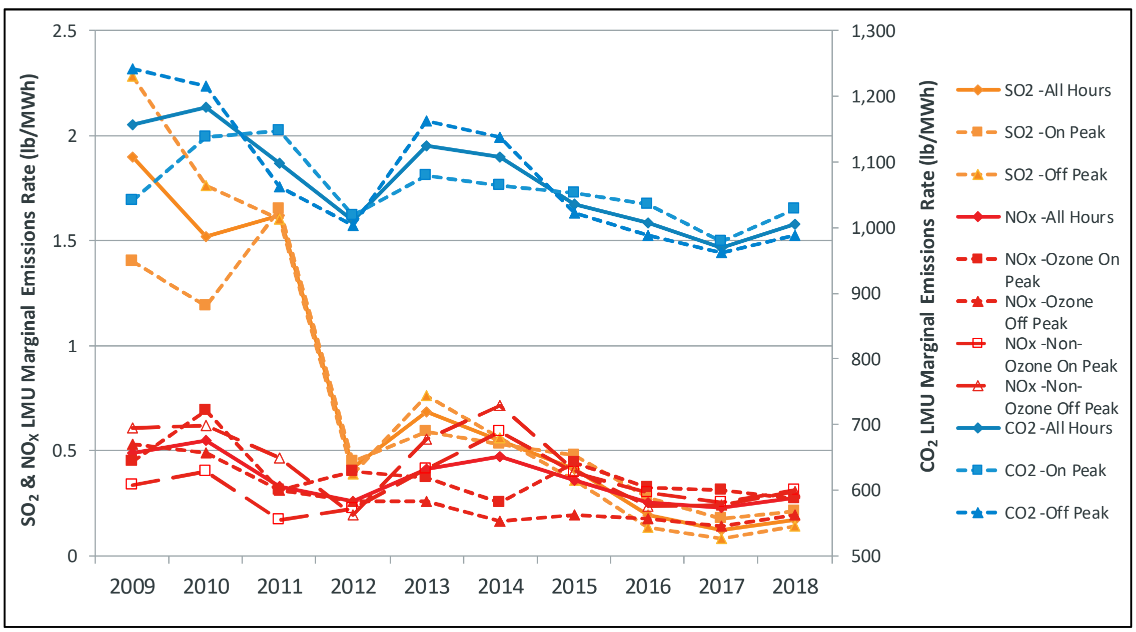

Figure 5-10: Time-weighted LMU marginal emission rates, 2009 to 2018—emitting LMUs (lbs/MWh).

5.3.2 Marginal Emission Rates Using the Load-Weighted Approach

5.3.2.1 All-LMU Scenario

The 2018 load-weighted, all-LMU marginal emission rates were calculated based on the percentage of load served by all marginal units. Table 5-5 shows the rates in lbs/MWh. Appendix Table 18 shows these rates in lbs/MMBtu, with the associated marginal heat rate of 5.962 MMBtu/MWh used as the conversion factor. Figure 5-11, which shows the monthly load-weighted LMU marginal emission rates, can be compared with Figure 4-6 (showing the 2018 percentage of load for which various fuel types were marginal for all LMUs) and Figure 5-3 (showing the 2018 ISO New England system monthly average NO_X, SO_2, and CO_2 emission rates). Appendix Table 19 lists the values behind Figure 5-11.

Table 5-5
2018 Load-Weighted LMU Marginal Emission Rates—All LMUs (lbs/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	0.19	0.14	0.25	0.22	0.20
Annual Emissions (SO_2 and CO_2)					
Air Emission		Annual			Annual Average (All Hours)
		On-Peak	Off-Peak		
SO_2		0.16	0.11		0.13
CO_2		779	720		745

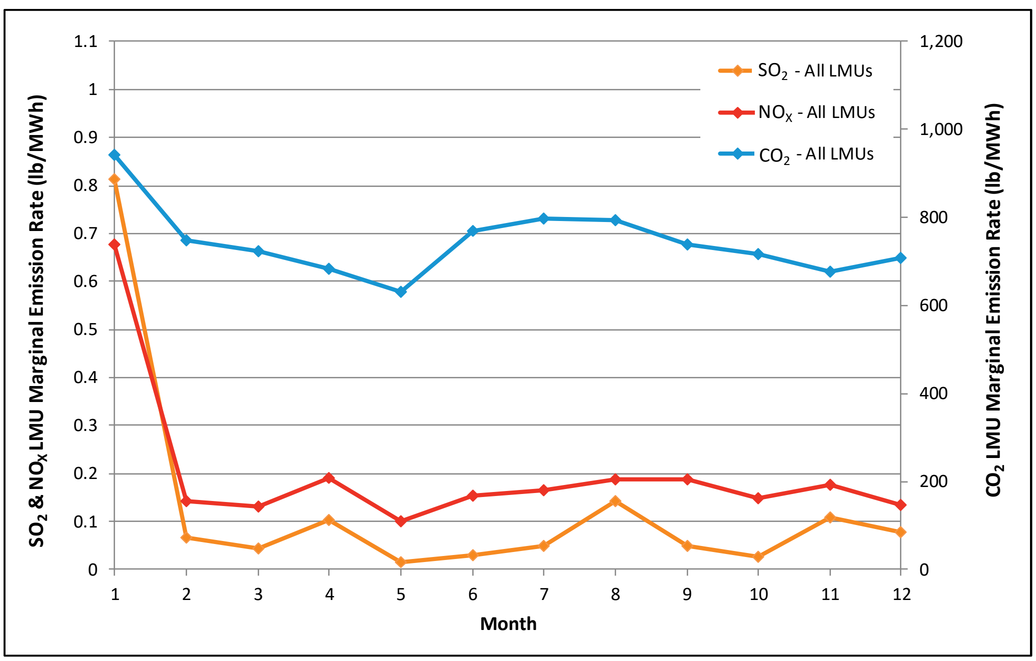

Figure 5-11: 2018 load-weighted monthly LMU marginal emission rates—all LMUs (lbs/MWh).

5.3.2.2 Emitting-LMU Scenario

Table 5-6 and Appendix Table 20 present the load-weighted marginal emission rates for emitting LMUs. The marginal heat rate for this scenario is 7.744 MMBtu/MWh. The values for the monthly rates shown in Figure 5-12 are shown inAppendix Table 21.

Table 5-6
2018 Load-Weighted LMU Marginal Emission Rates—Emitting LMUs (lbs/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	0.25	0.18	0.32	0.31	0.27
Annual Emissions (SO_2 and CO_2)					
Air Emission		Annual			Annual Average (All Hours)
		On-Peak	Off-Peak		
SO_2		0.20	0.14		0.16
CO_2		987	960		971

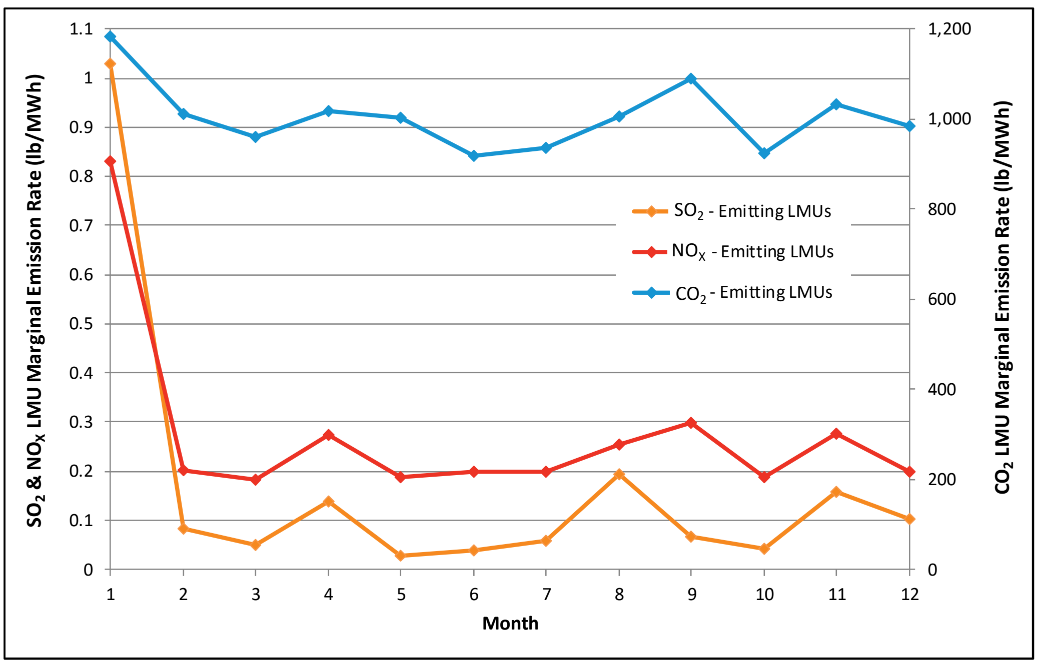

Figure 5-12: 2018 load-weighted monthly LMU marginal emission rates—emitting LMUs (lbs/MWh).

5.3.3 Comparison of Marginal Emission Rates Using the Time- and Load-Weighted Approaches

As shown in Table 5-7, the 2018 load-weighted marginal emission rates for the all-LMU scenario are significantly higher than the time-weighted marginal emission rates. This is because the load-weighted approach takes into consideration the fact that most of the wind units are located in export-constrained areas of northern New England and therefore set price for a small percentage of the system load. This in turn reduces the contribution of wind units to the marginal emission rates, resulting in higher average marginal rates. With the time-weighted approach, these constrained wind resources are given equal weight with other generators that set price for the remainder of the region, resulting in lower marginal emission rates. The contrast between the treatment of the LMUs can be seen in Figure 4-12, which compares the annual marginality for various fuel types based on the time-weighted vs. load-weighted approach for all LMUs.

In the case of the emitting-LMU scenario, the load-weighted marginal emission rates are lower than the time-weighted rates. This is because there are a significant number of emitting LMUs, primarily wood-burning plants, in export-constrained areas. Refer to Figure 4-13 for a comparison of the annual marginality calculated with the time-weighted vs. load-weighted approaches for the emitting-LMU scenario.

Table 5-7
2018 Time-Weighted and Load-Weighted LMU Marginal Emission Rates (lbs/MWh)

LMU Marginal Emissions			
	2018 Time-Weighted Annual Rate	2018 Load-Weighted Annual Rate	2018 Load Weighted vs. 2018 Time-Weighted
	(lbs/MWh)	(lbs/MWh)	(%)
All LMUs			
NO_X	0.17	0.20	17.6
SO_2	0.11	0.13	18.2
CO_2	655	745	13.7
Emitting LMUs			
NO_X	0.28	0.27	-3.6
SO_2	0.17	0.16	-5.9
CO_2	1,005	971	-3.4

Figure 5-13, Figure 5-14, and Figure 5-15 illustrate the differences between the load-weighted and time-weighted LMU monthly marginal emission rates for the all-LMU and emitting-LMU scenarios. In general, the greatest differences in the monthly rates for the all-LMU scenario occur during the non-summer months, when wind units are on the margin more often. During those months, the load-weighted LMU approach results in higher marginal rates due to the lower impact of wind. For the emitting-LMU scenario, the differences resulting from the two approaches are most apparent in those months that Other Renewables, primarily consisting of wood-burning units, are on the margin more often. In this case, the marginal rates calculated using the load-weighted approach are lower than those using the time-weighted approach.

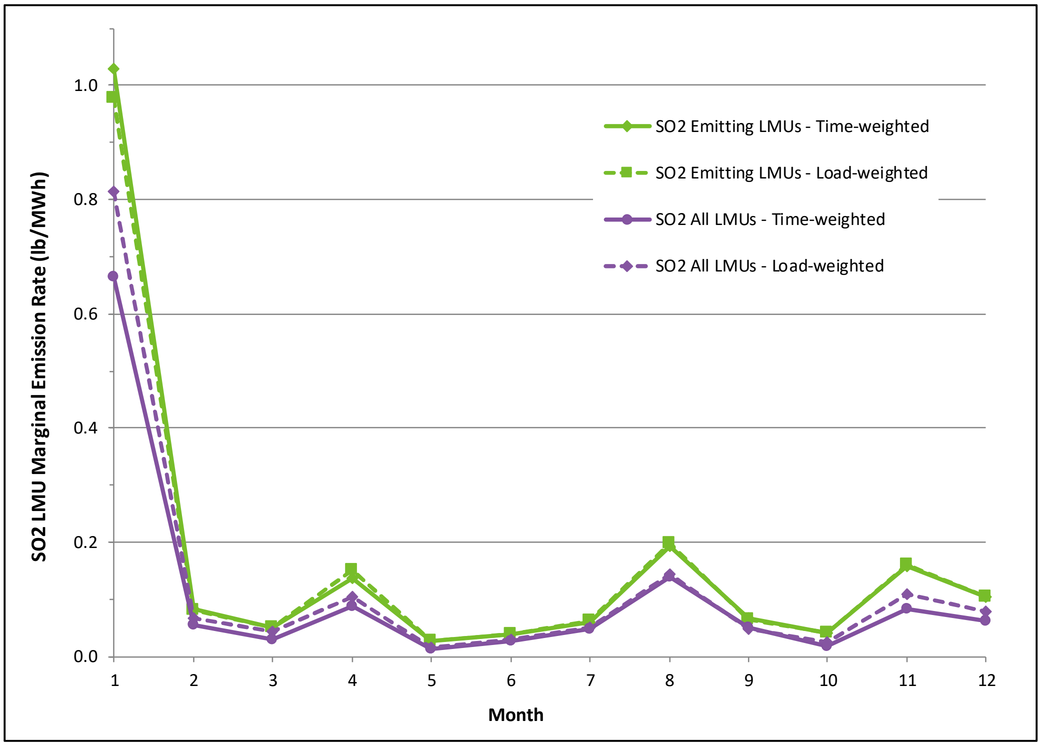

Figure 5-13: 2018 time- and load-weighted monthly LMU marginal SO_2 emission rates.

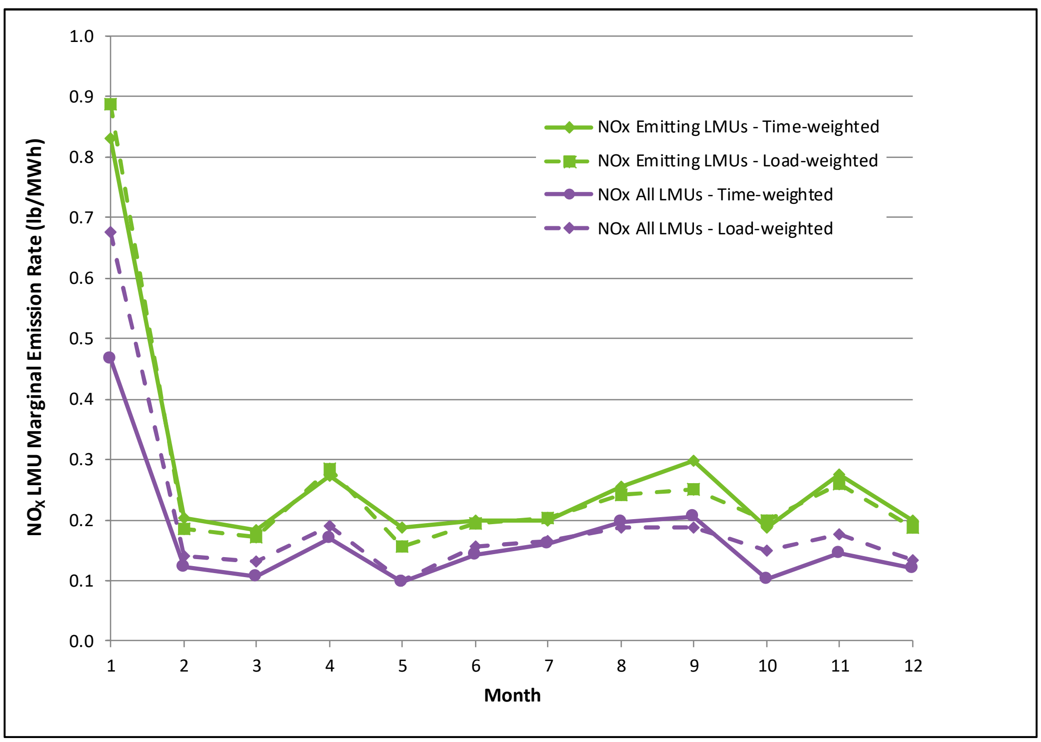

Figure 5-14: 2018 time- and load-weighted monthly LMU marginal NO_X emission rates.

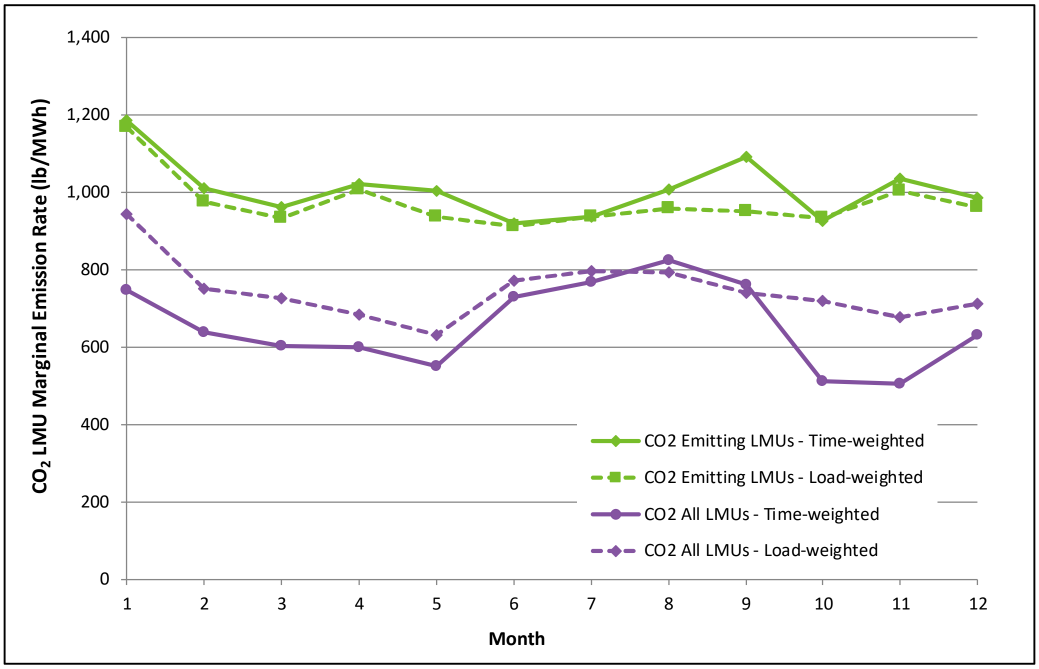

Figure 5-15: 2018 time- and load-weighted monthly LMU marginal CO_2 emission rates.

5.4 Marginal Emission Rates for High Electric Demand Days

Using the LMU methodology, the top-five high electric demand days in 2018 were examined. In 2018, the top five HEDDs were July 5, and August 6, 7, 28, and 29. The temperatures in New England during these days ranged from 89° to 93°F. Peak daily loads ranged from 24,512 MW on Thursday, July 5, to a high of 26,024 MW on Wednesday, August 29. Table 5-8 shows the average LMU marginal emission rate during these five days.

Table 5-8
High Electric Demand Day LMU Marginal Emission Rates (lbs/MWh)

HEDD LMU Marginal Emission Rate (lbs/MWh)				
	Time-Weighted		Load-Weighted	
	All LMUs	Emitting LMUs	All LMUs	Emitting LMUs
NO_X	0.60	0.82	0.61	0.83
SO_2	0.57	0.72	0.59	0.74
CO_2	902	1,201	933	1,209

5.5 Observations

ISO 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, also affect emissions. The LMU marginal emission rates reflect the dynamics of the ISO New England power system.

The time-weighted LMU annual marginal rates for SO_2, NO_X, and CO_2 have exhibited an overall decrease during the past ten years. Compared with 2009, the 2018 LMU SO_2 annual marginal rates have declined by over 90% 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 there was an increase in natural gas units on the margin combined with a significant decrease in marginal coal-fired units. In the case of marginal NO_X emission rates, there have been declines of 55% and 43% for the all-LMU and emitting-LMU scenarios, respectively, since 2009. During that period, the CO_2 rates have declined by 29% for the all-LMU scenario and 13% for the emitting-LMU scenario.

The greatest drop in the time-weighted all-LMU marginal CO_2 rate over the past ten years occurred in 2017, due to wind units being marginal a significant percentage of the time beginning that year. The load-weighted LMU marginal emission rates for the all-LMU scenario, which reflect the fact that wind is marginal for only a small percentage of the total system load, are significantly higher than the time-weighted rates. They range from 14% higher for CO_2 to 18% higher for both NO_X and SO_2. For the emitting LMU-scenario, the load-weighted rates are 3% to 6% lower than the time-weighted rates.

In 2018, the on-peak marginal rates for SO_2, CO_2, and NO_X were higher than the off-peak rates. This is likely due to the operation of older, less-efficient peaking units (jets or combustion turbines) dispatched to meet peak load.

Despite declines in the time-weighted LMU marginal emission rates since at least 2014, there was an uptick in all of the rates in 2018. This was most likely due to the significant amount of time that oil units were marginal during the January cold wave, as well as the increased time that emitting generators in the Other Renewables category were marginal (see Figure 4-9). A decrease in the amount of wind on the margin may also have had an impact. The changes in the marginal rates in 2018 were more dramatic than the changes in the system rates. The NO_X annual average marginal rates increased by 13% and 22% for the all-LMU and emitting-LMU scenarios, respectively, while there was no change in the NO_X system rate. The all-LMU and emitting-LMU marginal emission rates for SO_2 increased by around 40% in 2018, but there was only a 25% increase in the system rate. For CO_2, there was no change in the all-LMU marginal rate and the emitting-LMU rate increased by 3.5%. In contrast, the CO_2 system emission rate decreased by 3.5%.

Section 6
Appendix

Appendix Table 1
ISO New England Total Cooling and Heating Degree Days, 1999 to 2018

Year	Total Cooling Degree Days	Difference from Average (%)	Total Heating Degree Days	Difference from Average (%)
1999	360	8.8%	5,774	-3.8%
2000	211	-36.2%	6,380	6.3%
2001	319	-3.6%	5,870	-2.2%
2002	353	6.7%	5,938	-1.1%
2003	350	5.8%	6,628	10.4%
2004	249	-24.7%	6,332	5.5%
2005	417	26.0%	6,331	5.4%
2006	334	1.0%	5,532	-7.9%
2007	287	-13.3%	6,153	2.5%
2008	278	-16.0%	6,027	0.4%
2009	223	-32.6%	6,272	4.5%
2010	403	21.8%	5,636	-6.1%
2011	354	7.0%	5,802	-3.4%
2012	350	5.8%	5,285	-12.0%
2013	398	20.3%	6,137	2.2%
2014	238	-28.1%	6,299	4.9%
2015	334	1.0%	6,080	1.3%
2016	351	6.1%	5,705	-5.0%
2017	309	-6.6%	5,839	-2.7%
2018	499	50.8%	6,060	0.9%
Average	331		6,004	

Appendix Table 2
2018 ISO New England Summer Generating Capacity (MW, %)[a, b]

	Connecticut		Massachusetts		Maine		New Hampshire		Rhode Island		Vermont	
Unit Type	**MW**	**%**	**MW**	**%**	**MW**	**%**	**MW**	**%**	**MW**	**%**	**MW**	**%**
Coal	383.4	4.2	-	-	-	-	530.6	12.8	-	-	-	-
Natural Gas	3,747.0	40.8	6,319.3	55.3	1,574.4	51.3	1,240.7	29.9	1,889.0	97.1	-	-
Nuclear	2,073.1	22.6	-	-	-	-	1,250.4	30.1	-	-	-	-
Oil	2,650.9	28.9	2,537.8	22.2	738.4	24.1	481.4	11.6	-	-	132.4	31.1
Hydro	90.9	1.0	182.9	1.6	452.4	14.8	417.7	10.1	0.7	0.0	194.9	45.7
Pumped Storage	28.7	0.3	1,759.5	15.4	-	-	-	-	-	-	-	-
Solar	13.1	0.1	373.1	3.3	4.9	0.2	1.2	0.0	20.2	1.0	-	-
Wind	-	-	9.6	0.1	97.9	3.2	18.4	0.4	8.8	0.5	17.9	4.2
Other Renewables	187.3	2.0	244.4	2.1	198.9	6.5	213.5	5.1	26.6	1.4	80.8	19.0
Total	9,174.4	100.0	11,426.7	100.0	3,067.0	100.0	4,153.8	100.0	1,945.3	100.0	426.1	100.0

(a) Sum may not equal total due to rounding.
(b) Seasonal Claimed Capability as of January 1, 2019.

Appendix Table 3
2018 ISO New England Winter Generating Capacity (MW, %)[a, b]

	Connecticut		Massachusetts		Maine		New Hampshire		Rhode Island		Vermont	
Unit Type	**MW**	**%**	**MW**	**%**	**MW**	**%**	**MW**	**%**	**MW**	**%**	**MW**	**%**
Coal	382.5	3.9	-	-	-	-	534.7	12.1	-	-	-	-
Natural Gas	4,133.8	41.9	7,144.5	56.0	1,772.4	47.9	1,370.8	31.1	2,120.9	97.7	-	-
Nuclear	2,092.7	21.2	680.6	5.3	-	-	1,251.4	28.4	-	-	-	-
Oil	2,919.2	29.6	2,690.6	21.1	859.7	23.2	501.7	11.4	-	-	167.8	31.9
Hydro	107.7	1.1	213.5	1.7	573.3	15.5	483.0	11.0	1.9	0.1	230.0	43.7
Pumped Storage	28.4	0.3	1,755.6	13.8	-	-	-	-	-	-	-	-
Solar	3.1	0.0	3.6	0.0	0.1	0.0	-	-	0.3	0.0	-	-
Wind	-	-	20.8	0.2	279.8	7.6	46.8	1.1	21.6	1.0	46.1	8.8
Other Renewables	194.1	2.0	252.4	2.0	217.8	5.9	214.6	4.9	25.4	1.2	82.8	15.7
Total	9,861.4	100.0	12,761.6	100.0	3,703.1	100.0	4,403.0	100.0	2,170.2	100.0	526.6	100.0

(a) Sum may not equal total due to rounding.
(b) Seasonal Claimed Capability as of January 1, 2019.

Appendix Table 4
ISO New England System
Annual Generator Emissions, 2001 to 2018 (kilotons)[a]

Year	NOx	SO_2	CO_2	
	kilotons (short)	kilotons (short)	kilotons (short)	kilotons (metric)
2001	59.73	200.01	52,991	48,073
2002	56.40	161.10	54,497	49,439
2003	54.23	159.41	56,278	51,055
2004	50.64	149.75	56,723	51,458
2005	58.01	150.00	60,580	54,957
2006	42.86	101.78	51,649	46,855
2007	35.00	108.80	59,169	53,677
2008	32.57	94.18	55,427	50,283
2009	27.55	76.85	49,380	44,797
2010	28.79	80.88	52,321	47,465
2011	25.30	57.01	46,959	42,601
2012	20.32	16.61	41,975	38,079
2013	20.32	18.04	40,901	37,105
2014	20.49	11.67	39,319	35,670
2015	18.86	9.11	40,312	36,570
2016	16.27	4.47	37,467	33,990
2017	15.30	4.00	34,969	31,723
2018	15.61	4.96	34,096	30,931
Percent Reduction, 2001-2018	74	98	36	36

(a) Since greenhouse gas data is often expressed in metric tons, an additional column showing CO_2 emissions in metric kilotons is included in this table. A metric ton is approximately 2,205 lbs.

Appendix Table 5
2018 ISO New England System
Average Monthly Generator Emission Rates (lbs/MWh)

Monthly System Emission Rates (lb/MWh)			
Month	NO_X	SO_2	CO_2
1	0.53	0.46	787
2	0.30	0.07	623
3	0.28	0.05	621
4	0.28	0.10	583
5	0.26	0.04	527
6	0.28	0.04	631
7	0.26	0.08	701
8	0.26	0.05	705
9	0.28	0.04	678
10	0.31	0.04	742
11	0.29	0.08	643
12	0.27	0.06	596

Appendix Table 6
ISO New England System
Annual Average Generator Emission Rates, 1999 to 2018 (lbs/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
2015	107,916	0.35	0.17	747
2016	105,570	0.31	0.08	710
2017	102,562	0.30	0.08	682
2018	103,740	0.30	0.10	658
Percent Reduction, 1999 - 2018		78	98	35

Appendix Table 7
LMU Marginal Heat Rate, 2009 to 2018 (MMBtu/MWh)

LMU Marginal Heat Rate (MMBtu/MWh)				
	Time-Weighted		Load-Weighted	
Year	All Marginal LMUs	Emitting LMUs	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		
2015	6.707	8.096		
2016	6.625	7.925		
2017	5.428	8.043		
2018	5.153	7.855	5.962	7.744

Appendix Table 8
2018 Time-Weighted LMU Marginal Emission Rates—All LMUs (lbs/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	0.038	0.026	0.036	0.033	0.033
Annual Emissions (SO_2 and CO_2)					
Air Emission		Annual			Annual Average (All Hours)
		On-Peak	Off-Peak		
SO_2		0.027	0.016		0.021
CO_2		134	122		127

Appendix Table 9
2018 Monthly Time-Weighted LMU Marginal Emission Rates—All LMUs (lbs/MWh)

LMU Marginal Emission Rates (lb/MWh)			
Month	NO_X	SO_2	CO_2
1	0.47	0.66	746
2	0.12	0.05	638
3	0.11	0.03	603
4	0.17	0.09	598
5	0.10	0.01	550
6	0.14	0.03	727
7	0.16	0.05	767
8	0.20	0.14	825
9	0.21	0.05	761
10	0.10	0.02	512
11	0.15	0.08	505
12	0.12	0.06	629

Appendix Table 10
2018 Time-Weighted LMU Marginal Emission Rates—Emitting LMUs (lbs/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	0.035	0.025	0.040	0.039	0.035
Annual Emissions (SO_2 and CO_2)					
Air Emission		Annual			Annual Average (All Hours)
		On-Peak	Off-Peak		
SO_2		0.027	0.018		0.021
CO_2		131	126		128

Appendix Table 11
2018 Monthly Time-Weighted LMU Marginal Emission Rates—Emitting LMUs (lbs/MWh)

LMU Marginal Emission Rates (lb/MWh)			
Month	NO_X	SO_2	CO_2
1	0.83	1.03	1,184
2	0.20	0.08	1,010
3	0.18	0.05	959
4	0.27	0.14	1,019
5	0.19	0.03	1,003
6	0.20	0.04	917
7	0.20	0.06	936
8	0.26	0.19	1,005
9	0.30	0.07	1,091
10	0.19	0.04	924
11	0.28	0.16	1,034
12	0.20	0.10	986

Appendix Table 12
NO_X Time-Weighted LMU Marginal Emission Rates, 2009 to 2018 —All LMUs (lbs/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
2015	0.34	0.16	0.32	0.32	0.28	-27.2
2016	0.26	0.14	0.25	0.19	0.21	-25.0
2017	0.23	0.11	0.14	0.15	0.15	-28.6
2018	0.20	0.14	0.19	0.17	0.17	13.3
% Change 2009 - 2018	-45.1	-65.0	-35.2	-62.0	-55.0	

Appendix Table 13
NO_X Time-Weighted LMU Marginal Emission Rates, 2009 to 2018—Emitting LMUs (lbs/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
2015	0.44	0.19	0.39	0.41	0.36	-23.5
2016	0.33	0.18	0.30	0.24	0.25	-30.6
2017	0.31	0.14	0.25	0.24	0.23	-8.0
2018	0.27	0.20	0.31	0.31	0.28	21.7
% Change 2009 - 2018	-39.1	-62.9	-6.5	-49.1	-43.1	

Appendix Table 14
SO_2 Time-Weighted LMU Marginal Emission Rates, 2009 to 2018—All LMUs (lbs/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
2015	0.40	0.29	0.33	-26.8
2016	0.22	0.11	0.16	-51.5
2017	0.12	0.05	0.08	-50.0
2018	0.14	0.08	0.11	37.5
% Change 2009 - 2018	-87.4	-95.1	-92.5	

Appendix Table 15
SO_2 Time-Weighted LMU Marginal Emission Rates, 2009 to 2018—Emitting LMUs (lbs/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
2015	0.48	0.36	0.41	-25.5
2016	0.28	0.13	0.19	-53.7
2017	0.18	0.08	0.12	-36.8
2018	0.21	0.14	0.17	41.7
% Change 2009 - 2018	-85.0	-93.9	-91.1	

Appendix Table 16
CO_2 Time-Weighted LMU Marginal Emission Rates, 2009 to 2018—All LMUs (lbs/MWh)

Year	On-Peak	Off-Peak	Annual Average (All Hours)	Annual Average Percentage Change
2009	882	946	919	-
2010	1,019	1,036	1,029	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
2015	891	832	857	-9.0
2016	892	807	842	-1.7
2017	681	635	654	-22.3
2018	690	630	655	0.2
% Change 2009 - 2018	**-21.7**	**-33.4**	**-28.7**	

Appendix Table 17
CO_2 Time-Weighted LMU Marginal Emission Rates, 2009 to 2018—Emitting LMUs (lbs/MWh)

Year	On-Peak	Off-Peak	Annual Average (All Hours)	Annual Average Percentage Change
2009	1,042	1,242	1,157	-
2010	1,138	1,215	1,183	2.2
2011	1,148	1,061	1,097	-7.3
2012	1,019	1,003	1,010	-7.9
2013	1,079	1,163	1,125	11.4
2014	1,064	1,138	1,107	-1.6
2015	1,053	1,023	1,036	-6.4
2016	1,035	987	1,007	-2.8
2017	981	964	971	-3.6
2018	1,028	989	1,005	3.5
% Change 2009 - 2018	**-1.4**	**-20.3**	**-13.1**	

Appendix Table 18
2018 Load-Weighted LMU Marginal Emission Rates—All LMUs (lbs/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	0.032	0.023	0.041	0.037	0.034
Annual Emissions (SO_2 and CO_2)					
Air Emission		Annual			Annual Average (All Hours)
		On-Peak	Off-Peak		
SO_2		0.027	0.018		0.022
CO_2		131	121		125

Appendix Table 19
2018 Monthly Load-Weighted LMU Marginal Emission Rates—All LMUs (lbs/MWh)

LMU Marginal Emission Rates (lb/MWh)			
Month	NO_X	SO_2	CO_2
1	0.68	0.81	943
2	0.14	0.07	749
3	0.13	0.04	724
4	0.19	0.10	684
5	0.10	0.01	630
6	0.16	0.03	771
7	0.17	0.05	796
8	0.19	0.14	793
9	0.19	0.05	740
10	0.15	0.03	718
11	0.18	0.11	676
12	0.13	0.08	709

Appendix Table 20
2018 Load-Weighted LMU Marginal Emission Rates—Emitting LMUs (lbs/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	0.032	0.024	0.041	0.040	0.035
Annual Emissions (SO_2 and CO_2)					
Air Emission		Annual			Annual Average (All Hours)
		On-Peak	Off-Peak		
SO_2		0.026	0.018		0.021
CO_2		127	124		125

Appendix Table 21
2018 Monthly Load-Weighted LMU Marginal Emission Rates—Emitting LMUs (lbs/MWh)

LMU Marginal Emission Rates (lb/MWh)			
Month	NO_X	SO_2	CO_2
1	0.89	0.98	1,166
2	0.19	0.08	973
3	0.17	0.05	933
4	0.28	0.15	1,005
5	0.16	0.03	937
6	0.19	0.04	909
7	0.20	0.06	934
8	0.24	0.20	957
9	0.25	0.06	950
10	0.20	0.04	931
11	0.26	0.16	1,000
12	0.19	0.10	958